2024 General Power System Risk Review – Appendices

July 2024

Final report

A report for the National Electricity Market

Important notice

Please refer to the notice at the front of the 2024 General Power System Risk Review Final Report, which is published under clause 5.20A.3 of the National Electricity Rules. The Appendices in this document form part of that final report and are subject to the same disclaimer.

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Version control

Version	Release date	Changes
2.0	25/07/2024	Publication of final report

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Abbreviations

Abbreviation	Term	Abbreviation	Term
1P	single-phase	MWs	megawatt second/s
2ph-G	two phase-to-ground	NEM	National Electricity Market
3P	three-phase	NEMDE	National Electricity Market Dispatch Engine
3ph-G	three phase-to-ground	NEMOC	National Electricity Market Operations Committee
AC	alternating current	NER	National Electricity Rules (NER followed by a number indicates that numbered rule or clause of the NER)
AEC	Australian Energy Council	NERC	North American Electric Reliability Corporation
AEMC	Australian Energy Market Commission	NMAS	non-market ancillary services
APD	Alcoa Portland	NMI	National Metering Identifier
ARENA	Australian Renewable Energy Agency	NSCAS	network support and control ancillary services
ASCC	Automatic Sequencing Fault Calculation	NSP	network service provider
ASEFS2	Australian Solar Energy Forecasting System Phase 2	ODP	optimal development path
AVP	AEMO Victorian Planning	OEM	original equipment manufacturer/s
AVR	automatic voltage regulator	OFGS	over frequency generation shedding
BESS	battery energy storage system/s	OPDMS	Operations and Planning Data Management System
CB	circuit breaker	PASA	projected assessment of system adequacy
CBF	circuit breaker failure	PSDCS	Power System Data Communication Standard
CER	consumer energy resources	PD	pre-dispatch
CMLD	composite load model	PEC	Project EnergyConnect
CT	current transformer	PFR	primary frequency response
DER	distributed energy resources	PFRR	primary frequency response requirements
DNSP	distribution network service provider	PMU	phasor measurement unit
DPTS	Deer Park Terminal Station	POE	probability of exceedance
DPV	distributed photovoltaics	PSCAD™	Power System Computer Aided Design
DWDM	dense wavelength-division multiplexing	PSFRR	Power System Frequency Risk Review
EAPT	Emergency Alcoa-Portland Potline Tripping	PSS®E	Power System Simulation for Engineering
EFCS	emergency frequency control scheme	PSSG	Power System Security Guidelines
EMS	energy management system	PSSWG	Power System Security Working Group
EMT	electromagnetic transient	PST	phase shifting transformer
ESOO	electricity statement of opportunities	pu	per unit
ESS	essential system services	PV	photovoltaics
EUFR	emergency under frequency response	PVNSG	PV non-scheduled generation
FCAS	frequency control ancillary services	QNI	Queensland – New South Wales Interconnector
FFR	fast frequency response	RAS	remedial action scheme
FOS	frequency operating standard	REZ	renewable energy zone
FRT	fault ride-through	RoCoF	rate of change of frequency
FY	financial year	s	second/s

Abbreviation	Term	Abbreviation	Term
GPSRR	general power system risk review	SAIT RAS	South Australia Interconnector Trip Remedial Action Scheme
GW	gigawatt/s	SC	synchronous condenser/s
HIC	Heywood interconnector	SCADA	supervisory control and data acquisition
HV	high voltage	SESS	South East Switching Station
HVDC	high voltage direct current	SIPS	system integrity protection scheme
HYTS	Heywood Terminal Station	SISC	System Integration Steering Committee
Hz	hertz	SPS	special protection scheme/s
Hz/s	hertz per second	SVC	static VAR compensator
IBR	inverter-based resources	TIPS	Torrens Island Power Station
ICCP	Inter-Control Centre Communications Protocol	TNSP	Transmission Network Service Provider
IECS	interconnector emergency control scheme	ToR	terms of reference
IRR	interim reliability reserves	TUoS	Transmission Use of System
ISP	*Integrated System Plan*	UEL	under excitation limiter
KTS	Keilor Terminal Station	UFLS	under frequency load shedding
kV	kilovolt/s	VAR	volt-ampere reactive
kW	kilowatt/s	VNI	Victoria – New South Wales Interconnector
LCC	line commutated converter	VPP	virtual power plant
MASS	Market Ancillary Service Specification	VRE	variable renewable energy
MLTS	Moorabool Terminal Station	VSC	voltage source converter
ms	millisecond/s	WAMPAC	wide area monitoring protection and control
MV	medium voltage	WAMS	wide area monitoring scheme
MVA	megavolt ampere/s	WAPS	wide area protection scheme
MVAr	megavolt amperes reactive	WEM	Wholesale Electricity Market
MW	megawatt/s	WSB	Waratah Super Battery

Key terms

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
Satisfactory operating state	The power system is in a satisfactory operating state when all of the following apply: • 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 both: • The power system is in a satisfactory operating state.

Term	Definition
	• The power system will return to a satisfactory operating state following any credible contingency event.
Credible contingency event, or credible contingency	A contingency event is considered credible when AEMO considers its occurrence 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 (for example, a 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, or non-credible contingency	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).
Protected event	A non-credible contingency event that the Reliability Panel has declared to be a protected event under NER 8.8.4 after consultation on a request made by AEMO, where that declaration has not been revoked.

A1. Status of actions arising from recent major incidents

Table 1 presents a summary and update of the status of recommendations arising from major reviewable power system incidents that occurred since 2018-19. Actions reported as Closed in the 2023 General Power System Risk Review (GPSRR) are not included in the below table.

Table 1 Status of actions arising from major reviewable incidents

Incident	Recommendation	Status	Details
25 August 2018 – Queensland and South Australia system separation	**Circumstances for regional FCAS or frequency control** AEMO to investigate whether a minimum regional frequency control ancillary services (FCAS) requirement is feasible, or whether there is scope to manage frequency requirements arising from non-credible regional separation under the protected events framework in the National Electricity Rules (NER) after interim primary frequency control outcomes at the end of Q3 2019.	Closed	FCAS is only procured to cover credible events. Since the commencement of primary frequency response (PFR) implementation in 2020, a material improvement in frequency performance on the power system has been observed, lessening the impact of non-credible events. Following implementation of very fast FCAS[1], considering the effective PFR roll out and the significant challenges associated with the roll out of regional FCAS or frequency control AEMO does not see a sufficient benefit of implementing regional FCAS or frequency control and is therefore not progressing this initiative.
	Frequency response capability models Commencing in Q1 2019, AEMO to work with participants to obtain information required to fully and accurately model generator frequency response and all other active power controls.	Closed	AEMO continues to work with generators in monitoring their compliance obligations. AEMO plans greater collaboration with network service providers (NSPs) to ensure accuracy of generator models. As part of this collaboration AEMO wrote to all Generators with PFR-enabled synchronous generating units in September 2021, asking them to confirm that their Operations and Planning Data Management System (OPDMS) PSS®E models are up to date and reflects each generating unit's response to frequency events, or otherwise provide updates to the relevant NSP and AEMO. AEMO will continue to engage with Generators to ensure their models are updated as part of business as usual processes and is therefore closing this recommendation.
	Emergency frequency control schemes AEMO to continue implementation and investigate any further functional requirements of emergency frequency control schemes (EFCSs) for each region, commencing with South Australia and Queensland prior Q1 2020.	Ongoing	South Australia and Western Victoria over frequency generation shedding (OFGS): ElectraNet has implemented updated settings with approximately half of the required participants in South Australia. AEMO Victorian Planning (AVP) has implemented updated settings with a generator in South West Victoria, other generator settings may also be updated through ongoing operational improvement.

[1] As required by the National Electricity Amendment (Fast frequency response market ancillary service) Rule 2021 No. 8, https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

Incident	Recommendation	Status	Details
			Queensland OFGS: AEMO has identified a requirement to implement an OFGS in Queensland to help mitigate over frequency events, such as those due to Queensland – New South Wales Interconnector (QNI) tripping. AEMO is working on the design in consultation with Powerlink, which is planned for completion by Q3 2024. Following the detailed design, AEMO will cooperate with Powerlink as needed on the procurement, implementation, and commissioning schedule.
16 November 2019 – South Australia and Victoria separation	**Compliance of distributed photovoltaics (DPV) systems** AEMO and distribution network service providers (DNSPs) to work on auditing and establishment of methods for monitoring and improving compliance of DPV systems.	Open	AEMO's analysis has found significant improvement in compliance, increasing from just under 40% compliance in early 2022[2] to an estimated 75-80% compliance in early 2023[3]. AEMO continues to recommend a target of at least 90% of inverters installed from December 2023 compliant to the 2020 Standard, with further improvement thereafter. Work programs with original equipment manufacturers (OEMs), DNSPs and other stakeholders are continuing. AEMO is tracking compliance rates and working with DNSPs to ensure improvement opportunities are acted upon promptly.
4 January 2020 – New South Wales and Victoria Separation Event	**Review of PASA tools** Projected assessment of system adequacy (PASA) did not correctly determine reserve levels in New South Wales after islanding due to the effective change in region boundaries.	Open	AEMO is currently undertaking the Short Term (ST) PASA Replacement project which will incorporate the recommendations from this incident. The planning phase of this project has been completed which included the development of a high level design of the new ST PASA. To allow AEMO to implement the new design, AEMO proposed a rule change to ST PASA in August 2021. AEMC published the final rule change in May 2022 which becomes effective on 31 July 2025. The project is now in its final phase which includes development of the detailed design and formal procedure consultation followed by implementation of the new system. The project is facing some unplanned delays and AEMO will be working with stakeholders on options to provide the most effective and timely benefits.
	Visibility of DPV systems Visibility of distributed energy resources (DER) is becoming increasingly important for assessment and management of power system security. AEMO in collaboration with other stakeholders is continuing work to improve data sources, analysis tools, and power system models to investigate and represent distributed energy resources accurately.	Closed	AEMO continues to work with stakeholders on uplift of DER visibility, including: • Interval datasets (~5 s) for an adequate sample of individual DER devices to estimate fleet field behaviours in disturbances. • High speed datasets (~20 milliseconds (ms) or faster) at representative locations in transmission network service provider (TNSP) and DNSP

[2] AEMO (April 2023) *Compliance of Distributed Energy Resources with Technical Settings*, https://aemo.com.au/-/media/files/initiatives/der/2023/2023-04-27-compliance-of-der-with-technical-settings.pdf?la=en&hash=19A1CACD35565DAC69610542B2292DB3.

[3] AEMO (December 2023) *Compliance of Distributed Energy Resources with Technical Settings: Update*, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

Incident	Recommendation	Status	Details
			networks to observe aggregate transient behaviours of loads and DER in disturbances for model calibration. • Improvements to the DER register data quality and periodic updates of aggregate DER installed in AEMO energy management system (EMS) systems. • Improvements to DPV operational forecasting systems.
31 January 2020 – Victoria and South Australia Separation Event	**Alcoa Portland Pty Ltd review options to limit impacts of voltage disturbances** The trip of the Alcoa Portland (APD) potlines was in response to the voltage disturbance caused by line faults. This is a known issue. APD has advised AEMO that it is reviewing options to minimise the impact to the plant during similar events, but has not determined a timeframe for this work.	Open	APD is reviewing options to minimise the impact to the plant during similar events but has not determined a timeframe for this work.
12 March 2021 – Trip of Torrens Island A and B West 275 kilovolt (kV) busbars	**Identify root cause of Torrens CT failure** ElectraNet is working with the current transformer (CT) manufacturer to identify the underlying cause of the failure. Once identified, ElectraNet should share this information with AEMO and undertake any additional remedial actions.	Closed	ElectraNet's investigation into the CT failure has been completed and was unable to identify a root cause. Note that AEMO is also currently reviewing CT failure incidents in South Australia and Queensland.
25 May 2021 – Trip of multiple generators and lines in Central Queensland and associated under-frequency load shedding (UFLS)	AEMO will identify any practical changes to improve the accuracy of demand forecasts following this type of event, including improved visibility, and forecasting of the response of controlled loads.	Open	AEMO is exploring a number of initiatives which it hopes will improve the visibility and predictability of demand-side resources, including: • Visibility of small-to-medium non-scheduled generators and virtual power plant (VPP) through the Scheduled Lite mechanism. • The flow of relevant data from DNSPs to AEMO and TNSPs, including distribution outages and controlled load programs. • Visibility of coordinated and price-sensitive DER.
	CS Energy has undertaken an independent investigation into the root cause of this incident. On completion of CS Energy's independent investigation, the findings will be shared with AEMO. AEMO and CS Energy may identify additional recommendations based on the outcome of this independent investigation.	Open	AEMO is awaiting further information from CS Energy on its independent investigation into the root cause of this incident.
10 June 2022 to 25 June 2022 – National Electricity Market (NEM) suspension and operational challenges in June 2022	AEMO to identify tools and processes needed to cater for energy limitations.	Open	AEMO is currently in the process of identifying tools and processes needed to cater for energy limitations as part of the ST PASA Replacement Project: • The ST PASA Replacement Project involves a comprehensive review of the pre-dispatch (PD) and ST PASA methodology, exploring the development of a system that will serve the NEM now and into the future, noting that the current PD and ST PASA systems were designed when

Incident	Recommendation	Status	Details
			most of the generation in the NEM was supplied from large thermal units connected to the transmission network[4]. • This project includes a review of how the PD and ST PASA systems can best capture the sharing of reserves across different regions and the allocation of energy-limited resources. Note also the related recommendations from the 4 January 2020 New South Wales and Victoria separation event incident.
Trip of Liapootah – Palmerston – Waddamana No 1 and No 2 220 kV lines on 14 October 2022	AEMO recommends TasNetworks considers the installation of line circuit breakers and any associated works to enable the Liapootah – Waddamana and the Waddamana – Palmerston circuits to be sectionalised at Waddamana as part of its plans for Waddamana substation to improve security for the loss of any of the line sections.	Closed	TasNetworks has considered the installation of line circuit breakers to enable the Liapootah – Waddamana and the Waddamana – Palmerston circuits to be sectionalised at Waddamana. TasNetworks included projects which improve system security at Waddamana in its proposed transmission capital expenditure in its 2024-2029 Regulatory Proposal.
	AEMO recommends TasNetworks and Musselroe Wind Farm review the inputs to the Anti-Islanding Scheme to minimise the risk the wind farm disconnects due to Slip Acceleration under similar network conditions.	Open	TasNetworks has advised AEMO that TasNetworks has reviewed the Anti-Islanding Scheme of Musselroe Wind Farm and TasNetworks is further investigating potential settings changes for the scheme. TasNetworks is in the process of considering these potential settings updates and plans to implement any identified changes during the latter part of 2024.
	AEMO recommends Hydro Tasmania implement the under excitation limiter (UEL) function during the automatic voltage regulator (AVR) replacement planned by Hydro Tasmania at Lemonthyme Power Station during 2024. This function should minimise the risk of the power station tripping under similar fault conditions.	Open	Hydro Tasmania is planning to implement the AVR replacement as part of the Lemonthyme Power Station upgrade project. The station outage for these major works is currently scheduled to commence in October 2025 with a return to service in October 2026.
Trip of South East – Tailem Bend 275 kV lines on 12 November 2022	AEMO recommends ElectraNet complete its investigation of the tower failure and advise of any additional risks or need for reclassification to manage system security. Once investigations have been completed later this year, AEMO will publish a supplementary or updated report including further details on the results of ElectraNet's investigations and any further actions ElectraNet is taking or considers it will need to take in response to the tower failure.	Open	ElectraNet's investigations revealed that the combination of the soil condition and the design of the tower has caused this tower to fail. Highly corrosive soil with high variations in water table has caused this tower to deteriorated faster than expected. Deteriorated condition was worse than the forecast model used by ElectraNet. Soil Sample collection for all identified high corrosion exposure locations along the interconnector have been completed. High corrosion exposure sites were identified based on the depth of water table, high content of salinity/salts, soil moisture etc, based on the government sourced data. ElectraNet inspected 25% of the identified high corrosion exposure locations lines in this corridor (there are total 710 towers on this line). Based on the inspection the ElectraNet was able to revalidate the model and remedial actions were made to nine high risk sites. ElectraNet is continuously reviewing the corrosion model and will take necessary actions if similar conditions are identified. The risk of a similar

[4] See https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

Incident	Recommendation	Status	Details
			failure in this transmission corridor or other transmission corridors is considered low.
	AEMO recommends that compliance of DER with technical settings (AS/NZS4777.2:2020) in all regions is improved as an urgent priority, targeting at least 90% of new installations to be set correctly to AS/NZS4777.2:2020 by December 2023. This requires collaborative engagement from many stakeholders.	Open	AEMO released an update to the compliance report in December 2023: https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en. Refer to Section 2.3 in the 2024 GPSRR for more information on DER compliance.
	AEMO recommends SA Power Networks implement improved frameworks in South Australia to achieve consistently high compliance of DPV systems with curtailment requirements (ensuring systems are properly set up, and maintained over time, to deliver curtailment requirements, and can be curtailed in an accurate and timely manner when directed).	Open	AEMO understands SA Power Networks work programs to improve DPV responses to curtailment instructions are in progress through the implementation of the Flexible Exports mechanism.
	AEMO recommends emergency curtailment backstop capabilities are implemented in all regions (ability to curtail all new DPV installations to zero active power if required as a last resort to maintain power system security) as a priority.	Open	AEMO is working with jurisdictions to implement emergency backstop capabilities in all NEM regions.
	By end of 2023, AEMO, SA Power Networks, and the relevant market participants to investigate the availability of DER to deliver FCAS during periods of DPV curtailment.	Open	This investigation is ongoing.
	By Q1 2024, AEMO to develop a plan for implementing fit-for-purpose improvements to tools that monitor the DPV in operation in real time and the visibility of DPV curtailment when it is occurring.	Open	A final scope has been delivered to a vendor for a new ASEFS3 DPV product which aims to improve the real time visibility of DPV estimated actuals. In discussions with SA Power Networks, AEMO has been provided with DPV curtailment availabilities. Further work is required for implementing improvements to nowcasting and forecasting of DPV curtailment in AEMO's systems in real time based on outcomes from discussions with SA Power Networks.
Multiple incidents impacting NEM SCADA between 24 January 2021 and 18 November 2023	• AEMO will meet with each NSP individually by the end of Q2 2024 to share relevant supervisory control and data acquisition (SCADA) questionnaire findings and identify areas for potential improvement. NSPs and AEMO will progress additional actions or recommendations identified during these discussions as appropriate. • At these meetings, AEMO will also confirm with NEM SCADA operators that existing after-hours support arrangements are aligned with meeting the requirements of the Power System Data Communication Standard (PSDCS).	Open	AEMO is currently meeting with individual NSPs to progress this recommendation. To date, 50% of NSP meetings have been completed.
	AEMO will establish a SCADA working group with representatives from NEM and Wholesale Electricity Market (WEM) NSPs, to report to National Electricity Market Operations Committee (NEMOC). The group will be tasked with improving SCADA system resilience and reliability, across the NEM and WEM. The expected outcome is a measured reduction in SCADA outages. The relevant incident report outlines	Closed	The first SCADA working group meeting with representatives from NEM NSPs occurred in May 2024 with the group Terms of Reference agreed thereafter. The group is now meeting at least quarterly to improve SCADA system resilience and reliability.

Incident	Recommendation	Status	Details
	specifics of this recommendation including the key elements of the Terms of Reference.		
	• By the end of Q4 2024, AEMO, in consultation with NSPs, will establish a standardised process for the notification of planned works on NSP and AEMO SCADA systems. • To support this process, AEMO will create a set of guidelines which outline when and how NSPs and participants should notify AEMO of higher risk planned SCADA work.	Open	The NEM SCADA working group is progressing this recommendation.
	NSPs and AEMO to review existing automated backup and failover system testing procedures and identify opportunities for improvements by the end of Q3 2024. Note: AEMO has previously recommended NSPs undertake routine failover testing of their SCADA systems, in the published Victorian Market Suspension market event report[5].	Open	This recommendation has been communicated to NEM NSPs and is being progressed.
	• By the end of Q4 2024, AEMO and NSPs to complete a review of existing SCADA monitoring tools to ensure they are able to promptly identify "downtime" of SCADA services to AEMO at: – The telecommunications level (including telco wide area network monitoring at the bearer and the application-level utilising dedicated tools (where possible)), – The network level, and – The SCADA application level. – Monitoring should occur in real time and allow tracking of trends in historical data. • During the above review, AEMO and NSPs should: – Investigate and, wherever feasible, implement multiple and overlapping EMS/SCADA System monitoring capabilities. These should be deployed within and outside the EMS, including telco bearer monitoring, Inter-Control Centre Communications Protocol (ICCP) Application monitoring, "heart-beat" monitoring and "stale" SCADA data monitoring. – Where possible (and appropriate), consider adding alarms/alerts to monitoring systems to notify operators and support teams whenever "downtime" or other issues are detected. Note: AEMO has previously recommended implementation of suitable alarms and heartbeat displays to alert operators in the published New South Wales market suspension market event report and the total loss of NEM SCADA incident report[6].	Open	This recommendation has been communicated to NEM NSPs and is being progressed.

Incident	Recommendation	Status	Details
	AEMO will address the lack of familiarity with the PSDCS and its requirements among NSPs via the SCADA working group and through the preparation and distribution of training material by Q3 2024.	Open	AEMO has created a summary document of PSDCS and plans to share this with participants and publish it on AEMO's website by Q3 2024 to address this recommendation.
	• By Q4 2024, the SCADA working group will review and update AEMO's proposed standard SCADA incident report information form. Once the proposed standard SCADA incident report information form is finalised by the working group, information related to any SCADA incidents should be recorded in the approved format to ensure consistency. • By Q4 2024, the SCADA working group to review the PSDCS and consider: – Inclusion of a template SCADA Incident Report information form (based on the agreed template above). – A requirement for NSPs to complete and submit the SCADA Incident Report information and root cause identification within 20 business days of the incident date (for incidents where the outage time exceeded the allowable time in the PSDCS). Note: a 20-business day requirement would align SCADA incident investigation and reporting timeframes with the existing response timeframes under NER 4.8.15(g). – In cases where a SCADA incident leads to a complete loss of data from a NSP or participants, mandate a comprehensive investigation to identify the causes and implement corrective actions within an agreed timeframe. – Whether any requirements outlined in the PSDCS should be reflected in the NER.	Open	-
	• By Q1 2025, AEMO and the TNSPs, DNSPs and participants from which AEMO receives SCADA data should review their telecommunications systems and consider implementing changes (as required) to allow each entity to have a reliable, independent means of communication with AEMO in the event of a major network outage at their respective sites. • By the end of Q4 2024 AEMO to: – Investigate the communications connections between its New South Wales control room and Transgrid's network to provide alternative communication links for New South Wales region data. – Investigate the communications connections between its Queensland control room and Energy Queensland's network and onto Powerlink to provide alternative communication links for Queensland region data.	Open	This recommendation has been communicated to NEM NSPs and is being progressed.
Loss of SCADA and line protection at	During the incident, five out of eight dense wavelength-division multiplexing (DWDM) communication cards failed and the KTS A and B 48 V DC supplies tripped.	Open	AusNet's investigation into the root cause of the A and B 48 V DC supplies and DWDM power supply card failures at KTS is ongoing.

Incident	Recommendation	Status	Details
Keilor Terminal Station (KTS) on 29 June 2023	• AusNet's investigation into the root cause of the A and B 48 V DC supplies and DWDM power supply card failures at KTS is ongoing. • Once AusNet's investigation is complete, AusNet will: – Share the findings with AEMO. – Share the findings with relevant industry groups, notably the Power System Security Working Group (PSSWG) and NEMOC. – Identify whether a review of other terminal station communication, DC systems or contingency plans is required. AEMO and AusNet may identify additional recommendations based on the outcome of this investigation.		
	AusNet procedures were not adequate to allow operators to accurately and promptly identify the level of protection that was operational during this incident. AEMO recommends that all TNSPs review the information readily available to operators to ensure they are able to accurately identify the level of protection which is operational on equipment following DC system, communications and SCADA outages.	Closed	TNSPs confirmed at the Q2 2024 PSSWG that they have successfully completed this review.
	AusNet is planning to implement an alternative SCADA route to Deer Park Terminal Station (DPTS) by 30 June 2024.	Open	AusNet is planning to implement an alternative SCADA route to DPTS by 30 June 2024.
	This event, where two generators had unexpected responses due to settings issues, highlights the potential for incorrect settings or unexpected performance to exacerbate disturbance events. To raise industry awareness of the need for all generators to ensure settings changes are appropriately managed, AEMO plans to share this finding and relevant details with all NEM generators by the end of Q2 2024.	Open	AEMO shared this finding with NEM generators in June 2024 and has requested NEM generators to confirm receipt of the email.
	This event, where two generators had unexpected responses due to settings issues, highlights the potential for incorrect settings or unexpected performance to exacerbate disturbance events. AEMO will consider this and other incidents in its annual review of events and may identify further recommendations.	Open	AEMO will consider this finding in its review of the financial year (FY) 2023-24 incident trends. The review and associated engagements with industry groups such as the PSSWG, is expected to be completed by the end Q3 2024.
	There was a minimal reduction of small DPV systems (<30 kilowatts (kW)) observed in Victoria. However, a significant portion (24%) of larger DPV systems (30-100 kW) were observed to disconnect in Victoria. It was recommended that AEMO and Powercor complete their ongoing investigation into the cause of the significant portion of DPV unit disconnections for units larger than 30 kW.	Open	The investigation into the cause of the significant portion of DPV unit disconnections for units larger than 30 kW is ongoing.

Incident	Recommendation	Status	Details
Trip of Ross 275 kV busbar on 21 October 2023	AEMO recommends Powerlink assess all the equipment subjected to the overloading to confirm elements have not suffered permanent damage which may affect equipment serviceability or ratings.	Closed	Powerlink has assessed the elements and confirmed to AEMO that they have not suffered any permanent damage which may affect equipment serviceability or ratings.
	AEMO plans to present to the TNSP planners on the need to consider the implementation of control schemes when using asset ratings of less than 15 minutes and for the control schemes to provide facilities to automatically disconnect overloaded assets, including the use of load shedding, to allow the power system to return to a satisfactory operating without the need for operator intervention. It is noted that there is an increasing use of dynamic ratings and five-minute ratings in the power system and this event confirms that coordination between control rooms exceeds this timeframe.	Open	AEMO is working to schedule the relevant presentation(s).
	AEMO recommends refresher training of TNSP control room staff to reinforce the need to consider manual interruption of load under some power system topologies. This will be included in the AEMO – NSP Load Shedding and System Restart training.	Open	AEMO is working to refine the medium and timing of load interruption refresher training.

A2. Status of previous GPSRR/PSFRR recommendations

Table 2 contains the status of previous GPSRR and Power System Frequency Risk Review (PSFRR) recommendations and a brief update on actions taken to progress each recommendation.

Table 2 Summary of previous GPSRR and PSFRR recommendation status

Report	Recommendation	Status	Update
2020 PSFRR (Executive summary, Page 7)	Emergency Alcoa Portland Tripping scheme review	Closed	AEMO recently completed several reviews of Emergency Alcoa-Portland Potline Tripping (EAPT) in response to a maloperation in 2018[5] and also as part of an impact assessment of recent network changes. As a result, setting changes have been implemented to minimise the risk of future mal-operation, and recommendations made to further modify the scheme to improve its reliability. Other findings include: • It is inappropriate to modify the EAPT to address a frequency performance issue introduced by high generation along the Heywood Terminal Station (HYTS) to Moorabool Terminal Station (MLTS) lines. AEMO's preferred solution to address this generation-driven issue is to trip or runback generation, not to trip APD load. It should be noted that all existing generation connected along the line, with the exception of Macarthur Wind Farm, would be tripped if separation from MLTS occurs, which could be sufficient in addressing any issue driven by renewable generation connected to South-West Victoria. • The reliability of the EAPT scheme is greatly improved by changing its contingency detection from a performance-based approach to a topology-based approach. This is in line with the *Final Report – Queensland and South Australia System Separation on 25 August 2018* and the 2020 PSFRR recommendation to avoid mal-operation due to unexpected interaction with the interconnector emergency control scheme (IECS). The EAPT upgrade project was completed in August 2023. • With the use of the topology-based contingency detection, the response time of the scheme is minimised, which will address the high RoCoF issue identified in the PSFRR, and also improve coordination between EAPT and UFLS as recommended by the 2020 PSFRR. • If necessary, AEMO will investigate, jointly with ElectraNet, possible new control schemes to address any high generation-driven issues. AVP will continue to monitor the latest changes in the area and will assess the need to further modify the EAPT accordingly.

[5] See AEMO, *Final Report – Queensland and South Australia System Separation on 25 August 2018*, https://www.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.

Report	Recommendation	Status	Update
2020 PSFRR **(Section 2.5.1, page 25)**	ElectraNet in collaboration with AEMO to enhance the reliability of the system integrity protection scheme (SIPS) by implementing a wide area protection scheme (WAPS)	Ongoing	Stage 1 and Stage 2 of SIPS (the battery response and load shedding stages) has been replaced by a WAPS, which can dynamically calibrate load shedding and battery response to increase the effectiveness of the scheme at preventing Heywood separation following a trip of South Australian generation, while minimising the amount of load shed. WAPS was commissioned in December 2023. Works is underway for WAPS extension to include Project EnergyConnect (PEC) Stage 1. AEMO is currently working on the model validation. Stage 3 of SIPS (loss of synchronism protection of the Heywood interconnector) will remain in place.
2020 PSFRR **(Section 6.2.1, Table 37, page 73)**	Various recommendations to address the identified South Australia UFLS issues	In progress	As reported in Section 6.3, several initiatives are underway to address these issues: • Dynamic arming of UFLS in South Australia commenced rollout in October 2022. The project will recover an estimated 385 megawatts[6] (MW) to the UFLS scheme in South Australia by the time of first phase completion in 2024. It is anticipated that SA Power Networks will continue to monitor feeder flows, and maintain suitable coverage of dynamic arming over time, as more feeders pass reverse flow thresholds. • AEMO has provided recommendations to SA Power Networks about adaptive arming (updating relay frequency settings in real-time depending on power system conditions), indicating this provides some benefit to minimise binding of Heywood constraints, although implementation may only be justified if costs are low. SA Power Networks is implementing this functionality alongside Dynamic Arming Rollout. Costs have been kept low by leveraging Dynamic Arming works. The functionality will be available in the relevant relays, but be disarmed and unused. Further future works will be required to arm the functionality at the right frequency settings. It is expected these settings adjustments can be achieved remotely. In March 2024, AEMO indicated that this functionality is unlikely to be required in the near term. • AEMO is providing recommendations to SA Power Networks about increasing the amount of load on delayed UFLS blocks to better assist frequency recovery[7]. SA Power Networks identification of circuits has been finalised and implementation underway (target completion: September 2024). • SA Power Networks has cased exploration of alternate pathways to procure emergency under frequency response (EUFR) as a complement to traditional UFLS. Responses from expressions of interest were not economically viable and AEMO has advised that Dynamic Arming measures will be sufficient once implemented. Shortfall could be meaningfully reduced by frequency response settings on new resources – in some cases at zero marginal cost.

[6] Estimated forecast based on historical feeder level data from SA Power Networks.

[7] Further information on AEMO advice on delayed UFLS is provided in 2022 PSFRR, Section 3.3.3 (July 2022), https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

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2020 PSFRR (Executive summary, Page 6 and page 70)	AEMO, in consultation with ElectraNet, will review the effectiveness of the OFGS and modify it if required, to include additional generation in the scheme.	In progress	South Australian and Western Victoria OFGS – ElectraNet has implemented updated settings with approximately half of the required participants in South Australia. AEMO has implemented updated settings with a generator in South West Victoria, other generator settings may also be updated through ongoing operational improvement. See also details in recommendation for the 25 August 2018 – Queensland and South Australia system separation event.
2022 PSFRR Recommendation 1	New OFGS scheme to manage Queensland over frequency during Queensland separation: AEMO and Powerlink to implement OFGS in Queensland.	Ongoing	AEMO is currently working on the design of a Queensland OFGS in consultation with Powerlink. The design is expected to be complete in Q3 of 2024. See also details in recommendation for the 25 August 2018 – Queensland and South Australia system separation event.
2022 PSFRR Recommendation 2	To manage the loss of both Dederang Terminal Station – South Morang Terminal Station 330 kV lines: AVP to review existing IECS when Victoria is importing and develop a new SPS for when Victoria is exporting, jointly with Transgrid.	Ongoing	AVP's review of the existing IECS scheme for Victoria import conditions concluded that there is a low risk of losing the two adjacent single circuit transmission lines simultaneously. Hence, IECS is only armed at times of high bush fire risk for Victoria import conditions. AVP and Transgrid concluded that the solution to manage this non-credible contingency are within Victoria. AVP has tested various combination of generation tripping solutions which determined the most effective locations and size of generation and load tripping required. AVP is in the progress of further testing the impact of the DER model to the voltage stability performance and re-calibrate the tripping solutions for a new SPS to manage this non-credible contingency.
2022 PSFRR Recommendation 3	To manage loss of both Columboola – Western Downs 275 kV lines: Powerlink to implement a new SPS under NER S5.1.8.	Ongoing	Powerlink has initiated a project to install wide area monitoring protection and control (WAMPAC) panels in the Surat Zone to detect this double circuit non-credible contingency. Resource availability is impacting the timing for delivery of this scheme. The current commissioning time frame is mid-2025. Depending on the load and generation within Surat Zone, if there is a need to trip the generation outside of the Surat Zone to arrest possible QNI instability, the scheme will leverage the generators that are available under the CQ-SQ N-2 SPS.
2022 PSFRR Recommendation 4a	Management of Queensland UFLS: 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.	Ongoing	As reported in Section 6.3, several initiatives are underway to address these issues: • AEMO report provided to NSPs identifying declining load in UFLS due to DPV. AEMO recommended NSPs explore rectification options. • NSPs auditing UFLS scheme, identifying areas of improvement. Work continues in improving UFLS performance across the Energex/Ergon Energy network. • NSPs identify metering uplifts required, especially to identify UFLS circuits in reverse power flow. Energy Queensland has completed excluding certain reverse flowing feeders. • Energy Queensland has developed proof of concept UFLS dashboard for real-time visibility of UFLS load.
2022 PSFRR Recommendation 4b	QNI instability: To manage QNI instability and separation after Heywood interconnector contingencies, AEMO plans to conduct further investigation to consider appropriate mitigation measures such as a protected	Closed	AEMO completed a protected event assessment as part of the 2023 GPSRR, and studied events which could lead to QNI instability as a risk. As a result, the GPSRR recommends that Powerlink, in collaboration with Transgrid, designs and implements a SPS to manage QNI instability.

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	event or work with Powerlink for a SPS under NER S5.1.8.		This recommendation is closed and is now superseded by 2023 GPSRR recommendation 2.
2022 PSFRR Recommendation 5	Review of WAMPAC scheme to mitigate risks associated with non-credible loss of Calvale – Halys 275 kV lines: Powerlink to review the adequacy of WAMPAC to manage increased risks due to QNI transfers increases following QNI upgrade (tranche 2).	Ongoing	Powerlink is focusing on updating transient stability limit advice for credible contingencies (N-1) for the CQ-SQ grid section and southerly power transfer across QNI based on AEMO's current version of the composite and DER load model. Following the completion of this work, Powerlink will prioritise reassessment of the CQ-SQ N-2 SPS settings, taking account of the revised composite and DER load model. The logic that chooses how much load/gen to trip for a CQ-SQ transfer is implemented in EMS. EMS signals are sent to the WAMPAC panels to then arm/trip certain load/gen sites. As connections of new renewable generators in CQ and NQ progress, Powerlink has been installing the necessary WAMPAC panels for these projects such that these plants can be integrated into the CQ-SQ N-2 SPS or, as appropriate, other WAMPAC based schemes. In addition to expanding the footprint for candidate CQ or NQ variable renewable energy (VRE) generator tripping, Powerlink has also been leveraging planned secondary system replacement projects in SQ to (where appropriate) also install WAMPAC panels such that additional load blocks can be added into the CQ-SQ N-2 SPS and/or other schemes as required.
2022 PSFRR Recommendation 6	Further work is required to mitigate risks associated with reduced effectiveness of UFLS schemes as reported in the 2020 PSFRR: a) To address the impact of DPV growth on UFLS, NSPs should regularly audit the availability of effective UFLS considering the impact of DPV in their respective networks. b) 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. c) NSPs to investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits.	Ongoing	NSPs, in collaboration with AEMO, have extensive current and planned initiatives to improve the efficacy of UFLS. These are discussed extensively in Sections 6.2 and 6.3 of the 2024 GPSRR.
2022 PSFRR Recommendation 8	Revise constraints on Heywood associated with the existing protected event for destructive wind conditions in South Australia: AEMO plans to retain the existing protected event until PEC stage 1 is commissioned. Post PEC Stage 1 commissioning, during destructive wind conditions, AEMO plans to increase the Heywood Interconnector limit from 250 MW.	Closed	AEMO considers the existing South Australian destructive winds protected event, as currently declared, is better aligned with the modified contingency reclassification framework, which considers power system security during temporary 'abnormal conditions' and now recognises 'indistinct events' where the specific assets at risk and impacts cannot be explicitly identified. AEMO submitted a request to the Reliability Panel to revoke the protected event prior to 1 October 2023. On 14 September 2023, the Reliability Panel (Panel) published a final determination to revoke the South Australian destructive winds protected event. The protected

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			event will be revoked from 30 March 2024, prior to the connection of PEC Stage 1 with the grid, expected in April 2024. See Section 7 for more details.
2022 PSFRR Recommendation 9	Manage risks associated with large generation ramping events in South Australia: 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.	Ongoing	AEMO's analysis and review is ongoing. Due to the continuous growth and increasing penetration of DPV and transmission-connected IBR, South Australia is becoming increasingly susceptible to large generation ramping events. An example of a ramping event in South Australia was in 2021 where the combined DPV and IBR generator output reduced by over 1,750 MW over 2.5 hours. Since then, ramping events pertaining to sudden or unexpected changes in solar generation have been captured as potential abnormal conditions impacting the power system and the risk is being managed through the Reclassification Criteria in the Power System Security Guidelines (PSSG), which also outline likely measures to be taken to manage power system security. Any further risks and developments to manage these potential abnormal events will be considered for inclusion in the PSSG.
2022 PSFRR Recommendation 10	Manage risks associated with non-credible loss of future North Ballarat – Sydenham 500 kV lines: The non-credible loss of the proposed 500 kV lines between North Ballarat and Sydenham during periods when the new 500 kV lines flow exceeds the limits of the parallel 220 kV lines could result in multiple line losses. AVP will consider this risk in the planning process.	Open	The preferred option for the Western Renewables Link project has been updated to include a new 500 kV line between Bulgana and Sydenham, instead of North Ballarat and Sydenham. The preferred option is still under public consultation.
2023 GPSRR Recommendation 1	Based on findings in relation to busbar faults at Tamworth (Risk 2), AEMO recommends that: • Transgrid continue to maintain CB 5102 and associated equipment with consideration to the criticality and potential impact of its failure. • Transgrid maintain the 132 kV system distance protection systems near Tamworth and associated equipment with consideration to the criticality and potential impact of its failure.	Closed	CB 5102 is in mid-life (21 years old) and the CTs are relatively new (six years old). These assets are subject to standard maintenance strategies with no planned renewal requirements. Self-checking microprocessor-based relays are installed on all 132 kV transmission lines in the Tamworth region except for Lismore Substation which operates on five discrete component devices for 132 kV feeders. Response times regarding protection alarms are in alignment with NER requirements and AEMO's operational zones delegated to Transgrid. Self-checking assets are maintained every eight years and discrete component devices are maintained every three years as per Transgrid's Maintenance Plans. The average age of the self-checking 132 kV transmission line relays in the Tamworth region is less than 12 years old. The five discrete component assets at Lismore Substation are planned for replacement in the 2023-2028 regulatory period.
2023 GPSRR Recommendation 2	Given the potentially significant impact QNI instability could have on the NEM, AEMO recommends that Powerlink and Transgrid investigate, design and implement an SPS under NER S5.1.8 to mitigate the risk of QNI instability and synchronous separation of Queensland following a range of non-credible contingencies. If a scheme is found viable, AEMO recommends this scheme be commissioned as soon as possible, and no later than June 2025. This	Ongoing	A working group comprising of AEMO, Powerlink and Transgrid is set up to address this issue. Powerlink has completed initial studies for Queensland export and import conditions and concluded that QNI stability can be preserved if sufficient load is tripped in the same region as the initiating generation contingency. Transgrid has agreed to progress the QNI SPS for Queensland export conditions, and recommended to involve AVP as load trip in Victoria could be required.

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	recommendation follows on from recommendation 4b in the 2022 PSFRR.		
2023 GPSRR Recommendation 3	Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas (three of which may be viable islands), AEMO recommends that AEMO, AVP, ElectraNet and Transgrid continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) operates effectively in conjunction with existing NEM system protection and generation tripping schemes (see Appendix A3.2 for relevant schemes), as well as any future QNI SPS and other protection schemes.	Ongoing	AEMO, AVP, ElectraNet, and Transgrid are progressing this through the PEC SISC working group. In addition to this, AVP and ElectraNet are undertaking further investigations under Joint Planning on non-credible contingencies in Victoria that the PEC SPS is not expected to cover.
2023 GPSRR Recommendation 4	AEMO recommends that each participating jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risks. These plans should be for an appropriate level of capacity for the region, and encompass details of the generation technology, connection point and connection arrangement, fuel supply adequacy, environmental considerations, construction, and commissioning timelines as well as equipment availability and lead times.	Ongoing	Refer to Section 6.4 for more information.
2023 GPSRR Recommendation 5	In the context of the transforming power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.	Ongoing	ElectraNet is installing phasor measurement units (PMUs) at multiple substations across South Australia and also implementing a Wide Area Monitoring Scheme (WAMS) to improve operational situational awareness. The WAMS will assist with detecting oscillations on the system, which are not visible on SCADA. In addition, ElectraNet is performing a review of current and future operational systems capability needs, conducted by international experts. The outcome of this review is expected to lead to some reprioritising of existing Operational Technology capital and operating plans. Transgrid is already working to address this through the Transgrid System Security Roadmap[8].
2023 GPSRR Recommendation 6	AEMO recommends that, in line with the requirements of NER S5.1.8, NSPs continue to consider non credible contingency events which could adversely impact the stability of the power system. In considering these non-	Ongoing	AEMO is currently following up with NSPs around risks identified under S5.1.8 and the need for associated remedial actions.

[8] See https://www.transgrid.com.au/about-us/network/network-planning/system-security-roadmap.

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	credible contingency events, NSPs should identify and implement suitable controls to mitigate any identified risks. It is anticipated that these controls may involve the implementation of new remedial action schemes (RAS), in which case NSPs should consult with AEMO and refer to the RAS Guidelines developed by AEMO and NSPs.		
2023 GPSRR Recommendation 7	Transgrid is investigating the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following potential Eraring Power Station closure. AEMO recommends that Transgrid share its investigation findings with AEMO for consideration in future GPSRRs.	Ongoing	Transgrid is investigating the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong when Waratah Super Battery (WSB) SIPS is enabled.
2023 GPSRR Recommendation 8	AEMO to finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.	Ongoing	AEMO is currently drafting the policy document and is in the process of implementation. Upon completion, this will be communicated to participants.
2023 GPSRR Recommendation 9	AEMO to review the protected event and reclassification frameworks by Q4 2023. As part of this review, AEMO will consider the submission of a rule change proposal to enhance the protected event framework.	Ongoing	AEMO has completed a review of the protected event framework and considered whether a rule change submission to enhance the protected event framework is necessary. AEMO has concluded that the existing protected event framework alongside the updated Power System Security Guidelines (SO_OP_3715) allow AEMO to effectively manage existing identified power system risks. During its review AEMO did not identify any current need to apply the protected event framework or request the creation of a new protected event. However, AEMO believes that there are potential future risks that could be managed under the existing protected event framework and as such AEMO is not progressing with a protected event framework rule change submission at this time.

A3. Key updates since the 2023 GPSRR

A3.1 Key updates since the 2023 GPSRR

Since the 2023 GPSRR, a number of key reforms and publications have been progressed or completed. Below is a summary of these work fronts which influence the scope, considerations and assumptions for the 2024 GPSRR.

Amendment of Market Ancillary Service Specification (MASS) – Very Fast FCAS

The Australian Energy Market Commission (AEMC) published a final determination and a final rule[9] on 15 July 2021 to introduce two new market ancillary service categories into the National Electricity Rules (NER) under the existing frequency control ancillary services (FCAS) arrangements for the very fast raise service and very fast lower service.

As a result, AEMO amended the MASS to accommodate two new markets for very fast FCAS:

- Very fast raise contingency FCAS.
- Very fast lower contingency FCAS.

The very fast raise and very fast lower FCAS markets commenced on Monday 9 October 2023 at 1.00pm AEST[10]. The two new markets allow AEMO to procure fast frequency response (FFR) services to assist with maintaining the frequency within the frequency operating standard (FOS) following contingencies. The services procured through the two new markets operate at a much smaller time scale (1 s) than other existing Contingency FCAS markets. Therefore, the services procured though very fast FCAS market respond much faster to a locally sensed frequency signal to arrest a fall and rise in frequency.

Engineering Roadmap to 100% Renewables

AEMO published its *Engineering Roadmap to 100% Renewables* report in December 2022[11], building on the Engineering Framework[12]. The report aimed to provide a technical base to inform industry prioritisation of steps necessary to securely, reliably and affordably transition.

In July 2023, AEMO published the *Engineering Roadmap FY2024 priority action report*[13], which provided an overview of the actions that AEMO planned to undertake in the 2023-24 financial year (FY2024) to progress readiness efforts for the first periods of 100% instantaneous renewables in the NEM.

Of the 174 actions identified in the Roadmap, AEMO made progress towards over 80 of these actions in FY2024.

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9 See https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

10 See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/very-fast-fcas-market-transition.

11 See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf?la=en&hash=42E784478D88B1DFAF5D92F7C63D219D.

12 See https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

13 See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/nem-engineering-roadmap-fy2024--priority-actions.pdf?la=en&hash=DED803FB758F555EE934A898367E66C6.

Improving security frameworks for the energy transition

AEMC made a final determination and a more preferable final rule on 28 March 2024 to improve market arrangements for security services[14]. This rule change is aimed to address the system security challenges that arise with the energy transition to higher penetrations of inverter-based resources (IBR). As such, the final rule focuses on enhancing essential system services (ESS) procurement frameworks, which reduce the use of directions and enable investment opportunities in providing system security services in the long run.

In summary, the final rule aims to:

- Align the existing inertia and system strength frameworks procurement timeframes.
- Remove the exclusion to procuring inertia network services and system strength in the network support and control ancillary services (NSCAS) framework.
- Adjust TNSP cost recovery procedures for non-network security options to support efficient contracting, arrangements and minimise volatility for electricity consumers.
- Create a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition and to trial new sources of security services.
- Empower AEMO to enable (or ‘schedule’) security services with a whole-of-NEM perspective.
- Improve directions transparency.
- Introduce a new annual reporting requirement on AEMO, known as the ‘transition plan for system security’ (or transition plan), in which AEMO will report annually on the steps it will take to manage security through the transition.

Efficient provision of inertia

The AEMC initiated a rule change request on 2 March 2023 from the Australian Energy Council (AEC) on introducing an inertia spot market in the NEM[15]. This rule change proposal identifies the need to reconsider the existing inertia framework in the backdrop of declining inertia levels across NEM.

The existing inertia framework was introduced in 2017 to ensure minimum levels of inertia are met when regions are at risk of islanding from the rest of the NEM. Under this framework, AEMO determines the minimum and secure levels of operating inertia for each region and identifies any projected inertia shortfalls. If AEMO identifies a projected shortfall of inertia in a region at risk of islanding, the relevant TNSP must procure the inertia or alternative frequency control services to address the gap. This framework is primarily used to determine the required inertia to maintain system security with respect to frequency during islanding events. It does not necessarily lend itself to determine the required inertia to maintain secure operation during normal operating conditions.

The existing framework may be sufficient to address the inertia requirements in the medium term, however, further work may be necessary to determine whether a long-term solution is warranted to address the broad power system security concerns raised as the inertia reduces. As such, this consultation is aimed to explore

[14] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[15] See https://www.aemc.gov.au/rule-changes/efficient-provision-inertia#:~:text=On%202%20March%202023%2C%20the,power%20system%20through%20the%20energy.

alternative approaches to meet the inertia requirements for a secure and reliable power system in the long term. The AEMC will publish a directions paper by November 2024 that investigates the key economic and technical considerations of options of managing inertia in operational timeframes. The AEMC has formally extended the timeframe for a draft determination to 27 June 2025.

Clarifying mandatory primary frequency response obligations for bi-directional plant

On 7 March 2024, the AEMC made a more preferable final rule[16] to clarify the mandatory primary frequency response (PFR) obligations of scheduled bidirectional units (batteries with a capacity of 5 MW or greater) in response to a rule change request received from AEMO.

Under the final rule, scheduled bidirectional units will be required to comply with the primary frequency response requirements (PFRR) when:

- They receive a dispatch instruction to generate a volume greater than zero MW – commencing 3 June 2024.
- They receive a dispatch instruction to charge (consume electricity) at a volume greater than zero MW (except when solely powering auxiliary loads) – commencing 8 June 2025.
- They receive a dispatch instruction to provide a regulation service – commencing 8 June 2025.

Importantly, under the final rule batteries will not be required to provide PFR when at rest and when enabled solely for contingency FCAS.

2024 *Integrated System Plan* (ISP)

The Draft 2024 ISP was published on 15 December 2023[17]. The ISP, updated every two years, is a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure to meet future energy needs.

The optimal development path (ODP) identified in the Draft 2024 ISP continues to find that as coal retires, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation is the lowest way to supply reliable electricity to homes and businesses throughout Australia's transition to net zero.

Key outcomes from the Draft 2024 ISP include:

- About 90% of the NEM's coal fleet is forecast to retire before 2035 in the *Step Change* scenario, and the entire fleet before 2040.
- The Draft 2024 ISP calls for urgent investment in generation, firming and transmission that targets secure, reliable and affordable electricity through the energy transition.
- Under forecasts for the *Step Change* scenario, the ODP calls for investment that would triple grid-scale VRE by 2030 and increase it seven-fold by 2050, and would almost quadruple firming capacity.

[16] See https://www.aemc.gov.au/rule-changes/clarifying-mandatory-primary-frequency-response-obligations-bidirectional-plant.

[17] The final 2024 ISP was published on 26 June 2024 but was not considered in the analysis for the GPSRR due to its publication timeframe. See https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en.

2023 NEM *Electricity Statement of Opportunities* (ESOO)

In August 2023, AEMO published the 2023 ESOO, which provides a 10-year outlook on reliability and energy adequacy for the NEM[18]. The latest ESOO report has identified that there is a growing reliability gap since the previous ESOO report published in 2022 over the next 10 years. The 2023 ESOO forecast reliability gaps in all mainland NEM regions over this period.

There are several factors that contribute to the expanding gap in reliability. These include:

- Coal retirement.
- Coal and gas supply chain management.
- Transmission network expansion.

Reliability risks are expected to be managed within relevant standards over the next 10 years as long as federal and state government programs, actionable transmission developments and consumer energy resources (CER) continue progressing on schedule. Any impact to these programs could add further reliability risk to the NEM.

Current schemes underway include:

- The federal Capacity Investment Scheme.
- The New South Wales Electricity Infrastructure Roadmap, and firming tenders.
- The Victorian Renewable Energy Target Auction 2.
- The Queensland Energy and Jobs Plan.
- The South Australian Hydrogen and Jobs Plan.

In summary, further commitments are required for generation and transmission investments to address the issues coming from coal retirement and increasing maximum demand to reduce any risks associated with reliability.

Update to the 2023 NEM *Electricity Statement of Opportunities* (ESOO)

New information regarding system reliability has become available since AEMO released the 2023 ESOO in August 2023 that warranted reassessment of the supply and demand outlook in the NEM. An Update to the 2023 ESOO was published in May 2024[19] to address this. This new information included new commissioning dates for PEC, mothballed gas generators in South Australia, and approximately 4.6 gigawatts (GW) of new generation and storage projects.

Reliability gaps continue to be forecast over the 10-year outlook in all mainland NEM regions when considering only those developments that meet AEMO's commitment criteria. Reliability risks in the ESOO Central scenario, relative to the 2023 ESOO, have:

- Increased in New South Wales between 2024-25 and 2027-28 due to advised delays to previously considered battery projects and revised assumptions for demand allocation within New South Wales.

[18] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

[19] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/may-2024-update-to-the-2023-electricity-statement-of-opportunities.pdf?la=en.

- Increased in Victoria until 2027-28 due to mothballed generators in South Australia and transmission limitations affecting flows into Melbourne.
- Increased in South Australia in 2026-27 due to the advised delay of PEC Stage 2 to after the previously advised closure timings of the Torrens Island B and Osborne Power Stations, resulting in a newly identified reliability gap.
- Decreased in Victoria and South Australia from 2028-29 when Yallourn Power Station retires, due to a newly advised transmission configuration planned for the Latrobe Valley transmission network.

As a result of the reliability gaps forecast in the ESOO Central scenario, AEMO will tender for interim reliability reserves (IRR) which support New South Wales and Victoria to minimise the consumer impact of reliability risks should low reserve conditions emerge over summer 2024-25.

A4. Study approach

The study approach for the 2024 GPSRR was outlined in the final approach paper[20]. The approach paper gave an overview of the general methodology for historical and future scenario selection, PFR governor models, IBR models for large-scale wind and solar generation, SPS models and OFGS models.

This section covers the models and assumptions used for the study in more detail. AEMO used both Power System Simulation for Engineering (PSS®E) and Power System Computer Aided Design (PSCAD™) software to assess the priority risks. Where fault ride-through (FRT) behaviours of IBR and voltage stability might impact the assessment, results were studied in PSCAD™. Other events were studied using PSS®E.

The full NEM model (as described in OPDMS) and simplified NEM models were used to study the network and its dynamic behaviour.

A4.1 System strength

Table 3 and Table 4 show 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 as per the 2022 ISP forecasting assumptions[21] and Draft 2024 ISP forecasting assumptions[22], respectively.

The tables detail that, beyond FY 2029-30, in most regions there will be periods when no large synchronous generating units need to be online to maintain power system security. 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.

[20] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-gpsrr/final-document/2024-gpsrr-approach-paper---final.pdf?la=en.

[21] From AEMO, 2021 Inputs and assumptions Workbook, Power System Constraints sheet, 30 June 2022, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en.

[22] From AEMO, Draft 2024 ISP Inputs and Assumptions Workbook, Power System Constraints sheet, 15 Dec 2023, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/supporting-materials/draft-2024-isp-inputs-and-assumptions-workbook.xlsx?la=en.

Table 3 Forecasting power system constraints – synchronous generating units

Region	Condition	Number of 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[D]
	Post PEC Stage 2	≥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 online as part of their detailed studies and assessments.
D. AEMO and ElectraNet are presently developing and implementing limits advice, and updating operating procedures to facilitate the secure operation of the South Australian power system with a minimum of one large synchronous generating unit online under some operating conditions, prior to PEC Stage 2.

Table 4 Synchronous unit commitment requirement, all scenarios except for the *Green Energy Exports* scenario

Year	Coal unit commitment requirements[A]				Gas unit commitment requirements[A]
	QLD[B]	NSW	VIC	TAS[C]	SA[D]
2022-23	11	7	5	-	2
2023-24	11	7	5	-	2
2024-25	11	7	5	-	1
2025-26	8	5	3	-	1
2026-27	6	3	2	-	0
2027-28	4	2	2	-	0
2028-29	3	2	1	-	0
2029-30	2	1	1	-	0
2030-31	1	1	0	-	0
2031-32	1	0	0	-	0
2032-33	1	0	0	-	0
≥2033-34	0	0	0	-	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. Tasmania does not have any unit commitment constraints applied.
D. AEMO and ElectraNet are presently developing and implementing limits advice, and updating operating procedures to facilitate the secure operation of the South Australian power system with a minimum of one large synchronous generating unit online under some operating conditions, prior to PEC Stage 2.

Consistent with other planning studies, the 2024 GPSRR has applied market modelling based on AEMO's *Step Change* scenario from the 2022 ISP to project the operational behaviour of synchronous generation units across the NEM and identify potential stability risks for the future studies and dispatch selection. Note that the future dispatch scenarios selected were reviewed based on the latest ISP information available following the publication of the Draft 2024 ISP[23], as detailed in Appendix A4.7.1.

The assumed reduction in the minimum required number of online synchronous generating units poses both challenges and opportunities for the management of risks in the NEM. Managing power system security within the required operating voltage and frequency bands and managing FRT capabilities of IBR under reduced fault level and system strength will be challenging, particularly following non-credible contingencies. The impacts of reduced fault levels on power system security, protection devices and generator FRT needs to be evaluated – this is discussed in Section 6.

A4.2 Network augmentations

The 2022 ISP and its ODP support Australia's complex and rapid energy transformation towards net zero emissions. At the time the 2024 GPSRR studies were completed, the 2022 ISP *Step Change* scenario was considered by energy industry stakeholders to be the most likely scenario to play out[24], so forecasting data from the 2022 ISP *Step Change* scenario was used in the 2024 GPSRR for future projections. Note that the future dispatch scenarios selected were reviewed based on the latest ISP information available following the publication of the Draft 2024 ISP[25], as detailed in Appendix A4.7.1.

Consistent with the Transmission Augmentation Information workbook published in December 2023[26], Table 5 displays each of the major ISP committed, anticipated and actionable projects in the next five years.

The projects listed in Table 5 were considered to be major augmentations that could impact the contingencies proposed to be studied in the 2024 GPSRR and as a result, these projects were considered in the assessment of future network conditions. Announced potential closures of power stations such as Eraring Power Station (2025) and Yallourn Power Station (2028) were also considered in future studies. Minor augmentations that were determined to not have a significant impact on the proposed contingencies were not included.

[23] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[24] See Section 2.3 of the 2022 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[25] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[26] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Table 5 Committed, anticipated and actionable major transmission projects to June 2029

Project	Capacity release date[A]	Status
Victoria – New South Wales Interconnector (VNI) Minor	July 2023	Completed
Eyre Peninsula Link	July 2023	Completed
QNI Minor	Early 2024[B]	Completed
Northern Queensland Renewable Energy Zone (QREZ) Stage 1	April 2024	Completed
Central West Orana REZ Transmission Link	August 2028	Anticipated
Project EnergyConnect	July 2026[C]	Committed
Western Renewables Link	July 2027	Anticipated
HumeLink	July 2026	ISP Actionable Project
Sydney Ring (Option 1/Hunter Transmission Project 1.0)[D]	December 2027	New South Wales Actionable Project[E]
New England REZ Transmission Link	September 2028	New South Wales Actionable Project[E]

A. This field provides an indication of timing for the full capacity of the project to become available in the NEM. The capacity release of the project requires the successful completion of inter-network testing where necessary, which may require certain conditions in the NEM.
B. Some capacity for this project has already been released. Further capacity release expected over the coming months subject to market conditions for further inter-network testing.
C. This projected delivery date for PEC refers to full capacity available following completion of inter-regional testing.
D. Sydney Ring Option 1 (Northern 500 kV loop) was selected in the ODP of the 2022 ISP and 2024 ISP. Option 2 (Sydney Ring Southern 500kV loop) was not selected in the ODP of the 2022 ISP and therefore was not modelled for the 2024 GPSRR studies.
E. Sydney Ring and New England REZ Transmission Link are actionable under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

A4.3 Wide-area EMT analysis methodology (priority risk 1)

A4.3.1 PSCAD™ wide-area model set-up

The circuit breaker (CB) fail contingency in Latrobe Valley was identified as a potential existing risk to the system due to its impact on system strength at Hazelwood. Consistent with the System Strength Requirements Methodology[27], to assess contingencies relating to system strength issues or FRT behaviours of IBR, AEMO conducted electromagnetic transient (EMT) analysis using the four state NEM PSCAD™ version 5 model. This model is made up of the four NEM mainland regions of New South Wales, Queensland, South Australia, and Victoria, and contains all the transmission networks elements, as well as key distribution network elements for each of these states.

The use of EMT analysis is preferred for power system stability studies to identify system strength issues, such as control interactions between IBR, in time horizons where network and generator models are precise (such as 1-2 years). However, EMT simulations are not fit-for-purpose in long-term planning studies because their accuracy is limited by the use of generic models for conceptual projects. Hence, the CB failure risk detailed below was assessed in the 1-2-year time horizon.

[27] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en.

A4.3.2 Dispatch conditions

The cases were developed and the study was performed in accordance with the System Strength Requirements Methodology[28]:

- A system normal configuration with all transmission network elements in service was considered.
- A low demand in Victoria was considered, as a low demand scenario would result in lower levels of damping for power system transients in general.
- Most of the operational IBR in Victoria, New South Wales, Queensland, and South Australia were kept online and the case was modified to dispatch as many IBR at 80% as possible. When the IBR has been dispatched, all its inverters were assumed online, regardless of the MW output.
- Both power flow directions of Basslink were studied and the Basslink flow has been determined based on the trend analysis of the historical flow values during the past financial year.

Summary of study cases

Table 6 Priority risk 1 – summary of cases studied

Case name	Description
Case 1	VIC_9 combination and Basslink flow is from Victoria to Tasmania
Case 2	VIC_9 combination and Basslink flow is from Tasmania to Victoria
Case 3	VIC_39 combination and Basslink flow is from Victoria to Tasmania
Case 4	VIC_39 combination and Basslink flow is from Tasmania to Victoria

A summary of key parameters for each case studied is given in Table 7.

Table 7 Priority risk 1 – summary of key parameters

Case name	Loy Yang B units (MW)[A]	Valley Power units (MW)	Basslink power flow from Tasmania to Victoria (MW)[B]
Case 1	845	152	-442
Case 2	797	136	492
Case 3	875	300	-442
Case 4	834	240	492

A. The contingency size in all four cases ranges from 933 MW to 1,175 MW.
B. The highest Basslink flows recorded for both directions during past financial year were considered (442 MW from Victoria to Tasmania, and 492 MW from Tasmania to Victoria).

A4.3.3 Pre-contingent and post contingent fault level assessment

The pre-contingent and post-contingent three-phase fault levels at Hazelwood and Loy Yang were calculated in PSS®E using the Automatic Sequencing Fault Calculation (ASCC) method[29] – see Table 8.

[28] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en.

[29] See PSS®E documentation Program Application Guide on Fault calculations.

The following settings were used with the ASCC method for calculating fault levels:

- All Bus voltages set to its base value at 0 degree.
- Sub-transient reactance for synchronous machines assumed.
- Transformer tap ratios set to 1.0 pu and phase shift angles to 0 degree.
- DC lines and FACTS devices blocked.
- Zero sequence transformer impedance correction applied.
- Line charging option set to 0.0 in all sequences.
- Line shunts, fixed shunts, switched shunts and transformer magnetizing admittance option set to 0.0 in all sequences.
- Load option set to 0.0 in all sequences.
- Synchronous and asynchronous machines real and reactive power outputs set to 0.0.
- All asynchronous generators modelled with high source impedance to ensure their fault contribution was kept negligible.

Table 8 Priority risk 1 – Fault level at Hazelwood and Loy Yang (MVA)

Case name	Fault level at Loy Yang 500 kV		Fault level at Hazelwood 500 kV	
	Pre-contingent	Post-contingent	Pre-contingent	Post-contingent
Case 1	7,961	4,416	7,863	4,437
Case 2	7,961	4,416	7,863	4,437
Case 3	7,843	3,901	7,711	3,910
Case 4	7,843	3,901	7,711	3,910

The fault levels at Loy Yang and Hazelwood reduced by roughly 50% following the contingency.

A4.4 Future full NEM PSS®E model methodology (priority risk 2)

A4.4.1 Assumptions of the future NEM model

Five-year ahead (2028-29) studies for the non-credible loss of double-circuit HumeLink 500 kV transmission lines were carried out by AEMO, in collaboration with Transgrid, using a PSS®E full NEM network model based on OPDMS cases. This model was modified to include the new interconnectors, generation and network augmentations that are planned for completion by June 2029 – refer to Appendix A4.2. Future dispatch conditions were based on the five-year 2022 ISP *Step Change* projection data. The key system forecast parameters that were considered in setting up the study cases are included in Section 4.1.2. Future studies assumed a system normal network configuration[30].

[30] System normal snapshots restore the nominal configuration of the network. Network outages (planned or unplanned) were restored to the nominal configuration while generation and load were retained as they were in the snapshot timestamp. In the future studies the load and generation were redispatched, and network projects were added to match the forecast network conditions.

For the future NEM model, the following network configuration and modelling approaches were used:

- South Australia, Victoria and New South Wales represented as per OPDMS.
- Queensland represented by a common high voltage (HV) 330 kV bus. All the regional generators assumed to be connected to these regional common buses through appropriate generator transformers.
  - Regional generators lumped as steam, gas, hydro, wind and solar with appropriate generic models such as alternator, voltage controller, governors and IBR controllers included with the lumped generators according to each generator type.
  - The grouped DPV feeders also connected to common HV buses through appropriate transformers.
- The OPDMS Basslink line commutated converter (LCC) high voltage direct current (HVDC) interconnector model included, and Tasmania represented as a single swing bus.

A4.4.2 DPV model

The DERAEMO1 model developed by AEMO was used to model the dynamic behaviour of the DPV generation modelled in the full NEM model cases[31] – see Appendix A4.6.5.

DPV mapping to buses

For these studies, the standard DPV modelling approach was applied[31]. DPV generation was lumped at different bus locations in the OPDMS full NEM model based on data from distribution network service providers (DNSPs) and the Clean Energy Regulator which was analysed and compiled by AEMO as part of the development of the DERAEMO1 model. This approach most accurately reflects the physical distribution of this type of generation in the system. Therefore, it better captures how DPV generation will respond to power system disturbances, because the proximity of DPV installations to the fault location is better represented.

A4.4.3 Load modelling

The AEMO composite load model (CMLD) was used to model load response in all GPSRR PSS®E full NEM studies – refer to Appendix A4.6.5.

A4.4.4 Transgrid network model

In accordance with NER S5.1.8, Transgrid has undertaken initial studies to assess the impact of the non-credible loss of the future 500 kV HumeLink lines on Transgrid's network and the feasibility of different remedial measures. To complete these studies, Transgrid developed a separate PSS®E full NEM model including the Snowy 2.0 development[32] based on an OPDMS system normal case. The key assumptions of this model are summarised below:

- All NEM regions modelled as per OPDMS.
- Snowy 2.0 pumped hydro generation modelled with custom user dynamic models.

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[31] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

[32] The completion date for Snowy 2.0 was after FY 2028/29 in the July 2023 Generation Information workbook (see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information). Therefore, the project was removed from the 2022 ISP market modelling data for the 2024 GPSRR studies.

- Comprised six 340 MW units connecting into Maragle 330 kV network.
- Two cases included the Sydney Ring Option 2 (Southern 500 kV loop)[33] augmentation:
  - A new substation in the locality of South Creek into Eraring – Kemps Creek 500 kV lines and Bayswater – Sydney West and Regentville – Sydney West 330 kV lines.
  - New 500 kV double-circuit lines from Bannaby to the new substation in the locality of South Creek.
- New South Wales Southwest REZ generation modelled as a negative load.
- DPV and CMLD models not included.
  - A traditional polynomial static load (ZIP) model was used to represent NEM loads.
- Other augmentations included consistent with GPSRR modelling:
  - Sydney Ring Option 1 (Northern 500 kV loop).
  - Central West Orana REZ Transmission Link.
  - New England REZ Transmission Link.
  - WSB project.
  - Western Renewables Link.
  - PEC Stage 2.

A4.5 Simplified PSS®E model methodology (priority risk 3)

The under frequency load shedding (UFLS) screening studies (Risk 3) were assessed against both historical FY 2022-23 and future FY 2028-29 operating conditions. For the assessment based on historical conditions, AEMO used a simplified NEM network model of the current system and select historical dispatches from FY 2022-23 representing operating boundaries relevant for each contingency considered. Five-year ahead (2028-29) studies for UFLS adequacy were carried out using a simplified NEM network model which included the QNI Minor upgrade and PEC Stage 2. Future dispatch conditions were based on the five-year 2022 ISP *Step Change* projection data.

Importantly, the use of a simplified NEM model enabled the assessment of a wider range of future dispatch scenarios and contingencies. The performance of this simplified NEM network model was previously benchmarked against results of studies completed for the previous 2022 PSFRR using a modified full NEM OPDMS model as part of the 2023 GPSRR[34]. All UFLS studies will assume a system normal network configuration.

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[33] Sydney Ring Option 1 (Northern 500 kV loop) was selected in the ODP of the 2022 ISP and 2024 ISP. Option 2 (Sydney Ring Southern 500kV loop) was not selected in the ODP of the 2022 ISP and therefore was not modelled for the 2024 GPSRR studies.

[34] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr-appendices.pdf?la=en.

A4.5.1 Assumptions and limitations of the simplified NEM model

The historical and future UFLS screening studies were completed using a PSS®E simplified NEM model consistent with that used for the 2023 GPSRR and 2022 PSFRR[35].

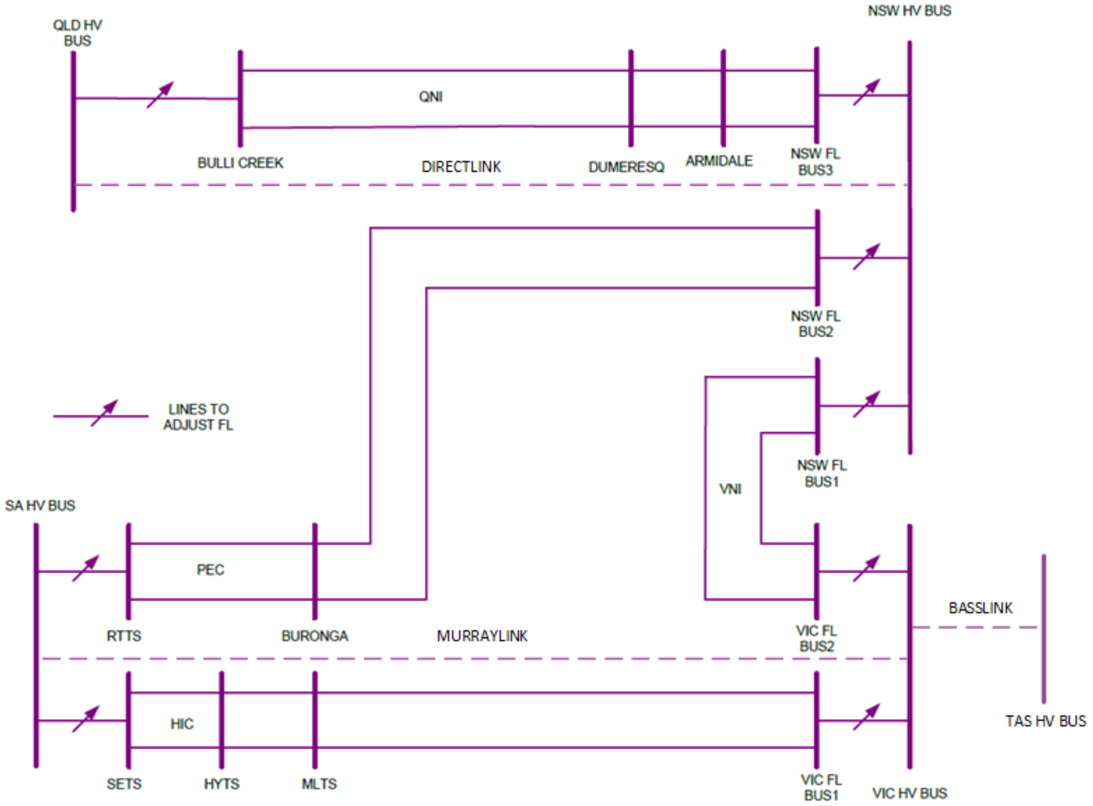
For the PSS®E simplified NEM model, the following network configuration and modelling approaches were used:

- Each mainland region represented by a common HV bus (New South Wales, Victoria and Queensland 330 kV and South Australia 275 kV buses). All the regional generators assumed to be connected to these regional common buses through appropriate generator transformers.
- Regional generators lumped as steam, gas, hydro, wind, solar and large-scale battery energy storage systems (BESS) with appropriate generic models such as alternator, voltage controller, governors (see Appendix A4.6.3) and IBR controllers included with the lumped generators according to each generator type.
- UFLS and underlying DPV grouped according to their frequency trip bands and connected at medium voltage (MV) buses:
  - 121 New South Wales UFLS bands.
  - 23 Victoria UFLS bands.
  - 33 Queensland UFLS bands.
  - 30 South Australia UFLS bands.
- The grouped UFLS and DPV feeders also connected to common HV buses through appropriate transformers.
- Alternating current (AC) interconnectors (aside from Victoria – New South Wales Interconnector (VNI)) modelled as per OPDMS network with compensating devices, such as reactors, capacitors, and static VAR compensators (SVCs). VNI represented as two single-circuit lines in the simplified model (meaning it was not fully represented as per the OPDMS full model – this simplification does not significantly impact the model accuracy for the risks being studied as part of the GPSRR).
- OPDMS models for the Basslink LCC HVDC interconnector, and the Murraylink and Directlink voltage source converter (VSC) HVDC interconnectors integrated into the simplified model.
- For future studies for FY 2029, PEC Stage 2 (and the associated SPS) included based on the latest planning information available (at the time of study).
- The HV network between South East Switching Station (SESS) and MLTS, and between Robertstown Terminal Station and Buronga, modelled as per OPDMS network.
- South Australia generators and generators connected between HYTS and MLTS modelled as per OPDMS including their dynamic models.
- APD network loads modelled as per the OPDMS.
- The South Australian OFGS generators modelled as per OPDMS generator models for the respective plants along with their existing OFGS trip settings.

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

A single line diagram of the simplified model including PEC Stage 2 is shown in Figure 1.

Figure 1 Single line diagram of the updated simplified NEM model with PEC Stage 2 integrated



Although the simplified network can capture frequency variations with reasonable accuracy, it is impacted by the following limitations:

- The model excludes actual network impedances (aside from interconnectors, which are modelled as per OPDMS as detailed above), therefore, it cannot accurately predict power system voltages.
  - The model provides an approximation of fault ride-through characteristics of IBR plant.
  - The model provides an approximation of the voltage-based tripping behaviour of DPV. As detailed in Appendix A4.5.4, for the UFLS studies using the simplified model, the voltage response of DPV was emulated by force tripping a fixed percentage of regional DPV based on findings from AEMO's previous studies.
  - The power swings on interconnectors and their angular stability predictions may be optimistic when compared with the full NEM OPDMS model.
- To estimate the accuracy of the simplified model used for the 2023 GPSRR studies, the model responses were benchmarked against responses from the full NEM OPDMS model[36].

[36] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr-appendices.pdf?la=en.

A4.5.2 Rate of change of frequency (RoCoF) > 3 Hz/s

The FOS was updated in October 2023, and now requires that AEMO use reasonable endeavours to maintain RoCoF within ±3 Hertz per second (Hz/s), measured over any 300 milliseconds (ms) period, following a multiple contingency event[37]. UFLS may not successfully arrest the frequency decline if RoCoF exceeds ±3 Hz/s[38]. In these cases:

- UFLS relays may maloperate.
- Inherent time delays in UFLS relays (required to allow accurate measurement of frequency) mean that load blocks will not trip in time to arrest frequency before it falls below 47 Hertz (Hz).
- Due to time lags, there can be excessive load tripping followed by frequency overshoot.

A4.5.3 Load modelling

As detailed in Appendix A4.6.5, the CMLD model was used to model the load response in the GPSRR studies that used the OPDMS full NEM model. However, as stated in Appendix A4.5.1, given that the simplified NEM model does not accurately capture severe voltage disturbances, only shallow faults were studied using the simplified model. Therefore, it is not necessary to capture load shake-off in response to large disturbances in the simplified NEM model. Additionally, the frequency dependent load relief in the NEM is minimal (currently assumed to be 0.5 %) and is projected to reduce into the future due to the increase in inverter loads[39]. Therefore, a traditional polynomial static load (ZIP) model was used to represent NEM loads in the simplified model.

A4.5.4 Contingencies involving DPV tripping and load shake-off

In periods with very low operational demand and high levels of DPV operating, the largest originating contingency events could involve a trip of the DPV itself. This will interact with UFLS functionality in complex ways:

- A trip of DPV will reduce DPV generation on UFLS circuits, which may “expose” more net UFLS load and thereby partially restore UFLS functionality.
- Some mechanisms that lead to DPV tripping may also be associated with load shake-off, which will tend to offset the original contingency size, but will also reduce the net load on UFLS circuits.

Some possible mechanisms for DPV tripping are summarised in Table 9.

[37] At https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf.

[38] AEMO (December 2022) AEMO advice: reliability panel review of frequency operating standard, Section 3.2, https://www.aemc.gov.au/sites/default/files/2022-12/AEMO%20FOS%20advice%20to%20the%20Reliability%20Panel%20FINAL%20for%20Publishing%20221205.pdf.

[39] Load relief is an assumed change in load that occurs when power system frequency changes. It relates to how particular types of loads (particularly traditional motors, pumps, and fans) draw less power when frequency is low, and more power when frequency is high. AEMO is acting on a recent review of load relief in the NEM. Accordingly, from September 2019, AEMO slowly reduced assumed mainland load relief from 1.5% to its current value of 0.5%, with a review point at 1%. Subsequently, AEMO’s analysis of power system events in the mainland during 2020 confirmed that a load relief value of 0.5% remains appropriate at this stage for the mainland NEM.

Table 9 Possible causes of a large DPV contingency

Possible reason for DPV trip	Mechanism	Example(s)	Associated with load shake-off?
DPV shake-off in response to a deep transmission fault	DPV has been observed to disconnect ("shake-off") in response to deep transmission faults.	• 3 March 2017[A] – 40% of DPV in South Australia tripped in response to faults. • Many other events documented[B].	Yes
DPV shake-off in response to frequency falling below 49 Hz	Up to 14% of legacy DPV is considered likely to disconnect ("shake-off") in response to power system frequency falling below 49 Hz[C].	• 25 August 2018 (separation of Queensland and South Australia) – 12-13% of DPV in New South Wales/Victoria island estimated to disconnect in response to under-frequency.	No
Type fault	A "type fault" could lead to unexpected disconnection of a large proportion of the DPV fleet (for example, incorrect settings due to untested firmware update on an OEM's products).	• 23 June 2022[D] - Power system reactive power oscillations in South Australia led to a disconnection of 95% of an OEM's battery fleet. • 28 September 2016 – Wind farm tripping due to multiple fault ride-through settings in South Australia leading to a black system event.	No
Other common mode of failure via internet connectivity	Many DER are now connected to the internet, which can lead to other common modes of failure which could result in disconnection of a large proportion of the DPV fleet.	Identified as a risk in international literature.	No

A. AEMO (March 2017) *Fault at Torrens Island switchyard and loss of multiple generating units on 3 March 2017*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/report-sa-on-3-march-2017.pdf.
B. AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.
C. See Section A5.3.
D. AEMO (February 2023) *Power System Oscillations in South Australia on 23 June 2022*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/south-australia-power-system-oscillations.pdf?la=en.

DPV and load shake-off in response to a deep transmission fault

AEMO has compiled considerable evidence of DPV disconnection in response to severe faults[40]. The level of DPV disconnection depends on the severity of the originating fault, and the strength of the network (which affects the proportion of DPV systems in the network that will be exposed to a deep voltage dip).

The new AS/NZS4777.2.2020 Australian Standard became mandatory from 18 December 2021, and requires improved ride-through capabilities. Compliance with the new standard was initially low[41], but is improving over time[42]. As the proportion of DPV compliant with this new standard increases, the share of DPV disconnecting following a fault should decrease over time. However, there remains a large legacy fleet (>15 GW) with the older 2015 and 2005 standards applied. These legacy inverters are not designed to ride through power system disturbances, and will continue to demonstrate these behaviours until they are eventually replaced.

Severe events that result in high levels of DPV disconnection typically also result in load shake-off[43]. As noted above, load shake-off can have complex effects on frequency outcomes. Load shake-off will tend to offset the

[40] At https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[41] AEMO (April 2023) *Compliance of Distributed Energy Resources with Technical Settings*, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en&hash=FC30DF5A3B9EF853093709012242D897.

[42] AEMO (December 2023) *Compliance of Distributed Energy Resources with Technical Settings: Update*, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

[43] AEMO (November 2022) *PSS®E models for load and distributed PV in the NEM*, https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

original generation contingency, and help arrest the frequency decline in a similar manner to load tripping from UFLS action. However, it will also reduce the net load on UFLS circuits, which may further reduce the effectiveness of UFLS. To study these competing effects, AEMO implemented load shake-off and DPV shake-off functionality in the multi-mass model used for the studies in this report, and tested the outcomes in scenarios including and excluding load shake-off.

It was found that load-shake off at the levels observed in past disturbances generally tends to improve frequency nadir outcomes (compared with scenarios that featured the same level of DPV shake-off, but without associated load-shake-off). For example, the significant multiple contingency event in Victoria on 13 February 2024 involved approximately 1,000 MW of load shake-off[44].

As detailed in Appendix A4.5.1, the simplified NEM model cannot simulate load shake-off or DPV shake-off in response to deep faults. Therefore, sensitivities were completed force tripping 5-10% of total regional DPV to represent DPV shake-off for each contingency studied – this value aligns with findings from AEMO's previous studies in terms of the average amount of net DPV shake-off for a wide range of contingencies across mainland NEM regions.

DPV shake-off in response to frequency falling below 49 Hz

Older inverters installed under the 2005 standard have frequency trip settings that will cause them to progressively disconnect as frequency falls below 49 Hz. A proportion of inverters installed under the 2015 standard have also been observed to disconnect in disturbances when frequency falls below 49 Hz, both from field measurements, and in laboratory testing. AEMO's collected observations of DPV inverter behaviours in response to power system frequency are summarised in an extensive report[45]. These observations have informed the calibration of frequency trip settings included in the models used in this analysis.

This mechanism for DPV tripping has been included in all studies in this report but was not assumed to be the initiating original contingency. It acts to compound the challenges arresting frequency in scenarios where frequency falls below 49 Hz, as a function of the amount of DPV operating in a scenario.

Type faults leading to DPV trip

A type fault refers to an incorrect setting or designed behaviour that results in an unexpected trip of a large proportion of DER. This might relate to the settings for all the products from a particular OEM, or associated with a particular VPP, for example. Some possible mechanisms might include:

- Unexpected responses of devices during unusual power system conditions, with known examples including:
  - Power system oscillations causing the measurement systems in the inverter to malfunction, leading to unit tripping.
  - Unspecified settings in the inverters (such as multiple fault ride-through settings prior to these being specified in the relevant rules or standards).

[44] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

[45] AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, Section 3, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

- An untested firmware update pushed out to an OEM's fleet which fundamentally changes device performance in disturbances (possibly so it no longer meets the specified requirements in standards).
- Poor governance arrangements leading to OEM products in the field that do not meet the specified requirements of standards.

AEMO is aware of examples in all these categories, and many others are likely. As the power system evolves, with new types of resources and novel operating conditions occurring more frequently, more examples will come to light. These are the kinds of issues for which emergency under frequency response (EUFR) should be available as a last resort mechanism, so these "known unknowns" do not lead to cascading failure.

Proportion of DPV that could trip due to a type fault

AEMO analysed installation data from the Clean Energy Regulator database, for the entire fleet of DPV installed in the NEM based on data as of December 2022. If the largest single OEM had an incorrect setting across their fleet, this could result in 21% of DPV in the NEM tripping in an erroneous response. If the issue was common to two OEMs, this could result in a trip of 33% of DPV, and if it were common to the full fleet of products from the largest three OEMs, this could result in a trip of 45% of DPV.

Proportion of DPV exposed

Most OEMs now have the ability to remotely connect to their devices in the field and can remotely control the unit, change settings, implement firmware updates, and so on. For this analysis it has been assumed that the proportion of new DPV installations that are internet-connected has grown from almost none in 2017 to 75% in 2022. Based on this, it is estimated that at present approximately 33% of the entire DPV fleet could be connected to the internet, and this is likely to grow to 43% by 2025[46].

Furthermore, by 2025 it is estimated that around 30% of the DER fleet will be internet-connected, and associated with OEMs from a single country of origin (which may escalate risks of a common mode of failure). By 2027, this proportion is projected to increase to 35%.

Simulating the risk associated with type faults leading to significant tripping of DPV generation is out of scope of the analysis for the 2024 GPSRR UFLS screening studies, but will be considered in future risk reviews as required.

A4.5.5 Regional UFLS data

Regional UFLS bands

Each NEM region has multiple UFLS bands with distinct trip settings, with frequency thresholds ranging from 47 Hz to 49 Hz:

- 121 New South Wales UFLS bands.
- 23 Victoria UFLS bands.
- 33 Queensland UFLS bands.
- 30 South Australia UFLS bands.

[46] Assuming DPV will grow linearly to 2027 according to the *Step Change* scenario in the 2023 Input, Assumptions and Scenarios Workbook. The estimation does not consider the replacement of old inverters with new inverters.

South Australia

Historical studies

As the Heywood UFLS constraint requires real-time estimates of UFLS load and DPV generation, AEMO's energy management system (EMS) feed has been updated to receive this information, including a new SCADA feed established from SA Power Networks and ElectraNet[47]. Therefore, historical SCADA data for the total SA Power Networks and ElectraNet UFLS was available for FY 2022-23.

For the 2024 GPSRR, UFLS for South Australia was modelled as lumped load blocks for each frequency band. Block MW sizes were based on historical load distribution across bands and scaled based on present installed DPV capacities associated with each band.

Future studies

The historical South Australia DPV and UFLS data described above was used to create a regression to estimate the amount of UFLS on each band for future FY 2028-29 dispatches based on the South Australia operational demand and total DPV generation.

AEMO is currently working with SA Power Networks to introduce 'dynamic arming' of the UFLS scheme in South Australia[48]. This involves changes to UFLS relays so they will automatically "disarm" when a given circuit is in reverse flow. This increases the net load available under the UFLS, and also mitigates the growing potential for operation of the scheme 'in reverse'. For the 2024 GPSRR future FY 2028-29 studies, as a simplification, dynamic arming was modelled at the UFLS band level – this is conservative compared to modelling it the distribution feeder level, which effectively increases the net UFLS load available on each band.

Victoria

Historical studies

In Victoria, most UFLS relays are located at the 66 kV level. These UFLS relays trip "sub-transmission loops" of network. Additionally, the APD loads are on their own UFLS bands with tripping frequencies of 49 Hz and 48.95 Hz. The locations of the UFLS relays align closely with the locations of Transmission Use of System (TUoS) metering in the Victorian network. As AEMO has direct access to this TUoS metering, it was possible for AEMO to extract and aggregate half-hourly load measurements to estimate the total amount of load in the UFLS at each frequency trip setting, in each half-hour.

As part of AEMO's UFLS review of Victoria in 2021[49], AusNet's transmission business (AusNet Transmission) provided a mapping to AEMO indicating which TUoS National Metering Identifier (NMI) was associated with each sub-transmission loop. These sub-transmission loops could be matched against the UFLS settings schedules to determine the trip frequency and delay time settings associated with each load. AEMO was then able to extract

[47] See https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

[48] See https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

[49] See https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

historical half-hourly operational load data for calendar years 2021 and 2022 from sub-transmission (66 kV) TUoS metering, and sum this to determine the total amount of load at each trip setting, in each historical half-hour.

Future studies

The historical Victoria net UFLS data described above was used to create a regression to estimate the amount of UFLS on each band for future FY 2028-29 dispatches based on the Victoria operational demand.

Proposed Victoria Stage 1 UFLS actions

To address the decreasing amount of net load on the UFLS scheme in Victoria, a staged approach for UFLS remediation has been proposed by AEMO, AusNet Transmission, and the Victorian DNSPs, namely[50]:

- Stage 1 – Add load: add and remove UFLS sub-transmission loops identified by AusNet Transmission. Loops with large generating units are proposed to be removed from the scheme and alternative loops with large amounts of consistent load are proposed to be included in the scheme.
- Stage 2 – Reverse flow blocking (66 kV): implement reverse flow blocking at selected sites at the 66 kV level. Likely to be feeders with solar or wind farms behind UFLS relay or significant DPV generation that were not removed in Stage 1.
- Stage 3 – Long-term measures: explore possible longer-term options. These might include moving UFLS implementation from the 66 kV sub-transmission network to the 22 kV distribution network, or moving UFLS implementation to customer smart meters.

AusNet Transmission has conducted an audit of the Victorian UFLS scheme and developed a proposal for actions to implement under Stage 1.

Therefore, as part of the 2024 GPSRR future FY 2028-29 studies, additional sensitivities were completed with the Victoria Stage 1 UFLS actions implemented.

New South Wales

In New South Wales, the UFLS relays are located at variety of voltage levels ranging from the 66 kV transmission level down to 11 kV distribution level. As part of AEMO's UFLS review of New South Wales in 2021[51], AEMO requested the half-hourly load data from relevant NSPs for financial years 2018-19 and 2019-20. The data provided by NSPs was either provided at the feeder level or aggregated up to the relevant UFLS band. All NSPs also provided a setting schedule of time delay and frequency settings for the UFLS relays. Data provided at the feeder level was aggregated by AEMO to the relevant UFLS band.

The half-hourly generation of DPV associated with each UFLS band was estimated for the historical 2018-19 to 2019-20 period based on the estimated generation of DPV across New South Wales in the relevant time period (based on AEMO's DPV forecasting system, the Australian Solar Energy Forecasting System Phase 2 (ASEFS2), scaled according to the proportion of regional DPV installed on each UFLS band.

[50] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2023-05-25-vic-ufls-2022-review.pdf?la=en&hash=CFDBA2D60117E8E7FE452B2C2F468B3B.

[51] See https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.

Consistent with the previous AEMO UFLS review[51], to estimate UFLS for historical periods after FY 2019-20 and for future FY 2028-29 dispatches, the half-hourly underlying load in future years was also scaled in line with the 2022 ISP *Step Change* scenario, via a growth factor applied to the 2019-20 underlying load. DPV generation was assumed to have the same half-hourly capacity factor as the reference year, with DPV generation scaled up based on the larger installed capacity. The net load at each UFLS circuit was then calculated as:

*Net load 2022 = (Underlying load 2021 * Growth Factor 2022) - DPV generation 2022*

This provided an approximate indication of how UFLS load may evolve over the coming years, as DPV levels continue to grow.

Queensland

In Queensland, most UFLS relays are located at the 11 kV and 22 kV level in the network. These UFLS relays trip “feeders” of the distribution network. AEMO aggregated the feeder level half-hourly load measurements provided by Energy Queensland, to estimate the total amount of load in the UFLS at each frequency trip setting, in each half hour, for 2018-19 and 2019-20.

Powerlink supplied half-hourly load data for transmission connected customers included in the UFLS schedule at the 132 kV, 110 kV and 66 kV level. Customer feeders were grouped by their frequency and time delay settings and mapped to their corresponding load data. This load data was cleaned, aggregated, and summed to determine the total amount of load at each trip setting, in each historical half-hour for FY 2018-19 to FY 2019-20.

The installed capacity of DPV data provided by Energy Queensland was scaled according to regional DPV generation data from AEMOs forecasting system ASEFS2. The installed capacity per feeder in FY 2018-19 and FY 2019-20 was summed by UFLS trip setting, then converted to a percentage of the total installed capacity for Queensland.

Consistent with the previous AEMO UFLS review[52], to estimate UFLS for historical periods after FY 2019-20 and for future FY 2028-29 dispatches, the half-hourly underlying load in future years was also scaled in line with the 2022 ISP *Step Change* scenario, via a growth factor applied to the 2019-20 underlying load. The underlying Energy Queensland (EQ) load was therefore calculated as:

*EQ Underlying load 2022 = EQ Underlying load 2021 * Growth Factor 2022*

The underlying load for industrial customers was assumed to be equal the operational load provided by Powerlink (PL) as they were stated to have no DPV installed:

PL Underlying load 2019-20 = PL Net load 2019-20

The half-hourly underlying load for industrial customers in future years was assumed to remain identical to the 2019-20 reference year.

DPV generation was assumed to have the same half-hourly capacity factor as the reference year, with DPV generation scaled up based on the larger installed capacity.

The net load at each trip setting was then calculated as:

[52] See https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

Net load 2022 = PL Underlying load 2019-20 + EQ Underlying load 2022 - DPV generation 2022

This provided an approximate indication of how UFLS load may evolve over the coming years as DPV levels continue to grow.

A4.5.6 Queensland – New South Wales Interconnector (QNI) UFLS inhibit scheme

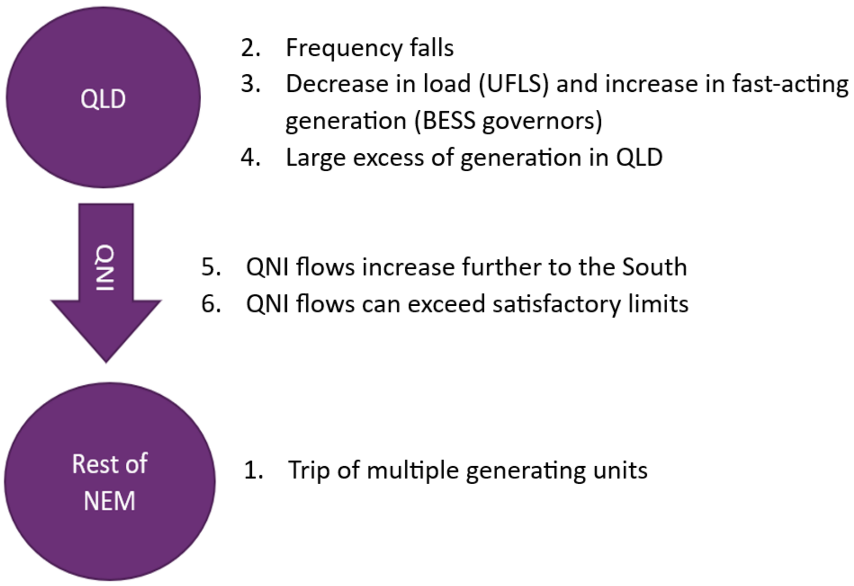
This scheme was introduced in 2008-09, and was proposed by Powerlink as a way of managing risks of QNI separation. The actions of the QNI inhibit scheme, as described below, were modelled for all GPSRR UFLS studies.

The scheme is intended to manage the following scenario (shown in Figure 2):

- QNI operating close to export limit from Queensland to New South Wales.
- Loss of multiple generating units in New South Wales leading to widespread under frequency load shedding in Queensland and other regions.
- Loss of load in Queensland can significantly increase flow on QNI towards New South Wales, potentially beyond levels that would be seen due to credible contingency events (on which limits/constraints are based).
- This could lead to separation of QNI resulting in:
  - Significantly higher levels of UFLS outside of Queensland.
  - Major over frequency issues in Queensland.

This risk was identified following a "near miss" event occurring in 2007, where a large trip of generating units occurred in New South Wales, although a QNI separation did not occur.

Figure 2 Graphical depiction of risk identified



To reduce this risk, Powerlink proposed that the amount of load tripping the early frequency stages of the Queensland UFLS should be reduced under conditions where QNI exports to New South Wales are high, and where Queensland operational demand is low[53].

The scheme that was implemented acts to inhibit/move some UFLS blocks in Queensland under the conditions outlined in Table 10. The thresholds of demand and QNI transfer are settable from the Powerlink control centre. Powerlink has confirmed that these have not changed since original implementation in 2008-09.

Table 10 Conditions where QNI inhibit is activated

	QNI transfer MW (Queensland to New South Wales)			
	QNI < 510 MW	715 > QNI > 510	730 > QNI > 715	QNI > 730 MW
Qld Demand < 4,215 MW	Inhibit OFF	Inhibit ON	Inhibit ON	Inhibit ON
5,249 > Qld Demand > 4,215	Inhibit OFF	Inhibit ON	Inhibit ON	Inhibit ON
7,274 > Qld Demand > 5,249	Inhibit OFF	Inhibit OFF	Inhibit ON	Inhibit ON
Qld Demand > 7,274 MW	Inhibit OFF	Inhibit OFF	Inhibit OFF	Inhibit ON

When the inhibit is ON, the actions summarised in Table 11 were originally proposed to be implemented. Energy Queensland and Powerlink have advised that some elements have changed since the original proposal:

- Additional load has been added to the Q1 block, so this is now substantially more than the original 75 MW (now more like 400-500 MW). This likely undermines the original intention of the QNI inhibit scheme, and needs to be reviewed.
- The Q3 block does not appear to be enabled in the inhibit scheme as per the original design.

Table 11 Actions taken when inhibit is ON

UFLS block	Trip frequency	Original typical load (at time introduced)	Notes	Action taken when inhibit ON
Q1	49.0 Hz	75 MW	Now includes additional load (400-500 MW)	No action
Q2	48.95 Hz	390 MW	This block features some Powerlink connected load	Block at 48.95 Hz, and move to load under control to 48.84 Hz
Q3	48.9 Hz	204 MW	This block features feeders in both Energex and Ergon networks. EQL does not have the inhibit active for this block	Block
Q4	48.85 Hz	213 MW	Q4 is the largest block in Ergon network (~71 MW average). Load is also allocated to this block in the Energex network.	Block Q4, trip Q2

[53] The documentation available is unclear on why Queensland operational demand was an important factor in scheme design. This may have been due to concern around the Queensland island being more vulnerable to an over-frequency event due to the lower level of load relief at these times.

A4.5.7 QNI distance protection

Consistent with the 2023 GPSRR[54], to be able to model the tripping of QNI in response to instability, the distance protection relays for QNI at Bulli Creek and Dumaresq were modelled using the RXR1 and DISTR1 PSS®E library models based on data supplied by Transgrid and Powerlink. It is important to note that these library models are not able to capture all of the settings of the actual QNI distance protection relays at Bulli Creek and Dumaresq.

A4.5.8 Dispatch selection

Historical dispatch selection

To assess risks against historical operating conditions, AEMO selected historical dispatches representing operating boundaries relevant to each contingency event.

Data collation

Data collated from the OPDMS was used to co-optimise each network condition to obtain the most onerous system condition for each UFLS contingency. Each historical contingency was assessed against all historical study scenarios. Table 12 provides a summary of the maximum and minimum values of the parameters that were considered by AEMO when selecting the relevant historical dispatches for use in these studies.

Table 12 Summary of the maximum and minimum values of the parameters (for FY 2022-23)

Parameter	Maximum	Minimum
New South Wales operational demand (MW)	13,754	4,299
Victoria operational demand (MW)	9,029	2,237
Queensland operational demand (MW)	11,547	3,404
South Australia operational demand (MW)	3,385	177
New South Wales inertia (megawatt second/s (MWs))	54,803	19,298
Victoria inertia (MWs)	30,158	8,468
Queensland inertia (MWs)	48,605	18,702
South Australia inertia (MWs)	18,361	4,032
New South Wales DPV generation (MW)	4,172	0
Victoria DPV generation (MW)	3,045	0
Queensland DPV generation (MW)	4,002	0
South Australia DPV generation (MW)	1,701	0
QNI flow (Queensland export +ve) (MW)	1,427	835
Heywood flow (South Australia export +ve) (MW)	617	-741
VNI flow (Victoria export +ve) (MW)	1667	-1,658
Basslink flow (Victoria export +ve) (MW)	499	-469
Kogan Creek generation (MW)	785	0
Mt Piper generation (MW)	1,442	86
Loy Yang A generation (MW)	2,231	556

[54] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr-appendices.pdf?la=en.

Parameter	Maximum	Minimum
Loy Yang A + Torrens Island Power Station (TIPS) B generation (MW)	2,603	684
Eraring + Kogan Creek generation (MW)	3,575	412
Loy Yang A + Mt Piper + TIPS (MW)	3,825	907
Loy Yang A + TIPS B + Mt Piper + Kogan Creek generation (MW)	4,585	907
Bayswater + Mt Piper generation (MW)	3,406	395
Bayswater + Mt Piper + Gladstone generation (MW)	4,635	942
Eraring + Bayswater generation (MW)	5,526	1,206
Loy Yang B + Valley Power generation (MW)	1,440	251
Callide generation (MW)	1,097	0
TIPS B generation (MW)	598	0

The percentage quantities of the trended data were used to co-optimise each network condition to obtain the most onerous system condition for each contingency. When calculating the percentage trended values of the flows on transformers and transmission lines, the sign (direction of the flow) was taken into consideration. Therefore, the percentage was calculated based on the corresponding maximum value of the trended data for the particular flow direction. When calculating the percentage of other quantities, the percentage was linearly proportioned to the minimum and maximum of the trended data. For example, the minimum and the maximum load level obtained from the trended data was 10 MW and 110 MW, respectively. The load level of a specific timestamp of 20 MW would have a percentage of 10% which is proportioned to these minimum and maximum values.

Distributed photovoltaic assumptions

For the GPSRR historical UFLS studies, AEMO used half-hourly DPV values calculated based on ASEFS2 data[55]. To calculate the half-hourly generation data for PV non-scheduled generation (PVNSG, defined as PV systems larger than 100 kW but smaller than 30 MW non-scheduled generators), the half-hourly capacity factors of the small-scale DPV generators calculated from the ASEFS2 data was scaled by the PVNSG capacity for FY 2022-23. The small-scale PV and PVNSG capacities used for this scaling were taken from the 2021 Inputs, Assumptions and Scenarios Workbook[56]. To estimate DPV availability, AEMO then applied identical weather patterns to all small-scale PV and PVNSG in each region. The sum between the small-scale DPV and PVNSG was then used as the half-hourly DPV generation values to select each historical snapshot.

Dispatch selection

A standard set of 15 historical dispatches were studied for each contingency. Table 13 shows the overview of selected timestamps for historical dispatch with key network conditions and their levels.

[55] ASEFS2 involves the production of solar generation forecasts for small-scale DPV systems, defined as less than 100 kW system capacity. The half-hourly generation data for small-scale PV is retrieved from ASEFS2 data (in the data visualisation tool NEO) from 1 July 2021 to 30 June 2022.

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

Table 13 Key NEM parameter values of selected historical dispatches

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
1	4/02/2023 13:30	NSW: 5,055 VIC: 3,623 QLD: 6,666 SA: 460	NSW: 3,016 VIC: 1,559 QLD: 3,515 SA: 269	NSW: 3,726 VIC: 1,232 QLD: 1,486 SA: 1,038	NSW: 30,121 VIC: 16,131 QLD: 28,560 SA: 6,231	NSW: 1,876 VIC: 2,597 QLD: 1,557 SA: 554	NSW: 0 VIC: 300 QLD: 100 SA: 160	QNI flow (QLD export +ve): -619 Heywood interconnector (HIC) flow (SA export +ve): 317 VNI flow (VIC export +ve): 976 Basslink flow (VIC export +ve): 458 Millmerran generation: 858 (2,280 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 468 (4,960 MWs) Loy Yang A generation: 1,268 (9,052 MWs) Loy Yang B generation: 544 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 84 (1,800 MWs) Pelican Point generation: 0 (0 MWs) Eraring generation: 973 (7,450 MWs) Bayswater generation: 905 (7,450 MWs) Gladstone generation: 382 (3,400 MWs)
2	10/07/2022 10:30	NSW: 9,052 VIC: 4,987 QLD: 4,835 SA: 1,379	NSW: 5,754 VIC: 2,474 QLD: 2,680 SA: 1,090	NSW: 1,063 VIC: 802 QLD: 1,926 SA: 581	NSW: 30,191 VIC: 10,029 QLD: 27,844 SA: 10,709	NSW: 2,397 VIC: 1,203 QLD: 1,368 SA: 1,358	NSW: 0 VIC: 300 QLD: 100 SA: 160	QNI flow (QLD export +ve): 1095 HIC flow (SA export +ve): 423 VNI flow (VIC export +ve): -246 Basslink flow (VIC export +ve): -225 Millmerran generation: 812 (2,280 MWs) Callide C generation: 410 (1,750 MWs) Mt Piper generation: 1,385 (4,960 MWs) Loy Yang A generation: 1,122 (4,330 MWs) Loy Yang B generation: 1,160 (3,315 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Valley Power generation: 0 (0 MWs) TIPS B generation: 84 (1,800 MWs) Pelican Point generation: 184 (3,540 MWs) Eraring generation: 1,800 (7,450 MWs) Bayswater generation: 1,820 (7,440 MWs) Gladstone generation: 590 (5,650 MWs)
3	11/12/2022 16:30	NSW: 7,628 VIC: 5,121 QLD: 6,423 SA: 1,097	NSW: 4,756 VIC: 2,621 QLD: 3,437 SA: 610	NSW: 1,327 VIC: 213 QLD: 1,558 SA: 631	NSW: 33,089 VIC: 16,150 QLD: 25,895 SA: 6,360	NSW: 1,637 VIC: 1,000 QLD: 1,458 SA: 1,330	NSW: 0 VIC: 300 QLD: 0 SA: 200	QNI flow (QLD export +ve): 538 HIC flow (SA export +ve): 486 VNI flow (VIC export +ve): -249 Basslink flow (VIC export +ve): 478 Millmerran generation: 834 (2,280 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 451 (2,480 MWs) Loy Yang A generation: 2,150 (9,050 MWs) Loy Yang B generation: 1,095 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 40 (900 MWs) Pelican Point generation: 0 (0 MWs) Eraring generation: 1,755 (7,450 MWs) Bayswater generation: 1,440 (7,440 MWs) Gladstone generation: 830 (4,520 MWs)
4	9/12/2022 8:30	NSW: 6,523 VIC: 4,543 QLD: 5,681 SA: 1,108	NSW: 4,074 VIC: 2,783 QLD: 3,023 SA: 1,071	NSW: 2,006 VIC: 1,380 QLD: 1,988 SA: 306	NSW: 25,007 VIC: 16,228 QLD: 20,741 SA: 9,338	NSW: 2,235 VIC: 1,534 QLD: 1,845 SA: 560	NSW: 0 VIC: 300 QLD: 100 SA: 200	QNI flow (QLD export +ve): 542 HIC flow (SA export +ve): -225 VNI flow (VIC export +ve): 154 Basslink flow (VIC export +ve): 469 Millmerran generation: 760 (2,280 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Callide C generation: 0 (0 MWs) Mt Piper generation: 210 (2,480 MWs) Loy Yang A generation: 2,135 (9,050 MWs) Loy Yang B generation: 998 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 108 (900 MWs) Pelican Point generation: 170 (3,540 MWs) Eraring generation: 955 (4,970 MWs) Bayswater generation: 980 (7,440 MWs) Gladstone generation: 500 (4,520 MWs)
5	29/04/2023 14:31	NSW: 7,642 VIC: 3,627 QLD: 5,879 SA: 582	NSW: 5,016 VIC: 1,561 QLD: 3,697 SA: 350	NSW: 529 VIC: 1,130 QLD: 1,049 SA: 739	NSW: 28,652 VIC: 15,380 QLD: 23,038 SA: 9,793	NSW: 845 VIC: 963 QLD: 969 SA: 343	NSW: 0 VIC: 300 QLD: 100 SA: 400	QNI flow (QLD export +ve): 303 HIC flow (SA export +ve): 154 VNI flow (VIC export +ve): 686 Basslink flow (VIC export +ve): 340 Millmerran generation: 430 (1,140 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 620 (4,960 MWs) Loy Yang A generation: 1,625 (7,080 MWs) Loy Yang B generation: 1,130 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 60 (900 MWs) Pelican Point generation: 130 (3,540 MWs) Eraring generation: 2,620 (9,930 MWs) Bayswater generation: 1,130 (4,960 MWs) Gladstone generation: 820 (4,520 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
6	25/10/2022 21:00	NSW: 7,787 VIC: 4,962 QLD: 7,037 SA: 1,365	NSW: 5,052 VIC: 2,923 QLD: 3,537 SA: 1,290	NSW: 0 VIC: 0 QLD: 0 SA: 0	NSW: 32,210 VIC: 19,733 QLD: 33,344 SA: 9,967	NSW: 616 VIC: 565 QLD: 37 SA: 335	NSW: 0 VIC: 300 QLD: 100 SA: 160	QNI flow (QLD export +ve): -596 HIC flow (SA export +ve): -274 VNI flow (VIC export +ve): 633 Basslink flow (VIC export +ve): -326 Millmerran generation: 350 (2,280 MWs) Callide C generation: 365 (1,750 MWs) Mt Piper generation: 1,270 (4,960 MWs) Loy Yang A generation: 1,970 (9,050 MWs) Loy Yang B generation: 1,150 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 70 (900 MWs) Pelican Point: 235 (3,540 MWs) Eraring generation: 2,020 (7,450 MWs) Bayswater generation: 1,900 (7,440 MWs) Gladstone generation: 1,020 (5,650 MWs)
7	15/07/2022 11:31	NSW: 8,129 VIC: 5,364 QLD: 4,432 SA: 1,527	NSW: 5,178 VIC: 2,565 QLD: 2,374 SA: 1,206	NSW: 1,964 VIC: 1,019 QLD: 2,300 SA: 285	NSW: 35,581 VIC: 14,175 QLD: 29,916 SA: 13,086	NSW: 1,703 VIC: 1,235 QLD: 1,378 SA: 1,222	NSW: 0 VIC: 300 QLD: 100 SA: 200	QNI flow (QLD export +ve): 999 HIC flow (SA export +ve): 280 VNI flow (VIC export +ve): -250 Basslink flow (VIC export +ve): 125 Millmerran generation: 550 (2,280 MWs) Callide C generation: 262 (1,750 MWs) Mt Piper generation: 1,430 (4,960 MWs) Loy Yang A generation: 1,670 (9,050 MWs) Loy Yang B generation: 1,160 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 120 (2,700 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Pelican Point generation: 360 (5,410 MWs) Eraring generation: 1,740 (9,930 MWs) Bayswater generation: 1,660 (7,440 MWs) Gladstone generation: 680 (5,560 MWs)
8	7/05/2023 23:31	NSW: 8,132 VIC: 5,163 QLD: 5,872 SA: 1,553	NSW: 4,846 VIC: 2,509 QLD: 3,113 SA: 1,220	NSW: 0 VIC: 0 QLD: 0 SA: 0	NSW: 26,001 VIC: 16,243 QLD: 28,759 SA: 9,897	NSW: 1,616 VIC: 1,541 QLD: 593 SA: 289	NSW: 0 VIC: 300 QLD: 100 SA: 375	QNI flow (QLD export +ve): 1,011 HIC flow (SA export +ve): -621 VNI flow (VIC export +ve): -288 Basslink flow (VIC export +ve): 0 Millmerran generation: 430 (1,140 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 1,110 (4,960 MWs) Loy Yang A generation: 1,640 (7,080 MWs) Loy Yang B generation: 1,155 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 60 (900 MWs) Pelican Point generation: 405 (5,410 MWs) Eraring generation: 1,300 (4,970 MWs) Bayswater generation: 2,620 (9,920 MWs) Gladstone generation: 1,160 (5,650 MWs)
9	13/05/2023 2:00	NSW: 6,919 VIC: 4,302 QLD: 5,416 SA:1,327	NSW: 4,386 VIC: 1,978 QLD: 2,795 SA: 1,094	NSW: 0 VIC: 0 QLD: 0 SA: 0	NSW: 27,177 VIC: 15,379 QLD: 20,273 SA: 9,809	NSW: 546 VIC: 742 QLD: 554 SA: 904	NSW: 0 VIC: 300 QLD: 100 SA: 375	QNI flow (QLD export +ve): 338 HIC flow (SA export +ve): 0 VNI flow (VIC export +ve): -240 Basslink flow (VIC export +ve): 279 Millmerran generation: 425 (1,140 MWs) Callide C generation: 0 (0 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Mt Piper generation: 820 (4,960 MWs) Loy Yang A generation: 1,630 (7,080 MWs) Loy Yang B generation: 1,150 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 40 (900 MWs) Pelican Point generation: 360 (5,410 MWs) Eraring generation: 1,960 (7,450 MWs) Bayswater generation: 2,620 (9,920 MWs) Gladstone generation: 1,100 (5,650 MWs)
10	22/06/2023 12:00	NSW: 9,370 VIC: 5,785 QLD: 4,957 SA: 2,160	NSW: 6,846 VIC: 2,891 QLD: 3,742 SA: 1,850	NSW: 1,057 VIC: 992 QLD: 2,304 SA: 140	NSW: 37,140 VIC: 14,646 QLD: 21,317 SA: 10,729	NSW: 336 VIC: 1,577 QLD: 1,586 SA: 1,465	NSW: 0 VIC: 300 QLD: 100 SA: 350	QNI flow (QLD export +ve): 1,184 HIC flow (SA export +ve): -212 VNI flow (VIC export +ve): -485 Basslink flow (VIC export +ve): 0 Millmerran generation: 805 (2,280 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 1,210 (4,960 MWs) Loy Yang A generation: 1,680 (6,300 MWs) Loy Yang B generation: 1,160 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 140 (1,800 MWs) Pelican Point generation: 415 (5,410 MWs) Eraring generation: 2,740 (9,930 MWs) Bayswater generation: 2,660 (9,920 MWs) Gladstone generation: 420 (4,520 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
11	10/10/2022 10:31	NSW: 6,919 VIC: 3,801 QLD: 5,902 SA: 750	NSW: 4,129 VIC: 1,857 QLD: 3,163 SA: 746	NSW: 2,152 VIC: 2,199 QLD: 762 SA: 721	NSW: 29,947 VIC: 13,762 QLD: 24,603 SA: 6,233	NSW: 2,053 VIC: 1,036 QLD: 1,456 SA: 1,119	NSW: 0 VIC: 300 QLD: 100 SA: 175	QNI flow (QLD export +ve): 301 HIC flow (SA export +ve): 516 VNI flow (VIC export +ve): 834 Basslink flow (VIC export +ve): 461 Millmerran generation: 640 (2,280 MWs) Callide C generation: 350 (1,750 MWs) Mt Piper generation: 600 (2,480 MWs) Loy Yang A generation: 1,690 (6,300 MWs) Loy Yang B generation: 1,140 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 86 (1,800 MWs) Pelican Point generation: 0 (0 MWs) Eraring generation: 412 (2,480 MWs) Bayswater generation: 1,720 (7,440 MWs) Gladstone generation: 840 (4,520 MWs)
12	9/07/2022 11:01	NSW: 7,387 VIC: 5,164 QLD: 4,326 SA: 1,405	NSW: 4,776 VIC: 2,548 QLD: 2,490 SA: 1,245	NSW: 1,666 VIC: 770 QLD: 2,167 SA: 274	NSW: 38,179 VIC: 13,626 QLD: 27,844 SA: 12,514	NSW: 1,420 VIC: 911 QLD: 1,515 SA: 362	NSW: 0 VIC: 300 QLD: 100 SA: 165	QNI flow (QLD export +ve): 1,065 HIC flow (SA export +ve): -30 VNI flow (VIC export +ve): -786 Basslink flow (VIC export +ve): -113 Millmerran generation: 640 (2,280 MWs) Callide C generation: 310 (1,750 MWs) Mt Piper generation: 1,310 (4,960 MWs) Loy Yang A generation: 1,130 (4,330 MWs) Loy Yang B generation: 1,160 (3,315 MWs) Valley Power generation: 145 (810 MWs) TIPS B generation: 144 (1,800 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Pelican Point generation: 460 (5,410 MWs) Eraring generation: 1,660 (7,450 MWs) Bayswater generation: 1,670 (7,440 MWs) Gladstone generation: 590 (5,650 MWs)
13	17/09/2022 20:00	NSW: 8,495 VIC: 6,091 QLD: 6,582 SA: 1,795	NSW: 5,463 VIC: 3,461 QLD: 3,436 SA: 1,448	NSW: 0 VIC: 0 QLD: 0 SA: 0	NSW: 31,245 VIC: 13,609 QLD: 25,460 SA: 7,421	NSW: 1,643 VIC: 3,355 QLD: 277 SA: 1,842	NSW: 0 VIC: 300 QLD: 100 SA: 135	QNI flow (QLD export +ve): -661 HIC flow (SA export +ve): 194 VNI flow (VIC export +ve): 1,092 Basslink flow (VIC export +ve): 0 Millmerran generation: 480 (2,280 MWs) Callide C generation: 420 (1,750 MWs) Mt Piper generation: 910 (4,960 MWs) Loy Yang A generation: 1,680 (6,300 MWs) Loy Yang B generation: 1,130 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 80 (1,800 MWs) Pelican Point generation: 0 (0 MWs) Eraring generation: 1,325 (7,450 MWs) Bayswater generation: 1,920 (7,440 MWs) Gladstone generation: 1,065 (5,650 MWs)
14	1/07/2022 20:31	NSW: 10,687 VIC: 6,581 QLD: 7,041 SA: 2,078	NSW: 6,530 VIC: 3,356 QLD: 3,595 SA: 1,739	NSW: 0 VIC: 0 QLD: 0 SA: 0	NSW: 44,829 VIC: 23,519 QLD: 32,935 SA: 12,144	NSW: 1,081 VIC: 989 QLD: 125 SA: 361	NSW: 0 VIC: 300 QLD: 100 SA: 200	QNI flow (QLD export +ve): 131 HIC flow (SA export +ve): -463 VNI flow (VIC export +ve): -122 Basslink flow (VIC export +ve): -430 Millmerran generation: 865 (2,280 MWs) Callide C generation: 375 (1,750 MWs) Mt Piper generation: 1,340 (4,960 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Loy Yang A generation: 1,680 (6,300 MWs) Loy Yang B generation: 1,160 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 520 (2,700 MWs) Pelican Point generation: 250 (3,540 MWs) Eraring generation: 2,830 (9,930 MWs) Bayswater generation: 1,990 (7,440 MWs) Gladstone generation: 810 (5,650 MWs)
15	6/12/2022 11:31	NSW: 6,014 VIC: 3,886 QLD: 5,232 SA: 810	NSW: 3,529 VIC: 2,239 QLD: 2,952 SA: 555	NSW: 3,865 VIC: 2,107 QLD: 3,982 SA: 844	NSW: 32,394 VIC: 14,874 QLD: 22,563 SA: 6,511	NSW: 2,609 VIC: 954 QLD: 2,208 SA: 544	NSW: 0 VIC: 300 QLD: 100 SA: 160	QNI flow (QLD export +ve): 447 HIC flow (SA export +ve): -13 VNI flow (VIC export +ve): -768 Basslink flow (VIC export +ve): 422 Millmerran generation: 650 (2,280 MWs) Callide C generation: 0 (0 MWs) Mt Piper generation: 220 (2,480 MWs) Loy Yang A generation: 1,400 (9,050 MWs) Loy Yang B generation: 1,110 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 40 (900 MWs) Pelican Point generation: 0 (0 MWs) Eraring generation: 965 (7,450 MWs) Bayswater generation: 995 (7,440 MWs) Gladstone generation: 450 (4,520 MWs)

Future dispatch selection

Data to assess future scenarios

To assess contingencies with future network operating conditions, the following five-year ISP 2022 *Step Change* scenario projection data was applied:

- Regional load (high and low).
- Regional inertia (high and low).
- DER generation (high and low).
- UFLS load availability (high and low).

Dispatch selection

The key system forecast parameters relevant to each UFLS contingency that were considered in setting up the study cases are listed below:

- Regional inertia.
- Contingency size.
- Net UFLS availability.
- DER generation.
- Regional large-scale BESS headroom.
- Interconnector flows.
- Regional operational demand.

A standard set of 11 future dispatches were studied for each contingency. Table 14 shows the overview of selected timestamps for future dispatch with key network conditions and their levels.

Table 14 Key NEM parameter values of selected future dispatches

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
1	20/04/2029 11:00	NSW: 4491 VIC: 2488 QLD: 5569 SA: 936	NSW: 2418 VIC: 859 QLD: 3047 SA: 709	NSW: 6190 VIC: 4840 QLD: 4670 SA: 1440	NSW: 14072 VIC: 8035 QLD: 18776 SA: 4466	NSW: 4346 VIC: 798 QLD: 3253 SA: 1009	NSW: 3900 VIC: 400 QLD: 380 SA: 500	QNI flow (QLD export +ve): -651 HIC + PEC flow (SA export +ve): 75 Basslink flow (VIC export +ve): -478 Millmerran generation: 736 (2,279 MWs) Callide C generation: 654 (3,400 MWs) Mt Piper generation: 842 (4,960 MWs) Loy Yang A generation: 930 (4,720 MWs) Loy Yang B generation: 1,118 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 671 CWO REZ generation: 1,042
2	8/03/2029 11:00	NSW: 7713 VIC: 1132 QLD: 3847 SA: -372	NSW: 4194 VIC: 24 QLD: 2062 SA: -436	NSW: 4284 VIC: 5032 QLD: 6044 SA: 2528	NSW: 17085 VIC: 8035 QLD: 19714 SA: 4466	NSW: 5453 VIC: 1505 QLD: 3844 SA: 421	NSW: 3930 VIC: 380 QLD: 275 SA: 400	QNI flow (QLD export +ve): 1,370 HIC + PEC flow (SA export +ve): 580 Basslink flow (VIC export +ve): 353 Millmerran generation: 650 (2,280 MWs) Callide C generation: 360 (3,400 MWs) Mt Piper generation: 1,295 (4,966 MWs) Loy Yang A generation: 600 (4,720 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 697 CWO REZ generation: 1,139
3	1/09/2028 12:30	NSW: 7033 VIC: 1397 QLD: 2592 SA: -252	NSW: 3936 VIC: 187 QLD: 1610 SA: -318	NSW: 4551 VIC: 5708 QLD: 5855 SA: 2390	NSW: 16896 VIC: 10288 QLD: 14628 SA: 4466	NSW: 4886 VIC: 1076 QLD: 3420 SA: 746	NSW: 3850 VIC: 400 QLD: 380 SA: 400	QNI flow (QLD export +ve): 1,215 HIC + PEC flow (SA export +ve): 1,175 Basslink flow (VIC export +ve): 476 Millmerran generation: 334 (1,140 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Callide C generation: 180 (1,700 MWs) Mt Piper generation: 540 (4,966 MWs) Loy Yang A generation: 1,483 (7,083 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 1,316 CWO REZ generation: 716
4	7/09/2028 14:30	NSW: 5419 VIC: 6438 QLD: 3970 SA: 1229	NSW: 3174 VIC: 3294 QLD: 2141 SA: 1480	NSW: 3811 VIC: 455 QLD: 4272 SA: 158	NSW: 8922 VIC: 16732 QLD: 14720 SA: 6181	NSW: 4970 VIC: 1107 QLD: 4520 SA: 94	NSW: 2440 VIC: 350 QLD: 190 SA: 500	QNI flow (QLD export +ve): 1,365 HIC + PEC flow (SA export +ve): -362 Basslink flow (VIC export +ve): -478 Millmerran generation: 730 (2,280 MWs) Callide C generation: 180 (1,700 MWs) Mt Piper generation: 972 (4,966 MWs) Loy Yang A generation: 1,624 (7,083 MWs) Loy Yang B generation: 1,038 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 310 (2,700 MWs) NE REZ generation: 1,446 CWO REZ generation: 757
5	23/08/2028 11:00	NSW: 6387 VIC: 4734 QLD: 2699 SA: 31	NSW: 3024 VIC: 2244 QLD: 1700 SA: 171	NSW: 5599 VIC: 2856 QLD: 6373 SA: 2284	NSW: 15796 VIC: 10288 QLD: 17518 SA: 4466	NSW: 4985 VIC: 1215 QLD: 4950 SA: 1280	NSW: 4150 VIC: 590 QLD: 375 SA: 400	QNI flow (QLD export +ve): 1,358 HIC + PEC flow (SA export +ve): 908 Basslink flow (VIC export +ve): -287 Millmerran generation: 400 (2,279 MWs) Callide C generation: 360 (3,400 MWs) Mt Piper generation: 926 (4,966 MWs) Loy Yang A generation: 1,620 (7,083 MWs) Loy Yang B generation: 1,118 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								NE REZ generation: 1,967 CWO REZ generation: 607
6	8/03/2029 12:00	NSW: 7309 VIC: 2600 QLD: 3772 SA: -417	NSW: 3813 VIC: 929 QLD: 2036 SA: -463.9	NSW: 4580 VIC: 5442 QLD: 6082 SA: 2732	NSW: 17085 VIC: 8035 QLD: 19714 SA: 4466	NSW: 4045 VIC: 3245 QLD: 3729 SA: 472	NSW: 3880 VIC: 525 QLD: 275 SA: 400	QNI flow (QLD export +ve): 1,330 HIC + PEC flow (SA export +ve): 625 Basslink flow (VIC export +ve): 478 Millmerran generation: 652 (2,279 MWs) Callide C generation: 360 (3,399 MWs) Mt Piper generation: 1,351 (4,966 MWs) Loy Yang A generation: 600 (4,720 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 653 CWO REZ generation: 932
7	13/07/2028 12:00	NSW: 5980 VIC: 6336 QLD: 4661 SA: 591	NSW: 3453 VIC: 3232 QLD: 2565 SA: 1106	NSW: 4945 VIC: 2179 QLD: 4572 SA: 1178	NSW: 16890 VIC: 22415 QLD: 26404 SA: 7629	NSW: 3740 VIC: 300 QLD: 3826 SA: 124	NSW: 3880 VIC: 660 QLD: 320 SA: 400	QNI flow (QLD export +ve): 1,350 HIC + PEC flow (SA export +ve): 75 Basslink flow (VIC export +ve): -478 Millmerran generation: 746 (2,279 MWs) Callide C generation: 709 (3,400 MWs) Mt Piper generation: 1,133 (4,966 MWs) Loy Yang A generation: 1,643 (7,083 MWs) Loy Yang B generation: 1,004 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 440 (2,700 MWs) NE REZ generation: 1,031 CWO REZ generation: 737
8	23/10/2028 11:30	NSW: 6790 VIC: 2529 QLD: 4482 SA: -370	NSW: 3563 VIC: 885 QLD: 2400 SA: -472	NSW: 3652 VIC: 5766 QLD: 4092 SA: 2607	NSW: 10646 VIC: 8320 QLD: 17072 SA: 4466	NSW: 8400 VIC: 2624 QLD: 3794 SA: 373	NSW: 4135 VIC: 500 QLD: 375 SA: 400	QNI flow (QLD export +ve): 32 HIC + PEC flow (SA export +ve): 625 Basslink flow (VIC export +ve): 242 Millmerran generation: 400 (2,279 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								Callide C generation: 360 (3,400 MWs) Mt Piper generation: 270 (2,483 MWs) Loy Yang A generation: 600 (5,115 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 3,578 CWO REZ generation: 856
9	19/10/2028 10:30	NSW: 6097 VIC: 3850 QLD: 3089 SA:-661	NSW: 3458 VIC: 1699 QLD: 1846 SA: -278	NSW: 5722 VIC: 3345 QLD: 5896 SA: 2493	NSW: 11948 VIC: 5568 QLD: 17426 SA: 4466	NSW: 6276 VIC: 3268 QLD: 2245 SA: 705	NSW: 3464 VIC: 350 QLD: 363 SA: 400	QNI flow (QLD export +ve): -223 HIC + PEC flow (SA export +ve): 1,146 Basslink flow (VIC export +ve): 127 Millmerran generation: 200 (1,140 MWs) Callide C generation: 360 (3,400 MWs) Mt Piper generation: 270 (2,483 MWs) Loy Yang A generation: 300 (2,364 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs) NE REZ generation: 0 CWO REZ generation: 3,353
10	15/11/2028 12:00	NSW: 4988 VIC: 2642 QLD: 6636 SA: -152	NSW: 3036 VIC: 954 QLD: 3457 SA: -216	NSW: 5379 VIC: 5726 QLD: 3739 SA: 2471	NSW: 16896 VIC: 10288 QLD: 14940 SA: 4466	NSW: 5274 VIC: 2780 QLD: 3100 SA: 675	NSW: 3420 VIC: 410 QLD: 200 SA: 450	QNI flow (QLD export +ve): -940 HIC + PEC flow (SA export +ve): 350 Basslink flow (VIC export +ve): 420 Millmerran generation: 666 (2,279 MWs) Callide C generation: 781 (3,400 MWs) Mt Piper generation: 540 (4,966 MWs) Loy Yang A generation: 900 (7,083 MWs) Loy Yang B generation: 640 (3,315 MWs) Valley Power generation: 0 (0 MWs) TIPS B generation: 0 (0 MWs)

Case	Timestamp	Operational demand (MW)	Net UFLS (MW)	Regional DPV (MW)	Regional inertia (MWs)	Regional VRE (MW)	FFR headroom available (MW)	Contingency size (MW)
								NE REZ generation: 1,366 CWO REZ generation: 990
11	28/01/2029 15:30	NSW: 6771 VIC: 8104 QLD: 6173 SA:1517	NSW: 4013 VIC: 4321 QLD: 3227 SA: 1864	NSW: 3606 VIC: 3625 QLD: 3136 SA: 1129	NSW: 12405 VIC: 28642 QLD: 17518 SA: 7343	NSW: 5930 VIC: 1349 QLD: 6476 SA: 522	NSW: 1980 VIC: 350 QLD: 190 SA: 400	QNI flow (QLD export +ve): 1,108 HIC + PEC flow (SA export +ve): -781 Basslink flow (VIC export +ve): -478 Millmerran generation: 417 (2,279 MWs) Callide C generation: 360 (3,400 MWs) Mt Piper generation: 444 (2,483 MWs) Loy Yang A generation: 1,414 (7,083 MWs) Loy Yang B generation: 1,090 (3,315 MWs) Valley Power generation: 190 (809 MWs) TIPS B generation: 310 (2,700 MWs) NE REZ generation: 2,071 CWO REZ generation: 712

A4.5.9 Historical full NEM validation studies

A number of additional studies were completed using a PSS®E full NEM OPDMS model for the historical dispatches to validate the results of the simplified model. Additionally, as part of the 2023 GPSRR[57], the simplified model responses for South Australia separation were benchmarked against responses from the full NEM OPDMS model used for the 2022 PSFRR[58].

Historical full NEM model

The full NEM OPDMS cases were modified to include the following dynamic models required for accurate simulation of power system frequency performance.

DPV model

The DERAEMO1 model developed by AEMO was used to model the dynamic behaviour of the DPV generation modelled in both the simplified and full NEM model cases[59] – see Appendix A4.6.5.

UFLS and DPV mapping to buses

At the time of the study, AEMO did not have a PSS®E model of UFLS that accurately maps the load and DPV behind UFLS relays to individual transmission buses for all NEM regions. This model is currently under development. To deliver studies for this report, an interim approach was applied:

- For cases where regional NEM frequencies did not fall below 49 Hz (and UFLS therefore was not triggered), the standard DPV modelling approach was applied[31]. DPV generation was lumped at different bus locations in the OPDMS full NEM model based on data from DNSPs and the Clean Energy Regulator which was analysed and compiled by AEMO as part of the development of the DERAEMO1 model. This approach most accurately reflects the physical distribution of this type of generation in the system. Therefore, it better captures how rooftop PV generation will respond to power system disturbances, because the proximity of rooftop PV installations to the fault location is better represented.
- For cases where regional NEM frequencies did fall below 49 Hz, it is important to include a representation of UFLS. For these cases, a lumped representation of UFLS and DPV was applied, mapping load and DPV against UFLS relay settings randomly to achieve the overall total net UFLS in each frequency block[60]. The number of regional lumped blocks that were considered are detailed below. The individual blocks were dispersed across the relevant region and the PSS®E UFLS relay dynamic model was attached to each lumped UFLS load.
  - 121 New South Wales UFLS bands.

[57] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr-appendices.pdf?la=en.

[58] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en.

[59] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

[60] System loads were randomly assigned to each UFLS band. DPV generation was then added to each UFLS load based on static percentage data representing the amount of DPV in each regional UFLS band. An additional load representing the load supported by the DPV was also added in conjunction with the DPV generation to ensure that the operational demand and power flows were maintained. Therefore, this approach could result in DPV being placed either electrically further away from or closer to the fault location than is the case in reality.

- 23 Victoria UFLS bands.
- 33 Queensland UFLS bands.
- 30 South Australia UFLS bands.
- Tasmanian UFLS models were included for historic cases as per the data and models provided to AEMO by TasNetworks.

This approach to modelling DPV and UFLS is anticipated to provide a reasonably accurate result for cases where frequency does not fall below 49 Hz (using the first approach), or where the disturbance is primarily frequency-related, and there is minimal voltage disturbance (using the second approach). However, it will not be accurate for any case with a significant voltage disturbance involved that may lead to DPV shake-off[61]. For this reason, cases with a combined frequency disturbance below 49 Hz and significant voltage disturbance would present challenges regarding the modelling of both DPV tripping and UFLS behaviour. This issue will be further explored in future GPSRR studies when suitable models are available.

Load modelling

The AEMO CMLD model was used to model load response in all GPSRR PSS®E full NEM studies – refer to Appendix A4.6.5.

OFGS models

The OFGS models for South Australian generators were used in both OPDMS and simplified NEM models. Tasmanian OFGS models were included for historic cases as per the data and models provided by TasNetworks.

Historical full NEM study results

As detailed in Appendix A4.5.1, a number of the historical studies were repeated using a full NEM PSS®E model. The full NEM study results confirm the key findings listed above based on the simplified model studies. Table 15 contains the detailed results for the sensitivity studies.

As shown in Figure 3 through to Figure 8, the system frequency performance matches well between the simplified and full NEM models for shallow faults – the figures below show overlays of the frequency performance for different contingency events. Therefore, the full NEM sensitivity results indicate that the simplified model accurately captures system frequency performance, in particular the frequency nadir/peak following multiple contingency events, noting the model assumptions and limitations outlined in Appendix A4.5.1.

[61] The impact of a frequency disturbance is seen system-wide, whereas the impact of a voltage disturbance is localised. Therefore, when a fault leads to a voltage depression, this will only be seen by DPV generators that are electrically close to the fault location.

Table 15 Benchmarking results for 2024 GPSRR historical dispatches

Case, contingency (high impedance 2ph-g fault)	OPDMS full NEM model		Simplified NEM model	
	South Australia/ Queensland frequency peak/nadir (Hz)	NEM frequency peak/ nadir (Hz)	South Australia/ Queensland frequency peak/nadir (Hz)	NEM frequency peak/ nadir (Hz)
Case 8, QNI trip	51.9	49.1	51.9	49.2
Case 8, Heywood trip	48.4	50.2	48.4	50.2
Case 8, Millmerran + Mt Piper + Loy Yang A trip	50.8	48.4	50.8	48.6
Case 1, QNI trip	48.0	50.3	48.0	50.3
Case 1, Heywood trip	50.6	49.9	50.6	49.9
Case 1, Millmerran + Mt Piper + Loy Yang A trip	48.9	48.9	48.9	48.9

Figure 3 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 8, QNI trip (night-time case)

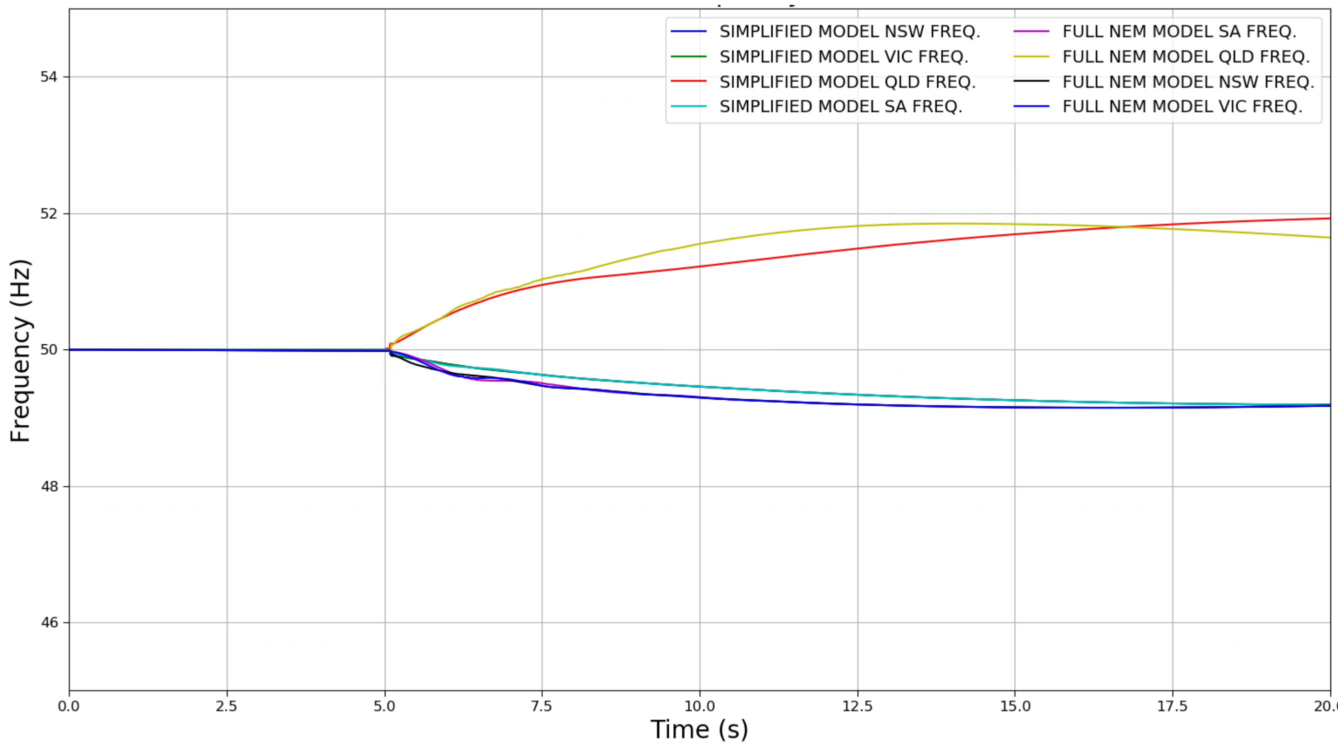


Figure 4 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 8, Heywood trip (night-time case)

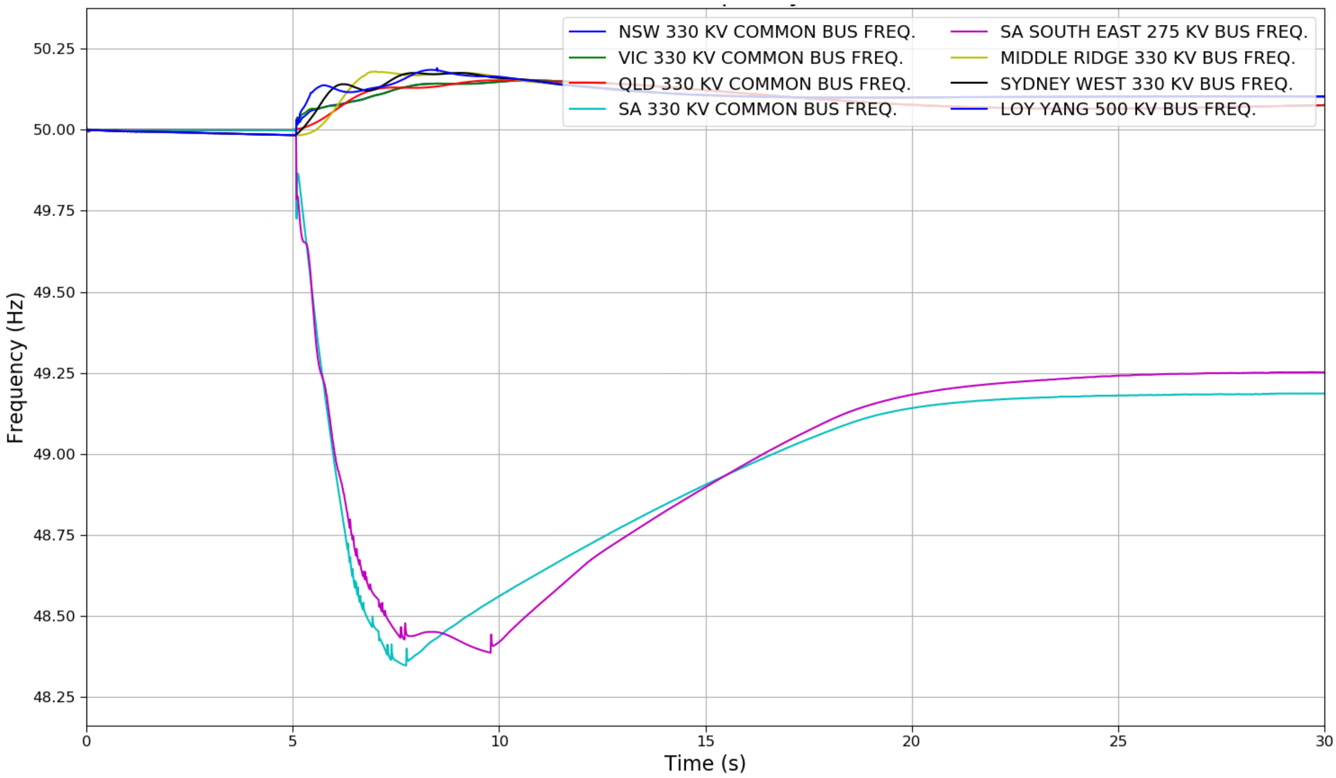


Figure 5 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 8, Millmerran + Mt Piper + Loy Yang A trip (night-time case)

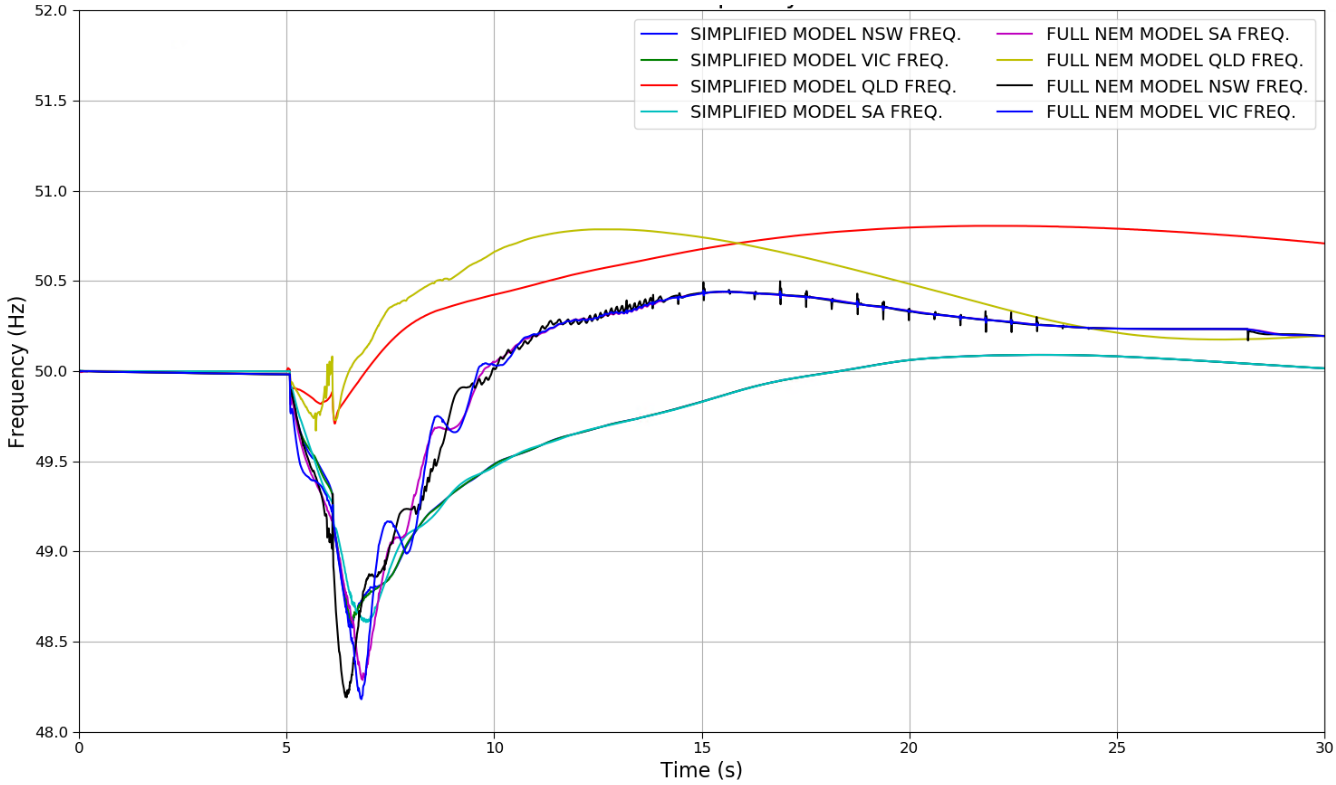


Figure 6 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 1, QNI trip (daytime case)

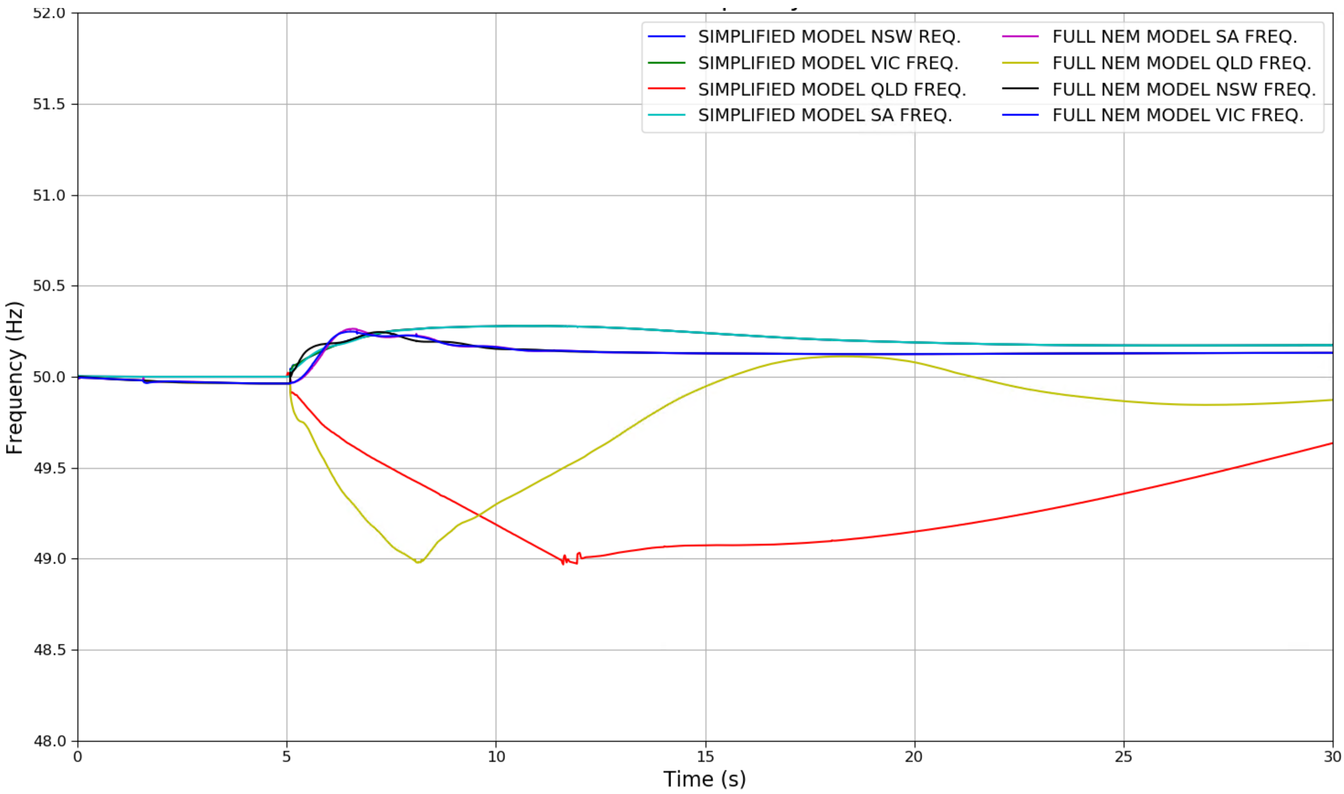


Figure 7 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 1, Heywood trip (daytime case)

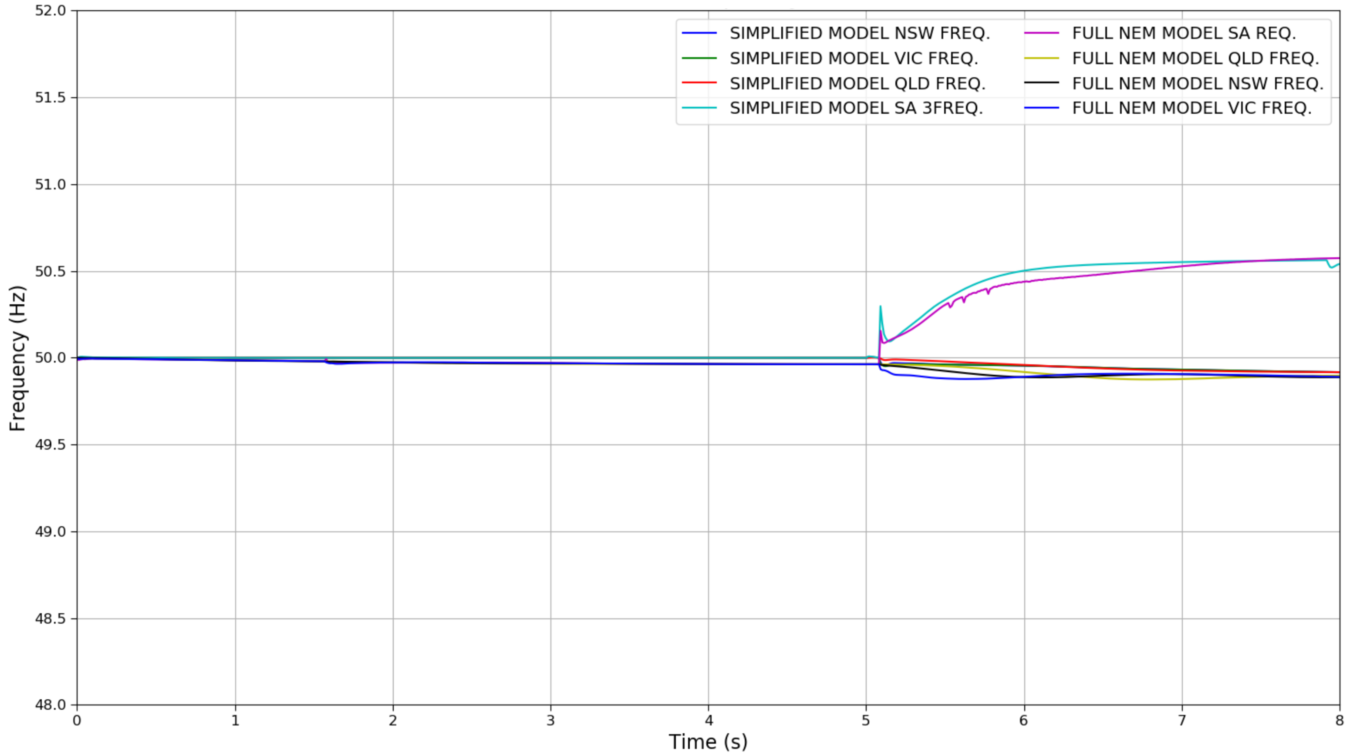
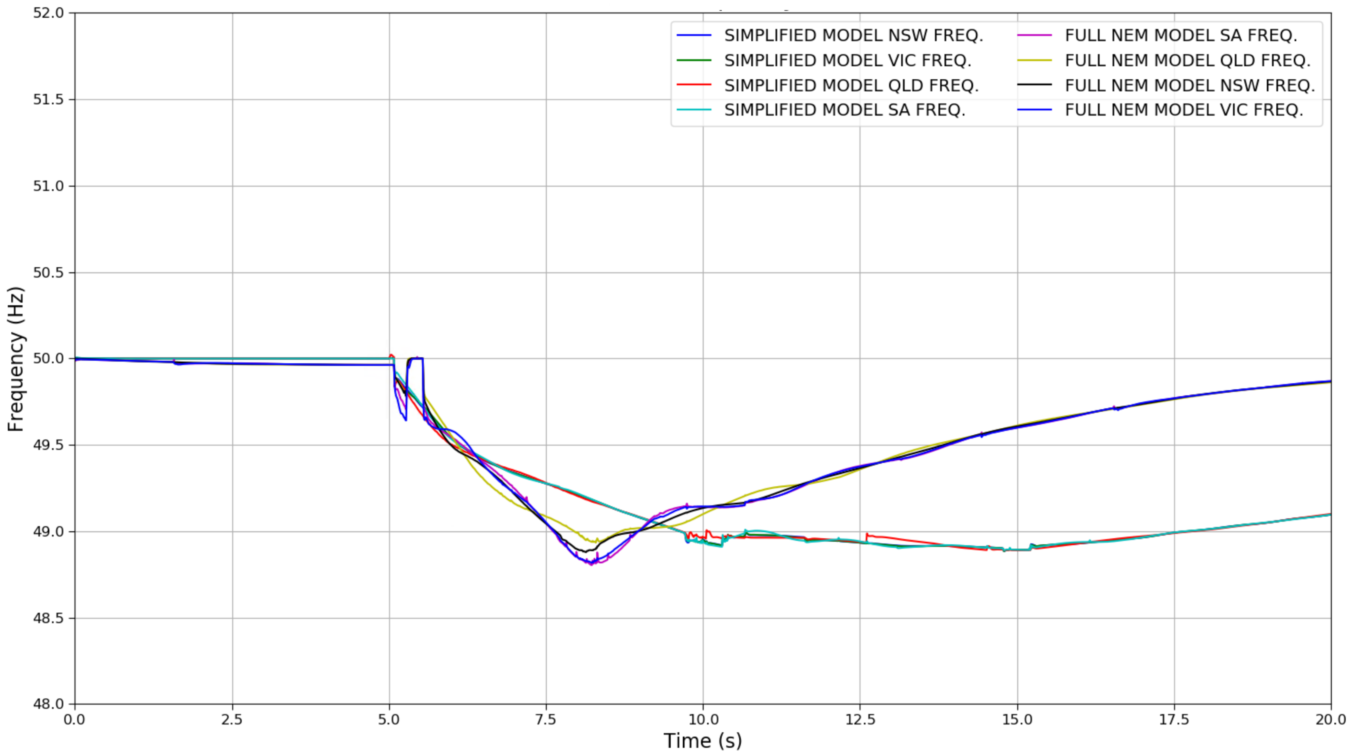


Figure 8 Overlay of simplified model and OPDMS full NEM model system frequency traces for historical Case 1, Millmerran + Mt Piper + Loy Yang A trip (daytime case)



2023 GPSRR benchmarking results

Additionally, as part of the 2023 GPSRR[62], the simplified model responses for South Australia separation were benchmarked against responses from the full NEM OPDMS model used for the 2022 PSFRR[63]. The results of these benchmarking studies are summarised in the tables and figures below.

Table 16 Benchmarking results for 2022 PSFRR historical Export Case 1, South Australia separation at Heywood

2022 PSFRR historical Export Case 1, South Australia separation at HYTS				
Model	South Australia frequency peak (Hz)	South Australia OFGS generation tripped (MW)	DPV tripped on inverter settings only (MW)	Was the case stable? (Yes/No)
OPDMS full NEM model	51	193	97	Yes
Simplified NEM model	51.2	87	100	Yes

[62] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr-appendices.pdf?la=en.

[63] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en.

Figure 9 Simplified PSS®E model and OPDMS full NEM PSS®E model South Australia frequency, South Australia separation at Heywood, 2022 PSFRR Export Case 1

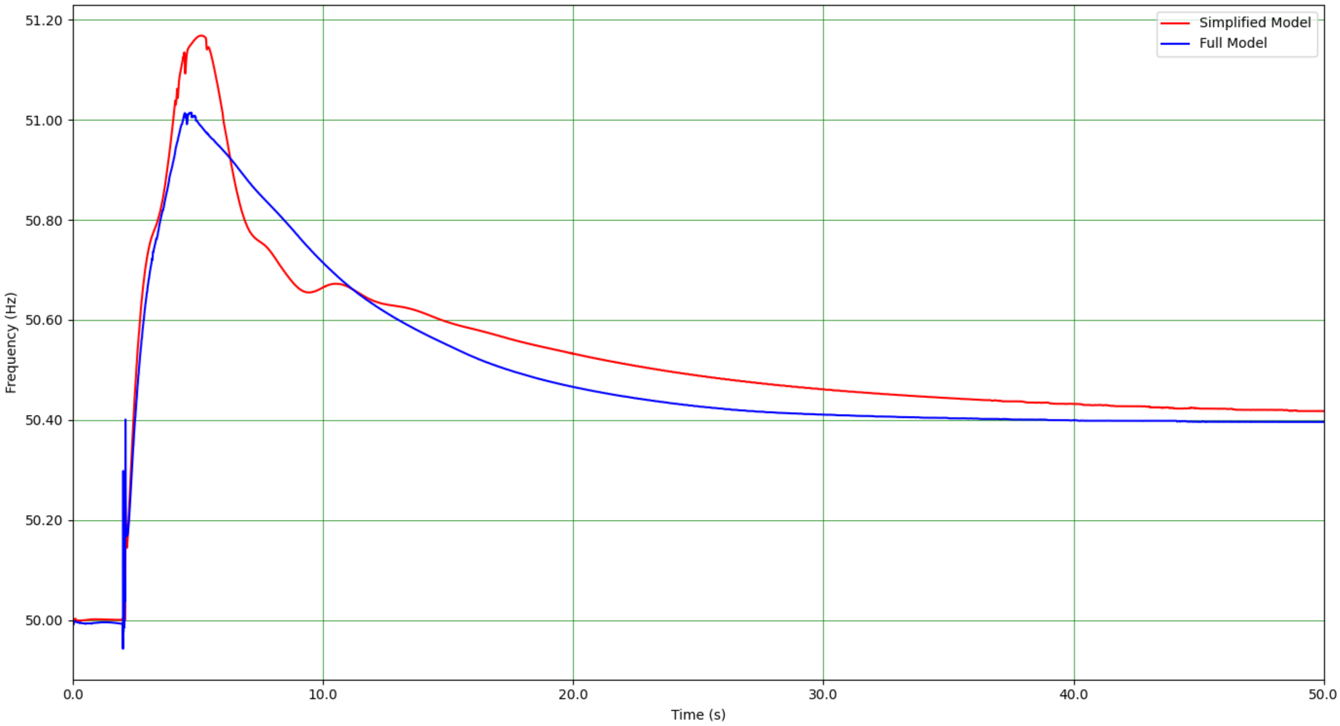


Table 17 Benchmarking results for 2022 PSFRR historical Import Case 1, South Australia separation at Heywood

2022 PSFRR historical Import Case 1, South Australia separation at HYTS				
Model	South Australia frequency nadir (Hz)	South Australia net UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	Was the case stable? (Yes/No)
OPDMS full NEM model	47.8	506	10	Yes
Simplified NEM model	47.6	601	17	Yes

Figure 10 Simplified PSS®E model and OPDMS full NEM PSS®E model, South Australia frequency, South Australia separation at Heywood, 2022 PSFRR import Case 1

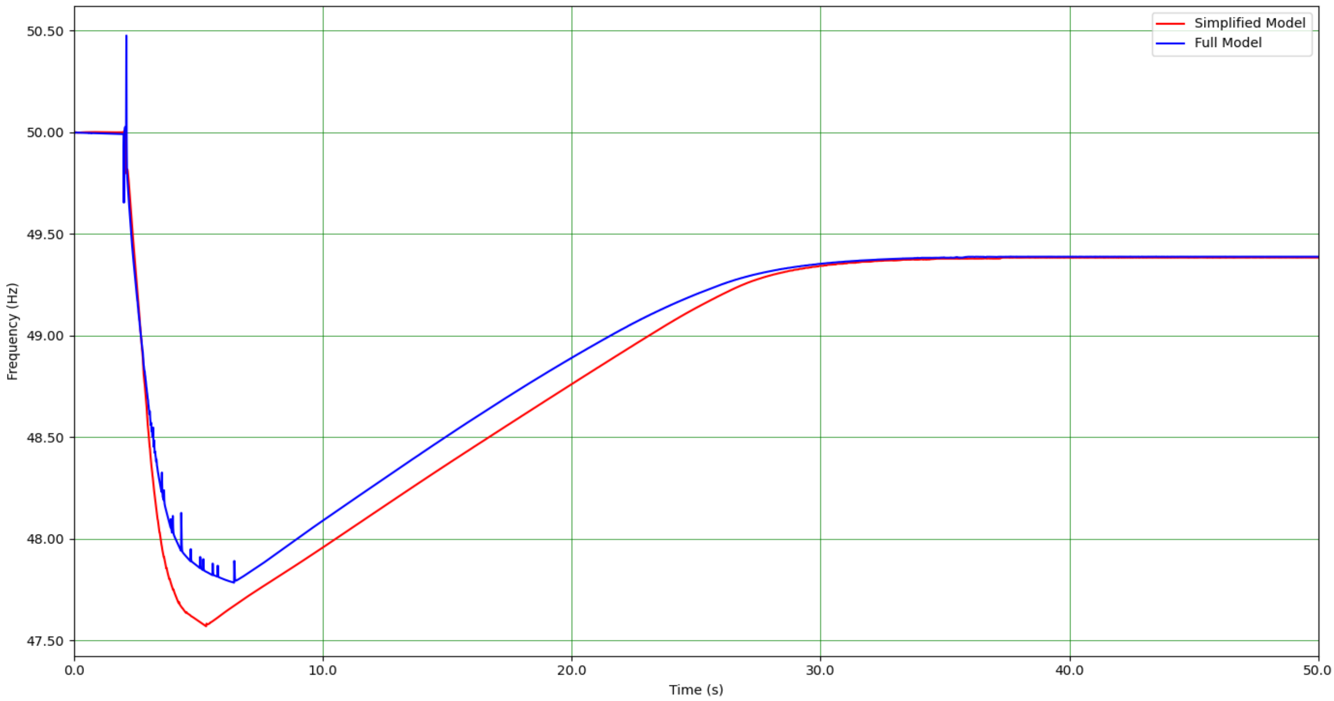
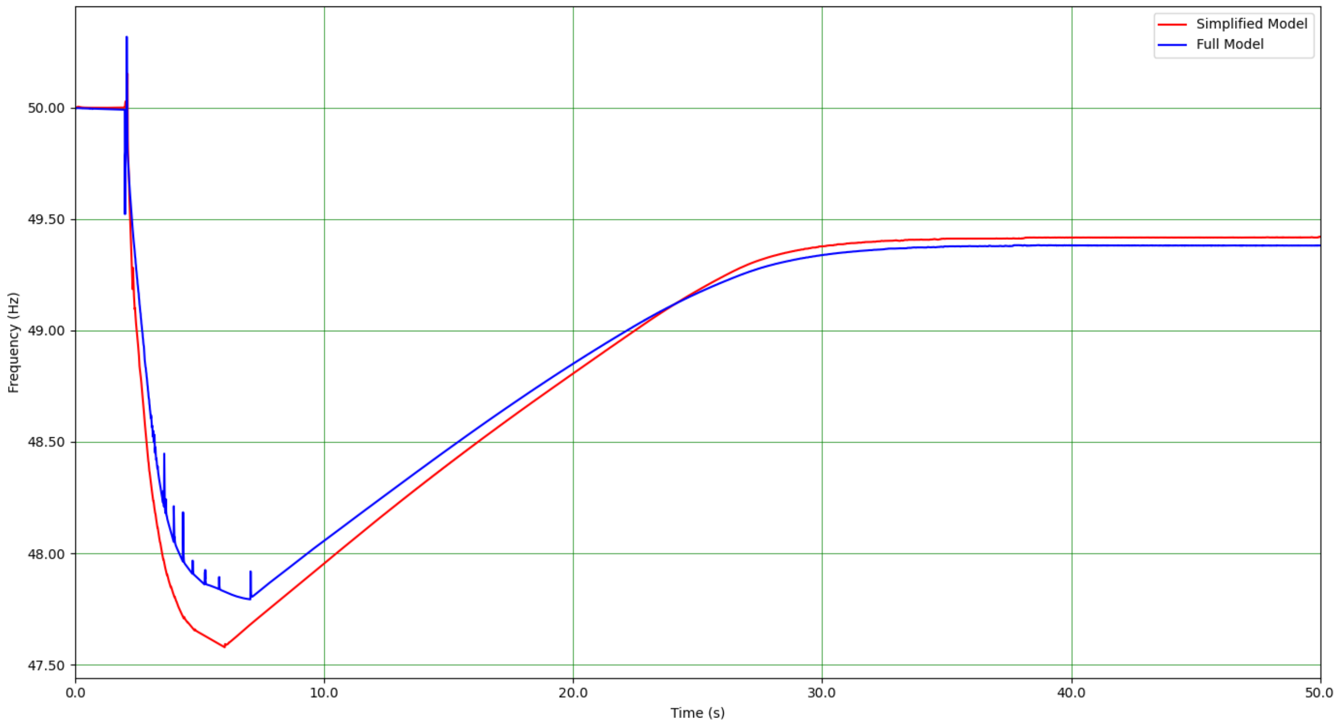


Table 18 Benchmarking results for 2022 PSFRR historical Import Case 1, South Australia separation at Moorabool

2022 PSFRR historical Import Case 1, South Australia separation at MLTS				
Model	**South Australia frequency nadir (Hz)**	**South Australia net UFLS tripped (MW)**	**DPV tripped on inverter settings only (MW)**	**Was the case stable? (Yes/No)**
OPDMS full NEM model	47.8	506	11	Yes
Simplified NEM model	47.6	601	11	Yes

Figure 11 Simplified PSS®E model and OPDMS full NEM PSS®E model, South Australia frequency, South Australia separation at MLTS, Import Case 1



A4.6 Dynamic modelling

A4.6.1 IBR models for large-scale wind and solar generation

The following approach was used for modelling of IBR in the GPSRR studies:

- For those IBR units that have completed PFR commissioning, where appropriate, the generator supplied model represented in OPDMS was used.
- Legacy IBR plants represented in OPDMS as negative loads in New South Wales were represented using generic PSS®E IBR models.
- Anticipated REZ generation was represented using generic PSS®E IBR models.
- Regional lumped IBR generation in the simplified model was represented using generic PSS®E IBR models.

A4.6.2 Battery energy storage system models

For the future FY 2028-29 simplified model studies, for future committed projects where specific models of BESS were not available, a suitable regional lumped generic PSS®E BESS model was used. The total regional large-scale BESS capacities modelled were as per the 2022 ISP *Step Change* scenario market modelling data. The assumed frequency droop for all anticipated large-scale regional BESS was 1.9%[64].

[64] The frequency droop is the percent change in frequency causing unit generation to change by 100% of its capability. This frequency droop value for anticipated BESS was determined as a conservative estimate based on existing projects.

AEMO's analysis suggests that FFR from BESS contributes significantly to the arrest of frequency in significant multiple contingency events, with 1 MW of BESS headroom delivering PFR approximately equivalent to 1 MW of UFLS net load trip[65].

A4.6.3 Primary frequency response (PFR) governor models

PFR applied settings

The following assumption was made for simplified NEM model study cases to account for recent PFR changes applied to generating units:

- The generic governor and controller models were used for the lumped synchronous and IBR plant with minimum PFR settings. The generator's maximum FCAS raise was limited to +5 % of Pmax and lower limited to - 10 % of Pmax.

Governor models for units with no governor models available in OPDMS

Where generating units have implemented new PFR settings, updated governor models were not available to AEMO (in the majority of cases). To address this, AEMO developed three generic governor models corresponding to steam, hydro and gas turbines which represent governor response in line with new PFR settings during frequency events. These generic governor models were used for the 2024 GPSRR studies.

Governor models for units with governors in OPDMS

Generators have an ongoing obligation to provide NSPs and AEMO with up-to-date modelling information which encompasses all control systems that respond to voltage or frequency disturbances on the power system. AEMO sent correspondence to all large mainland NEM generators of their obligations to provide updated frequency control models, and the need for this information to support the GPSRR. Where updated site-specific information was not available, generic governor models with appropriate PFR settings were used.

A4.6.4 Frequency control ancillary services response

Unless stated otherwise, FCAS response of synchronous generators was not considered in the studies apart from the frequency responses provided by PFR governors. The FCAS lower capabilities of IBR were considered according to PFR settings, if PFR commissioning is completed. The PFR capability of IBR plants was not considered if confirmation of frequency control enablement from the generator was not available at the time of the study.

A4.6.5 Load and distributed photovoltaic (DPV) modelling

Load model

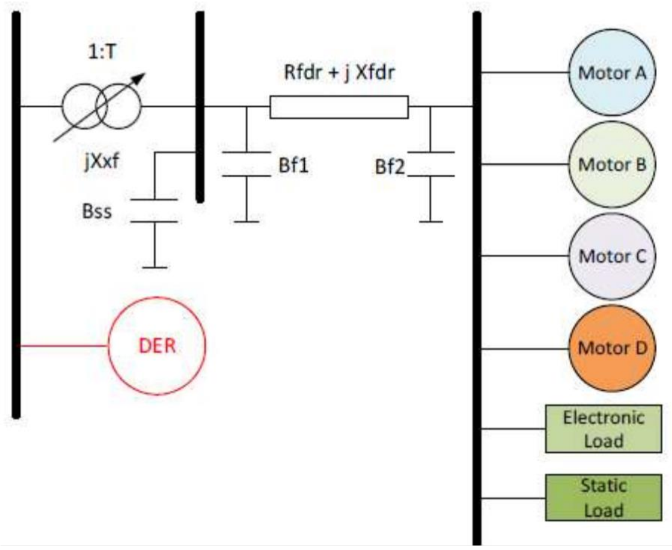
The AEMO CMLD model was used to model load response in all 2024 GPSRR PSS®E full NEM studies. AEMO, NSPs and other stakeholders in the NEM conducting power system studies have used a traditional polynomial static load (ZIP) model to represent the majority of NEM load for over 20 years. Load composition has changed

[65] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645.

considerably over this time, and more sophisticated load models are now available. Adoption of the CMLD model is generally considered industry best practice[66,67].

The CMLD model structure is shown in Figure 12. It consists of six load components at the end of a feeder equivalent circuit, which is represented by a series impedance and shunt compensation. It is intended to emulate various load components' aggregate behaviour. It includes three three-phase (3P) induction motor models (motor A, B and C), a single-phase (1P) capacitor-start motor performance model (motor D), static load components (constant current and constant impedance), and a power electronic load model (constant active and reactive power)[68].

Figure 12 The CMLD model structure and the implementation of the DERAEMO1 model



The CMLD model captures load shake-off in response to large disturbances, which is a significant improvement compared with the previous ZIP model, which does not represent load shake-off. Since the CMLD model comprises explicit representations of different motor types, it better captures load dynamics due to the response of motors.

Distributed photovoltaic (DPV) model

The DERAEMO1 model developed by AEMO was used to model the dynamic behaviour of the DPV generation modelled in the full NEM model cases[66]. A single instance of the DERAEMO1 model was connected to each regional transmission bus, as shown in Figure 12. This single model represents the aggregate behaviour of all DPV connected downstream of that transmission bus, which includes a proportion of DPV installed under different AS4777 standards (and therefore demonstrating different behaviours). Each of the 134 parameters in the DERAEMO1 model was calibrated to represent the total aggregate behaviour of the DPV connected downstream of that bus, depending on the composition of DPV installed.

[66] North American Electric Reliability Corporation (NERC) Reliability Guideline – Developing Load Model Composition Data, March 2017, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_-_Load_Model_Composition_-_2017-02-28.pdf.

[67] NERC Technical Reference Document – Dynamic Load Modelling, December 2016, https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Dynamic%20Load%20Modeling%20Tech%20Ref%202016-11-14%20-%20FINAL.PDF.

[68] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

A4.6.6 Special protection scheme (SPS) models

Typically, for most simulation studies that involve assessment of credible contingency events, SPS models are not included. Given the criticality of such models in the assessment of power system security in response to non-credible contingency events, key SPS models were considered in the studies, as outlined in Table 19. For the 2024 GPSRR studies, if any updated SPS model/relay models were not available, the latest SPS models available at the time of study or appropriate study assumptions were used.

Table 19 Special protection scheme models considered

Model	Region	Model owner	Implementation	Description
EAPT Scheme	VIC	AVP	Fortran	The EAPT scheme is designed to detect loss of 500 kV connection between Heywood and Moorabool and trip the Heywood to South East lines at Heywood, effectively separating the South Australia region at Heywood. The updated EAPT model was included for the GPSRR future studies, with the normally enabled Mode 1 selected. In Mode 1, the EAPT scheme operates as a combination of a topology-based and performance-based scheme.
SIPS/WAPS	SA	ElectraNet	Fortran	The SIPS is an EFCS designed to rapidly identify and respond to conditions that could otherwise result in a loss of synchronism between South Australia and Victoria. It is designed to correct these conditions by rapidly injecting power from batteries or shedding some load to assist in re-balancing supply and demand in South Australia, to prevent a loss of the Heywood interconnector. The SIPS incorporates three discrete progressive stages. The outcome of each stage is intended to defer or prevent the onset of the next stage: Stage 1 – Fast response trigger to inject energy from battery energy storage systems (BESS); Stage 2 – Load shedding trigger to shed approximately 200 MW of South Australian load; and Stage 3 – Out-of-step trip scheme (islanding South Australia). Stage 1 and Stage 2 of SIPS (the battery response and load shedding stages) was replaced by WAPS following its commissioning at the end of 2023, which dynamically calibrates load shedding and battery response to increase the effectiveness of the scheme at preventing Heywood separation following a trip of South Australian generation, while minimising the amount of load shed. Note that Stage 3 of SIPS (loss of synchronism protection of the Heywood interconnector) remains in place. ElectraNet developed and provided PSS®E and PSCAD™ models of the WAPS scheme. For historical FY 2022-23 UFLS studies (using both the simplified and full NEM models), the existing SIPS model was used. Following PEC Stage 2, the SAIT RAS will replace WAPS.
SAIT RAS	SA	ElectraNet	Python	The transmission NSP for South Australia, ElectraNet, is currently designing a special protection scheme – SAIT RAS – to enable maximum transfer on PEC and Heywood interconnectors, while avoiding South Australia islanding in the event of a non-credible loss of either PEC or Heywood interconnector causing transient instability on the remaining interconnector. At the time of this study, specific details of the planned RAS are not available, however, the study assumes a simplified RAS action through South Australian load and generation tripping. Time delay for the RAS trigger was assumed to be 250 ms. The SAIT RAS was assumed to be a topological-based scheme that trips an amount of load (for South Australia import conditions) or generation (for South Australia export conditions) that is calculated based on the level of South Australia import/export. The import/export threshold for the RAS was assumed to be 800 MW, with a difference value of 750 MW. Therefore, if the total South Australia import/export exceeds 800 MW, the amount of load/generation that is tripped by the scheme is equal to the South Australia import/export level minus 750 MW. Note that the tripping of PEC in the event of the loss of synchronism/angular separation of South Australia to island South Australia was not simulated.

A4.7 Forecasting assumptions

The 2022 ISP forecasting methodology, set out in the 2021 ISP Methodology[69], was applied to forecast future network dispatch conditions, noting that the conditions selected were reviewed based on the latest ISP information available following the publication of the Draft 2024 ISP[70] (refer to Appendix A4.7.1). The following parameters were applied to the 2024 GPSRR future projections:

- Short-term schedule half hourly dispatches.
- FY 2028-29.
- High and low demand traces (10% probability of exceedance (POE) and 90% POE).
- Five reference years[71].
- Three solution iterations, to capture different model probabilistic outcomes, such as generation outages.
- The generation build and retirements in the 2022 ISP *Step Change* scenario (see Section 2.1).
- Full network constraints representing the network augmentations assumed in the 2022 ISP *Step Change* scenario (see Appendix A4.2). Minor augmentations that were determined to not have a significant impact on the proposed contingencies were not included.
- No units constrained on for system strength (see Appendix A4.1).

The announced potential closures of power stations such as Eraring Power Station (2025) and Yallourn Power Station (2028) were also considered in future studies.

Assumptions were used which align with AEMO forecasting information including from the ISP. AEMO used the following information sources:

- Regional operational load (high and low) – ISP.
- Regional inertia (high and low) – ISP.
- DER generation for all regions – ISP.
- UFLS load availability for all regions – projected values provided by AEMO.

A4.7.1 Key changes from the 2022 ISP

The Draft 2024 ISP published on 15 December 2023 set out how AEMO has identified the ODP for the NEM[68]. The ISP is adjusted as economic, physical and policy environments change.

As detailed above, the 2022 ISP was used as a basis for developing the future study scenarios for the 2024 GPSRR, as this was the latest market modelling information available at the time of study. AEMO notes the following key differences between the 2022 ISP and the Draft 2024 ISP, and the implications for the 2024 GPSRR HumeLink and future UFLS studies.

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[69] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en.

[70] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf?la=en.

[71] AEMO optimises expansion decisions across multiple historical weather years known as "reference years" to account for short- and medium-term weather diversity.

Updates to inputs, assumptions and scenarios used to analyse the optimal development path

- Stronger emissions reduction policies now apply, with Australia's Paris Agreement commitment increased to 43% emissions reduction by 2030 and the complementary Powering Australia Plan for an 82% share of renewable generation by 2030.
- AEMO's refined scenario set reflects significant expansions in commitments to net zero. AEMO's *Step Change*, *Progressive Change* and *Green Energy Exports* scenarios all align with the updated commitments. *Step Change*, which stakeholder consultation considered 'most likely', is centred around achieving a scale of energy transition that supports Australia's contribution to limiting global temperature rise to below 2°C (and may be compatible with 1.5°C pathways for the NEM, depending on the actions taken across other sectors of Australia's economy).
- CER are forecast to be taken up even faster than before, with 18 GW more rooftop solar by 2050 under *Step Change* compared to the 2022 ISP.
  – The regional DPV installed capacity directly impacts dispatch patterns, and therefore the FY 2029 dispatches studied for the 2024 GPSRR HumeLink studies. An increase in installed DPV capacity could also result in larger contingency sizes due to additional DPV shake-off. As such, updates in DPV projections need to be considered in future GPSRRs. However, the primary parameters that influence power system performance for the non-credible loss of the HumeLink lines are HumeLink flow and the dispatch around Bannaby. Therefore, the findings from these studies are still likely reflective of future scenarios.
  – The regional DPV installed capacity directly impacts available UFLS as well as dispatch patterns. An increase in installed DPV capacity would result in reduced UFLS availability and the potential for larger contingency sizes due to DPV shake-off. As such, updates in DPV projections need to be considered in future UFLS reviews and GPSRRs. However, as detailed in Appendix A4.5.4, sensitivities with a wide range of levels of DPV generation and DPV shake off/tripping were assessed as part of the 2024 GPSRR studies. Therefore, the findings from these studies are still likely reflective of future scenarios.
- Higher costs for transmission, generation and storage have been observed in recent years due to supply chain issues and workforce shortages, including around 30% increases for transmission projects. AEMO expects that transmission project costs will continue to increase beyond the rate of inflation as the sector adapts to market pressures and to account for environmental and land costs.

Further analysis to inform the optimal development path

- Sensitivity analysis now considers the impact of low social licence on the development opportunities and transmission network developments considered in the ISP.
- Analysis considers the impact of gas system capacity limitations on the operation of gas-fired generation during peak periods.
- Consumer risk preferences have been investigated through in-person focus groups and an online survey, finding that in general consumers are open to some prudent infrastructure investment now to manage the risk of future price shocks – although this needs to be weighed carefully against any near-term bill impact.

Changes to the speed or scale of the optimal development path

- The entire coal fleet in the NEM is retired by 2038 in *Step Change* in the Draft 2024 ISP, five years earlier than in the 2022 ISP.
  - All generation retirements for FY 2028-29 were modelled in the GPSRR future studies, as per the 2022 ISP. Any subsequent changes in potential retirement dates will be considered in future GPSRRs.
- Renewable energy is needed earlier, with a need for 6 GW of new renewable energy per year under *Step Change* in the coming decade, compared to 4 GW in the 2022 ISP (and a current rate of almost 4 GW[72]). This is to replace the coal generation capacity that is exiting faster and to meet the higher demand forecast compared to the 2022 ISP.
  - For the 2024 GPSRR future studies, large-scale REZ generation was modelled as lumped generators in both the simplified and OPDMS full NEM models. The capacity of renewable generation in the GPSRR FY 2028-29 dispatches is consistent with the 2022 ISP *Step Change* scenario.
- There is an increased need for dispatchable supply and a shift towards consumer-owned storage. The Draft 2024 ISP increases backup gas-powered generation capacity to 16 GW by 2050, up from 10 GW in the 2022 ISP. The forecast need for medium-depth storage has reduced by 5 GW due to increased wind generation and increased storage capacity from consumer energy resources.
- The 2023 *Progressive Change* scenario acknowledges more rapid change due to new policies and is now considered almost as likely as *Step Change*. However, the near-term need for projects across the NEM is common to both scenarios, with only two actionable projects required slightly later in *Progressive Change* than *Step Change*.
  - For the 2024 GPSRR future studies, the 2022 ISP *Step Change* scenario was used because it was considered most likely at the time of study. Minor modifications were made to the dispatches/market modelling assumptions based on changes since the 2022 ISP – namely, the removal of the Snowy 2.0 project due its completion date being after FY 2028-29 in the July 2023 Generation Information workbook[73].

Changes to investment in the ODP

- Net market benefits of transmission investment have reduced by 37%, from $27.7 billion in the 2022 ISP to $17.45 billion, due to factors including increased transmission costs, generator and storage costs, updated energy policies, commitment to transmission projects whose benefits are now assumed and not included in the total, and lower gas prices.
- The need for new transmission network is broadly the same over the coming decade. Beyond the next decade, the ODP sees slightly less transmission build than the 2022 ISP, due to higher transmission costs, the optimisation of project options, and more generation from sources that need less transmission.

[72] This is generation which commenced operating at its full capacity.

[73] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

- There is more offshore wind in Victoria and more pumped hydro (and supporting transmission) in Queensland in line with state government policies.
  - These additional projects have anticipated completion dates later than FY 2028-29, and therefore do not impact the 2024 GPSRR future studies. The impact of these projects will be considered in future GPSRRs.
- Transmission projects have progressed across the NEM:
  - Some planned projects have been completed and are now operational, including QNI Minor, VNI Minor and Eyre Peninsula Link.
    - As detailed in Appendix A4.2, these augmentations are considered in all 2024 GPSRR studies.
  - There are also newly committed or anticipated transmission projects, such as CopperString 2032 and increased capacity planned for the Central West Orana REZ Transmission Link.
    - The CopperString 2032 project does not impact the 2024 GPSRR future studies, as its completion date is later than FY 2028-29. Instead, the impact of this augmentation will be considered in future GPSRRs.
    - The latest Central West Orana REZ Transmission Link full capacity timing advised by the proponent is August 2028, which is later than the date advised in the 2022 ISP. However, this date is still within the timeframe for the GPSRR future studies (FY 2028-29).
  - Future ISP projects have become actionable projects, as expected. In Queensland, SuperGrid South (formerly Central to Southern Queensland) and Gladstone Grid Reinforcement have become actionable. In New South Wales, the New England REZ Extension and further augmentation are now included as stages in the New England REZ Transmission Link project.
    - These Queensland ISP projects have completion dates later than FY 2028-29, and therefore do not impact the 2024 GPSRR future studies.
    - Regarding the New England REZ, for the 2024 GPSRR future studies, large-scale REZ generation was modelled as lumped generators in the simplified model. The capacity of renewable generation in the GPSRR FY 2028-29 dispatches is consistent with the 2022 ISP *Step Change* scenario.
  - Since the 2022 ISP, the VNI West augmentation completion[74] date was brought forward to December 2029. As this completion date is still later than FY 2028-29, the impact of this augmentation will be considered in the 2025 GPSRR.

ARENA Large Scale Battery Funding Round

- In December 2022, eight batteries were selected to receive the Australian Renewable Energy Agency's (ARENA) Large Scale Battery Storage funding round[75].
- This additional investment will see an additional 500 MW of large-scale BESS capacity installed in Queensland, 400 MW in South Australia, 250 MW in New South Wales and 550 MW in Victoria, compared to what was included in the 2022 ISP market modelling data used for the 2024 GPSRR UFLS studies.

[74] This date corresponds to the 'capacity release date' published in the Transmission Augmentation Information workbook.

[75] See https://arena.gov.au/funding/large-scale-battery-storage-funding-round/.

- Additional large-scale BESS headroom availability will directly improve the under-frequency response of the system and reduce the reliance on UFLS. Therefore, the 2024 GPSRR future UFLS screening studies are likely conservative in terms of the future available BESS capacity/headroom.

A4.8 PEC Stage 1 destructive wind limits modelling approach

A4.8.1 Assumptions of the current NEM model

A current OPDMS model was updated to include PEC Stage 1 and committed generation in South Australia to reflect operating conditions post PEC Stage 1. This model was modified as outlined in Section 4.2.

In addition, the following assumptions were used for the modelling approach:

- AEMO DER and CMLD models were included as outlined in Appendix A4.8.2 and Appendix A4.8.3, with percentage DPV as specified for each case as outlined in Appendix A4.8.6.
- AEMO generic governor models were applied to all NEM generators where dynamic models with updated PFR settings were not available.
- UFLS relays were not modelled, because NEM frequency should not fall below 49 Hz as a result of the loss of 500 MW of generation (as this is smaller than the largest credible contingency in the mainland NEM), and South Australia separation was considered a fail with respect to the study acceptance criteria.
- OFGS schemes were not included, because NEM frequency should not increase as a result of loss of 500 MW of generation and South Australia separation was considered a fail with respect to the study acceptance criteria.
- The wide area protection scheme (WAPS)[76] in South Australia was not integrated into the model or considered when studying destructive wind conditions after PEC Stage 1. This was decided to maintain consistency with the approach taken to determine the original 250 MW limit for destructive wind conditions for the protected event.
- Given the focus of these studies on the South Australia system and the modelling approach to exclude the WAPS, the inclusion of any other SPS models was not required.
- A 500 MW generation loss was assumed as the initial contingency size in line with the approach taken with the original protected event, but other contingency sizes were considered in sensitivity studies. This is discussed in more detail in Section 4.2.
- A minimum of two synchronous units online in South Australia was assumed for these studies where PEC Stage 1 was in service. This was chosen because the voltage control and support in the Adelaide region requires at least one synchronous unit to be online, meaning that, operationally, two synchronous online units are required to manage the loss of one. The current operational requirements are two synchronous online units in South Australia and it is assumed for these studies that this will be the case until PEC Stage 2 is operational.
- It was assumed that generation tripping occurs simultaneously for the contingencies applied in these studies. This represents the worst-case scenario and therefore was adopted as the base case. However, sensitivities

[76] See the 2020 PSFRR for more details: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-2/2020-psfrr-stage-2-final-report.pdf?la=en.

were run with varied generation tripping times to understand the impact delayed tripping had on interconnector stability.

- In the 2022 PSFRR, AEMO calculated that constraining Heywood import to 430 MW and PEC Stage 1 import to 70 MW should be sufficient to prevent either interconnector exceeding the satisfactory limits of 850 MW for Heywood and 250 MW for PEC Stage 1 following a trip of 500 MW of South Australia generation. These were studied to determine if a 500 MW contingency size at these transfer levels would cause instability.
- Differences between the National Electricity Market Dispatch Engine (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. As per the 2022 PSFRR, the transfer levels of 430 MW for Heywood and 70 MW for PEC Stage 1 were determined assuming that up to 100 MW of interconnector drift may occur.

A4.8.2 DPV model

The DERAEMO1 model developed by AEMO was used to model the dynamic behaviour of the DPV generation modelled in the full NEM model cases[77] – see Appendix A4.6.5.

DPV mapping to buses

For these studies the standard DPV modelling approach was applied[31]. DPV generation was lumped at different bus locations in the OPDMS full NEM model based on data from DNSPs and the Clean Energy Regulator which was analysed and compiled by AEMO as part of the development of the DERAEMO1 model. This approach most accurately reflects the physical distribution of this type of generation in the system. Therefore, it better captures how DPV generation will respond to power system disturbances, because the proximity of DPV installations to the fault location is better represented.

A4.8.3 Load modelling

The AEMO CMLD model was used to model load response in all GPSRR PSS®E full NEM studies – refer to Appendix A4.6.5.

A4.8.4 Contingency size

To align with the approach taken in the upgraded SIPS design, the contingency size of 500 MW was also considered as the initial contingency for these studies. However, sensitivities were run to understand the impact that larger contingencies would have on the system.

[77] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

New connections in South Australia

Since 2019 and as of Q1 2024, there have been a number of new connections to the South Australia network that would not have been considered in the reasoning for the original 500 MW contingency size. Significant connections include:

- Port Augusta Renewable Energy Park – Solar (79 MW).
- Lincoln Gap Wind Farm Stage 2 (86 MW).
- Tailem Bend Stage 2 Solar (105 MW).
- Torrens Island BESS (250 MW).

These connections are not larger than existing generators in South Australia and do not substantially increase the likelihood of larger contingency sizes. The connection of Torrens Island BESS should assist in reducing the effective contingency size if online and available to provide FFR.

Committed and anticipated generation in South Australia

In addition to the new connections that are currently in the grid, there is also substantial committed and anticipated generation proposed, such as:

- Goyder South Wind Farm 1A (209 MW committed).
- Goyder South Wind Farm 1B (203 MW committed).
- Cultana Solar Farm (357 MW anticipated).

With the addition of this large capacity committed and anticipated generation in South Australia, the likelihood of contingency sizes greater than 500 MW may increase once they are operational. These connections are larger than many of the existing wind or solar farms, and losing all of Goyder South or Cultana Solar Farm will result in a large portion of the 500 MW contingency size already being met. Sensitivity studies have been considered for generation contingencies greater than 500 MW to account for this.

The recently commissioned WAPS is designed to reduce the likelihood of Heywood tripping following disconnection of up to 500 MW of South Australian generation. WAPS improves on the previous SIPS by using a more sophisticated and accurate method of detecting impending unstable power swings on Heywood, increasing the available battery response, and sizing its response according to the severity of the incident to avoid tripping excessive load. ElectraNet will modify WAPS as needed so it remains effective for the network topology that includes PEC Stage 1.

DPV impact on contingency size

In low load and high DPV conditions, it is possible for the load and DPV shake-off caused by the initial contingency to increase the contingency size by several hundred megawatts. The impact of the DPV shake-off was not considered in the original request for the protected event, except for noting the uncertainty in how embedded generation such as DPV would respond during the event. As more DPV connects to the South Australia network, the impact of DPV shake off increases the possibility the contingency sizes larger than 500 MW may be experienced. Due to this, sensitivities were studied with contingency sizes greater than 500 MW.

A4.8.5 South Australia destructive wind transfer limit contingencies

Three different contingencies were studied as part of the 2024 GPSRR, with the following assumptions:

- A two phase-to-ground (2ph-G) zero impedance fault was applied at the Torrens Island or Robertstown 275 kV bus.
- Generation was tripped of either 100 MW or 500 MW of synchronous or asynchronous generation, depending on the contingency and the case.
- Contingencies were assessed assuming the NER primary fault clearance time of 100 ms[78].

The initial contingencies listed in Table 20 cover scenarios with variation in contingency size, location of fault and type of generation tripped.

Table 20 Initial study contingencies

Contingency #	Contingency size (MW)	Faulted bus	Clearing time (s)	Outage(s)/description
1 (100 MW synchronous)	100	275 kV TIPS B bus	0.1	Loss of 100 MW generation through tripping TIPS B Unit 2
2 (500 MW synchronous)	500	275 kV TIPS B bus	0.1	Tripping of 500 MW of synchronous generation (if dispatched synchronous generation is less than 500 MW, additional asynchronous generation tripped to make the 500 MW total contingency size).
3 (500 MW asynchronous)[A]	500	275 kV Robertstown bus	0.1	Tripping of 500 MW of asynchronous generation (if dispatched asynchronous generation is less than 500 MW, trip all asynchronous generators and additional synchronous generation required to make the 500 MW total contingency size).

A. This contingency is less onerous than contingency 2, but is designed to reflect the contingency that was experienced in the 2016 South Australia black system incident: 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.

Contingency size sensitivity contingencies

For the sensitivity studies involving variation of the contingency size, contingencies were selected ranging from 100 MW to 1,000 MW of generation. As the total online generation in South Australia was limited, the contingencies shown in the table were split across both synchronous and asynchronous generation types. These contingencies apply to cases 2c1-2c8, 5c1-5c8, 10c1-10c8 and 5c11-5c18. The last two contingencies 12 and 13 were only applied for the cases that were studied with no CMLD/DER models included.

Table 21 Contingency size sensitivity contingencies

Contingency #	Contingency size (MW)	Faulted bus	Clearing time (s)	Outage(s)/description
4	100	275 kV TIPS B bus	0.1	Simultaneous loss of 100 MW sync/ async generation in South Australia region
5	200	275 kV TIPS B bus	0.1	Simultaneous loss of 200 MW sync/ async generation in South Australia region
6	300	275 kV TIPS B bus	0.1	Simultaneous loss of 300 MW sync/ async generation in South Australia region

[78] See Table S5.1a.2 in NER Chapter 5.

Contingency #	Contingency size (MW)	Faulted bus	Clearing time (s)	Outage(s)/description
7	400	275 kV TIPS B bus	0.1	Simultaneous loss of 400 MW sync/ async generation in South Australia region
8	500	275 kV TIPS B bus	0.1	Simultaneous loss of 500 MW sync/ async generation in South Australia region
9	600	275 kV TIPS B bus	0.1	Simultaneous loss of 600 MW sync/ async generation in South Australia region
10	700	275 kV TIPS B bus	0.1	Simultaneous loss of 700 MW sync/ async generation in South Australia region
11	800	275 kV TIPS B bus	0.1	Simultaneous loss of 800 MW sync/ async generation in South Australia region
12	900	275 kV TIPS B bus	0.1	Simultaneous loss of 900 MW sync/ async generation in South Australia region
13	1,000	275 kV TIPS B bus	0.1	Simultaneous loss of 1000 MW sync/ async generation in South Australia region

Delayed generation tripping sensitivity contingencies

For sensitivity studies involving delayed generation tripping times, four contingencies were used to investigate the effect a delay in machine tripping times could have on stability. Each machine was delayed by one and two seconds for contingency 14 and 15 respectively. The contingencies shown in Table 22 were used for cases 5d1, 5d2, 5d3, 5d4 and only tripped asynchronous generation.

Table 22 Delayed tripping sensitivity contingencies

Contingency #	Contingency size (MW)	Faulted Bus	Clearing time (s)	Outage(s)/Description
14	500	275 kV Robertstown bus	0.1	Tripping of 500 MW of asynchronous generation, with 1 second delay between trip of each machine.
15	500	275 kV Robertstown bus	0.1	Tripping of 500 MW of asynchronous generation, with 2 second delay between trip of each machine.

A4.8.6 Sensitivities

After the initial studies identified the cases that were closest to the stability limits, sensitivities were run to understand the impact of the following factors on system stability:

- Contingency size.
- Interconnector flow.
- Inertia/system strength (number of synchronous generators).
- Delay between tripping of generation.
- Ratio of flow over Heywood/PEC.

Interconnector flow sensitivities

For interconnector flow studies, the pre-contingent flow over Heywood and PEC was modified to understand the impact that this would have on the stability of the interconnectors. Base cases 2, 5, 6, 7 and 10 were selected to run interconnector flow sensitivities. For each of these cases, the interconnector flow ratios between Heywood and PEC Stage 1 were kept approximately constant, but the total interconnector import levels into South Australia was varied. These sensitivities were designed to understand the required headroom for stability for the interconnectors for each of the base cases studied.

Table 23 Interconnector flow sensitivities – denoted by suffix "a":

Case	SA non-DER Load [MW]	DPV in SA [%]	Number of sync gens in SA	SA inertia [MWs]	SA synchronous generation [MW]	SA asynchronous generation [MW]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (HIC+PEC) [MW]
2a1	2,079	40	16	5,757	500	934	463	152	100	615
2a2	1,979	40	16	5,757	500	934	381	125	100	506
2a3	1,779	40	16	5,757	500	934	222	70	100	292
2a4	1,679	40	16	5,757	500	934	144	46	100	190
2a5	1,579	40	16	5,757	500	934	33	20	100	53
5a2	2,690	15	2	5,333	100	2,041	516	84	167	600
5a3	2,590	15	2	5,333	100	2,041	430	70	167	500
5a4	2,490	15	2	5,333	100	2,041	344	56	167	400
5a5	2,390	15	2	5,333	100	2,041	258	42	167	300
6a1	2,817	15	2	5,333	100	2,551	218	55	95	272
6a2	2,717	15	2	5,333	100	2,551	138	35	95	172
7a1	2,509	20	2	5,333	100	1,484	734	183	167	917
7a2	2,309	20	2	5,333	100	1,484	559	128	167	687
7a3	2,209	20	2	5,333	100	1,484	475	98	167	573
7a4	2,109	20	2	5,333	100	1,484	390	72	167	462
7a5	2,009	20	2	5,333	100	1,484	309	44	167	353
7a6	1,909	20	2	5,333	100	1,484	230	16	167	246
10a1	2,309	60	2	5,333	100	1,484	565	126	167	691
10a2	2,209	60	2	5,333	100	1,484	479	97	167	576
10a3	2,109	60	2	5,333	100	1,484	392	70	167	462
10a4	2,009	60	2	5,333	100	1,484	309	42	167	351
10a5	1,909	60	2	5,333	100	1,484	127	16	167	143

Inertia and system strength sensitivities

Sensitivities were completed varying the number of synchronous machines online to investigate the impact on interconnector stability. Base case 5 was selected for this sensitivity because it was unstable with high pre-contingent interconnector flows. The aim of these studies was to identify if additional system strength and inertia could result in a marginally stable case. As synchronous generation was added to the model for each sensitivity, asynchronous generation was reduced to compensate, keeping the total generation and load approximately constant.

Table 24 Inertia/system strength sensitivities – denoted by suffix "b":

Case	SA non-DER Load [MW]	DPV in SA [%]	Number of sync gens in SA	SA inertia [MWs]	SA synchronous generation [MW]	SA asynchronous generation [MW]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (HIC+PEC) [MW]
5b1	2,890	15	3	6,200	200	1,941	645	155	167	800
5b2	2,890	15	4	7,100	300	1,841	645	155	167	800
5b3	2,890	15	5	8,000	400	1,741	645	155	167	800
5b4	2,890	15	6	9,100	500	1,641	645	155	167	800
5b5	2,890	15	7	10,000	600	1,541	645	155	167	800
5b6	2,890	15	8	11,000	700	1,441	645	155	167	800

Contingency size sensitivities

Sensitivities varying the generation contingency size were completed to determine the size of generation loss that would result in instability for a range of South Australia operating conditions. The interconnector flows were kept constant across all cases at the levels specified in the 2022 PSFRR, at 430 MW and 70 MW for Heywood and PEC respectively. Cases 2, 5 and 10 were selected as the base for these sensitivities, with the only adjustment being the interconnector flows and load to align with the transfer levels. Case 5 was used as a base for two different model variations. One case (5c1 – 5c8) has more asynchronous generation, while the other (5c11 – 5c18) has more synchronous machines. For each of these cases, contingencies were applied that ranged from 100 MW to 800 MW in increments of 100 MW. This study was designed to identify the point of instability across different dispatches when operating at these limits.

Table 25 Contingency size sensitivities – denoted by suffix "c":

Case	SA non-DER Load [MW]	DPV in SA [%]	Number of sync gens in SA	SA inertia [MWs]	SA synchronous generation [MW]	SA asynchronous generation [MW]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (HIC+PEC) [MW]
2c1 – 2c8	1,973	40	16	5,757	500	934	430	70	100	500
5c1 – 5c8	2,590	15	2	5,333	100	2,041	430	70	115	500
10c1 – 10c8	2,109	60	2	5,333	100	1,484	430	70	129	500
5c11-5c18	2,590	15	8	11,000	700	1,441	430	70	167	500

The contingency size for each case is designated by the naming convention of the cases. The ending characters of the case correspond to the following contingency sizes:

- c1/c11 = 100 MW.
- c2/c12 = 200 MW.
- c3/c13 = 300 MW.

- c4/c14 = 400 MW.
- c5/c15 = 500 MW.
- c6/c16 = 600 MW.
- c7/c17 = 700 MW.
- c8/c18 = 800 MW.

Delay of generation tripping sensitivities

This sensitivity study was designed to investigate the impact of staggered generation tripping on interconnector stability in comparison to the base case contingencies where all generation is lost simultaneously. This sensitivity was chosen to run to simulate similar conditions to the 2016 black system event in South Australia, where generation tripped gradually. For these sensitivities, instead of tripping all the generators at the same time, generator outages were staggered by one second and two seconds. Case 5 was used as a base model for case 5d1 and 5d2, and case 5a2 was used as a base model for 5d3 and 5d4. The intent was to understand how delaying generator tripping affects the severity of the contingency and any impact on the stability of the Heywood and PEC interconnectors.

Table 26 Delay of generation tripping sensitivities – denoted by suffix "d":

Case	SA non-DER Load [MW]	DPV in SA [%]	Number of sync gens in SA	SA inertia [MWs]	SA synchronous generation [MW]	SA asynchronous generation [MW]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (HIC+PEC) [MW]
5d1	2,890	15	2	5,333	100	2,041	645	155	167	500
5d2	2,590	15	2	5,333	100	2,041	645	155	167	500
5d3	2,690	15	2	5,333	100	2,041	516	84	167	500
5d4	2,690	15	2	5,333	100	2,041	516	84	167	500

Where:

- d1, d3 = 1 second delay between each generator tripping.
- d2, d4 = 2 second delay between each generator tripping.

Different ratio of PEC/Heywood flow sensitivities

The ratio of power flow across Heywood and PEC can be modified by changing the angle of the phase shifting transformer (PST) at Buronga. Sensitivity studies were run with five different PST angles selected to take PEC from approximately 0 MW to its satisfactory limit of 250 MW. These studies were chosen to investigate whether utilising different ratios of flow on the interconnectors would impact on the stability limits. If one interconnector becomes unstable before the other, these sensitivities were designed to study what the optimal PST angle would be to allow for the largest total transfer before instability.

Table 27 Different ratios of PEC/Heywood flows – denoted by suffix "e":

Case	SA non-DER Load [MW]	DPV in SA [%]	Number of sync gens in SA	SA inertia [MWs]	SA synchronous generation [MW]	SA asynchronous generation [MW]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (HIC+PEC) [MW]
7e1	2,109	20	2	5,333	100	1,484	475	2	167	477
7e2	2,109	20	2	5,333	100	1,484	408	62	167	470
7e3	2,109	20	2	5,333	100	1,484	340	125	167	465
7e4	2,109	20	2	5,333	100	1,484	274	188	167	462
7e5	2,109	20	2	5,333	100	1,484	212	251	167	463
10e1	2,009	60	2	5,333	100	1,484	350	4	167	354
10e2	2,009	60	2	5,333	100	1,484	283	66	167	349
10e3	2,009	60	2	5,333	100	1,484	221	127	167	348
10e4	2,009	60	2	5,333	100	1,484	157	192	167	349
10e5	2,009	60	2	5,333	100	1,484	99	252	167	351

A5. Simulation results

This section gives detailed references to study cases, results, sensitivity studies, and key result graphs for the three priority risks as well as the PEC Stage 1 destructive wind limit studies.

A5.1 Priority risk 1: Circuit breaker failure (CBF) event in Latrobe Valley leading to trip of multiple large generating units and Basslink instability

A5.1.1 VIC_39 case, Basslink flow from Tasmania to Victoria

The figures below show that, following the contingency, the Loy Yang A3 unit loses stability and produces large oscillations. This causes the whole power system to become unstable due to cascading failures.

Figure 13 VIC_39 case, Loy Yang A3 generating unit active power output (MW)

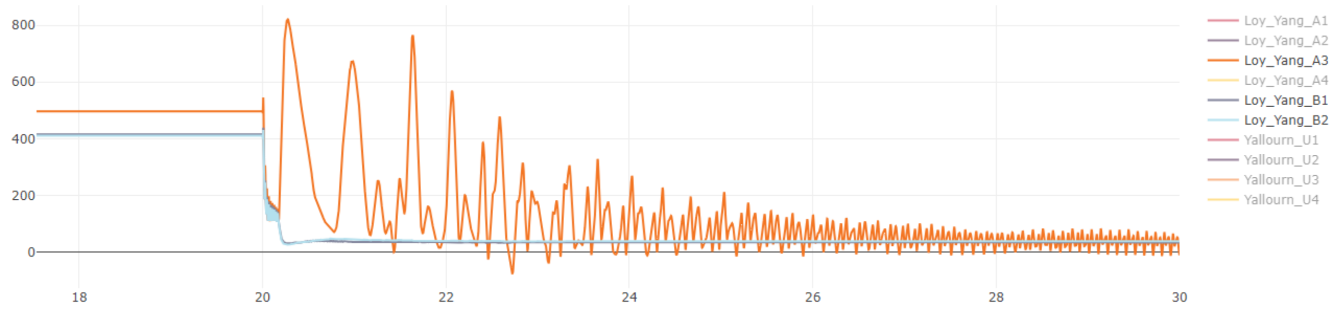


Figure 14 VIC_39 case, voltage levels in buses in Victoria (pu)

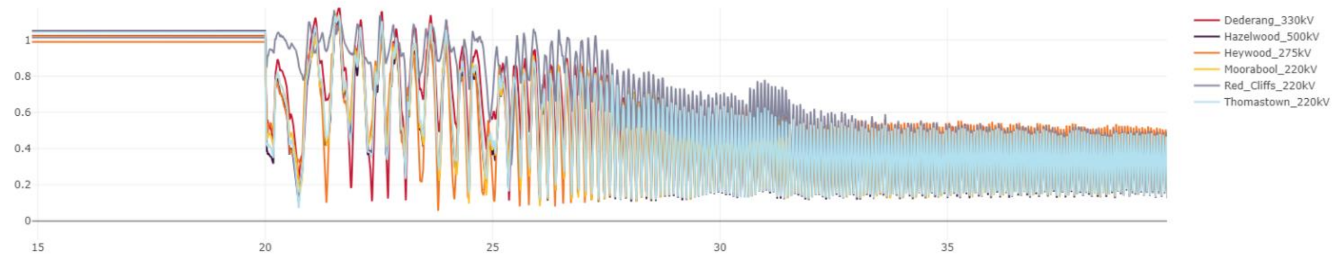
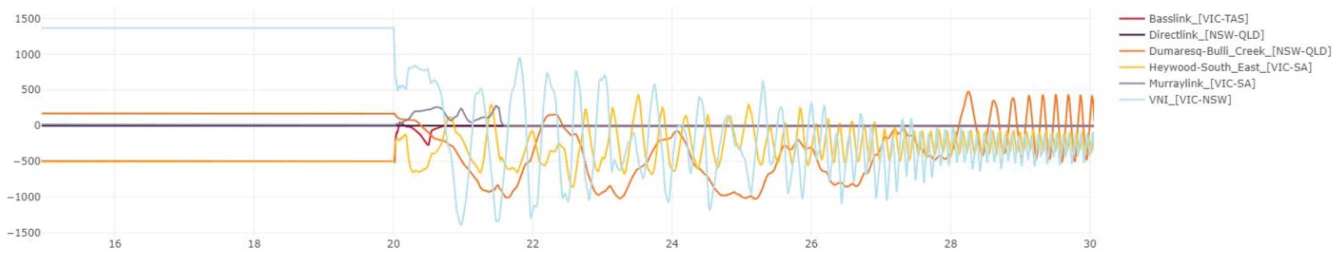


Figure 15 VIC_39 case, interconnector power flow levels (MW)



A5.1.2 VIC_9 case, Basslink flow from Tasmania to Victoria

The figures below show that, following the contingency, large low-frequency voltage oscillations can be observed around Darlington Point, Wagga, and Jindera.

Figure 16 VIC_9 case, Victoria system voltages (pu)

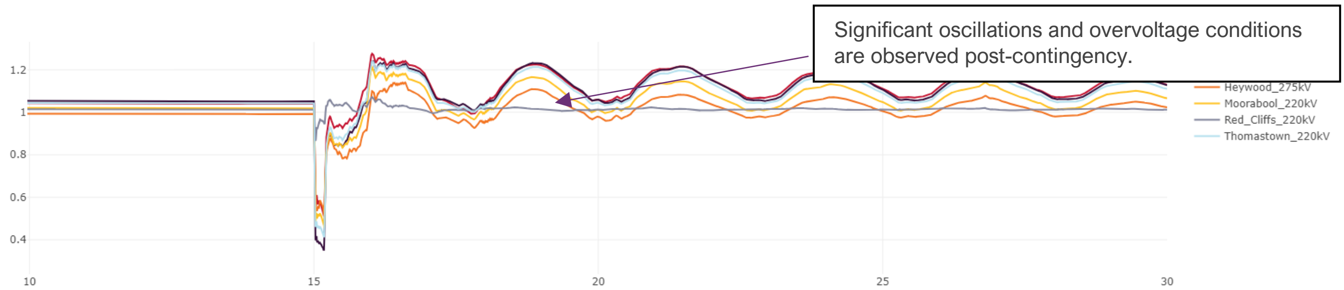
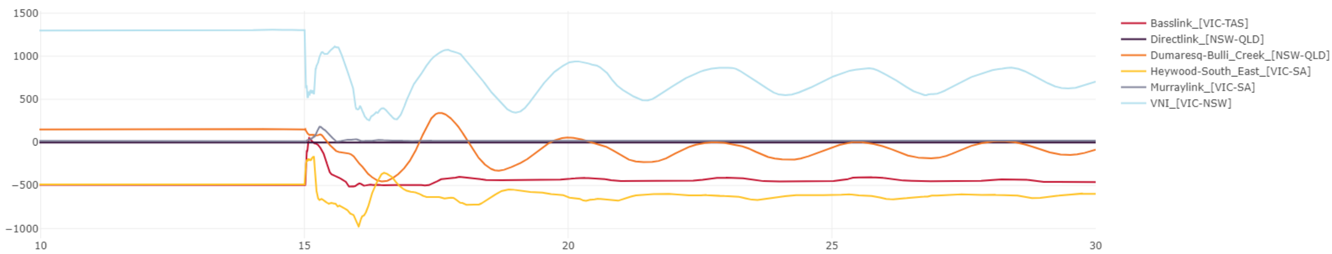


Figure 17 VIC_9, interconnector power flow levels (MW)



A5.1.3 Sensitivities

Basslink flow from Victoria to Tasmania

Table 28 Risk 1 study results (Basslink flow Victoria to Tasmania)

Combination	2phg - 175 ms	3ph-G	
		175 ms	100 ms
VIC_9	☑	☒	☑
VIC_39	☑	☒	☑

- The VIC_39 case marginally passed the acceptance criteria when a 2ph-G fault was applied and with a clearance time of 175 ms.
  - Oscillations were prominent in the active power output of the Loy Yang A3 unit.
  - Basslink reduced its power output to 50 MW following the clearing of the fault.
  - Two wind farms in Victoria (Salt Creek Wind Farm and Moorabool Wind Farm) showed unstable behaviour post fault-clearance.
- Both the VIC_9 and VIC_39 cases became unstable after applying a three-phase-to-ground (3ph-G) fault with a clearance time of 175 ms.

- The instability was initially caused by the pole slipping of the remaining Loy Yang A3 synchronous generating unit. This led to the tripping of Basslink and cascading failure of the whole power system.

- When 3ph-G fault was applied and cleared at 100 ms, both VIC_9 and VIC_39 cases recovered and became stable.
  - Some damped oscillations were observed in the active power output of the remaining Loy Yang A3 unit.
- For the VIC_9 case, the frequency nadir measured at Hazelwood was approximately 49.4 Hz following fault clearance.

Note that unmodelled system dynamics, such as the response of DPV generation, could significantly increase the effective contingency size.

Figure 18 VIC_9 case, Loy Yang A3 generating unit active power output (MW)

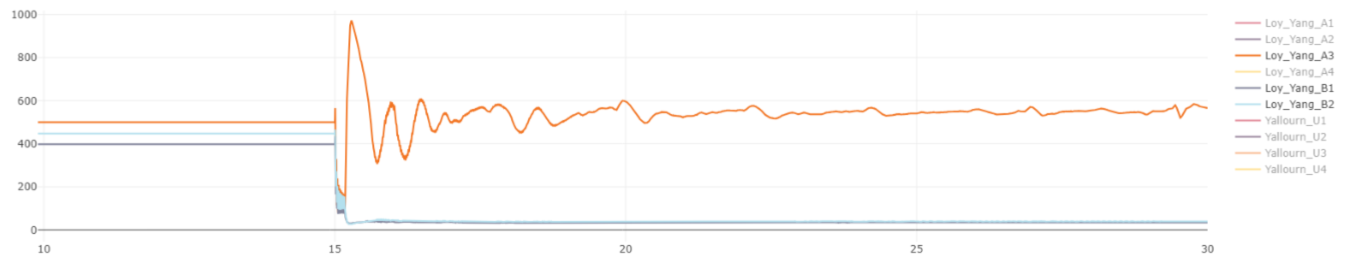
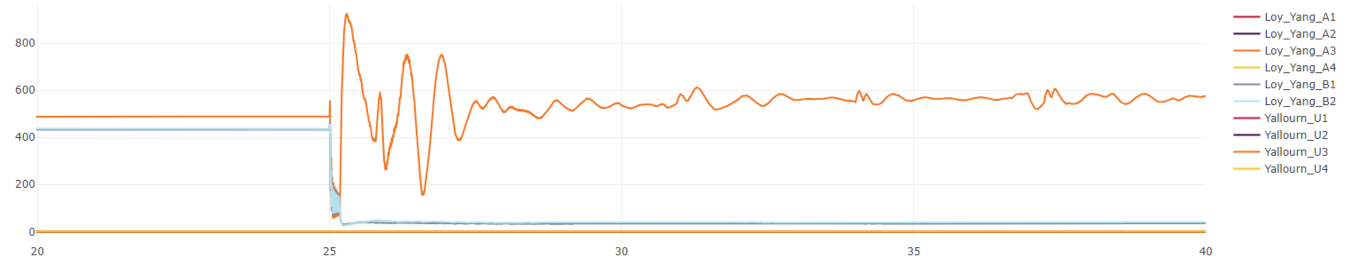


Figure 19 VIC_39 case, Loy Yang A3 generating unit active power output (MW)



A5.2 Priority risk 2: Non-credible loss of the future double circuit HumeLink 500 kV lines

A5.2.1 Northerly HumeLink flow cases

Case 1 – 7/06/2029 0500 hrs

For case 1, voltage collapse occurred at Bannaby following the loss of both Bannaby HumeLink lines.

Figure 20 Case 1, Bannaby contingency: line active power flows (MW)

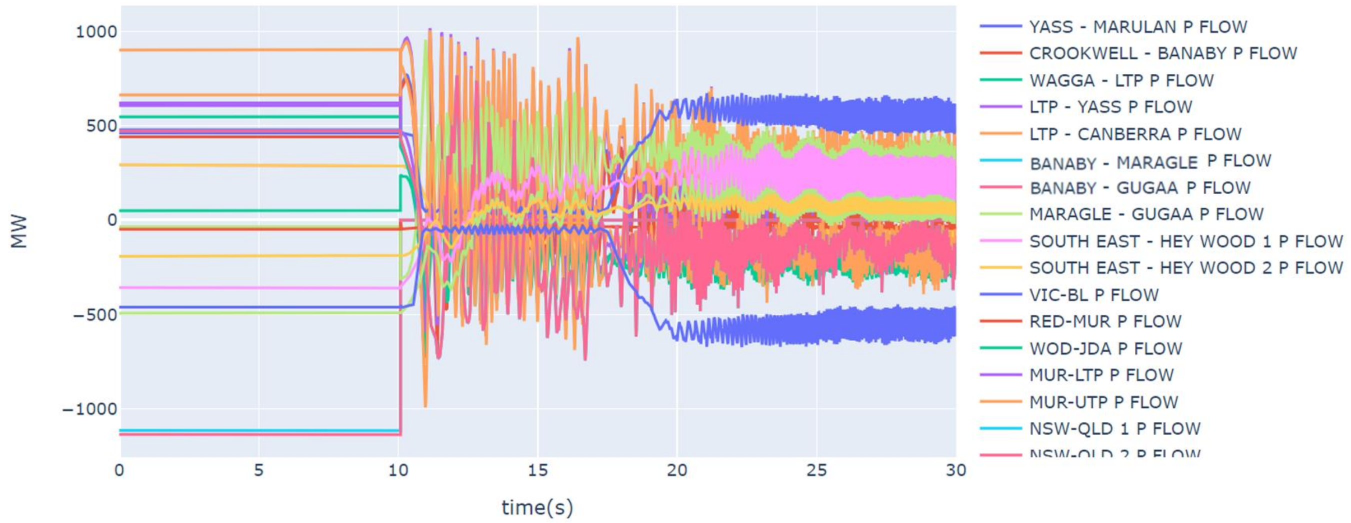
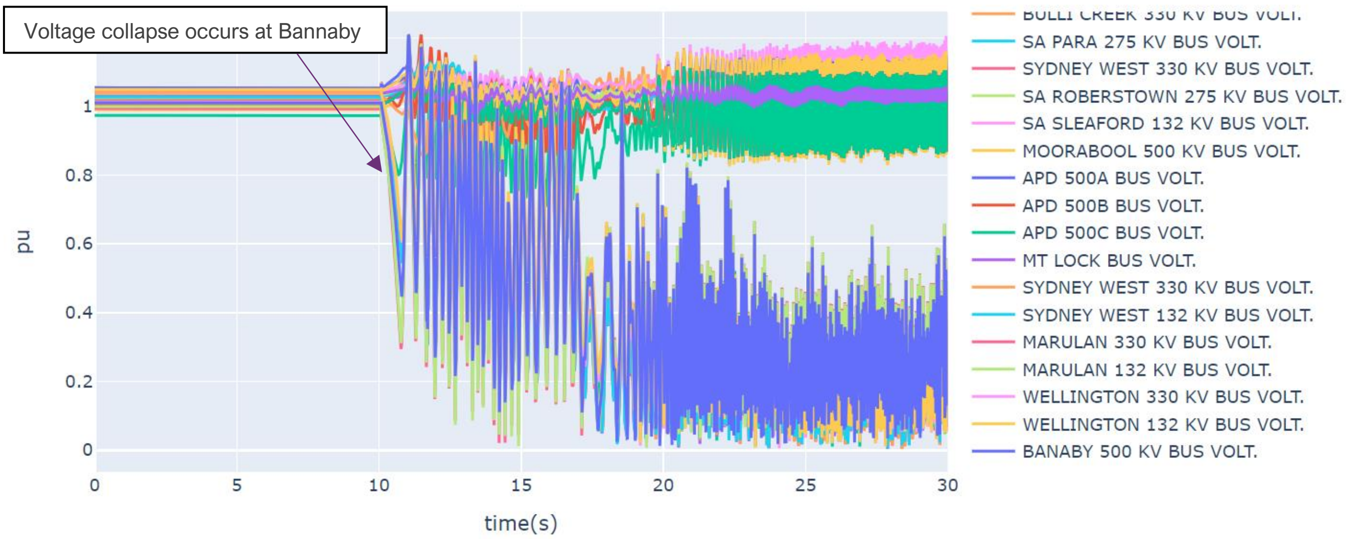


Figure 21 Case 1, Bannaby contingency: system voltages (pu)



Case 2 – 29/11/2028 1500 hrs

For case 2, the system landed satisfactory following the loss of both Bannaby lines.

Figure 22 Case 2, Bannaby contingency: line active power flows (MW)

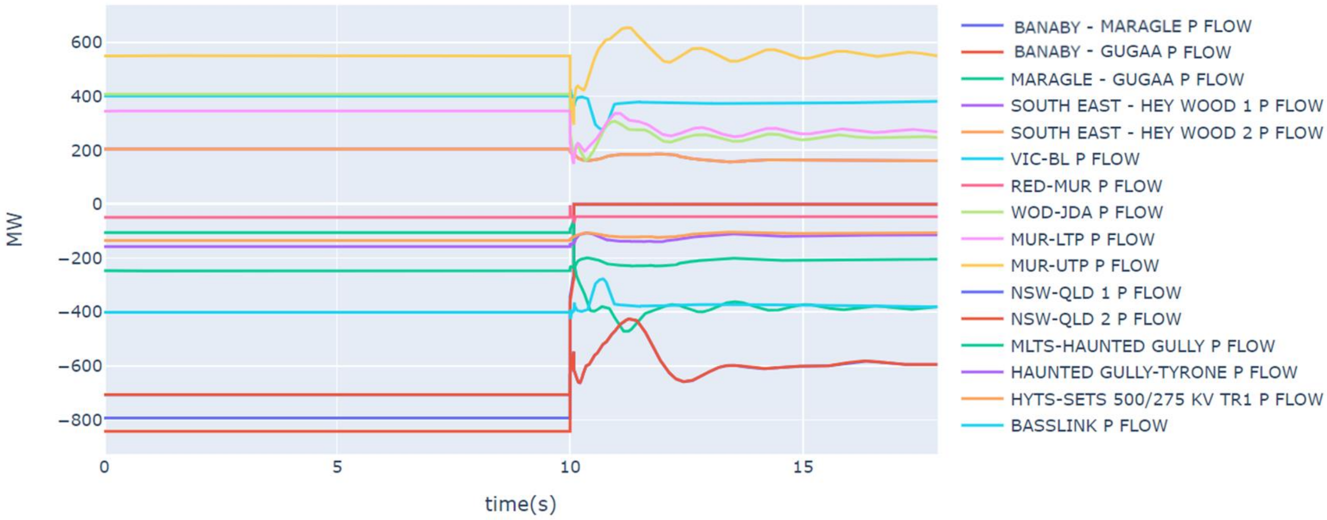
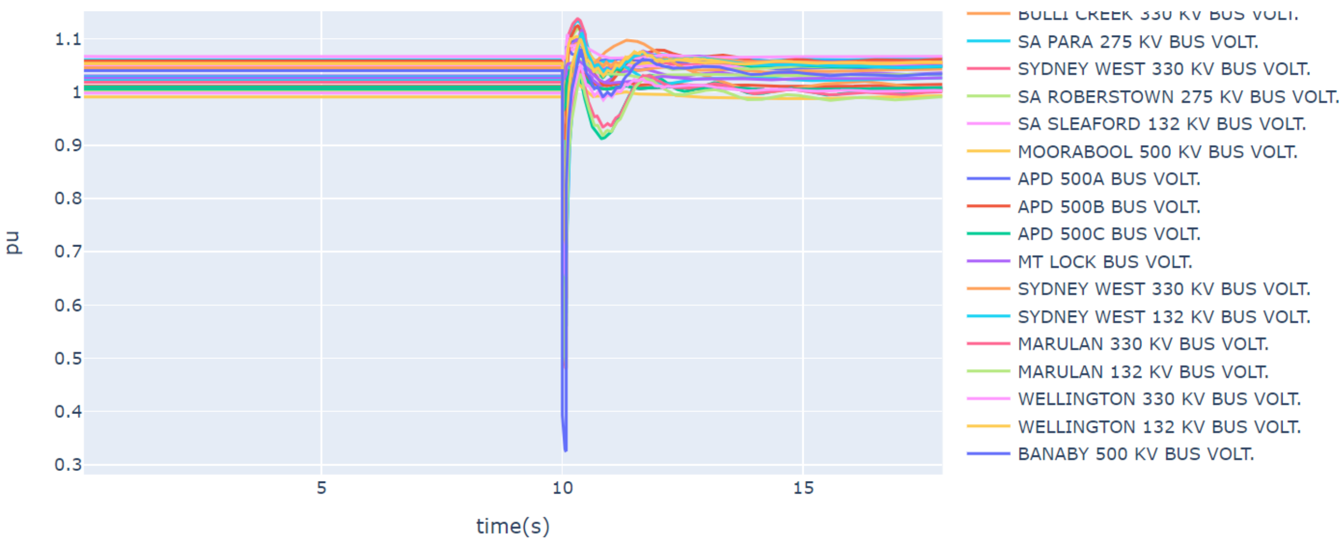


Figure 23 Case 2, Bannaby contingency: system voltages (pu)



Case 3 – 29/06/2029 1000 hrs

For case 3, voltage collapse occurred at Bannaby following the loss of both Bannaby HumeLink lines.

Figure 24 Case 3, Bannaby contingency: line active power flows (MW)

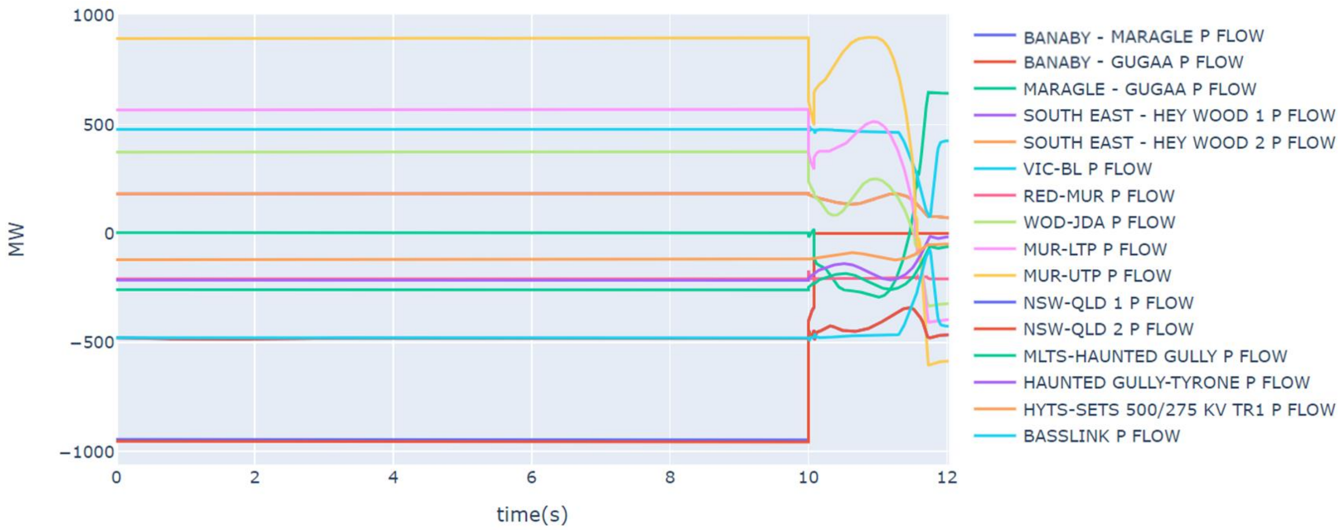
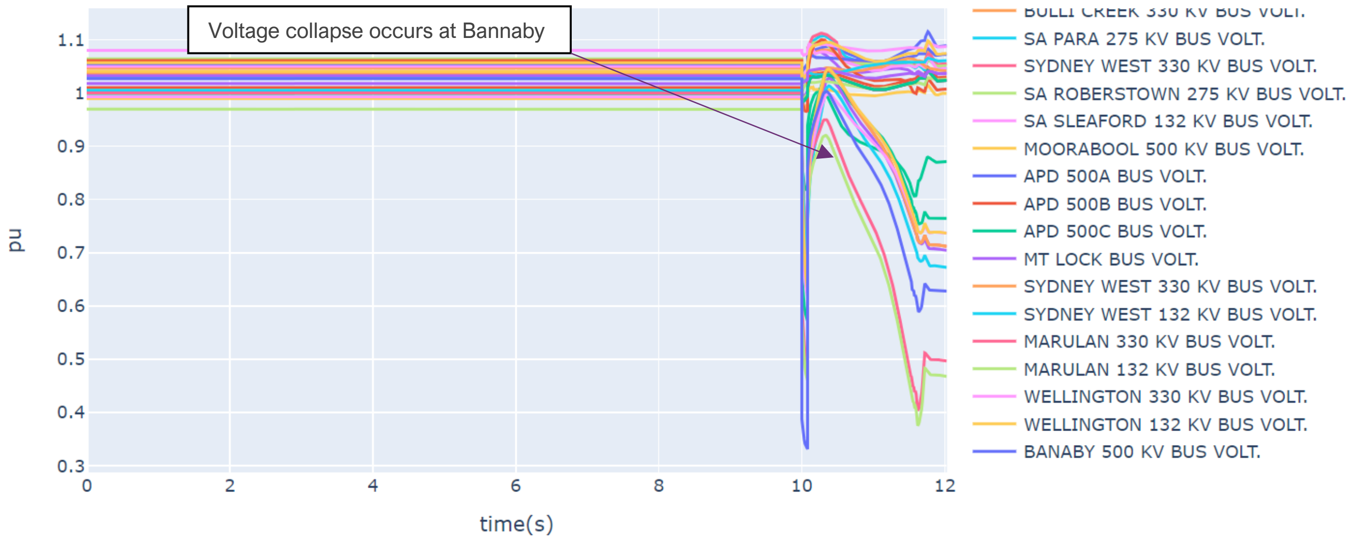


Figure 25 Case 3, Bannaby contingency: system voltages (pu)



Case 4 – 15/07/2028 2230 hrs

For case 4, voltage collapse occurred at Bannaby following the loss of both Bannaby HumeLink lines.

Figure 26 Case 4, Bannaby contingency: line active power flows (MW)

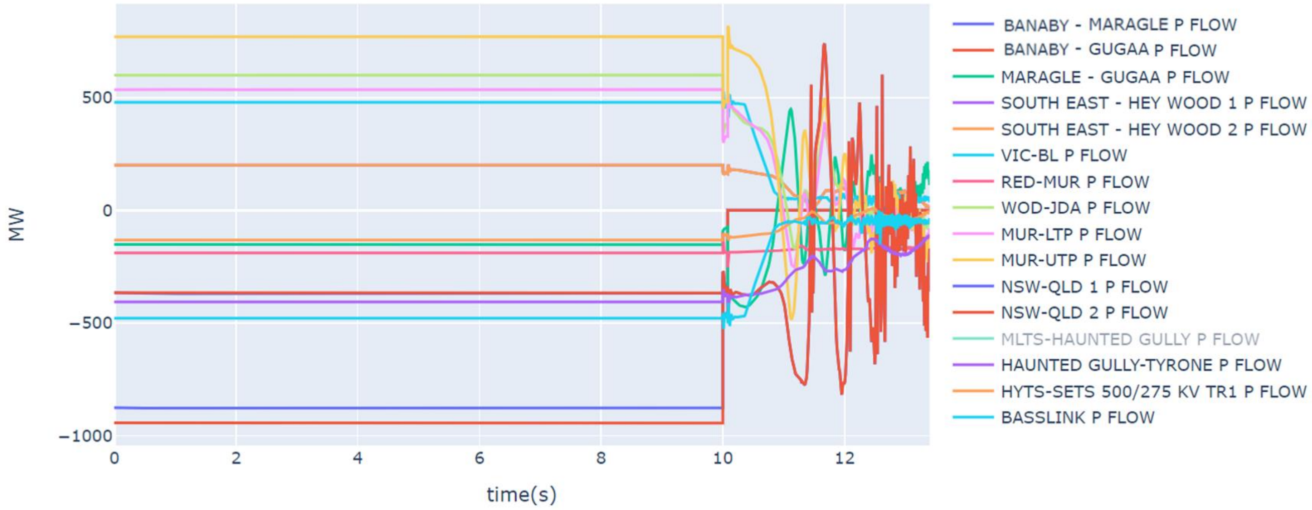
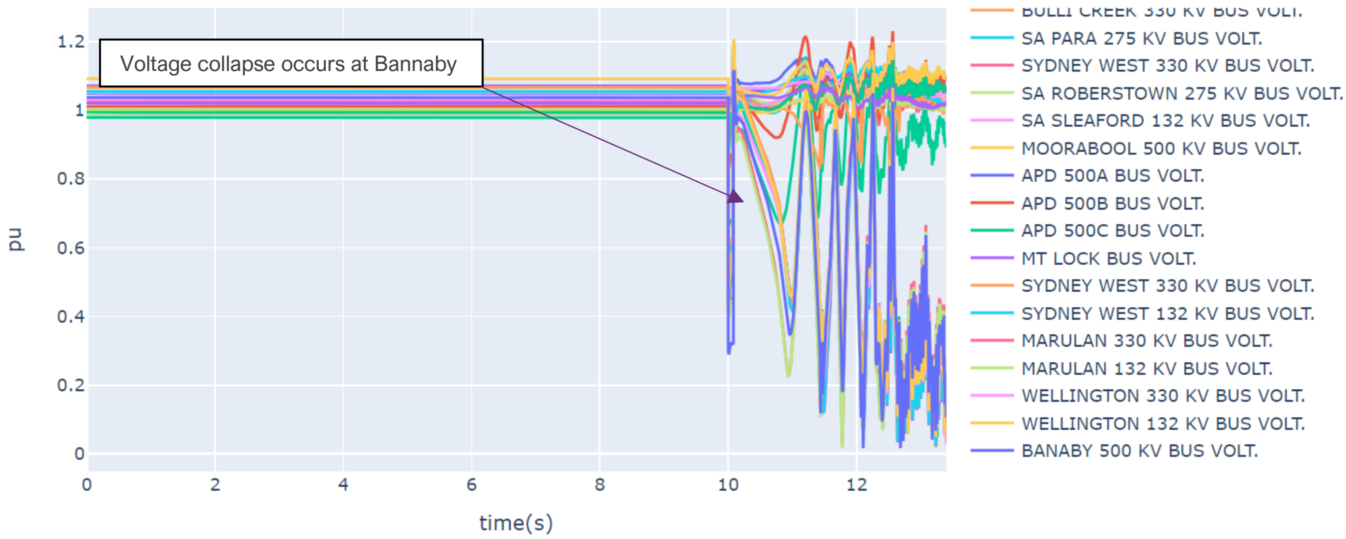


Figure 27 Case 4, Bannaby contingency: system voltages (pu)



Case T2

For case T2, voltage collapse occurred at Bannaby following the loss of both Bannaby HumeLink lines.

Figure 28 Case T2, Bannaby contingency: line active power flows (MW)

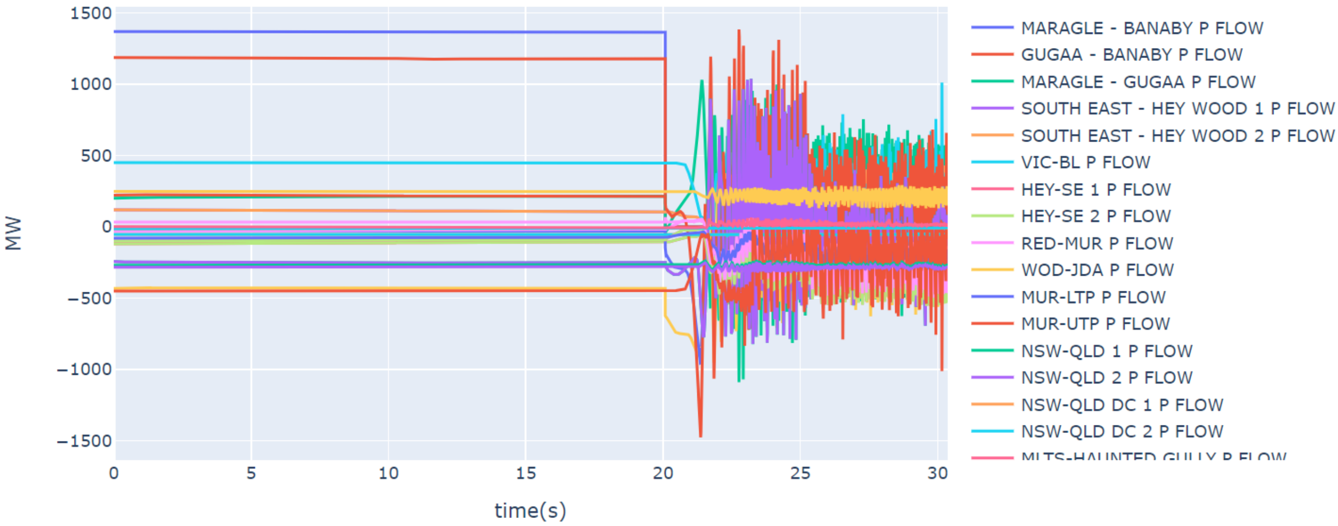
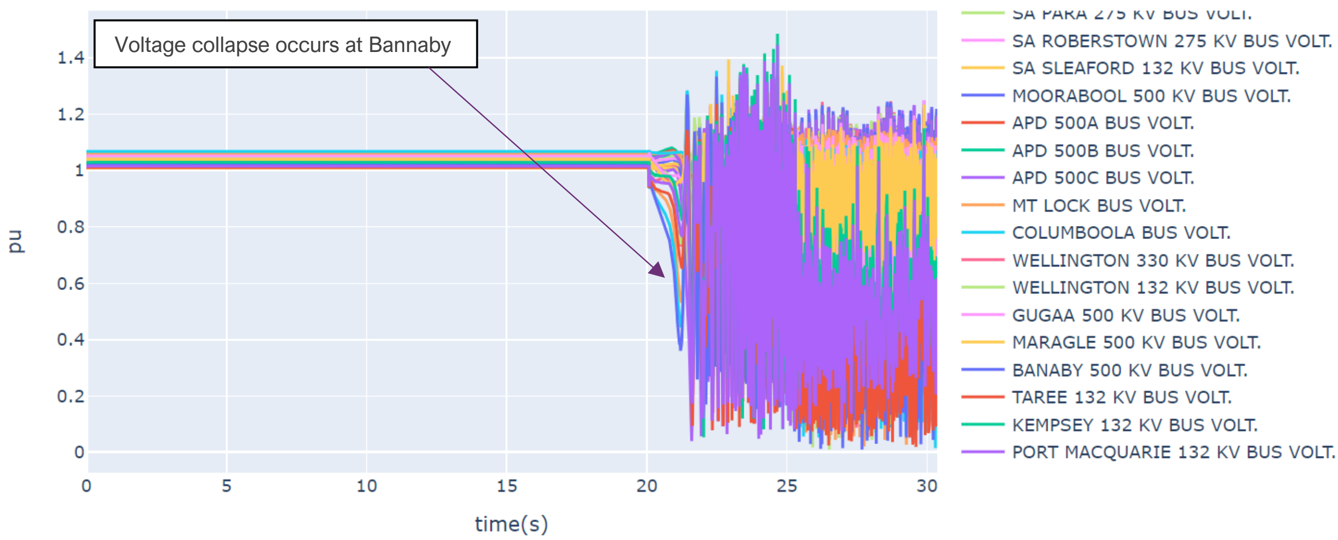


Figure 29 Case T2, Bannaby contingency: system voltages (pu)



Case T3

For case T3, the system landed satisfactory following the loss of both Bannaby lines.

Figure 30 Case T3, Bannaby contingency: line active power flows (MW)

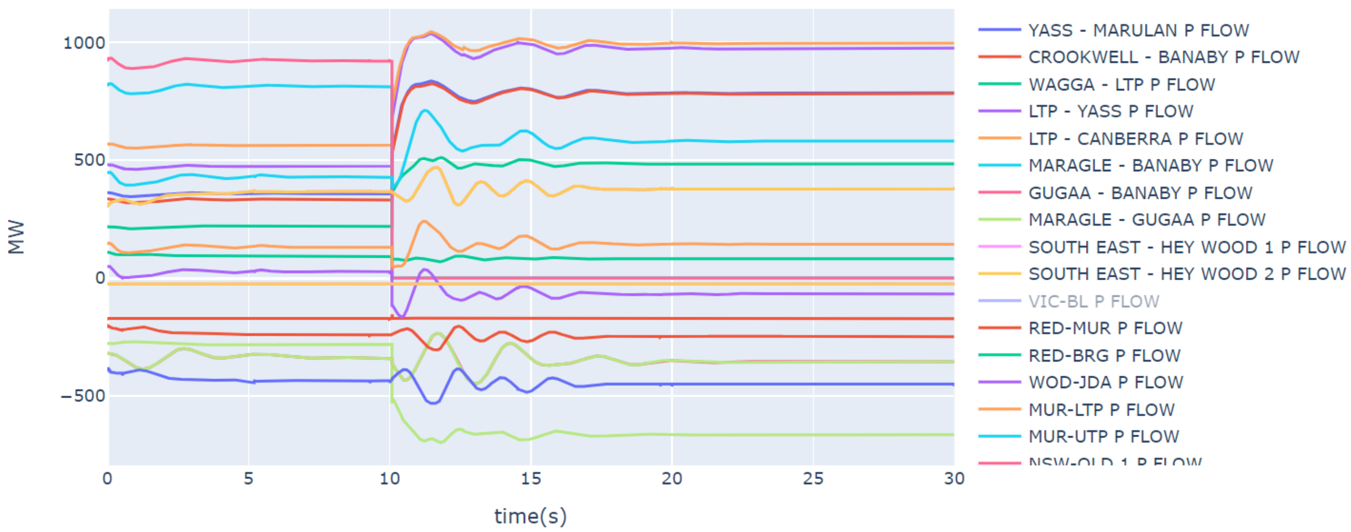
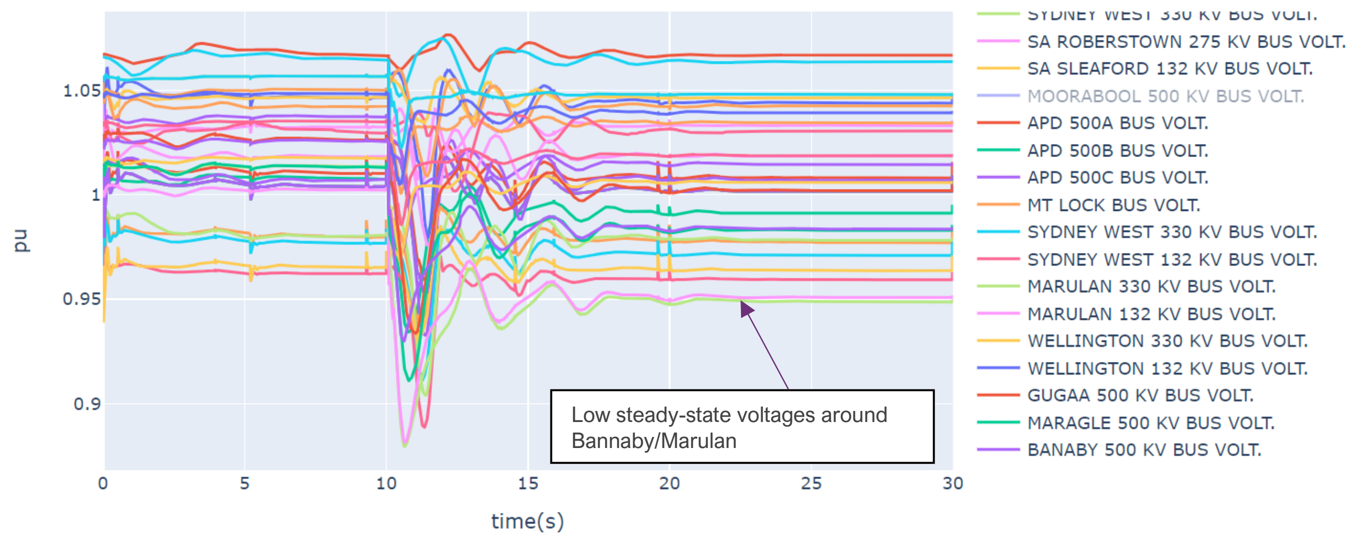


Figure 31 Case T3, Bannaby contingency: system voltages (pu)



A5.2.2 Southerly HumeLink flow cases

Case 5 – 9/03/2029 0330 hrs

For case 5, the system landed satisfactory following the loss of both Maragle lines.

Figure 32 Case 5, Bannaby contingency: line active power flows (MW)

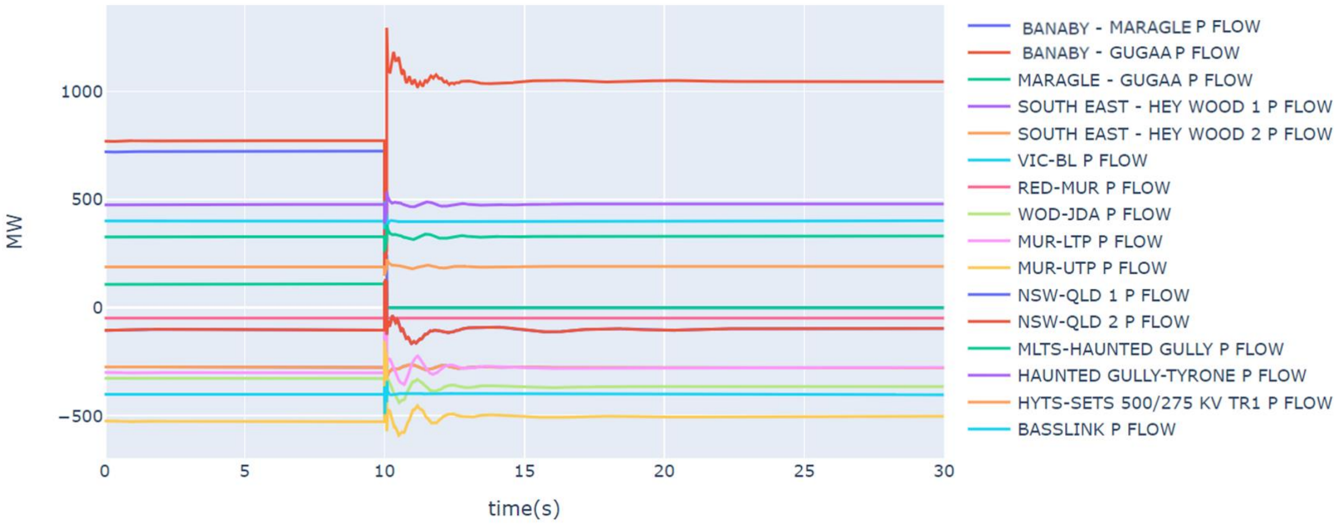
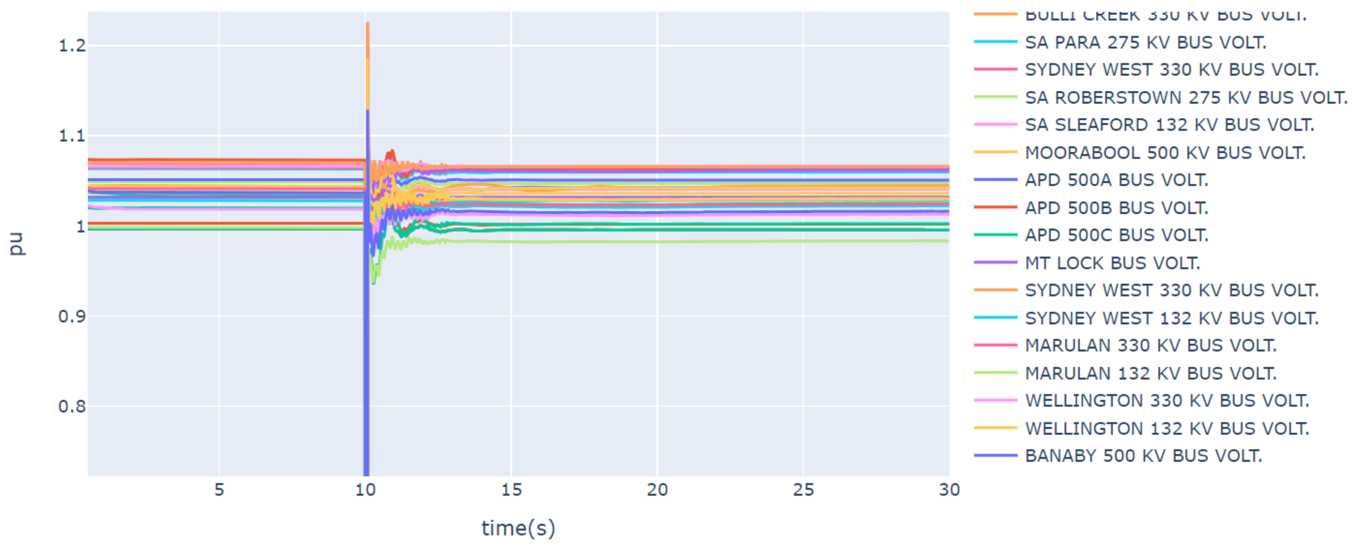


Figure 33 Case 5, Bannaby contingency: system voltages (pu)



Case T6

For case T6, the system landed satisfactory following the loss of both Maragle lines.

Figure 34 Case T6, Bannaby contingency: line active power flows (MW)

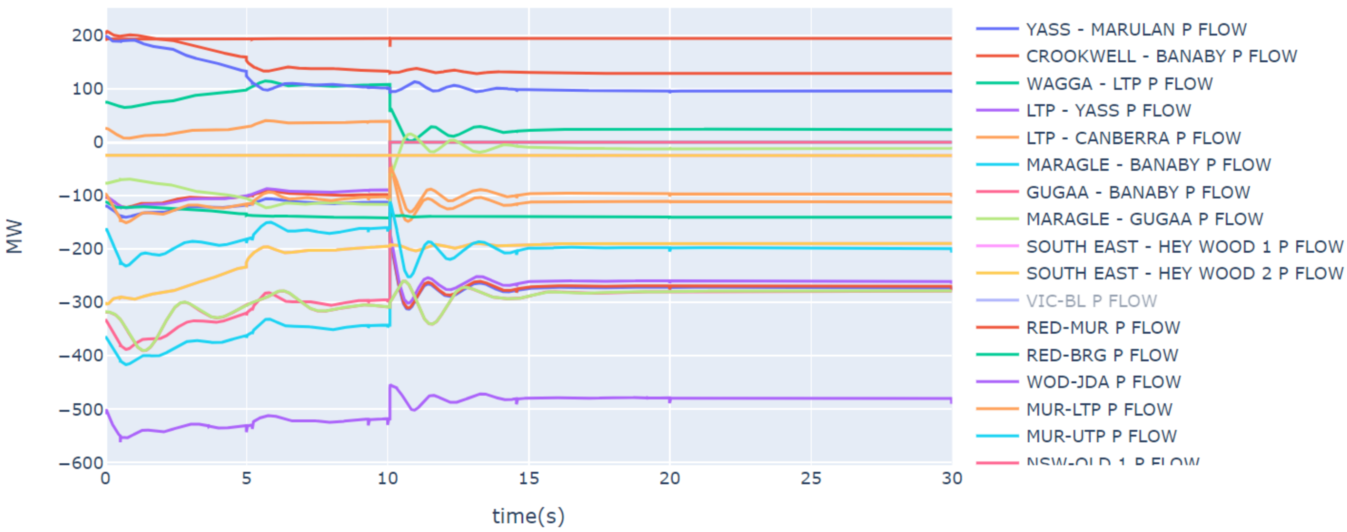
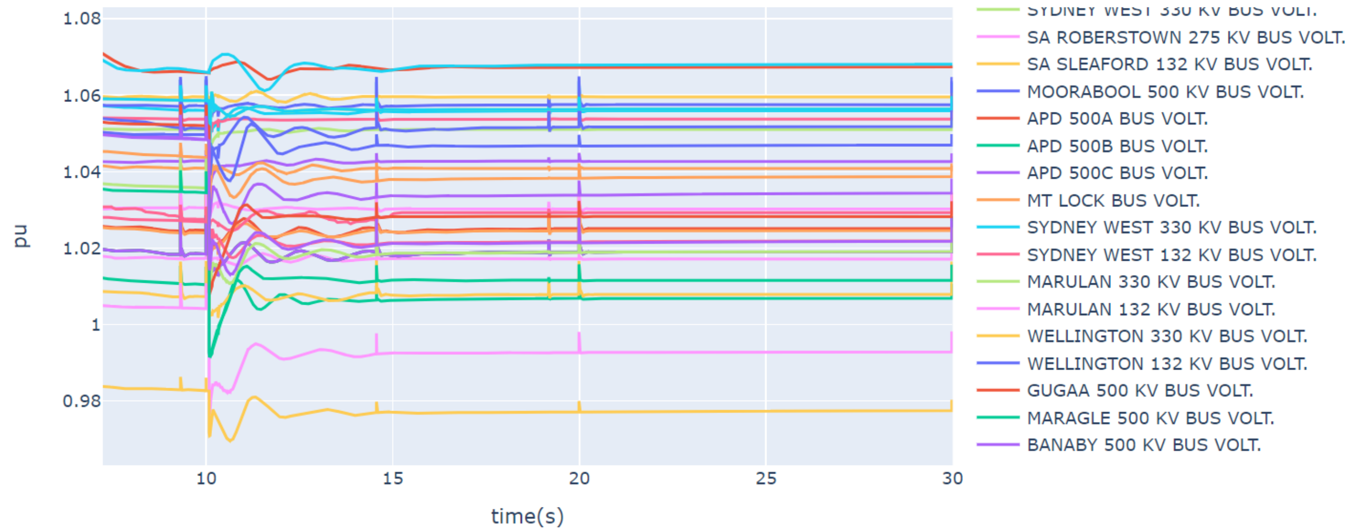


Figure 35 Case T6, Bannaby contingency: system voltages (pu)



A5.2.3 Reduced HumeLink flow sensitivity studies

Case 3 – 29/06/2029 1000 hrs

For case 3, the system landed satisfactory following the loss of both Bannaby lines if the HumeLink flow was reduced to 1,750 MW.

Figure 36 Case 3, reduced HumeLink flows, Bannaby contingency: line active power flows (MW)

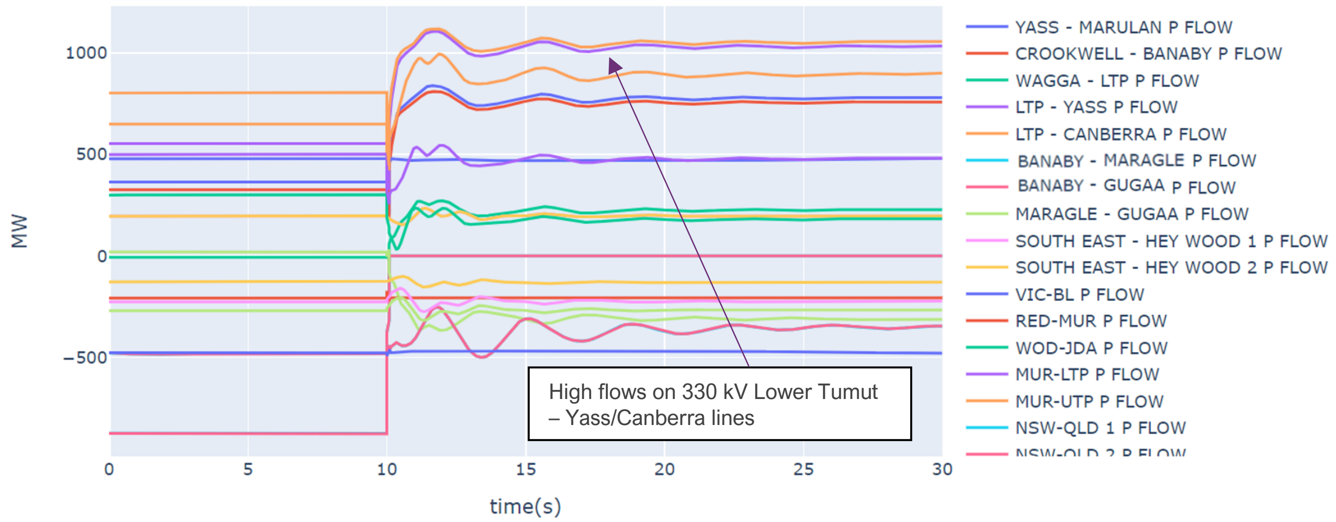
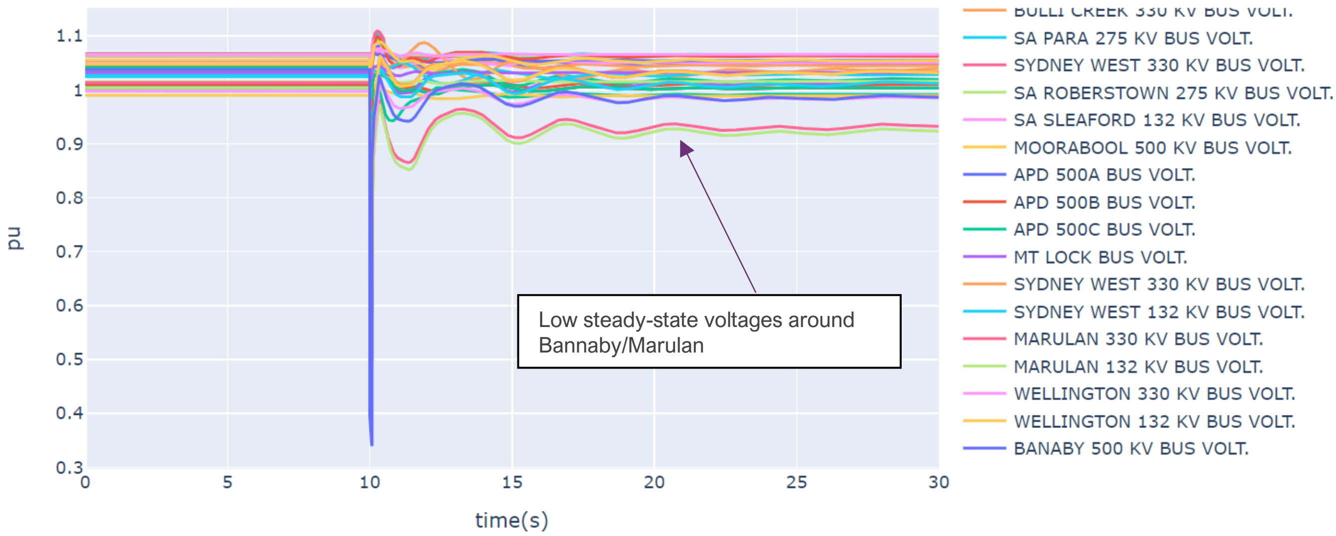


Figure 37 Case 3, reduced HumeLink flows, Bannaby contingency: system voltages (pu)



Case 4 – 15/07/2028 2230 hrs

For case 4, the system landed satisfactory following the loss of both Bannaby lines if the HumeLink flow was reduced to 1,600 MW.

Figure 38 Case 4, Bannaby contingency: line active power flows (MW)

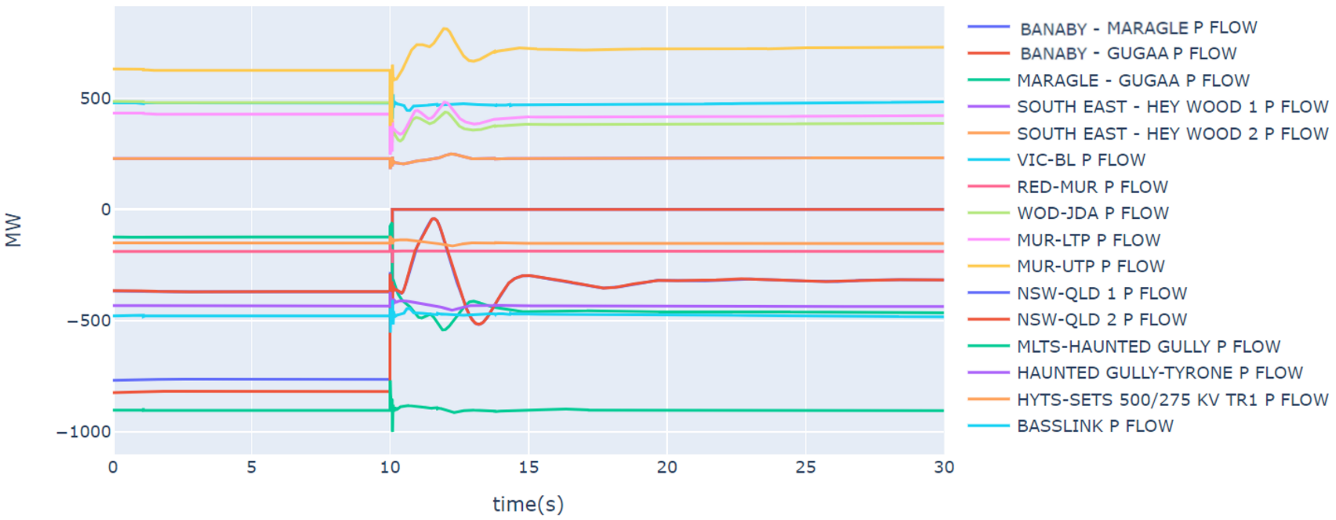
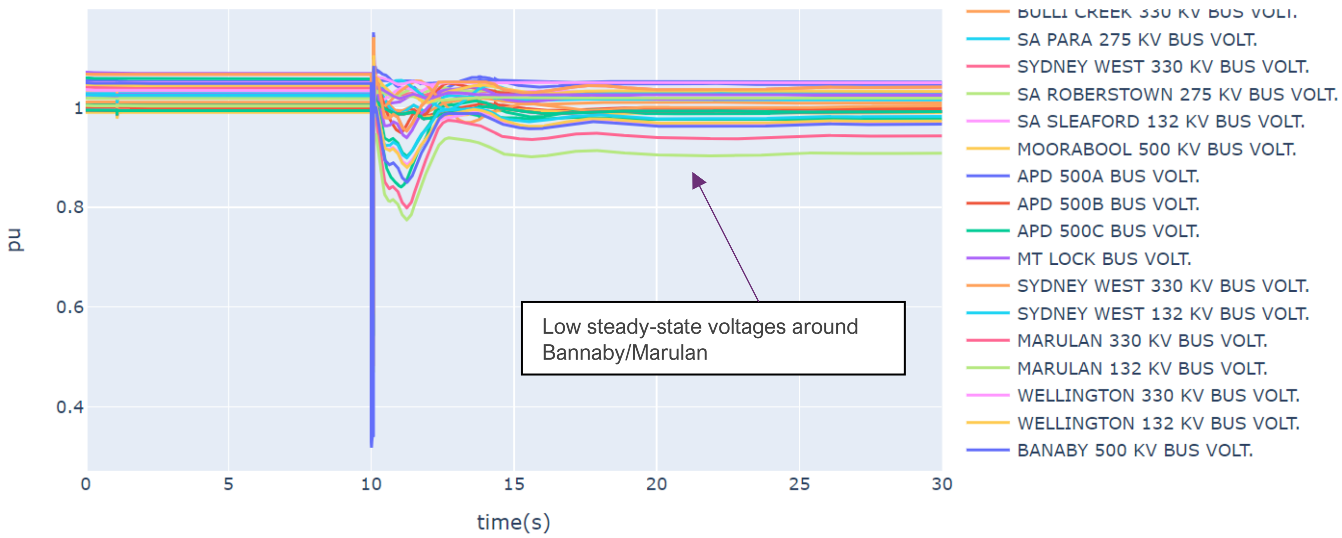


Figure 39 Case 4, Bannaby contingency: system voltages (pu)



Case T2

For case T2, the system landed satisfactory following the loss of both Bannaby lines if the HumeLink flow was reduced to 2,300 MW.

Figure 40 Case T2, Bannaby contingency: line active power flows (MW)

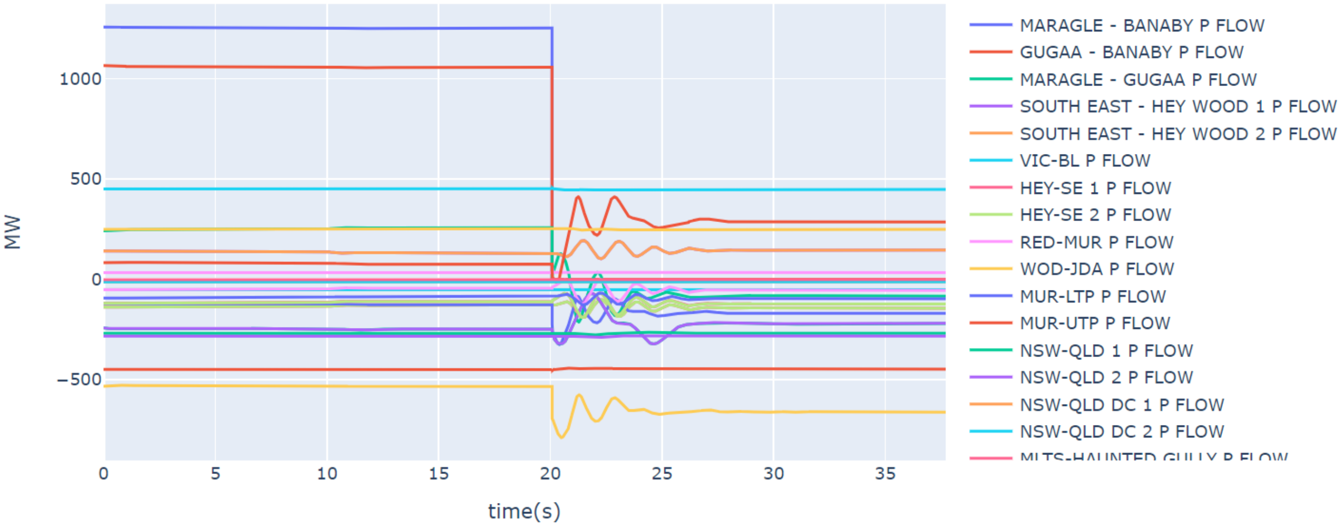
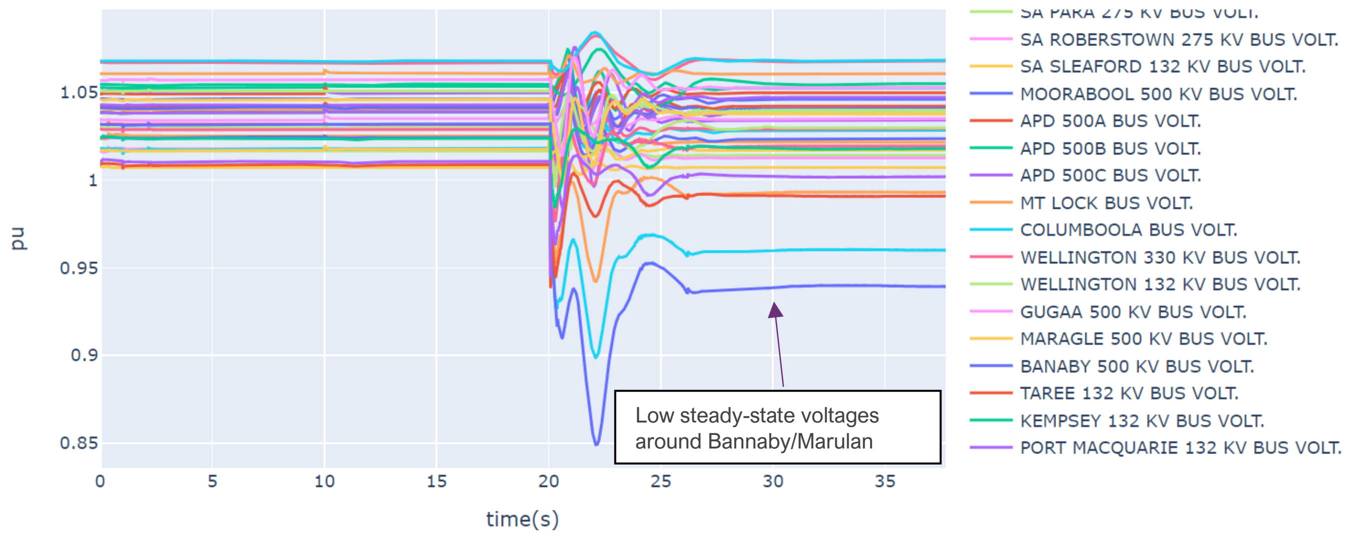


Figure 41 Case T2, Bannaby contingency: system voltages (pu)



A5.2.4 Reactive compensation sensitivity studies

Table 29 details the steady state voltages following the tripping of both Bannaby HumeLink lines with different reactive support options.

Table 29 Reactive compensation sensitivity results

Site	Voltage (kV)	Solution	Size (MVAR)	Steady state voltage after fault clearance (pu)
None				0.885
Bannaby	500	Cap Bank	100	0.892
Bannaby	500	Cap Bank	200	0.897
Bannaby	500	Cap Bank	300	0.903
Bannaby	500	Cap Bank	400	0.912
Bannaby	330	Cap Bank	100	0.895
Bannaby	330	Cap Bank	200	0.907
Bannaby	330	Cap Bank	300	0.923
Bannaby	330	Cap Bank	400	0.935
Bannaby	330	SVC	280	0.902
Kemps Creek	500	Cap Bank	100	0.891
Kemps Creek	500	Cap Bank	200	0.893
Kemps Creek	500	Cap Bank	300	0.897
Kemps Creek	500	Cap Bank	400	0.901
Kemps Creek	330	Cap Bank	100	0.891
Kemps Creek	330	Cap Bank	200	0.895
Kemps Creek	330	Cap Bank	300	0.899
Kemps Creek	330	Cap Bank	400	0.903
Kemps Creek	330	SVC	280	0.893
South Creek	500	Cap Bank	100	0.891
South Creek	500	Cap Bank	200	0.894
South Creek	500	Cap Bank	300	0.897
South Creek	500	Cap Bank	400	0.901
South Creek	330	Cap Bank	100	0.89
South Creek	330	Cap Bank	200	0.891
South Creek	330	Cap Bank	300	0.893
South Creek	330	Cap Bank	400	0.896
South Creek	330	SVC	280	0.89

A5.2.5 RAS sensitivity studies

Case 3 – 29/06/2029 1000 hrs

For case 3, the system landed satisfactory following the loss of both Bannaby lines if 1,200 MW of generation south of Maragle and 1,200 MW of load north of Bannaby was tripped within 250 ms.

Figure 42 Case 3, RAS action, Bannaby contingency: line active power flows (MW)

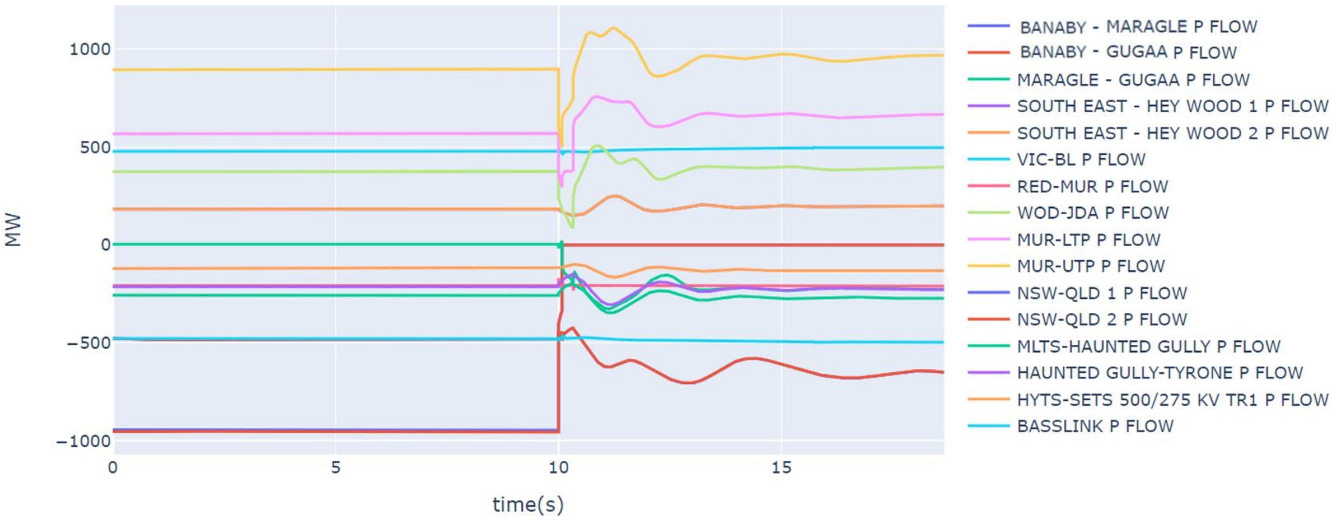
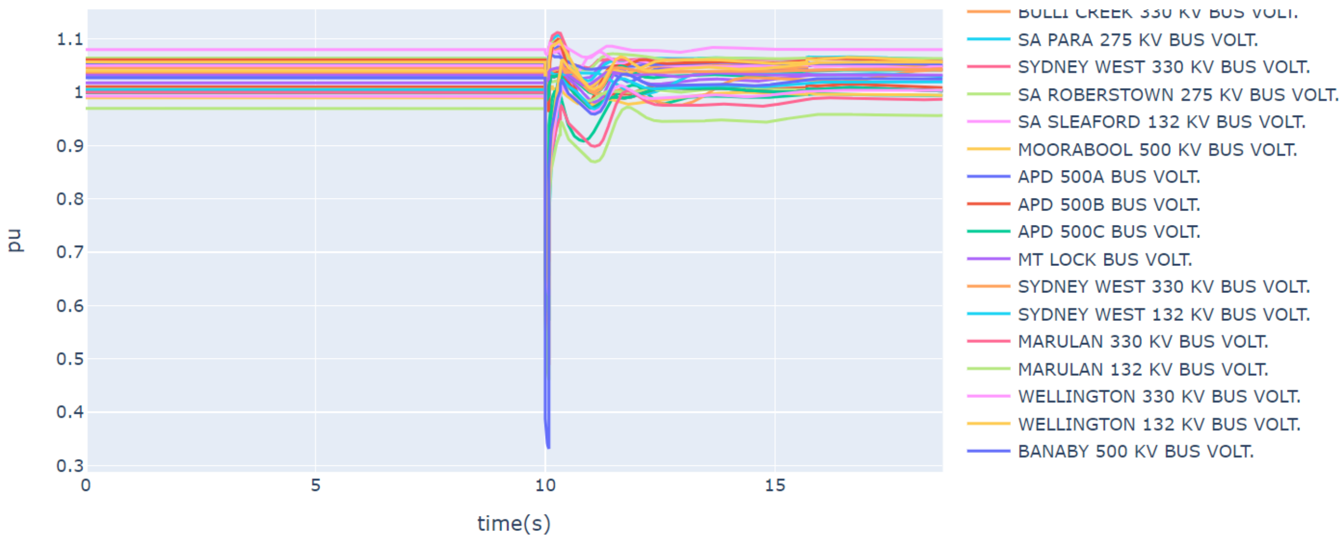


Figure 43 Case 3, RAS action, Bannaby contingency: system voltages (pu)



Case 4 – 15/07/2028 2230 hrs

For case 4, the system landed satisfactory following the loss of both Bannaby lines if 1,000 MW of generation south of Maragle and 1,000 MW of load north of Bannaby was tripped within 250 ms.

Figure 44 Case 4, RAS action, Bannaby contingency: line active power flows (MW)

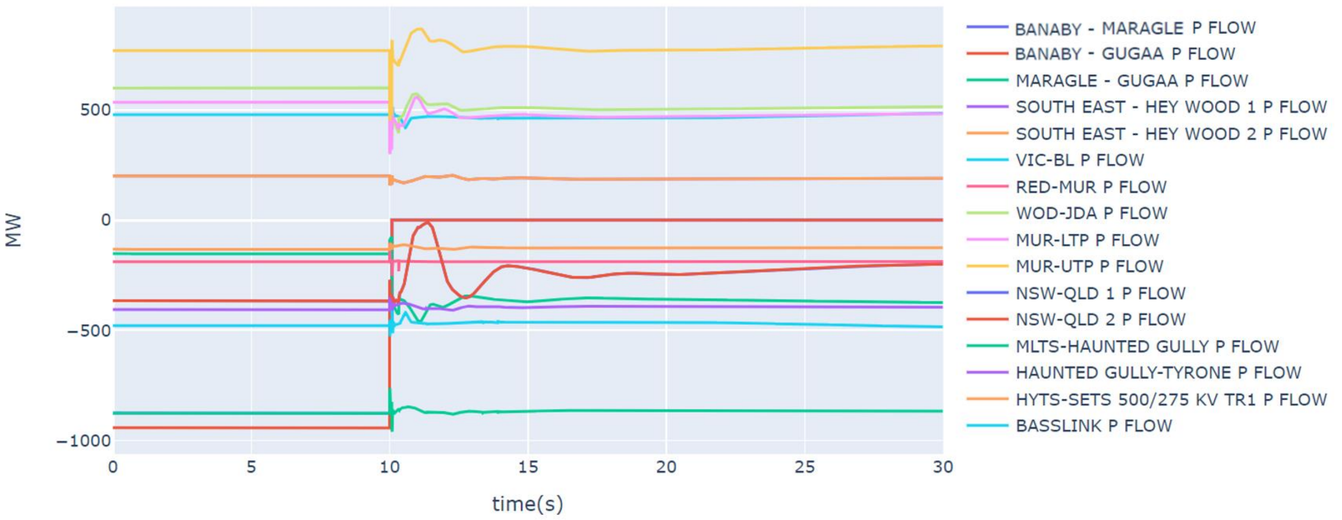
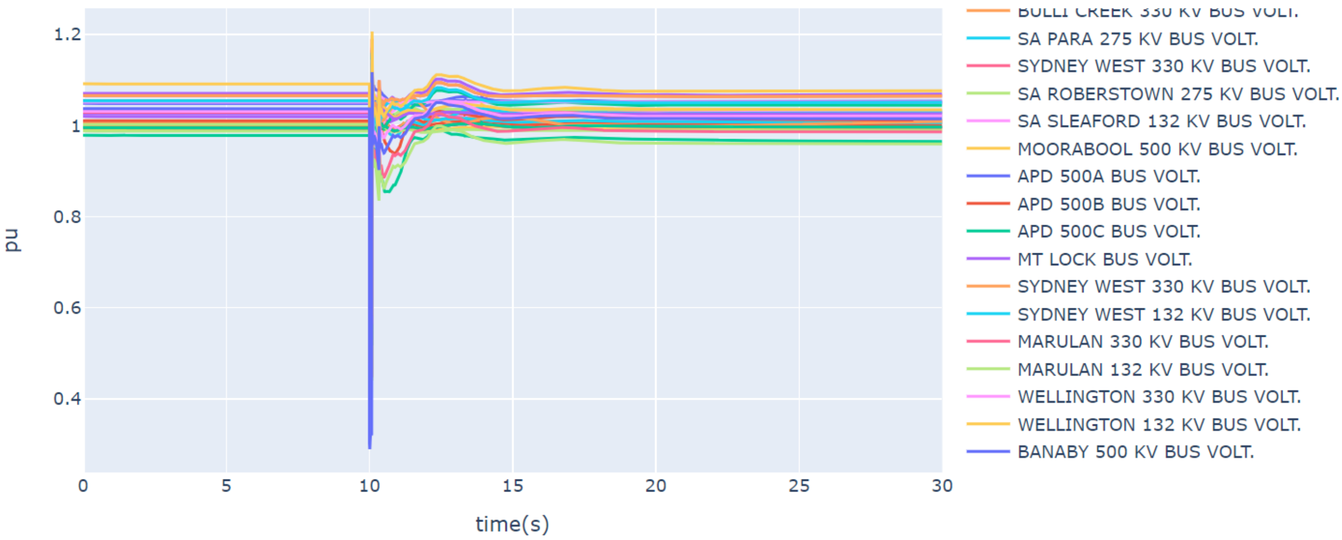


Figure 45 Case 4, RAS action, Bannaby contingency: system voltages (pu)



A5.3 Priority risk 3: UFLS screening studies

A5.3.1 Historical UFLS screening study results

The key parameters of each of the historical dispatch studies are detailed in Table 30 and Table 31.

Table 30 Detailed historical study results, contingencies 1-9

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9
1	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.25 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.43 NEM net UFLS tripped (MW): 853 (10%) NEM DPV tripped on protection (MW): 575	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.48 NEM net UFLS tripped (MW): 853 (10%) NEM DPV tripped on protection (MW): 575	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.32 NEM net UFLS tripped (MW): 1284 (15%) NEM DPV tripped on protection (MW): 571	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.66 NEM net UFLS tripped (MW): 1701 (20%) NEM DPV tripped on protection (MW): 727	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.72 NEM net UFLS tripped (MW): 2799 (33%) NEM DPV tripped on protection (MW): 658	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.31 NEM net UFLS tripped (MW): 466 (6%) NEM DPV tripped on protection (MW): 575	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.29 NEM net UFLS tripped (MW): 1287 (15%) NEM DPV tripped on protection (MW): 570	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.5 NEM net UFLS tripped (MW): 986 (12%) NEM DPV tripped on protection (MW): 570
2	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0 NEM RoCoF (Hz/s): 0.79 NEM Net UFLS tripped (MW): 2058 (17%) NEM DPV tripped on protection (MW): 355	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.29 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 39	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.31 NEM Net UFLS tripped (MW): 6 (0%) NEM DPV tripped on protection (MW): 39	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.65 NEM Net UFLS tripped (MW): 2140 (18%) NEM DPV tripped on protection (MW): 346	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 51.0 NEM RoCoF (Hz/s): 1.71 NEM Net UFLS tripped (MW): 3086 (26%) NEM DPV tripped on protection (MW): 291	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.75 NEM Net UFLS tripped (MW): 3282 (27%) NEM DPV tripped on protection (MW): 326	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 51.1 NEM RoCoF (Hz/s): 1.53 NEM Net UFLS tripped (MW): 2604 (22%) NEM DPV tripped on protection (MW): 344	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.5 NEM Net UFLS tripped (MW): 2139 (18%) NEM DPV tripped on protection (MW): 355	NEM freq nadir (Hz): 48.5 QLD freq peak (Hz): 51.1 NEM RoCoF (Hz/s): 1.82 NEM Net UFLS tripped (MW): 3318 (28%) NEM DPV tripped on protection (MW): 333
3	NEM freq nadir (Hz): 49.8 NEM RoCoF (Hz/s): 0.14 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.7 NEM RoCoF (Hz/s): 0.74 NEM Net UFLS tripped (MW): 1710 (15%) NEM DPV tripped on protection (MW): 223	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.7 NEM RoCoF (Hz/s): 0.86 NEM Net UFLS tripped (MW): 1773 (16%) NEM DPV tripped on protection (MW): 226	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.52 NEM Net UFLS tripped (MW): 1606 (14%) NEM DPV tripped on protection (MW): 301	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 50.7 NEM RoCoF (Hz/s): 1.28 NEM Net UFLS tripped (MW): 2212 (19%) NEM DPV tripped on protection (MW): 218	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.77 NEM Net UFLS tripped (MW): 2657 (23%) NEM DPV tripped on protection (MW): 280	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.8 NEM RoCoF (Hz/s): 0.8 NEM Net UFLS tripped (MW): 1710 (15%) NEM DPV tripped on protection (MW): 223	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.45 NEM Net UFLS tripped (MW): 2030 (18%) NEM DPV tripped on protection (MW): 296	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 50.7 NEM RoCoF (Hz/s): 1.48 NEM Net UFLS tripped (MW): 2727 (24%) NEM DPV tripped on protection (MW): 215

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9
4	NEM freq nadir (Hz): 49.9 NEM RoCoF (Hz/s): 0.1 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.4 NEM RoCoF (Hz/s): 0.93 NEM Net UFLS tripped (MW): 2983 (27%) NEM DPV tripped on protection (MW): 720	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 50.6 NEM RoCoF (Hz/s): 1.06 NEM Net UFLS tripped (MW): 1925 (18%) NEM DPV tripped on protection (MW): 409	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.4 NEM Net UFLS tripped (MW): 1503 (14%) NEM DPV tripped on protection (MW): 427	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 50.6 NEM RoCoF (Hz/s): 1.41 NEM Net UFLS tripped (MW): 2334 (21%) NEM DPV tripped on protection (MW): 397	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 0.81 NEM Net UFLS tripped (MW): 2808 (26%) NEM DPV tripped on protection (MW): 441	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.37 NEM Net UFLS tripped (MW): 672 (6%) NEM DPV tripped on protection (MW): 404	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.37 NEM Net UFLS tripped (MW): 1565 (14%) NEM DPV tripped on protection (MW): 523	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.55 NEM Net UFLS tripped (MW): 1904 (17%) NEM DPV tripped on protection (MW): 523
5	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.21 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.45 NEM Net UFLS tripped (MW): 20 (0%) NEM DPV tripped on protection (MW): 68	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.48 NEM Net UFLS tripped (MW): 1074 (10%) NEM DPV tripped on protection (MW): 231	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.02 NEM Net UFLS tripped (MW): 2108 (20%) NEM DPV tripped on protection (MW): 298	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.7 NEM Net UFLS tripped (MW): 1651 (16%) NEM DPV tripped on protection (MW): 288	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.69 NEM Net UFLS tripped (MW): 1699 (16%) NEM DPV tripped on protection (MW): 299	NEM freq nadir (Hz): 49.8 NEM RoCoF (Hz/s): 0.2 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 0.21 NEM Net UFLS tripped (MW): 20 (0%) NEM DPV tripped on protection (MW): 30	QLD freq peak (Hz): 50.4 NEM RoCoF (Hz/s): 1.61 NEM Net UFLS tripped (MW): 2828 (27%) NEM DPV tripped on protection (MW): 147
6	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.38 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.46 NEM Net UFLS tripped (MW): 425 (3%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.48 NEM Net UFLS tripped (MW): 685 (5%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.68 NEM Net UFLS tripped (MW): 1083 (8%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.86 NEM Net UFLS tripped (MW): 1676 (13%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.86 NEM Net UFLS tripped (MW): 2175 (17%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.51 NEM Net UFLS tripped (MW): 682 (5%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.51 NEM Net UFLS tripped (MW): 1083 (8%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.14 NEM Net UFLS tripped (MW): 2971 (23%) NEM DPV tripped on protection (MW): 0
7	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.9	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.9	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.59	NEM freq nadir (Hz): 48.5 QLD freq peak (Hz): 50.9	NEM freq nadir (Hz): 48.5 QLD freq peak (Hz): 50.2	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.29	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.29	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 51.0

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9
	NEM RoCoF (Hz/s): 0.95 NEM Net UFLS tripped (MW): 2102 (19%) NEM DPV tripped on protection (MW): 411	NEM RoCoF (Hz/s): 0.78 NEM Net UFLS tripped (MW): 1663 (15%) NEM DPV tripped on protection (MW): 408	NEM RoCoF (Hz/s): 0.85 NEM Net UFLS tripped (MW): 2230 (20%) NEM DPV tripped on protection (MW): 398	NEM Net UFLS tripped (MW): 1935 (17%) NEM DPV tripped on protection (MW): 483	NEM RoCoF (Hz/s): 1.39 NEM Net UFLS tripped (MW): 4007 (35%) NEM DPV tripped on protection (MW): 367	NEM RoCoF (Hz/s): 1.4 NEM Net UFLS tripped (MW): 3982 (35%) NEM DPV tripped on protection (MW): 271	NEM Net UFLS tripped (MW): 11 (0%) NEM DPV tripped on protection (MW): 51	NEM Net UFLS tripped (MW): 1535 (14%) NEM DPV tripped on protection (MW): 488	NEM RoCoF (Hz/s): 1.4 NEM Net UFLS tripped (MW): 3317 (29%) NEM DPV tripped on protection (MW): 385
8	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.31 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 52.0 NEM RoCoF (Hz/s): 0.8 NEM Net UFLS tripped (MW): 1388 (12%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 52.0 NEM RoCoF (Hz/s): 1.11 NEM Net UFLS tripped (MW):1462 (13%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.56 NEM Net UFLS tripped (MW): 808 (7%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 51.9 NEM RoCoF (Hz/s): 1.81 NEM Net UFLS tripped (MW): 2968 (25%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 50.8 NEM RoCoF (Hz/s): 1.36 NEM Net UFLS tripped (MW): 2968 (25%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 52.0 NEM RoCoF (Hz/s): 1.56 NEM Net UFLS tripped (MW): 2810 (24%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 50.4 NEM RoCoF (Hz/s): 1.32 NEM Net UFLS tripped (MW): 2810 (24%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.4 QLD freq peak (Hz): 52.0 NEM RoCoF (Hz/s): 1.72 NEM Net UFLS tripped (MW): 3915 (33%) NEM DPV tripped on protection (MW): 0
9	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.27 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.42 NEM Net UFLS tripped (MW): 7 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.43 NEM Net UFLS tripped (MW): 24 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.71 NEM Net UFLS tripped (MW): 1222 (12%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 QLD freq peak (Hz): >52 NEM RoCoF (Hz/s): 0.91 NEM Net UFLS tripped (MW): 2527 (25%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.73 NEM Net UFLS tripped (MW): 1382 (13%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 1.64 NEM Net UFLS tripped (MW): 705 (7%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.64 NEM Net UFLS tripped (MW): 1256 (12%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.4 QLD freq peak (Hz): 50.6 NEM RoCoF (Hz/s): 1.91 NEM Net UFLS tripped (MW): 3526 (34%) NEM DPV tripped on protection (MW): 0
10	NEM freq nadir (Hz): 48.9 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.99	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.83	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.5	NEM freq nadir (Hz): 48.2 QLD freq peak (Hz): 51.0

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9
	NEM RoCoF (Hz/s): 0.73 NEM Net UFLS tripped (MW): 1215 (8%) NEM DPV tripped on protection (MW): 395	NEM RoCoF (Hz/s): 0.92 NEM Net UFLS tripped (MW): 1788 (12%) NEM DPV tripped on protection (MW): 386	NEM RoCoF (Hz/s): 0.76 NEM Net UFLS tripped (MW): 1846 (12%) NEM DPV tripped on protection (MW): 389	NEM Net UFLS tripped (MW): 3031 (20%) NEM DPV tripped on protection (MW): 419	NEM RoCoF (Hz/s): 1.55 NEM Net UFLS tripped (MW): 3989 (26%) NEM DPV tripped on protection (MW): 295	NEM Net UFLS tripped (MW): 3031 (20%) NEM DPV tripped on protection (MW): 340	NEM RoCoF (Hz/s): 0.95 NEM Net UFLS tripped (MW): 2654 (17%) NEM DPV tripped on protection (MW): 328	NEM RoCoF (Hz/s): 0.89 NEM Net UFLS tripped (MW): 2456 (16%) NEM DPV tripped on protection (MW): 218	NEM RoCoF (Hz/s): 2.36 NEM Net UFLS tripped (MW): 6943 (45%) NEM DPV tripped on protection (MW): 297
11	NEM freq nadir (Hz): 49.8 NEM RoCoF (Hz/s): 0.12 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.53 NEM Net UFLS tripped (MW): 1086 (11%) NEM DPV tripped on protection (MW): 440	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.58 NEM Net UFLS tripped (MW): 1516 (15%) NEM DPV tripped on protection (MW): 580	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.38 NEM Net UFLS tripped (MW): 1627 (16%) NEM DPV tripped on protection (MW): 577	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.65 NEM Net UFLS tripped (MW): 1635 (17%) NEM DPV tripped on protection (MW): 578	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.64 NEM Net UFLS tripped (MW): 2351 (24%) NEM DPV tripped on protection (MW): 544	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.4 NEM Net UFLS tripped (MW): 1085 (11%) NEM DPV tripped on protection (MW): 442	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.4 NEM Net UFLS tripped (MW): 1615 (16%) NEM DPV tripped on protection (MW): 578	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.71 NEM Net UFLS tripped (MW): 1592 (16%) NEM DPV tripped on protection (MW): 440
12	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 51.0 NEM RoCoF (Hz/s): 0.75 NEM Net UFLS tripped (MW): 1807 (16%) NEM DPV tripped on protection (MW): 344	NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 0.25 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 45	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.27 NEM Net UFLS tripped (MW): 7 (0%) NEM DPV tripped on protection (MW): 45	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.57 NEM Net UFLS tripped (MW): 1908 (17%) NEM DPV tripped on protection (MW): 405	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 51.0 NEM RoCoF (Hz/s): 1.3 NEM Net UFLS tripped (MW): 2893 (26%) NEM DPV tripped on protection (MW): 324	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.62 NEM Net UFLS tripped (MW): 3095 (28%) NEM DPV tripped on protection (MW): 380	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.3 NEM Net UFLS tripped (MW): 7 (0%) NEM DPV tripped on protection (MW): 45	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.29 NEM Net UFLS tripped (MW): 803 (7%) NEM DPV tripped on protection (MW): 423	NEM freq nadir (Hz): 48.6 QLD freq peak (Hz): 51.0 NEM RoCoF (Hz/s): 1.13 NEM Net UFLS tripped (MW): 3573 (32%) NEM DPV tripped on protection (MW): 380
13	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.31	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.47	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.5	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.43	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.82	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.82	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 0.39	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.39	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.81

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9
	NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 818 (6%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 824 (6%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 818 (6%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 1601 (12%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 2101 (15%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 23 (0%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 1239 (9%) NEM DPV tripped on protection (MW): 0	NEM Net UFLS tripped (MW): 1373 (10%) NEM DPV tripped on protection (MW): 0
14	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.31 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.27 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 0.3 NEM Net UFLS tripped (MW): 29 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.74 NEM Net UFLS tripped (MW): 2174 (14%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 QLD freq peak (Hz): 50.2 NEM RoCoF (Hz/s): 0.7 NEM Net UFLS tripped (MW): 2456(16%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.68 NEM Net UFLS tripped (MW): 2549 (17%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.3 NEM Net UFLS tripped (MW): 362 (2%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.3 NEM Net UFLS tripped (MW): 1161 (8%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.7 QLD freq peak (Hz): 50.1 NEM RoCoF (Hz/s): 1 NEM Net UFLS tripped (MW): 3378 (22%) NEM DPV tripped on protection (MW): 0
15	NEM freq nadir (Hz): 49.8 NEM RoCoF (Hz/s): 0.13 NEM Net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.4 NEM Net UFLS tripped (MW): 1407 (15%) NEM DPV tripped on protection (MW): 958	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.42 NEM Net UFLS tripped (MW): 1815 (20%) NEM DPV tripped on protection (MW): 958	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.41 NEM Net UFLS tripped (MW): 1854 (20%) NEM DPV tripped on protection (MW): 943	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.48 NEM Net UFLS tripped (MW): 1815 (20%) NEM DPV tripped on protection (MW): 963	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 0.7 NEM Net UFLS tripped (MW): 3070 (33%) NEM DPV tripped on protection (MW): 1031	NEM freq nadir (Hz): 49.0 NEM RoCoF (Hz/s): 0.34 NEM Net UFLS tripped (MW): 944 (10%) NEM DPV tripped on protection (MW): 747	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.33 NEM Net UFLS tripped (MW): 1802 (19%) NEM DPV tripped on protection (MW): 743	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.55 NEM Net UFLS tripped (MW): 1815 (20%) NEM DPV tripped on protection (MW): 964

Table 31 Detailed historical study results, contingencies 10-12

Case	Contingency 10	Contingency 11	Contingency 12
1	VIC freq nadir (Hz): 49.7 NEM freq nadir (Hz): 48.9 VIC RoCoF (Hz/s): 0.33	QLD freq nadir (Hz): 48.7 NEM freq peak (Hz): 50.2 QLD RoCoF (Hz/s): 1.09	SA freq peak (Hz): 50.4 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.0

Case	Contingency 10	Contingency 11	Contingency 12
	NEM RoCoF (Hz/s): 0.44 NEM net UFLS tripped (MW): 1262 (15%) NEM DPV tripped on protection (MW): 523	NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1585 (19%) NEM DPV tripped on protection (MW): 85	NEM RoCoF (Hz/s): 0.12 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0
2	VIC freq nadir (Hz): 48.8 NEM freq peak (Hz): 50.1 VIC RoCoF (Hz/s): 1.62 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 656 (5%) NEM DPV tripped on protection (MW): 115	QLD freq nadir (Hz): 49.9 NEM freq nadir (Hz): 49.0 QLD RoCoF (Hz/s): 0.04 NEM RoCoF (Hz/s): 0.4 NEM net UFLS tripped (MW): 432 (4%) NEM DPV tripped on protection (MW): 186	SA freq peak (Hz): 50.4 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.01 NEM RoCoF (Hz/s): 0.13 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0
3	VIC freq nadir (Hz): 48.5 NEM freq peak (Hz): 50.1 VIC RoCoF (Hz/s): 2.7 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1432 (13%) NEM DPV tripped on protection (MW): 44	QLD freq peak (Hz): 50.1 NEM freq nadir (Hz): 49.8 QLD RoCoF (Hz/s): 0.23 NEM RoCoF (Hz/s): 0.16 NEM net UFLS tripped (MW): 639 (6%) NEM DPV tripped on protection (MW): 80	SA freq peak (Hz): 51.0 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.39 NEM RoCoF (Hz/s): 0.12 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 33
4	VIC freq nadir (Hz): 48.6 NEM freq nadir (Hz): 49.9 VIC RoCoF (Hz/s): 2.41 NEM RoCoF (Hz/s): 0.05 NEM net UFLS tripped (MW): 1125 (10%) NEM DPV tripped on protection (MW): 100	QLD freq nadir (Hz): 49.0 NEM freq nadir (Hz): 49.7 QLD RoCoF (Hz/s): 0.3 NEM RoCoF (Hz/s): 0.19 NEM net UFLS tripped (MW): 626 (6%) NEM DPV tripped on protection (MW): 102	SA freq nadir (Hz): 48.3 NEM freq peak (Hz): 50.1 SA RoCoF (Hz/s): 1.78 NEM RoCoF (Hz/s): 0 NEM net UFLS tripped (MW): 412 (4%) NEM DPV tripped on protection (MW): 11
5	VIC freq nadir (Hz): 48.9 NEM freq nadir (Hz): 49.5 VIC RoCoF (Hz/s): 1.05 NEM RoCoF (Hz/s): 0.19 NEM net UFLS tripped (MW): 89 (1%) NEM DPV tripped on protection (MW): 145	QLD freq nadir (Hz): 49.7 NEM freq nadir (Hz): 49.9 QLD RoCoF (Hz/s): 0.08 NEM RoCoF (Hz/s): 0.09 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	SA freq nadir (Hz): 49.7 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.32 NEM RoCoF (Hz/s): 0.05 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0
6	VIC freq nadir (Hz): 48.9 NEM freq nadir (Hz): 49.7 VIC RoCoF (Hz/s): 1.2	QLD freq nadir (Hz): 49.0 NEM freq peak (Hz): 50.2 QLD RoCoF (Hz/s): 0.42	SA freq nadir (Hz): 48.4 NEM freq peak (Hz): 50.1 SA RoCoF (Hz/s): 1.66

Case	Contingency 10	Contingency 11	Contingency 12
	NEM RoCoF (Hz/s): 0.17 NEM net UFLS tripped (MW): 214 (2%) NEM DPV tripped on protection (MW): 0	NEM RoCoF (Hz/s): 0.02 NEM net UFLS tripped (MW): 680 (5%) NEM DPV tripped on protection (MW): 0	NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 470 (4%) NEM DPV tripped on protection (MW): 0
7	VIC freq nadir (Hz): 48.5 NEM freq peak (Hz): 50.1 VIC RoCoF (Hz/s): 2.08 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1106 (10%) NEM DPV tripped on protection (MW): 79	QLD freq peak (Hz): 50.2 NEM freq nadir (Hz): 49.2 QLD RoCoF (Hz/s): 0.01 NEM RoCoF (Hz/s): 0.31 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 34	SA freq nadir (Hz): 49.0 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.7 NEM RoCoF (Hz/s): 0.07 NEM net UFLS tripped (MW): 34 (0%) NEM DPV tripped on protection (MW): 14
8	VIC freq nadir (Hz): 48.6 NEM freq peak (Hz): 50.1 VIC RoCoF (Hz/s): 2.25 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1159 (10%) NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 49.3 QLD RoCoF (Hz/s): 0.02 NEM RoCoF (Hz/s): 0.37 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	SA freq nadir (Hz): 46.5 NEM freq peak (Hz): 50.2 SA RoCoF (Hz/s): 4.0 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1200 (10%) NEM DPV tripped on protection (MW): 0
9	VIC freq nadir (Hz): 48.7 NEM freq peak (Hz): 50.1 VIC RoCoF (Hz/s): 1.91 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 784 (8%) NEM DPV tripped on protection (MW): 0	QLD freq nadir (Hz): 49.9 NEM freq nadir (Hz): 49.9 QLD RoCoF (Hz/s): 0.04 NEM RoCoF (Hz/s): 0.1 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0	SA freq nadir (Hz): 48.7 NEM freq nadir (Hz): 50.0 SA RoCoF (Hz/s): 1.3 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 181 (2%) NEM DPV tripped on protection (MW): 0
10	VIC freq nadir (Hz): 48.5 NEM freq peak (Hz): 50.2 VIC RoCoF (Hz/s): 2.6 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1843 (12%) NEM DPV tripped on protection (MW): 64	QLD freq nadir (Hz): 50.0 NEM freq nadir (Hz): 49.2 QLD RoCoF (Hz/s): 0.02 NEM RoCoF (Hz/s): 0.33 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 22	SA freq peak (Hz): 50.2 NEM freq peak (Hz): 50.1 SA RoCoF (Hz/s): 2.88 NEM RoCoF (Hz/s): 0 NEM net UFLS tripped (MW): 896 (6%) NEM DPV tripped on protection (MW): 6
11	VIC freq nadir (Hz): 48.8 NEM freq nadir (Hz): 49.0 VIC RoCoF (Hz/s): 1.01	QLD freq nadir (Hz): 49.0 NEM freq nadir (Hz): 49.9 QLD RoCoF (Hz/s): 0.24	SA freq peak (Hz): 51.0 NEM freq nadir (Hz): 49.8 SA RoCoF (Hz/s): 0.28

Case	Contingency 10	Contingency 11	Contingency 12
	NEM RoCoF (Hz/s): 0.33 NEM net UFLS tripped (MW): 920 (9%) NEM DPV tripped on protection (MW): 512	NEM RoCoF (Hz/s): 0.1 NEM net UFLS tripped (MW): 286 (3%) NEM DPV tripped on protection (MW): 39	NEM RoCoF (Hz/s): 0.17 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 30
12	VIC freq nadir (Hz): 48.6 NEM freq peak (Hz): 50.4 VIC RoCoF (Hz/s): 1.79 NEM RoCoF (Hz/s): 0.03 NEM net UFLS tripped (MW): 851 (8%) NEM DPV tripped on protection (MW): 91	QLD freq peak (Hz): 50.1 NEM freq nadir (Hz): 49.1 QLD RoCoF (Hz/s): 0.01 NEM RoCoF (Hz/s): 0.31 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 28	SA freq nadir (Hz): 48.1 NEM freq nadir (Hz): 50.0 SA RoCoF (Hz/s): 1.95 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 562 (5%) NEM DPV tripped on protection (MW): 8
13	VIC freq nadir (Hz): 49.3 NEM freq nadir (Hz): 49.0 VIC RoCoF (Hz/s): 0.66 NEM RoCoF (Hz/s): 0.42 NEM net UFLS tripped (MW): 818 (6%) NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.2 NEM freq peak (Hz): 50.2 QLD RoCoF (Hz/s): 0.77 NEM RoCoF (Hz/s): 0.02 NEM net UFLS tripped (MW): 1191 (9%) NEM DPV tripped on protection (MW): 0	SA freq peak (Hz): 50.4 NEM freq nadir (Hz): 49.9 SA RoCoF (Hz/s): 0.01 NEM RoCoF (Hz/s): 0.06 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 0
14	VIC freq nadir (Hz): 48.8 NEM freq nadir (Hz): 50.0 VIC RoCoF (Hz/s): 1.18 NEM RoCoF (Hz/s): 0 NEM net UFLS tripped (MW): 659 (4%) NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.1 NEM freq nadir (Hz): 50.0 QLD RoCoF (Hz/s): 0.34 NEM RoCoF (Hz/s): 0.03 NEM net UFLS tripped (MW): 701 (5%) NEM DPV tripped on protection (MW): 0	SA freq peak (Hz): 50.7 NEM freq peak (Hz): 50.1 SA RoCoF (Hz/s): 3.36 NEM RoCoF (Hz/s): 0.01 NEM net UFLS tripped (MW): 1416 (9%) NEM DPV tripped on protection (MW): 0
15	VIC freq nadir (Hz): 48.3 NEM freq peak (Hz): 50.3 VIC RoCoF (Hz/s): 2.1 NEM net UFLS tripped (MW): 1428 (15%) NEM DPV tripped on protection (MW): 184	QLD freq peak (Hz): 50.2 NEM freq nadir (Hz): 49.8 QLD RoCoF (Hz/s): 0.36 NEM RoCoF (Hz/s): 0.15 NEM net UFLS tripped (MW): 1035 (11%) NEM DPV tripped on protection (MW): 257	SA freq nadir (Hz): 49.3 NEM freq nadir (Hz): 50.0 SA RoCoF (Hz/s): 0.38 NEM RoCoF (Hz/s): 0.02 NEM net UFLS tripped (MW): 0 (0%) NEM DPV tripped on protection (MW): 7

Case 1 – 4/02/2023 1330 hrs, contingency 6 (Loy Yang A + TIPS B + Mt Piper + Millmerran station trip)

For case 1, the NEM frequency fell to 48.8 Hz following the trip of Loy Yang A + Torrens Island Power Station (TIPS) B + Mt Piper + Millmerran units.

Figure 46 Case 1, Loy Yang A + TIPS B + Mt Piper + Millmerran trip: system frequency traces (Hz)

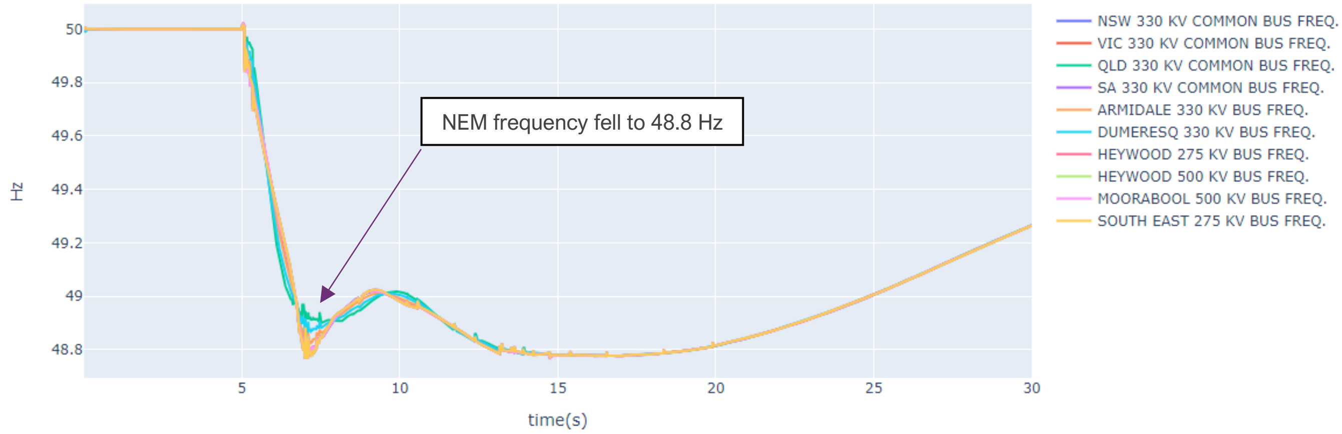
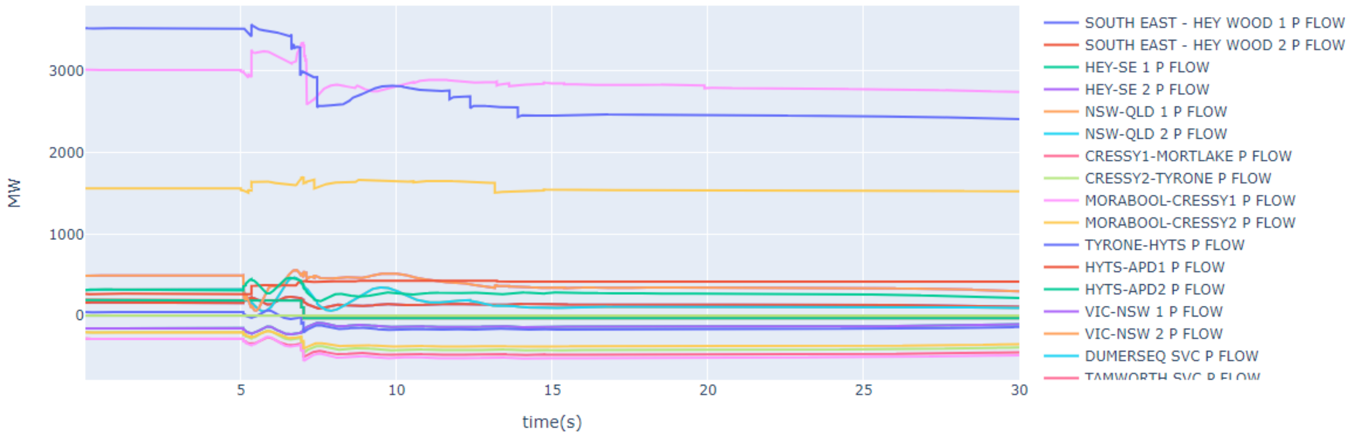


Figure 47 Case 1, Loy Yang A + TIPS B + Mt Piper + Millmerran trip: line active power flows (MW)



Case 8 – 7/05/2023 2330 hrs, contingency 11 (loss of QNI/Queensland separation)

For case 8, the Queensland system frequency exceeded 52 Hz following the trip of QNI if the Wandoan BESS was out of service.

Figure 48 Case 8, loss of QNI: system frequency traces (Hz)

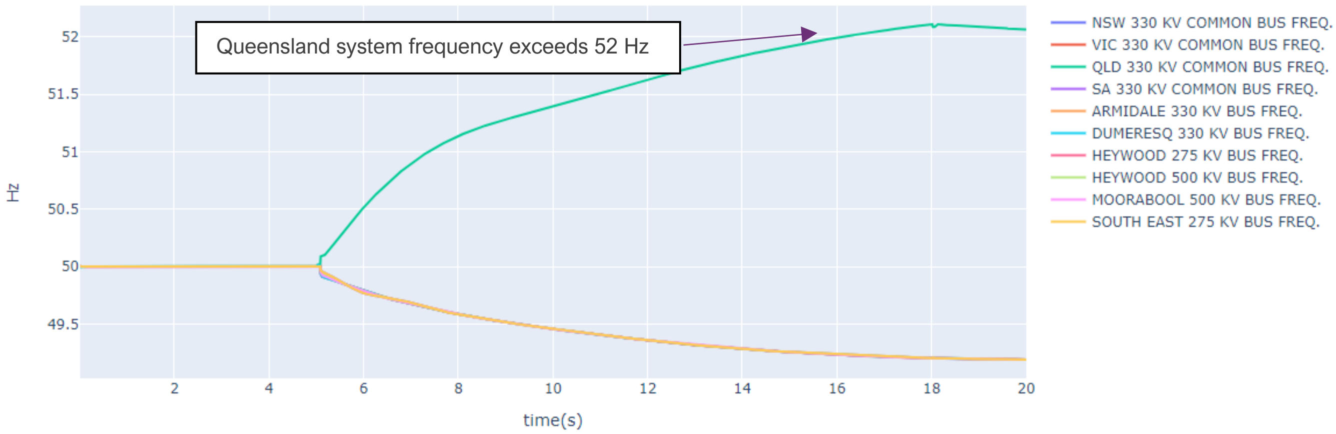
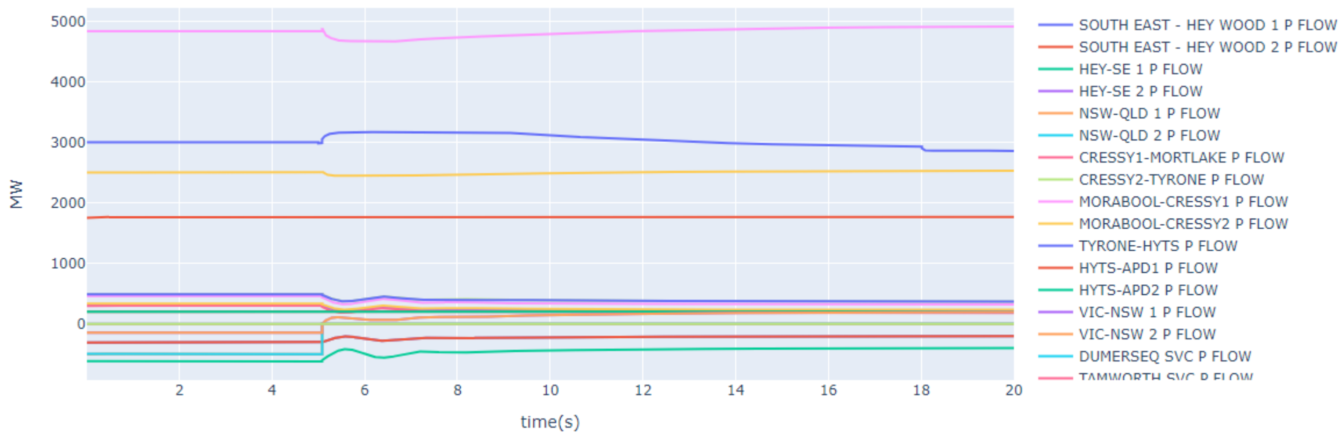


Figure 49 Case 8, loss of QNI: line active power flows (MW)



Case 10 – 22/06/2023 1200 hrs, contingency 9 (Bayswater + Eraring station trip)

For case 10 and contingency 9, the NEM frequency fell to 48.1 Hz and Queensland islands following the trip of Bayswater and Eraring units.

Figure 50 Case 10, Bayswater + Eraring station trip: system frequency traces (Hz)

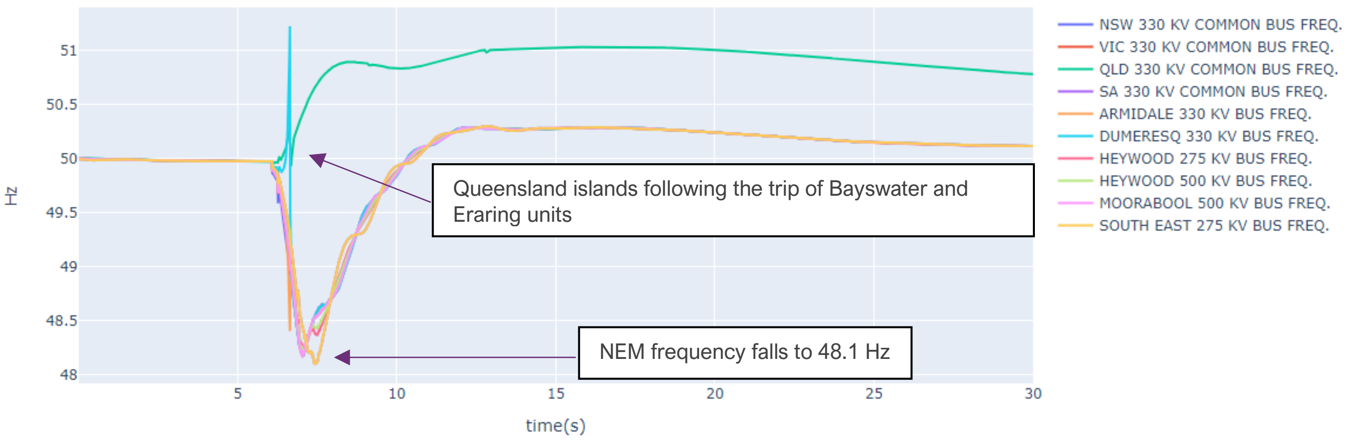
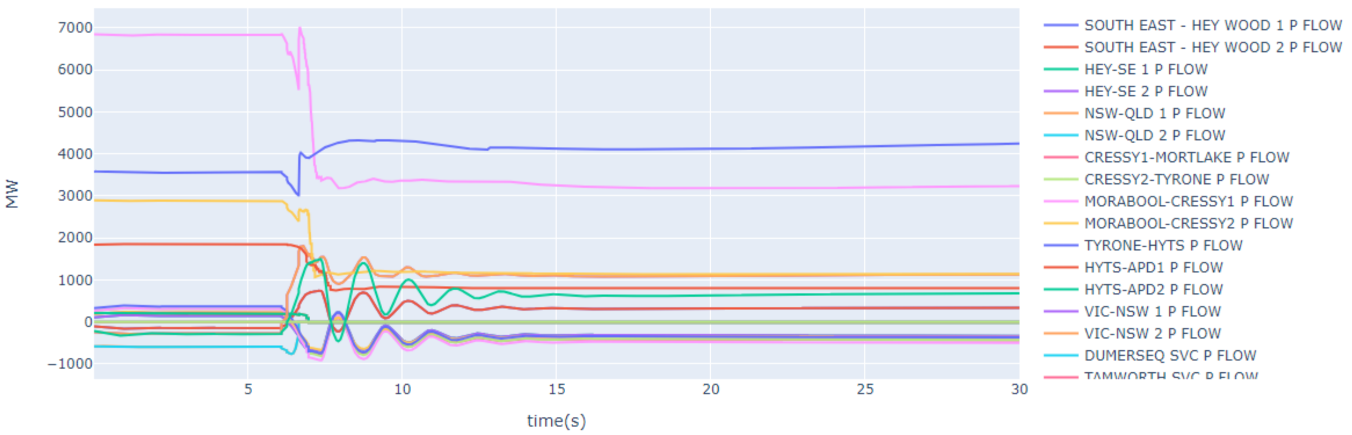


Figure 51 Case 10, Bayswater + Eraring station trip: line active power flows (MW)



Case 10 – 22/06/2023 1200 hrs, contingency 12 (loss of Heywood + TIPS B + Pelican Point station trip)

For case 10 and contingency 12, the South Australia system frequency fell below 48 Hz following separation and the trip of the TIPS B and Pelican Point units.

Figure 52 Case 10, loss of Heywood + TIPS B + Pelican Point station trip: system frequency traces (Hz)

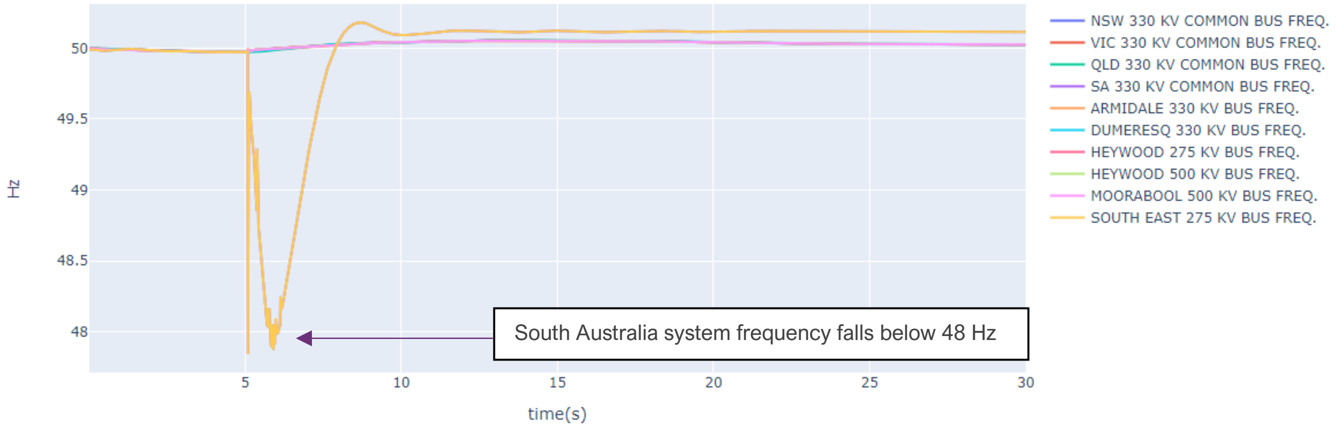
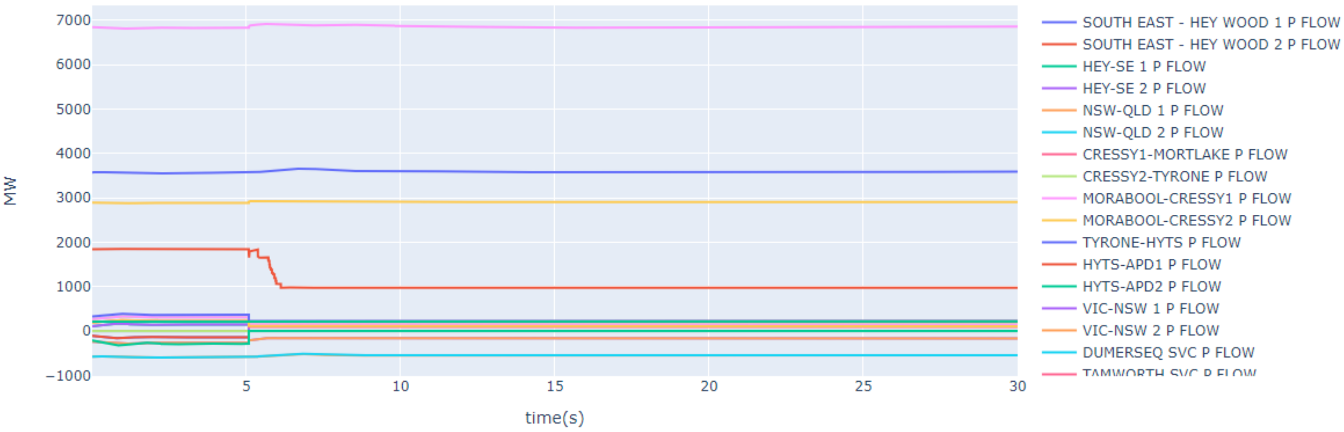


Figure 53 Case 10, loss of Heywood + TIPS B + Pelican Point station trip: line active power flows (MW)



Case 11 – 10/10/2022 1030 hrs, Loy Yang A + Millmerran station trip (full NEM model)

For case 11 with the Torrens Island BESS in service, the NEM frequency fell to 49.2 Hz and the Heywood interconnector flow rose to 930 MW in less than 5 seconds following the trip of the Loy Yang A and Millmerran units. Voltage collapse occurred around South East following the power swing on Heywood, causing South Australia to lose synchronism with the rest of the NEM.

Figure 54 Case 11, Loy Yang A + Millmerran station trip: system frequency traces (Hz)

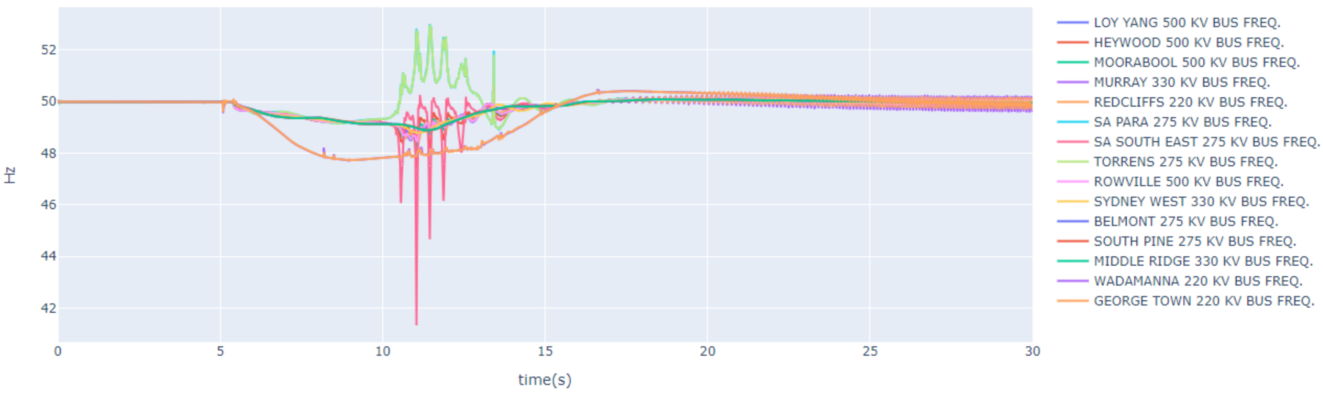


Figure 55 Case 11, Loy Yang A + Millmerran station trip: system voltage traces (pu)

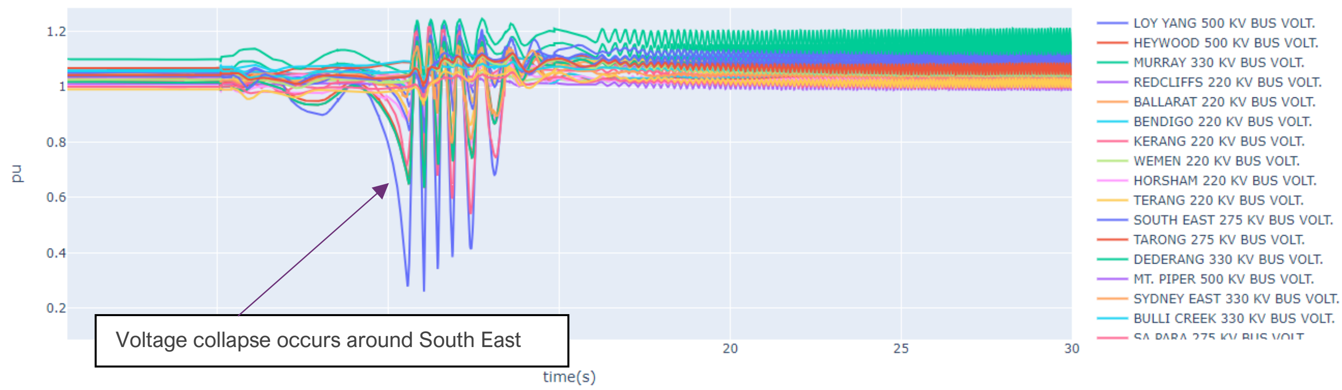


Figure 56 Case 11, Loy Yang A + Millmerran station trip: Heywood active power flow (MW)

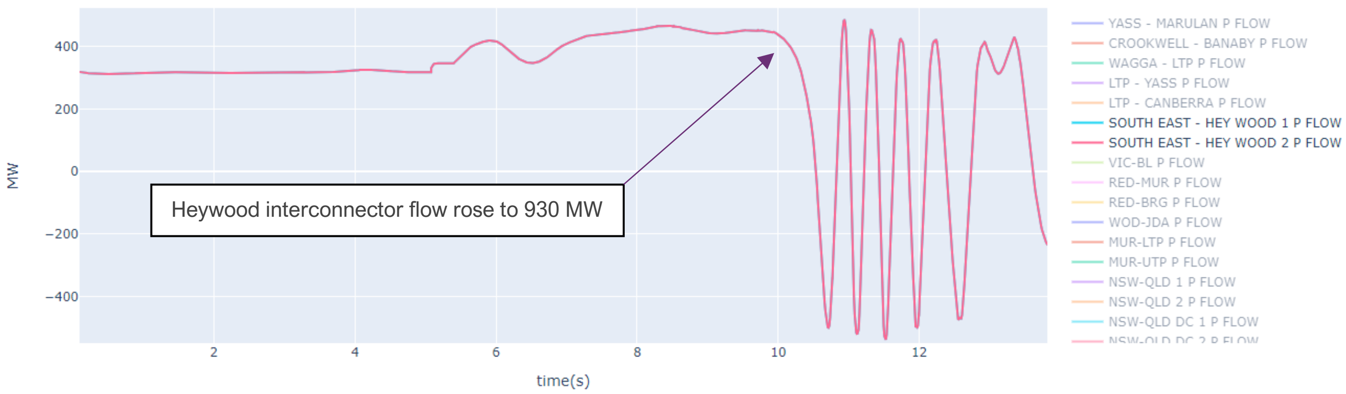
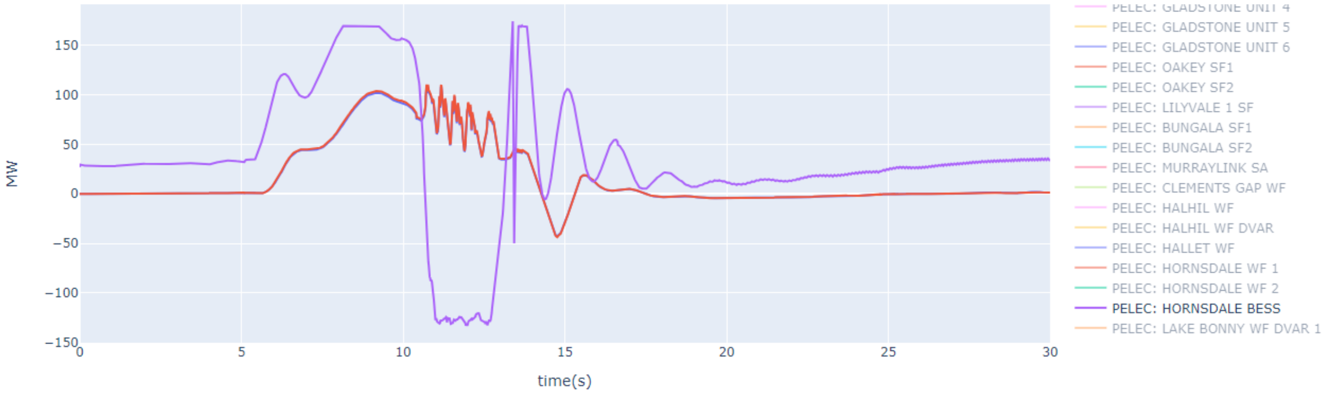


Figure 57 Case 11, Loy Yang A + Millmerran station trip: Hornsdale and Torrens Island BESS active power response (MW)



Case 14 – 1/07/2022 2030 hrs, contingency 12 (loss of Heywood + TIPS B + Pelican Point station trip)

For case 14, the South Australia system frequency fell to 47.3 Hz following separation and the trip of the TIPS B and Pelican Point units.

Figure 58 Case 14, loss of Heywood + TIPS B + Pelican Point station trip: system frequency traces (Hz)

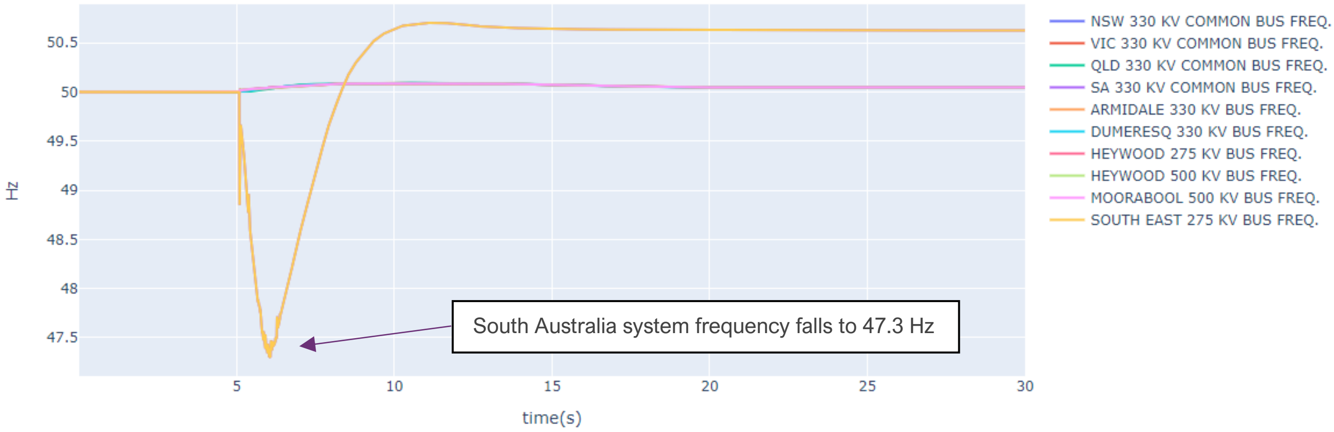
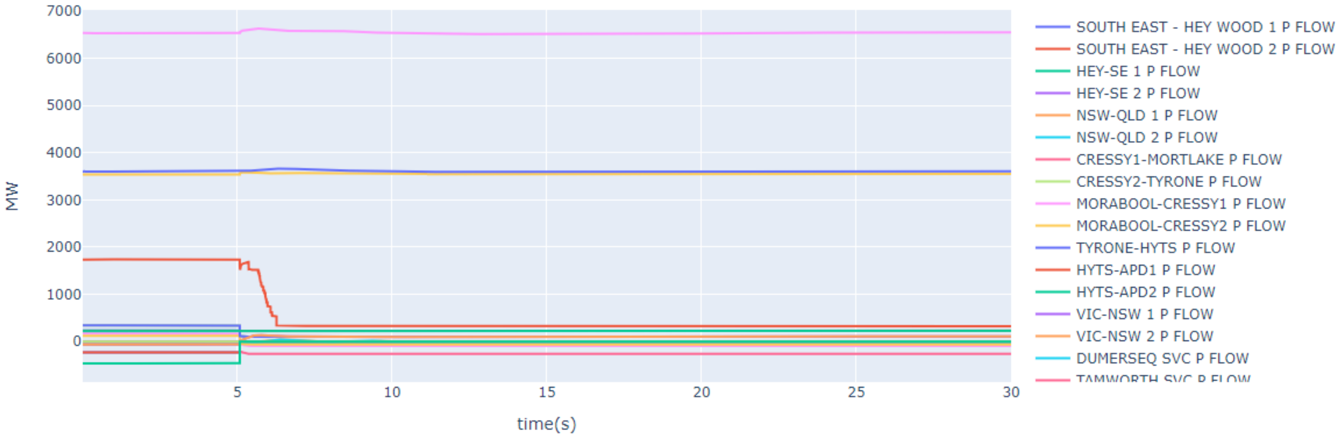


Figure 59 Case 14, loss of Heywood + TIPS B + Pelican Point station trip: line active power flows (MW)



Case 15 – 6/12/2022 1130 hrs, contingency 10 (loss of VNI + Loy Yang A station trip)

For case 15, the Victoria/South Australia frequency dropped to 48.3 Hz following the loss of VNI and Loy Yang A units.

Figure 60 Case 15, loss of VNI + Loy Yang A station trip: system frequency traces (Hz)

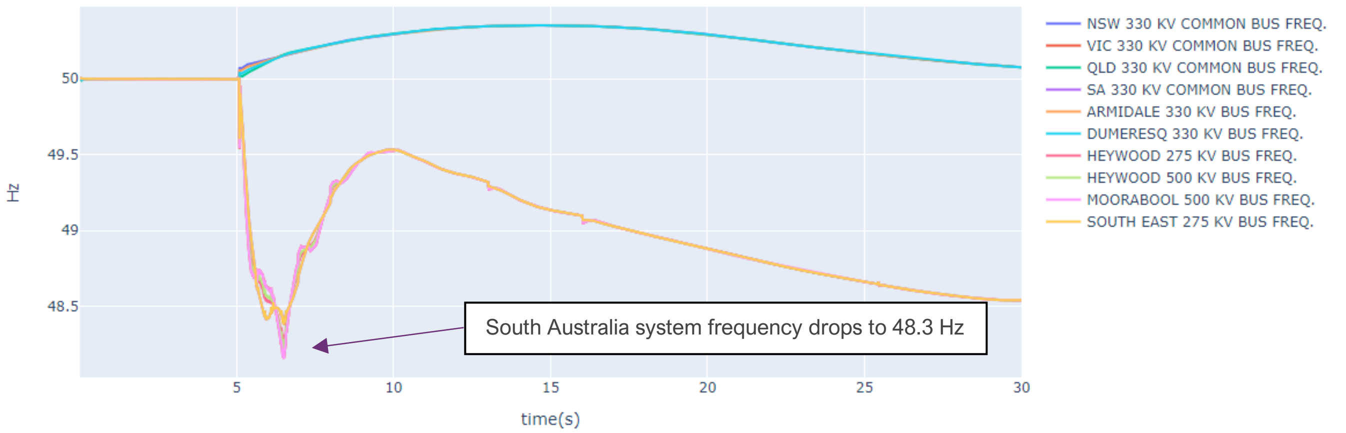
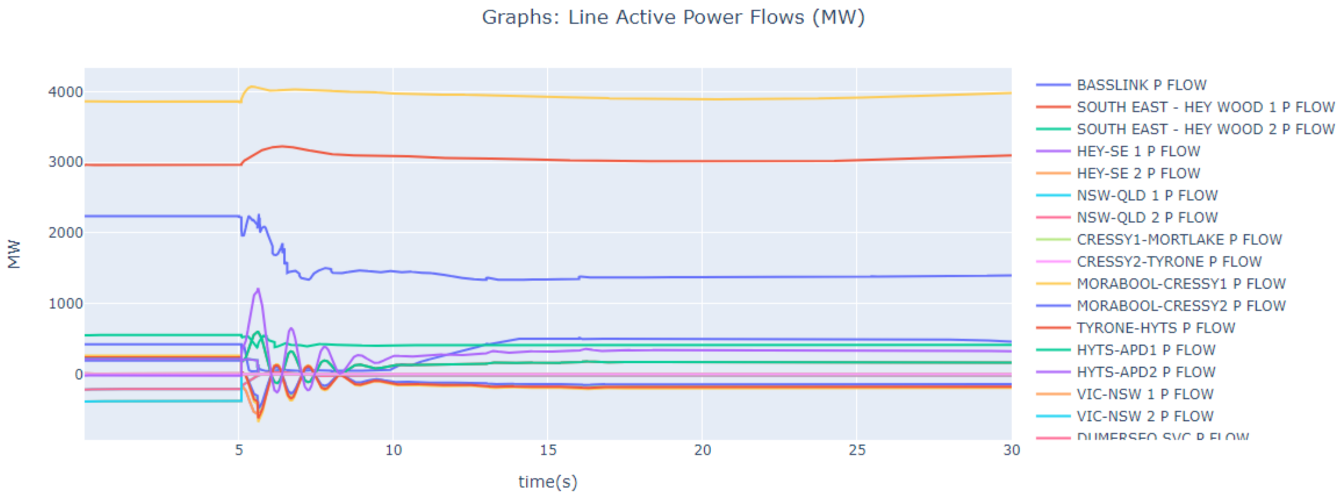


Figure 61 Case 15, loss of VNI + Loy Yang A station trip: line active power flows (MW)



A5.3.2 Future UFLS screening study results

The key parameters of each of the future dispatch studies are detailed in Table 32.

Table 32 Detailed future study results, 10% regional DPV force tripped

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9	Contingency 10	Contingency 11
1	QLD freq nadir (Hz): 48.2 NEM freq peak (Hz): 50.3 NEM RoCoF (Hz/s): 1.48 QLD net UFLS tripped (MW): 1999 (63 %) QLD DPV tripped on protection (MW): 222	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.55 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.49 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.54 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.18 NEM net UFLS tripped (MW): 1622 (10%) NEM DPV tripped on protection (MW): 1711	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.94 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.4 NEM RoCoF (Hz/s): 2.01 NEM net UFLS tripped (MW): 2880 (27%) NEM DPV tripped on protection (MW): 1395	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.36 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.24 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.75 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq nadir (Hz): 48.2 NEM freq peak (Hz): 50.3 QLD RoCoF (Hz/s): 2.25 QLD net UFLS tripped (MW): 1936 (58%) QLD DPV tripped on protection (MW): 220
2	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.63 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 48.5 NEM RoCoF (Hz/s): 1.32 NEM net UFLS tripped (MW): 1741 (31%) NEM DPV tripped on protection (MW): 1065	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 48.5 NEM RoCoF (Hz/s): 1.76 NEM net UFLS tripped (MW): 1495 (21%) NEM DPV tripped on protection (MW): 851	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 48.4 NEM RoCoF (Hz/s): 2.04 NEM net UFLS tripped (MW): 1767 (31%) NEM DPV tripped on protection (MW): 791	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 47.5 NEM RoCoF (Hz/s): 2.87 NEM net UFLS tripped (MW): 3208 (57%) NEM DPV tripped on protection (MW): 864	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.94 NEM net UFLS tripped (MW): 1187 (9%) NEM DPV tripped on protection (MW): 1200	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.74 NEM net UFLS tripped (MW): 1933 (16%) NEM DPV tripped on protection (MW): 1239	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.38 NEM net UFLS tripped (MW): 1131 (14%) NEM DPV tripped on protection (MW): 1168	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.8 NEM net UFLS tripped (MW): 925 (7%) NEM DPV tripped on protection (MW): 1515	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.72 NEM net UFLS tripped (MW): 1344 (17%) NEM DPV tripped on protection (MW): 868	QLD freq peak (Hz): 50.4 NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.95 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW):0
3	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.46 NEM net UFLS tripped (MW): 0	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.41	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48.4 NEM RoCoF (Hz/s): 1.52	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48.3 NEM RoCoF (Hz/s): 1.74	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48 NEM RoCoF (Hz/s): 1.52	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.65 NEM net UFLS tripped (MW): 0	NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.25 NEM net UFLS tripped (MW): 1973 (18%)	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.64	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 1.03	QLD freq peak (Hz): 51.1 NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.79	QLD freq peak (Hz): 50.6 NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.78

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9	Contingency 10	Contingency 11
	NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 669 (8%) NEM DPV tripped on protection (MW): 1012	NEM net UFLS tripped (MW): 1687 (27%) NEM DPV tripped on protection (MW): 877	NEM net UFLS tripped (MW): 1952 (33%) NEM DPV tripped on protection (MW): 1754	NEM net UFLS tripped (MW): 2408 (43%) NEM DPV tripped on protection (MW): 821	NEM DPV tripped on protection (MW): 0	NEM DPV tripped on protection (MW): 1236	NEM net UFLS tripped (MW): 1250 (16%) NEM DPV tripped on protection (MW): 981	NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 854 (12%) NEM DPV tripped on protection (MW): 957	NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0
4	NEM freq nadir (Hz): 49 NEM RoCoF (Hz/s): 0.56 NEM net UFLS tripped (MW): 1230 (8%) NEM DPV tripped on protection (MW): 616	QLD freq peak (Hz): 51.3 NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.4 NEM net UFLS tripped (MW): 2330 (28%) NEM DPV tripped on protection (MW): 373	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.86 NEM net UFLS tripped (MW): 2387 (29%) NEM DPV tripped on protection (MW): 444	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 48.5 NEM RoCoF (Hz/s): 1.98 NEM net UFLS tripped (MW): 2861 (25%) NEM DPV tripped on protection (MW): 675	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 48.2 NEM RoCoF (Hz/s): 1.86 NEM net UFLS tripped (MW): 3963 (36%) NEM DPV tripped on protection (MW): 592	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.04 NEM net UFLS tripped (MW): 2349 (19%) NEM DPV tripped on protection (MW): 584	NEM freq nadir (Hz): 48.3 NEM RoCoF (Hz/s): 2.03 NEM net UFLS tripped (MW): 4413 (39%) NEM DPV tripped on protection (MW): 532	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 48.5 NEM RoCoF (Hz/s): 1.4 NEM net UFLS tripped (MW): 2681 (32%) NEM DPV tripped on protection (MW): 455	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 49 NEM RoCoF (Hz/s): 2.11 NEM net UFLS tripped (MW): 468 (4%) NEM DPV tripped on protection (MW): 466	QLD freq peak (Hz): 51.2 NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.51 NEM net UFLS tripped (MW): 2646 (32%) NEM DPV tripped on protection (MW): 452	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.93 NEM net UFLS tripped (MW): 1085 (11%) NEM DPV tripped on protection (MW): 493
5	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.47 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.53 NEM net UFLS tripped (MW): 1219 (16%) NEM DPV tripped on protection (MW): 1142	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 2.26 NEM net UFLS tripped (MW): 1469 (18%) NEM DPV tripped on protection (MW): 1167	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.83 NEM net UFLS tripped (MW): 1583 (22%) NEM DPV tripped on protection (MW): 1166	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.3 NEM RoCoF (Hz/s): 2.26 NEM net UFLS tripped (MW): 2775 (44%) NEM DPV tripped on protection (MW): 741	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.81 NEM net UFLS tripped (MW): 1137 (7%) NEM DPV tripped on protection (MW): 1594	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.44 NEM net UFLS tripped (MW): 2753 (26%) NEM DPV tripped on protection (MW): 1442	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.35 NEM net UFLS tripped (MW): 1546 (22%) NEM DPV tripped on protection (MW): 1095	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 49.06 NEM RoCoF (Hz/s): 1.46 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 51 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.61 NEM net UFLS tripped (MW): 1043 (11%) NEM DPV tripped on protection (MW): 1198	QLD freq peak (Hz): 50.4 NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.84 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0
6	NEM freq nadir (Hz): 49.3	QLD freq peak (Hz): 50.9	QLD freq peak (Hz): 51	QLD freq peak (Hz): 50.9	QLD freq peak (Hz): 50.9	NEM freq nadir (Hz): 48.8	NEM freq nadir (Hz): 48.5	QLD freq peak (Hz): 50.9	QLD freq peak (Hz): 50.9	QLD freq peak (Hz): 50.9	QLD freq peak (Hz): 50.4

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9	Contingency 10	Contingency 11
	NEM RoCoF (Hz/s): 0.59 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.19 NEM net UFLS tripped (MW): 1492 (25%) NEM DPV tripped on protection (MW): 1206	NEM freq nadir (Hz): 48.7 NEM RoCoF (Hz/s): 1.68 NEM net UFLS tripped (MW): 714 (10%) NEM DPV tripped on protection (MW): 986	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.38 NEM net UFLS tripped (MW): 1276 (21%) NEM DPV tripped on protection (MW): 1127	NEM freq nadir (Hz): 48.2 NEM RoCoF (Hz/s): 2.68 NEM net UFLS tripped (MW): 2687 (52%) NEM DPV tripped on protection (MW): 1042	NEM RoCoF (Hz/s): 0.94 NEM net UFLS tripped (MW): 1693 (13%) NEM DPV tripped on protection (MW): 1302	NEM RoCoF (Hz/s): 1.8 NEM net UFLS tripped (MW): 2731 (30%) NEM DPV tripped on protection (MW): 1498	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.35 NEM net UFLS tripped (MW): 875 (9%) NEM DPV tripped on protection (MW): 1328	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.82 NEM net UFLS tripped (MW): 537 (5%) NEM DPV tripped on protection (MW): 1481	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.51 NEM net UFLS tripped (MW): 889 (9%) NEM DPV tripped on protection (MW): 1307	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.91 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0
7	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.36 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.2 NEM net UFLS tripped (MW): 647 (6%) NEM DPV tripped on protection (MW): 700	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 1.24 NEM net UFLS tripped (MW): 709 (7%) NEM DPV tripped on protection (MW): 694	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.57 NEM net UFLS tripped (MW): 1193 (12%) NEM DPV tripped on protection (MW): 682	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.6 NEM RoCoF (Hz/s): 1.97 NEM net UFLS tripped (MW): 2649 (34%) NEM DPV tripped on protection (MW): 634	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 0.77 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.13 NEM net UFLS tripped (MW): 2199 (15%) NEM DPV tripped on protection (MW): 1170	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 49 NEM RoCoF (Hz/s): 1.16 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.9 NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.63 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq peak (Hz): 50.8 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.98 NEM net UFLS tripped (MW): 647 (6%) NEM DPV tripped on protection (MW): 705	QLD freq peak (Hz): 50.1 NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.53 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0
8	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.3 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.8 NEM RoCoF (Hz/s): 0.19 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.42 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.52 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.97 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.4 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.92 NEM net UFLS tripped (MW): 966 (8%) NEM DPV tripped on protection (MW): 1546	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.96 NEM net UFLS tripped (MW): 1227 (10%) NEM DPV tripped on protection (MW): 1553	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.2 NEM net UFLS tripped (MW): 1088 (10%) NEM DPV tripped on protection (MW): 1271	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.28 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq nadir (Hz): 48.6 NEM freq peak (Hz): 50.1 QLD RoCoF (Hz/s): 1.16 QLD net UFLS tripped (MW): 966 (43%) NEM DPV tripped on

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9	Contingency 10	Contingency 11
											protection (MW): 257
9	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.2 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.28 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.17 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.35 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.64 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 0.46 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.2 NEM RoCoF (Hz/s): 0.86 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.15 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.88 NEM net UFLS tripped (MW): 1126 (7%) NEM DPV tripped on protection (MW): 1541	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.2 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq nadir (Hz): 48.5 NEM freq peak (Hz): 50.2 QLD RoCoF (Hz/s): 1.39 QLD net UFLS tripped (MW): 1255 (49%) NEM DPV tripped on protection (MW): 344
10	QLD freq nadir (Hz): 48.2 NEM freq peak (Hz): 50.4 QLD RoCoF (Hz/s): 1.19 QLD net UFLS tripped (MW): 2358 (69%) NEM DPV tripped on protection (MW): 165	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.46 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.69 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.75 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 1.18 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.6 NEM RoCoF (Hz/s): 0.64 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 48.5 NEM RoCoF (Hz/s): 1.87 NEM net UFLS tripped (MW): 2716 (20%) NEM DPV tripped on protection (MW): 1268	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.72 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.23 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM freq nadir (Hz): 49.7 NEM RoCoF (Hz/s): 0.22 NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	QLD freq nadir (Hz): 48 NEM freq peak (Hz): 50.3 QLD RoCoF (Hz/s): 2.15 QLD net UFLS tripped (MW): 2432 (72%) NEM DPV tripped on protection (MW): 143
11	NEM freq nadir (Hz): 49.4 NEM RoCoF (Hz/s): 0.18 NEM net UFLS tripped (MW): 0	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 49 NEM RoCoF (Hz/s): 0.64	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 48.9 NEM RoCoF (Hz/s): 0.77	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.78	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.0	NEM freq nadir (Hz): 49 NEM RoCoF (Hz/s): 0.41 NEM net UFLS tripped (MW): 0	NEM freq nadir (Hz): 49.1 NEM RoCoF (Hz/s): 0.62 NEM net UFLS tripped (MW): 0	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 1.53	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 49.5 NEM RoCoF (Hz/s): 1.35	QLD freq peak (Hz): 51.5 NEM freq nadir (Hz): 48.8 NEM RoCoF (Hz/s): 0.59	QLD freq peak (Hz): 50.6 NEM freq nadir (Hz): 49.3 NEM RoCoF (Hz/s): 0.48

Case	Contingency 1	Contingency 2	Contingency 3	Contingency 4	Contingency 5	Contingency 6	Contingency 7	Contingency 8	Contingency 9	Contingency 10	Contingency 11
	NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 1138 (9%) NEM DPV tripped on protection (MW): 1187	NEM net UFLS tripped (MW): 1712 (15%) NEM DPV tripped on protection (MW): 1171	NEM net UFLS tripped (MW): 2460 (23%) NEM DPV tripped on protection (MW): 820	NEM DPV tripped on protection (MW): 0	NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 2187 (19%) NEM DPV tripped on protection (MW): 831	NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0	NEM net UFLS tripped (MW): 1703 (15%) NEM DPV tripped on protection (MW): 1178	NEM net UFLS tripped (MW): 0 NEM DPV tripped on protection (MW): 0

Case 2 – 8/03/2029 1100 hrs, contingency 5 (Loy Yang A + Mt Piper station trip)

For case 2, mainland NEM system frequency fell to a nadir of 47.5 Hz following the simultaneous trip of the Loy Yang and Mt Piper generating units and 10% regional DPV.

Figure 62 Case 2, Loy Yang + Mt Piper station trip: system frequency traces (Hz)

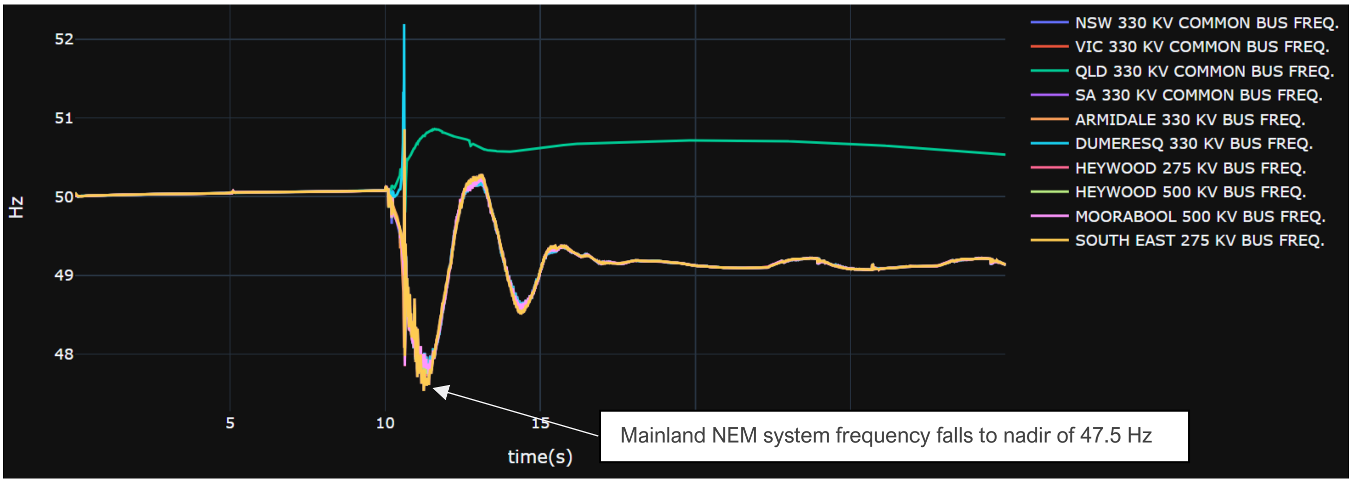
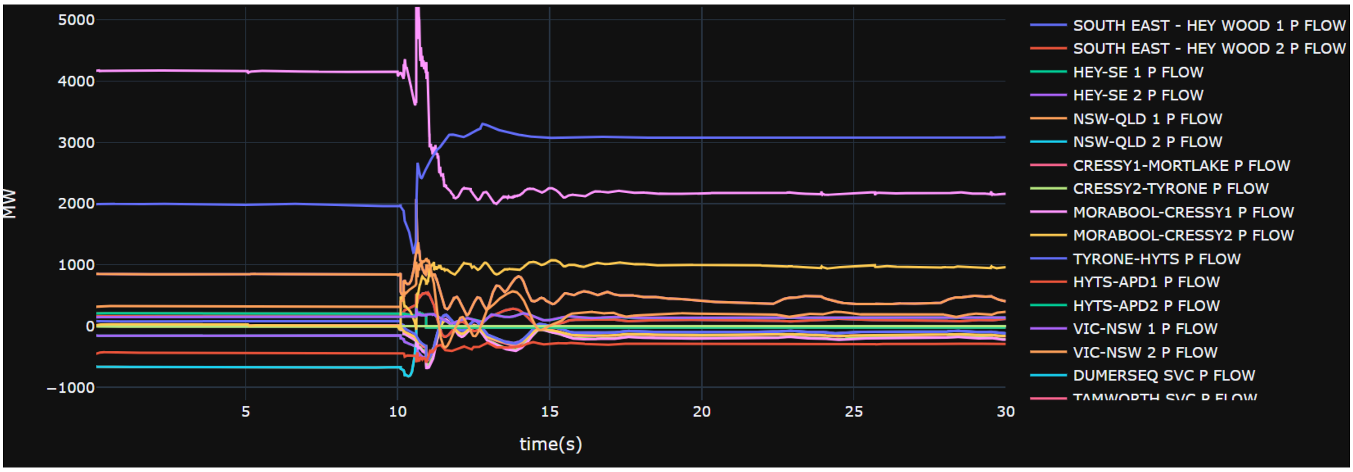


Figure 63 Case 2, Loy Yang + Mt Piper station trip: line active power flows (MW)



Case 3 – 1/09/2028 1230 hrs, contingency 5 (Loy Yang A + Mt Piper station trip)

For case 3, mainland NEM system frequency fell below 48 Hz following the simultaneous trip of the Loy Yang and Mt Piper generating units and 10% regional DPV.

Figure 64 Case 3, Loy Yang + Mt Piper station trip: system frequency traces (Hz)

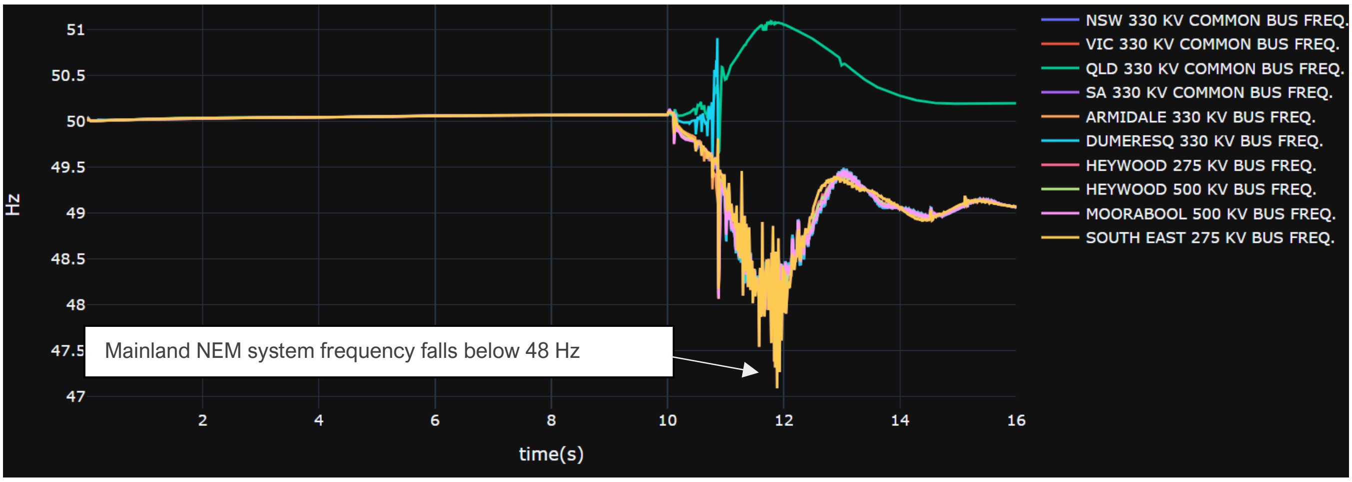
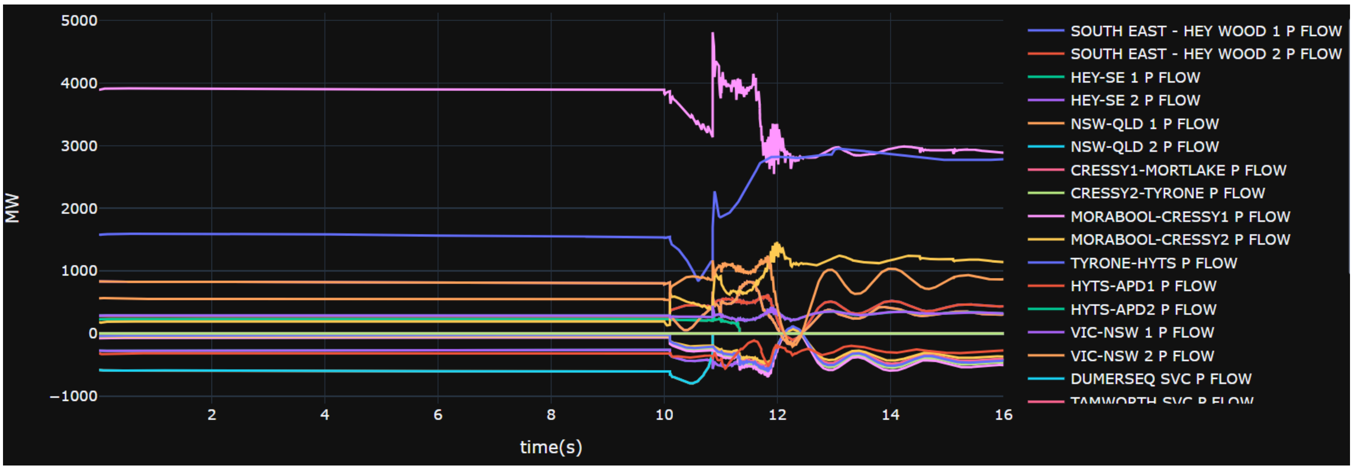


Figure 65 Case 3, Loy Yang + Mt Piper station trip: line active power flows (MW)



Case 2 – 8/03/2029 1100 hrs, contingency 7 (Loy Yang A + TIPS B + Mt Piper + Millmerran station trip) with reduced BESS headroom

For case 2 with the BESS headroom in New South Wales reduced to 0 MW, QNI lost stability and Queensland islanded following this multiple contingency event. Following Queensland separation, the NEM system frequency collapsed.

Figure 66 Case 2, reduced BESS headroom, contingency 15: system frequency traces (Hz)

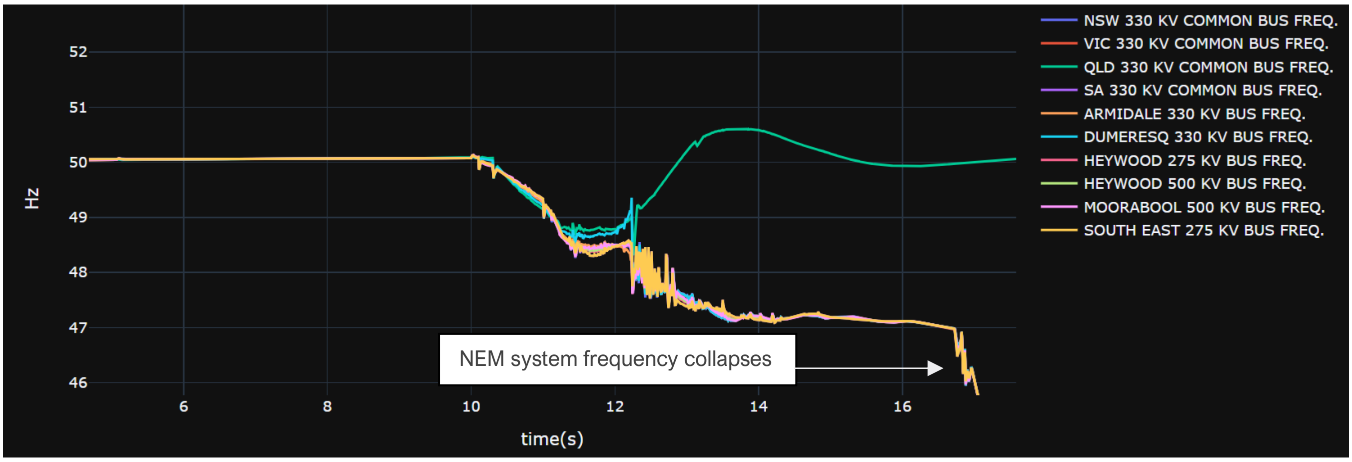
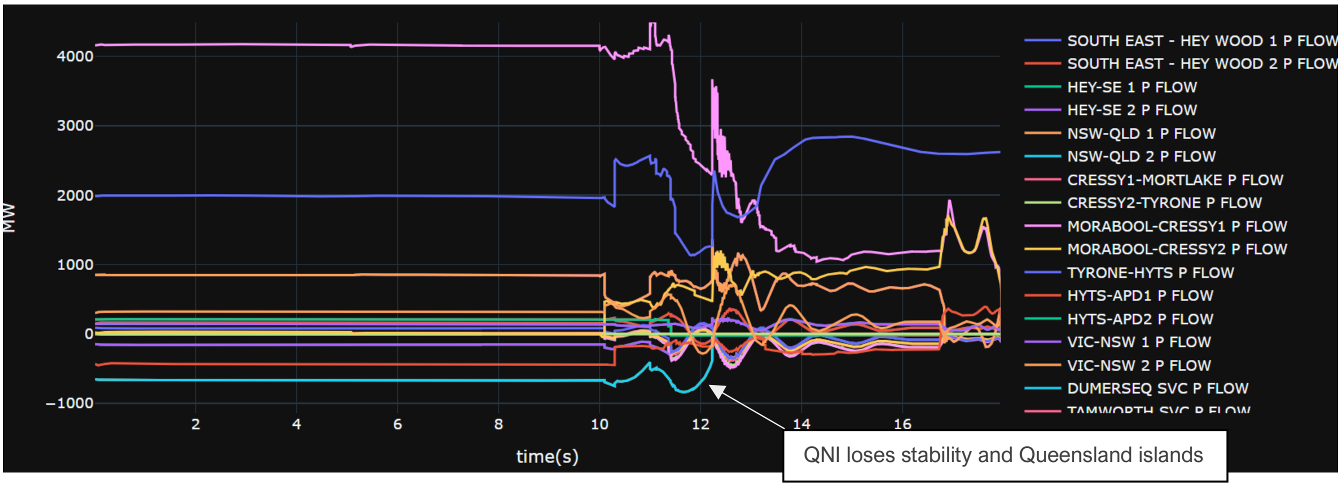


Figure 67 Case 2, reduced BESS headroom, contingency 15: line active power flows (MW)



Case 4 – 7/09/2028 1430 hrs, generation trip = 60% of operational demand

For case 4, mainland NEM system frequency fell to a nadir of 47.7 Hz following a cascading generation contingency equal to 60% of mainland NEM operational demand. If the Victoria Stage 1 UFLS actions were included, NEM frequency fell to 47.8 Hz.

Figure 68 Case 4, generation trip = 60% of operational demand: system frequency traces (Hz)

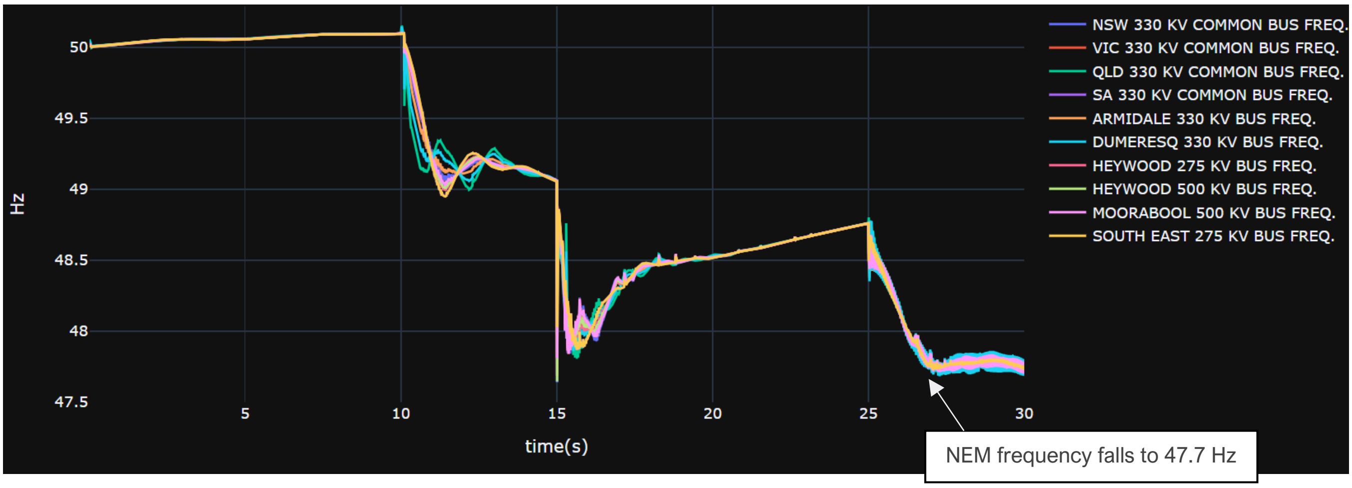


Figure 69 Case 4, generation trip = 60% of operational demand: line active power flows (MW)

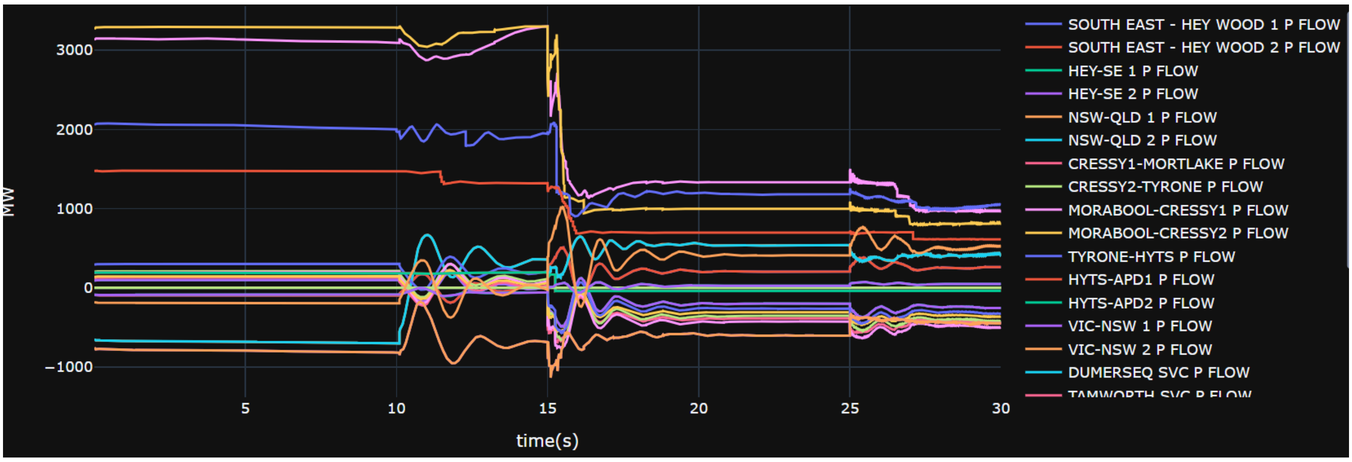


Figure 70 Case 4, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: system frequency traces (Hz)

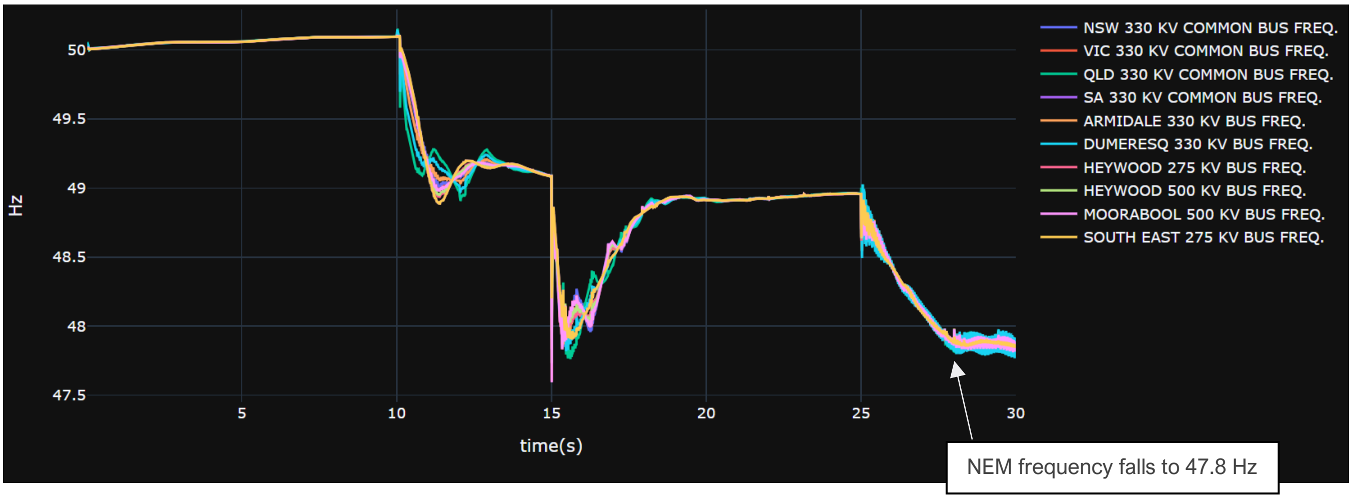
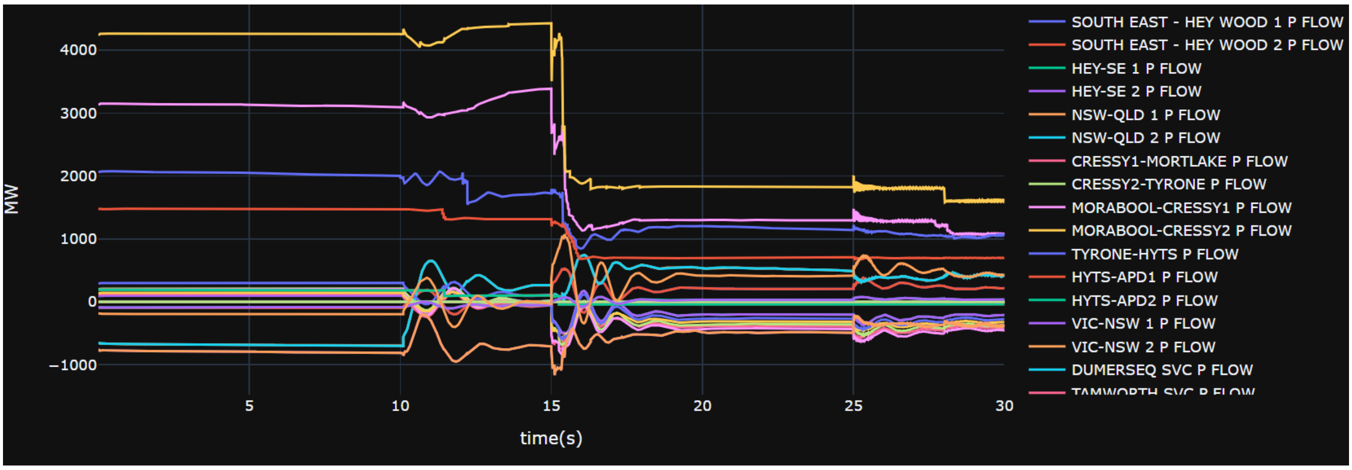


Figure 71 Case 4, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: active power flows (MW)



Case 5 – 23/08/2028 1100 hrs, generation trip = 60% of operational demand

For case 5, mainland NEM system frequency fell to a nadir of 47.7 Hz following a cascading generation contingency equal to 60% of mainland NEM operational demand. If the Victoria Stage 1 UFLS actions were included, NEM frequency fell to 47.8 Hz.

Figure 72 Case 5, generation trip = 60% of operational demand: system frequency traces (Hz)

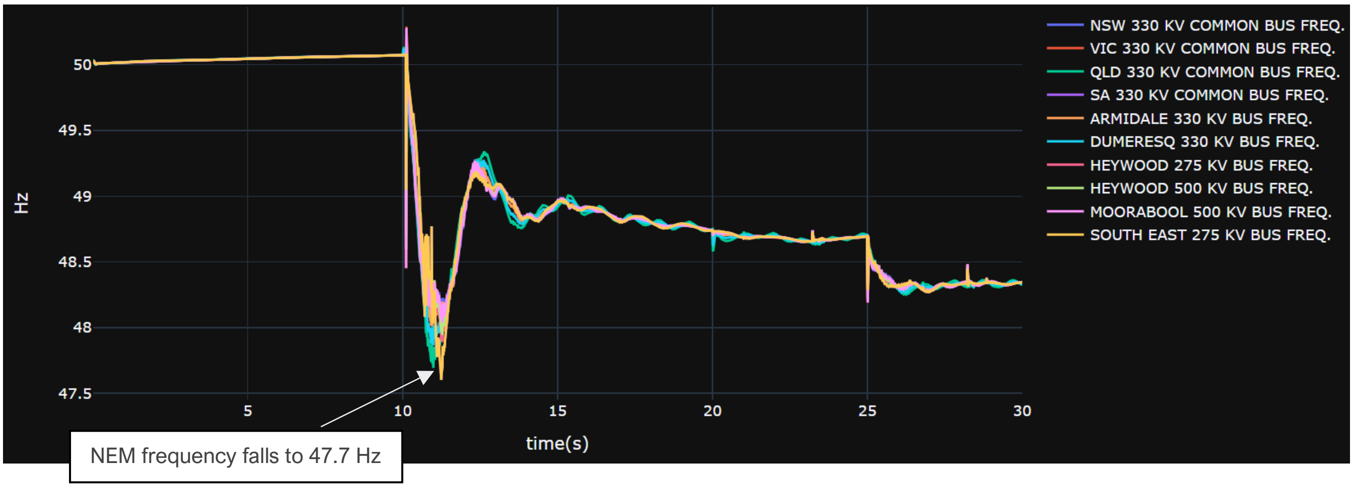


Figure 73 Case 5, generation trip = 60% of operational demand: line active power flows (MW)

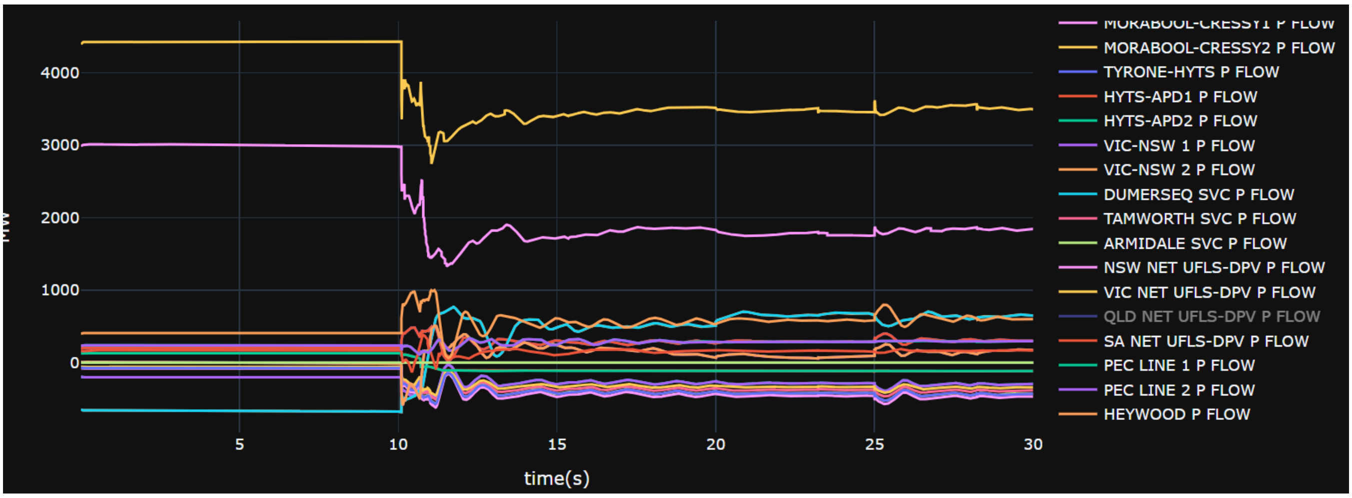


Figure 74 Case 5, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: system frequency traces (Hz)

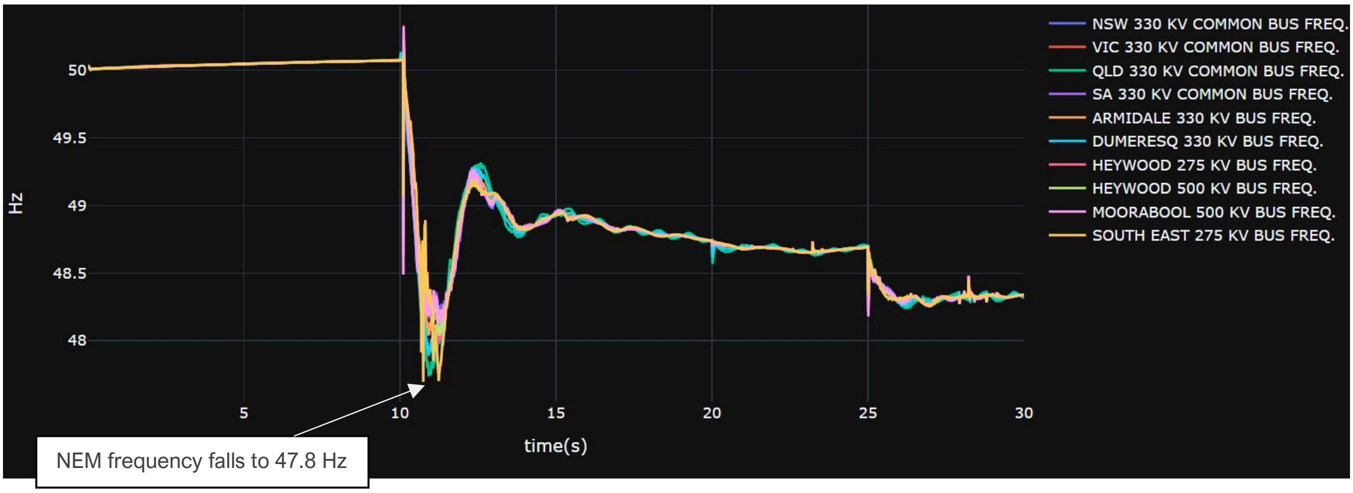
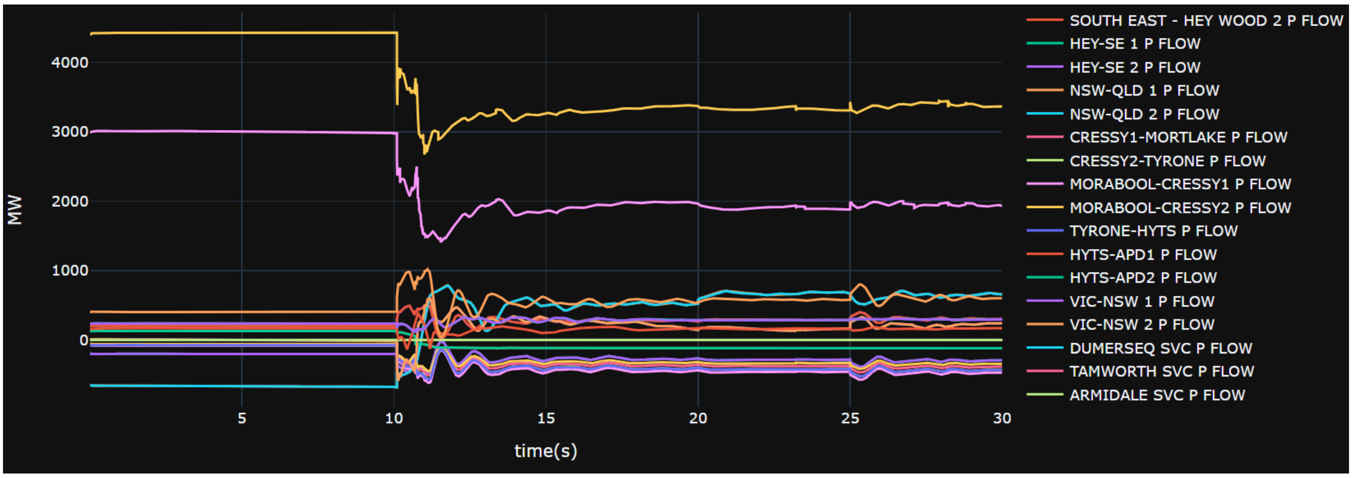


Figure 75 Case 5, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: active power flows (MW)



Case 6 – 8/03/2029 1200 hrs, contingency 7 (Loy Yang A + TIPS B + Mt Piper + Millmerran station trip) with reduced BESS headroom

For case 6 with the BESS headroom in New South Wales reduced to 0 MW, QNI lost stability and Queensland islanded following this multiple contingency event. After Queensland separation, the NEM system frequency fell to a nadir of 47.6 Hz.

Figure 76 Case 6, reduced BESS headroom, contingency 15: system frequency traces (Hz)

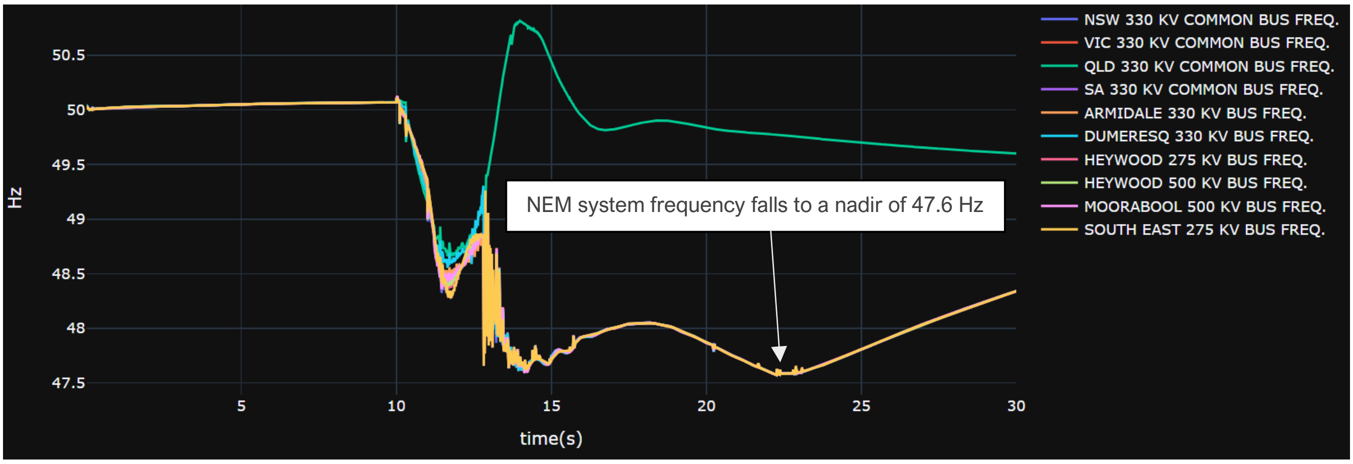
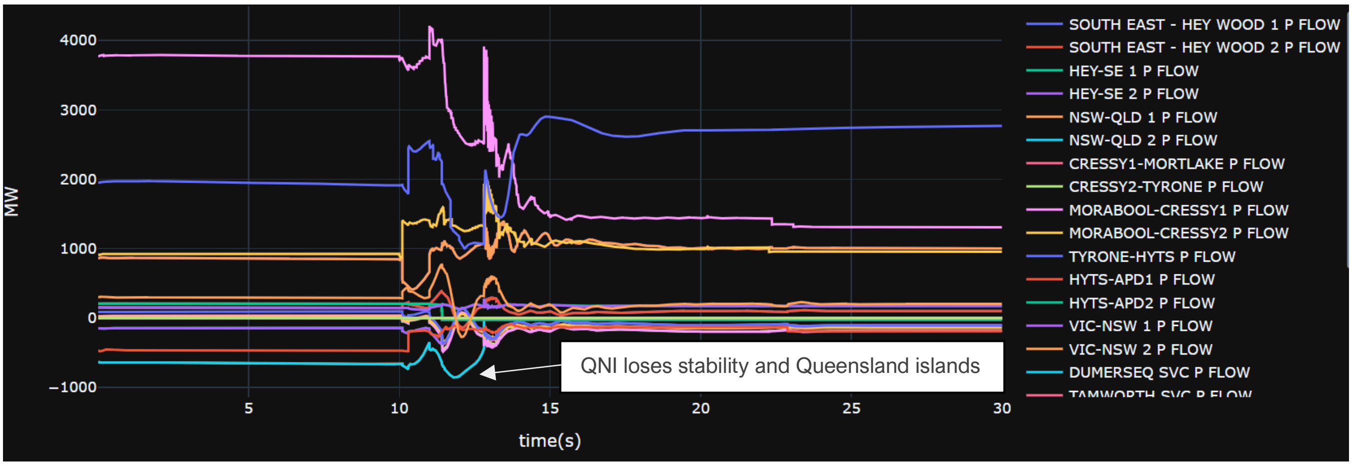


Figure 77 Case 6, reduced BESS headroom, contingency 15: line active power flows (MW)



Case 10 – 15/11/2028 1200 hrs, contingency 11 (Loss of QNI + Callide C station trip)

For case 10, Queensland system frequency fell to a nadir of 47.8 Hz following the simultaneous trip of QNI, the Callide C generating units and 5% regional DPV.

Figure 78 Case 10, QNI + Callide trip: system frequency traces (Hz)

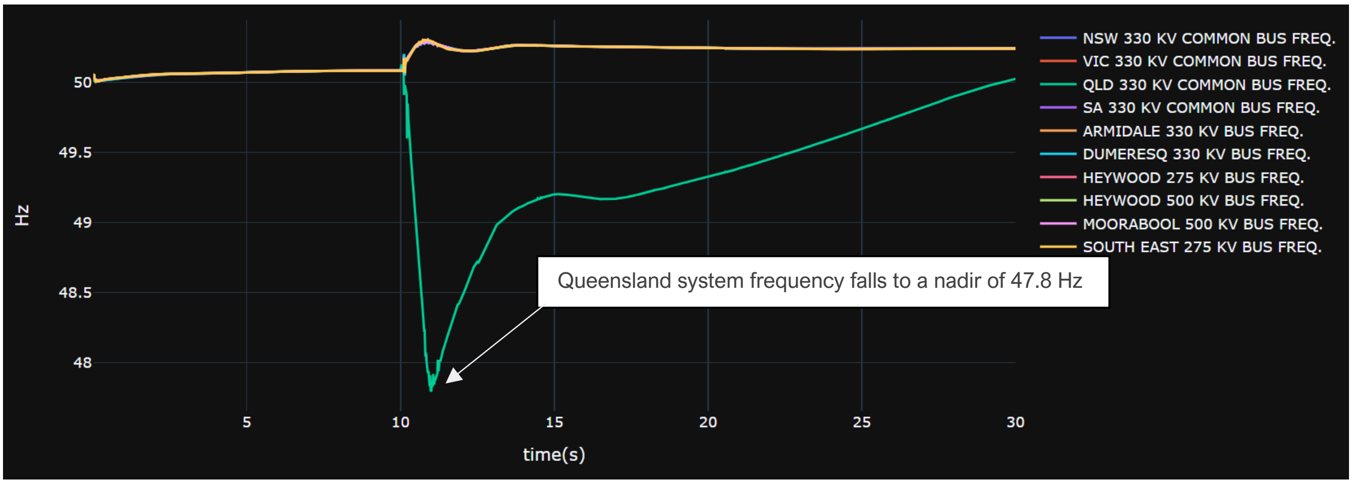
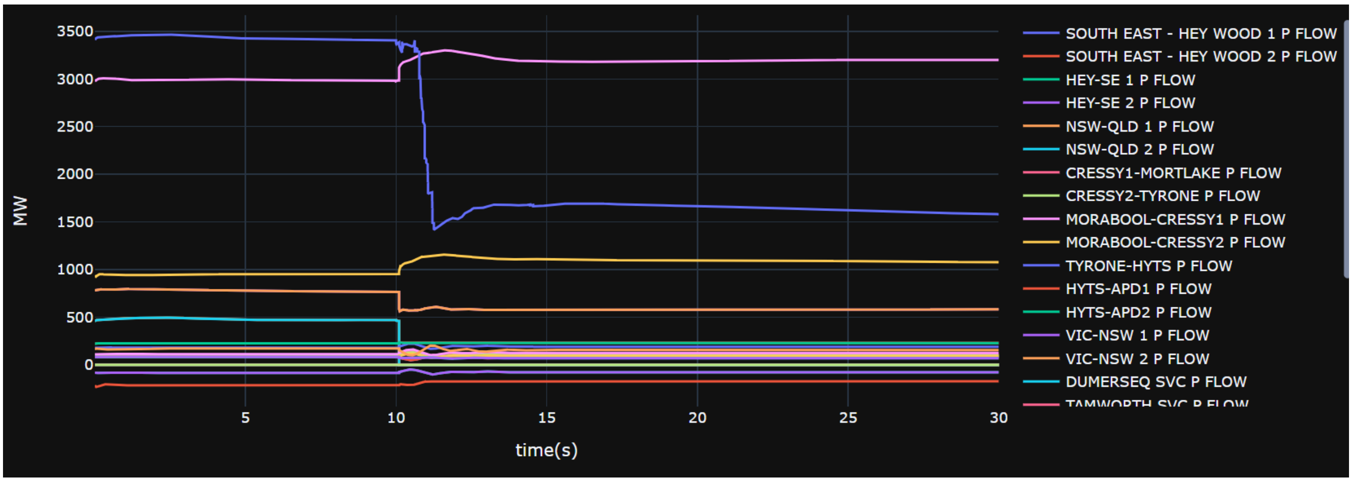


Figure 79 Case 10, QNI + Callide trip: line active power flows (MW)



Case 10 – 15/11/2028 1200 hrs, generation trip = 60% of operational demand

For case 10, mainland NEM system frequency fell to a nadir of 47.6 Hz following a cascading generation contingency equal to 60% of mainland NEM operational demand. If the Victoria Stage 1 UFLS actions were included, NEM frequency fell to 47.7 Hz.

Figure 80 Case 10, generation trip = 60% of operational demand: system frequency traces (Hz)

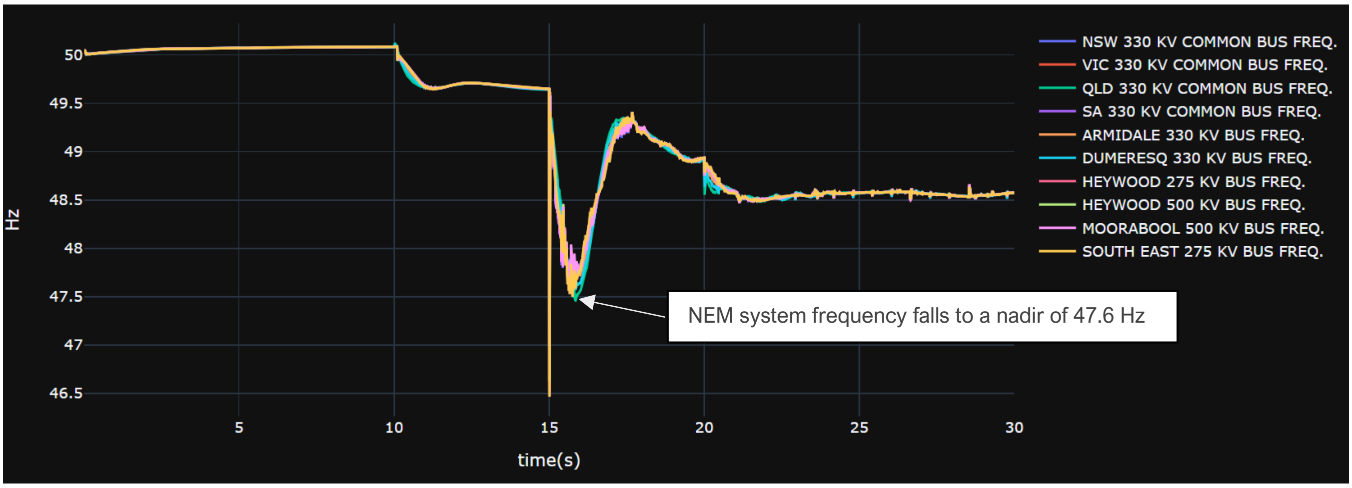


Figure 81 Case 10, generation trip = 60% of operational demand: line active power flows (MW)

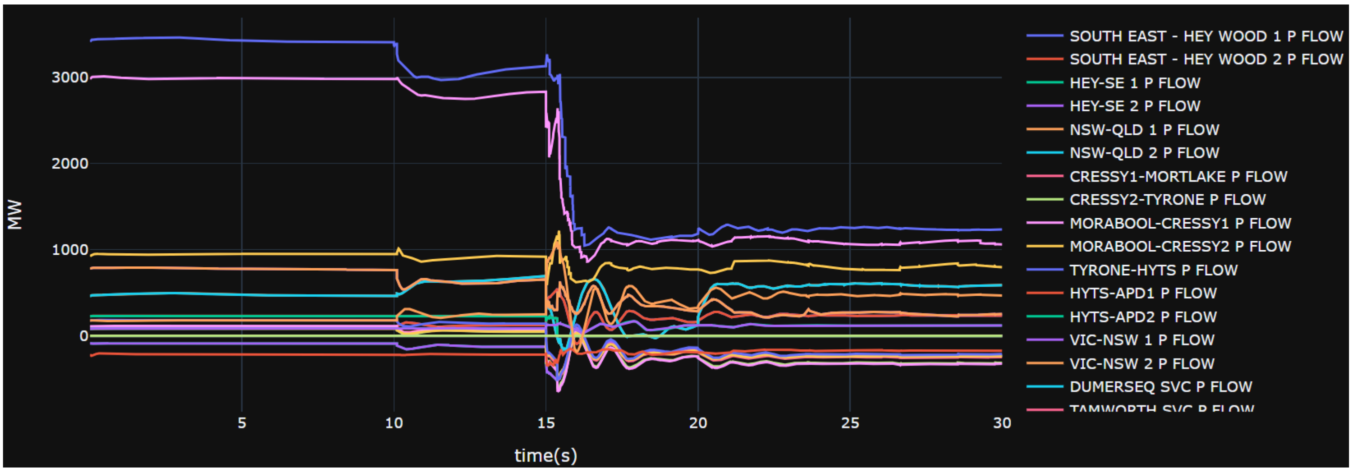


Figure 82 Case 10, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: system frequency traces (Hz)

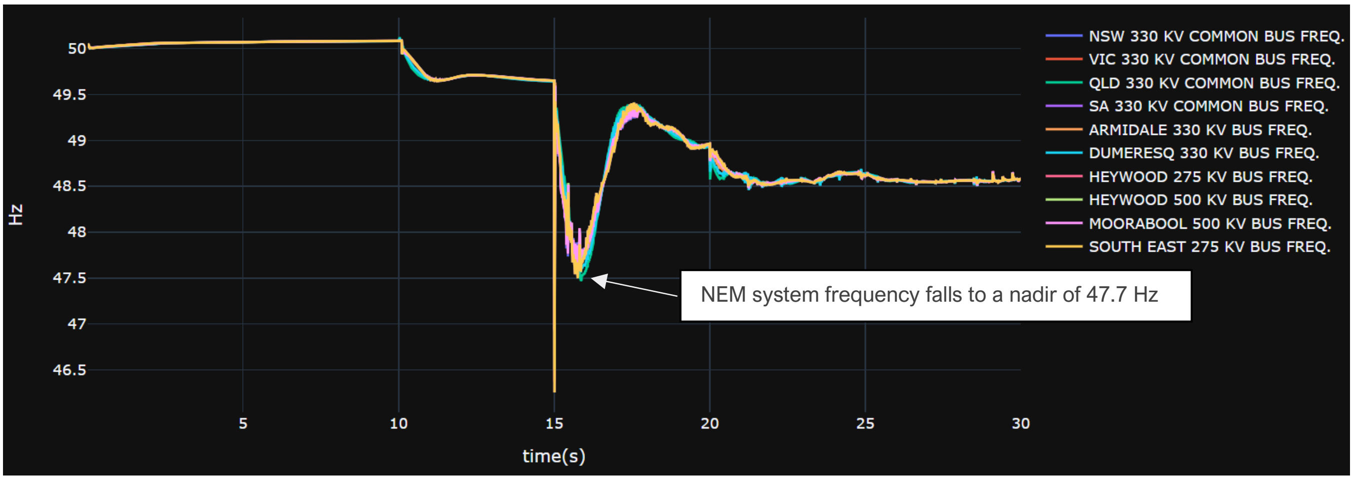
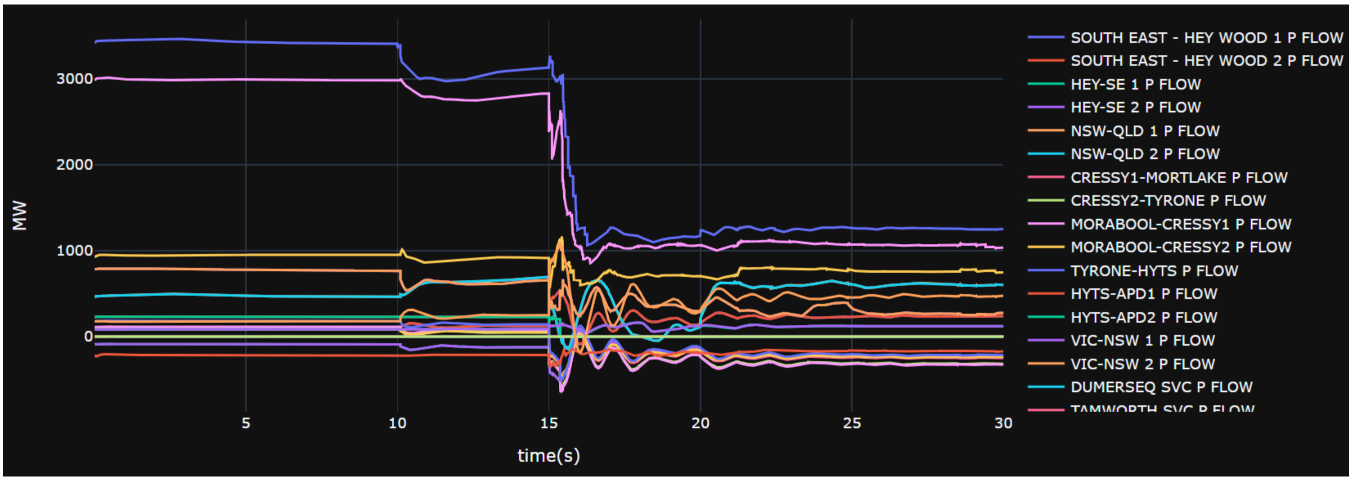


Figure 83 Case 10, including Victoria Stage 1 UFLS actions, generation trip = 60% of operational demand: active power flows (MW)



Case 11 – 28/01/2029 1530 hrs, generation trip = 60% of operational demand

For case 11, mainland NEM system frequency fell to a nadir of 47.8 Hz following a cascading generation contingency equal to 60% of mainland NEM operational demand.

Figure 84 Case 11, generation trip = 60% of operational demand: system frequency traces (Hz)

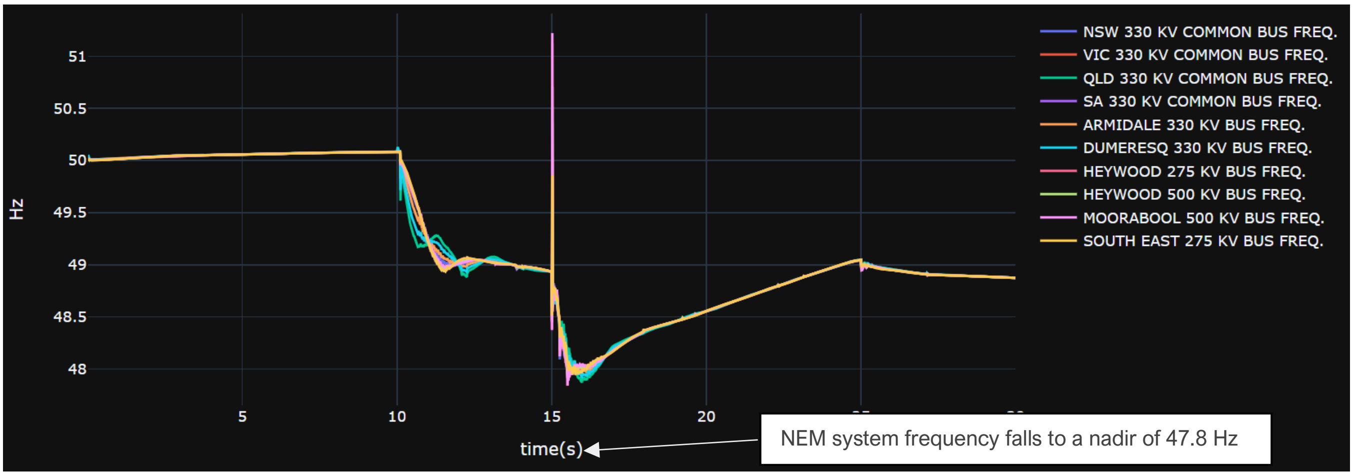
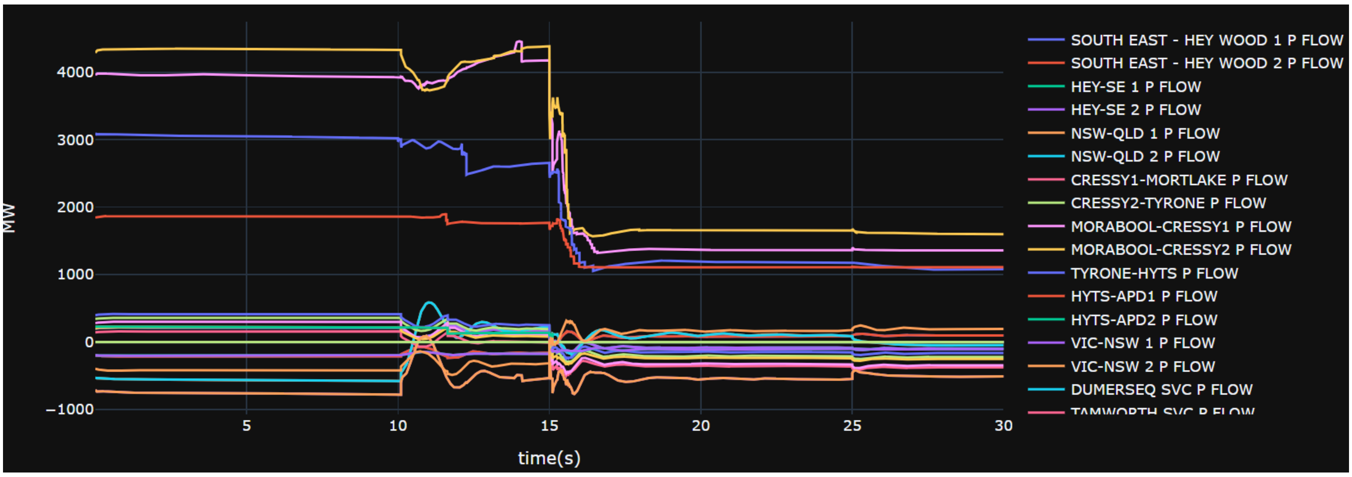


Figure 85 Case 11, generation trip = 60% of operational demand: line active power flows (MW)



A5.3.3 Sensitivity study results

Future UFLS studies with Victoria Stage 1 actions implemented

Future case sensitivities were completed including the implementation of the Victoria Stage 1 UFLS remedial actions (see Appendix A4.5.5). As expected, the sensitivity study results showed that these remedial actions and the associated increase in net Victoria UFLS improved the mainland NEM system frequency response. However, several of the future cases still failed the acceptance criteria for the contingency impacting 60% of mainland NEM system load (as per the NER 4.3.1(k) requirement). Table 33 contains the detailed results for the sensitivity studies.

Table 33 Detailed future study sensitivity results (inclusion of Victora Stage 1 UFLS actions)

Case, contingency	NEM freq nadir (Hz)	NEM RoCoF (Hz/s)	NEM net UFLS tripped (MW)	NEM DPV tripped on protection (MW)
Case 3, generation trip = 60% of op demand	48	2.09	3,895 (48%)	1,425
Case 4, generation trip = 60% of op demand	47.8	1.42	7,640 (70%)	524
Case 5, generation trip = 60% of op demand	47.8	1.8	4,842 (51%)	1700
Case 10, generation trip = 60% of op demand	47.7	2.0	6,084 (68%)	1221

Future UFLS studies with APD loads offline

The APD loads were assumed to be online for all of the future studies, based on typical historical dispatches (for the historical UFLS studies, the dispatch of the APD loads was based on historical data). Therefore, further future sensitivity studies were completed with the APD loads offline. As expected, the sensitivity study results indicated that without the APD load UFLS bands, the mainland NEM system frequency response was slightly degraded. Table 34 contains the detailed results for the sensitivity studies.

Table 34 Detailed future study sensitivity results (APD loads offline)

Case, contingency	NEM freq nadir (Hz)	NEM RoCoF (Hz/s)	NEM net UFLS tripped (MW)	NEM DPV tripped on protection (MW)
Case 1, contingency 7	48.4	2.09	3,100 (35%)	1,438
Case 2, contingency 7	48.5	1.42	3,258 (37%)	1,348
Case 6, contingency 7	48.5	1.8	2,904 (33%)	1,464
Case 10, contingency 7	48.4	2.0	3,193 (28%)	1,410

A5.4 PEC Stage 1 destructive wind limits

A5.4.1 Assessment of cases 1 to 16

The initial base cases 1 to 16 were initially studied to gain an understanding of the operating envelope of the system. These cases were designed to provide an initial assessment of the system stability against a variety of operating conditions that would then be studied in more detail through various sensitivities.

The majority of the initial base cases that were studied passed for the contingencies that were applied. However, a number of cases did not pass because they exhibited instability or exceeded the satisfactory limits of the interconnectors. These cases were Case 3, Case 4, Case 5, Case 7, Case 8 and Case 10.

These cases were either operating at interconnector flows that meant a 500 MW contingency size resulted in the existing satisfactory limits being exceeded, or they were high DPV cases that meant an initial 500 MW contingency resulted in a much larger effective contingency size. These cases are discussed in Appendix A5.4.5 to provide more understanding of the modes of failure.

From this initial assessment of cases 1 to 16, sensitivities were developed to further understand the transfer limits of Heywood and PEC Stage 1.

A5.4.2 Effect of contingency type

Of the three contingencies that were applied to the initial base cases (refer to Appendix A4.8.5), it was found that Contingency 2 was the most onerous for all cases. This was due to a few reasons:

- It resulted in an initial loss of 500 MW of generation, which was equal in size or greater than the other contingencies.
- The loss of generation was comprised of synchronous generation first, and additional asynchronous generation if required to make the 500 MW contingency size. This reduced system strength more than Contingency 3, which primarily had asynchronous generation trip, with additional synchronous generation only tripped to make up the total contingency size for cases where there was less than 500 MW asynchronous generation.
- Contingency 2 had the fault applied at Torrens Island. This was close to the Adelaide metropolitan area and resulted in the largest amount of DPV shake-off.
  - The results shown in the figures in Appendix A5.4.5 focus on the application of Contingency 2, because it represented the worst-case scenario of the contingencies studied.

A5.4.3 Impact of DPV and load tripping

The AEMO CMLD/DER model that was used in the PEC Stage 1 destructive wind limit studies indicated that depending on certain factors, a significant amount of load and DPV generation can trip off for the large disturbances that have been studied. Depending on the conditions of the case, this can either increase or decrease the total contingency size that is experienced by the South Australia network. In cases that are already close to the stability limit, this increase or decrease can be significant enough to determine if the case is stable post-contingency.

The initial studies that were completed on cases 1 to 16 resulted in a range of load and DPV tripping depending on these main factors:

- Location of fault.
- Amount of DPV online.
- Amount of load online.
- Severity of fault (shallow or deep fault).

Table 35, Table 36 and Table 37 show the results of how much DPV and load were tripped for cases 1 to 16.

Table 35 DPV/CMLD Trip for contingency 1 (fault applied at Torrens Island)

Case	SA load (MW)	DPV in SA (%)	DPV in SA (MW)	DPV trip for contingency 1 (MW)	CMLD trip for contingency 1 (MW)	% online DPV trip	% online load trip	Net increase in contingency size (MW)
1	1,879	40	960	293	163	30.5	8.7	130
2	1,879	40	960	290	164	30.2	8.7	126
3	1,195	60	1,440	438	149	30.4	12.5	289
4	1,195	60	1,440	434	143	30.1	12.0	291
5	2,890	15	360	118	201	32.8	7.0	-83
6	2,917	15	360	115	197	31.9	6.8	-82
7	2,409	20	480	117	146	24.4	6.1	-29
8	2,890	40	960	427	512	44.5	17.7	-85
9	2,917	40	960	411	486	42.8	16.7	-75
10	2,409	60	1,440	533	363	37.0	15.1	170
11	2,408	20	480	109	136	22.7	5.6	-27
12	623	37	888	268	50	30.2	8.0	218
13	487	55	1,320	268	53	20.3	10.9	215
14	1,005	49	1,176	358	93	30.4	9.3	265
15	509	50	1,200	267	53	22.3	10.4	214
16	1,121	52	1,248	380	109	30.4	9.7	271

Table 36 DPV/CMLD Trip for contingency 2 (fault applied at Torrens Island and 500 MW contingency)

Case	SA load (MW)	DPV in SA (%)	DPV in SA (MW)	DPV trip for contingency 2 (MW)	CMLD trip for contingency 2 (MW)	% online DPV trip	% online load trip	Net increase in contingency size (MW)
1	1,879	40	960	296	204	30.8	10.9	92.0
2	1,879	40	960	290	198	30.2	10.5	92.0
3	1,195	60	1,440	440[A]	184[A]	30.6	15.4	256.0
4	1,195	60	1,440	443	184	30.8	15.4	259.0
5	2,890	15	360	120[A]	215[A]	33.3	7.4	-95.0
6	2,917	15	360	116	213	32.2	7.3	-97.0
7	2,409	20	480	116	175	24.2	7.3	-59.0
8	2,890	40	960	430[A]	510[A]	44.8	17.6	-80.0
9	2,917	40	960	410[A]	490[A]	42.7	16.8	-80.0
10	2,409	60	1,440	550[A]	390[A]	38.2	16.2	160.0
11	2,408	20	480	109	140	22.7	5.8	-31.0
12	623	37	888	268	57	30.2	9.1	211.0
13	487	55	1,320	268	58	20.3	11.9	210.0
14	1005	49	1,176	358	106	30.4	10.5	252.0
15	509	50	1,200	267	58	22.3	11.4	209.0
16	1,121	52	1,248	381	137	30.5	12.2	244.0

A. This denotes unstable cases where values of DPV and load tripping as a result of the initial contingency have been estimated.

Table 37 DPV/CMLD Trip for contingency 3 (fault applied at Robertstown and 500 MW contingency)

Case	SA load (MW)	DPV in SA (%)	DPV in SA (MW)	DPV trip for contingency 3 (MW)	CMLD trip for contingency 3 (MW)	% online DPV trip	% online load trip	Net increase in contingency size (MW)
1	1,879	40	960	208	290	21.7	15.4	-82.0
2	1,879	40	960	194	311	20.2	16.6	-117.0
3	1,195	60	1,440	316	262	21.9	21.9	54.0
4	1,195	60	1,440	300	277	20.8	23.2	23.0
5	2,890	15	360	106	234	29.4	8.1	-128.0
6	2,917	15	360	95	187	26.4	6.4	-92.0
7	2,409	20	480	98	153	20.4	6.4	-55.0
8	2,890	40	960	240 [A]	260 [A]	25.0	9.0	-20.0
9	2,917	40	960	239	276	24.9	9.5	-37.0
10	2,409	60	1,440	360 [A]	217 [A]	25.0	9.0	143.0
11	2,408	20	480	83	175	17.3	7.3	-92.0
12	623	37	888	227	83	25.6	13.3	144.0
13	487	55	1,320	223	115	16.9	23.6	108.0
14	1,005	49	1,176	271	204	23.0	20.3	67.0
15	509	50	1,200	205	112	17.1	22.0	93.0
16	1,121	52	1,248	265	220	21.2	19.6	45.0

A. This denotes unstable cases where values of DPV and load tripping as a result of the initial contingency have been estimated.

Location of fault

Faults that were applied closer to the Adelaide CBD at Torrens Island generally resulted in larger amounts of DPV tripping. As the results in Table 38 below show, applying contingency 2 at Torrens Island resulted in an increase in the amount of DPV tripped for every case, compared to applying contingency 3. This increase ranged from 18% up to almost a 50% increase in DPV tripped. The largest differential in MW magnitude was experienced in case 4, where the total contingency size was increased by an additional 143 MW for the fault that was closer to the Adelaide CBD.

Fault locations are shown in Figure 86. The location of the fault and closer proximity to the Adelaide CBD mean that the voltage depression was more severe for closer faults such as for contingency 1 or contingency 2. This resulted in more difficulty for the large amount of DPV located in Adelaide to ride through the fault, and subsequently resulted in more DPV tripping.

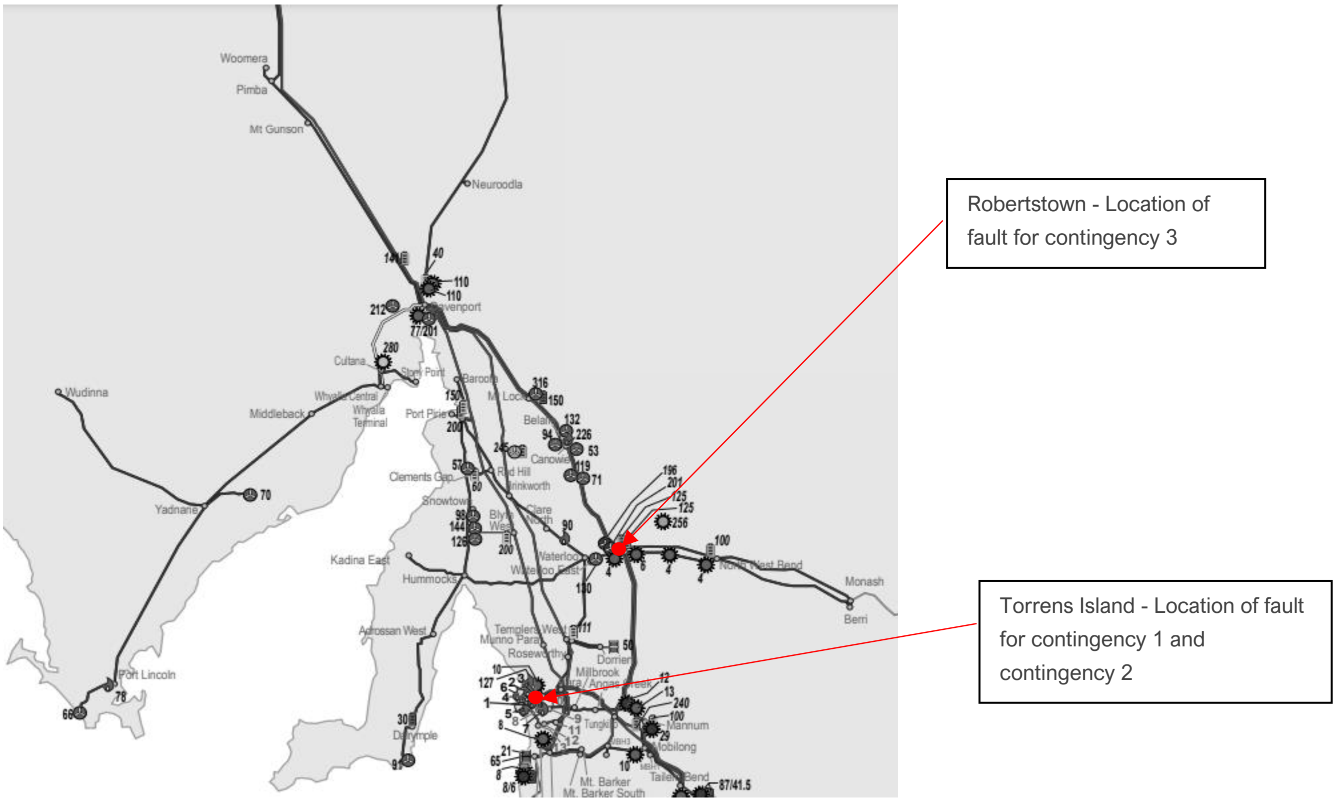
For the more remote faults located at Robertstown, there was enough impedance in the transmission lines that the full depression of the voltage sag was not seen by the DPV close to the Adelaide CBD. As a result, the quantity of DPV that tripped was reduced.

Table 38 Comparison of DPV tripping in South Australia between contingency 2 and contingency 3

Case	DPV in South Australia tripped for contingency 2 (Torrens Island 2ph-G fault and 500 MW contingency)	DPV in South Australia tripped for contingency 3 (Robertstown 2 ph-G fault and 500 MW contingency)	Increase in DPV tripped in South Australia for contingency 2 (MW)	% increase in DPV tripped for contingency 2 compared to contingency 3
1	296	208	88	42.3
2	290	194	96	49.5
3	440 A	316	124	39.2
4	443	300	143	47.7
5	120 A	106	14	13.2
6	116	95	21	22.1
7	116	98	18	18.4
8	430 A	240 A	190	79.2
9	410 A	239	171	71.5
10	550 A	360 A	190	52.8
11	109	83	26	31.3
12	268	227	41	18.1
13	268	223	45	20.2
14	358	271	87	32.1
15	267	205	62	30.2
16	381	265	116	43.8

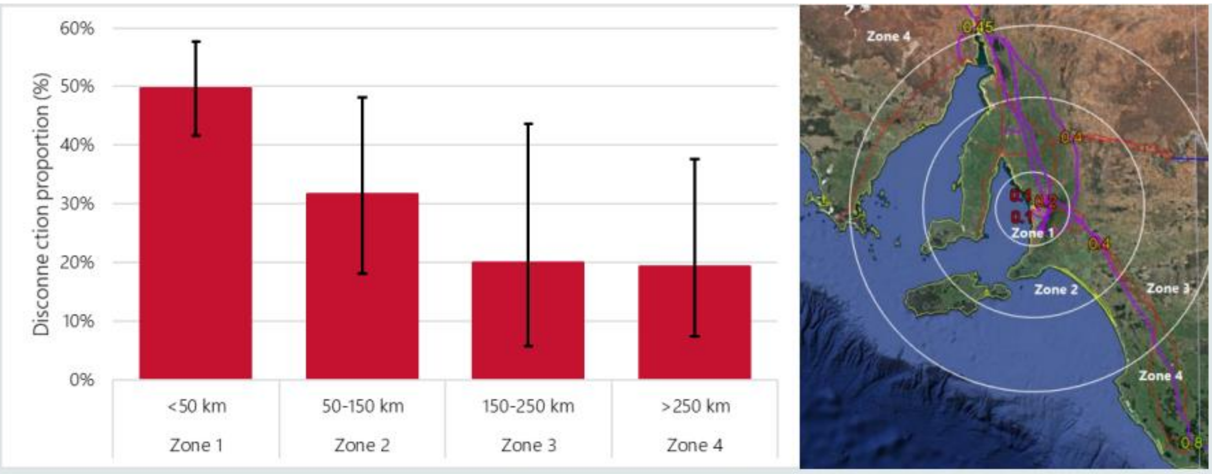
A. This denotes unstable cases where values of DPV and load tripping as a result of the initial contingency have been estimated.

Figure 86 Fault locations at Robertstown and Torrens Island



The phenomena observed in these studies are also supported by high-speed monitoring data measured for real power system incidents. In the *Behaviour of distributed resources during power system disturbances* report[79], it was found that faults close to the Adelaide metropolitan area resulted in larger quantities of DPV tripping than more remote faults. A figure from this report has been included in Figure 87, showing the expected DPV tripping percentage as a function of distance from Adelaide.

Figure 87 Measured DPV disconnections by distance from fault location in South Australia



Numbers on map display minimum single phase voltage reached during disturbance recorded by HSM in the transmission network.

Magnitude of DPV online

The quantity of DPV online is a significant factor in determining the amount of DPV that could trip as a result of a fault under destructive wind conditions. For the initial cases 1 to 16, the amount of DPV that tripped was generally in the range of 20% to 40% of online DPV at the time. For cases with higher levels of DPV online, this resulted in a larger contingency in MW due to the DPV tripping.

The highest DPV cases that were studied for cases 1 to 16 had up to 60% of available DPV online, which could result in up to an additional 500 MW of DPV tripping, as was seen in case 10.

Magnitude of load online

The amount of load online in the case impacts the contingency size that the tripping of the DPV and load has on the case. For higher load cases, there is more load available that may trip as a result of the fault. Any load that trips assists in offsetting the generation that is lost from the DPV tripping.

The worst-case scenarios were found when the differential between the amount of DPV tripping and the amount of load tripping was the highest. These cases resulted in the largest net increase in contingency size. The cases that demonstrated this most clearly are cases 3, 4 and cases 12-16. These cases were all relatively low load cases, meaning that there was not a significant amount of load online that would trip as a result of the fault. In addition, these were all high DPV cases, with approximately 60% DPV online for these cases. The combination of high DPV, low load cases must be considered when determining the interconnector limit, as the final contingency size will be affected significantly.

[79] See https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

Severity of fault

Sensitivities were also run applying a high impedance fault to determine the effect this would have on the amount of DPV shake-off. As the amount of DPV tripping is sensitive to how deep the voltage depression is at the point of connection, it was found that higher impedance faults resulted in lower amounts of DPV being tripped.

A5.4.4 Sensitivity study results

Pre-contingent interconnector flow/interconnector headroom

The load and generation balance in South Australia determines the power imported or exported by other states. These sensitivity studies investigating the impact of headroom on the interconnectors were developed by scaling the load in South Australia. As the South Australia load was scaled up or down, more (or less) power flowed across the interconnectors into South Australia. All other aspects of the cases remained the same between cases.

The aim of this sensitivity study was to determine the stability limits on PEC and Heywood by gradually changing the amount of active power flowing over Heywood and PEC to determine a marginally stable operating point when responding to a 500 MW initial contingency size.

Models were set up based on the original cases 2, 5, 6, 7 and 10 and contain the “a” suffix. Each variation adjusted the load by 100 MW, as shown in the table below.

Table 39 Pre-contingent interconnector flow sensitivity case results

Case	Load	Initial active power flow across PEC (MW)	Initial active power flow across Heywood (MW)	Final active power flow across PEC (MW)	Final active power flow across Heywood (MW)	Total contingency size (MW)	Pass/ Fail	Comment
2a1	2,079	152	463	303	882	570	Fail	Satisfactory limits of Heywood and PEC exceeded
2a2	1,979	125	381	273	837	593	Fail	Satisfactory limits of Heywood and PEC exceeded
2a3	1,779	70	222	224	704	617	Pass	
2a4	1,679	46	144	202	632	636	Pass	
2a5	1,579	20	66	177	554	649	Pass	
5a2	2,690	84	516	203	812	423	Pass	Stable
5a3	2,590	70	430	193	746	440	Pass	Stable
5a4	2,490	56	344	177	670	445	Pass	
5a5	2,390	42	258	166	588	459	Pass	
6a1	2,817	55	218	168	515	436	Pass	
6a2	2,717	35	138	150	446	449	Pass	
7a1	2,509	183	734	321	1,014	570	Fail	Satisfactory limits of Heywood and PEC exceeded
7a2	2,309	128	559	258	888	538	Fail	Satisfactory limits of Heywood and PEC exceeded

Case	Load	Initial active power flow across PEC (MW)	Initial active power flow across Heywood (MW)	Final active power flow across PEC (MW)	Final active power flow across Heywood (MW)	Total contingency size (MW)	Pass/ Fail	Comment
7a3	2,209	98	475	227	406	540	Pass	
7a4	2,109	72	390	204	730	522	Pass	
7a5	2,009	44	309	174	650	518	Pass	
7a6	1,909	16	230	146	576	508	Pass	
10a1	2,309	126	565	280	800	669	Fail	Large, undamped voltage oscillations. Case unstable
10a2	2,209	97	479	293	854	680	Fail	Oscillations not adequately damped and thermal limits exceeded
10a3	2,109	70	392	253	840	680	Fail	Oscillations not adequately damped and thermal limits exceeded
10a4	2,009	42	309	225	796	678	Pass	
10a5	1,909	16	127	200	730	695	Pass	

In the cases studied, it was found that reducing the pre-contingent flow over the interconnectors assisted in the stability of the network. Cases that were previously unstable in the initial base case studies could be made stable for large contingency sizes by reducing the pre-contingent flow over the interconnectors.

Cases 2a, 5a, 6a and 7a all showed that the satisfactory limits of the interconnectors were exceeded before any instability was experienced.

Case 10a was the exception, showing instability in conjunction with exceeding the interconnector limits, however this was a high DPV case, with 60% online DPV. This meant that the initial 500 MW contingency size resulted in an almost 700 MW total contingency size when taking into account the tripped DPV and load as part of the contingency. This further emphasises that the amount of DPV online must be considered when setting the limits during destructive wind conditions.

Figures showing interconnector headroom key results are provided in Appendix A5.4.5.

Inertia and system strength

Additional sensitivities were investigated to observe the impact that having additional synchronous machines online in South Australia would have on the stability limits of the system. These additional synchronous machines increased the inertia and system strength in South Australia.

The sensitivities completed were based on Case 5, which was unstable and operating at high pre-contingent PEC and Heywood flows. Additional machines were added for each sensitivity to observe the impact that this would have on the stability limits of the system and whether this would result in a stable case post fault. Each sensitivity case adjusts the inertia by approximately 900 to 1,100 megawatt seconds (MWs) as shown in the table below.

Table 40 Pre-contingent interconnector flow sensitivity case results

Case	SA inertia [MWs]	Initial active power flow across PEC (MW)	Initial active power flow across Heywood (MW)	Final active power flow across PEC (MW)	Final active power flow across Heywood (MW)	Total contingency size (MW)	Pass/ Fail	Comment
5b1	6,200	155	645	266	906	400	Fail	Oscillations not adequately damped and thermal limits exceeded
5b2	7,100	155	645	279	933	403	Fail	System stable but interconnector satisfactory limits exceeded
5b3	8,000	155	645	274	939	404	Fail	System stable but interconnector satisfactory limits exceeded
5b4	9,100	155	645	276	945	415	Fail	System stable but interconnector satisfactory limits exceeded
5b5	10,000	155	645	274	944	417	Fail	System stable but interconnector satisfactory limits exceeded
5b6	11,000	155	645	273	949	422	Fail	System stable but interconnector satisfactory limits exceeded

As the table shows, the main outcome from these studies was that the additional inertia and system strength in the system did improve stability outcomes. Case 5b2, with an additional 900 MWs of inertia and additional synchronous machines online, resulted in adequately damped voltages after the contingency.

The initial trip of 500 MW of generation had a large impact on the South Australia system, resulting in both large active and reactive power swings on the interconnectors and throughout the network. By having more synchronous machines online in South Australia, there was greater reactive support available to support system voltages. There were also more online machines to provide PFR, which reduced the amount of active power required to be imported over the interconnectors.

The combination of these effects means that by increasing the number of machines online, the system could be stable post-contingency, even when the interconnector satisfactory limits were exceeded. In cases 5b2 to 5b6, all showed stable responses. However, these were failed cases because the interconnector satisfactory limits were exceeded, and this would not be an acceptable operating condition as it may cause permanent damage to equipment. Similar to results found in other sensitivities, the interconnector satisfactory limits were reached first before other forms of instability.

The figures in Appendix A5.4.5 show the effect of the additional machines on the stability of the Heywood and PEC interconnectors. As more synchronous machines were online in South Australia, the case results became more stable.

Contingency size

The impact of contingency size was found to be a significant factor on the stability of the system post-contingency. The larger the contingency size, the larger the impact on the South Australia system, including the required final import over the interconnectors and the loss of the active and reactive power in the system from the tripped generation. The increased contingency size resulted in the system coming closer to instability.

To investigate the effects of contingency size, and to understand the limits of operation, a number of sensitivity cases were studied with an initial continency size ranging from 100 MW to 800 MW. In addition to the initial contingency, the effects of DPV and load tripping were considered in terms of their contribution to either increasing or decreasing the total contingency size.

Contingencies applied for these sensitivities were developed as a variation on Contingency 2 from the initial studies. Contingency 2 was found to be the most onerous contingency due to its fault location at Torrens Island (close to the Adelaide metropolitan area), and the loss of a mixture of synchronous and asynchronous generation. The contingencies started with loss of the online synchronous generators first, then as the contingency size increased, asynchronous generation was tripped to make the larger contingency totals.

The results for these sensitivities are shown in Table 41. It shows that for a 500 MW total contingency size or smaller, the Heywood and PEC Stage 1 satisfactory limits were maintained, and there was still at least 100 MW of headroom to allow for interconnector drift. However, for high DPV cases, the increase in total contingency size due to DPV tripping must be considered. This can result in higher contingency sizes that exceed 500 MW even if the initial contingency was less than 500 MW. This may result in the interconnector satisfactory limits being exceeded.

Table 41 Sensitivity case results for contingency size

Case	SA Load (MW)	SA DPV (%)	Inertia (MWs)	Heywood flow (MW)	PEC flow (MW)	Initial contingency size (MW)	Total contingency size (+DPV and load trip) (MW)	Pass/Fail	Comment
2c1	1,973	40	5,757	430	70	100	233	Pass	
2c2	1,973	40	5,757	430	70	200	328	Pass	
2c3	1,973	40	5,757	430	70	300	419	Pass	
2c4	1,973	40	5,757	430	70	400	498	Pass	
2c5	1,973	40	5,757	430	70	500	587	Fail	Stable, but Heywood limit exceeded
2c6	1,973	40	5,757	430	70	600	679	Fail	Stable, but Heywood and PEC limit exceeded
2c7	1,973	40	5,757	430	70	700	755	Fail	Marginally stable, but Heywood and PEC limit exceeded
2c8	1,973	40	5,757	430	70	800	>850	Fail	Unstable, undamped oscillations
5c1	2,590	15	5,333	430	70	100	65	Pass	
5c2	2,590	15	5,333	430	70	200	163	Pass	
5c3	2,590	15	5,333	430	70	300	259	Pass	
5c4	2,590	15	5,333	430	70	400	356	Pass	

Case	SA Load (MW)	SA DPV (%)	Inertia (MWs)	Heywood flow (MW)	PEC flow (MW)	Initial contingency size (MW)	Total contingency size (+DPV and load trip) (MW)	Pass/Fail	Comment
5c5	2,590	15	5,333	430	70	500	450	Pass	
5c6	2,590	15	5,333	430	70	600	543	Pass	
5c7	2,590	15	5,333	430	70	700	631	Fail	Heywood and PEC limits exceeded
5c8	2,590	15	5,333	430	70	800	705	Fail	Marginally stable but Heywood and PEC limits exceeded
5c11	2,590	15	11,000	430	70	100	64	Pass	
5c12	2,590	15	11,000	430	70	200	164	Pass	
5c13	2,590	15	11,000	430	70	300	262	Pass	
5c14	2,590	15	11,000	430	70	400	359	Pass	
5c15	2,590	15	11,000	430	70	500	455	Pass	
5c16	2,590	15	11,000	430	70	600	553	Pass	
5c17	2,590	15	11,000	430	70	700	646	Fail	Heywood and PEC limits exceeded
5c18	2,590	15	11,000	430	70	800	732	Fail	Heywood and PEC limits exceeded
10c1	2,109	60	5,333	430	70	100	303	Pass	
10c2	2,109	60	5,333	430	70	200	380	Pass	
10c3	2,109	60	5,333	430	70	300	469	Pass	
10c4	2,109	60	5,333	430	70	400	560	Pass	Marginally within Heywood and PEC limits
10c5	2,109	60	5,333	430	70	500	>650	Fail	Unstable and exceeds Heywood and PEC limits
10c6	2,109	60	5,333	430	70	600	>750	Fail	Unstable and exceeds Heywood and PEC limits
10c7	2,109	60	5,333	430	70	700	>850	Fail	Unstable and exceeds Heywood and PEC limits
10c8	2,109	60	5,333	430	70	800	>950	Fail	Unstable and exceeds Heywood and PEC limits

For each of the contingency size sensitivity cases that were studied, a similar response was seen. For a total contingency size larger than around 560 MW, the satisfactory limits of Heywood and PEC Stage 1 would be exceeded, but the case would generally remain stable. Above this contingency size, there would be an increased contingency size where the interconnector limits are further exceeded, but the case remains stable. This ranged between 100 MW and 200 MW above the satisfactory interconnector limits. By increasing the contingency size further beyond this point, the system would become unstable, either through voltage instability or angular instability.

The case that became unstable for the smallest initial contingency size was Case 10c5, but as this was a high DPV case with 60% DPV online, the additional contingency size from the DPV shake-off contributed to the instability. For all other cases, there was a reasonable margin after exceeding the interconnector satisfactory limits before instability was observed.

Examples of how the 5c6 to 5c8 cases approach instability are discussed in Appendix A5.4.5.

Contingency size results without CMLD/DER model

Sensitivity studies were also conducted without the CMLD/DER model added, so the impact of the contingency size could be studied independently. The tripping behaviour of CMLD and DER can impact the contingency size, so these cases were studied to verify that the same behaviour is seen for similar contingency sizes when there is no CMLD/DER tripping.

Table 42 Sensitivity case results for contingency size without CMLD/DER model

Case	SA non-DER Load [MW]	DPV in SA [%]	Heywood transfer (VIC->SA) [MW]	PEC transfer (NSW->SA) [MW]	Murraylink transfer (VIC->SA) [MW]	Combined SA import (Heywood and PEC) (MW)	Contingency size interconnector limits were exceeded (MW)	Contingency size case is unstable (MW)
Case 1	1,879	0	394	105	125	499	600	900 (out of step)
Case 2	1,879	0	298	98	100	396	700	1,000 (out of step)
Case 5	2,890	0	645	155	167	800	500	700
Case 6	2,917	0	303	69	95	372	700	1,000
Case 7	2,409	0	649	149	167	798	500	700
Case 11	2,408	0	168	42	53	210	800	Stable up to 1,000

The last two columns in Table 42 show the contingency size where the interconnectors exceeded their satisfactory limits, and where the case became unstable. As can be seen by comparing these two columns, there was at least a 200 MW margin between when the case exceeded its interconnector satisfactory limits, and when it became unstable.

As can be seen in the figures in Appendix A5.4.5, Case 1 first reached instability after a 900 MW contingency, resulting in out of step conditions. This was also observed for Case 2, which displayed out of step conditions for a 1,000 MW total contingency size.

For Cases 5, 6 and 7, it was found that voltage instability was the first mode of instability that was seen, similar to the cases where the CMLD and DER model was incorporated.

Delay of generation tripping sensitivities

This sensitivity was designed to study the effects of delayed tripping of the generators, similar to how the South Australia black system event occurred in 2016. Two sensitivity cases were studied, with delayed tripping of one and two seconds used to check the differences in post-contingency response of the network. The impact of the delayed tripping of the asynchronous generators was not found to be a significant factor on the stability of the system post-contingency.

The major difference that was found in comparison with base case without delayed tripping was the oscillation of reactive power. For cases with delayed tripping, the post-contingency reactive power oscillations were lower than observed in the base case. Therefore, these sensitivities confirmed that studying the worst-case scenario where all generation trips simultaneously is the more conservative and appropriate method when investigating the PEC Stage 1 destructive wind transfer limits.

Table 43 outlines the results for the cases studied in these sensitivities.

Table 43 Sensitivity case results for delayed tripping

Case	Load	Final active power flow across PEC (MW)	Final active power flow across Heywood (MW)	DPV trip (MW)	CMLD trip (MW)	Comment
5	2,890	254 A	855 A	196 A	549 A	Unstable case
5d1	2,890	254 A	855 A	196 A	549 A	Less swing in active and reactive power right after the fault than case 5 but becomes unstable after 500 MW of asynchronous generator trips
5d2	2,890	254 A	855 A	196 A	549 A	Less swing in active and reactive power right after the fault than case 5 but becomes unstable after 500 MW of asynchronous generator trips
5a2	2,690	203	812	120	215	Stable case
5d3	2,690	203	812	120	215	Less swing in active and reactive power right after the fault than case 5a2
5d4	2,690	203	812	120	215	Less swing in active and reactive power right after the fault than case 5a2

A. This denotes unstable cases where values of DPV and load tripping as a result of the initial contingency have been estimated.

These results show that tripping generation gradually was less onerous for the system than when generation tripped simultaneously.

With gradual tripping, the system is responding to smaller active power changes at any time. This means there is a smaller angle change, and less overshoot is seen in the active power response of generators and over the interconnectors. Similarly, the system also has smaller reactive power changes it needs to respond to for each trip, meaning that there is less overshoot in the reactive power responses of the interconnectors, machines and SVCs. However, while the gradual tripping makes the system response better dynamically, it may still become unstable once the total contingency size is applied if the system is too weak, or the contingency is too severe.

These results confirmed that applying the contingency simultaneously represented the more onerous case and should be considered as the base assumption.

Variation in ratio of PEC/Heywood flow

The ratio of flow over Heywood and PEC was investigated to determine if there was any difference in the stability results if one interconnector was loaded at a higher ratio than the other. This was done by developing several cases that each varied the angle of the PST at Buronga. This impacts the power flow into South Australia by adjusting its voltage angle, hence controlling the flows over PEC and Heywood. Models were developed using cases 7a4 and 10a4 as base models, with the only changed variable of this study being the angle of the PST.

Five variations of each model were created (using the "e" suffix), with the PST angle set to range from 0 MW on PEC to its satisfactory limit of 250 MW.

The results presented below are based on applying Contingency 2, as this was the most onerous contingency.

Table 44 Sensitivity case results for variation in Buronga PST angle

Case	Phase Shifting Transformer Angle (deg)	Initial active power flow across PEC (MW)	Initial active power flow across Heywood (MW)	Final active power flow across PEC (MW)	Final active power flow across Heywood (MW)	Pass/ Fail	Comment
7e1	-12	2	475	144	806	Pass	
7e2	4	62	408	194	742	Pass	
7e3	21	125	340	248	678	Pass	
7e4	38	188	274	301	616	Fail	PEC thermal limit exceeded
7e5	55	251	212	347	564	Fail	PEC thermal limit exceeded
10e1	-3	4	350	195	823	Pass	
10e2	13	66	283	245	776	Pass	
10e3	29	127	221	293	724	Fail	PEC thermal limit exceeded
10e4	46	192	157	338	672	Fail	PEC thermal limit exceeded
10e5	62	252	99	374	632	Fail	PEC thermal limit exceeded

From the graphs presented in Appendix A5.4.5, the transient period following the fault showed oscillations in active power for each case. These oscillations were similar in shape over time and were offset only by the initial difference in interconnector flow. This indicated that changing the angle of the PST did not provide significant benefits in the dynamic response of the system and would generally only impact whether the satisfactory limits of the interconnectors were exceeded. From the sensitivities studied here, the dynamic performance was very similar for each model and the PST angle did not show a significant impact on dynamic stability.

The PST did impact the flows across the interconnectors before and after the contingency. For this reason, it would be best used to ensure that both interconnectors are sufficiently below their satisfactory limits if destructive winds are expected.

The key finding from the PEC/Heywood ratio sensitivities was that there was no significant impact on the dynamic response of the studies. The studies undertaken suggest that the main consideration when determining the

PEC/Heywood ratio should be ensuring that the interconnector satisfactory limits are maintained post-contingency for the contingency size that is expected.

A5.4.5 Simulation results for PEC Stage 1 destructive wind limit studies

This section gives detailed references to study cases, results, and key result graphs to supplement the observations provided in Section 5 and Appendix A5.3.3.

Base case key results

Case 3 results – low load and high DPV case

Applying Contingency 2 to Case 3 resulted in instability, with both Heywood and PEC interconnectors exceeding their satisfactory limits. In addition, large, undamped oscillations were present throughout the system.

The pre-contingent conditions in Case 3 had initial flows over Heywood of 395 MW and 106 MW over PEC. While this appeared to be sufficient headroom to allow for a 600 MW contingency and still remain below the 850 MW Heywood and 250 MW PEC Stage 1 satisfactory limits, this case was unstable. This is because the initial 500 MW contingency that was applied also resulted in around 300 MW of additional generation loss due to the combination of DPV and load tripping. This case has 60% of available DPV online, and is also a relatively low load case, with only around 1,000 MW of South Australia operational demand. This combination of low load and high DPV results in a large amount of DPV tripping, and only a low quantity of corresponding load shake off. Due to these factors, the total contingency size increases to approximately 800 MW and instability is seen in the system as the import flows on the South Australia interconnectors swing above their limits.

In Figure 88, the South Australia interconnector import flows increase sharply post contingency due to the large loss of generation in South Australia. However, this cannot be sustained as the interconnectors approach their satisfactory limits. The large disturbance in the system also creates a large reactive power swing on the interconnectors as reactive plants such as the SVCs in South Australia hit their limits. This is seen in Figure 89 and Figure 90 where significant reactive power swings result in a large voltage depression and reduced voltages around South Australia post contingency. In addition to the oscillations, the reduced voltage at the interconnectors limits the amount of power transfer possible. Figure 91 shows South Australia network remains in synchronism after the disturbance despite the presence of power oscillations.

Figure 88 Case 3 interconnector active power response (MW)

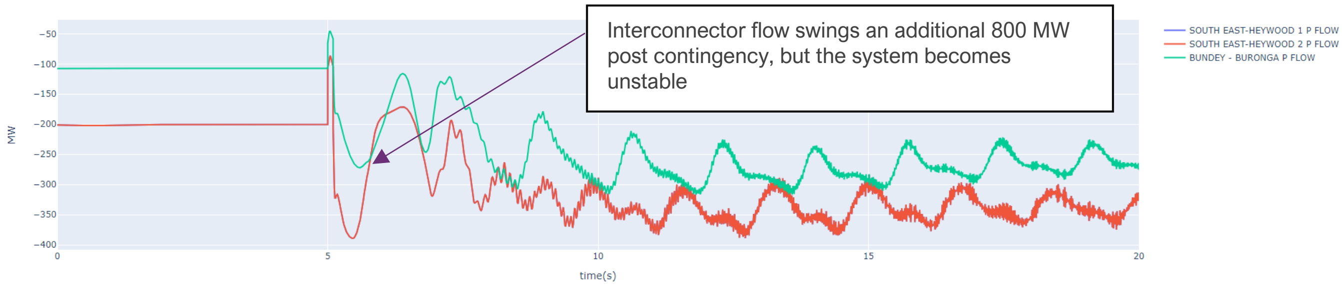


Figure 89 Case 3 interconnector reactive power response (MVAr)

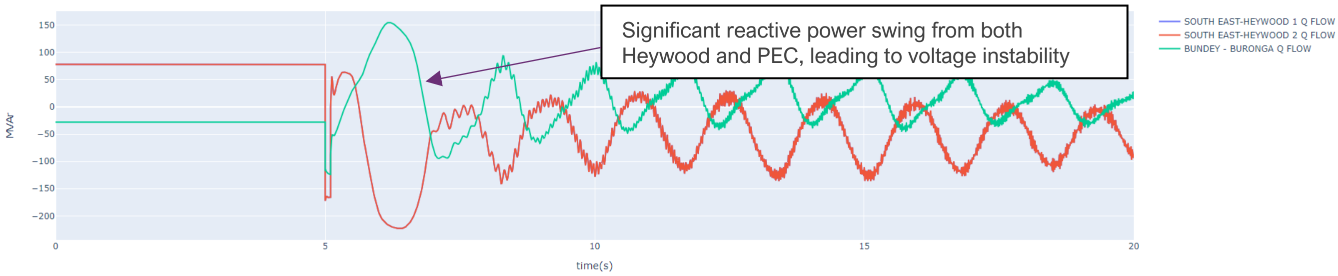


Figure 90 Case 3 South Australia voltage response (pu)

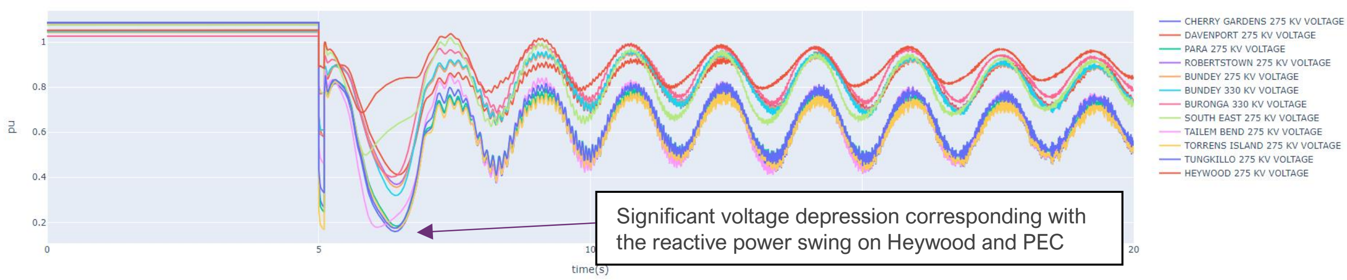
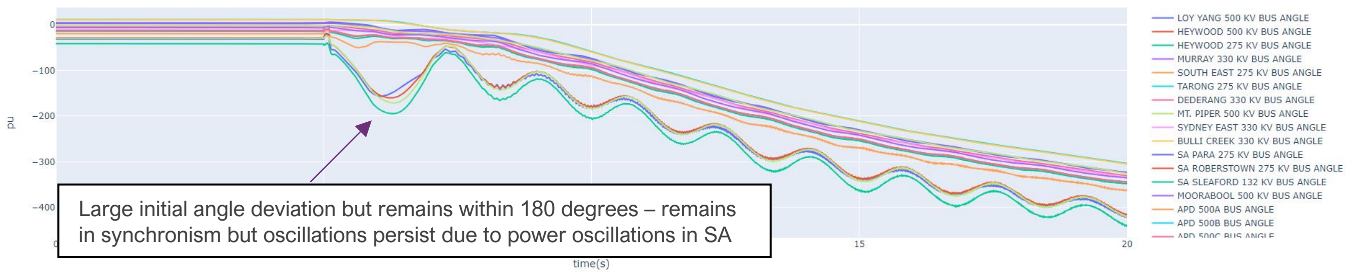


Figure 91 Case 3 system angles (pu)



Case 4 results – low load and high DPV case

Case 4 is similar to Case 3, except with an additional 125 MW of headroom on the interconnectors. While this was not enough headroom for the interconnectors to remain below their satisfactory limits, it was marginally enough to avoid the instability that was seen in Case 3. Contingency 2 was applied to Case 4 to produce the results shown. As this was a very similar case to Case 3, a similar amount of DPV and load was observed to trip, resulting in a total contingency size of around 800 MW again. However, the additional headroom on the interconnectors resulted in a stable system, despite large initial oscillations in the system.

Figure 92 Case 4 interconnector active power response (MW)

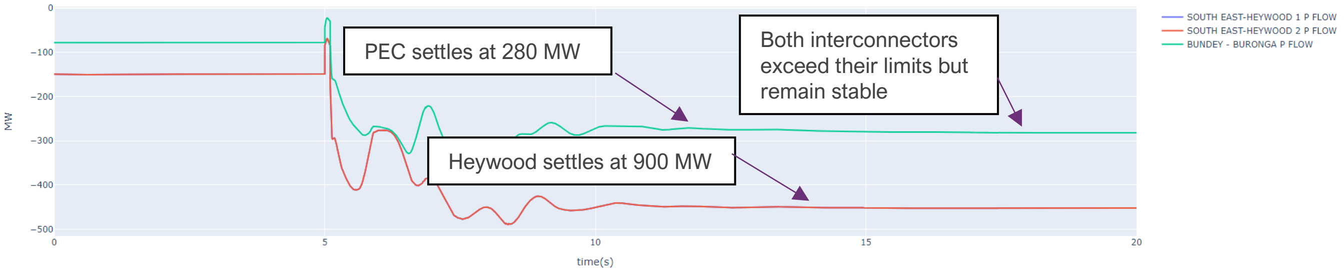


Figure 93 Case 4 interconnector reactive power response (MVAR)

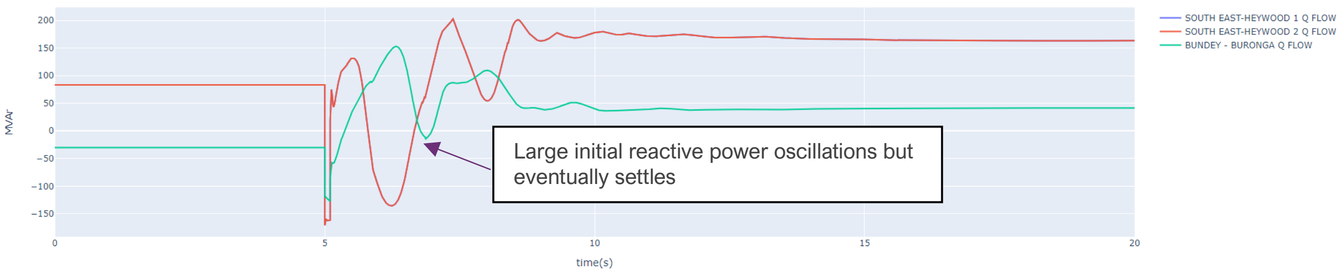


Figure 94 Case 4 South Australia voltage response (pu)

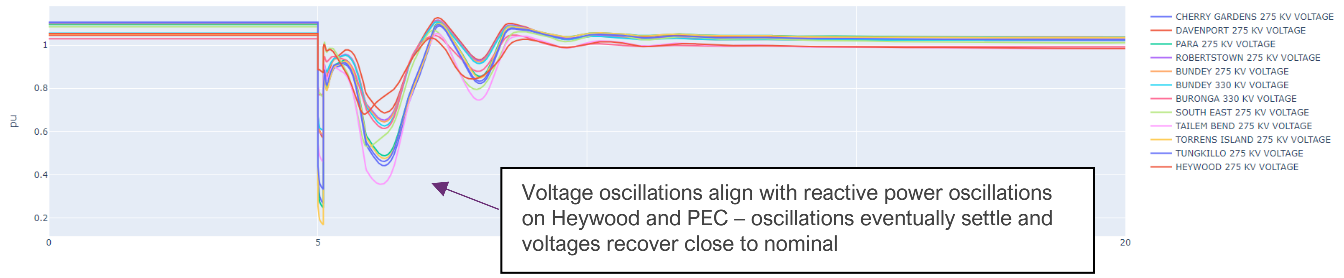
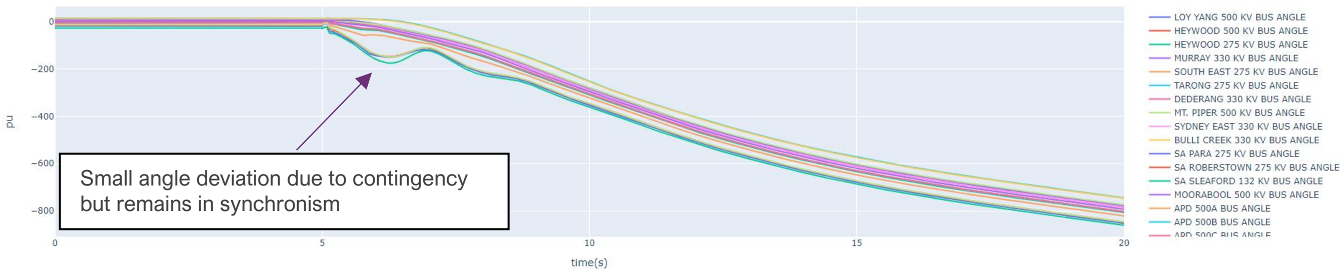


Figure 95 Case 3 system angles (pu)



Case 5 results – interconnectors at maximum pre-contingent flows, high load and high asynchronous generation

Case 5 investigated the scenario where Heywood and PEC Stage 1 are operating at their maximum pre-contingent flows. This was 645 MW on Heywood and 155 MW on PEC. This case showed significant voltage instability after the fault, with large undamped oscillations present in the voltages and reactive power in the system.

This case had 15% online DPV, and a high South Australia load, meaning the contingency size was reduced slightly from 500 MW down to around 420 MW due to the combination of load and DPV tripping. However, even with the reduced contingency size, this contingency was still large enough to exceed the satisfactory limits of Heywood and PEC.

This case also had high asynchronous generation. The low system strength may have also contributed to the instability in the system after the loss of the Torrens Island synchronous machines.

Figure 96 Case 5 interconnector active power response (MW)

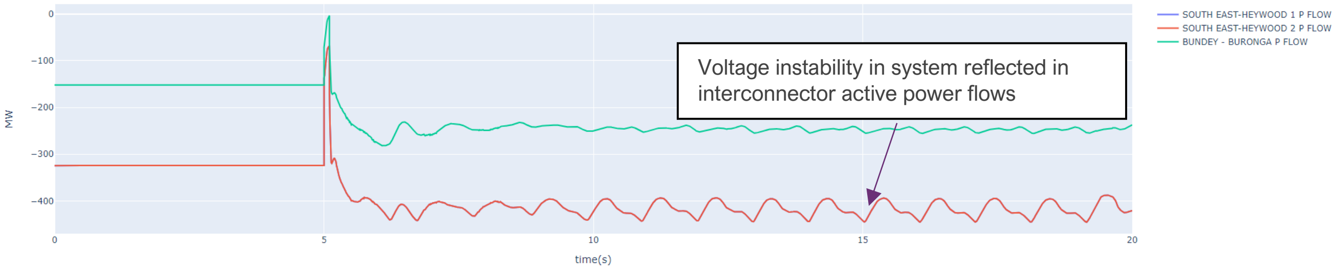


Figure 97 Case 5 interconnector reactive power response (MVAR)

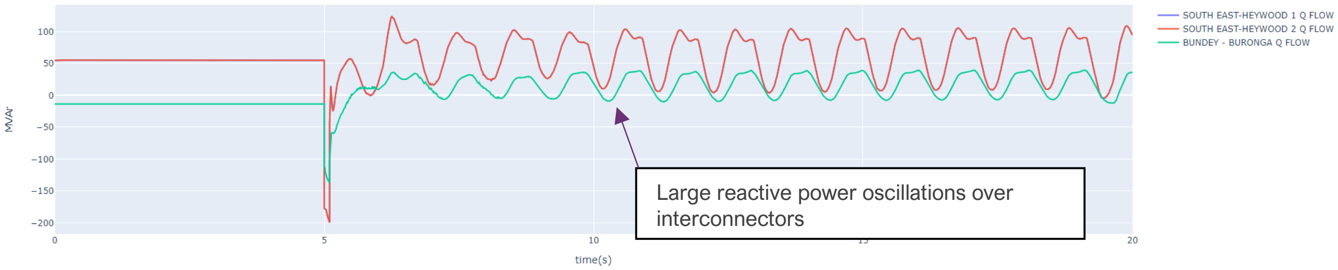


Figure 98 Case 5 South Australia voltage response (pu)

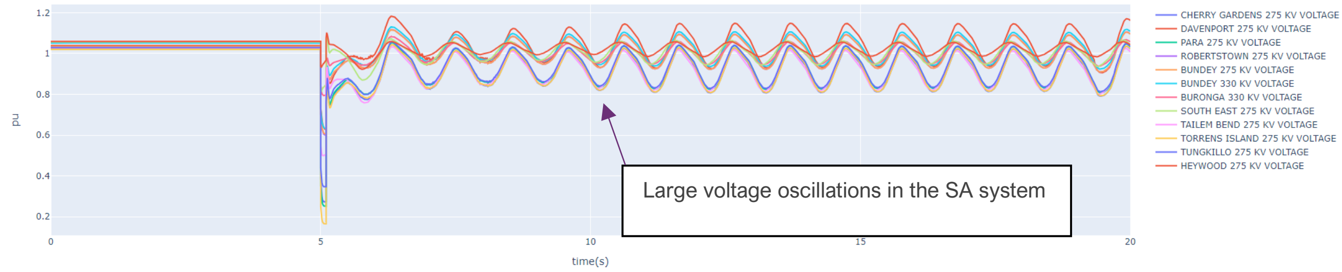
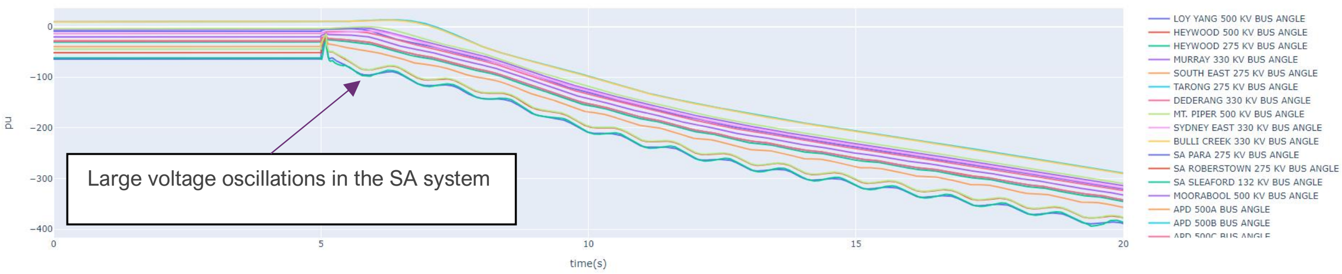


Figure 99 Case 5 system angles (pu)



While Case 5 was unstable when operating at 645 MW on Heywood and 155 MW on PEC pre-contingency, some further sensitivities were run to understand the operating limits for this case. Appendix A4.8.4 includes a variation of this case where pre-contingent flows were 430 MW on Heywood and 70 MW on PEC. In these studies, the system could manage up to a 600 MW total contingency before the interconnector satisfactory limits were reached, and it was not until a total contingency size of 700 MW that the system approached the point of instability.

Case 7 results – interconnectors at maximum pre-contingent flows, medium load and medium asynchronous generation

This was similar to Case 5, but with reduced amount of asynchronous generation in system, and slightly less load. This case operated at very high pre-contingent flows, but the system remained stable despite exceeding the satisfactory limits for Heywood and PEC.

Figure 100 Case 7 interconnector active power response (MW)

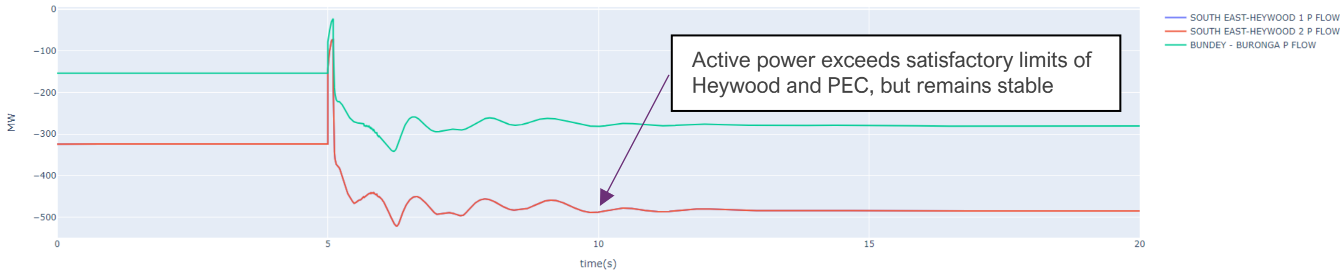


Figure 101 Case 7 interconnector reactive power response (MVAR)

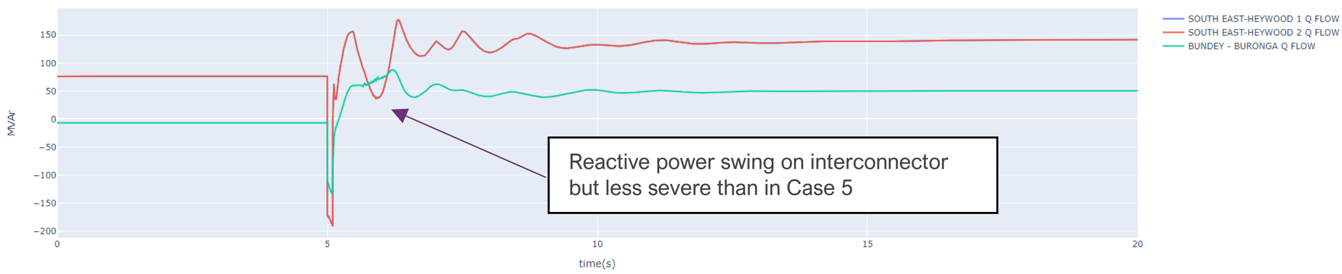


Figure 102 Case 7 South Australia system voltages (pu)

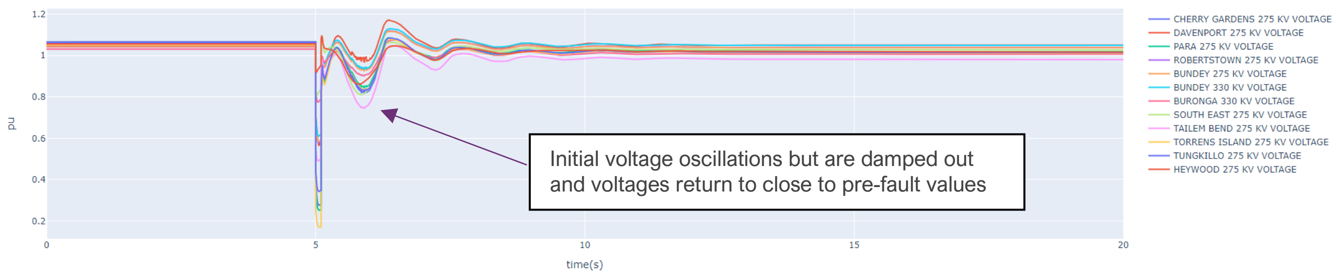
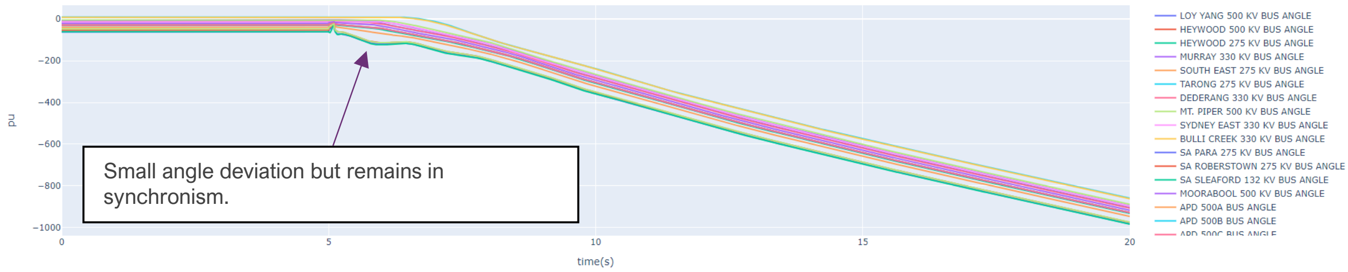


Figure 103 Case 7 system angles (pu)



Interconnector headroom sensitivity key results

Figure 104 Heywood active power flow (MW) – Contingency 2 – Case 2a1-5

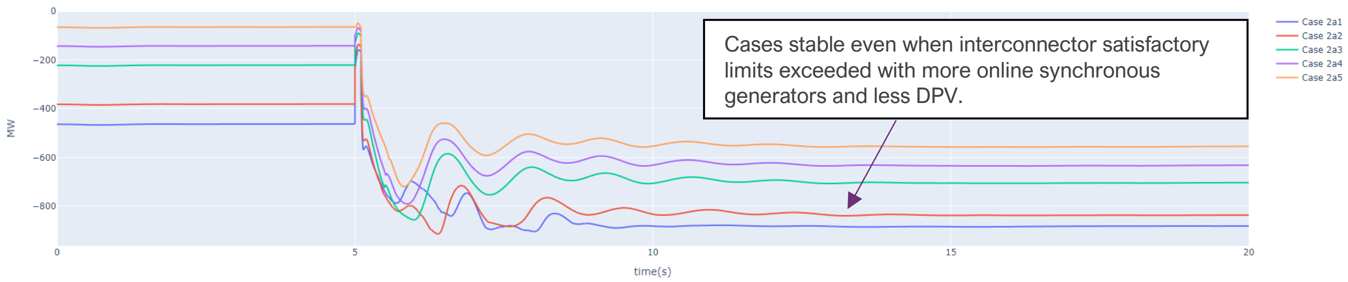


Figure 105 PEC active power flow (MW) – Contingency 2 – Case 2a1-5

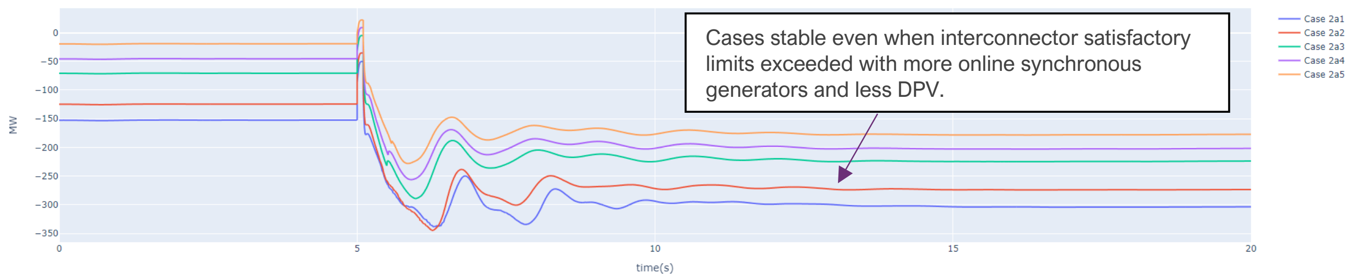


Figure 106 Heywood active power flow (MW) – Contingency 2 – Case 10a1-5

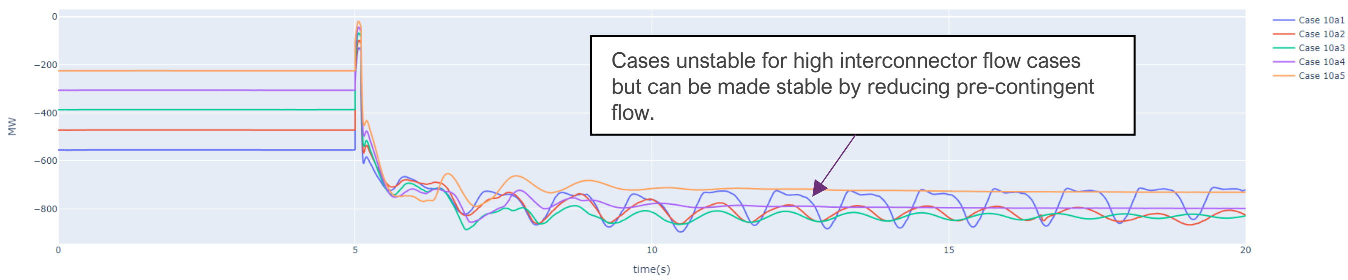
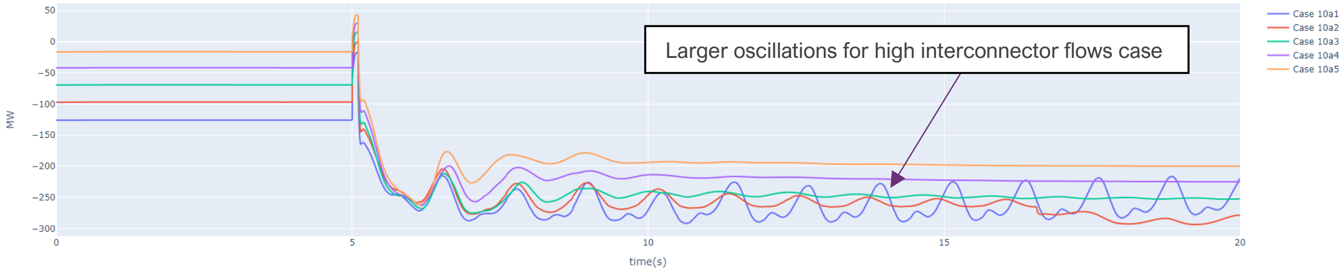


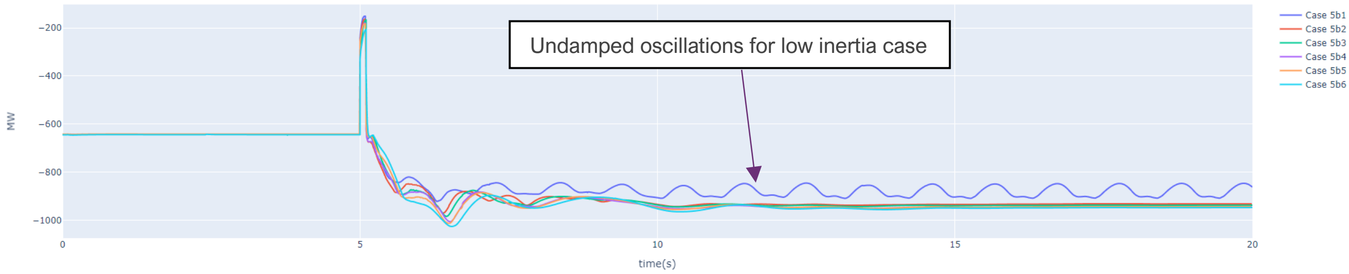
Figure 107 PEC active power flow (MW) – Contingency 2 – Case 10a1-5



System strength and inertia sensitivity results

The previously unstable case 5b1 is seen in the blue trace in Figure 108, with undamped oscillations in the active power flows over Heywood. By increasing the number of machines online in South Australia, it can be seen that the active power oscillations are no longer present. The active power flowing over Heywood did not change significantly between these cases, but the reactive power response did change. This indicates that the additional machines online helped assist the reactive support of the system to prevent voltage instability after the loss of a large amount of generation.

Figure 108 Heywood aggregated active power flow (MW) (both lines) – Contingency 2 – Case 5b1-6



A similar response is seen for the active power flow over PEC, as shown in Figure 109. The lowest system strength case had small oscillations in the active power trace, but these were removed for all subsequent cases. The oscillations were not as severe on PEC as they were on Heywood. This suggests that the voltage stability issue is closer to Heywood.

Figure 109 PEC active power flow (MW) – Contingency 2 – Case 5b1-6

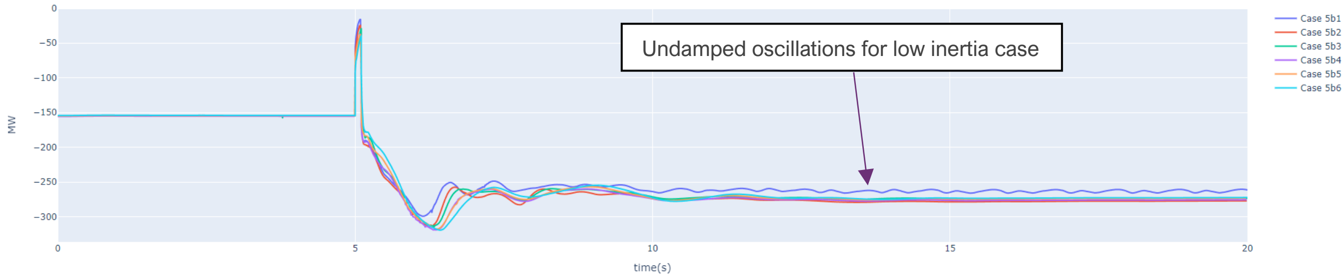
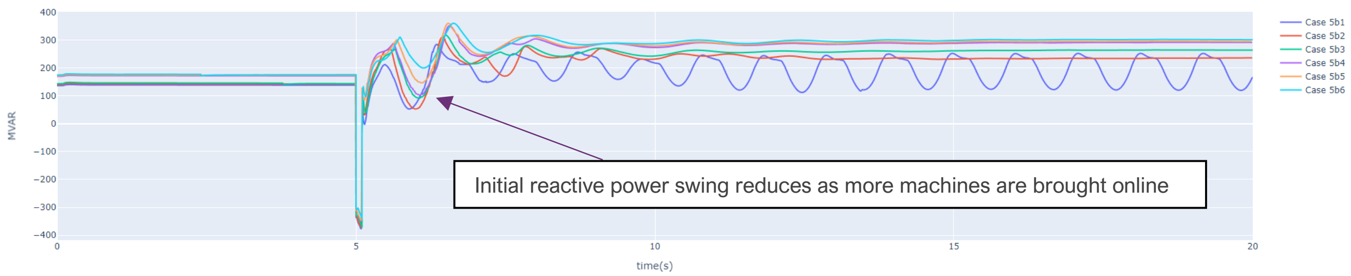


Figure 110 shows the reactive power response over Heywood for the various system strength sensitivity cases. As can be seen, each additional machine online reduced the initial reactive power swing on the Heywood interconnector and made the case more stable. As more machines were online to produce more reactive power when required, fewer of the existing machines and SVCs hit their limits, and there was more reactive support in South Australia.

Figure 110 Heywood reactive power flow (MVAR) – Contingency 2 – Case 5b1-6



This sensitivity shows that the voltage instability and oscillations seen in these cases can be solved through the addition of more synchronous machines online. Even for this extreme case, with the interconnectors operating at 645 MW on Heywood and 155 MW on PEC pre-contingency, the addition of synchronous machines is one method to remove the voltage instability seen post-contingency.

However, this case was not a realistic operating point, because the satisfactory interconnector limits would be exceeded for contingencies much less than 500 MW. In addition to this, as the contingency size sensitivities detailed in Appendix A5.4.4 show, there is no need for additional synchronous machines to come online for levels of 430 MW on Heywood and 70 MW on PEC when managing a 500 MW contingency size. While the addition of synchronous machines is beneficial to the system, it does not appear that it is necessary.

Contingency size sensitivity key results

Case 5c6 – 600 MW initial contingency

Case 5c6 had an initial 600 MW of generation tripped as a result of the contingency applied. As this was a high load, low DPV case, the combination of load and DPV shake-off resulted in the total contingency size reducing slightly to around 540 MW.

The interconnectors were operating at 430 MW on Heywood and 70 MW on PEC pre-contingency. After the fault was applied, the interconnectors were still within their satisfactory limits and the case was stable. This showed that for this case, a total contingency size of 540 MW was acceptable to maintain within the satisfactory limits of the interconnectors.

Figure 111 Case 5c6 interconnector active power response (MW)

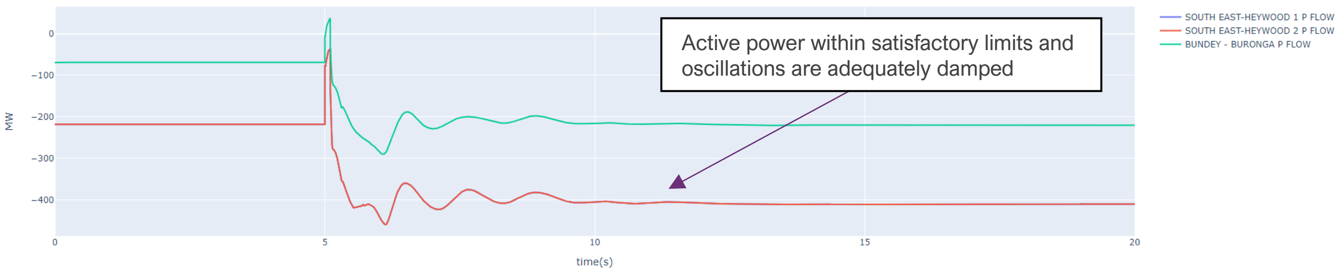


Figure 112 Case 5c6 interconnector reactive power response (MVAR)

Case 5c7 – 700 MW initial contingency

Increasing the contingency size by an additional 100 MW for Case 5c7 resulted in the satisfactory limits of PEC and Heywood being exceeded. However, while there was a large reactive power swing on Heywood as the system recovered after the fault, the system was stable and oscillations damped out reasonably quickly. This case is still considered to be a failed case due to it exceeding the satisfactory limits of the interconnectors, but it shows that instability was not found directly after the interconnector limits were exceeded. This case shows that a total contingency size of 630 MW does not cause instability in this case.

Figure 113 Case 5c7 interconnector active power response (MW)

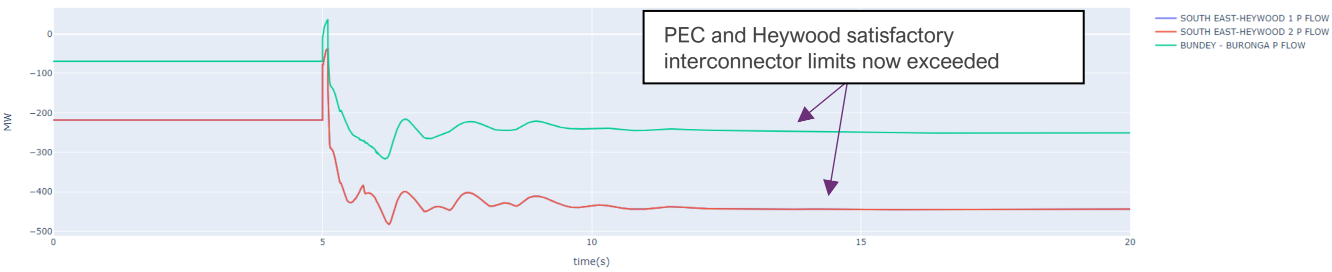
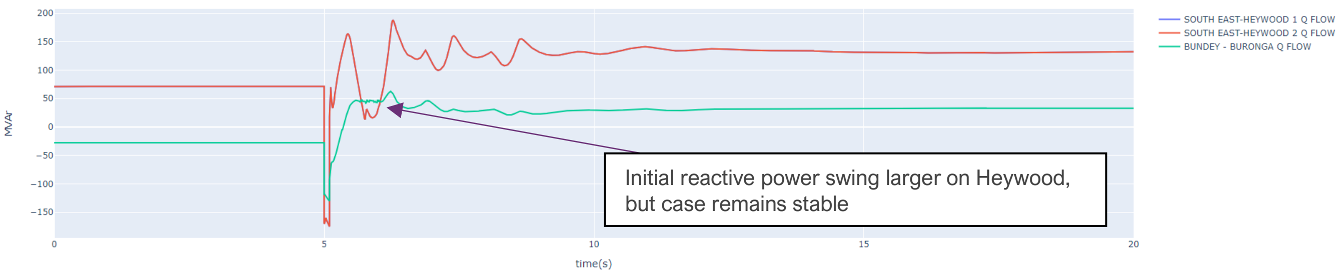


Figure 114 Case 5c7 interconnector reactive power response (MVAR)



Case 5c8 – 800 MW initial contingency

The initial contingency size for this case was 800 MW, which resulted in a total contingency size of 705 MW. This further pushed the interconnectors above their satisfactory limits, and as can be seen in the reactive power response of Heywood, the case began to approach instability. Large, lightly damped oscillations were present in the Heywood reactive power response. However, they eventually dampened out, but only very slowly. This case was only marginally stable and close to reaching voltage instability. This shows that while the satisfactory limits of PEC and Heywood were exceeded for an initial contingency size of 500 MW of generation, this case had an approximately 200 MW margin before it would come close to instability above the satisfactory limits.

Figure 115 Case 5c8 interconnector active power response (MW)

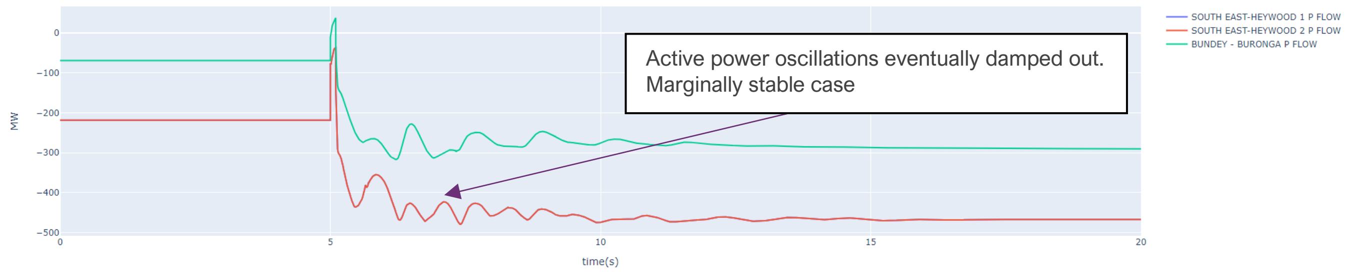
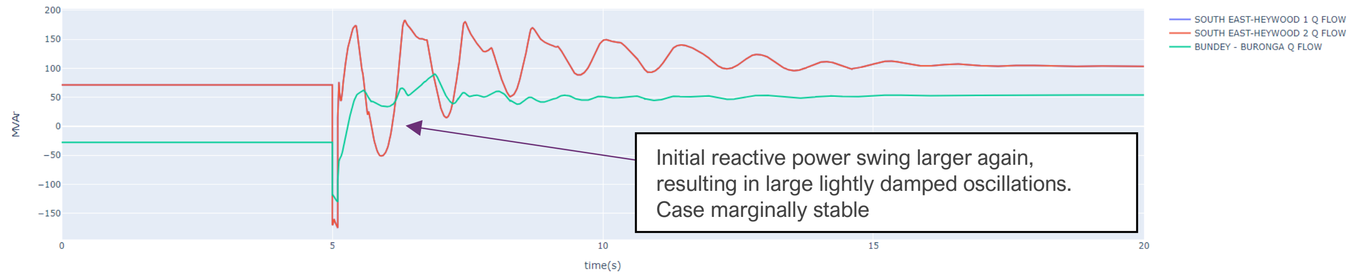


Figure 116 Case 5c8 interconnector reactive power response (MVAR)



Case 1 no CMLD/DER results – Angular instability example

As discussed, angular instability was seen in Case 1 as the first mode of instability (see Figure 117), for a 900 MW total contingency size. This provides an example of a case where the system was sufficiently strong that voltage instability was not seen as the first mode of instability. In this case, angular instability was seen at a contingency size 300 MW higher than when the interconnector satisfactory limits were exceeded. This was a significant event, and it can be seen that the South Australia system separated into multiple frequency islands in Figure 118.

Figure 117 Case 1 Heywood active power flow for various contingency sizes with no CMLD/DER models (MW)

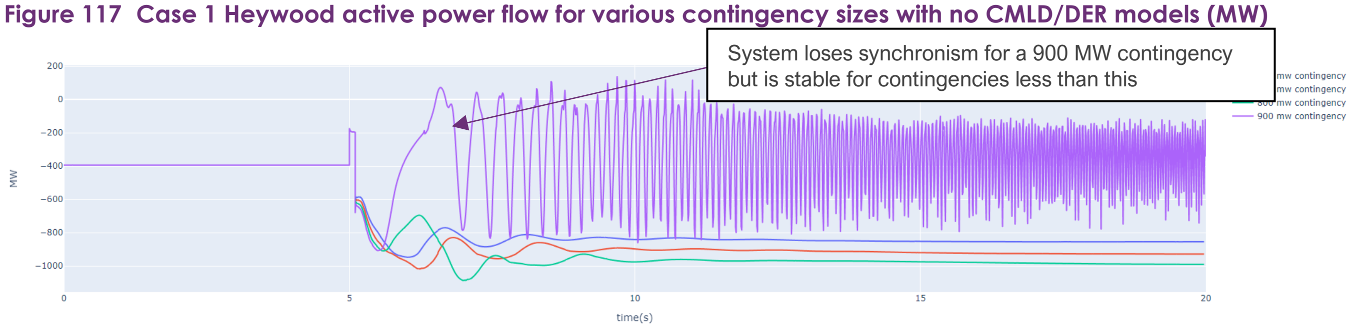
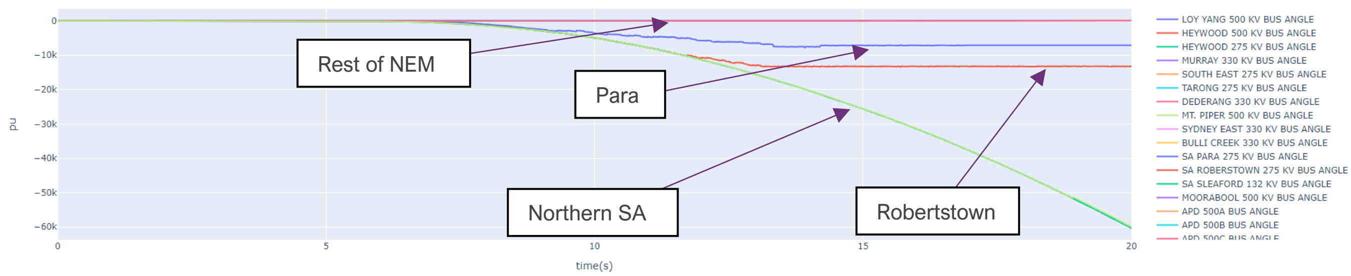


Figure 118 Case 1 system angles for 1,000 MW contingency size with no CMLD/DER models (pu)



Delay of generation tripping sensitivity key results

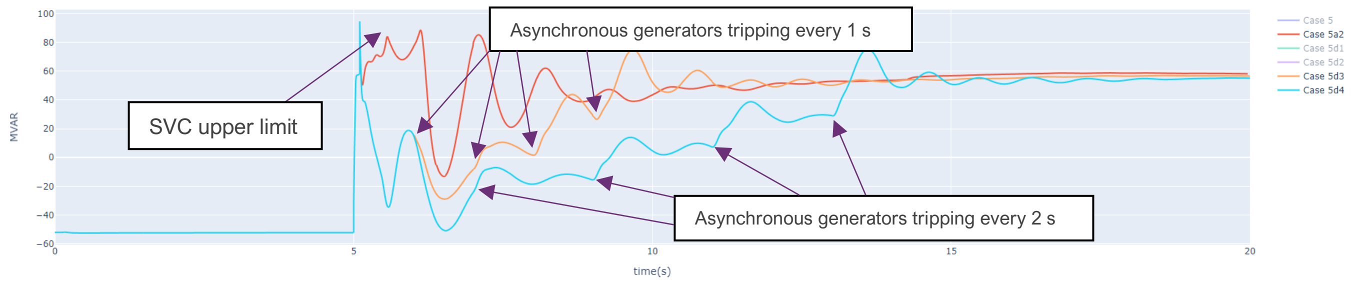
Case 5d3 and 5d4 – stable case

Case 5d3 and 5d4 were based on the stable case 5a2, which was studied in the interconnector flow sensitivities. Cases 5d3 and 5d4 had the same case parameters as 5a2, except with delayed tripping of generation for the contingency of one second and two seconds respectively.

It was found that the delayed tripping resulted in a better reactive power response in the network. As the system did not have to manage the large reactive power changes resulting from losing all the generation at once, it was found that key reactive plant did not hit their limits. Figure 119 shows the reactive power response of the South East SVCs for all three cases 5a2, 5d3, and 5d4. For the original case 5a2 (red trace), the SVC hit a limit directly after the fault, resulting in large reactive power swings. These are similar to the reactive power swings in other cases where the system became unstable due to voltage instability.

In contrast, when delayed tripping contingencies were applied, there is less stress on the system as it only needs to dynamically react to a smaller contingency size at once. As expected, the network response was improved, with delayed tripping, as the reactive power swings of the SVCs were much lower than the base case. This shows the most onerous case would be to consider the base case to study the interconnector flow limit.

Figure 119 South East SVC (MVAR) – Contingency 2 – Case 5a2, 5d3, and 5d4



With the improved reactive power response of the system, there were also less oscillations on the active power responses of the interconnectors, as shown in Figure 120 and Figure 121.

Figure 120 PEC active power flow (MW) – Contingency 2 – Case 5a2, 5d3, and 5d4

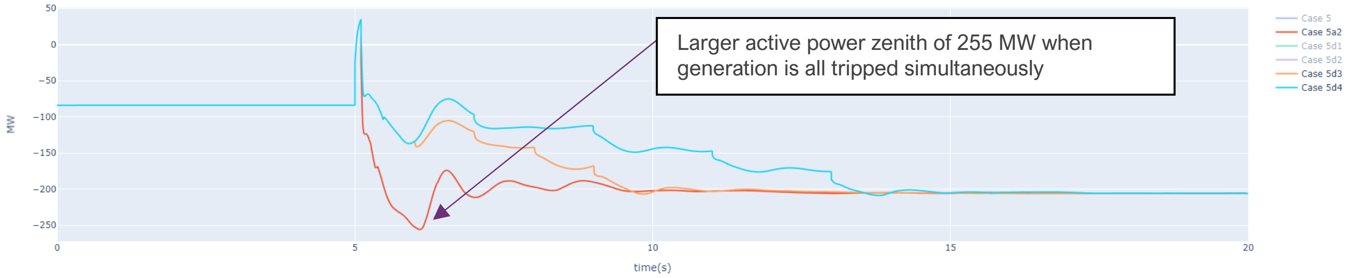
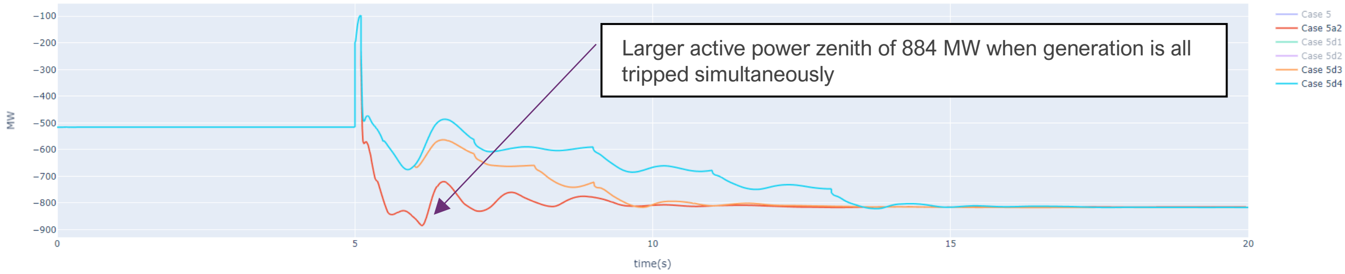


Figure 121 Heywood active power flow (MW) – Contingency 2 – Case 5a2, 5d3, and 5d4



Case 5d1 and 5d2 – unstable case

In addition to studying the effect of delayed tripping for a stable case, Case 5 was used as a base case to check if the delayed tripping of asynchronous generators could help in post-contingent stability for a previously unstable case. This case had high pre-contingent flow on Heywood (645 MW) and PEC (155 MW) and showed voltage instability after the fault, with large undamped reactive power oscillations.

Figure 122 shows the overlay of reactive power flow over the interconnectors for cases 5, 5d1, and 5d2. While the delayed tripping improved the reactive power response of the system, it was not sufficient to prevent the case from becoming unstable once all the generators were tripped.

Figure 122 Heywood reactive power flow (MVAR) – Contingency 2 – Case 5, 5d1, and 5d2

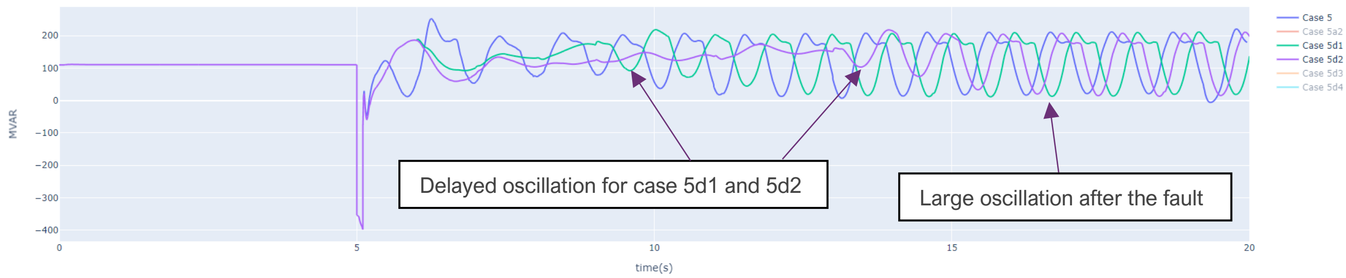


Figure 123 and Figure 124 show active power response over Heywood and PEC.

Figure 123 Heywood active power flow (MW) – Contingency 2 – Case 5, 5d1, and 5d2

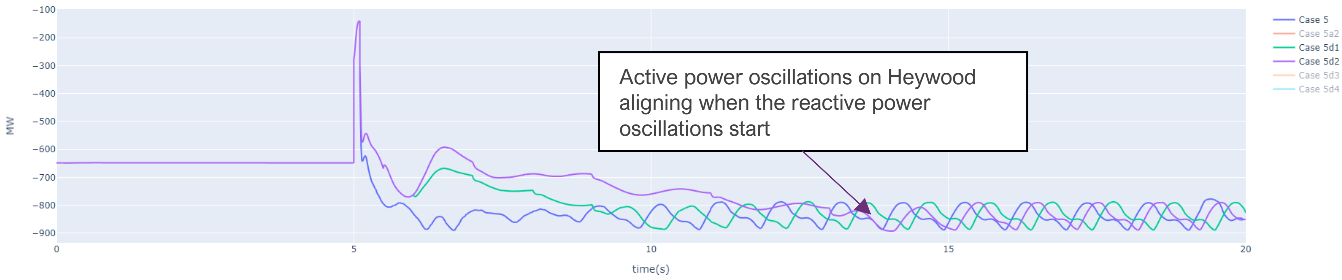
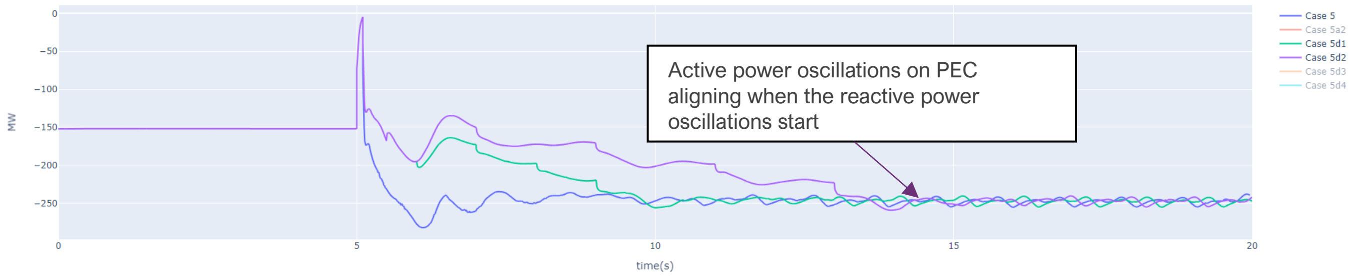


Figure 124 PEC active power flow (MW) – Contingency 2 – Case 5, 5d1, and 5d2



PEC/Heywood ratio sensitivity key results

The results for the PEC/Heywood ratio sensitivity key results are shown in the figures below. It was found that the ratio did not significantly change the dynamic performance.

Figure 125 Heywood active power flow (MW) – Contingency 2 – Case 7e1-5

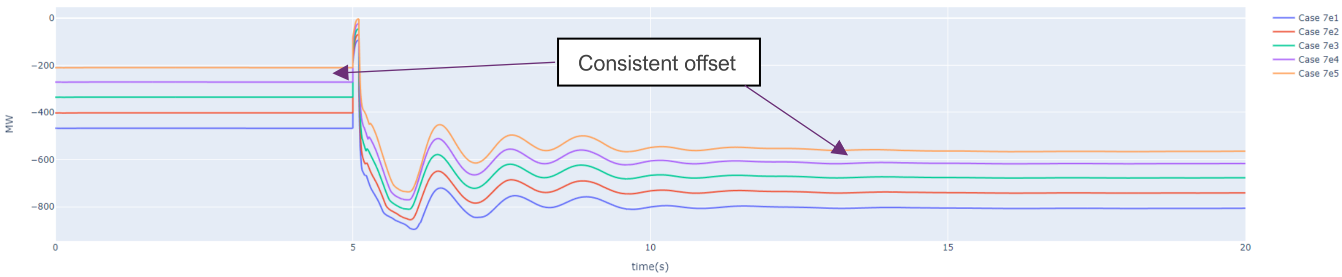


Figure 126 PEC active power flow (MW) – Contingency 2 – Case 7e1-5

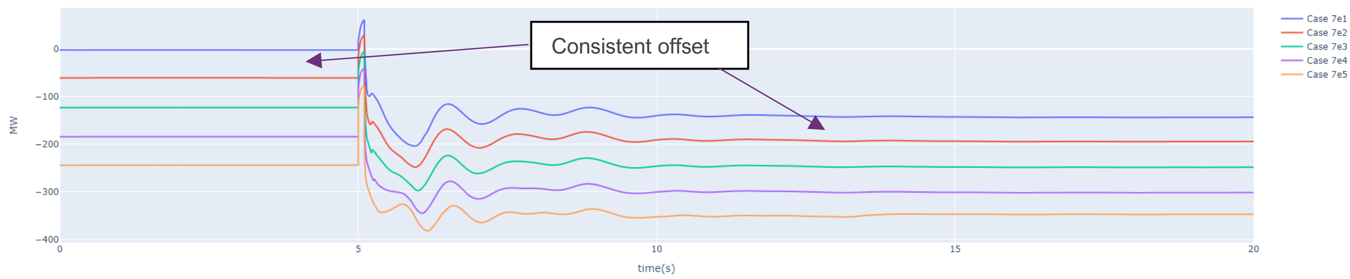


Figure 127 Heywood active power flow (MW) – Contingency 2 – Case 10e1-5

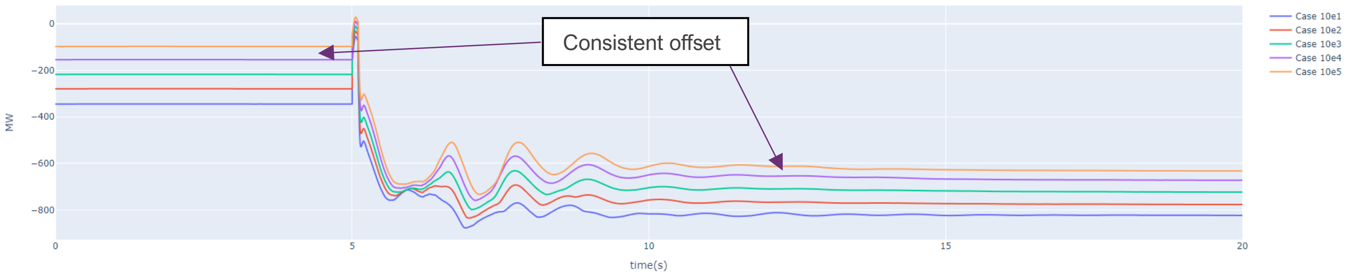
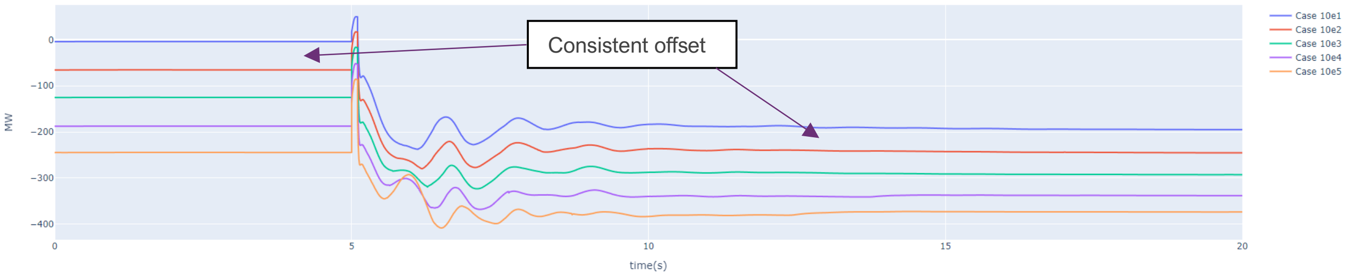


Figure 128 PEC active power flow (MW) – Contingency 2 – Case 10e1-5



A6. Draft 2024 GPSRR report feedback

AEMO sought submissions on the draft 2024 GPSRR report during a public consultation between 30 May 2024 and 14 June 2024.

AEMO did not receive any written submissions from stakeholders during the public consultation period in regards to the 2024 GPSRR.

On 7 June 2024, AEMO held an open question-and-answer session with all interested parties, at which attendees were invited to ask questions and provide any feedback in relation to the 2024 GPSRR.

The following sections include summaries of the comments and questions from the question-and-answer session, together with AEMO's responses, where relevant.

AEMO thanks all stakeholders who engaged with the 2024 GPSRR for their contributions to shaping the review and finalising this report.

A6.1 2024 GPSRR question and answer session

A summary of the key questions raised during the 7 June 2024 session is provided below with AEMO responses.

Question

Why was the Latrobe Valley contingency chosen for priority risk 1 instead of the trip of generators and/or major transmission lines in central Queensland from a system strength perspective?

AEMO response

- This priority risk was raised in the risk assessments received from NSPs as part of the consultation on the 2024 GPSRR approach. Studies were undertaken on this risk as a case study to understand the potential impacts that a non-credible contingency involving the loss of multiple large synchronous generating units could have on system strength. This specific contingency was not selected due to a higher likelihood of occurring compared to other CBF contingencies. It was selected because of the significant impact it could have on the network and system strength.
- This priority risk highlights that in certain operating conditions, one CB fail could cause loss of all Loy Yang B and Valley Power units, with the potential for system strength impacts. For future GPSRRs, AEMO may study other non-credible contingencies like this one and the subsequent impacts on system strength. This may include the trip of generators and major transmission lines in Queensland.

Question

Was the study of the Loy Yang circuit breaker failure risk chosen because it was more likely to occur than other non-credible contingencies? Is this a critical issue for Victoria at the moment?

AEMO response

- This non-credible contingency is not more likely to occur than other non-credible CBF contingencies in the NEM. This specific contingency was chosen as a case study due to the severe consequences if it were to occur under certain low system strength dispatch conditions.
- This work will lead to identifying other similar non-credible contingencies in the NEM that could result in significant system strength impacts. In terms of criticality for the Victorian network, this risk is not more likely to occur than other circuit breaker failure events. Based on the topology of Loy Yang substation, the potential impact is larger.

Question

Do the proposed new PEC limits apply when the loss of the Heywood interconnector is considered to be credible due to destructive winds, that is, when the location of the destructive winds is around the Heywood flow path from Moorabool to Tailem Bend itself? We are talking about generation in South Australia being lost, but what about if we lost Heywood itself?

AEMO response

- The limits studied in the 2024 GPSRR apply for destructive wind conditions that could result in the loss of multiple transmission elements causing generation disconnection in South Australia to reduce the likelihood of South Australia islanding. This is distinct from the South Australia import constraints that are invoked for destructive wind conditions impacting Heywood where South Australia islanding is reclassified as credible. As PEC Stage 1 will be inter-tripped with Heywood, the South Australia destructive wind transfer import limit for the credible loss of Heywood will remain at 250 MW.

Question

Relying on directions may not be possible. What will happen if due to unplanned outages there is nothing available to direct? Will you consider using stochastic models for plant failure in your studies?

AEMO response

- In recommendation 4 of the 2024 GPSRR, AEMO has recommended that operational procedures are developed for scenarios where units are not available to direct for system strength. These operational procedures will include a bow-tie risk assessment approach that incorporates limit advice and contingencies plans from NSPs. The bow-tie risk assessment will have multiple measures in place to respond to the operational challenges.
- As suggested, the ESOO published by AEMO uses stochastic modelling and could be used as a basis for plant failure for future GPSRR studies.

Question

Could the response of BESS in New South Wales or Queensland to remote contingencies result in QNI instability as more BESS is installed in these regions in the future?

AEMO response

- BESS response to remote contingencies and the impact on interconnectors has so far been identified by ElectraNet as a potential issue regarding the stability of the Heywood interconnector. While this issue has not yet been identified for credible contingencies in other regions, there is potential that credible or non-credible contingencies could result in instability on QNI under certain operating conditions, and in future BESS scenarios.
- If significantly greater quantities of BESS were to be installed in Queensland, and a contingency occurred when there was minimal headroom on QNI, it is possible that instability could occur. This may be investigated in a future GPSRRs.