Emergency Under Frequency Response for South Australia

May 2024

Quantification of risks from significant multiple contingency events

A report for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to provide advice to Network Service Providers and other stakeholders on the amount of emergency under-frequency response (EUFR) required in South Australia to adequately arrest the impacts of a range of significant multiple contingency events. This is related to AEMO's responsibilities under the National Electricity Rules to assess the adequacy of EUFR (NER clause 4.3.1(k)).

This publication is generally based on information available to AEMO as at 1 December 2023 unless otherwise indicated.

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Executive summary

This report aims to assess the total amount of Emergency Under Frequency Response (EUFR) needed in South Australia (SA) to adequately manage a range of significant multiple contingency events. EUFR includes the response from Under Frequency Load Shedding (UFLS), as well as the frequency response from fast responding resources such as Battery Energy Storage Systems (BESS) and other types of inverter-based resources (IBR) which can also contribute to arrest of a fast frequency decline.

This report focuses particularly on quantifying the amount of EUFR required in low demand periods, accounting for the complex effects and interactions with distributed photovoltaics (DPV), much of which is located on circuits which are traditionally disconnected by UFLS. Increasing DPV generation impacts UFLS schemes in several ways:

- **Reduced contingency sizes (reducing risk)** – in low operational demand periods, significant multiple contingency events that involve a loss of centralised generation will tend to be smaller, which reduces the amount of EUFR required in these periods to adequately manage risks.
- **Reduced UFLS effectiveness (increasing risk)** – low operational demand and high DPV generation reduces the effectiveness of UFLS in arresting a frequency decline, by reducing the net load on UFLS circuits, and potential disconnection of circuits that are in reverse flows (potentially exacerbating a frequency decline).
- **Increase in RoCoF (increasing risk)** – reduced NEM inertia (due to fewer synchronous units operating in periods of low operational demand) increases the rate of change of frequency (RoCoF). Previous studies have indicated that conventional UFLS is unlikely to successfully arrest frequency for RoCoF exceeding ~3 hertz per second (Hz/s)[1].

This report applies a multi-mass model (MMM) to study these effects. The model has been benchmarked against a full root mean square (RMS) representation of the operation of UFLS in the SA transmission network in PSS®E.

Table 1 summarises the events selected for consideration. These have been selected to represent a range of different types of significant but plausible multiple contingency events affecting up to 60% of the total power system load (as per National Electricity Rules (NER) 4.3.1(k)(2)).

Table 1 Significant multiple contingency events studied

Contingency description	Sequence of trips during modelling simulation		
	t = 0.1s	t = 1s	t = 2s
Separation + 1 station trip	Synchronous separation of SA	The largest generating station trips	
Separation + 2 station trip	Synchronous separation of SA	The largest generating station trips	The second largest generating station trips
Separation + 1 station + 30% DPV trip	Synchronous separation of SA	The largest generating station trips	30% of DPV trips
Separation + 40% DPV trip	Synchronous separation of SA	40% of DPV trips	

[1] AEMO (Dec 2022) AEMO Advice: Reliability Panel Review of the 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.

A trip of 30-40% of DPV in the region is included to represent possible type faults or other common modes of failure leading to a large proportion of DPV tripping (without associated load shake-off). This quantity is approximately representative of the proportion of the DPV fleet associated with the largest 2-3 equipment manufacturers (which could share common type faults) or the proportion of the DPV fleet associated with a common country of origin and with internet connectivity by 2025.

Each of these significant multiple contingency events was modelled in the MMM in each half-hour period in 2023 and 2025 based on dispatch forecasts from a time-sequential model[2]. The amount of BESS headroom was increased iteratively in each simulation to increase EUFR availability until frequency arrest above 47.6 Hz was achieved in all cases[3]. The amount of EUFR required in each case was then calculated as the sum of the amount of UFLS tripped, plus the amount of BESS fast frequency response delivered.

Figure 1 shows the calculated amounts of EUFR required in each half-hour, for varying levels of operational demand, as box and whisker plots. Each panel shows the results for each of the four contingency types studied. A "guide to the eye" is also included as a purple line, illustrating 60% of operational demand.

AEMO is responsible for assessing the adequacy of reserves to arrest the impacts of a range of significant multiple contingency events affecting up to 60% of the total power system load (NER 4.3.1(k)(2)). These multiple contingency events were selected to be probabilistically representative of events affecting this level of power system load, as well as representing the most onerous plausible multiple contingency events that could occur in both high and low demand periods.

In Figure 1, the contingencies in the top two panels do not involve a DPV trip. In these cases, the EUFR required scales relatively closely with operational demand. At higher levels of operational demand, contingency sizes are generally larger, so more EUFR is required. As operational demand trends towards zero, the contingency size similarly becomes small, and the studies suggest minimal EUFR is generally required to manage these traditional types of multiple contingency events in low demand periods. This indicates that it is likely appropriate to define a EUFR target for these more traditional contingency types based on a percentage of operational demand.

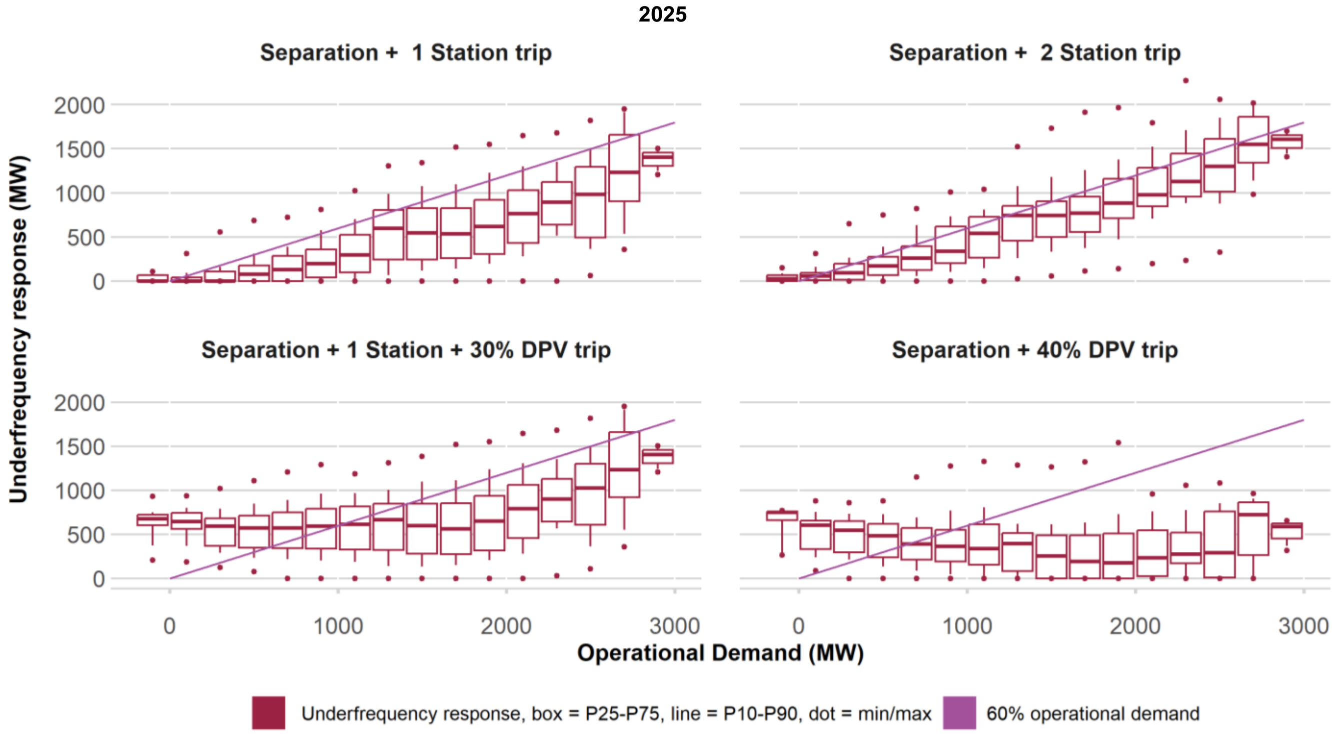
However, for the more novel contingency types that involve a trip of DPV (shown in the bottom two panels in Figure 1), the EUFR required does not scale with operational demand. Significant amounts of EUFR can be required even in scenarios with very low levels of operational demand, if the original contingency involves a trip of DPV. A percentage of operational demand is therefore not a good indicator of a EUFR target in these low demand scenarios, accounting for these more novel contingency types involving a trip of DPV.

Figure 2 combines the four panels in Figure 1 by taking the EUFR required in each half-hour period to adequately manage frequency (arrest > 47.6 Hz[3]) for each of the four contingency types. Two segments are revealed; for high levels of operational demand (>1,200 megawatts (MW)), the EUFR required scales with operational demand, but for low levels of operational demand (<1,200 MW), the EUFR required is relatively constant.

[2] Dispatch forecasts were sourced from a time-sequential model used for the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO. For more details on the time-sequential model refer to the ISP methodology: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

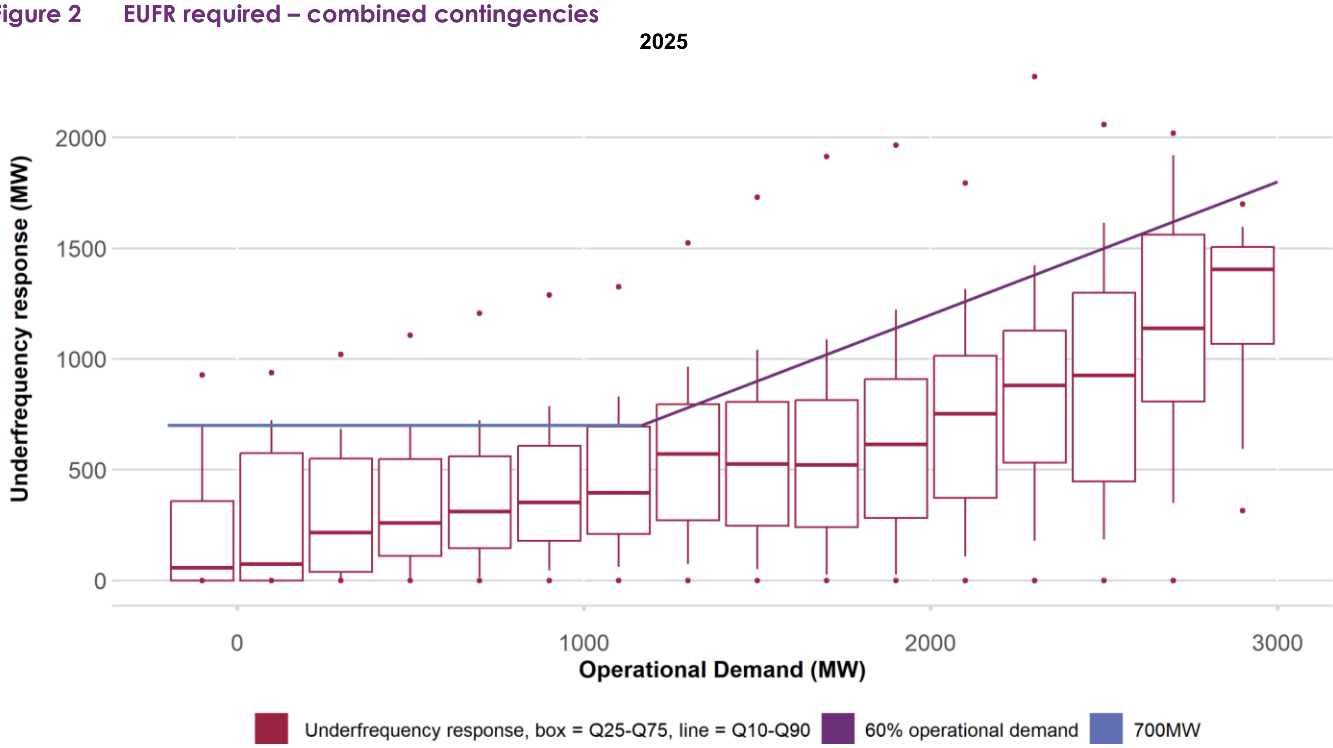
[3] Refer to Section 3.1.1 for acceptance criteria applied. Cases with RoCoF > 3Hz/s were excluded since these are unlikely to be managed effectively via conventional UFLS.

Figure 1 EUFR required to arrest f > 47.6Hz following a significant multiple-contingency event



Note: the boxes represent quartiles, the whiskers represent 10th and 90th percentiles, and the dots represent maximum and minimum values for the amount of EUFR required to arrest frequency above 47.6Hz in each half-hour dispatch period, grouped at each level of operational demand.

Figure 2 EUFR required – combined contingencies



On this basis, AEMO proposes that the EUFR target for South Australia be defined as follows:

Proposed EUFR target for South Australia

AEMO's assessment is that to maintain reasonable continuity with the historical risk profile, based on historical levels of UFLS, would require an SA EUFR target which is the higher at any point in time of:

- 700 MW, or
- 60% of operational demand.

This report indicates that this target provides enough EUFR to manage the four contingency events studied ~80% of the time.

This should be reviewed following commissioning of Project EnergyConnect (PEC) Stage 2.

AEMO is continuing to review EUFR adequacy, and this advice may change as this work continues.

There will always be a risk associated with non-credible contingencies requiring larger amounts of EUFR than this target, as well as larger contingencies than those studied in this report. The analysis in this report aims to provide a simple target that delivers reasonable continuity of the probabilistic risk profile over time, as a guide to balance costs and risks to consumers. This proposed target provides enough EUFR to manage the four contingency events studied ~80% of the time, delivering a similar risk profile to historical levels of coverage via traditional UFLS.

There are a number of factors that influence EUFR availability. SA Power Networks (SAPN) is in the process of rolling out "dynamic arming" of UFLS relays (relays designed to dynamically disarm if the circuit is in reverse flows), with anticipated full rollout in September 2024, and ongoing works thereafter to address any new sites that exceed reverse flow thresholds. Several new BESS have also recently been commissioned (such as the AGL 250 MW BESS at Torrens Island, and the Tailem Bend BESS), significantly increasing the amount of BESS headroom that will be typically available in South Australia. With the EUFR target defined as described above, Table 2 provides an estimate of the percentage of time this target would be met, in various scenarios accounting for these changing factors.

Table 2 Percentage of time EUFR target is met

Scenario	Representative period	% of time EUFR target is met
2023, no dynamic arming 150 MW BESS headroom	Representative of typical EUFR availability in 2023 (prior to commissioning of Torrens Island BESS)	84 %
2023, no dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability at present (following commissioning of Torrens Island BESS in late 2023)	91 %
2023, with dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability once dynamic arming rollout is complete in late 2024	99.97 %
2025, with dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability in 2025, with ongoing growth in DPV	99.8 %

The actions already underway significantly increase the proportion of time that this EUFR target is met:

- **Dynamic arming of UFLS** – in a counterfactual scenario where dynamic arming was not implemented in 2025, the suggested target would only be met 88% of the time (even with 400 MW BESS headroom available).
- **Additional battery capacity in SA** – if there was only 150 MW of battery headroom in 2025 instead of 400 MW, the EUFR target would only be met 93% of the time.

The combination of actions taken and in progress mean the suggested target should be met ~99.8% of the time in 2025[4]. This delivers a similar level of residual risk to historical levels.

In 2025 it is estimated that the total residual risk for SA associated with inadequate EUFR for the four contingency events studied is in the order of ~$7 million per annum of unserved energy (USE) (based on the value of customer reliability)[5]. This residual risk is associated relatively equally with high demand and low demand periods, and shows a diminishing returns relationship. It is estimated that increasing EUFR availability by approximately 100 MW in all periods would reduce risk associated with the four contingency events studied by ~$3 million per annum. This suggests that if there are options to increase EUFR availability in the order of 100 MW for less than ~$3 million per annum, and these options could be implemented sufficiently ahead of PEC Stage 2, these may be worth investigating further.

AEMO is continuing to review UFLS adequacy, and this advice may change as this body of work progresses. This should be reviewed following commissioning of PEC Stage 2, which will fundamentally change the nature of the multiple contingency events being managed.

AEMO is also continuing analysis of UFLS and EUFR in other NEM regions. Other network service providers (NSPs) in the National Electricity Market (NEM) have not yet committed to implementation of dynamic arming of UFLS relays, and reverse flows are already evident in many locations. AEMO continues to recommend that NSPs in Victoria[6,7], New South Wales[8] and Queensland[9] investigate approaches for management of the impacts of reverse flowing feeders on UFLS functionality, including consideration of dynamic arming options[10]. The analysis in this report indicates that dynamic arming of UFLS in South Australia has been beneficial, and warranted on a cost/benefit assessment (see Appendix A3).

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[4] This assumes a static availability of BESS headroom for frequency response which would generally be delivered if the BESS are dispatched close to 0 MW as they might when participating in frequency control ancillary services (FCAS). In reality, in some periods BESS will have different levels of headroom available, depending on their dispatch levels. In low demand periods, there may be more BESS headroom available if the BESS are dispatched as a load while charging (potentially more likely in periods of low demand, often associated with low wholesale market prices). This suggests the EUFR available in low demand periods might be higher than indicated in this assessment, on average.

[5] Based on estimating the likelihood of an unplanned separation and contingency event, the likelihood that the separation may lead to a black system based on these studies, the amount of USE associated with a black system event, and the value of customer reliability, with full assumptions outlined in Appendix A3.

[6] AEMO (May 2023) Victoria UFLS load assessment update, 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.

[7] AEMO (August 2021) Phase 1 UFLS Review: Victoria, https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

[8] AEMO (December 2021) Phase 1 UFLS Review: New South Wales, https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.

[9] AEMO (December 2021) Phase 1 UFLS Review: Queensland, https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

[10] AEMO (October 2023) Under Frequency Load Shedding: Exploring dynamic arming options for adapting to distributed PV, https://aemo.com.au/-/media/files/initiatives/der/2023/dynamic-arming-options-for-ufls.pdf?la=en&hash=F6B7A015C8EB872C835 13BA9C95EFE5B.

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1 Introduction

1.1 Emergency Frequency Control Schemes (EFCS)

If a sudden failure or trip of multiple generating units occurs, power system frequency will rapidly reduce. In the absence of measures to manage such an event, a severe under-frequency event can lead to cascading failure and a black system.

Emergency Frequency Control Schemes (EFCS) are the main measures designed to prevent cascading failure to a black system if a significant multiple contingency event occurs (such as a trip of multiple generating units). Under Frequency Load Shedding (UFLS) is the main EFCS designed to arrest severe under-frequency events. UFLS involves the automatic disconnection of progressive blocks of customer load in less than half a second.

AEMO has responsibility for coordinating the provision of EFCS by network service providers (NSPs) and determining the settings and intended sequence of response of those schemes (NER 4.3.1(p1)). NSPs have responsibility for ensuring that sufficient load is under the control of under-frequency relays or other facilities (NER S5.1.10.1(a)).

This report aims to assess the quantity of Emergency Under Frequency Response (EUFR) required in South Australia (SA) to adequately manage a range of significant multiple contingency events, delivering a similar risk profile to historical levels of coverage via traditional UFLS. EUFR includes the response from UFLS, as well as the frequency response from fast responding resources such as battery energy storage systems (BESS) and other types of inverter-based resources (IBR) which can also contribute significantly to arrest of a fast frequency decline, and are becoming prevalent in the National Electricity Market (NEM).

This report has been developed in the context of a range of other work programs designed to assist in managing the non-credible separation of South Australia, such as constraints implemented under South Australian Government Regulation 88A[11] (which require limiting Rate of Change of Frequency (RoCoF) in South Australia in relation to the non-credible coincident trip of both circuits of the Heywood Interconnector to below 3Hz/s) and upgrades of the South Australian System Integrity Protection Scheme (SIPS) to the Wide Area Protection Scheme (WAPS)[12], and studies conducted as part of the General Power System Risk Review (GPSRR)[13]. AEMO's recently published studies on non-credible separation of South Australia also provide further detail and context for this work[14].

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[11] https://www.legislation.sa.gov.au/__legislation/lz/c/r/electricity%20(general)%20regulations%202012/current/2012.199.auth.pdf

[12] ElectraNet (October 2023) Transmission Annual Planning Report, https://www.electranet.com.au/wp-content/uploads/231115_2023-TAPR.pdf

[13] AEMO, General Power System Risk Review, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review

[14] AEMO (May 2023) Separation leading to Under Frequency in South Australia, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645

1.2 Impacts of distributed PV on UFLS in South Australia

Increasing distributed PV (DPV) generation impacts UFLS schemes in several ways:

- **Reduced contingency sizes (reducing risk)** – in low operational demand periods, significant multiple contingency events that involve a loss of centralised generation will tend to be smaller, which reduces the amount of EUFR required to adequately manage risks.
- **Reduced UFLS effectiveness (increasing risk)** – low operational demand and high DPV generation reduces the effectiveness of UFLS in arresting a frequency decline.
- **Increase in RoCoF (increasing risk)** – reduced NEM inertia (due to fewer synchronous units operating in periods of low operational demand) increases the rate of change of frequency (RoCoF).

These competing effects are discussed further below.

1.2.1 Reduced contingency sizes (reducing risk)

At times of very low operational demand, centralised generating units are more likely to be dispatched at low levels, and interconnectors are less likely to be importing to a region. This means that the same multiple contingency event (such as a non-credible separation and station trip) is likely to be smaller at these times, reducing the amount of EUFR required to arrest it. This could mean that the amount of EUFR required at times of low operational demand to adequately manage risks is lower.

The largest contingencies in periods of very low operational demand are likely to involve a trip of DPV generation itself. The trip of DPV in the original contingency event will tend to increase net UFLS load (since much of the DPV is located on UFLS circuits). This can thereby act to increase UFLS effectiveness for managing these types of contingencies in low operational demand periods.

These factors mean that the amount of EUFR required at times of very low demand is likely lower than at times of high demand. These effects have been quantified in this report by analysis of representative dispatch scenarios at varying levels of operational demand (influencing the contingency size in each period), as well as by capturing the effects of DPV trip on UFLS operation in the models applied.

1.2.2 Reduced UFLS effectiveness (increasing risk)

Although the amount of EUFR required at times of low demand may be lower (due to reduced contingency sizes), the effectiveness of the UFLS scheme is reduced at times of low demand and high DPV generation in the following ways:

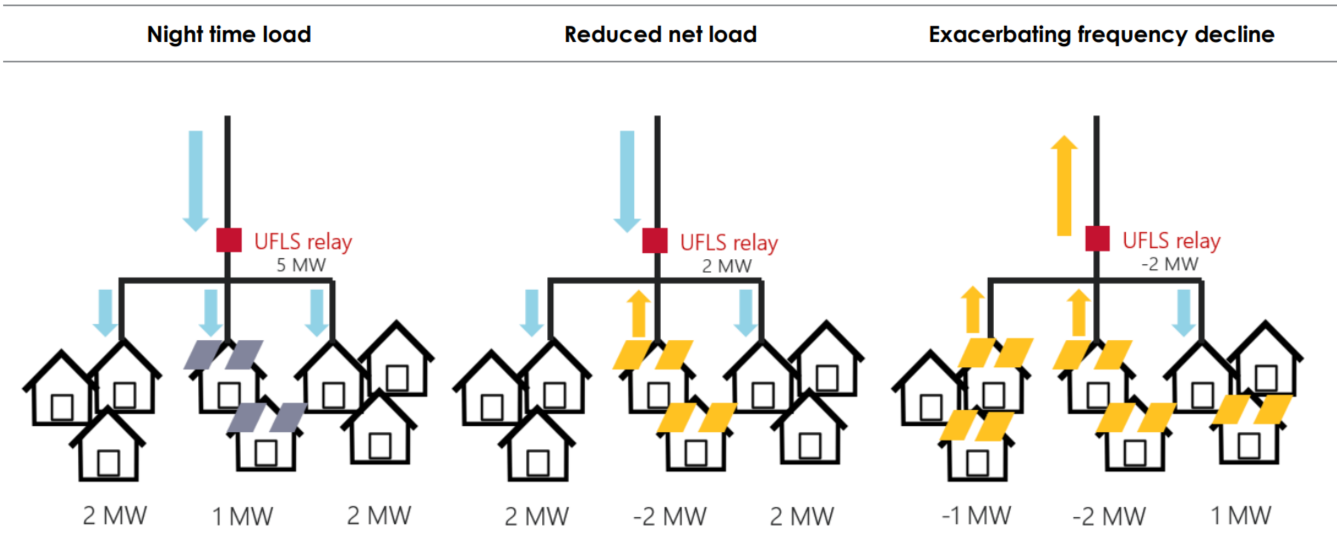
- **Reduced net load on UFLS –** increasing levels of generation from DPV reduces 'net' load on UFLS load circuits. Total UFLS load in South Australia reached a minimum of -25 megawatts (MW) in spring 2022, and was below 200 MW for 1.5% of 2023.
- **Reverse flows** – when circuits experience reverse power flows at certain times, they effectively become net "generators". This means that tripping these circuits results in further generation loss, thereby exacerbating

the disturbance, rather than helping to correct it. In calendar year 2023, total distribution-connected[15] UFLS load in South Australia was below 0 MW for ~150 hours in the year, and many individual circuits were in reverse flows for longer periods.

- **DPV tripping** – it is estimated that up to 14% of legacy DPV systems installed in South Australia at present may demonstrate under-frequency disconnection behaviour when frequency falls below 49 hertz (Hz)[16]. This means a severe under-frequency event can be exacerbated by the disconnection of DPV that trips at the same time as UFLS stages. This exacerbates the size of the contingency event, further increasing the probability that the UFLS will be inadequate to arrest a severe under-frequency event.

The first two effects are illustrated in Figure 3.

Figure 3 Reduction in UFLS net load from DPV and reverse flows



AEMO reported analysis on these effects in the Power System Frequency Risk Review (PSFRR) reports released in July 2020[17], December 2020[18], and July 2022[19], and also in a dedicated report quantifying risks associated with non-credible separation of South Australia from the rest of the NEM[20]. This report builds on that analysis. The models applied in the studies in this report are designed to capture all these effects.

[15] Distribution-connected UFLS load in South Australia typically makes up the majority of the region's UFLS load, contributing 85% of UFLS load in low-DPV periods. Transmission-connected UFLS loads are less impacted by DPV generation, but are typically on the lower UFLS trip frequency bands and can vary through the year based on individual requirements of large sites. In 2022, transmission-connected UFLS load was typically 200 MW, but fell below 130 MW in some periods.

[16] See Section A1.1.

[17] AEMO (July 2020), 2020 Power System Frequency Risk Review – Stage 1, Appendix A1, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

[18] AEMO (December 2020), Power System Frequency Risk Review – Stage 2 Final Report, Section 6.2, https://aemo.com.au/-/media/files/initiatives/der/2020/2020-psfrr-stage-2-final-report.pdf?la=en&hash=9B8FF52E750F25F56665F2BE10EBFDFA.

[19] AEMO (July 2022), Power System Frequency Risk Review, Section 3.3 and Section 7.3, https://aemo.com.au/-/media/files/initiatives/der/2020/2020-psfrr-stage-2-final-report.pdf?la=en&hash=9B8FF52E750F25F56665F2BE10EBFDFA.

[20] AEMO (May 2023) Separation leading to under-frequency in South Australia, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645.

1.2.3 Increase in RoCoF (increasing risk)

In periods of high DPV generation, there are typically fewer synchronous units operating, which reduces power system inertia. Under low inertia conditions, the same contingency size can lead to a higher RoCoF. AEMO provided advice to the Reliability Panel on the risks associated with high RoCoF as part of the review of the Frequency Operating Standards[21]. One of the risks noted was that UFLS is less likely to arrest frequency successfully when RoCoF exceeds 3 hertz per second (Hz/s), partly due to possible maloperation of relays, and partly because the inherent time delays in UFLS relay operation mean that load blocks do not trip sufficiently quickly to arrest the disturbance if RoCoF is exceeding ~3 Hz/s.

This has been factored into the analysis in this report by explicitly noting cases where RoCoF exceeds 3 Hz/s. Increasing the amount of conventional EUFR available is unlikely to resolve risks in these cases, so these cases were not used to define the EUFR target. The risks associated with these scenarios would need other management measures (such as increased levels of inertia).

1.3 Measures that increase EUFR adequacy in South Australia

1.3.1 Dynamic arming

SA Power Networks (SAPN) is in the process of implementing dynamic arming of UFLS relays (also termed reverse flow blocking of relays) in their network. Dynamically armed relays monitor the flows on the circuit and disarm the frequency trip setting if the circuit is in reverse flows.

Dynamic arming was recommended by AEMO in 2021[22], and approved by the Australian Energy Regulator (AER) as a cost pass-through in 2023[23]. Dynamic arming will prevent UFLS net load availability in South Australia going significantly negative as further DPV is installed.

The rollout of dynamically armed relays is expected to be completed by the end of 2024 in South Australia and is expected to increase the minimum UFLS net load in 2024 from approximately -230 MW to around 170 MW.

The positive impacts of dynamic arming can already be seen by looking at distributed UFLS levels during minimum demand days in South Australia. In spring 2022, before the implementation of dynamically armed relays, the minimum demand record for South Australia was 69 MW and the distributed UFLS available was -195 MW at this time. In summer of 2023, after a partial implementation of dynamically armed relays, a new minimum operational demand record was set at -41 MW. Despite the minimum demand decreasing by over 100 MW, the total amount of distributed UFLS available improved by 87 MW to -108 MW during this time.

The studies in this report assume there is no dynamic arming in 2023, and in 2025 dynamic arming is fully implemented, unless otherwise noted.

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[21] AEMO (December 2022) AEMO Advice: Reliability Panel Review of the 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.

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

[23] AER (1 June 2023) SA Power Networks – Cost pass through – Emergency standards 2021-22, https://www.aer.gov.au/networkspipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards2021%E2%80%9322.

1.3.2 BESS

South Australia has several utility-scale BESS connected to the grid. When there are significant under-frequency events, BESS can respond quickly to deliver primary frequency response and contribute significantly to the arrest of frequency. Given the significant influence of BESS in arresting significant multiple contingency events, this report refers to the combined rapid frequency response of UFLS and BESS as "Emergency Under Frequency Response" (EUFR).

AEMO's analysis suggests that fast frequency response from BESS contributes significantly to the arrest of frequency in significant multiple contingency events, with 1 MW of BESS headroom delivering fast frequency response being approximately equivalent to 1 MW of UFLS net load trip. They have therefore been considered equivalent sources of EUFR in this report.

1.4 International approaches to assessing DER impacts on UFLS

There is a growing awareness internationally on the impacts of distributed energy resources (DER) on UFLS schemes.

The North American Electric Reliability Corporation (NERC) has released a specific Reliability Guideline advocating recommended approaches for UFLS program design with increasing penetrations of DER[24], stating that if a significant percentage of load is served by DER, electrical island-level frequency will be impacted. It notes:

- When studying UFLS adequacy, it is increasingly important to study a wider range of expected operating conditions, particularly with respect to DER output levels, to understand the worst-case scenarios regarding UFLS operation. In particular, NERC recommends including additional cases reflecting other load conditions than peak load.
- Dynamic models of both utility-scale and residential-scale DPV should be modelled in simulations, representing the voltage and frequency trip settings for DPV.
- There may need to be more detailed solutions implemented than traditional UFLS to manage under-frequency events. Targeting specific loads, circuits, or customers for inclusion in the UFLS program may require greater granularity in the future compared to past experience.
- Conventional UFLS relaying (that is, on a circuit-level basis) may become obsolete or may require additional solutions when faced with increasing DER penetrations. For example, BESS may be able to provide fast-responding net load reduction by providing either fast discharging capability or fast reduction of charging capability.
- Lack of visibility with DER leads to challenges. To maintain a robust UFLS scheme, NERC recommends that operators should improve awareness and visibility of DER connected to their system and monitor real-time output of the aggregate DER impacting the feeders armed for UFLS to the greatest possible extent. This helps in ensuring there is enough load armed in UFLS and helps with modelling.

[24] NERC (December 2021) Reliability Guideline, recommended approaches for UFLS program design and increasing penetrations of DERs, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf.

The analysis developed for this report has been mindful of these recommendations.

1.5 Purpose of this report

SAPN and the SA Government have requested that AEMO provide advice on the amount of EUFR required in SA to adequately arrest the impacts of a range of significant multiple contingency events.

This work has a focus on assessing EUFR in periods with a high penetration of DPV, since this represents a significant change in the operating conditions of the UFLS scheme. AEMO has previously provided preliminary advice which outlined that UFLS load is reducing, and that AEMO was conducting further work to assess the power system risks[25].

Work will be ongoing beyond this report, as AEMO continues to assess the evolving power system and as new information and improved models become available. AEMO will continue to provide further advice as new evidence becomes available.

Table 3 summarises the scope of the studies included in this report.

Table 3 Scope of studies

	Scope of studies completed in this report
Region	South Australia
Years	2023 and 2025 Studies focus only on the period prior to commissioning of Project EnergyConnect (PEC) Stage 2 (a new interconnector that will increase transfer capacity between SA and New South Wales (NSW)), targeting commissioning in July 2026. PEC Stage 1 is expected to release up to 150 MW of transfer capacity between NSW and SA from July 2024[26] and is factored into the studies in this report. Further analysis will be required to assess EUFR targets in the period following full commissioning of PEC Stage 2, and is outside of the scope of this report.
Forecasts	Forecast half-hourly dispatch data was developed from a time-sequential model[27] used for the 2024 Draft Integrated System Plan (ISP) with network constraints and scenario assumptions from the 2022 and 2023 Electricity Statement of Opportunities (ESOO) *Step Change* forecast.
Contingency events	All studies consider separation of SA from the rest of the NEM, combined with a trip of generation (discussed in Section 2): • For studies in 2023, the separation occurs at the Heywood Interconnector (HIC), with flows based on dispatch scenarios • For studies in 2025, the separation occurs at HIC and also assumes simultaneous trip of PEC Stage 1, with flows on both HIC and PEC Stage 1 based on dispatch scenarios (more detail in Section 3.2.5).
Models	• Most dispatch scenarios were studied in a multi-mass model (MMM). • A selected case was benchmarked against a full network root mean square (RMS) representation (UFLS relays represented at individual transmission buses in PSS®E).
EUFR assumptions	Unless stated otherwise, studies assume: • In 2023: – No dynamic arming (reverse flow blocking) of UFLS relays. – 150 MW of BESS headroom. • In 2025: – Dynamic arming is fully enabled across SAPN's network.

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

[26] The capacity release and timing is conditional on availability of suitable market conditions and good test results.

[27] For more details on the time-sequential model refer to the ISP methodology: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

	Scope of studies completed in this report
	– 400 MW of BESS headroom.

1.6 Approach

The following approach has been applied:

1. **Define contingencies** – define a set of plausible significant multiple contingency events (Section 2).
2. **Quantify risks** – model the frequency outcomes of these significant multiple contingency events in a multi-mass model (MMM) across a wide range of possible power system conditions and dispatch scenarios (Section 4).
3. **Benchmarking against RMS model** – benchmark selected scenarios against a root mean square (RMS) model and confirm there are no confounding factors (Section 3.3.3).
4. **EUFR required in each case** – determine the amount of EUFR required for successful arrest of frequency in each case. For cases where frequency arrest fails (frequency nadir < 47.6Hz), iteratively increase the EUFR capacity in the model until the case passes (f > 47.6Hz) (Section 5).
5. **EUFR target as a function of system conditions** – determine a simple approach for defining the EUFR target as a function of system conditions, based on probabilistic outcomes of studies (Section 5.1).

2 Significant multiple contingency events

This section discusses the selection of suitable significant multiple contingency events to study, to assess EUFR adequacy in South Australia.

2.1 Historical events

Historical events provide a guide to what is plausible. Table 4 outlines several historical events that have led to UFLS activation. Some commonalities between these historical events are discussed below.

Table 4 Significant historical events that led to UFLS activation

Date	Description	High level summary
25 May 2021	Fire at Callide led to the loss of approximately 2,300 MW of generation in Central Queensland, leading to a trip of the Quieensland – New South Wales Interconnector (QNI)[28].	• QNI separation • Loss of 2,300 MW of generation at five stations
3 March 2017	A series of faults at Torrens Island switchyard resulted in the loss of approximately 610 MW of generation in SA[29].	• HIC separation • Loss of 610 MW of generation at two stations
28 September 2016	SA black system[30] caused by multiple line faults leading to the loss of 456 MW of generation at a number of wind farms, related to multiple fault ride-through settings. This led to a HIC trip.	• HIC separation • Loss of 456 MW of generation at nine stations

Loss of an interconnector resulting in an islanded region

All of the events listed in Table 4 involved a separation of a region from the rest of the NEM. Separation events usually result in the most severe frequency disturbance because the pre-contingent flows on the interconnector contribute to the contingency, and the separated region must rely on local inertia and frequency arrest mechanisms.

If there is no separation as part of the contingency, the full frequency reserves and inertia across the whole mainland NEM will be available to assist in arresting the frequency drop, typically resulting in a much less severe disturbance.

Similarly, when a region is already separated and operating as an island, any subsequent contingency is typically less onerous. When a region is already operating as an island, the contingency will not include the potentially large flows on the interconnector, and local contingency frequency control ancillary services (FCAS) is procured (increasing the local frequency response). The generation levels of units are also co-optimised with FCAS available, which may lead to the largest units being dispatched at reduced levels if limited FCAS is available.

[28] AEMO (October 2021) Trip of multiple generators and lines in Central Queensland and associated under-frequency load shedding on 25 May 2021, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf?la=en.

[29] AEMO (10 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.

[30] AEMO (March 2017) Black System South Australia 28 September 2016, https://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?la=en&hash=7C24C97478319A0F21F7B17F470DCA65.

It is therefore likely that the most onerous contingencies in SA will involve a separation from the rest of the NEM, and therefore the EUFR target in SA will be informed by separation events.

All contingencies considered for this analysis are separation events, since these are expected to be the most onerous, and will therefore likely define the EUFR target in a region.

Loss of multiple generating stations

As shown in the events listed in Table 4, historical events have seen loss of generation across multiple generating stations (in addition to a separation from the rest of the NEM). It seems reasonable to plan sufficient EUFR availability to manage similar contingencies to those observed in the past.

International system operators often consider loss of multiple generating stations as part of their planning studies for emergency frequency management. For example, NERC's transmission system planning performance requirements specify that the loss of two generating stations should not result in cascading failure[31].

The significant multiple contingency events studied in this report involve separation plus loss of generation at multiple generating stations, since events of this type have been observed, and it seems reasonable and prudent to plan sufficient EUFR availability to manage such scenarios if they occur again.

2.2 Contingencies involving DPV

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 5. The discussion below elaborates further on each, and how this informs the selection of significant multiple contingency events for study in this report.

[31] NERC, TPL-001-5 – Transmission System Planning Performance Requirements, https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

Table 5 Possible causes of a large DPV contingency

Possible reason for DPV trip	Mechanism	Example(s)	Associated with load shake-off?	Further discussion
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[32] – 40% of DPV in SA tripped in response to faults • Many other events documented[33]	Yes	Section 2.2.1
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[34].	• 25 August 2018 (separation of Queensland (QLD) and SA), 12-13% of DPV in NSW/Victoria (VIC) island estimated to disconnect in response to under-frequency	No	Section 2.2.2
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 original equipment manufacturer's (OEM's) products)	• 23 June 2022[35] – power system reactive power oscillations in SA 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 SA led to a system black event	No	Section 2.2.3
Other common mode of failure via internet connectivity	Many DER are now connected to the internet, or are exposed to other types of 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	Section 2.2.4

2.2.1 DPV shake-off in response to a deep transmission fault

AEMO has compiled considerable evidence of DPV disconnection in response to severe faults[36]. 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[37], but is improving over time[38]. 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 gigawatts (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.

[32] 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.

[33] 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.

[34] See Section A1.1.

[35] 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.

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

[37] 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.

[38] 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.

Severe events that result in high levels of DPV disconnection typically also result in load shake-off[39]. As noted above, load shake-off can have complex effects on frequency outcomes. Load shake-off will tend to offset the 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 MMM 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).

Since DPV shake-off in response to a deep fault is typically associated with load shake-off, and since load shake-off tends to improve frequency nadir outcomes, for these studies it has been assumed that DPV shake-off in response to a deep fault is unlikely to be the most onerous significant multiple contingency that drives EUFR targets, and therefore this has not been the focus of studies in this report. Load shake-off can sometimes result in overshoot and over-frequency scenarios, which could be studied further in future work.

2.2.2 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[40]. 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.

2.2.3 Type faults leading to a 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 original equipment manufacturer (OEM), or associated with a particular virtual power plant (VPP), for example. Possible mechanisms might include:

- Unexpected responses of devices during unusual power system conditions, with known examples including:

[39] 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.

[40] 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.

   - Power system oscillations causing the measurement systems in the inverter to malfunction, leading to unit tripping[41].
   - Unspecified settings in the inverters (such as multiple fault ride-through settings prior to these being specified in the relevant rules or standards).
- 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 EUFR should be available as a last resort mechanism, so that 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 its fleet, this could result in 21% of DPV in the NEM tripping in an erroneous response[42]. 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.

2.2.4 Other common modes of failure leading to a DPV trip

Internationally, there have been cases where critical infrastructure has been compromised via a common mode of failure, including:

- A cyber attack against Denmark's energy infrastructure via a common firewall vulnerability in 2023[43].
- A cyber attack on Ukraine SCADA systems via acquired legitimate credentials in 2015[44].
- Malware infection Stuxnet in 2010[45].

[41] For example, see Section 6.8 of the 2023 General Power System Risk Review (GPSRR), which explores the potential impact of simultaneous trip of DPV due to oscillations in South Australia: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr.pdf?la=en. This was based on observations on 23 June 2022, when voltage and power oscillations were originated from the Port Augusta Renewable Energy Park (PAREP) in South Australia during commissioning tests: 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.

[42] This issue was also noted in: 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

[43] SektorCERT (November 2023) The attack against Danish critical infrastructure, https://sektorcert.dk/wp-content/uploads/2023/11/SektorCERT-The-attack-against-Danish-critical-infrastructure-TLP-CLEAR.pdf.

[44] Electricity Information Sharing and Analysis Centre (March 2015) Analysis of the cyber attack on the Ukranian power grid, https://media.kasperskycontenthub.com/wp-content/uploads/sites/43/2016/05/20081514/E-ISAC_SANS_Ukraine_DUC_5.pdf.

Cybersecurity & Infrastructure Security Agency (July 2021) Cyber-Attack against Ukrainian critical infrastructure, https://www.cisa.gov/news-events/ics-alerts/ir-alert-h-16-056-01.

[45] IEEE (May 2011) Stuxnet: Dissecting a Cyberwarfare Weapon, https://ieeexplore.ieee.org/document/5772960.

- Physical terrorism attack at San Jose substation in 2013[46].

The Institute of Electrical and Electronics Engineers (IEEE) and NERC identify the increased risk of physical and cyber security threats in the evolving energy sector and recommend that transmission planners study the unique contingencies posed by cyber threats[47]. They recommend that transmission planners identify transmission elements that share a cyber/physical security or communications related common mode failure (like DER that share a common control system). Once these commonalities are identified, the transmission planner can develop contingencies that simulate an outage of elements connected via a security-based attack.

IEEE and NERC note a number of corrective action plans that can be used to mitigate the reliability risk of a power system due to such threats, including load shedding programs[48].

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[49]. 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 increases to 35%.

Based on this analysis, for these studies, contingencies involving 30-40% of the DPV fleet tripping in SA have been included. DPV tripping at approximately this level might originate from either a type fault associated with 2-3 OEMs, or some other common mode of failure.

2.3 Proposed significant multiple contingency events

Table 6 summarises the significant multiple contingencies considered when assessing EUFR adequacy in SA (as per NER 4.3.1(k)(2)). These were selected to represent a range of different types of significant but plausible events.

All contingency types involve a synchronous separation of SA. When these contingencies are modelled in 2023, this involves a trip of HIC. When these contingencies are modelled in 2025, this involves a simultaneous trip of HIC and Project EnergyConnect (PEC) Stage 1. Section 3.2.5 further discusses these separation types.

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46 The Mercury News (August 2014) PG&E substation in San Jose that suffered a sniper attack has a new security breach, https://www.mercurynews.com/2014/08/27/pge-substation-in-san-jose-that-suffered-a-sniper-attack-has-a-new-security-breach/.

47 IEEE and NERC (December 2022) Towards Integrating Cyber and Physical Security for a More Reliable, Resilient, and Secure Energy Sector; NERC (May 2023) Cyber-informed transmission planning, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERO_Enterprise_Whitepaper_Cyber_Planning_2023.pdf.

48 At https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERO_Enterprise_Whitepaper_Cyber_Planning_2023.pdf.

49 Assuming DPV will grow linearly to 2027 according to the *Step Change* scenario in AEMO's 2023 Input, Assumptions and Scenarios workbook. The estimation does not consider the replacement of old inverters with new inverters.

The first two contingency types represent more "traditional" events, involving a separation and loss of centralised generation. The other two contingencies are more novel, featuring a trip of a large proportion of the DPV operating in the region, with the third contingency type involving DPV trip in combination with loss of centralised generation. As noted above, the trip of DPV can interact with UFLS functionality in important ways, and the trip of DPV may be the most significant contingency event in low demand periods, so these more novel contingency events may represent the most significant determinant of the EUFR target in low demand periods.

The contingencies modelled feature a one second time delay between each element tripping, as shown in Table 6. This slows the RoCoF to within the range where UFLS can function successfully to arrest frequency, and therefore provides a more useful indicator of EUFR adequacy. Without these time delays, these contingency events become unmanageable by conventional UFLS in many periods due to extreme RoCoF. Managing extreme RoCoF would require solutions beyond increasing EUFR availability and is beyond the scope of this report. Implementing a one second delay means fewer of the modelled contingencies are excluded from the study set based on extreme RoCoF conditions, and therefore represents the most onerous plausible contingency that might require larger amounts of EUFR.

Table 6 Proposed significant multiple contingency events

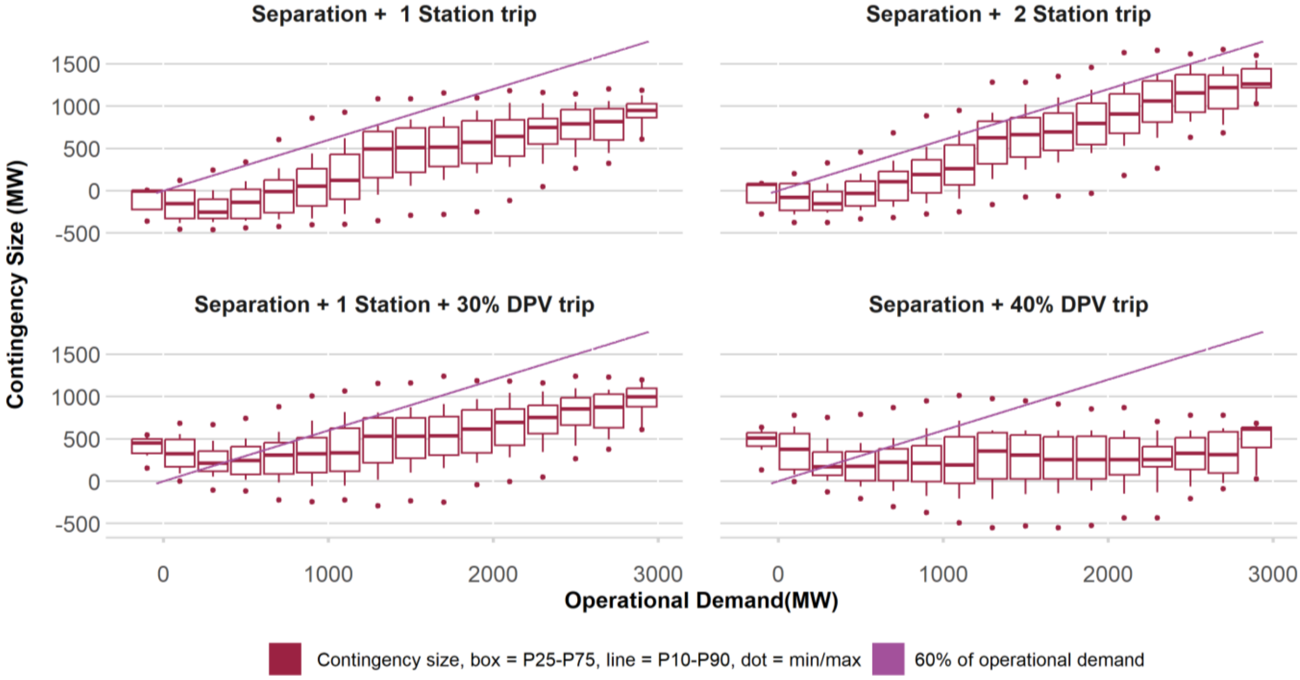
Contingency description	Sequence of trips during modelling simulation		
	t = 0.1s	t = 1s	t = 2s
Separation + 1 station trip	Synchronous separation of SA	The largest generating station trips	
Separation + 2 station trip	Synchronous separation of SA	The largest generating station trips	The second largest generating station trips
Separation + 1 station + 30% DPV trip	Synchronous separation of SA	The largest generating station trips	30% of DPV trips
Separation + 40% DPV trip	Synchronous separation of SA	40% of DPV trips	

Figure 4 illustrates the contingency sizes for these four contingency types as a function of operational demand. The box and whisker plots show for each range of operational demand the average contingency size in the centre, 25^{th} and 75^{th} percentiles at the edges of the box, 10^{th} and 90^{th} percentiles at the ends of the whiskers, and max/min outliers with dots.

For the "conventional" contingencies (separation + 1 station trip, separation + 2 station trip), the contingency size scales closely with operational demand. At low levels of operational demand in SA, imports on the interconnector are generally lower, and centralized units are generally dispatched at lower levels, leading to smaller contingency sizes. This is captured in the dispatch forecasts applied for these studies.

As per NER 4.3.1(k), AEMO is responsible for assessing the availability and adequacy of reserves to ensure they are appropriate to arrest the impacts of a range of significant multiple contingency events affecting up to 60% of the total power system load. As a guide to the eye, Figure 4 includes a purple line indicating the contingency size that would be indicated by 60% of operational demand. This trends towards zero when operational demand trends towards zero, and exceeds 1,500 MW in periods with high levels of operational demand. The top two contingency types provide a reasonable spread of contingencies at all levels of operational demand, below and up to this level, indicating they are suitable for testing EUFR adequacy as per this NER requirement.

Figure 4 Contingency sizes (2023 half-hourly dispatch forecast)



Notes:

- Based on half-hourly dispatch patterns developed from time-sequential model used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO *Step Change* forecast for 2023, with short run marginal cost (SRMC) bidding and minimum requirement for one synchronous unit online in SA.
- For some cases the total contingency size is negative during low demand periods when the interconnector(s) are exporting from SA. The contingency size of the separation while exporting is larger than the contingency size of the subsequent generation tripping, resulting in a net negative trip.

The bottom two panels in Figure 4 show the contingency sizes associated with the trip of DPV. For these more novel contingencies that include DPV trip, the contingency size does not scale closely with operational demand (the 60% line is a poor indicator of plausible contingency sizes). For these contingency types, the contingency size is more similar across the operational demand range, because in low operational demand periods, the amount of DPV generating is generally higher, leading to larger contingency sizes.

All four types of contingencies were simulated in each half-hour period, to assess EUFR adequacy for managing any of these four contingencies.

3 Modelling approach

3.1 Modelling overview

The following approach was applied to assessing the adequacy of EUFR and developing a proposed EUFR target in SA:

1. A multi-mass model (MMM) was developed to represent the frequency response of SA following significant multiple contingency events, incorporating the behaviour and interactions between load shake-off, DPV tripping, UFLS actions and BESS frequency responses.
2. The MMM was validated against an RMS model snapshot (in PSS®E), including a full representation of the transmission network, the locations of UFLS relays, and DPV and load mapped to each transmission bus. It was confirmed that measurements of voltage and frequency at the generator terminals for significant units remained within ranges where no tripping or other control interactions are likely. This indicates that the MMM likely provides a satisfactory representation of the relevant factors.
3. The MMM was used to simulate frequency outcomes for each of the four contingency events considered, in each half-hour period for 2023 and 2025 (based on forecasts from the time-sequential model[50]).
4. Frequency outcomes were assessed to determine whether the EUFR availability was sufficient to arrest frequency, based on the acceptance criteria in Table 7 below.
5. Cases with RoCoF exceeding 3 Hz/s were excluded from further consideration, since increasing the capacity of EUFR is unlikely to successfully arrest frequency in these cases.
6. For cases where the frequency nadir fell below 47.6 Hz (fail cases), the EUFR was iteratively increased (by increasing BESS headroom) until the case satisfactorily achieved a frequency nadir above 47.6 Hz.
7. The amount of EUFR (frequency response) used in each case for satisfactorily managing each contingency type was calculated based on the sum of the amount of UFLS tripped and the amount of BESS response.
8. Trends in the amount of EUFR required in each period for managing all four contingency types were analysed to determine a function for estimating the EUFR target, based on system conditions.

The sections below provide further detail.

3.1.1 Acceptance criteria

The acceptance criteria applied in these studies are summarised in Table 7.

[50] The time-sequential model used by the 2024 Draft ISP was used. For more details on the time-sequential model refer to the ISP methodology: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

Table 7 Acceptance criteria

	Frequency nadir	Likely outcomes
Fail (RoCoF > 3 Hz/s)	RoCoF > 3 Hz/s over 300 milliseconds (ms)	EUFR is unlikely to successfully arrest the frequency decline for these cases[51].
Fail	< 47.6 Hz	Cascading failure to a black system is considered likely. Setting the threshold at 47.6 Hz allows a buffer of 0.6 Hz over the requirement in the FOS, to account for modelling uncertainty.
Pass, but at risk	47.6 – 48 Hz	These cases are highlighted as severe events with frequency far outside normal ranges, with some risk of cascading failure (for example, due to factors not represented in these models).
Pass	> 48 Hz	For these cases, there is reasonable confidence that the power system will survive the separation.
	> 49 Hz	No UFLS activation (but will utilise EUFR from BESS).
	> 49.75 Hz	Remains in normal operating frequency excursion band.

3.2 Assumptions

3.2.1 Dispatch scenarios

Dispatch scenarios for each half-hour in 2023 and 2025 were sourced from a time-sequential model[52] used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 ESOO and 2023 ESOO. These scenarios provided plausible and internally-consistent assumptions in each half-hour period on the output of the largest generating stations, the total inertia online, total DPV generation, and the total operational and underlying demand.

3.2.2 UFLS load and DPV

The underlying demand and total DPV behind each UFLS frequency block in South Australia was estimated as a percentage of total regional values. Historical UFLS data provided by SAPN was used to develop a regression that was then applied to forecast data from the time-sequential model. Transmission-connected UFLS load was assumed to be unchanged from a half-hourly profile was taken from a reference year.

3.2.3 Minimum synchronous unit requirements

In both the 2023 and 2025 calendar years, there was assumed to be a minimum requirement for at least one synchronous generator online in SA. Following commissioning of the four ElectraNet synchronous condensers, there is an ongoing program of work to assess the minimum synchronous unit requirements in SA.

3.2.4 BESS headroom

BESS dispatch levels have a significant influence on study results, since this affects the amount of headroom they have available for fast frequency response. Predicting the dispatch of BESS in each half-hour period is challenging, since it is affected by co-optimised participation in frequency control markets as well as energy

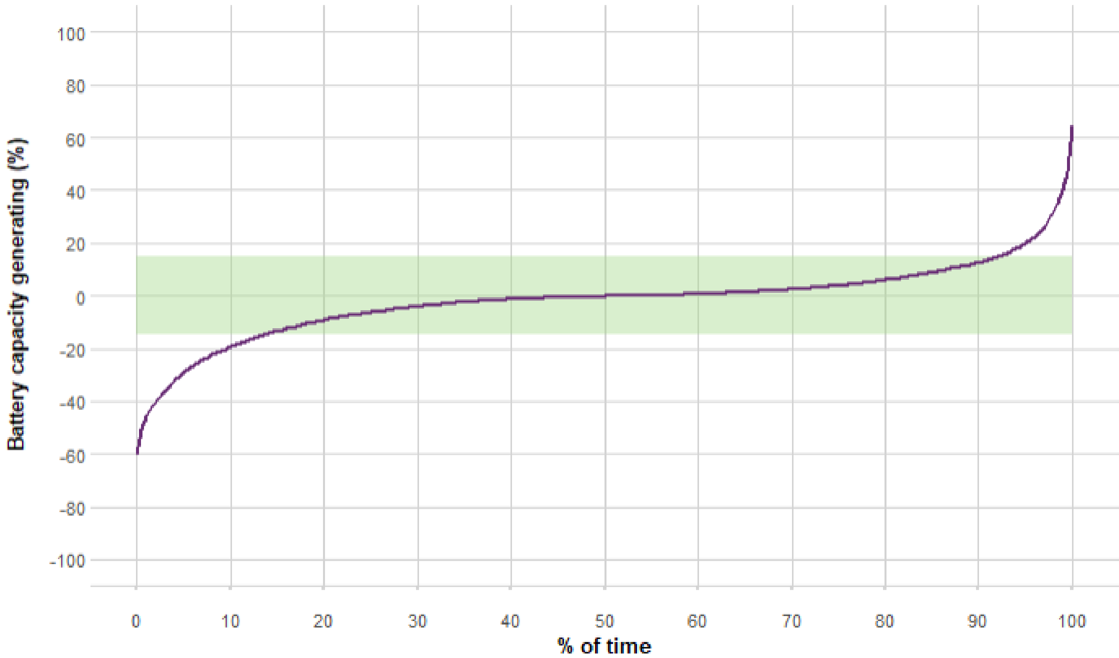
[51] AEMO (December 2022) AEMO Advice: Reliability Panel Review of Frequency Operating Standard, Section 3.2, https://www.aemc.gov.au/sites/default/files/2022-12/AEMO%20FOS%20advice%20to%20the%20Reliability%20Panel%20FINAL%20for%20Publishing%20221205.pdf.

[52] For more details on the time-sequential model refer to the ISP methodology: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

markets, and also affected by managing stored energy levels (both of which are difficult to model in a simple merit-order dispatch model)[53].

Figure 5 shows the distribution of dispatch levels for the combined capacity of the Hornsdale (150 MW) and Lake Bonney (25 MW) BESS in South Australia in 2022-23. In this year, these BESS had at least 150 MW of headroom (~85% of total capacity) 92% of the time. This suggests they are often dispatched at levels that allow the majority of their headroom to remain available most of the time for frequency response.

Figure 5 Dispatch of Hornsdale and Lake Bonney batteries (2022-23)



In late 2023, AGL commissioned a 250 MW BESS at Torrens Island. This increases the total capacity of scheduled BESS in South Australia delivering conventional fast frequency response to 425 MW, and has a significant influence on frequency outcomes in SA. A new BESS was also recently commissioned at Tailem Bend, and will similarly increase fast frequency response availability in South Australia.

For the studies in this report, it was assumed the combined BESS in SA have the following available:

- For 2023: 150 MW of headroom and 120 MW of footroom.
- For 2025: 400 MW of headroom and 370 MW of footroom.

The studies in this report involved iteratively increasing BESS headroom in each half-hour interval to determine the amount of EUFR required to successfully arrest frequency. This means that the baseline assumption for the BESS headroom available only constitutes a starting point for studies and should not significantly affect the recommendations of this report.

[53] AEMO (December 2023) Draft 2024 Integrated System Plan Appendix 4. System Operability, Page 30, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/appendices/a4-system-operability.pdf?la=en.

3.2.5 Project EnergyConnect Stage 1

The separation events studied in this report represent a synchronous separation of SA from the rest of the NEM. In 2023 this involves a separation at the Heywood Interconnector (HIC). Murraylink (a DC link) is assumed to remain connected and continue flows at the pre-separation levels (based on the relevant dispatch scenario).

PEC Stage 1 is projected to release its initial transfer capacity of up to 150 MW between New South Wales (NSW) and SA in July 2024[54]. For these studies, dispatch scenarios from a time-sequential model[55] which takes network constraints and scenario assumptions from the 2022 and 2023 ESOOs were applied. For the purpose of this study, it was assumed the combined transfer capacity of HIC and PEC Stage 1 into SA was increased by 100 MW when PEC Stage 1 is introduced.

A control scheme will be designed to inter-trip PEC Stage 1 if there is a separation at HIC[56]. To represent this inter-trip scheme, for studies in 2025, when the separation at HIC occurs, PEC Stage 1 was assumed to trip simultaneously, such that the total loss of flows is the combined levels across HIC and PEC Stage 1.

3.3 Multi-mass model (MMM)

The MMM was used to simulate the frequency containment response over a 15-second period in South Australia immediately following each contingency. Each of the four contingency types outlined in Section 2.3 was simulated in each half-hour dispatch period for each of the 2023 and 2025 forecast years.

The MMM representation of the SA power system applied for these studies was developed in Matlab Simulink, and includes:

- **Synchronous generator governor models** – aligned with mandatory Primary Frequency Response (PFR) requirements. The maximum frequency response from each unit was estimated based on FCAS maximum registered quantities and trapeziums (used as a proxy to represent the frequency capabilities and limitations of each unit).
- **Semi-scheduled IBR** – batteries were assumed to provide fast frequency response (FFR) with a 1.7% droop, a ±0.015 Hz deadband and responding with a 150 milliseconds (ms) delay[57]. A proportion of semi-scheduled wind and solar plant was also assumed to have an over-frequency droop response.

Further details on the modelling assumptions are summarised in AEMO's report *Separation leading to under-frequency in South Australia* [58], where an iteration of the same MMM was used.

[54] The capacity release and timing is conditional on availability of suitable market conditions and good test results.

[55] The time-sequential model used by the 2024 Draft ISP was used with underlying network constraints and scenario assumptions from the 2022 and 2023 ESOOs. For more details on the time-sequential model refer to the ISP methodology: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[56] Project EnergyConnect (December 2023) Industry Update – System Integration, https://www.projectenergyconnect.com.au/download.php?id=20.

[57] No sensitivities were performed on the level of droop on BESS for this analysis. This analysis does not explicitly model any new BESS beyond the AGL Torrens Island BESS, so if a different droop setting were applied to any subsequent new BESS, this would not affect the findings of this report.

[58] Full assumptions outlined in AEMO (May 2023) Separation leading to under-frequency in South Australia, Appendix A1, Table 46, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645.

3.3.1 Rate of change of frequency (RoCoF) > 3Hz/s

The Frequency Operating Standard was updated in October 2023, and now requires that AEMO use reasonable endeavours to maintain RoCoF within ±3 Hz/s (measured over any 300 ms period) following a multiple contingency event[59]. UFLS may not successfully arrest the frequency decline if RoCoF exceeds ±3 Hz/s[60]. 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 47Hz, and
- Due to time lags, there can be excessive load tripping followed by frequency overshoot.

For these reasons, cases with RoCoF exceeding ±3 Hz/s have been excluded from the evaluation of the EUFR target in South Australia[61]. Increasing the capacity of EUFR available is unlikely to adequately address risks in these cases. The proportion of cases where this occurs is noted. Addressing the risks associated with these cases is out of scope of the analysis in this report.

3.3.2 Calculating the EUFR required

For cases where the minimum frequency reached is below 47.6 Hz, the model runs an optimisation process to calculate how much EUFR would be required to arrest frequency in these cases. The model does this by incrementally adding extra BESS headroom until the minimum frequency is contained just above 47.6 Hz.

The EUFR required to arrest the frequency for each of the four contingency types modelled is then calculated in each half hour period as:

$$\text{EUFR required} = \text{Total BESS headroom utilised} + \text{ Total net UFLS load tripped} + \text{Total synchronous PFR}$$

3.3.3 Model validation in an RMS model

A study was conducted using an RMS model in PSS®E to benchmark the MMM and ensure no confounding factors. The RMS model incorporates the following features:

- Full transmission network representation of the NEM.
- DPV and composite load (CMLD) models to represent the aggregate behaviour of DPV and composite load during NEM power system disturbances. The CMLD also includes an inherent representation of load relief in response to frequency due to motor components in the model[62].

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

60 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

61 The dispatch patterns used for this analysis include application of constraints implemented under South Australian Government Regulation 88A, which require limiting RoCoF in South Australia in relation to the non-credible coincident trip of both circuits of the Heywood Interconnector to below 3Hz/s. The analysis in this report investigates more onerous contingencies that involve an additional trip of generation in South Australia, which can lead to RoCoF exceeding 3Hz/s. (https://www.legislation.sa.gov.au/__legislation/lz/c/r/electricity%20(general)%20regulations%202012/current/2012.199.auth.pdf)

62 AEMO (June 2023) Review of NEM load relief, https://aemo.com.au/-/media/files/initiatives/der/2023/2023-05-31-load-relief-fact-sheet-update.pdf?la=en

- Synchronous generator governor models. The droop response was removed in both the MMM and RMS models to represent a plausible worst-case scenario.
- UFLS protection relay models were applied to ~78% of the load in the SA region, in line with SAPN and transmission-connected UFLS datasets. The models did not include dynamic arming, reflecting this assumption in the MMM cases used for benchmarking.

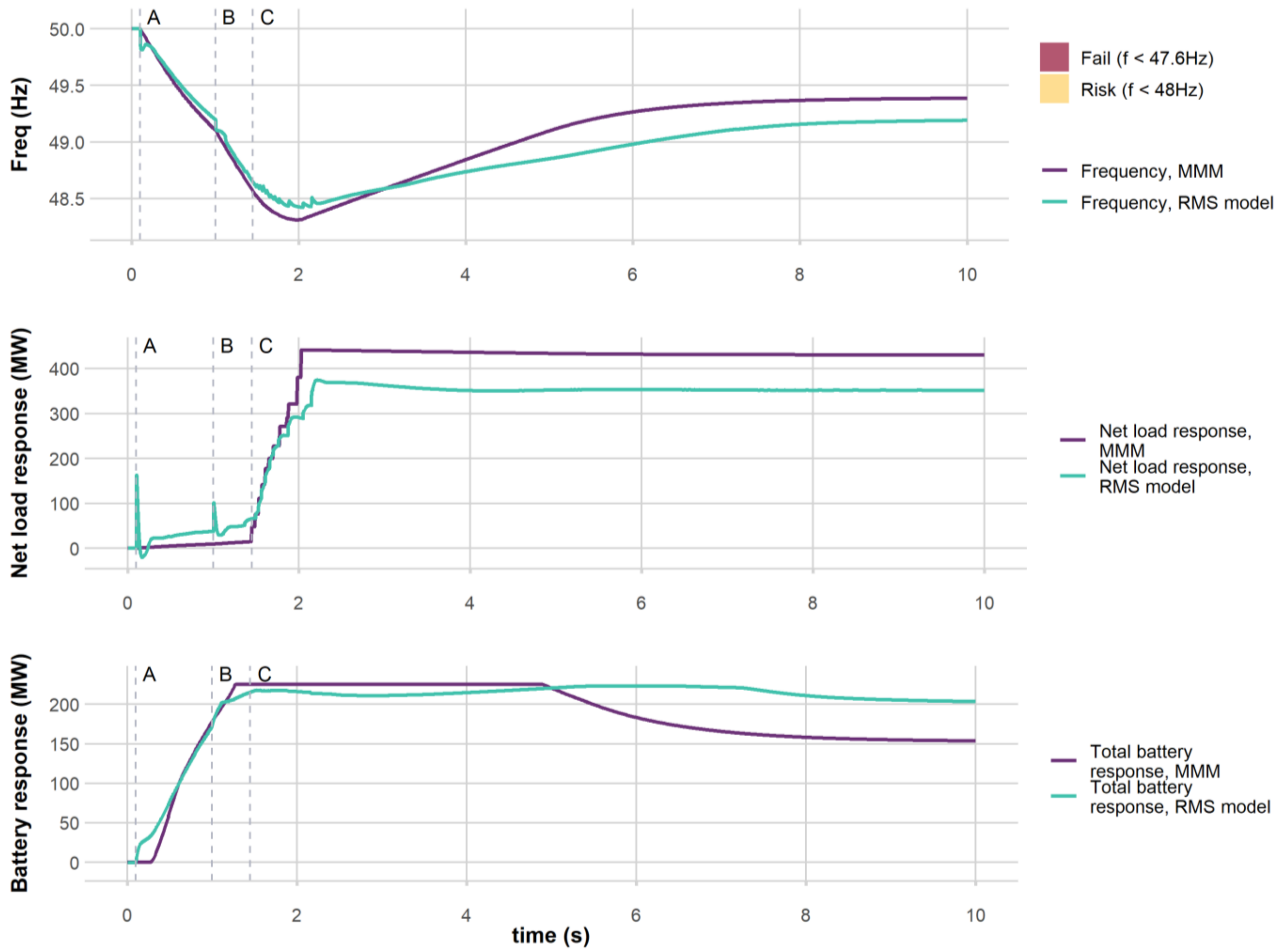
Key input conditions were aligned between the MMM and RMS models, including the underlying load and expected load relief, DPV output, the amount of load and DPV behind each UFLS frequency band, the amount of synchronous generation and inertia online, battery headroom and footroom, flows on HIC and flows on Murraylink. A case with no DPV generation was selected for this benchmarking exercise, since the DPV models in both the MMM and the RMS model are well understood and designed to show identical behaviours. The intention of the benchmarking exercise is to confirm no other confounding factors in the rest of the power system models, which is most simply achieved in a case with no additional DPV dynamics.

An identical contingency (separation + trip of largest generating station) was then modelled in both the MMM and RMS model. Figure 6 illustrates the frequency outcomes of both models, showing good alignment.

The RMS model shows a small amount of additional load reduction compared with the MMM, attributed to the voltage response of the CMLD load model (there is a small reduction in the network voltage seen across the SA region immediately following the contingency). This load voltage response results in a reduction of 1.35% of underlying load, equivalent to 19 MW. This is not accounted for in the MMM, but is sufficiently small that it does not affect the recommendations of this report.

Figure 6 Separation + 1 station trip

Condition	Operational Demand (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)	Generating Station trip size (MW)	Battery headroom (MW)	Load relief at frequency nadir (% of underlying load)
Historical snapshot, 14 November 2023 01:00	1,386 MW	8,980 MW	0 MW	440 MW	91 MW	143 MW	225 MW[63]	1.25%[64]



	Time	Description
A	0.1 s	HIC trips (South Australia synchronously separated from the rest of the NEM) while importing 440 MW. Frequency begins to decline. The battery responds according to its frequency droop settings.
B	1 s	The largest generating station trips (143 MW). In this scenario this is one Pelican Point Power Station unit. This accelerates the frequency decline. Frequency reaches 49 Hz, the battery reaches maximum output and cannot provide any further response beyond this level.
C	1.4 s	UFLS bands begin to trip in both the MMM and RMS model and frequency is contained.

[63] Although the simplified MMM assumed 150 MW of battery headroom available in 2023, the RMS snapshot selected included 225 MW of battery headroom that responds to under-frequency. This has been reflected in the MMM case as well, so that a like-for-like case can be compared between the two models.

[64] For most studies in this report, 0% load relief was assumed. Since the CMLD does inherently include some load relief related to motor components, this was included in the MMM for this benchmarking study only to confirm alignment of other factors.

Review of network conditions in the RMS model

Relevant protection settings of large generators and synchronous condensers in SA[65] were compared against the conditions observed in the RMS model cases following the contingency. The protection settings considered included the overexcitation, overvoltage, and undervoltage settings. It was found that following the contingency, network conditions stayed within the protection settings ranges. This indicates that the MMM sufficiently captures the relevant power system dynamics.

3.3.4 DER behaviours considered in the MMM

There are several different DPV behaviours and interactions modelled in the MMM, summarised in Table 8.

Table 8 DPV behaviours & UFLS interactions included in the MMM

Behaviour	Description	Representation in model	Impacts on outcomes
DPV reduces net UFLS load	DPV generation reduces the net load on UFLS bands	A regression was developed based on historical data in 2021 to estimate the net load on each UFLS frequency band, as a function of regional operational demand.	Reduced net UFLS load reduces effectiveness at arresting frequency decline.
Dynamic arming	Dynamic arming acts to disable trip settings of UFLS relays if that feeder is in reverse flows.	A regression was developed based on historical data to estimate net load on each UFLS frequency band with dynamic arming enabled.	Increases net load on UFLS bands in periods with high DPV generation. If there is a DPV contingency some relays may no longer be in reverse flows, but it is assumed the relays will not re-arm within the modelled period.
DPV trip as part of defined initial contingency	Trip of a proportion of DPV as part of the initial contingency event due to a DER type fault, or other common mode of failure.	Two of the four defined contingencies used to assess the EUFR target involve a trip of a proportion of DPV in the initial contingency, as described in Section 2.2.	DPV disconnection: • Causes an initial supply-demand imbalance, • Increases the net load on UFLS frequency bands, thereby increasing the EUFR capacity to arrest frequency, and • Reduces the total DPV online, decreasing the effects of subsequent DPV disconnection due to frequency. These effects are accounted for in the MMM.
DPV trip in response to frequency	Inherent over- and under-frequency trip settings of DPV inverters.	The model includes 14 frequency trip bands where DPV will disconnect, the largest at 49 Hz where up to 14% of legacy DPV can disconnect[66].	A DPV trip will typically worsen outcomes during an under-frequency event by worsening the generation and load imbalance. DPV disconnection also re-exposes UFLS load which can then help to improve the effectiveness of subsequent UFLS block trips. These effects are accounted for in the MMM.

[65] Units considered included Torrens Island B, Pelican Point, Osborne, Barker Inlet, Dry Creek, Quarantine, Snapper Point, Hallett, Robertstown synchronous condenser and Davenport synchronous condenser.

[66] See Section A1.1.

Appendix A1 contains further elaboration and case studies illustrating these behaviours.

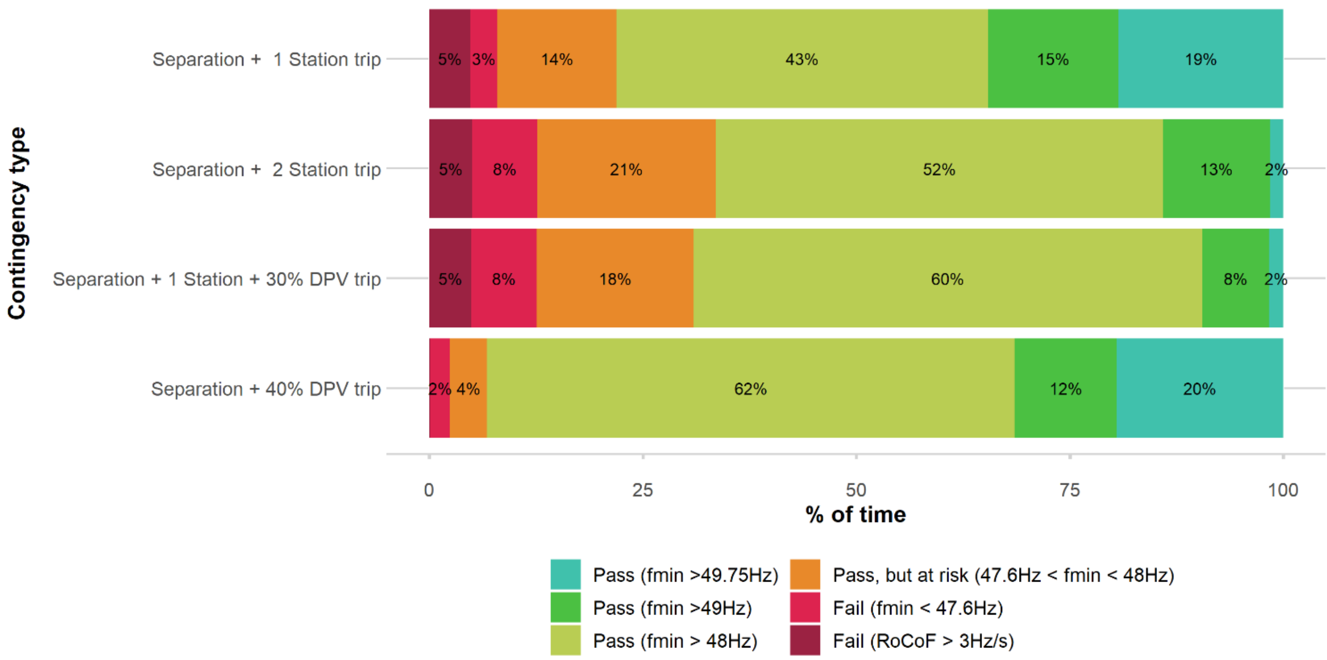
As discussed in Section 2.2.1, DPV “shake-off” can also occur in response to a severe voltage dip. This is usually also associated with load shake-off, which tends to make these contingency events less onerous (confirmed in sensitivity studies), so these types of contingency events have not been studied in this report.

4 Quantifying risks

4.1 Risks in 2023

Figure 7 shows the distribution of frequency outcomes for 2023, modelling each of the four contingency events in each half-hour period. For all four contingencies, more than 70% of cases arrest frequency above 48 Hz, and more than 90% of cases arrest frequency above 47.6Hz. For the cases that "fail" (likely to lead to cascading failure), roughly half of these are related to RoCoF exceeding 3 Hz/s. Risks are generally lowest associated with the contingency involving a separation + 40% DPV trip.

Figure 7 2023: Frequency outcomes following significant multiple-contingency events – no dynamic arming

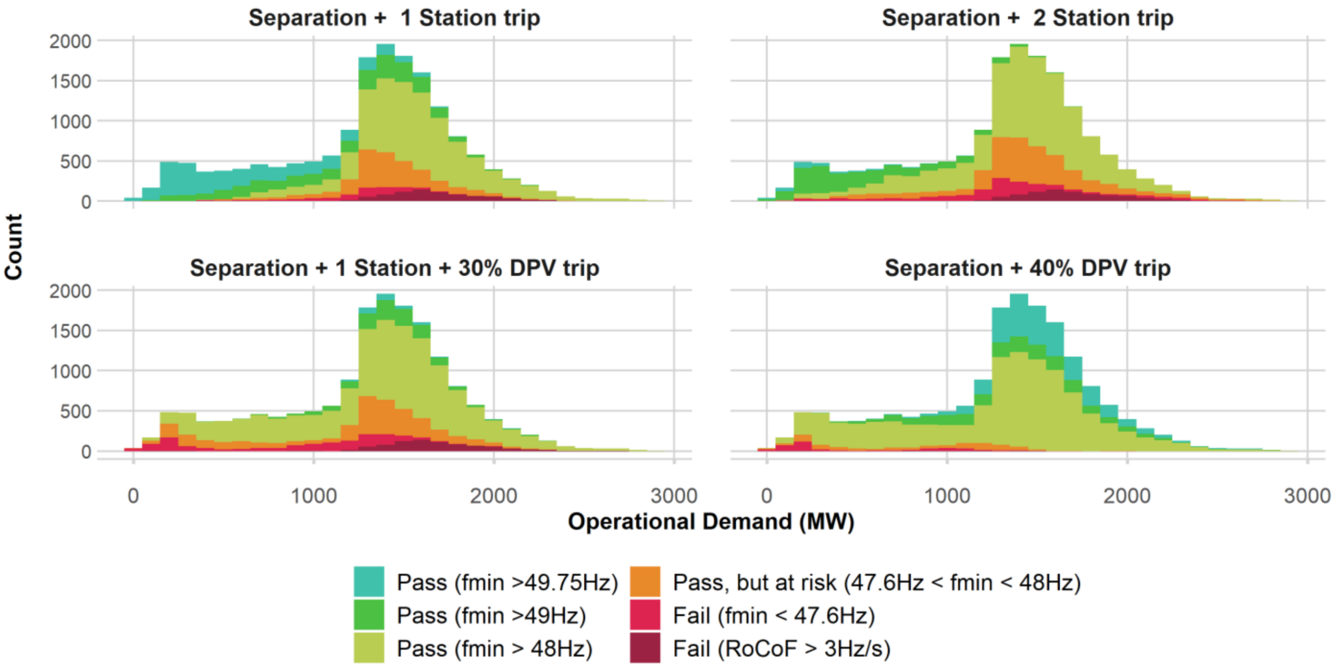


Note: key assumptions were 150 MW BESS headroom, UFLS dynamic arming not implemented, minimum of one synchronous unit online, based on half-hourly dispatch patterns developed from the time-sequential model used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO *Step Change* forecast data.

Figure 8 shows the distribution of frequency outcomes for 2023 at different demand ranges. The modelling assumptions mean there are a larger number of cases in the demand range between 1,000 MW and 2,000 MW (representing more typical operational demand conditions in SA), hence why a larger count of cases is seen in this demand range. Observations include:

- For the "traditional" contingency types involving station trips (top panels), fail scenarios are most often observed during moderate to high demand conditions (> 1,200 MW).
- For contingencies involving a DPV trip (bottom panels), risks can also arise during extreme low demand periods.

Figure 8 2023: Frequency outcomes following significant multiple-contingency events distributed by operational demand – no dynamic arming

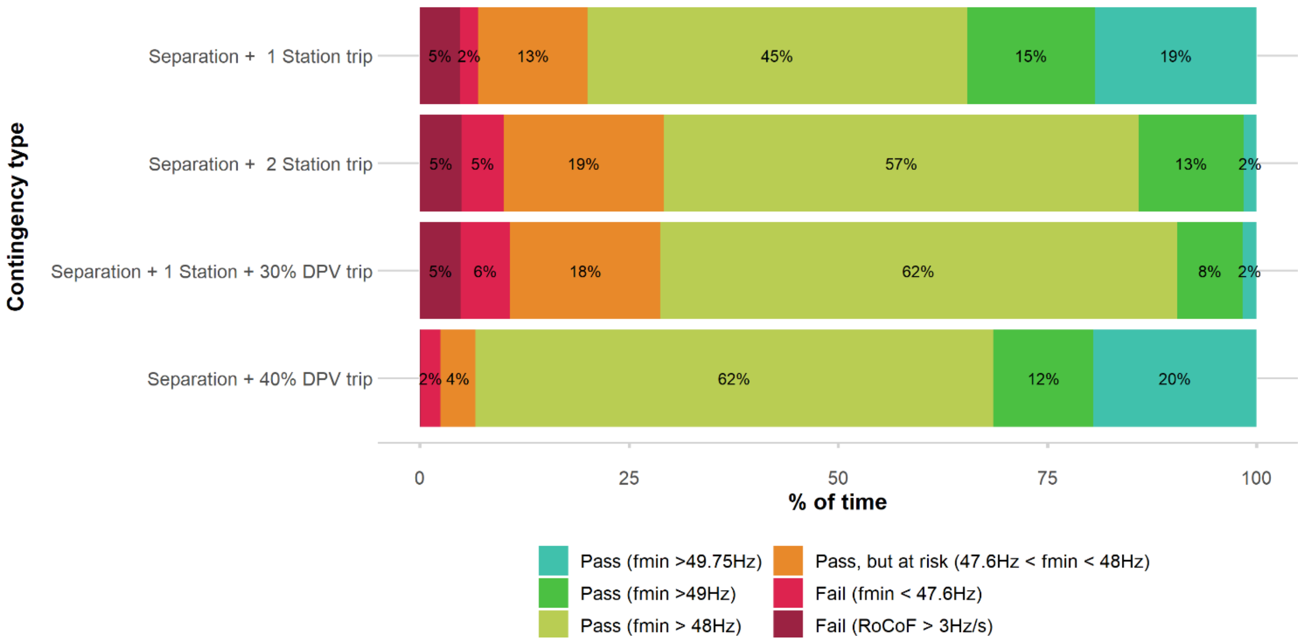


4.1.1 Influence of UFLS dynamic arming

Dynamic arming is in the process of being rolled out in South Australia, and is expected to be complete in September 2024.

Figure 9 provides a counterfactual sensitivity with dynamic arming fully enabled in South Australia in 2023, to estimate the reduction in risk associated with dynamic arming when it is complete. With dynamic arming, the estimated proportion of cases failing the acceptance criteria (f < 47.6 Hz) reduces from 5.2 % to 3.9 %.

Figure 9 Sensitivity: 2023 frequency outcomes following significant multiple-contingency events – with dynamic arming



Note: key assumptions were 150 MW BESS headroom, UFLS dynamic arming implemented, minimum of one synchronous unit online, based on half-hourly dispatch patterns developed from the time-sequential model used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO *Step Change* forecast data.

Appendix A3 provides the details of a cost-benefit assessment of UFLS dynamic arming in South Australia, indicating it has a net positive or neutral benefit in all scenarios considered.

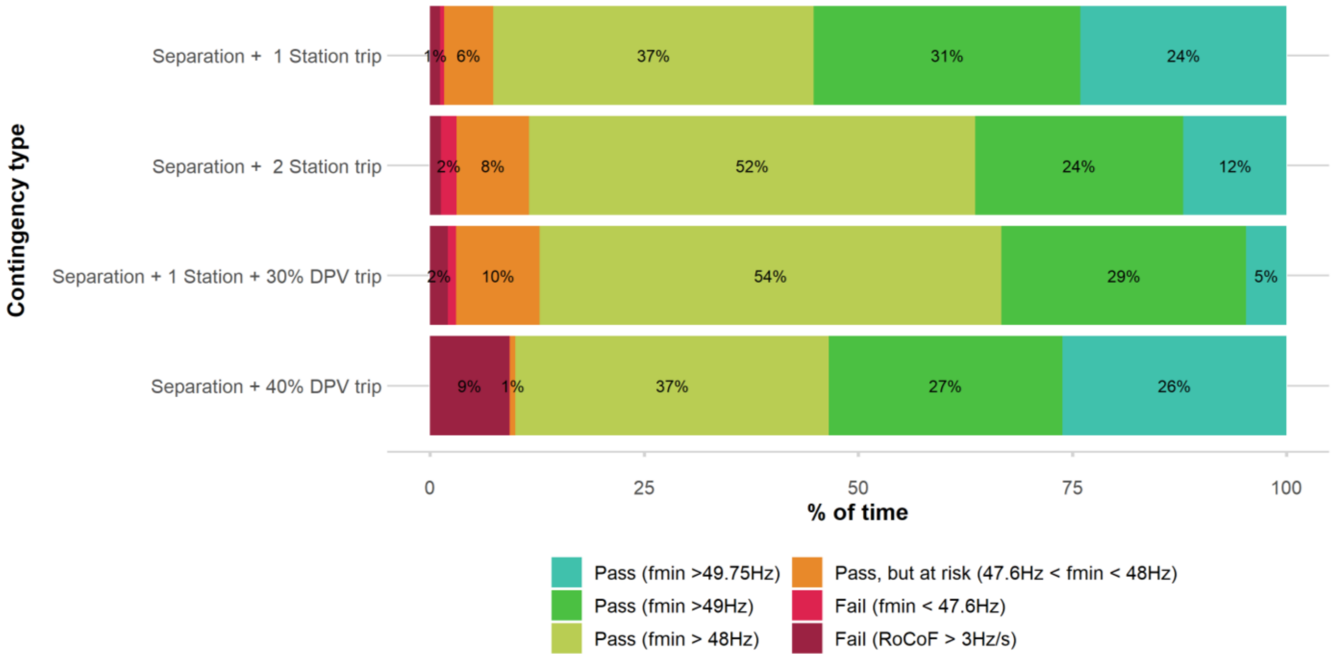
4.2 Risks in 2025

DPV levels are continuing to grow in SA. By 2025, it is projected that maximum DPV generation levels could grow by a further 270 MW. Scenarios for 2025 were considered, to investigate how EUFR adequacy is likely to evolve over time, as shown in Figure 10.

In 2025, for all four contingencies, it is projected that more than 85% of cases arrest frequency above 48 Hz, and more than 90% of cases arrest frequency above 47.6 Hz.

In this future projection, risks are now highest associated with the contingency involving a separation + 40% DPV trip, due to growth in DPV generation. Most of the fail cases for this contingency are associated with RoCoF > 3 Hz/s (the initial contingency is so large that EUFR has a low potential to prevent cascading failure).

Figure 10 2025: Frequency outcomes following significant multiple-contingency events



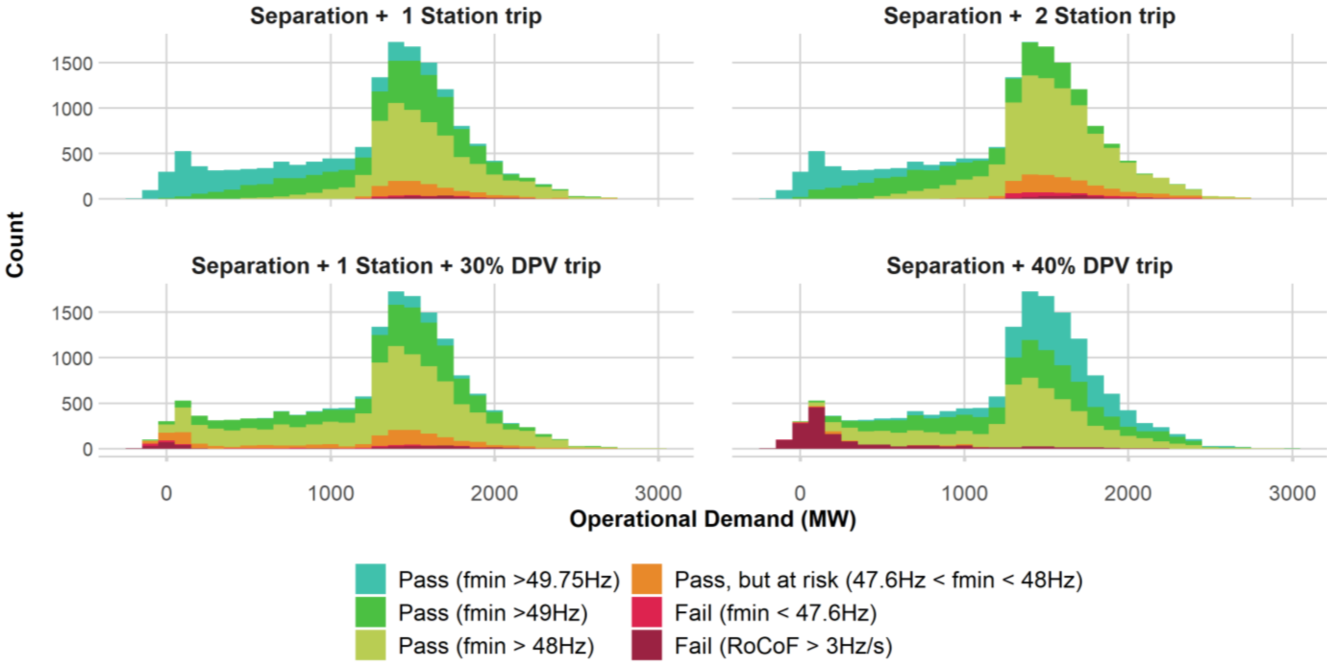
Note: key assumptions were 400 MW BESS headroom, UFLS dynamic arming implemented, minimum of one synchronous unit online, based on half-hourly dispatch patterns developed from the time-sequential model used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO Step Change forecast data, and PEC Stage 1 complete, increasing the transfer capacity into South Australia.

Figure 11 shows the distribution of frequency outcomes for 2025 at different demand ranges. As for 2023, the traditional station trip contingencies (top panels) show risks mostly during moderate to high demand conditions (>1,200 MW), while the contingencies involving a DPV trip show higher risks of failure in extreme low demand conditions (< 300 MW).

For the contingency that involves a separation + 40% DPV trip, there is an increased risk of failure due to high RoCoF (> 3 Hz/s) during these extreme low demand periods in comparison to 2023. This is because:

- The contingency size of the 40% DPV trip is on average larger due to the growing capacity of DPV between 2023 and 2025.
- There is less inertia during these periods due to the increased generation of wind and of distributed and utility-scale solar.
- Changes in system conditions means that the interconnector flows are on average importing more into SA in 2025 during these low demand periods, which can contribute to a higher RoCoF condition following a separation and a DPV trip.

Figure 11 2025: Frequency outcomes following significant multiple-contingency events

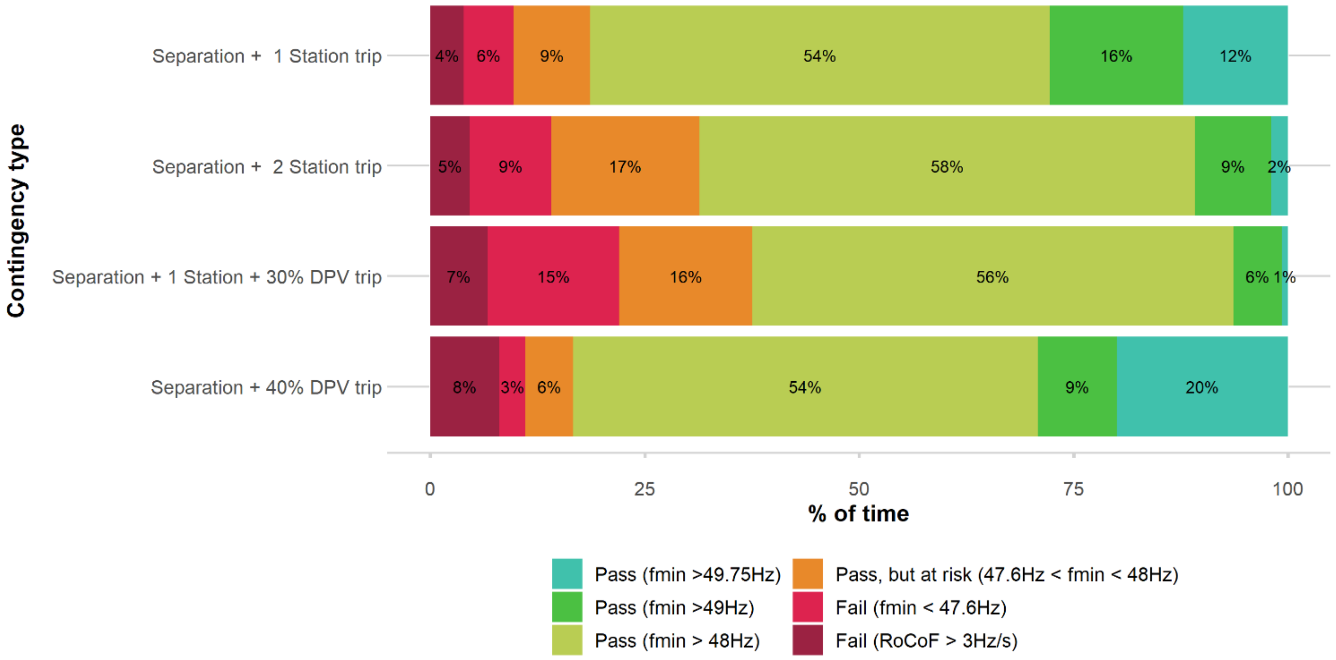


In general, these results indicate a reduction in risk from 2023 to 2025. This is mainly associated with the increase in battery headroom in 2025 (assumed to increase from 150 MW in 2023 to 400 MW in 2025, based on the Torrens Island 250 MW battery recently commissioned in South Australia).

4.2.1 Influence of BESS headroom

Figure 12 shows the frequency outcomes for a sensitivity projecting 2025, but with only 150 MW of headroom. By comparison with Figure 10, risks are much higher, indicating the substantial influence of the change in BESS headroom.

Figure 12 Sensitivity: 2025 Frequency outcomes with 150 MW of battery headroom



Note: key assumptions were 150 MW BESS headroom, UFLS dynamic arming implemented, minimum of one synchronous unit online, based on half-hourly dispatch patterns developed from the time-sequential model used by the 2024 Draft ISP with network constraints and scenario assumptions from the 2022 and 2023 ESOO *Step Change* forecast data, and PEC Stage 1 complete, increasing the transfer capacity into South Australia.

5 EUFR target

This section aims to assess the quantity of EUFR that is required in SA to adequately manage significant multiple contingency events, and develop this into simple and actionable advice to NSPs on an appropriate EUFR target.

Figure 13 shows the total under-frequency response required for each of the four multiple contingency events studied, in each half-hour dispatch interval of 2023 and 2025. This was calculated as follows:

- For “fail” cases, the amount of EUFR required was calculated by:
  - Iteratively increasing the BESS headroom available until frequency was contained above 47.6 Hz, and then
  - Summing the total amount of EUFR used (Total BESS headroom utilised + Total net UFLS load tripped + Total synchronous PFR).
- For “pass” cases, the amount of EUFR required was calculated by:
  - Determining the amount of EUFR “used” in each case (Total BESS headroom utilised + Total net UFLS load tripped + Total synchronous PFR).

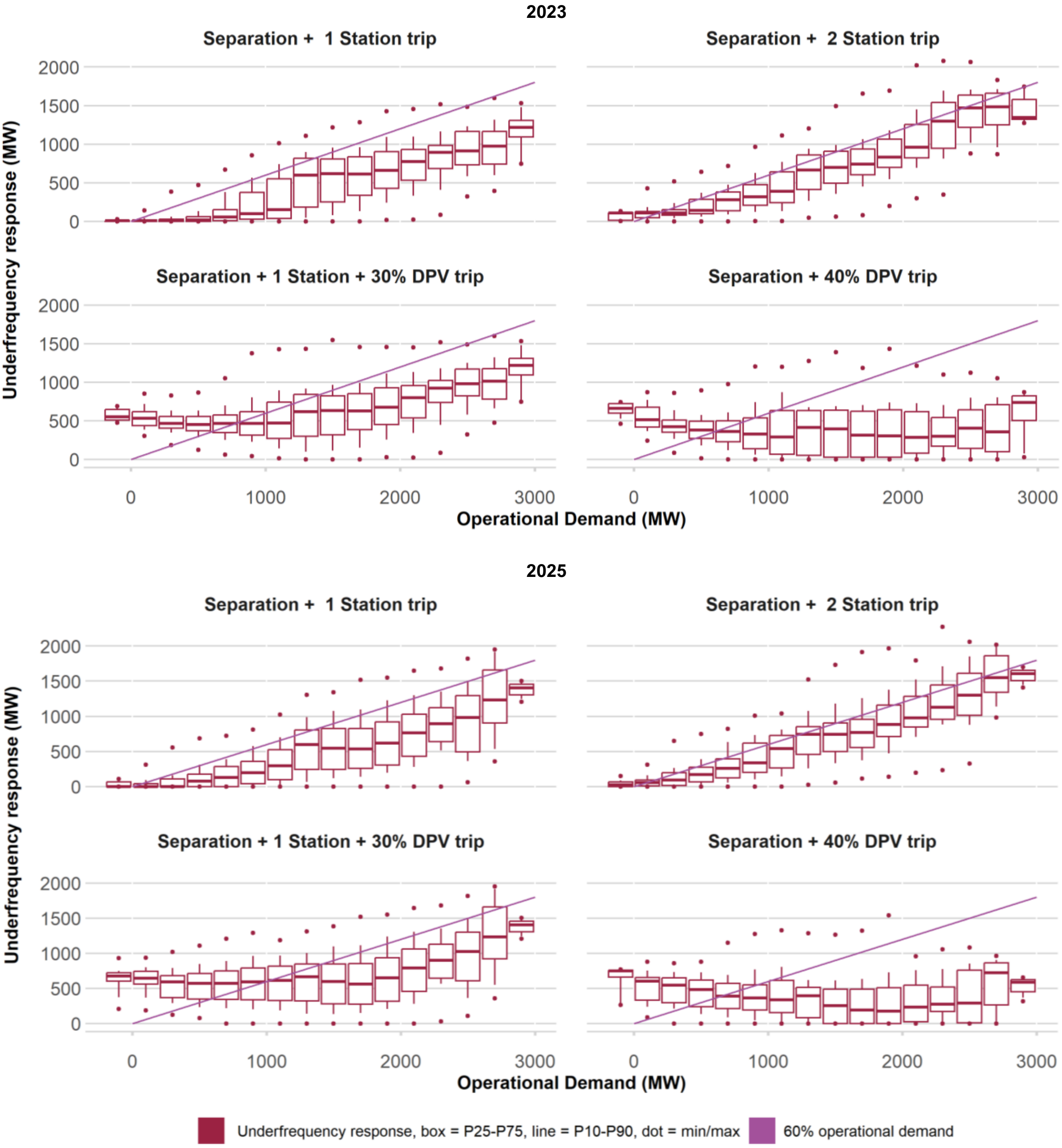
The EUFR required in each half-hour period is represented as a box and whisker plot to show the maximum, minimum, quartiles (box) and 10th and 90th percentiles (whisker) across different ranges of operational demand. A “guide to the eye” is also included as a purple line, illustrating 60% of operational demand.

The results in Figure 13 show that for the contingencies shown in the top two panels for 2023 and 2025 that do not involve a DPV trip, the under-frequency response (EUFR) required scales relatively closely with operational demand. This indicates that it is likely appropriate to define a EUFR target for these more traditional contingency types based on a percentage of operational demand. At higher levels of operational demand, contingency sizes are generally larger, so more EUFR is required. As operational demand trends towards zero, the contingency size similarly becomes very small, and the studies suggest very little EUFR is generally required to manage these traditional types of multiple contingency events.

However, for the more novel contingency types that involve a trip of DPV (shown in the bottom two panels for each 2023 and 2025 in Figure 13), the EUFR required does not scale with operational demand. Significant amounts of EUFR can be required even in scenarios with very low levels of operational demand, where a EUFR target based on a percentage of operational demand would imply that minimal or zero EUFR is required. A percentage of operational demand is therefore not a good indicator of EUFR required in these low demand scenarios, when accounting for these more novel contingency types involving a trip of DPV.

The EUFR required is found to be similar between 2023 and 2025. Increasing BESS headroom and UFLS dynamic arming act to significantly increase the amount of EUFR *available* and therefore improve frequency outcomes, but these factors do not significantly influence the amount of EUFR *required* to manage these same four contingency types (which is found to be relatively consistent between 2023 and 2025). Similarly, in 2025 the increasing levels of DPV generation will decrease the net UFLS load, and the scenarios in 2025 involve a significantly larger proportion of time operating at lower levels of operational demand. These factors will both reduce the amount of EUFR *available* (all else being equal), but do not significantly affect the EUFR *required* to manage these contingencies in those periods. This suggests that it is reasonable to develop a static definition of the EUFR target that applies for the period 2023-2025. The EUFR target will need to be reviewed, however, following commissioning of PEC Stage 2, which will fundamentally change the nature of the contingencies being managed.

Figure 13 Under-frequency response required to arrest f > 47.6 Hz following a significant multiple-contingency event



5.1 Proposed simple EUFR target

This section aims to develop a simple and actionable EUFR target, as a function of measurable power system parameters. Figure 14 shows the total EUFR required in 2023 and 2025, combining the four panels in Figure 13 above by taking the EUFR required in each half-hour period to adequately manage frequency (arrest > 47.6 Hz) for each of the four contingency types.

Figure 14 Underfrequency response required – combined contingencies

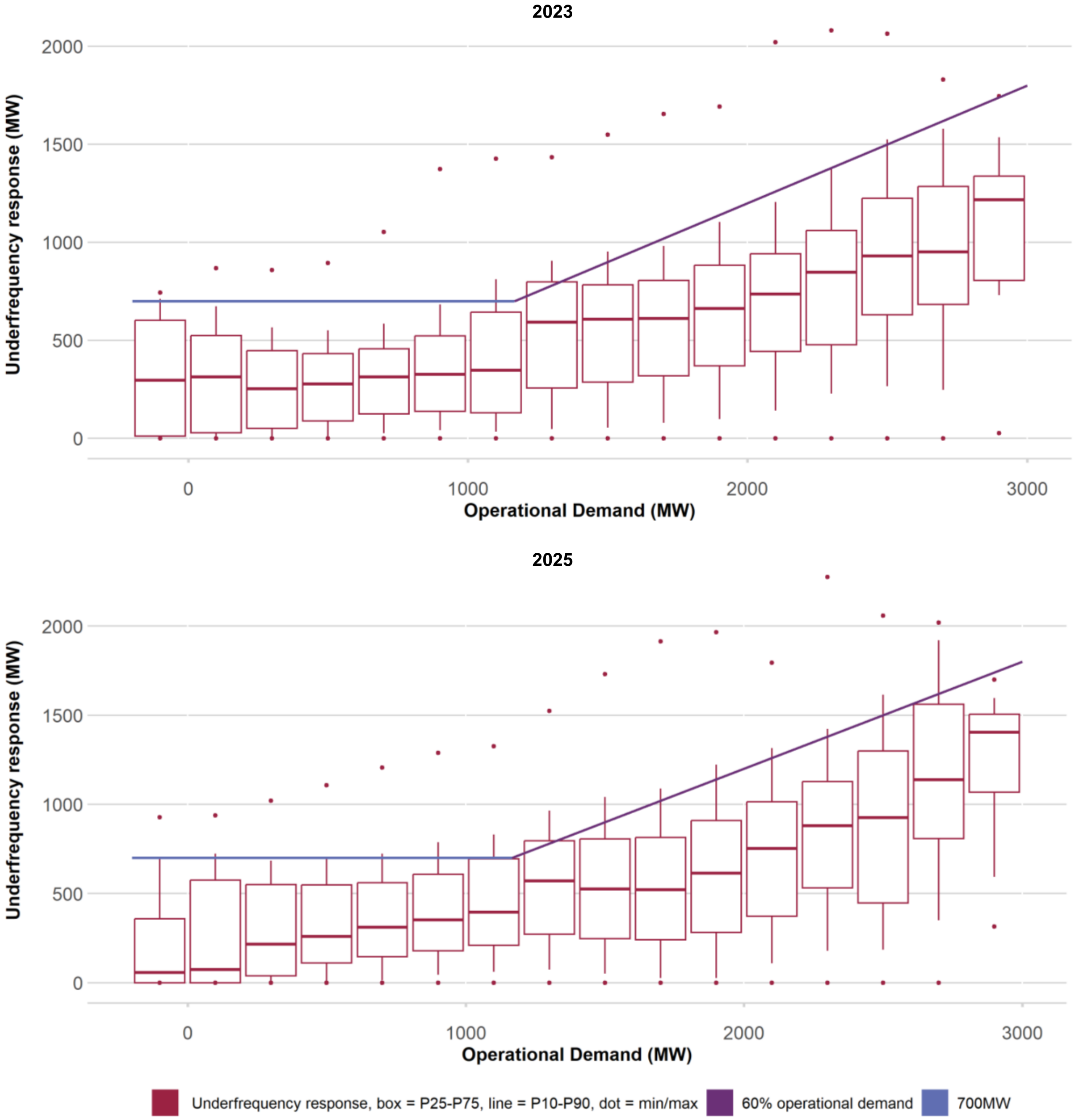


Figure 14 suggests two segments:

- For “high” demand cases (operational demand > 1,200 MW), the EUFR required scales with operational demand. The line showing 60% of operational demand provides a reasonable indication of EUFR required in these cases. Defining the EUFR target as 60% of operational demand for cases where demand > 1,200 MW results in sufficient EUFR to manage ~80% of these high demand cases.
- For “low” demand cases (operational demand < 1,200 MW), the EUFR required is relatively constant. For these low demand periods, defining a flat EUFR target of 700 MW results in sufficient EUFR to manage ~80% of these cases (giving a similar risk profile to high demand periods).

By these definitions, some periods will have inadequate EUFR to manage the four contingency events studied. It is noted that the selection of multiple contingency events is somewhat arbitrary, and there will always be some risk of significant multiple contingency events for which EUFR is inadequate. There is also a possibility of larger contingency events than those studied in this report. This analysis has aimed to provide a simple target that delivers reasonable continuity of the probabilistic risk profile over time, as a guide to balance costs and risks to consumers.

In the past, NSPs have typically targeted UFLS levels in the realm of 60% of demand, on the basis that this achieves an outcome consistent with NER 4.3.1(k) (indicating reserves should be adequate to arrest the impacts of a range of significant multiple contingency events affecting up to 60% of the total power system load). Maintaining this level for high demand periods (and developing arrangements for low demand periods that deliver a similar risk profile) therefore represents a continuation of the risk profile that has historically been present.

On this basis, the following is proposed:

Proposed EUFR target for South Australia

AEMO’s assessment is that to maintain reasonable continuity with the historical risk profile, based on historical levels of UFLS, would require an SA EUFR target which is the higher at any point in time of:

- 700 MW, or
- 60% of operational demand.

This report indicates that this target provides enough EUFR to manage the four contingency events studied ~80% of the time.

This should be reviewed following commissioning of PEC Stage 2.

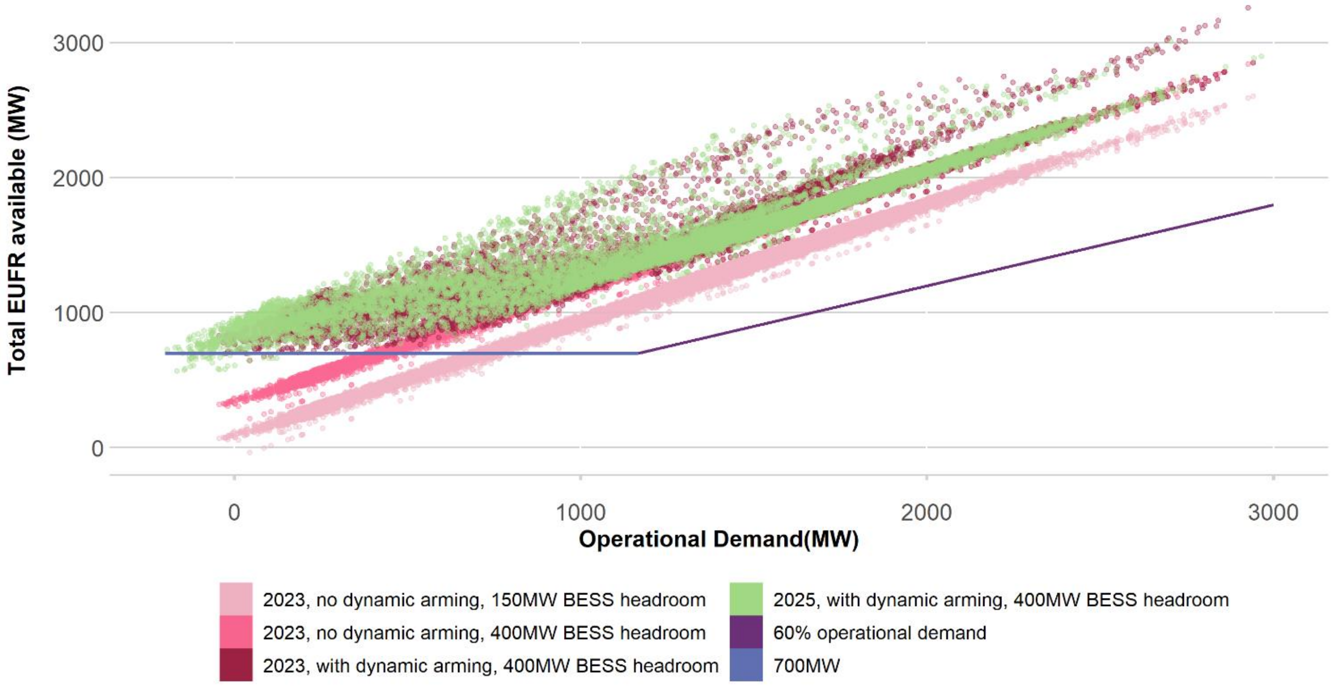
AEMO is continuing to review EUFR adequacy, and this advice may change as this work continues.

There will always be a risk associated with non-credible contingencies requiring larger amounts of EUFR than this target, as well as larger contingencies than those studied in this report in developing this target.

5.2 Ability to meet the proposed EUFR target

Figure 15 illustrates the amount of EUFR available in South Australia in several scenarios, compared with the proposed simple EUFR target definition.

Figure 15 EUFR available versus the suggested EUFR target



	Scenario	Representative period	% of time EUFR target is met
	2023, no dynamic arming 150 MW BESS headroom	Representative of typical EUFR availability in 2023 (prior to commissioning of Torrens Island BESS)	84 %
	2023, no dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability at present (following commissioning of Torrens Island BESS in late 2023)	91 %
	2023, with dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability once dynamic arming rollout is complete in late 2024	99.97 %
	2025, with dynamic arming 400 MW BESS headroom	Representative of typical EUFR availability in 2025, with ongoing growth in DPV	99.8 %

Figure 15 shows that in high demand periods (> 1,200 MW), the EUFR target is always met in all scenarios. As a short-term measure to increase EUFR availability in low demand periods, SAPN and ElectraNet have added most loads in SA into the UFLS scheme, which has boosted EUFR availability in all periods. This means that the EUFR target in high demand periods is always easily met, and no further action would be required to meet this EUFR target in high demand periods.

In low demand periods (< 1,200 MW), the proposed EUFR target is not met in a proportion of periods, as summarised in the table above, although this is improved by the various actions taken and underway.

These actions include:

- **Dynamic arming of UFLS** – if dynamic arming was not implemented in 2025, the suggested target is only met 88% of the time (even with 400 MW BESS headroom available). With dynamic arming, the target is met 99.8% of the time.

- **Additional battery capacity in SA** – if there was only 150 MW of battery headroom in 2025 instead of 400 MW, the EUFR target is only met 93% of the time. With 400 MW of BESS headroom, the target is met 99.8% of the time.

The combination of actions taken and in progress mean the suggested EUFR target should be met ~99.8% of the time in 2025. This assumes a static availability of BESS headroom for frequency response which would generally be delivered if the BESS are dispatched close to 0 MW, as they might when participating in FCAS. In reality, in some periods BESS will have less headroom available, depending on their dispatch levels. In other periods, there may be more BESS headroom available if the BESS has a negative dispatch (that is, the BESS is dispatched as a load while charging). This might be more likely in periods of low demand (often associated with low wholesale market prices), suggesting the EUFR available in low demand periods might be higher than indicated in this assessment, on average. It is also noted that there are further BESS in various stages of development in SA, including Tailem Bend 2 (41.5 MW, now commissioned), Blyth (200 MW), Templers (111 MW) and Bungama (150 MW)[67]. This will further increase the anticipated EUFR availability beyond what is quantified here, further reducing risks.

This suggests that with no further actions beyond those already in progress[68], and assuming that dynamic arming of UFLS relays continues to be maintained (addressing new sites appropriately as they also move into reverse flows beyond thresholds), the suggested EUFR target is expected to be met the majority of the time. This target provides enough EUFR to manage the four contingency events studied ~80% of the time, delivering a similar risk profile to historical levels of coverage via traditional UFLS.

5.3 Benefits of investment in additional EUFR availability

As outlined in Section 4, based on present EUFR availability and actions in progress, there will remain a level of residual risk. Most of this risk is associated with very large contingency events which would require more EUFR than the recommended target. Eliminating all risk, even associated with just the four contingency events studied, would require more than 2,000 MW of EUFR in SA in some cases, and there will always remain some risk associated with even larger non-credible contingency events than those studied.

In 2025 it is estimated that the total residual risk for SA associated with the four contingency events studied is in the order of 100-200 megawatt hours (MWh) of unserved energy (USE) per annum (estimating the likelihood of an unplanned separation and contingency event, the likelihood that the separation may lead to a black system based on these studies, and the amount of USE associated with a black system event, with full assumptions outlined in Appendix A3). This translates to approximately $7.5 million per annum of USE associated with inadequate EUFR (based on the value of customer reliability) for the four contingency events studied.

Approximately 80% of this USE is associated with periods where operational demand exceeds 1,200 MW. These higher demand periods occur ~70% of the time in the 2025 year, which indicates why a large share of USE risk is associated with these conditions. Approximately 20% of USE is associated with periods where operational demand

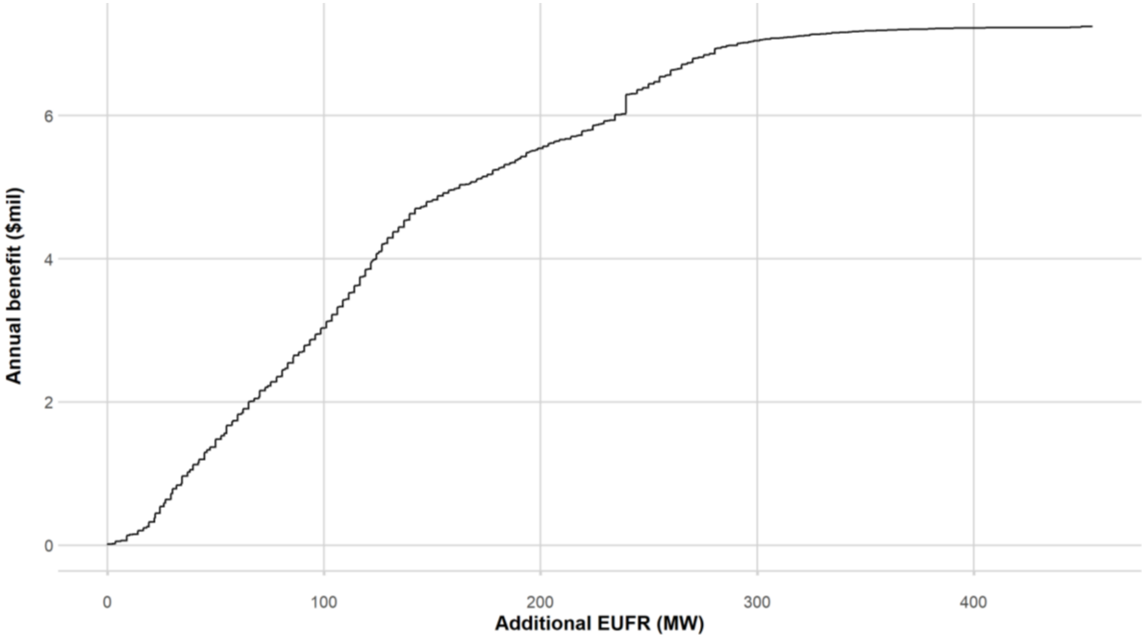
[67] AEMO (February 2024) Generation Information, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[68] It is expected that SAPN will continue to monitor feeder flows, and continue to incrementally implement dynamic arming (reverse flow blocking) of UFLS relays where appropriate, as DPV levels continue to grow and more feeders move into reverse flows.

is below 1,200 MW, which occur ~30% of the time in 2025. This suggests the per-period risks are comparable between high demand and low demand conditions.

Figure 16 provides an indication of the annual benefit from increasing EUFR availability in South Australia, based on the amount that USE risk would be reduced. This suggests that increasing EUFR availability by approximately 100 MW in all periods would reduce risk associated with the four contingency events studied by ~$3 million per annum.

Figure 16 Minimum annual benefit from investment in additional EUFR capacity (2025)



This suggests that if there are options to increase EUFR availability in the order of 100 MW for less than ~$3 million per annum, and these options could be implemented sufficiently ahead of PEC Stage 2, these may be worth investigating further. There may be novel options available in this cost range (such as enabling highly granular UFLS via advanced metering infrastructure at a subset of sites with capable hardware), but given the novel and untested nature of these types of solutions it may be challenging to bring these to implementation prior to commissioning of PEC Stage 2[69]. Benefits beyond that time have not been quantified in this analysis. Significantly higher cost options are unlikely to be justified based on the benefits they deliver in reduced power system risks.

5.3.1 Excessive RoCoF scenarios

There is a further residual risk associated with USE in scenarios where RoCoF exceeds 3Hz/s, estimated at approximately $7 million per annum. This risk is unlikely to be addressed by increasing EUFR availability, since traditional sources of EUFR may not be able to arrest these severe contingency events. Possible approaches to

[69] AEMO (October 2023) Under Frequency Load Shedding: Exploring dynamic arming options for adapting to distributed PV, https://aemo.com.au/-/media/files/initiatives/der/2023/dynamic-arming-options-for-ufls.pdf?la=en&hash=F6B7A015C8EB872C83513BA9C95EFE5B.

reducing these residual risks could be control schemes that prevent separation, methods that reduce the contingency size (such as constraints), or increases in power system inertia.

5.3.2 Dynamic arming of UFLS relays

This analysis assumed that SAPN will continue to monitor the flows on feeders in their network, and will continue to address new sites with dynamic arming (reverse flow blocking) capability as new sites move into excessive reverse flows beyond suitable thresholds. Continuing monitoring and maintenance of this dynamic arming capability at all suitable sites will be required on an ongoing basis as levels of DPV in SA continue to grow.

6 Recommendations and ongoing work

AEMO recommends that the EUFR target for South Australia is defined as follows:

Proposed EUFR target for South Australia

AEMO's assessment is that to maintain reasonable continuity with the historical risk profile, based on historical levels of UFLS, would require an SA EUFR target which is the higher at any point in time of:

- 700 MW, or
- 60% of operational demand.

This report indicates that this target provides enough EUFR to manage the four contingency events studied ~80% of the time.

This should be reviewed following commissioning of PEC Stage 2.

AEMO is continuing to review EUFR adequacy, and this advice may change as this work continues.

The rollout of dynamic arming of UFLS in SA and the extra battery headroom now available in SA (following commissioning of the Torrens Island BESS) mean that this target is expected to be met ~99.8% of the time, with no further actions (assuming that dynamic arming of UFLS relays continues to be maintained, addressing new sites appropriately as they also move into reverse flows beyond thresholds). This delivers a similar level of residual risk to historical levels.

AEMO is continuing to review EUFR adequacy, and this advice may change as this body of work progresses.

AEMO is also progressing further analysis of UFLS and EUFR adequacy in other NEM regions. It is noted that other NSPs have not yet implemented dynamic arming of UFLS relays, and reverse flows are already evident in many locations. AEMO continues to recommend that NSPs in Victoria[70,71], New South Wales[72] and Queensland[73] investigate approaches for management of the impacts of reverse flowing feeders on UFLS functionality, including consideration of dynamic arming options[74].

[70] AEMO (May 2023) Victoria UFLS load assessment update, 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.

[71] AEMO (August 2021) Phase 1 UFLS Review: Victoria, https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

[72] AEMO (December 2021) Phase 1 UFLS Review: New South Wales, https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.

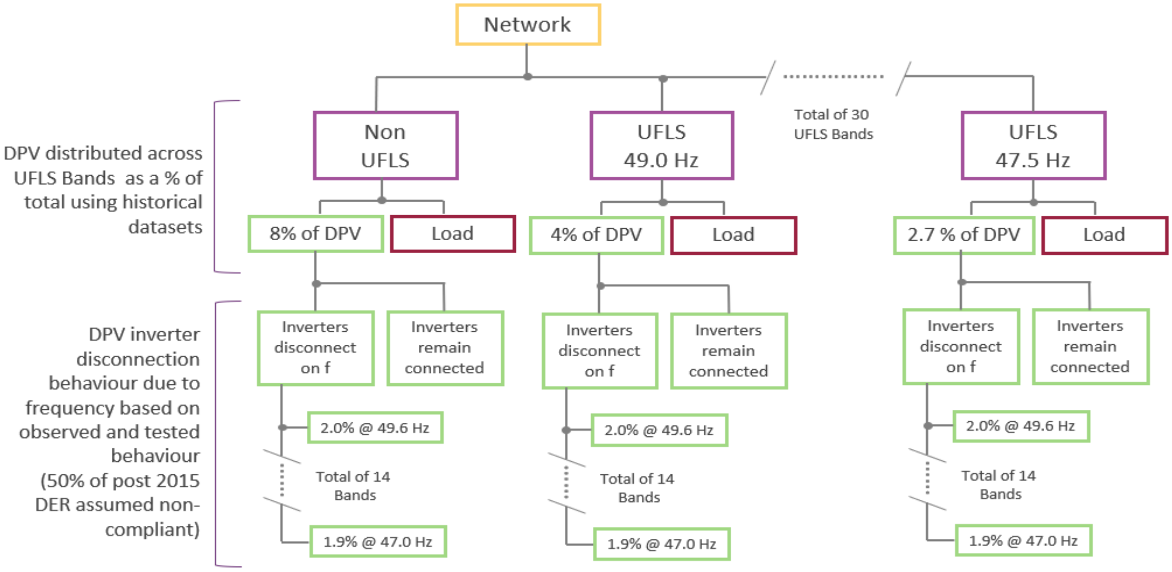
[73] AEMO (December 2021) Phase 1 UFLS Review: Queensland, https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

[74] AEMO (October 2023) Under Frequency Load Shedding: Exploring dynamic arming options for adapting to distributed PV, https://aemo.com.au/-/media/files/initiatives/der/2023/dynamic-arming-options-for-ufls.pdf?la=en&hash=F6B7A015C8EB872C83513BA9C95EFE5B.

A1. DPV interactions in the multi-mass model

This appendix elaborates on the representation of DPV in the MMM and the manner in which it interacts with UFLS in the model. Figure 17 provides a visual depiction of the interactions between DPV behaviour and the UFLS frequency bands in the MMM.

Figure 17 Interactions between DPV frequency trip settings and UFLS frequency bands



A1.1 DPV tripping behaviour in response to under-frequency

Various sources of evidence indicate that a proportion of DPV disconnects in response to severe frequency events[75]. This particularly relates to DPV installed under "legacy" standards. The category of "inverters installed under legacy standards" is assumed to include inverters installed under the 2005 inverter standard or inverters installed under the 2015 or 2020 standard which are non-compliant.

The share of DPV that is assumed to be on a legacy standard in 2023 is in the range 63-65%. This was calculated by assuming the following:

- All DPV installed prior to 2016 was installed on the 2005 inverter standard. It is estimated that the DPV capacity in SA in 2016 was 715 MW.
- 50% of DPV installations from 2016 have been installed under a legacy standard. The scenario assumptions from the 2023 ESOO estimate the total DPV capacity in SA in 2023 ranges from 2,450 MW to 2,720 MW[76]. This means that between 2015 and 2023, 865-1,005 MW of DPV has been installed on a legacy standard.

[75] 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.

[76] A range is specified to account for the impact of new installations throughout the 2023 calendar year.

To represent the frequency trip behaviour of DPV installed under legacy standards, the MMM includes 14 frequency trip bands where DPV will disconnect, the largest at 49 Hz where up to 14% of DPV on a legacy standard can disconnect. Table 9 details the frequency bands and pickup times modelled in the MMM, and the percentage of DPV that will trip at each band.

All other DPV was assumed to be installed under the AS/NZS4777.2.2015 or AS/NZS4777.2.2020 Australian standard which requires inverters to stay connected for a longer period during frequency events, and therefore will not trip in the MMM.

Table 9 Frequency trip settings assumed for DPV installed under legacy standards

Settings		Distribution of frequency settings	
Frequency (Hz)	Pickup time (seconds)	% of DPV with legacy settings that trip	% of entire DPV fleet in 2023 that trip
49.6	1.9	2 %	1.3 %
49.02	1.9	0.1 %	0.06 %
49.01	0.18	1.5 %	1.0 %
49	0.06	9.9 %	6.3 %
49	1.96	2.6 %	1.7 %
49	2	0.3 %	0.2 %
48.52	2	0.8 %	0.5 %
47.6	1.8	3 %	1.9 %
47.55	0.2	3.8 %	2.5 %
47.5	1.8	4.1 %	2.6 %
47.1	1.8	7.1 %	4.6 %
47	1.6	0.7 %	0.5 %
47	1.9	3 %	1.9 %
47	1.89	2 %	1.3 %

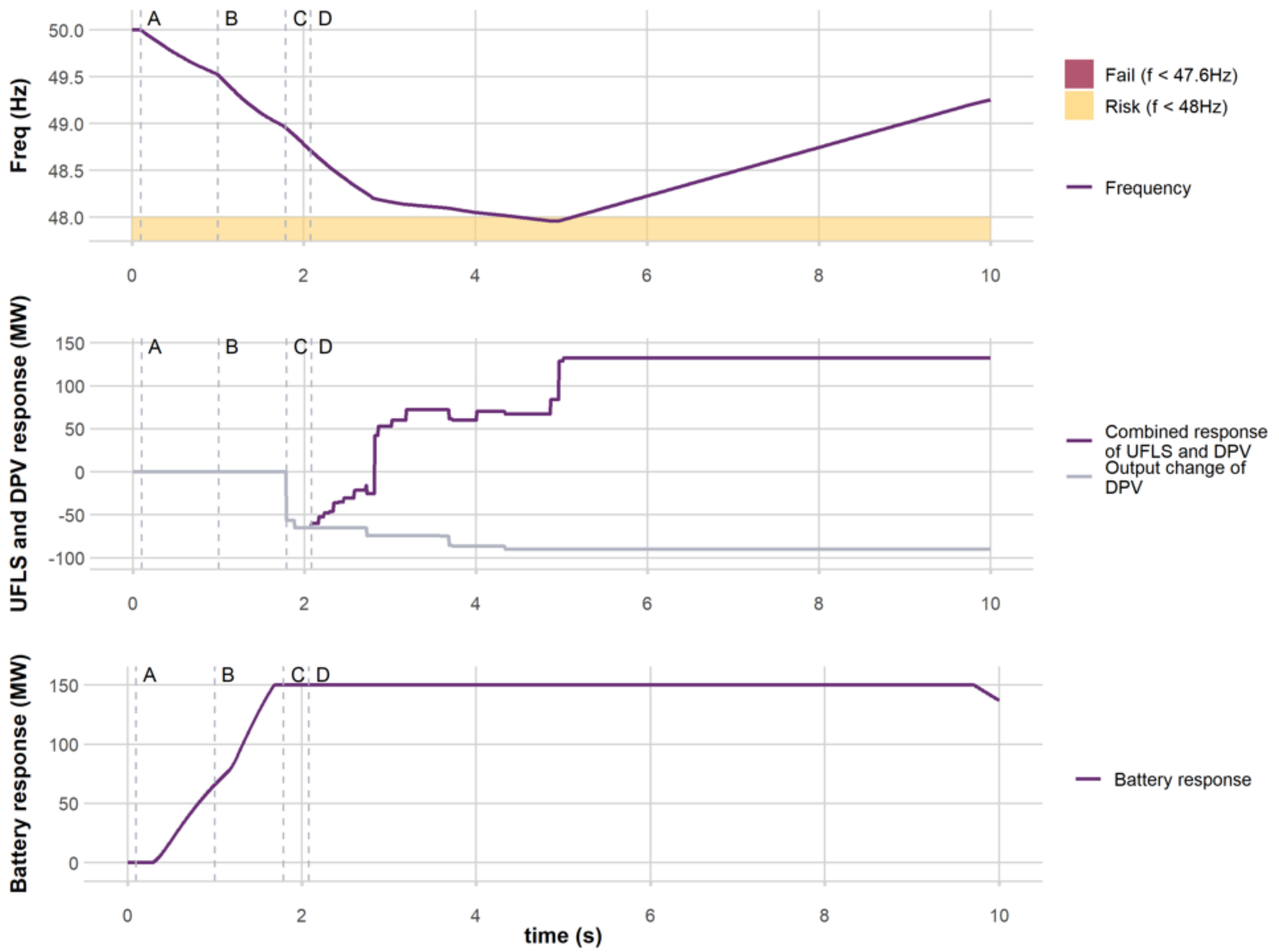
Some case studies are provided below to illustrate DPV behaviours during frequency events.

A1.2 Case study: Separation + 1 station trip

Figure 18 illustrates outcomes for a scenario with a separation and 1 station trip, in a scenario with high levels of DPV generation, and moderate imports on HIC. In this scenario, despite the relatively small initial contingency (157 MW of imports on HIC, plus trip of an 80 MW station), frequency declines enough to reach 49 Hz and then accelerates downwards further as a proportion of DPV trips in response to frequency. The reduced net load on UFLS bands means that the trip of these UFLS bands is then less effective in arresting frequency decline, and frequency falls below 48 Hz. This illustrates a relatively poor frequency outcome in a scenario with a relatively mild initial contingency, due to the impacts of DPV.

Figure 18 Case study: Separation + 1 Station trip

Operational Demand (MW)	Non-synchronous generation (MW)	Synchronous generation (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)	Generating Station trip size (MW)
518	245	80	6200	907	157	36	80



Note: dynamic arming implemented, 150 MW of BESS headroom available, case from 2023 therefore PEC Stage 1 not considered.

	Time	Description
A	0.1 s	HIC trips (SA synchronously separated from the rest of the NEM) while importing 157 MW, frequency begins to decline. The battery responds according to its frequency droop settings.
B	1 s	The largest generating station trips (80 MW); in this scenario this is Torrens Island Power Station. This accelerates the frequency decline.
C	1.8 s	Frequency reaches 49 Hz: – A share of DPV trips according to inverter frequency trip settings (6.2% at 49 Hz for 0.06s, see Table 9). This increases the supply-demand imbalance. – The battery reaches maximum output and cannot provide any further response beyond this level. – Frequency decline accelerates.
D	2.1 s	UFLS bands begin to trip to correct the supply-demand imbalance and contain frequency. As frequency declines some further DPV continues to trip due to frequency trip settings.

A1.3 Case study: Separation + 1 station + 30% DPV trip

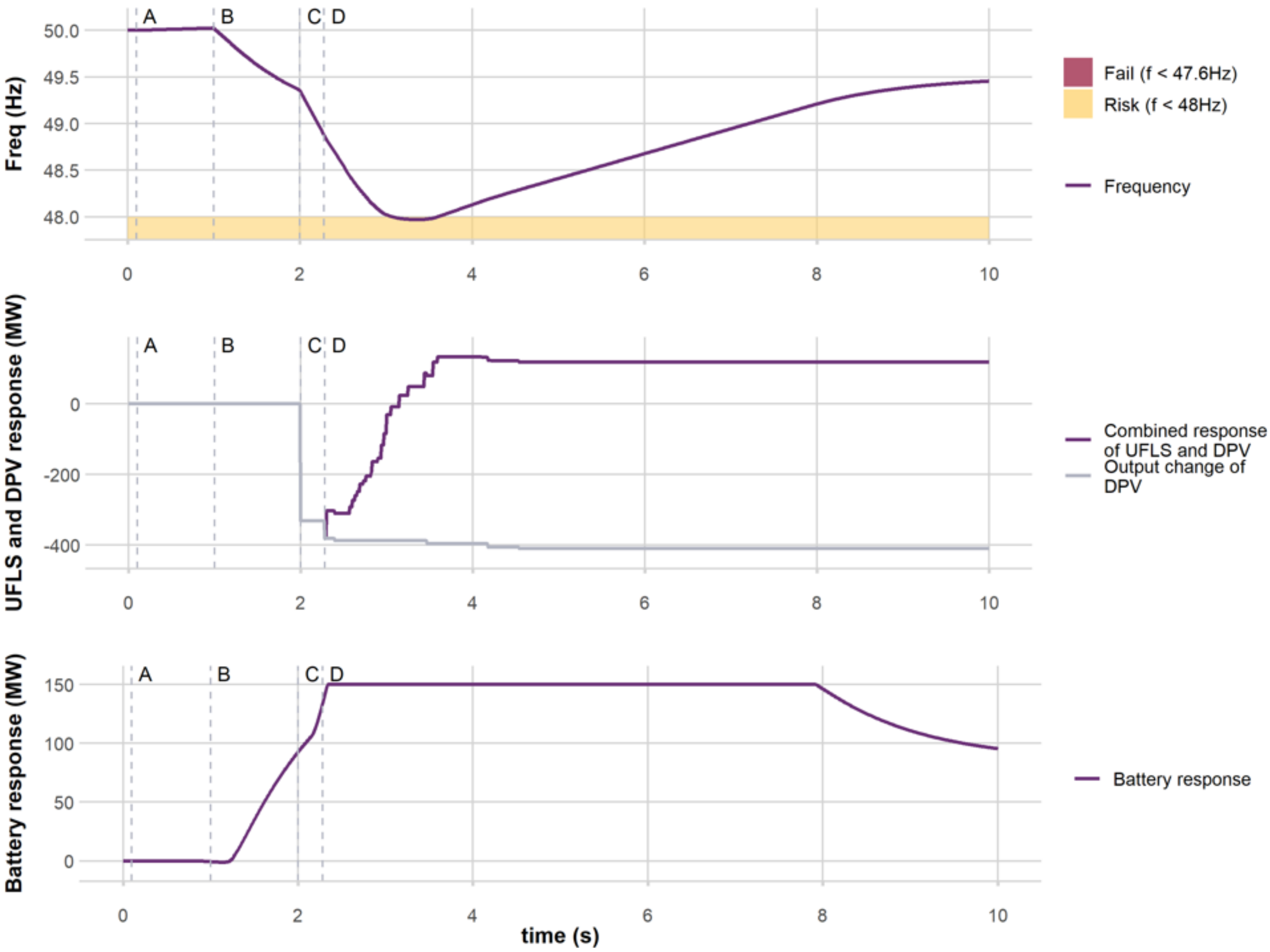
Figure 19 illustrates another case study for a period with high levels of DPV generation, this time for a separation plus a trip of the largest station, and a trip of 30% of the DPV in South Australia.

In this dispatch scenario, HIC has very low (slightly exporting) flows prior to the contingency. The trip of the generating station at 1 second (B) causes frequency to decline in SA. The further trip of 30% of the DPV in SA (perhaps due to a type fault) at 2 seconds (C) then causes a significant acceleration of the frequency decline. When frequency reaches 49 Hz (D), some further DPV trips in response to the frequency, although this amount has been reduced by the initial DPV trip. UFLS blocks also begin to trip. The UFLS blocks will have increased net load at each block, due to the earlier DPV trip.

This case study illustrates the various interactions between DPV tripping mechanisms and UFLS, and also illustrates a relatively poor frequency outcome (frequency nadir below 48 Hz) for a scenario with high levels of DPV operating and very low pre-contingent flows on the interconnector.

Figure 19 Case study: Separation + 1 Station + 30% DPV trip

Operational Demand (MW)	Non-synchronous generation (MW)	Synchronous generation (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)	Generating Station trip size (MW)
703	428	80	6200	1105	-7	202	208



Note: dynamic arming implemented, 150 MW of BESS headroom available, case from 2023 therefore PEC Stage 1 not considered.

	Time	Description
A	0.1 s	Heywood interconnector trips (SA synchronously separated from the rest of the NEM). Frequency remains relatively unchanged due to low interconnector flows.
B	1 s	The largest generating station trips (208 MW); in this scenario this is Bungala Solar Farm. Frequency begins to decline. The battery begins to respond according to its frequency droop settings.
C	2 s	30% of DPV trips (as part of the initiating contingency event). Frequency decline accelerates.
D	2.3 s	Frequency reaches 49 Hz: • A share of DPV trips according to inverter frequency trip settings (6.4% at 49 Hz for 0.06s, see Table 9). The amount that trips has been reduced by the earlier DPV trip (part of the initiating contingency). • The battery reaches maximum output and cannot provide any further response beyond this level. • Frequency decline accelerates. • UFLS bands begin to trip, offsetting DPV tripping, and helping arrest the frequency decline. The amount of net load on UFLS bands has been increased by the earlier DPV trip.

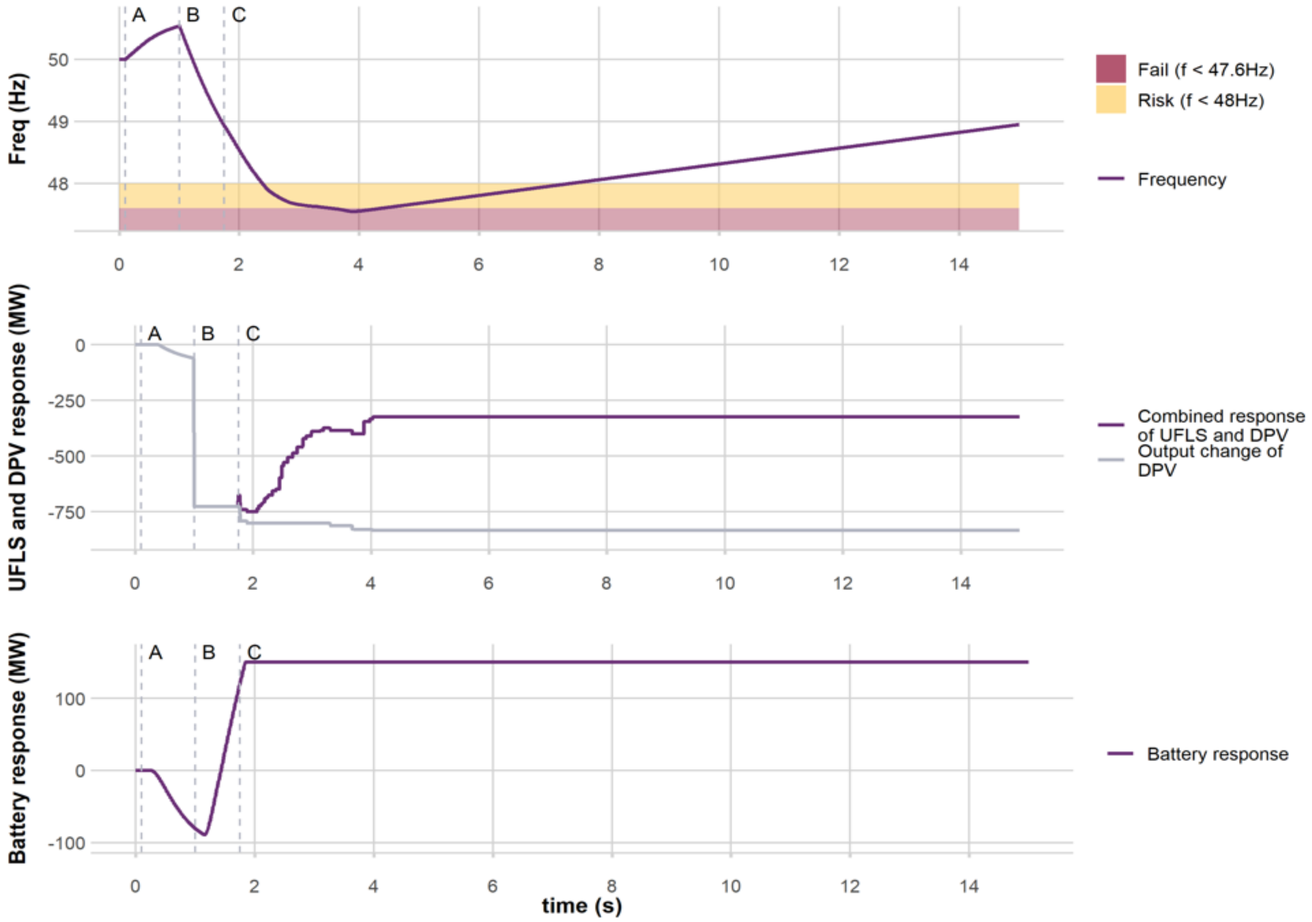
A1.4 Case study: Separation + 40% DPV trip

Figure 20 illustrates a case study for a period with very high DPV generation, with a contingency involving a separation and trip of 40% of DPV in SA. In this scenario, due to the very low level of operational demand in SA, the interconnector is exporting 205 MW from SA prior to the event. When the separation occurs, the frequency rises in SA until the subsequent trip of 40% of the DPV in SA at 1 second (B), after which frequency declines rapidly. When frequency reaches 49 Hz (C) UFLS bands begin to trip, and a proportion of the remaining DPV trips on frequency settings (although this amount has been reduced by the earlier DPV trip). The net load on UFLS bands has been increased by the earlier DPV trip, increasing their effectiveness in arresting the frequency decline.

In this case, frequency falls below 47.6 Hz. This is classified as a “fail” scenario due to inadequate EUFR availability.

Figure 20 Case study: Separation + 40% DPV trip

Operational demand (MW)	Non-synchronous generation (MW)	Synchronous generation (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)
134	126	80	6200	1726	-205	133



Note: dynamic arming implemented, 150 MW of BESS headroom available, case from 2023 therefore PEC Stage 1 not considered.

	Time	Description
A	0.1 s	Heywood interconnector trips while exporting 205 MW. Frequency begins to increase. The battery begins to charge according to its frequency droop settings. A share of the DPV begins to decrease its output according to DPV frequency droop settings[77].
B	1 s	40% of DPV trips as part of the initiating contingency. Frequency declines rapidly. The battery output becomes more positive according to its frequency droop settings.
C	1.8 s	Frequency reaches 49 Hz: • A share of DPV trips according to inverter frequency trip settings (6.4% at 49 Hz for 0.06s, see Table 9). The amount that trips has been reduced by the earlier DPV trip (as part of the initiating contingency). • The battery reaches maximum output and cannot provide any further response beyond this level. • Frequency decline accelerates.

[77] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, Section 3.3.4, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A

	Time	Description
		• UFLS bands begin to trip, offsetting DPV tripping, and helping to arrest the frequency decline. The amount of net load on UFLS bands has been increased by the earlier DPV trip.

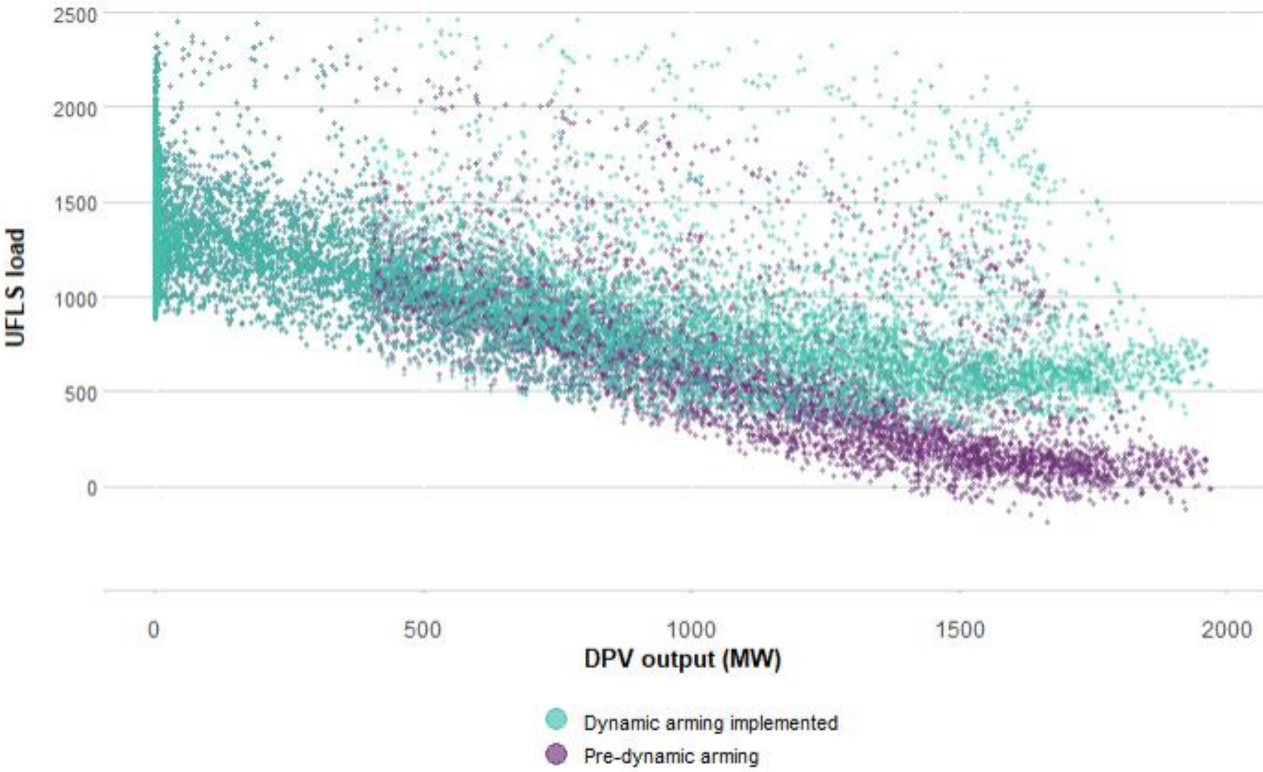
A2. Dynamic arming of UFLS

This appendix describes the manner in which dynamic arming of UFLS has been represented in the MMM studies.

SAPN provided AEMO with detailed half-hour data on net load measurements from its 11 kilovolts (kV) and 33 kV feeders for a full year (2018-19). This provided an indication of the net UFLS load available across the different UFLS bands, and allowed estimation of how dynamic arming would affect the total net UFLS load as DPV levels increase, based on a linear regression.

Figure 21 shows an estimate of total UFLS load with and without dynamic arming for the forecast year of 2023, based on estimates from the linear regression applied to operational demand and DPV generation levels in each half hour in the forecast scenario. In the absence of dynamic arming, the projected net load on UFLS declines linearly as DPV levels increase, and becomes negative in some scenarios once DPV levels exceed ~1,500 MW. With dynamic arming enabled, any feeder that moves into reverse flows is removed from the summation, and this is estimated to plateau the net UFLS load decline at around 500 MW. For lower levels of DPV generation, the net UFLS load remains unchanged (because no feeders are in reverse flows).

Figure 21 Impact of dynamic arming on UFLS load, 2023



Delays for re-arming

During high DPV periods, it is expected that many relays will be disarmed due to the detection of reverse flows. If a large generation contingency occurs, this means these relays will not trip and the reverse flow on the circuit can continue to supply the grid. However, if a large generation contingency occurs that involves the trip of the DPV behind the disarmed relays, this could re-expose some net UFLS load.

There is a programmable delay between the detection of flows on the circuit and the relay re-arming. For these studies, it was assumed that relays will not re-arm within the duration of the simulation, even if the circuit returns to being a net load due to a trip of DPV.

A2.1 Case studies illustrating effects of dynamic arming

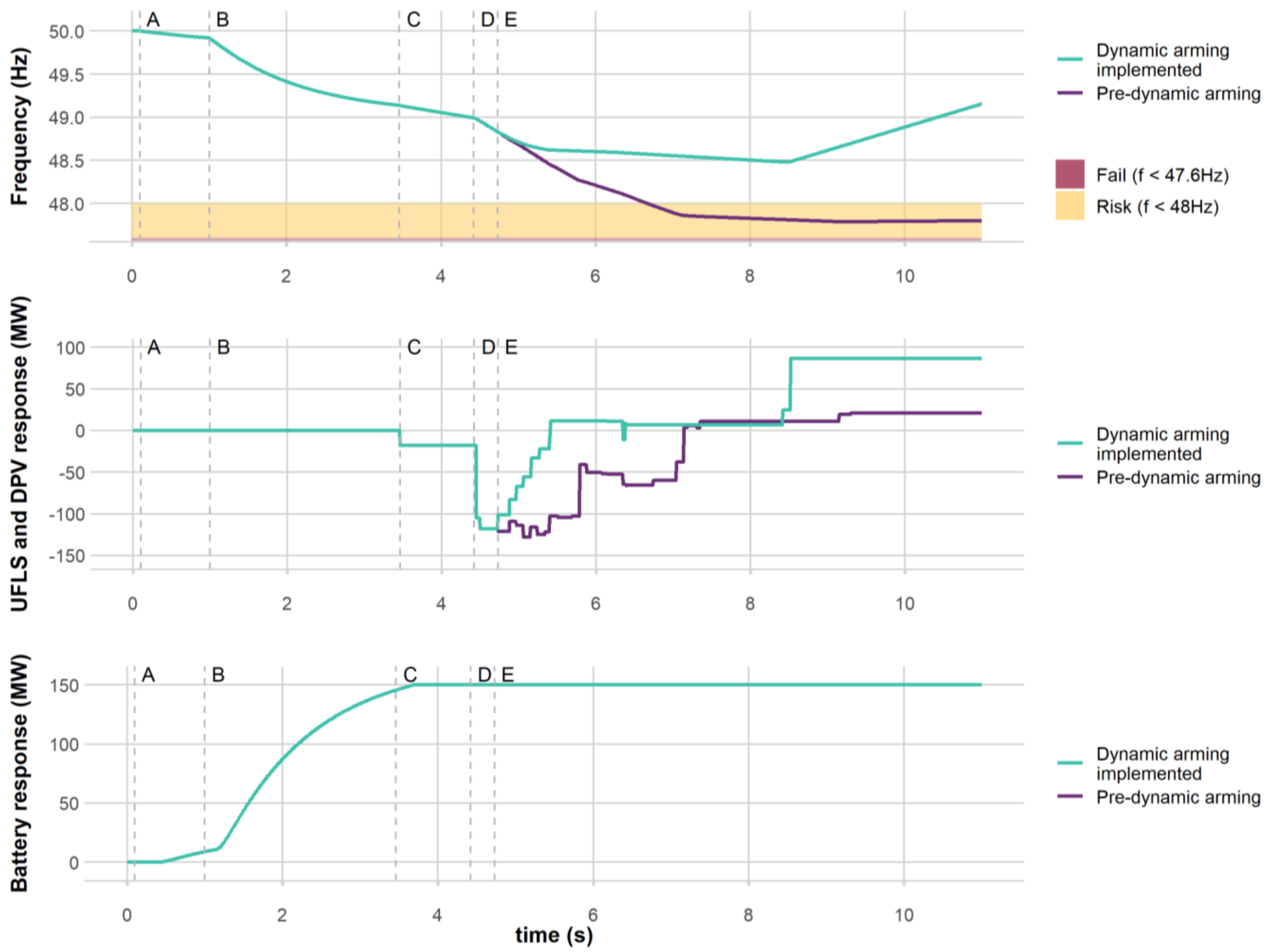
This section provides some case studies that illustrate the effects of dynamic arming on frequency outcomes.

A2.1.1 Case Study – Separation + 1 station trip

Figure 22 illustrates a case study for a period with very high DPV generation. In the case with dynamic arming implemented (teal), UFLS blocks have more net load, and reverse flowing blocks do not trip. This considerably improves the frequency outcomes, arresting frequency at 48.5 Hz. In the absence of dynamic arming (purple), numerous reverse flowing circuits are tripped. Frequency falls to 47.8 Hz in this scenario.

Figure 22 Case Study: Separation + 1 station trip (with and without dynamic arming)

Operational Demand (MW)	Non-synchronous generation (MW)	Synchronous generation (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)	Generating Station trip size (MW)
454	365	80	6200	1367	25	-16	144



Note: 150 MW of BESS headroom available, case from 2023 therefore PEC Stage 1 not considered.

	Time	Description
A	0.1 s	Heywood interconnector trips while importing 25 MW. Frequency begins to decline. Batteries respond according to frequency droop settings.
B	1 s	The largest generating station trips (208 MW); in this scenario this is Bungala Solar Farm. This accelerates the frequency decline. The response from batteries increases.
C	3.5 s	A share of DPV trips according to inverter frequency trip settings (1.3% at 49.6 Hz for 1.9 s, see Table 9).
D	4.4 s	Frequency reaches 49 Hz: • A share of DPV trips according to inverter frequency trip settings. (6.4% at 49 Hz for 0.06s, see Table 9). • The battery has reached its maximum output and cannot provide any further response beyond this level (1.7% droop, max capacity reached at 49.14 Hz, 150 ms delay)[78].

[78] BESS in all case studies are modelled with a 1.7% droop (max capacity reached at 49.14 Hz), 150 ms delay as outlined in Section 3.3. This effect is most visible in this example due to the slow frequency decline between 1-5 s.

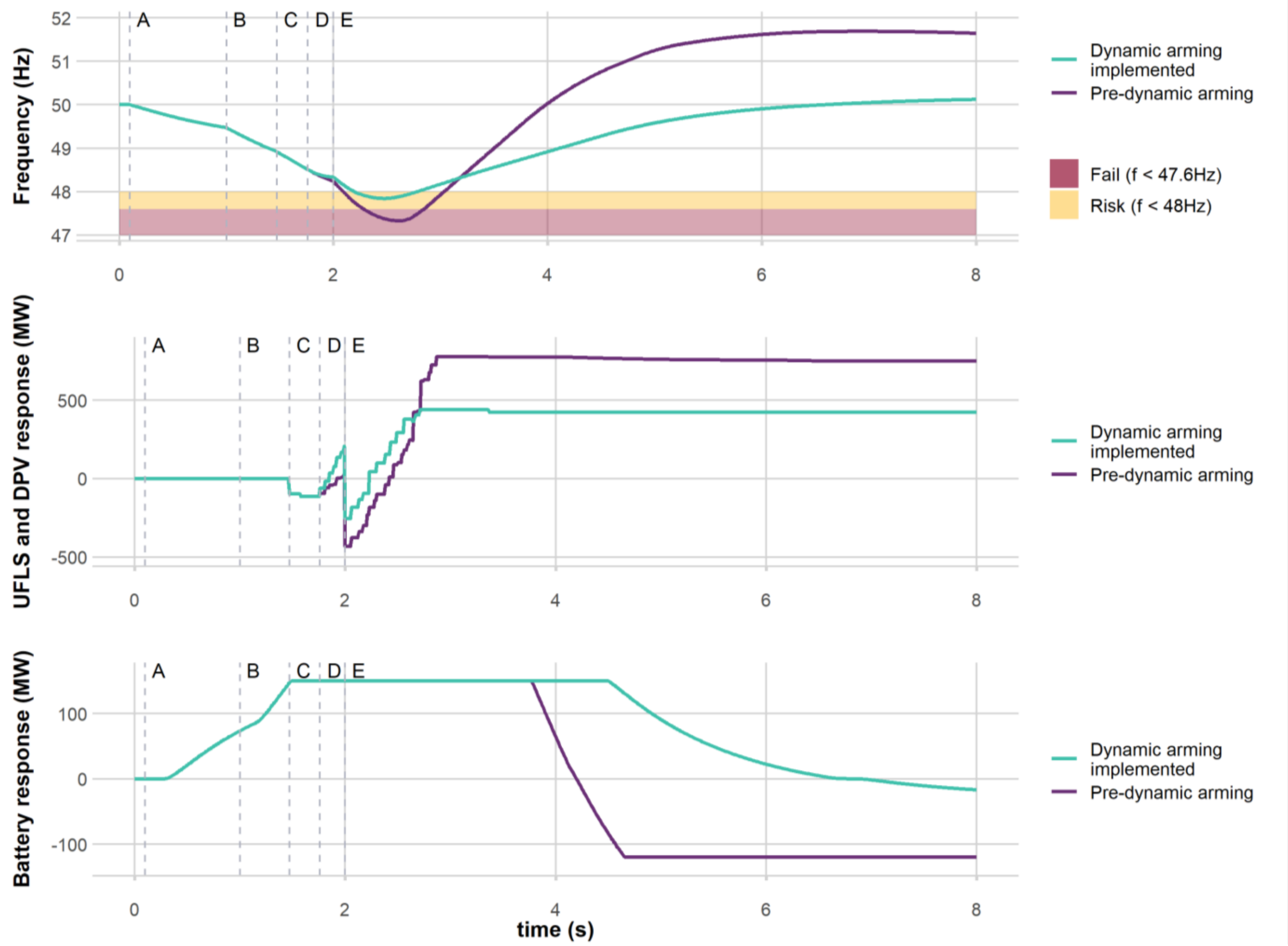
	Time	Description
		• Frequency decline accelerates.
E	4.7 s	UFLS bands begin to trip to arrest frequency. • In the case where dynamic arming is implemented, the net effect of each UFLS band tripping is a reduction in load which helps arrest frequency. • In the case where dynamic arming has not been implemented, some UFLS band trips result in a net trip of generation due to the tripping of reverse-flow relays. This results in a larger number of UFLS bands tripping (disconnecting more customers) and a more severe frequency event.

A2.1.2 Case study – Separation + 1 station + 30% DPV trip

The case study below shows the effects of UFLS dynamic arming in a scenario where the initiating contingency event involves a trip of DPV. In the case with dynamic arming implemented (teal), the action of UFLS is sufficient to arrest frequency just below 48 Hz. In contrast, in the case without dynamic arming implemented (purple), the action of UFLS is not sufficient to arrest frequency, and the nadir falls below 47.6 Hz (a “fail” scenario).

Figure 23 Case study: Separation + 1 station + 30% DPV trip (with and without dynamic arming)

Operational Demand (MW)	Non-synchronous generation (MW)	Synchronous generation (MW)	Inertia (MWs)	DPV output (MW)	HIC flow imports (MW)	Murraylink flow imports (MW)	Generating Station trip size (MW)
1242	786	80	6200	1535	175	201	219



Note: 150 MW of BESS headroom available, case from 2023 therefore PEC Stage 1 not considered.

	Time	Event
A	0.1 s	Heywood interconnector trips while importing 175 MW, frequency begins to decline. The battery begins to respond according to its frequency droop settings.
B	1 s	The largest generating station trips (219 MW); in this scenario this is Bungala Solar Farm. This accelerates the frequency decline and the response from the battery continues to increase.
C	1.5 s	Frequency reaches 49 Hz: • A share of DPV trips according to inverter frequency trip settings (6.4% at 49 Hz for 0.06s, see Table 9). • The battery reaches maximum output and cannot provide any further response beyond this level. • Frequency decline accelerates.
D	1.8 s	UFLS bands begin to trip and frequency decline slows: • With dynamic arming implemented (teal): the net trip of load is larger due to the removal of reverse-flow feeders from the UFLS scheme. • Without dynamic arming implemented (purple): the net trip of load is smaller.

	Time	Event
E	2 s	30% of DPV trips (as part of the initiating contingency). This causes frequency to decline further: • With dynamic arming implemented (teal): The action of UFLS is sufficient to arrest frequency just below 48 Hz. • Without dynamic arming implemented (purple): the net load behind each UFLS relay is smaller and the minimum frequency reaches below the “fail” threshold.

The studies in this report assume there is no dynamic arming in 2023, and in 2025 dynamic arming is fully implemented, unless otherwise noted.

A3. Cost benefit of dynamic arming in SA

The studies completed in this report facilitated estimation of a cost-benefit assessment for the implementation of dynamic arming of UFLS in SA. This is provided for transparency, and to inform NSPs in other regions who may be considering actions to manage DPV impacts on UFLS in their networks.

The costs of implementing dynamic arming were advised by SAPN. The benefits of implementing dynamic arming were estimated based on the reduced risk of USE due to system black events for the four different contingency events studied in this report (summarised in Section 2.3) in half-hourly dispatch intervals in 2023 and 2025. Full assumptions applied are summarised in Table 10.

It was found that across several different sensitivities, dynamic arming has a total net benefit ranging from $3 million to $60 million over the asset's 15-year benefit period. This assumes that the annual benefits estimated explicitly in 2023 and 2025 extend similarly over the coming 15-year period (including in the period post commissioning of PEC Stage 2). Benefits in years post-PEC Stage 2 were not calculated explicitly in this assessment.

The sensitivities tested included:

- 2023 and 2025 forecast scenarios.
- 150 MW and 400 MW of battery headroom.
- Minimum synchronous unit requirements of 1 unit or 2 units online.
- Cost reflective versus historical unit bidding profiles.

In all sensitivities, the cost benefit from implementing dynamic arming was positive or neutral. Benefits were largest in scenarios with less BESS headroom available (since the BESS frequency response assists in arresting frequency).

Table 10 Inputs and assumptions for dynamic arming cost benefit assessment

Description	Assumption	Details
Underlying load in SA	2,000 MW	Typical underlying demand in SA. Underlying demand is the best estimate of actual customer disconnection, as load supplied by DPV will also be disconnected during a black system event.
Load restoration profile	0.75	Load restoration profile is the percentage of energy not restored in the first eight hours of a black system event. This estimate is based on the profile of load restored in the first eight hours following the 2016 black system event. In this event, load restoration commenced approximately 2-3 hours after the separation, and was partially restored within eight hours. USE over the first eight hours is estimated to be 75% of the underlying demand.
Duration of system black event in SA	8.5 hrs	Duration to achieve majority of load restoration (assuming linear profile of restoration).
USE associated with each system black event	12,750 MWh	Based on assumptions above.
Likelihood of a significant multiple contingency event	0.3 per year	Likelihood of a significant multiple contingency event that includes a Heywood separation and some generation loss.

Description	Assumption	Details
		It has previously been estimated that an SA separation has a 0.6 occurrence per year[79]. It was assumed that ~50% of SA separations might also involve some significant generation loss.
Types of significant multiple contingency events	Separation + 1 station (25%) Separation + 2 station (25%) Separation + 1 station + 30% DPV (25%) Separation + 40% DPV (25%)	Assumed that if a significant multiple contingency event occurs it will be one of the four contingency events outlined in Section 2.3, with equal likelihood.
Likelihood of cascading failure	• "Fail" periods are assumed to have a 100% likelihood of leading to cascading failure • "Risk" periods are assumed to have a 50% likelihood of leading to cascading failure	Based on acceptance criteria summarised in Table 7, Section 3.1.
Capital cost of dynamic arming implementation in SA	$21.4 million	Estimated by SAPN in its emergency standards cost pass through application[80].
Asset benefit period (dynamic arming relays)	15 years	
Value of Customer Reliability (VCR)	$50.51/kWh	From 2023 IASR Workbook[81].
Weighted Average Cost of Capital (WACC)	2.34%	Aligned with discount rate in SAPN's RIT-D Project Assessment Report on the implementation of dynamic arming[82].
Discount rate	2.34%	From SAPN's RIT-D Project Assessment Report on the implementation of dynamic arming.

There are several other benefits to dynamic arming that have not been quantified in this assessment, including:

- Alleviating the V_S_HEYWOOD_UFLS constraint on HIC. This will, at times, increase the flow on HIC and improve access to the least-cost generation for customers in SA.
- Less underlying load tripped and therefore less customers disconnecting during under-frequency events.
- More granular operational visibility of UFLS load available. This will improve the accuracy of future assessments of EUFR adequacy in SA.

[79] AEMO (May 2023), Separation leading to under-frequency in South Australia, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645.

[80] At https://www.aer.gov.au/system/files/SA%20Power%20Networks%20-%20Cost%20pass%20through%20application%20-%20emergency%20standards%20%28PUBLIC%29.pdf.

[81] IASR Workbook (2023) https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[82] At https://www.sapowernetworks.com.au/public/download.jsp?id=321333.

Glossary

This document uses many terms that have meanings defined in the NER. The NER meanings are adopted unless otherwise specified.

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery energy storage system
DER	Distributed energy resources
DPV	Distributed photovoltaics
EFCS	Emergency Frequency Control Scheme
ESOO	Electricity Statement of Opportunities
EUFR	Emergency Under Frequency Response
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FOS	Frequency Operating Standards
GPS	Generator Performance Standard
HIC	Heywood Interconnector
IBR	Inverter-based resources
ISP	Integrated System Plan
MMM	Multi-mass model
NEM	National Electricity Market
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NSP	Network service provider
OEM	Original equipment manufacturer
PEC	Project EnergyConnect
PFR	Primary Frequency Response
PSFRR	Power System Frequency Risk Review
RMS	Root Mean Square model (PSS®E applied in this report)
RoCoF	Rate of Change of Frequency
SA	South Australia
SAPN	SA Power Networks
UFLS	Under Frequency Load Shedding
USE	Unserved energy