South Australia – power system operation as a viable island

June 2018

Important notice

PURPOSE

AEMO has prepared this document to provide information about the levels of system strength and inertia required to operate the South Australian region of the NEM under islanded conditions, as at the date of publication.

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VERSION CONTROL

Version	Release date	Changes
1.0	29/6/2018	Final version

Executive summary

This report details the results of AEMO's investigation into the operation of the South Australian (SA) power system when it is at a credible risk of islanding and when it is an island. This investigation fulfils Recommendation 8 in AEMO's final report on the September 2016 SA state-wide power outage[1], and supplements AEMO's *South Australia System Strength Assessment Report* and *Transfer Limit Advice for South Australia System Strength*[2], which set out the criteria for minimum online synchronous generation in SA.

This report focuses on the level of system strength and inertia required for the SA power system to operate in a secure operating state following a credible separation event. As such it contributes to confirming system strength requirements[3] under the National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10[4] and inertia requirements[5] under the National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9[6].

System strength under islanded conditions

AEMO has conducted a suite of assessments to determine what is required to manage the security of the SA power system when it is at a credible risk of islanding.

As discussed in AEMO's *South Australia System Strength Assessment Report*, operational periods with high levels of asynchronous generation present a challenge to maintaining adequate system strength. AEMO has assessed whether this condition would be exacerbated further under islanded conditions. Without the contribution of the rest of the National Electricity Market (NEM) through the Heywood Interconnector, the dynamic stability of generation in SA could be very different. Therefore, there are concerns that acceptable dispatch scenarios identified for system normal conditions might no longer be adequate to maintain the SA power system in a secure operating state.

Using detailed power system simulations and a methodology similar to that described in the *South Australia System Strength Assessment Report*, AEMO completed additional studies in which the SA region was subjected to a credible islanding condition, and then evaluated its performance when it is an island.

The results of the studies completed to date[7] indicate the following:

- No changes are required to the existing *Transfer Limit Advice for South Australia System Strength* for minimum in-service synchronous generation when SA is at a credible risk of separation.
- The minimum synchronous generation combinations specified in the *Transfer Limit Advice for South Australia System Strength* would be sufficient for the formation of a stable island.

Frequency control and inertia

In addition to the immediate SA system strength requirements, AEMO also investigated the frequency response of the SA power system following a credible islanding event that leads to a separation of the SA power system from the rest of the NEM. High levels of existing asynchronous generation not only impact system strength, but also have a limited ability to assist with rapid changes in power system frequency, due to having no inherent physical inertia.

Therefore, AEMO assessed whether islanded conditions could also result in increased susceptibility to higher rates of change of frequency (RoCoF) and, potentially, a limited ability for frequency to recover to within the required frequency levels for secure power system operation. This could be in response to the credible contingency event that caused SA to separate from the rest of the NEM, or a subsequent credible contingency event.

This assessment also considered whether, during periods of low system strength, voltage disturbances could have broader impacts on the SA power system compared to a stronger power system. This could affect more generation

[1] AEMO, *Black System South Australia 28 September 2016*, published March 2017, available at https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage.

[2] The *South Australia System Strength Assessment Report* was published on September 2017, and the *Transfer Limit Advice for South Australia System Strength* is updated from time to time. Both are available at https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment/

[3] Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review/2018

[4] Available at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

[5] Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review/2018

[6] Available at https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque.

[7] AEMO continues to evaluate scenarios in response to operational requirements.

and, in turn, lead to additional, more severe frequency disturbances if the affected generating systems were to reduce or rapidly change their output, or trip.

AEMO's investigation indicates:

- The existing *Transfer Limit Advice for South Australia System Strength* is sufficient to arrest the frequency within the containment band (47 hertz [Hz]) as specified in the frequency operating standards (FOS).
- Further frequency control services (comprising of Contingency FCAS or Fast Frequency Response (FFR)), in addition to that provided by the *Transfer Limit Advice for South Australia System Strength*, are required to avoid load shedding after a credible contingency in the SA island.
- Following the occurrence of a credible separation event and following a credible contingency in an islanded SA power system, most remote wind farms are more susceptible to tripping relative to system intact conditions.
  - Increasing the level of inertia in the network has not shown any substantial reduction in this susceptibility. Runback of the most susceptible remote wind farms is considered necessary to assist with re-securing the SA power system under islanded conditions.
- The maximum RoCoF observed in the studies conducted with acceptable combination of synchronous generating units was in the order of -0.9 Hz/s for the separation event, and approximately -1.4 Hz/s for the subsequent credible contingency in the island.

The following is, therefore, recommended:

1. **Controlled post-separation wind farm runback schemes to reduce frequency excursion following a credible contingency event in an island.**

   A controlled and co-ordinated post-separation runback of relevant wind farms would assist to limit and avoid further load shedding to maintain SA in a secure operating state following a credible contingency in the island.

2. **No change to the Heywood Interconnector import limit during a credible risk of separation.**

   AEMO recommends no change to the Heywood Interconnector import limit (of 50 MW) during periods of a credible risk of separation.

3. **Additional frequency control services required.**

   Further frequency control services (comprising Contingency FCAS and/or FFR), in addition to that provided by the system strength minimum synchronous generation combinations, are required to avoid load shedding following a credible contingency in the islanded power system.

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1. Introduction

Islanding of the South Australia (SA) region is itself a relatively rare event, and where a credible contingency event is likely to result in islanding, constraint equations are invoked that minimise the potential for generation and load disruption to the SA power system. As an island, the dynamics of the SA power system change remarkably, because the loss of the Heywood Interconnector prevents the provision of system strength and inertial contributions from the remainder of the National Electricity Market (NEM). This can affect the ability of the SA power system to remain in a secure and stable operating state, and have stable, controlled responses to subsequent contingency events.

Following the identification of a system strength gap in SA and recommendations in AEMO's *South Australia System Strength Assessment Report*[8] setting out the criteria for minimum online synchronous generation in SA, AEMO commenced detailed electromagnetic transient (EMT) power system studies using the PSCAD™/EMTDC™ tool to determine the system strength, frequency control and inertia requirements for the SA power system as an island.

The PSCAD™/EMTDC™ cases developed for the system strength studies have been validated and independently reviewed to confirm the veracity of the modelling methodology used by AEMO[9].

The purpose of the SA islanding PSCAD™/EMTDC™ studies was to:

- Determine whether the existing synchronous generation dispatch combinations for meeting the minimum system strength requirements in SA during system normal conditions would be sufficient to both:
  - Form a stable island following a credible separation event during import and export conditions.
  - Ensure secure and stable operation of the SA power system following a credible fault under islanded conditions.
- Determine the requirement for additional in-service synchronous generation or other mechanisms (such as generator runback schemes), if the existing synchronous generation dispatch combinations were found to not be sufficient to maintain adequate system strength to enable stable formation of an island and stable operation under islanded conditions.
- Assess the frequency response (in the Fast FCAS timeframe) of the SA power system following islanding on a credible loss of the Heywood Interconnector.
- Identify inertia and frequency control requirements to maintain frequency within the islanded SA power system within the required bands specified in the frequency operating standard (FOS).

[8] The *South Australia System Strength Assessment* report was published on September 2017, and the *Transfer Limit Advice for South Australia System Strength* is updated from time to time (most recently v.7.0 in April 2018). Both are available at https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment.

[9] Two independent review were commissioned by Manitoba HVDC Research Centre and PSC Consulting. The independent review reports can be found at https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment.

2. System strength

2.1 Minimum synchronous generator dispatch

Following the recommendations in AEMO's *South Australia System Strength Assessment Report*[10] setting out the criteria for minimum online synchronous generation in SA, AEMO commenced detailed electromagnetic transient (EMT) power system studies using the PSCAD™/EMTDC™ tool to determine the system strength requirements for the SA power system as an island.

The purpose of the SA islanding PSCAD™/EMTDC™ system strength studies using the minimum online synchronous generation was to determine:

- Whether the existing synchronous dispatch combinations for meeting minimum system strength requirements in SA during system normal conditions would be sufficient to both:
  - Form a stable island following a credible separation event during import and export conditions, and
  - Ensure stable operation of the SA power system following a credible fault under islanded conditions.
- The requirement for additional in-service synchronous generation or other mechanisms (such as generator runback schemes) to enable stable formation of an island and stable operation under islanded conditions, if the existing synchronous generation dispatch combinations were not sufficient.

Chapter 2.1 provides the PSCAD™/EMTDC™ results for the response of the islanded SA power system, using representative minimum synchronous generation combinations for system strength. It includes both the 1,295 megawatt (MW) (Stage 1) and 1,870 MW (Stage 2) asynchronous generation levels, which correspond to the asynchronous generation levels referred to in the *Transfer Limit Advice for South Australia System Strength*[11].

2.1.1 Generator dispatch scenarios and assumptions

The EMT cases developed for the *South Australia System Strength Assessment Report* (under interconnected conditions) were also used for the studies using the minimum synchronous generation dispatch in SA. However, to emulate the credible risk of separation and to take into account the latest network conditions, AEMO implemented the following changes to the cases.

Heywood Interconnector flow

For all cases, one of the South East to Heywood 275 kilovolt (kV) lines was set to out of service (OOS), to emulate a planned outage condition resulting in a credible risk of separation.

Under this credible risk of separation:

- The series capacitors on the South-East to Tailem Bend 275 kV lines were bypassed as per standard operational procedure during a planned outage of one of the South East to Heywood 275 kV lines.
- Heywood Interconnector import levels (flow from Victoria into SA) were limited to 50 MW, according to current operational practice.
- Heywood Interconnector export levels (flow from SA into Victoria) were either limited to 250 MW, or determined based on the amount of inertia available for each synchronous generation dispatch scenario to satisfy the 1 hertz per second (Hz/s) rate of change of frequency (RoCoF) SA constraint equation, which applies during a credible risk of separation for a planned outage condition.

Hornsdale Power Reserve (HPR) battery connection

The case was updated to include the HPR battery storage system. It was assumed that the initial output would be set to 30 MW, with a maximum of ±70 MW available for frequency control and emergency services.

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[10] The *South Australia System Strength Assessment* report was published on September 2017, and the *Transfer Limit Advice for South Australia System Strength* is updated from time to time. Both are available at https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment.

Synchronous generation dispatch combinations

Representative minimum synchronous generation dispatch combinations for system strength referred to in the SA limit advice were used.

The Low_XX and High_XX synchronous generation combinations referred to in Chapter 2.1 and the Appendices correspond to the dispatch combinations detailed in the SA limit advice.

Modelling of under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) schemes

The SA UFLS and OFGS schemes were also modelled:

- The automatic UFLS is activated if the power system frequency drops below 49 Hz. The extent of load shedding is determined by the frequency nadir (refer to Appendix A5).
- The OFGS is activated when the power system frequency increases above 51 Hz by tripping wind farms that participate in the OFGS. The participating wind farms and over-frequency level at which each wind farm will disconnect were as specified in the relevant wind farm performance standards.

2.1.2 Study sequence and assumptions

For all results presented in this chapter, the following steps were performed in the PSCAD™/EMTDC™ simulation:

1. Following initialisation of model dynamics, a credible SA separation event was applied at 15 or 20 seconds.
   - This involved applying a double-line-to-ground fault on the single in-service South East to Heywood 275 kV line, and tripping the line following fault clearance (100 milliseconds (ms)), separating SA from the rest of the NEM.
2. A second credible contingency event was applied after the SA power system had stabilised following the credible separation event.
   - This involved application of a double-line-to-ground fault near Snowtown 2 Wind Farm, resulting in its tripping (270 MW).

The following assumptions applied to all cases studied:

- All in-service synchronous generating units and the HPR battery have frequency droop control enabled, which activates when the frequency exceeds the normal frequency operating band (49.85 Hz-50.15 Hz).
- The HPR battery would be generating 30 MW prior to the credible separation event and, therefore, only 70 MW of raise response would be available for its fast frequency response (FFR).
- The discharge limitation (10 MW/hr) of the HPR battery raise response was modelled in the import cases by reducing the battery response to 0 MW, 10 seconds after separation, where the 10 seconds simulates the maximum discharge timeframe[12].
- All synchronous generation were operating at their minimum MW levels, consistent with the studies carried out for system strength assessment under system normal conditions.
- No wind farms provided frequency control responses.

2.1.3 Assessment criteria

The following criteria were used to determine if a generation dispatch scenario resulted in the formation of a stable island and stable operation under islanded conditions:

- All synchronous generation returns to steady-state conditions following the credible separation event and subsequent credible contingency event in an islanded condition.
- Asynchronous generation remains online, except for generation in electrically distant parts of the network[13] or where the trip occurs in accordance with performance standards (such as voltage protection) and the trip does not have any consequential impacts[14].
- The transmission network voltages across SA return to a steady-state nominal range (0.9 per unit (p.u.) – 1.1p.u.), after the credible separation event and subsequent credible contingency event in an islanded condition.

[12] The actual discharge time for the HPR battery operating at 100MW is about six minutes.

[13] As detailed in the *South Australia System Strength Assessment* report (September 2017), these electrically distant wind farms are still likely to significantly reduce output or disconnect in response to a credible fault with high asynchronous generation penetration. This known issue is due to the low short circuit ratio at their connection points.

[14] In accordance with the Power System Stability Guidelines, available at https://www.aemo.com.au/media/Files/Other/planning/0220_0005.pdf.

2.1.4 Summary of results

The results of the SA islanding PSCAD™/EMTDC™ studies indicate that, following a credible loss of the Heywood Interconnector, the minimum synchronous generation dispatch combinations for system strength for the 1,295 MW (Stage 1) and 1,870 MW (Stage 2) asynchronous generation levels would be sufficient to form a stable SA island, and that the SA island will remain stable following an additional credible contingency event.

For both import and export scenarios studied:

- The results also show that the South-East wind farms trip soon after the separation event on wind turbine protection in response to the nearby fault. For certain import scenarios, further electrically distant wind farms tripped following the subsequent credible contingency.

  However, even with the loss of these wind farms, all system strength success criteria were met and the formation of a stable island and stable operation under islanded conditions was achieved. Examples of power system voltage responses for the weakest scenario studied are provided in Appendices A1 and A2.

- While all transmission voltages remained within 0.9 p.u-1.1 p.u, the 11 kV metro distribution voltage (near North Adelaide) exceeded and remained above 1.1 p.u following the subsequent credible fault. It is expected that distribution network voltage control mechanisms (not modelled here) would act to correct this.

2.2 Recommendations

Based on the PSCAD™/EMTDC™ study results, AEMO recommends no change to the SA System Strength Limit Advice.

This is because the studies indicate that no additional synchronous generation above the combinations specified *Transfer Limit Advice for South Australia System Strength*, is needed:

- To form a stable island under import or export conditions, and
- For stable operation of the island following a further credible contingency event.

Further analysis will be conducted if the available level of synchronous generation were to be reduced, changed from the dispatch combinations in the current limit advice, or displaced by other synchronous machines (such as synchronous condensors).

3. Frequency control and inertia

In power systems that are synchronous in nature, inertia and frequency control are closely coupled. A power system with high inertia can resist large changes in frequency arising from a contingency that leads to an imbalance in supply and demand. Lower levels of inertia increase the susceptibility of the system to rapid changes in frequency because of such an imbalance.

AEMO conducted detailed studies to assess whether low inertia during islanded conditions could also result in increased susceptibility to higher RoCoF and potentially, a limited ability to recover frequency to within the required frequency levels for secure power system operation. This could be in response to the credible contingency event that caused SA to separate from the rest of the NEM, or a subsequent credible contingency event in the island.

The following assessment relating to the SA islanded system frequency response was conducted:

- Evaluation of the frequency response of the SA power system using the inertia provided by the minimum synchronous generation combinations for system strength. The frequency response was evaluated by its compliance with the Frequency Operating Standards for a credible contingency event; and
- Determination of additional measures that may be required to avoid load shedding in SA in response to frequency deviations, minimising the disruption of supply to customers.

3.1 Frequency Operating Standards

The Frequency Operating Standards[15] (FOS) specify that:

- In response to a contingency that results in an islanded region, the frequency should be contained within 49 to 51 Hz, or a wider band notified to AEMO by a relevant Jurisdictional System Security Coordinator.
  - In SA, this wider band is between 47 to 52 Hz.
- The frequency following islanding should recover to 49.5 to 50.5 Hz within 10 minutes.
- Once islanded, a further contingency event should result in the frequency being contained within 49 to 51 Hz, and then returning to 49.5 to 50.5 Hz within five minutes.
  - However, for a contingency event in an islanded system that results in a further contingency event (i.e. a multiple contingency event), frequency should be contained within 47 to 52 Hz.

In SA, the UFLS scheme begins shedding load at 49 Hz, and the OFGS scheme begins shedding generation at 51 Hz.

3.2 Modelling of AGC and slow acting frequency controllers

Power system dynamic studies conducted and presented in Chapter 3 only account for a Fast FCAS timeframe, therefore, modelling of automatic generation control (AGC) and its impact on frequency recovery has been excluded from the analysis.

[15] Available at https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

3.3 Frequency response and minimum Synchronous Generator dispatch for system strength

The results of the studies detailed in Chapter 2.1 were further analysed to assess the SA power system frequency response (in the Fast FCAS timeframe) following a credible separation event and subsequent credible contingency in the islanded system.

3.3.1 Assessment criteria

For assessment of the SA power system frequency response, maintenance of the frequency within the bands defined in the FOS was used. That is, whether the SA power system frequency is contained within 47 Hz to 52 Hz and then can be maintained within 49.5 Hz to 50.5 Hz, corresponding to the FOS for an islanded system (recovery) after the credible separation event and subsequent credible contingency event in the island.

3.3.2 Summary of results for export conditions

Table 4 and Table 5 in Appendix A3.1 summarise the approximate settled frequency observed for export conditions following a credible SA separation event and a subsequent credible contingency event in the island.

Examples of power system frequency responses for the weakest scenario is provided in Appendix A1. These show that following separation from the rest of the NEM and a subsequent fault, the SA power system frequencies can recover to within the FOS range for an islanded system (49.5 Hz to 50.5 Hz). The large spikes in frequency displayed in the plots in Appendix A1 are related to the PSCAD™/EMTDC™ frequency measurement approach and should not be considered to be an actual response of the power system.

For certain synchronous generation combinations, the Heywood Interconnector export levels were limited to below 250 MW to satisfy the 1 Hz/s rate of change of frequency (RoCoF) SA constraint equation that applies during a credible risk of separation for a planned outage. Where sufficient inertia existed pre-separation to meet the 1Hz/s RoCoF, the interconnector flow was limited to 250 MW according to current operational practice.

It is unlikely that the outcome of these studies would change even if a 250 MW Heywood Interconnector flow was studied for all scenarios. This is in part due to the observed loss (during separation) of the South-East wind farms, which assists with recovery from over-frequency.

The following general observations can be made:

- The South-East wind farms trip soon after separation in response to the nearby fault. The trips would assist with the frequency recovery to below 50.5 Hz on an export condition.
- The OFGS scheme did not operate for all scenarios studied, because the frequency excursion did not exceed 51 Hz, which is the frequency activation level of the OFGS schemes in SA.
- In addition to the loss of the South-East wind farms soon after separation, in certain cases either one or a combination of electrically distant wind farms and type II[16] wind farms trip on over-voltage protection some time following the credible islanding event. The voltage protection settings for the wind farms have been modelled in accordance with their performance standards.

3.3.3 Summary of results for import conditions

Table 6 and Table 7 in Appendix A3.2 summarise the approximate settled frequency observed for an import condition. Representative power system frequency and voltage responses have also been provided in Appendix A2.

The following general observations can be made:

- Similar to the export conditions, South-East wind farms tripped soon after separation in response to the nearby fault. Conversely to the export cases, the loss of these wind farms increased the frequency excursion following the credible separation event.
- In addition to the loss of the South-East wind farms soon after separation, in certain cases, either one or a combination of the electrically remote wind farms and type II wind farms tripped on over-voltage following the credible islanding event. The voltage protection settings for the wind farms have been modelled in accordance with their performance standards.
- In the majority of scenarios studied the frequency did not recover to 49.5 Hz following both the credible separation event and subsequent credible contingency. However, the initial separation event and, in some cases, the subsequent credible contingency resulted in additional unexpected tripping of remote wind farms. This was considered a multiple contingency event.

[16] A type II wind farm is one that compromises of wind turbine generators (WTG) that consist of wound rotor induction generators connected directly to the WTG step-up transformers, including a variable resistor in the rotor circuit. The variable resistance is achieved through resistors and power electronics devices.

The FOS for a separation event and multiple contingency events when SA is islanded allows for a wider containment band (47 Hz) and longer period for frequency recovery to 49.5 Hz. For all scenarios studied, the frequency did not exceed 47 Hz for the separation event or a subsequent multiple contingency event.

Therefore, all minimum synchronous generation dispatch scenarios investigated could maintain frequency within the FOS for containment but could not recover to 49.5 Hz, within the study timeframe. However, the impact of AGC intervention on frequency recovery was not accounted for in the simulation studies (refer to Chapter 3.2). Further controlled actions are required to restore the frequency to 49.5 Hz as discussed in this report.

- The maximum RoCoF observed was in the order of -0.9 Hz/s for the separation event, and approximately -1.4 Hz/s for the subsequent credible contingency in the island.
- The UFLS scheme operated for the majority of scenarios following separation and in all cases following the subsequent credible fault.
  - The wider FOS containment band for SA indicates that UFLS is considered an acceptable response to contain frequency following a separation event.
  - Following the credible separation, there were a few scenarios where UFLS did not operate due to the frequency remaining above 49 Hz[17].
  - UFLS operation following the subsequent credible fault is acceptable in these studies because of the multiple contingencies that occurred causing the frequency to exceed 49 Hz, triggering UFLS.

Contingency FCAS raise response for import scenarios

Table 1 shows the steady state MW frequency raise response of all in-service synchronous generation for Stage 1 (1,295 MW asynchronous generation) dispatch combinations.

The level of Contingency FCAS raise response was modelled by the droop characteristics of each generating unit's and frequency control system, including the HPR battery. That is, there would still be MW headroom on multiple synchronous generating systems included in the studies to provide further raise services if needed, which could be managed through AGC (not considered in the studies presented in Chapter 3.3)..

These results indicate that even with a large amount of frequency raise response and load shedding, power system frequency could not recover within 49.5 to 50.5 Hz under islanding conditions within the timeframe considered in the studies. The impact of AGC intervention in recovering the frequency within 49.5 Hz was not accounted for in the studies. Further controlled actions are required to restore the frequency to 49.5 Hz as discussed in Section 3.4 of this report.

Table 1 Summary of total frequency raise response observed in the Stage 1 import cases

Asynchronous generation combination	Approximate settled MW increase after credible separation event (MW)	UFLS following credible separation event? (%)	Approximate settled MW increase after subsequent credible fault (MW)	UFLS following subsequent credible fault? (%)
Low_2	134	10.3	25	35.4
Low_3	140	0	19	24
Low_4	106	8.5	-8	28
Low_5	196	16.5	-4	41
Low_6	62	14.5	7	35.5
Low_7	92	8.5	0	28
Low_8	160	3.8	41	24
Low_9	155	0	63	22.5
Low_10	133	5.5	33	28
Low_11	11	15	47	35.5
Low_12	205	14.5	-41	40.8
Low_13	173	5.5	26	28

[17] Appendix A5 shows the South Australian load shedding profile, where 49 Hz is where load shedding is first activated.

Asynchronous generation combination	Approximate settled MW increase after credible separation event (MW)	UFLS following credible separation event? (%)	Approximate settled MW increase after subsequent credible fault (MW)	UFLS following subsequent credible fault? (%)
Low_15	90	0	27	22.4
Low_18B	128	0	76	24.1
Low_19	85	14	10	42
Low_24	35	14.5	-13	41
Low_26	66	14.5	-44	40.7
Low_30	69	14.5	-29	41
Low_33	82	8.5	-17	29.7

3.3.4 Summary

On a credible separation of SA from the rest of the NEM, the following outcomes were observed:

- Export conditions (250 MW limit).
  - Generation shedding was not required.
  - Frequency was contained within 47 Hz to 52 Hz in accordance with the FOS for SA.
  - Frequency recovered to within the 49.5 Hz to 50.5 Hz recovery range in the FOS.
- Import conditions (50 MW limit).
  - Frequency was contained within 47 Hz to 52 Hz following the separation event and subsequent credible contingency in accordance with the FOS.
  - Load shedding occurred for both the separation event and the subsequent contingency event. However, this is acceptable due to the multiple unexpected contingencies (wind farm tripping) that occurred following both events.
  - Representative studies show that the Contingency FCAS and FFR raise response of the in-service generation was not sufficient for the frequency to recover to 49.5 Hz. In these cases, the Contingency FCAS and FFR raise response for each synchronous generating unit and the HPR battery was based on their governor/frequency controls. The impact of AGC intervention on frequency recovery was not considered.

    Further investigation of the impacts of Contingency FCAS and inertia on the SA frequency response is detailed in Chapter 3.5.

For both export and import conditions, the contingency that caused SA to island also resulted in the loss of South-East wind farms. This reduced the likelihood of generator shedding and over-frequency for export conditions, but exacerbated load shedding and under-frequencies for import conditions.

3.4 Sensitivity studies

3.4.1 Impact of additional synchronous generation on SA frequency response

Further studies included an additional synchronous generating unit pre-separation to assess its impact on power system frequency recovery for several dispatch scenarios. Table 2 summarises the new settled frequency for these sensitivity studies (refer to Appendix A4.2).

These additional synchronous generation sensitivity studies indicate that for the scenarios considered, power system frequency still may not recover to 49.5 Hz, within the study timeframe. In all cases considered, settled frequency only marginally improved with the inclusion of the additional synchronous generating unit. Frequency recovery with AGC intervention was not assessed. Further controlled actions are required to restore the frequency to 49.5 Hz as discussed in this report.

Table 2 Frequency response comparison for 50 MW import scenarios with an additional synchronous generator

Asynchronous generation combination	Approximate settled frequency after separation, no additional SG unit (Hz)	Approximate settled frequency after separation, with additional SG unit (Hz)	Approximate settled frequency after subsequent fault, no additional SG unit (Hz)	Approximate settled frequency after subsequent fault, with an additional SG unit (Hz)
Low_2 (Additional machine – Torrens Island Power Station [TIPS] B)	49.1	48.9	49.3	49.35
Low_3 (Additional machine – TIPS B)	49.3	49.48	49.3	49.4
Low_8 (Additional machine – TIPS B)	49.1	49.2	48.6-48.8	49.1-49.3
Low_9 (Additional machine – TIPS B)	49.3	49.45	49.2	49.4

3.4.2 Impact of additional synchronous generation on remote wind farm operation

The SA power system has a few wind farms that are electrically remote from synchronous generating units. As discussed in the *South Australia System Strength Assessment* [18] and Chapter 3.3.3, it has been observed that these remote wind farms are more susceptible to tripping following contingency events while SA is an island, regardless of the inertia in the system.

Further studies were conducted to assess whether increasing the inertia in the island would assist in avoiding remote wind farm tripping following a credible contingency. As summarised in Table 3, the studies show that additional inertia (in this case, additional synchronous generation) in SA does not avoid remote wind farm tripping, as system strength and inertia are, for the most part, decoupled properties of the power system.

Table 3 Summary results of level of SA inertia and loss of remote Asynchronous generators in an islanded system

Island Inertia (MWs)[19]	Susceptible remote wind farms tripped post-contingency?
12200	Yes
9800	Yes
6300	Yes
5100	Yes

3.4.3 Reduced synchronous generation

AEMO undertook representative studies to determine the island's response when fewer synchronous generators were online than the system strength advice requires. The Low_2 scenario was chosen with the Pelican Point steam turbine removed from service, as it has limited ability to respond rapidly to frequency deviations (that is, this is an optimistic case[20]).

The same sequence of events was applied as described in Chapter 2.1.2, whereby the island was importing 50 MW immediately prior to separation, the remaining interconnector tripped, and a subsequent fault was applied at Snowtown 2 Wind Farm that resulted in the loss of the largest generating unit.

The resultant power system response had the following characteristics:

- RoCoF in the order of -1 Hz/s for the separation event, and approximately -1.45 Hz/s for the subsequent fault.
- Widespread load shedding across the island, in excess of 45%.
- Over 680 MW of asynchronous generation tripping (some in direct response to the fault, others to the subsequent over-voltages).

[18] South Australia System Strength Assessment, available at https://www.aemo.com.au/-/media/Files/Media_Centre/2017/South_Australia_System_Strength_Assessment.pdf

[19] Rounded to nearest 100.

[20] Studies have shown that the removal of a synchronous generator capable of frequency support will result in greater frequency deviations and hence greater load shedding.

- High voltages across the power system.
- Frequency recovering to 49 Hz.

Although dynamically stable, the results show that utilising a reduced number of synchronous generating units compared to the *Transfer Limit Advice for South Australia System Strength* is not acceptable, given the excessive loss of numerous asynchronous generating systems. The results are shown in Appendix A4.3.

3.4.4 Pre-separation South-East wind farm runback investigation

AEMO conducted an additional study to assess the impact of the observed trip of the largest South-East wind farm on power system frequency response for an import condition following loss of the Heywood Interconnector (as detailed in Chapter 3.3.3).

The study was conducted because the loss of the South-East wind farms operating at even moderate MW levels plus the loss of up to 50 MW import across the interconnector, is likely to result in an active power deficit that Contingency raise FCAS from available generation in SA would struggle to recover in the timeframe considered. This, in turn, would result in load shedding in SA to maintain frequency within acceptable operating bands.

The study considered setting the largest South-East wind farm, which tripped soon after the credible separation event, to out of service – effectively pre-curtailing its output to 0 MW prior to loss of the Heywood Interconnector. The Low_2 dispatch scenario was used for this study, and the results are in Appendix A4.1.

The results demonstrate a lower initial frequency excursion that did not exceed 49 Hz following a credible separation event. This is because the MW loss following separation was reduced due to setting the South-East wind farm output to 0 MW, allowing the power system frequency to recover to 49.5 Hz.

Although pre-separation runback of the South-East wind farms would reduce the extent of the frequency excursion and likely avoid UFLS following the separation event, the wider FOS containment band for SA indicates that load shedding is considered an acceptable response to contain frequency following a separation event.

3.4.5 Impact of Heywood Interconnector flow

As was identified in Chapter 3.4.4, the pre-separation runback of the largest South-East wind farm allowed the frequency to remain above 49 Hz following the separation event when importing to SA.

It should be noted that, in this case, the Heywood interconnector import flow was kept to 50 MW as per current operational requirements when there is a credible risk of separation.

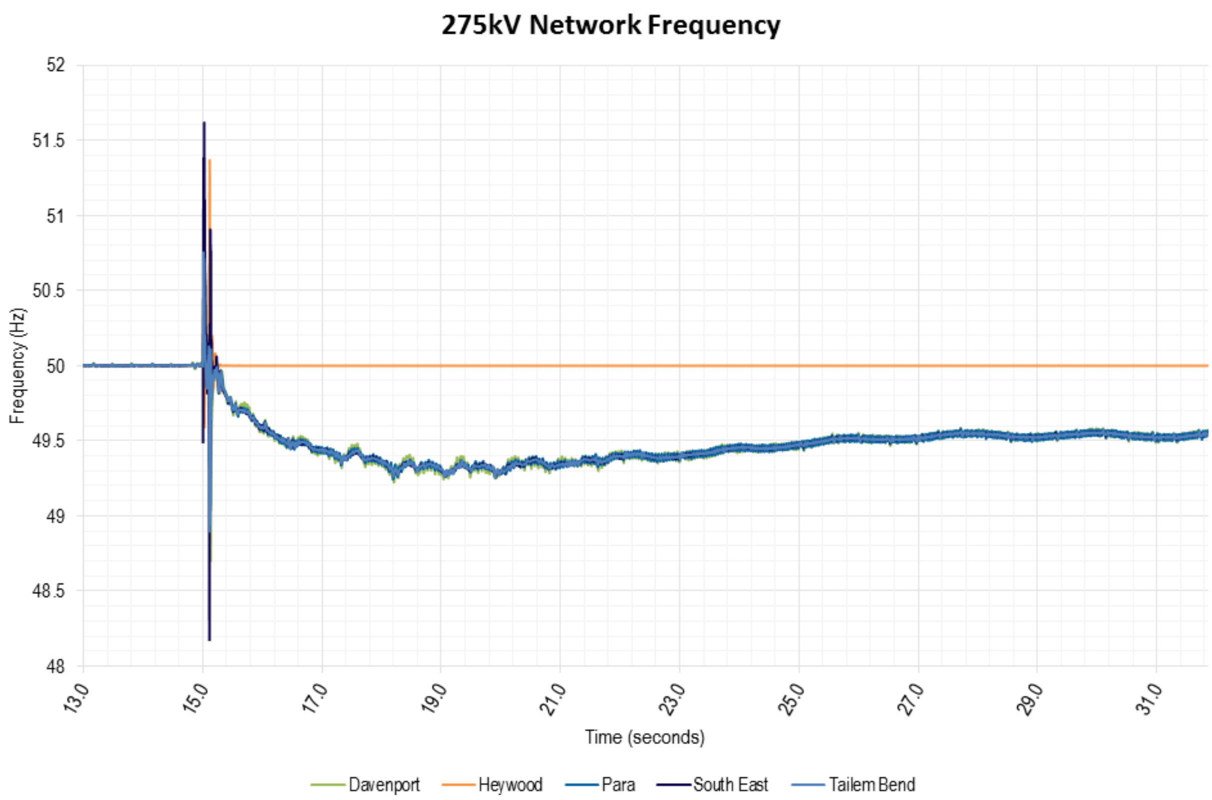
To assess the impact that the loss of the Heywood Interconnector importing at 50 MW would have on the SA frequency response following a credible separation event, further representative studies were conducted.

The studies identified that with the Heywood Interconnector importing 50 MW and with a pre-separation runback of all South-East wind farms to 0 MW, the island frequency remained above 49 Hz. Therefore, load shedding was not required to keep frequency with the FOS.

This indicates that the SA power system can avoid load shedding if the separation event only resulted in a loss of the Heywood Interconnector importing 50 MW, or a total generation loss of 50 MW following separation.

Refer to Figure 1 displaying an example of the SA islanded system frequency in response to a fault and trip of the Heywood Interconnector, where the South-East wind farms have been curtailed to 0 MW and the interconnector flow is importing 50 MW.

Figure 1 Frequency response following credible separation, with pre-separation runback of the South-East wind farms (Heywood Interconnector at 50 MW)



3.4.6 Summary

The sensitivity studies indicate the following:

- An additional synchronous generating unit, above the number required in the current *Transfer Limit Advice for South Australia System Strength*, would not assist with frequency recovery to 49.5 Hz, in the timeframe considered in the studies. The impact of AGC on frequency recovery was not considered. Further controlled actions are required to restore the frequency to 49.5 Hz as discussed in this report.
- An additional synchronous generating unit, above the number required in the current *Transfer Limit Advice for South Australia System Strength*, would not assist in avoiding potential remote wind farm tripping following a credible contingency in the island.
- A runback of the South-East wind farms would greatly reduce the chances of load shedding following a credible contingency that results in SA islanding, whilst utilising the minimum synchronous generation combinations. However, it is noted that load shedding is acceptable (albeit undesirable) following a credible separation event given the wider frequency containment band (47 Hz) for SA.
- When all South-East wind farms are curtailed to 0 MW, loss of the Heywood Interconnector importing 50 MW would not be likely to invoke load shedding following the credible separation event. This indicates there is no need to reduce the Heywood Interconnector import flow to below 50 MW during periods of credible risk of separation of SA.

3.5 Relationship between inertia and FCAS

Lower levels of inertia increase the susceptibility of the power system to fail to withstand rapid changes in frequency. Prior to the occurrence of a contingency that results in a frequency disturbance, the following two measures can be used to reduce the initial rate of change of frequency (RoCoF):

- Reduce the potential contingency size (e.g. reducing susceptible generation output or limiting interconnector flow), and/or
- Increase the inertia present in the system.

However, limiting RoCoF alone will only serve to increase the time before frequency moves outside the bands specified in the FOS. Therefore, the power system needs additional measures to bring frequency back within its normal operating range. Currently, Contingency FCAS is used for this purpose. To allow a higher level of RoCoF, faster correction of the imbalance between supply and demand is required. The timeframe of this correction needs to be faster than the than the *fast raise service* or *fast lower service*.

These types of corrections are often termed 'fast frequency response' (**FFR**). FFR requires accurate and reliable measurements of frequency. Time delays associated with the accurate measurement of frequency to facilitate an active FFR-type response would require sufficient inertia to be online prior to the contingency events.

Chapter 3.5 analyses the measures that can be considered sufficient to operate an islanded SA in a secure operating state, including the required levels of inertia and FCAS and avoidance of load shedding.

3.5.1 Identifying the worst contingency in the SA islanded system

To determine the levels of inertia and FCAS that would be needed to operate an islanded SA in a secure operating state, AEMO identified the worst case credible contingency that had the most impact when SA is islanded.

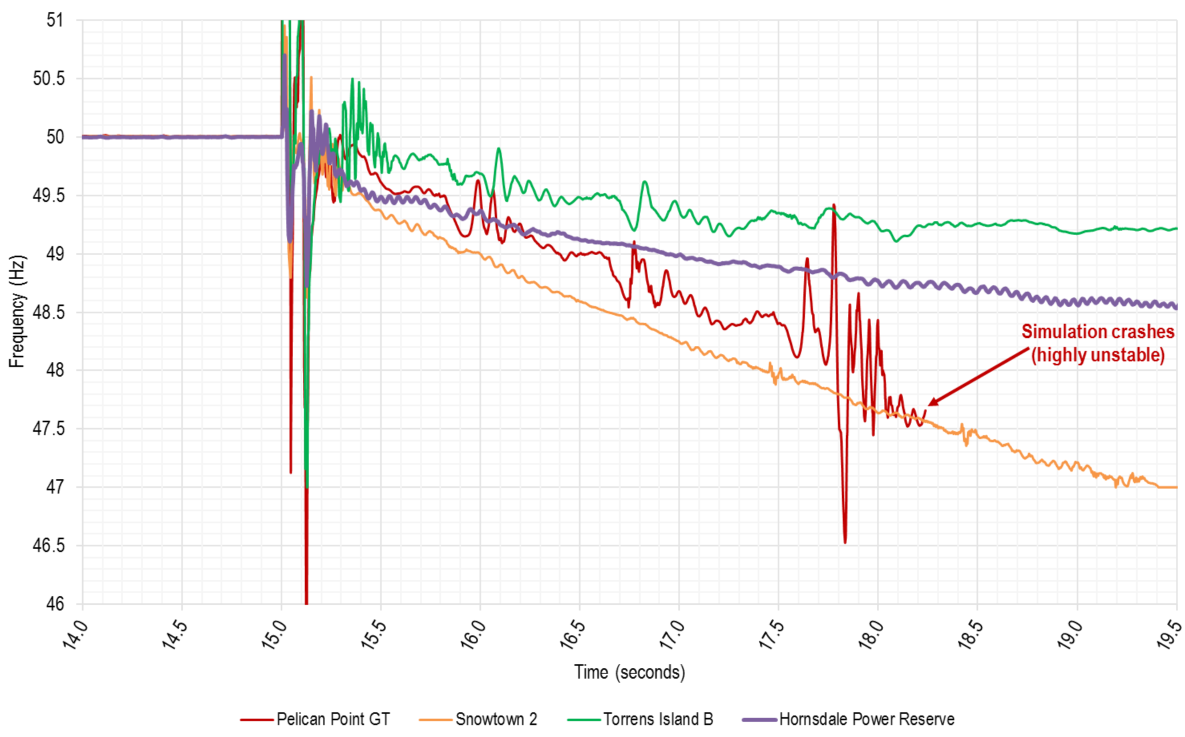
Generator contingency

The Generator contingency determined to have the most impact on an islanded SA is the loss of a Pelican Point gas turbine (GT) following a fault on its high voltage connection point. This is because the loss simultaneously:

- Reduces active power in the power system by at least 100 MW
- Results in the Pelican Point steam turbine being run back several seconds later, further reducing generation
- Reduces inertia in the power system by almost 2000 MWs
- Reduces system strength, increasing the likelihood of unstable responses and tripping of asynchronous generation

Other options were evaluated for the same operating conditions, including the loss of a 270 MW wind farm, and the loss of the HPR battery including its inherent fast frequency response. However, other non-ideal effects associated with the loss of a synchronous generating unit (in particular the Pelican Point GT) had a greater impact on power system stability than the loss of active power and FFR alone. This is shown in Figure 2.

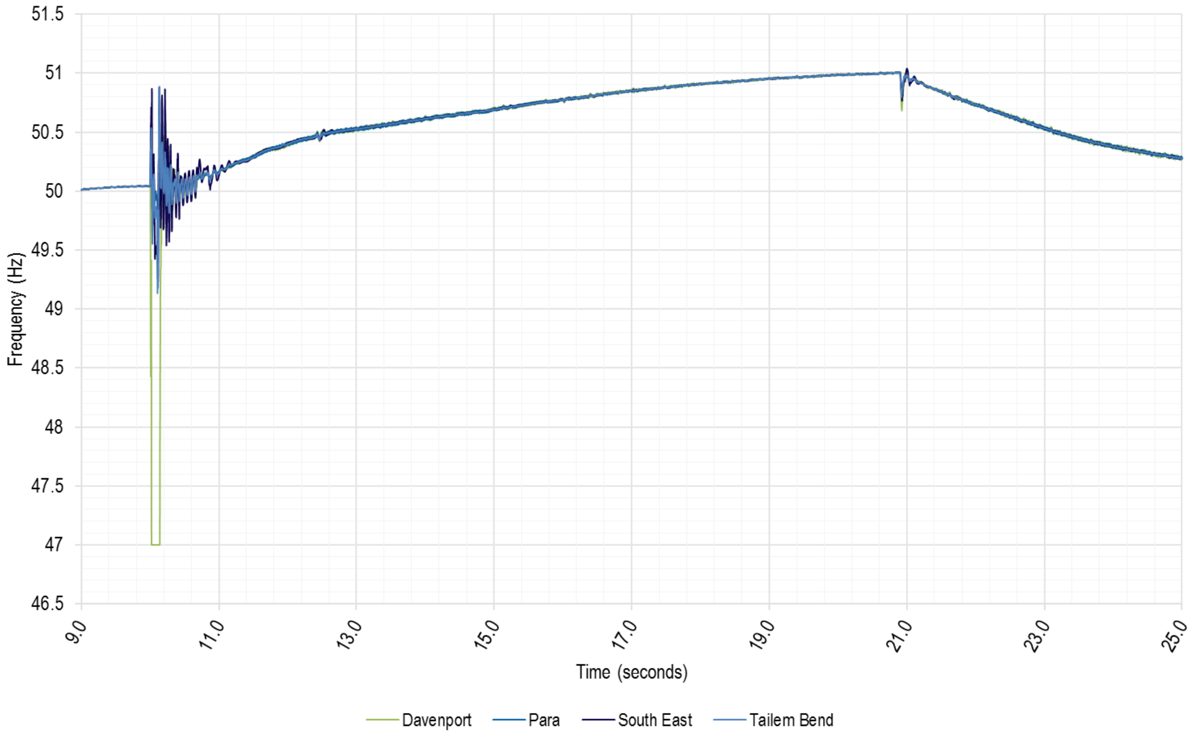
Figure 2 Comparison of contingency effects on frequency



Load contingency

The loss of a major industrial load and its impact on power system frequency was also considered. For this 172 MW contingency, Figure 3 shows the frequency response.

Figure 3 Frequency response following loss of a major load



The results show that first level OFGS was activated once the frequency reached 51 Hz.

Despite the need to activate the first level of OFGS, this contingency was not the most challenging to manage, as the average RoCoF was less than 0.1 Hz/s and no generation was lost as a direct result of the fault. Additionally, the loss of this load did not contribute to a loss of FCAS and system strength like the loss of a synchronous generating unit would.

Conclusion

It was identified that the most challenging and, hence, worst contingency in an islanded SA was the loss of a Pelican Point GT unit.

3.5.2 Frequency Control Ancillary Services and Inertia

As discussed in Chapter 2 and 3.3, the minimum generation combinations for system strength were sufficient to allow the formation of a viable island, however load shedding was a common result of multiple contingencies as frequency transiently fell below 49 Hz.

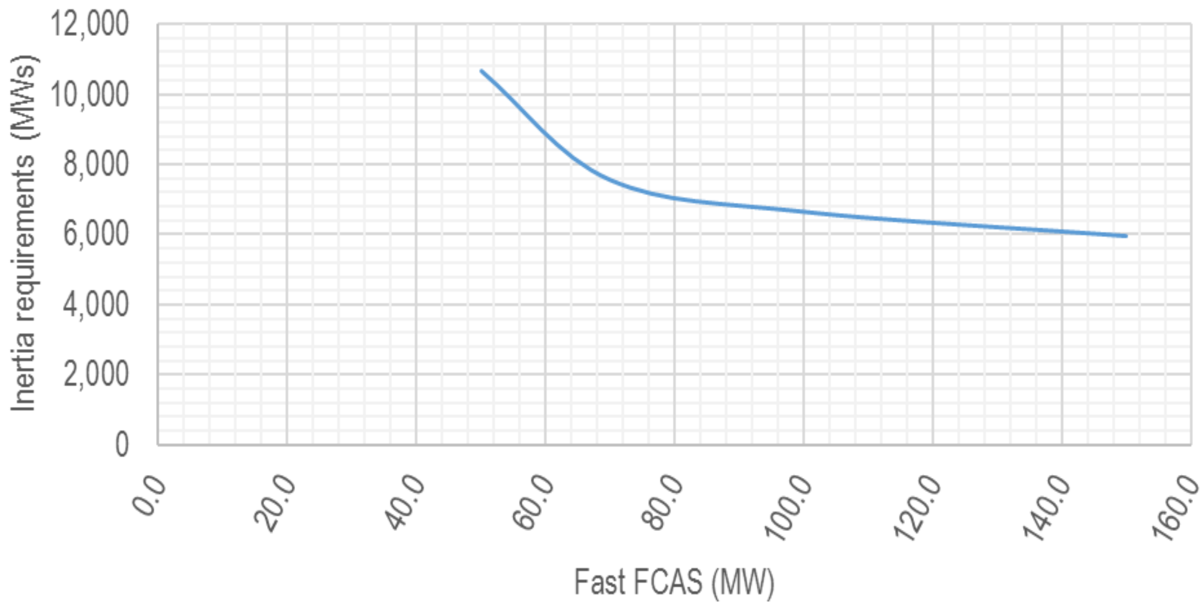
For the worst-case contingency (being the loss of a Pelican Point GT unit), iterative EMT studies were completed to determine the relationship between the amount of FCAS and inertia available in the island, and the avoidance of load shedding.

For all studies, the asynchronous generation in the island was kept at 1295 MW and priority was given to scenarios with as few synchronous generating units as possible. These relatively low system strength scenarios necessitate the use of PSCAD™/EMTDC™ to evaluate all non-ideal phenomena, as the simplified RMS models in PSS®E may lead to overly optimistic conclusions.

Inertia contributions were provided by synchronous machines only, whilst FCAS contributions were sourced from both synchronous generation and the HPR battery system, which provides an FFR-type response.

Figure 4 summarises the relationship between Fast FCAS and inertia required to operate the islanded SA in a secure operating state and avoid load shedding, for the worst-case contingency considered.

Figure 4 Relationship between Fast FCAS and inertia



3.6 Summary and recommendations

For the PSCAD™/EMTDC™ scenarios considered:

- The existing system strength minimum synchronous generator combinations will allow SA to form an island, and contain island frequency within the FOS containment band of 47 to 52 Hz.
- The existing system strength minimum synchronous generator combinations will allow SA to withstand a further contingency in an island, and contain island frequency within the FOS containment band of 47 to 52 Hz as part of a multiple contingency event.
- The existing system strength minimum synchronous generator combinations, will not allow island frequency in SA to recover to within the FOS recovery band of 49.5 to 50.5 Hz, following a separation event and subsequent contingency event. However, the impacts of AGC intervention on frequency recovery was not considered in this report. Further controlled actions are required to restore the frequency to 49.5 Hz as discussed in this report.
- The inclusion of an additional synchronous generating unit is not likely to assist island frequency to meet the FOS recovery band of 49.5 to 50.5 Hz within the timeframe studied.
- The inclusion of an additional frequency control services (Contingency FCAS or FFR) may assist in avoiding load shedding for a subsequent contingency after a secure island has formed.
- The inclusion of additional synchronous generating units does not demonstrate any tangible benefits in avoiding tripping of asynchronous generating units in remote locations.

3.6.1 Recommendations

AEMO recommends the following, based on the study outcomes presented in Chapter 3.6:

1. **Controlled post-separation wind farm runback schemes to reduce frequency excursion following a credible contingency event in an island**

   To assist with frequency recovery and returning the SA island to a secure operating state, runback of remote wind farms is required. It is recommended that the runback occur post-separation and include the remote wind farms most susceptible to trip following a credible contingency in the island.

   – Although pre-separation runback of the South-East wind farms would reduce the extent of the frequency excursion and likely avoid UFLS following the separation event (refer to Chapter 3.4.4), the wider FOS containment band for SA indicates that load shedding is considered an acceptable response to contain frequency following a separation event.

   – However, a controlled and co-ordinated post-separation runback of the relevant wind farms would assist to limit and avoid further load shedding in order to maintain the islanded SA in a secure operating state following a credible contingency.

2. **No change to the Heywood Interconnector import limit during a credible risk of separation**

   AEMO recommends no change to the Heywood Interconnector import limit (of 50 MW) when there is a credible risk of separation.

3. **Additional frequency control services required**

   Further frequency control services (comprising Contingency FCAS and/or FFR), in addition to that provided by the system strength minimum synchronous generation combinations, is required to avoid load shedding following a credible contingency in the islanded system.

Further analysis will need to be conducted if the available level of synchronous generation in SA were to be reduced, changed from the dispatch combinations in the current limit advice, or displaced by other synchronous machines (such as synchronous condensors).

A1. Minimum synchronous generator dispatch - export case example results

The following figures are for the Low_2 synchronous generation dispatch scenario under export conditions, where SA is islanded and a subsequent credible contingency occurs (loss of a major generating system).

Figure 5 Low_2 200 MW export case – Key network frequencies

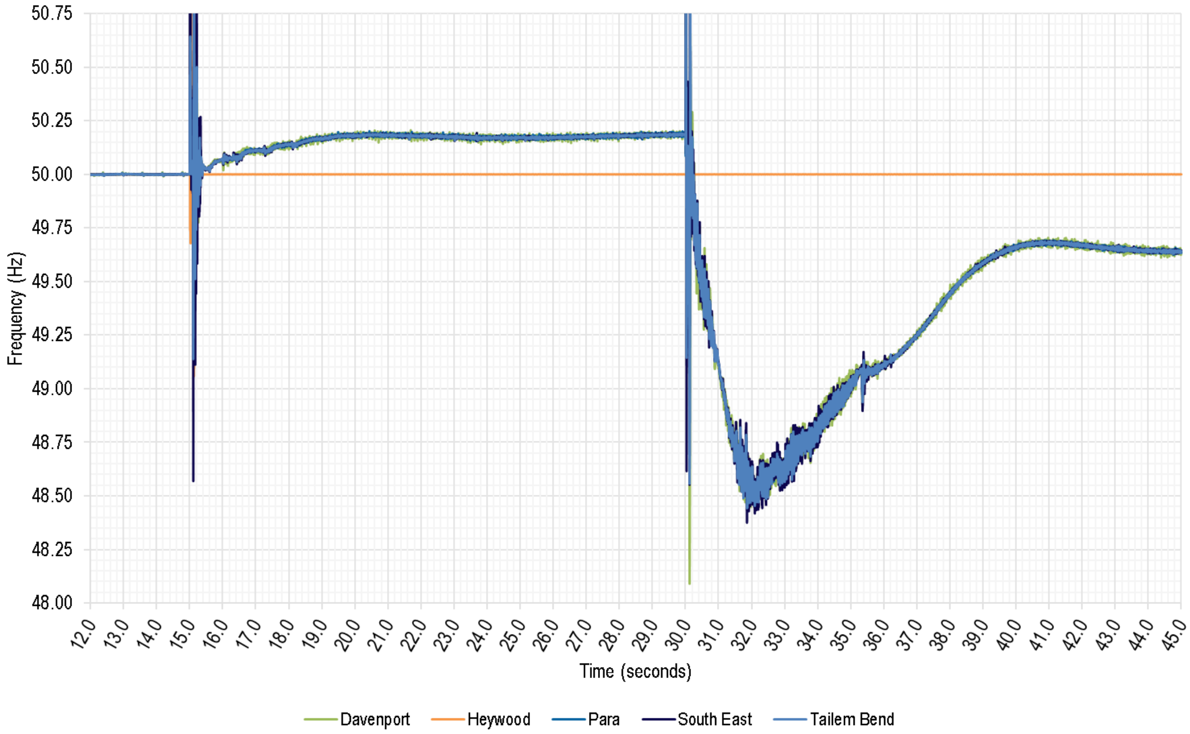


Figure 6 Low_2 200 MW export case – Key transmission network voltages

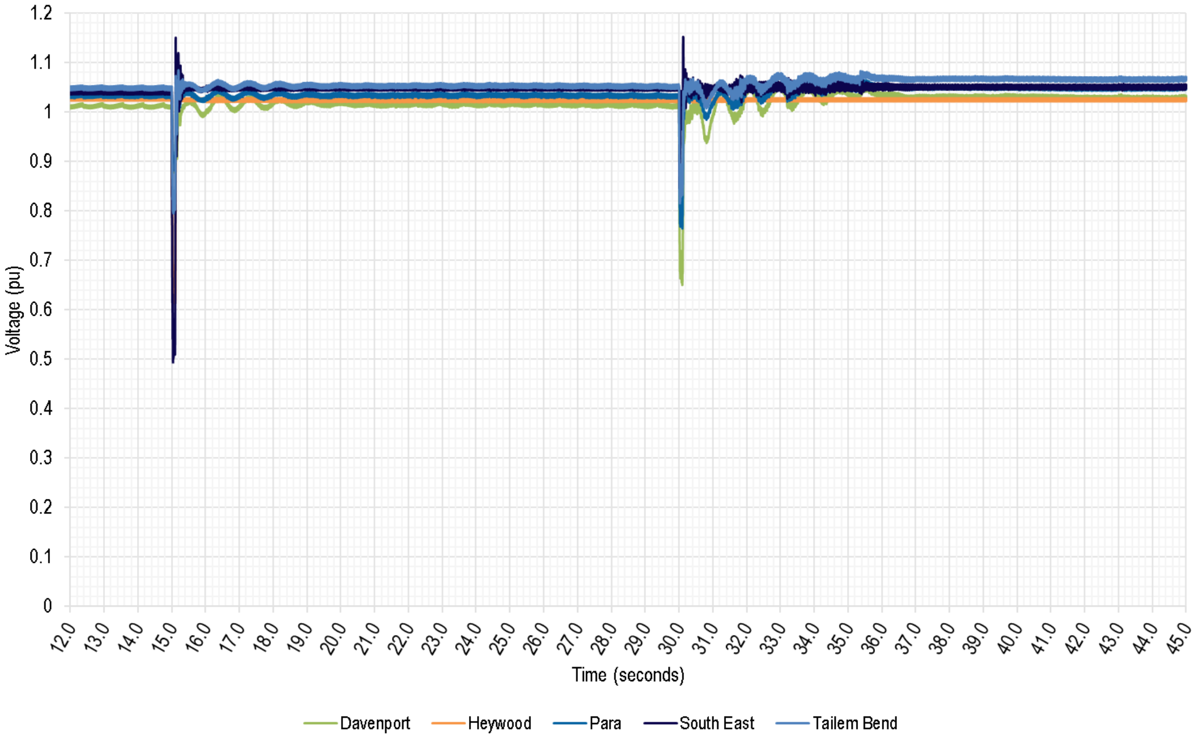


Figure 7 Low_2 200 MW export case – Key distribution voltages

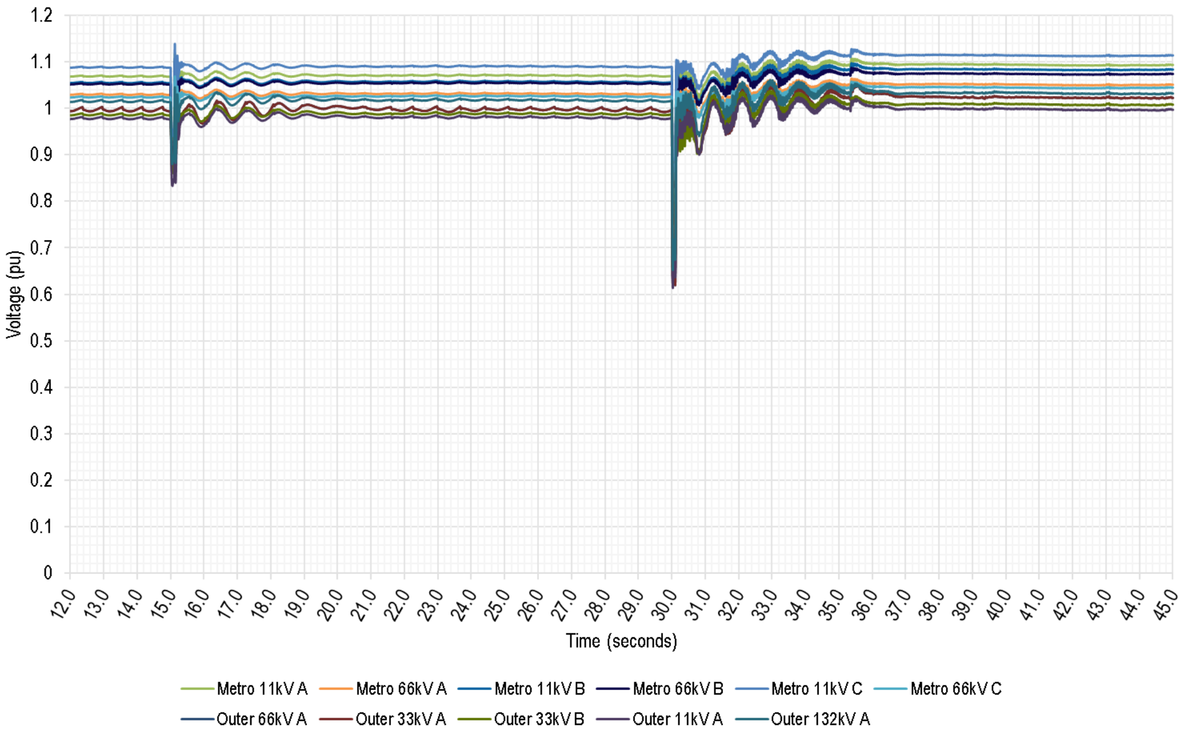
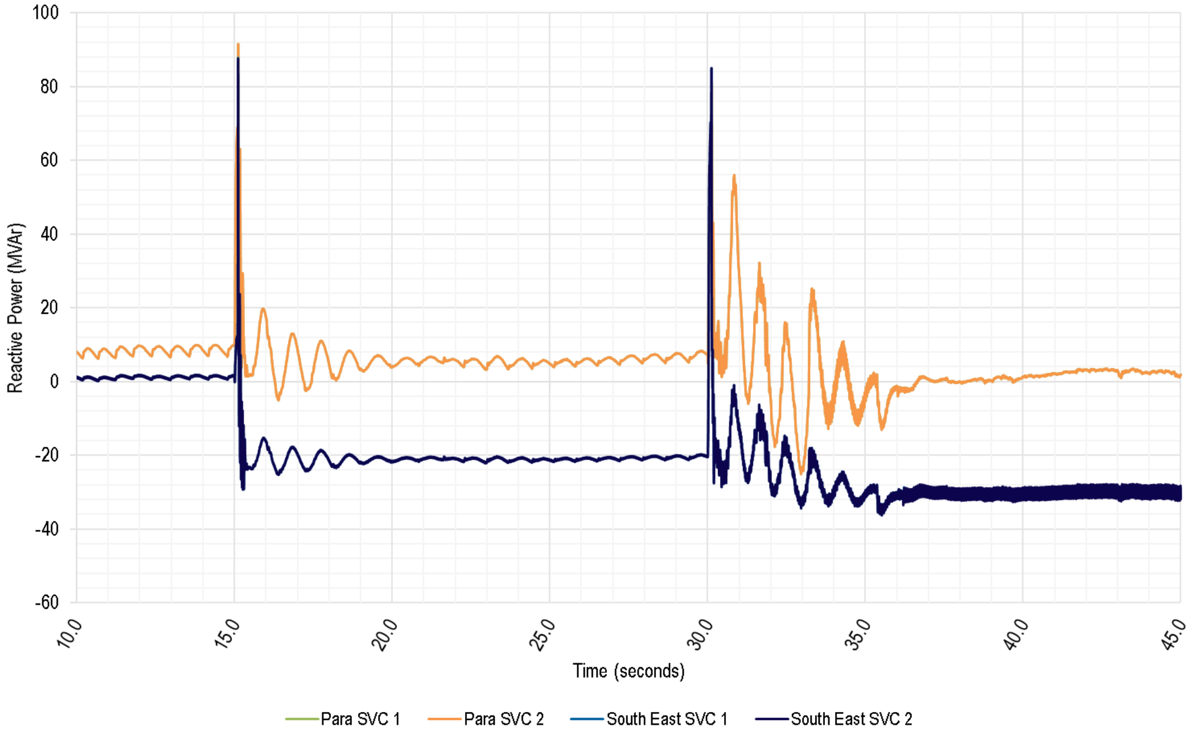


Figure 8 Low_2 200 MW export case – Para SVC and South East SVC reactive power output



A2. Minimum synchronous generator dispatch - import case example results

The following figures are for the Low_10 synchronous generation dispatch scenario under import conditions, where SA is islanded and a subsequent credible contingency occurs (loss of a major generating system).

Figure 9 Low_10 import case – Key network frequencies

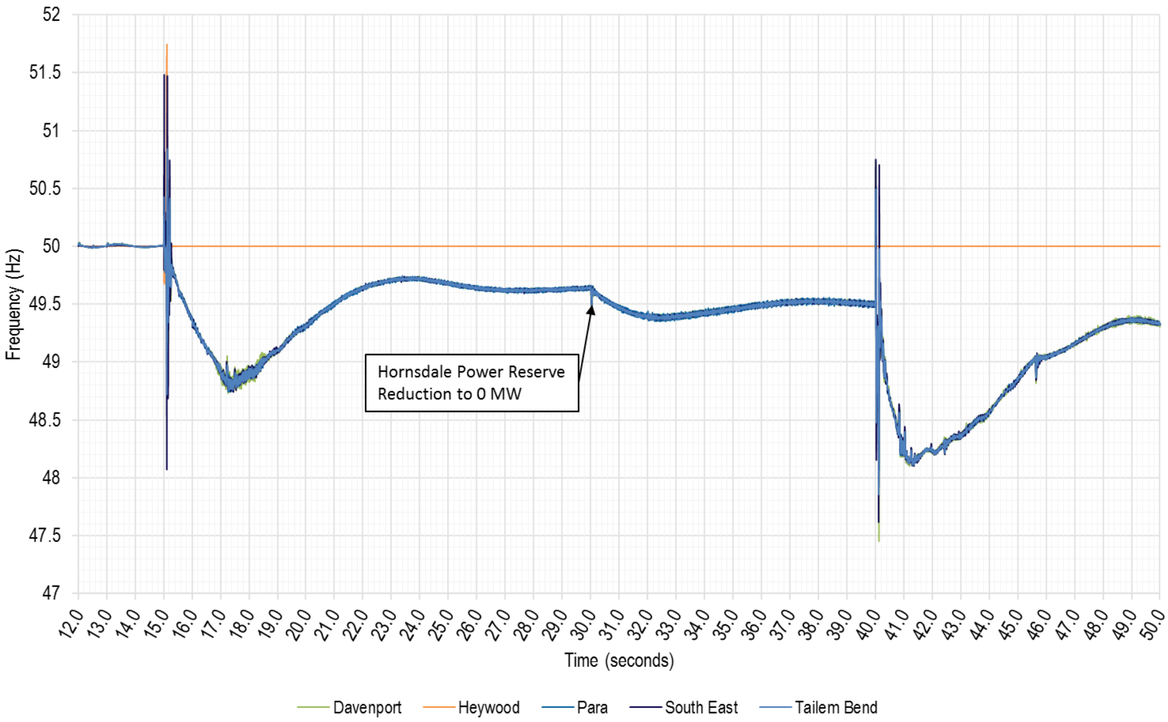


Figure 10 Low_10 import case – Key transmission voltages

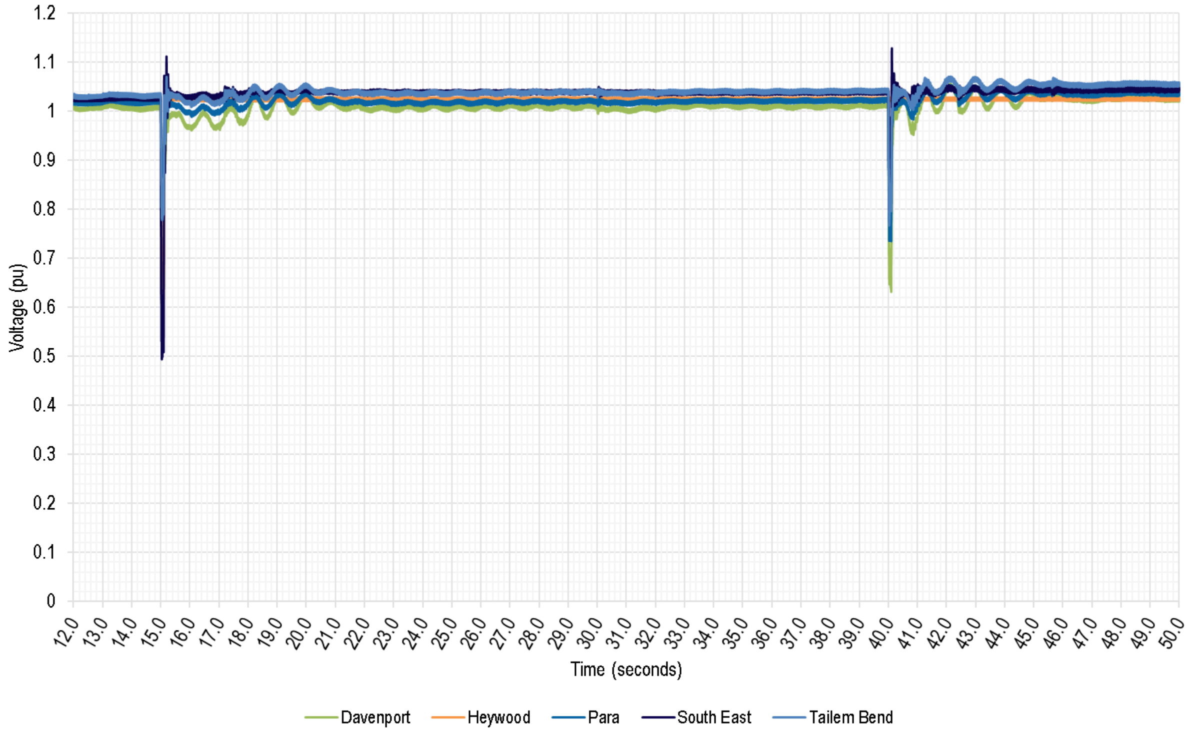


Figure 11 Low_10 import case – Key distribution voltages

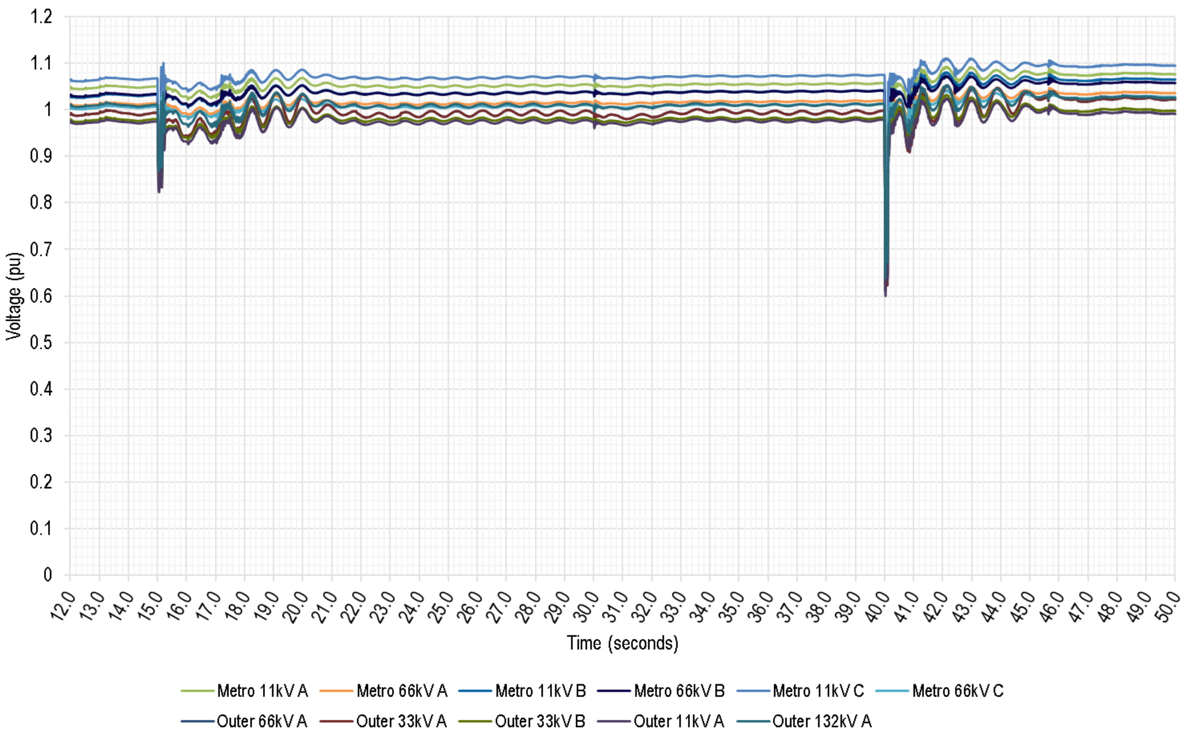
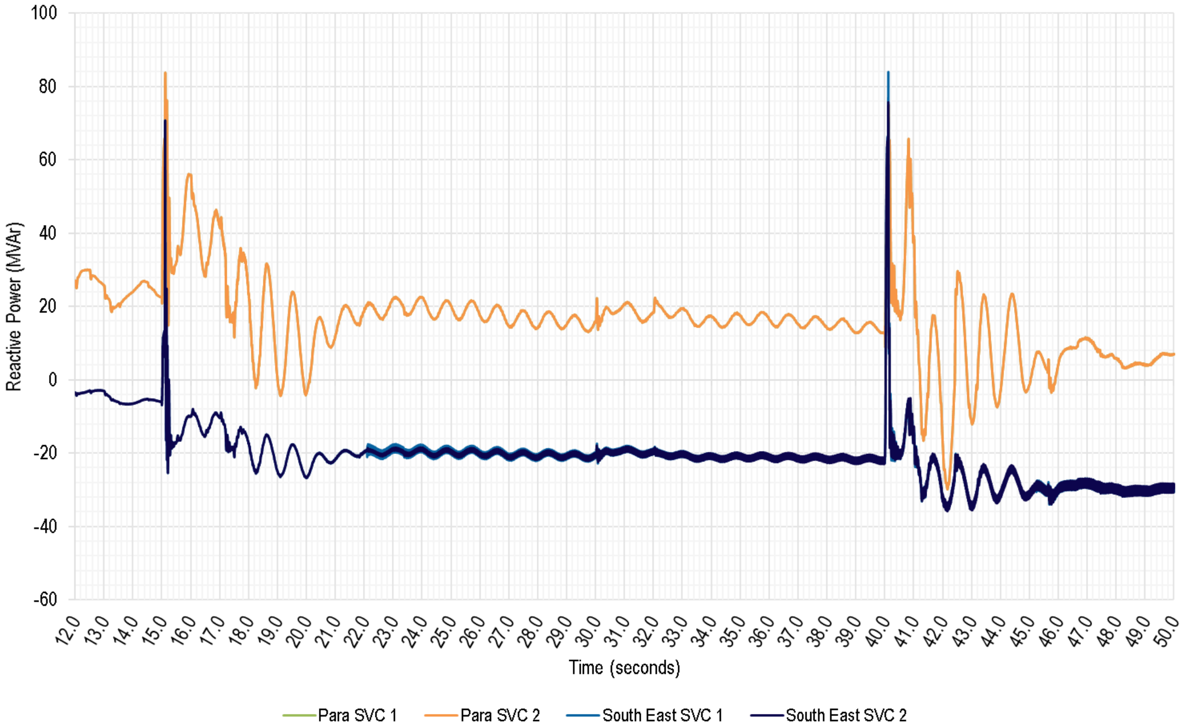


Figure 12 Low_10 import case – Para SVC and South East SVC reactive power output



A3. Frequency response results for minimum synchronous generator dispatch

A3.1 Export conditions

Table 4 Stage 1 (1295 MW asynchronous generation) frequency response summary for export scenarios

Asynchronous generation combination	Export level (MW)	Approximate settled frequency after a credible separation event (Hz)	Frequency recovered to 49.5 Hz-50.5Hz following credible separation? (Y/N)	Approximate settled frequency after a subsequent credible fault (Hz)	Frequency recovered to 49.5 Hz-50.5 Hz following credible fault? (Y/N)
Low_2	200	50.15	Y	49.65	Y
Low_3	170	50.2	Y	49.6	Y
Low_4	220	50.23	Y	49.62	Y
Low_5	170	50.01	Y	49.72	Y
Low_6	220	50.39	Y	49.8-49.85	Y
Low_7	220	50.3	Y	49.75-49.8	Y
Low_8	250	50.4	Y	49.6	Y
Low_9	190	50.2	Y	50	Y
Low_10	190	50.1	Y	49.9	Y
Low_11	220	50.39	Y	49.7	Y
Low_12	250	50.2-50.24	Y	49.85	Y
Low_13	200	50.2	Y	49.7-49.9	Y

Table 5 Stage 2 (1870 MW asynchronous generation) frequency response summary for export scenarios

Asynchronous generation combination	Export level (MW)	Approximate settled frequency after a credible separation event (Hz)	Frequency recovered to 49.5Hz to 50.5Hz following credible separation? (Y/N)	Approximate settled frequency after a subsequent credible fault (Hz)	Frequency recovered to 49.5Hz to 50.5Hz following credible fault? (Y/N)
High_2	250	49.8	Y	49.7	Y
High_3	250	50.1	Y	49.8	Y
High_4	250	49.8	Y	49.7	Y

Asynchronous generation combination	Export level (MW)	Approximate settled frequency after a credible separation event (Hz)	Frequency recovered to 49.5Hz to 50.5Hz following credible separation? (Y/N)	Approximate settled frequency after a subsequent credible fault (Hz)	Frequency recovered to 49.5Hz to 50.5Hz following credible fault? (Y/N)
High_5	250	49.9	Y	49.6	Y
High_6	250	50	Y	49.7	Y
High_7	250	50	Y	49.5	Y
High_9	250	50	Y	49.6	Y
High_10	250	50	Y	49.6	Y
High_12	250	50	Y	49.7	Y

A3.2 Import conditions

Table 6 Stage 1 (1,295 MW asynchronous generation) frequency response summary for 50 MW import scenarios

Asynchronous generation combination	Approximate settled frequency after a credible separation event (Hz)	Frequency recovered to 49.5 Hz-50.5Hz following credible separation? (Y/N)	Approximate settled frequency after a subsequent credible fault (Hz)	Frequency recovered to 49.5 Hz-50.5 Hz following credible fault? (Y/N)
Low_2	49.1	N	49.3	N
Low_3	49.3	N	49.3	N
Low_4	48.7	N	49.2	N
Low_5	48.9	N	48.9	N
Low_6	49.1	N	49.2	N
Low_7	49.4	N	49.4	N
Low_8	49.1	N	48.7	N
Low_9	49.3	N	49.2	N
Low_10	49.55	Y	49.35	N
Low_11	48.7	N	48.66	N
Low_12	48.9	N	49.3	N
Low_13	49.45	N	49.4	N
Low_15	49.25	N	49.4	N
Low_18B	49.45	N	49.35	N
Low_19	49.24	N	49.6	Y
Low_24	49.7	Y	49.9	Y
Low_26	49.6	Y	49.93	Y
Low_30	49.6	Y	49.8	Y
Low_33	49.1	N	49.4	N

Table 7 Stage 2 (1870 MW asynchronous generation) frequency response summary for 50 MW import scenarios

Asynchronous generation combination	Approximate settled frequency after a credible separation event (Hz)	Frequency recovered to 49.5 Hz-50.5Hz following credible separation? (Y/N)	Approximate settled frequency after a subsequent credible fault (Hz)	Frequency recovered to 49.5 Hz-50.5 Hz following credible fault? (Y/N)
High_2	49.3	N	49.3	N
High_3	49.4	N	49.3	N
High_4	49.5	Y	49.3	N
High_5	49.4	N	49.1	N
High_6	49.5	Y	49.3	N
High_7	49.4	N	49.1	N
High_9	49.2	N	49.1	N
High_10	49.4	N	49.3	N
High_12	49.25	N	49.5	Y

A4. Sensitivity study example results

A4.1 Pre-curtailment studies

Figure 13 Low_2 import case with largest south-east wind farm OOS – Key network frequencies

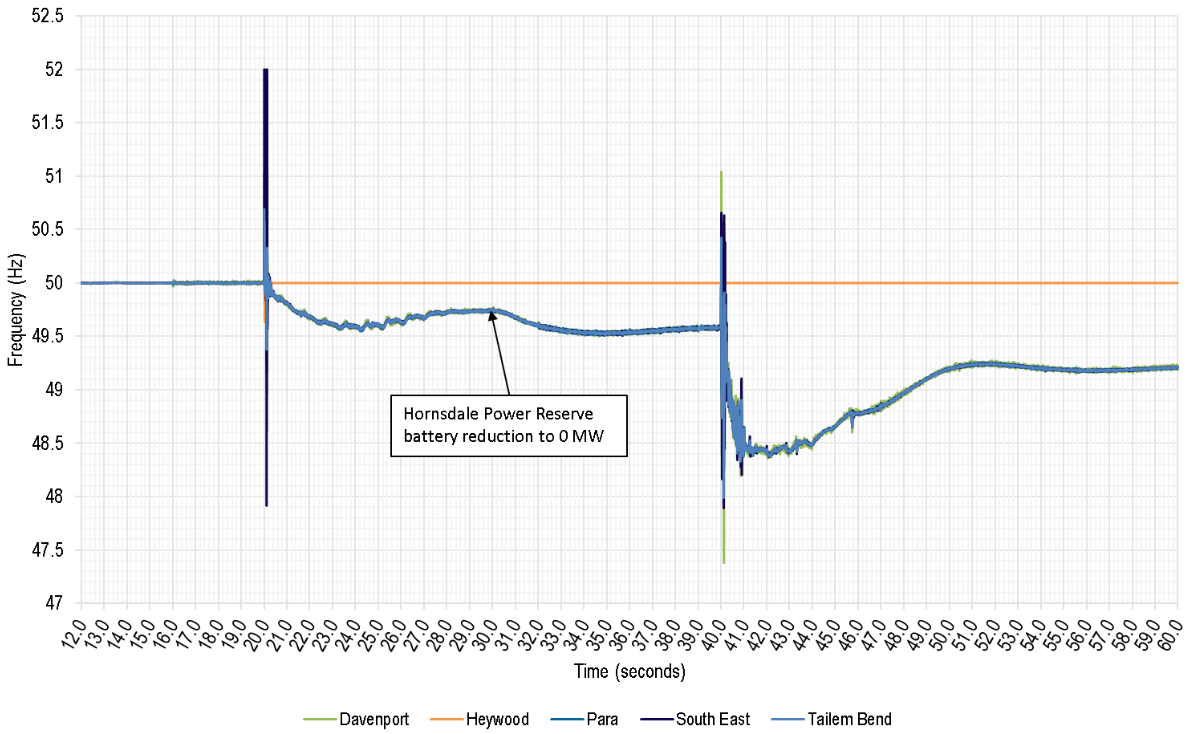


Figure 14 Low_2 import case with largest south-east wind farm OOS – Key transmission voltages

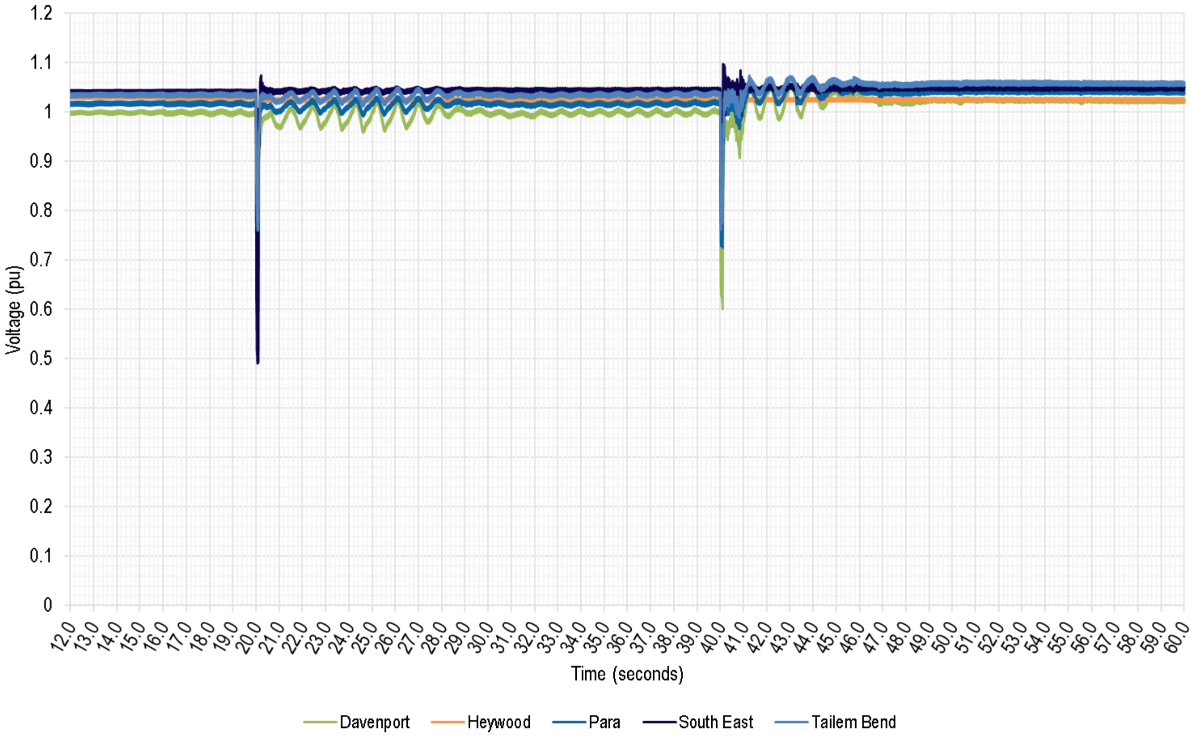
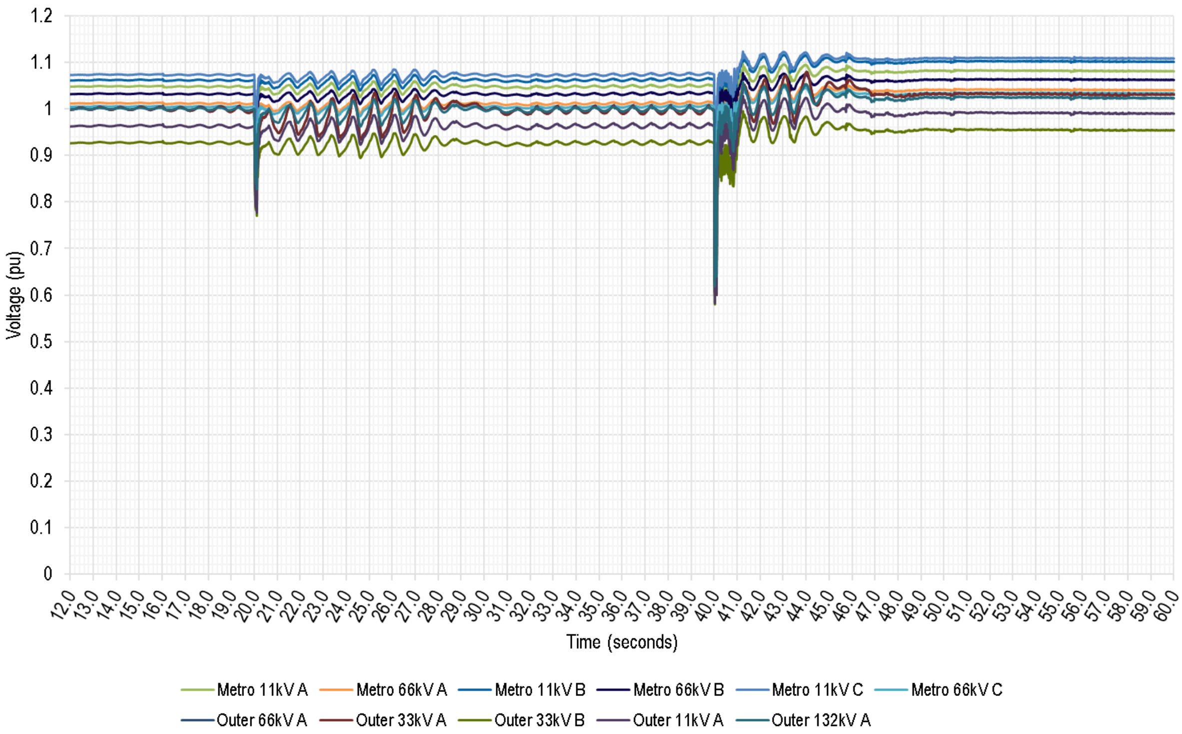


Figure 15 Low_2 import case with largest south-east wind farm OOS – Key distribution voltages



A4.2 Additional synchronous generation studies

Figure 16 Low_2 import case with additional Torrens Island Power Station (TIPS) B unit in service – Key network frequencies

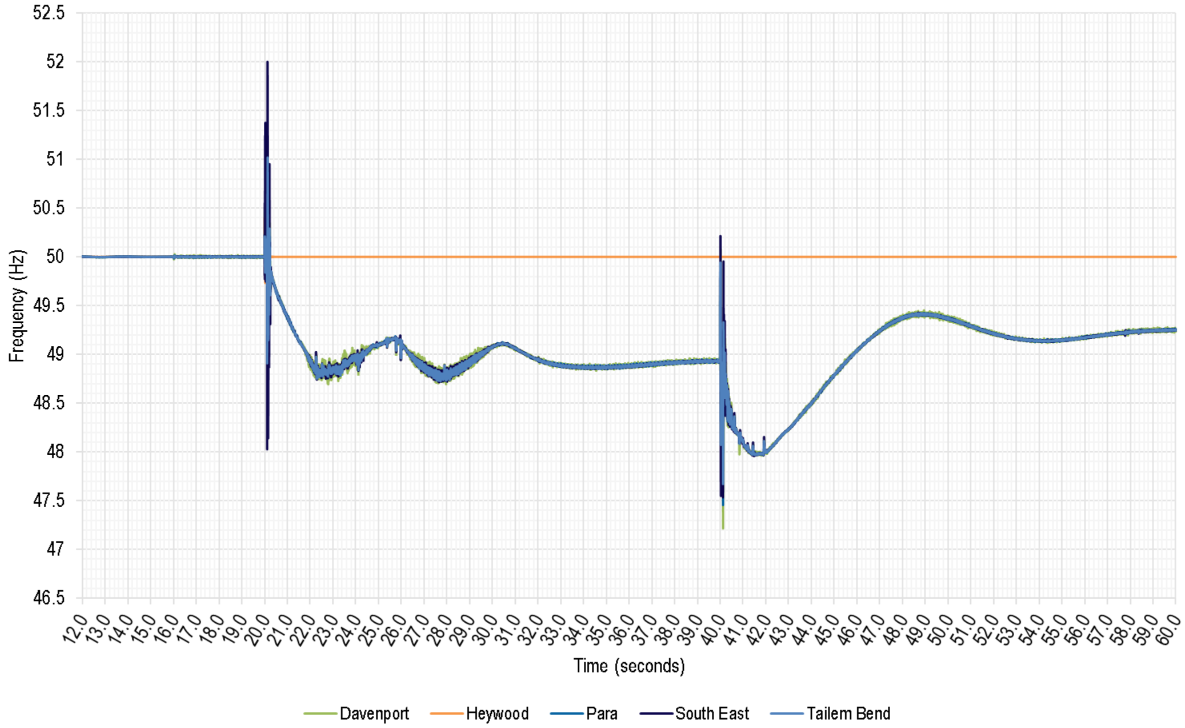


Figure 17 Low_2 import case with additional TIPS B unit in service – Key transmission voltages

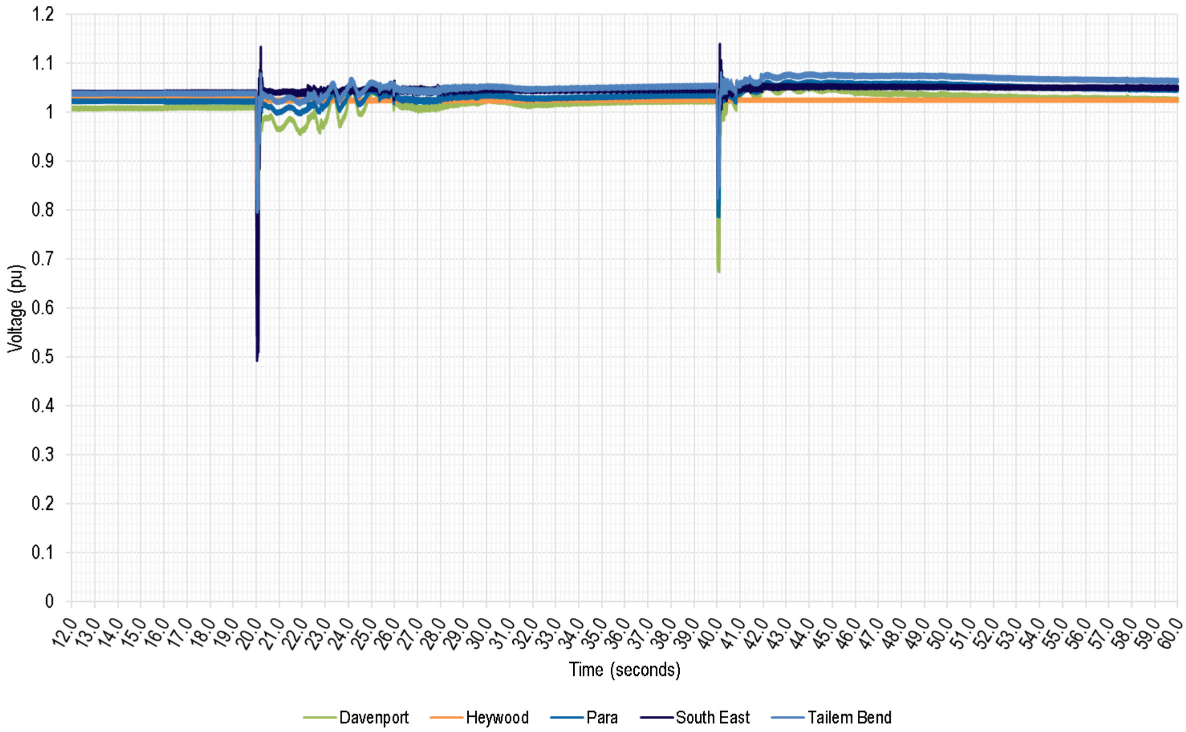
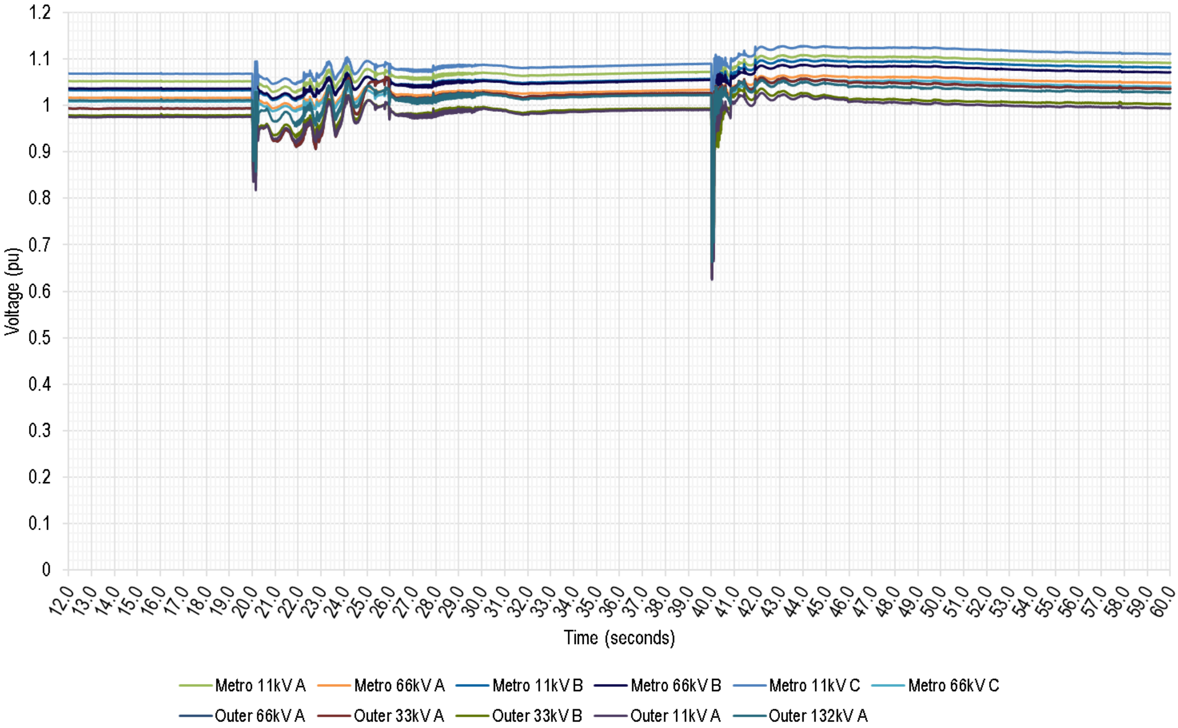


Figure 18 Low_2 import case with additional TIPS B unit in service – Key distribution voltages



A4.3 Reduced synchronous generation study

Figure 19 Low_2 import case with Pelican Point steam turbine (ST) out of service – Key network frequencies

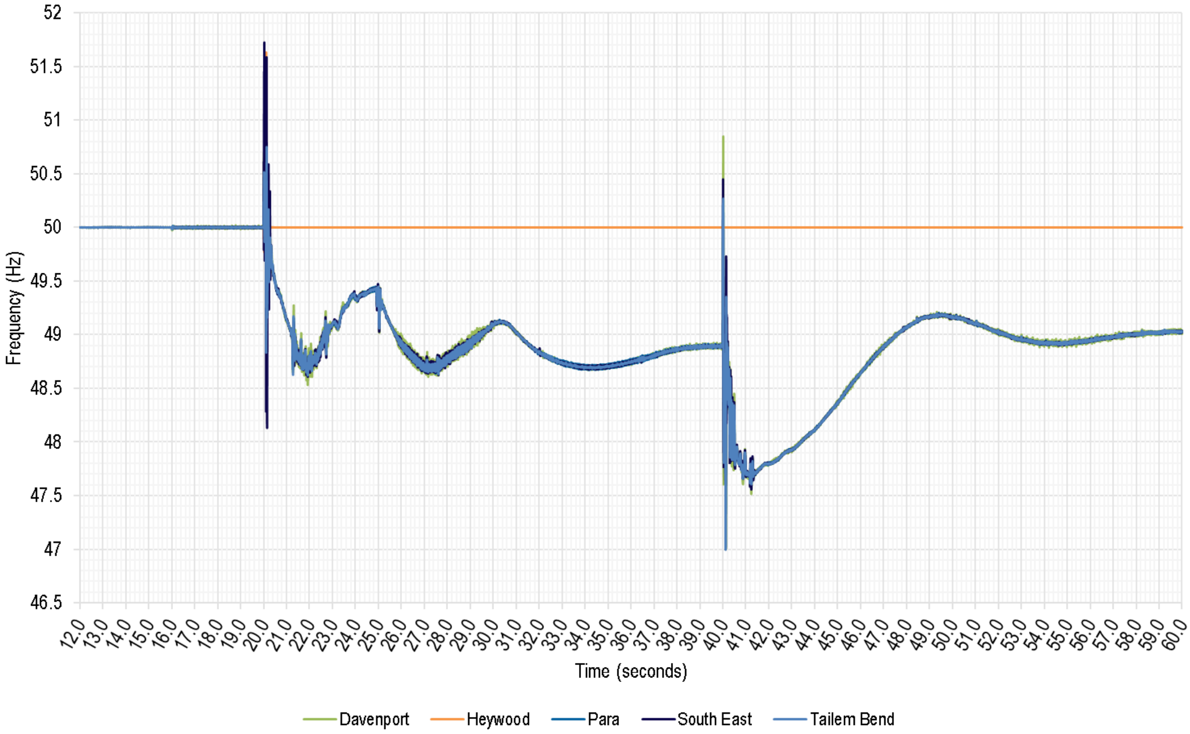


Figure 20 Low_2 import case with Pelican Point ST out of service – Key transmission voltages

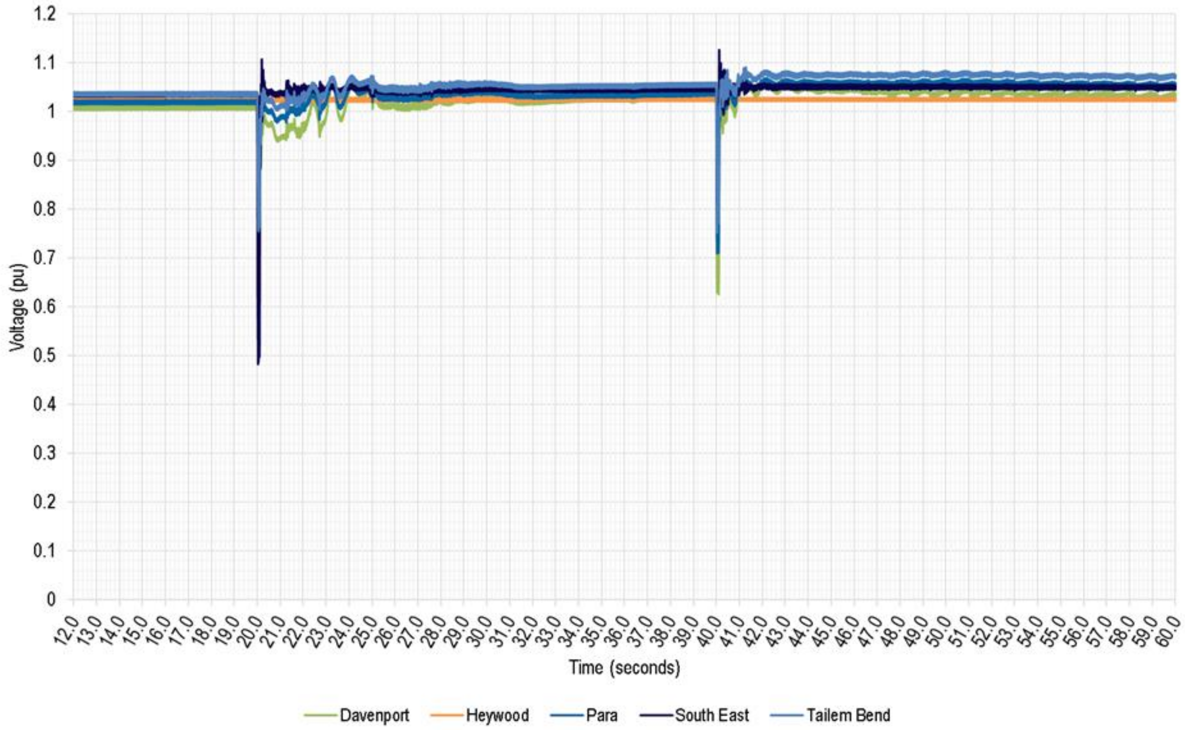
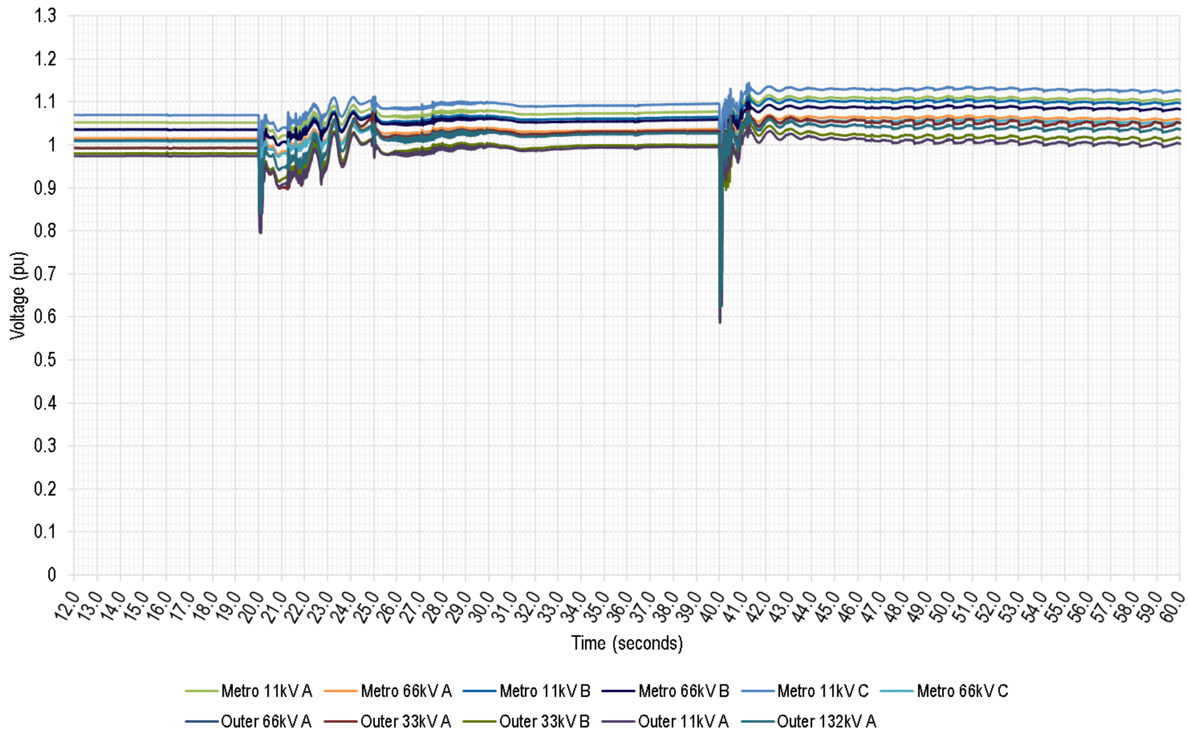
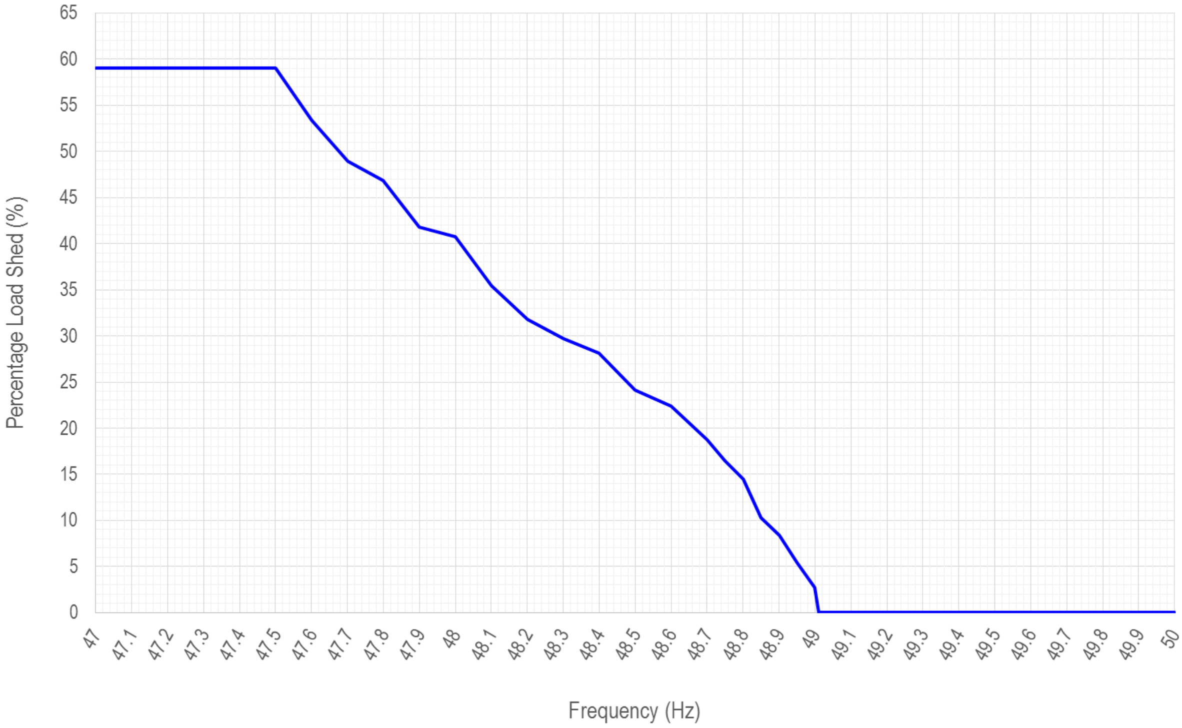


Figure 21 Low_2 import case with Pelican Point ST out of service – Key distribution voltages



A5. SA load shedding profile

Figure 22 Under frequency load shedding profile for SA



Glossary

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

Term	Definition
Credible separation event	A credible contingency event that involves loss of one of the Heywood Interconnector lines that results in separation of SA from the rest of the NEM. There is a risk of a credible separation event during a planned outage of one of Heywood Interconnector 275 kV lines.
Contingency FCAS	Each of the following: • Fast raise service; • Fast lower service; • Slow raise service; • Slow lower service; • Delayed raise service; and • Delayed lower service.
EMT	Electromagnetic Transient
EMTDC	Electromagnetic Transient with Direct Current
Fast FCAS	*Fast raise service* and *fast lower service*.
FCAS	Frequency control ancillary services
FFR	Fast frequency response
FOS	Frequency operating standard
HPR	Hornsdale Power Reserve
Hz	Hertz (cycles per second)
kV	Kilovolt
MW	Megawatt
MHRC	Manitoba HVDC Research Centre
NEM	National Electricity Market
OFGS	Over-frequency generation shedding
OOS	Out of service
PSCAD	Power System Computer Aided Design
PSS®E	Power System Simulator for Engineering
RoCoF	Rate of change of frequency
SA	South Australia
SVC	Static VAR (volt amperes reactive) compensator
TIPS B	Torrens Island B Power Station

Term	Definition
UFLS	Under-frequency load shedding