LOAD SHEDDING IN SOUTH AUSTRALIA ON SUNDAY 1 NOVEMBER 2015

AN AEMO POWER SYSTEM OPERATING INCIDENT REPORT FOR THE NATIONAL ELECTRICITY MARKET

Published: February 2016

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about this particular Power System Operating Incident.

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VERSION RELEASE HISTORY

VERSION	DATE	BY	CHANGES	CHECKED BY	AUTHORISED BY
1	29 Jan 2016	S Darnell	Final	Peter Biddle	Mark Stedwell

INCIDENT CLASSIFICATIONS

Classification	Detail
Time and date of incident	2151 hrs Sunday 1 November 2015
Region of incident	South Australia
Affected regions	South Australia
Event type	Loss of Transmission elements and load interruption
Generation Impact	11 MW of generation was disconnected as a result of this incident
Customer Load Impact	160 MW of load was disconnected as a result of this incident
Associated reports	Market Event Report: High FCAS Prices in SA – October and November 2015

DICTIONARY

Term	Meaning
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
CB	Circuit Breaker
FCAS	Frequency control ancillary services
HYTS	Heywood Terminal Station
Island	Electrical Island – separation of part of a power system from the remainder of the power system
kV	Kilovolt
Line 1	The Heywood – South East No.1 275 kV transmission line
Line 2	The Heywood – South East No.2 275 kV transmission line
L6 FCAS	Lower 6 second FCAS, also known as fast lower FCAS
L60 FCAS	Lower 60 second FCAS, also known as slow lower FCAS
L5 FCAS	Lower 5 minute FCAS, also known as delayed lower FCAS
MN	Market Notice
MW	Megawatt
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NOFB	Normal operating frequency band
R6 FCAS	Raise 6 second FCAS, also known as fast raise FCAS
R60 FCAS	Raise 60 second FCAS, also known as slow raise FCAS
R5 FCAS	Raise 5 minute FCAS, also known as delayed raise FCAS
SA	South Australia
SESS	South East Substation
TIPS	Torrens Island Power Station
UFLS	Under frequency load shedding scheme

CONTENTS

1. OVERVIEW

This report details AEMO's review of a power system operating incident that occurred on Sunday 1 November 2015 at the South East Substation (SESS) in South Australia (SA). At the time of the incident, the South East – Heywood No.2 275 kV transmission line (Line 2) was out of service.

This incident involved:

1. The trip of the South East – Heywood No.1 275 kV transmission line (Line 1), that resulted in the SA power system partially separating[1] (being islanded) from the interconnected power system.
2. The loss of 160 MW of customer load and 11 MW of generation.
3. Frequency control problems in operating the islanded SA power system

This incident is a reviewable operating incident under the National Electricity Rules (NER).[2] The NER require AEMO to assess the adequacy of the provision and response of facilities or services and the appropriateness of actions taken to restore or maintain power system security.

AEMO concluded that:

1. An incompatible protection relay configuration led to the unexpected tripping of Line 1 that, in turn, islanded the SA power system.
2. Under Frequency Load Shedding (UFLS) operated as expected for this type of incident.
3. The frequency standard in SA was breached during the period of islanded operation.
4. The SA power system was not in a secure operating state[3] during this incident. This was resolved when SA was reconnected to the interconnected system.

This report is based on information provided by ElectraNet[4], AGL[5], EnergyAustralia[6] and AEMO. National Electricity Market time (Australian Eastern Standard Time) is used in this report.

2. THE INCIDENT

On Sunday 1 November 2015, at 2151 hrs, Line 1 opened at the SESS end. At the time, Line 2 was of out of service as part of a planned outage. The combination of Line 1 tripping and Line 2 being out of service islanded the SA power system. This resulted in the disconnection of 160 MW of SA customer load and the trip of 11 MW of SA generation.

The SA power system operated as an island for 35 minutes. During this time, the SA frequency exceeded the normal frequency operating band (NOFB)[7] for 92 seconds[8] and Frequency Control Ancillary Service (FCAS) constraints equations violated for up to 35 minutes.[9]

[1] The SA power system AC connection opened but the DC (Murraylink) connection remained closed. This creates an abnormal frequency island – refer to AEMC NEM Mainland Frequency Operating Standards. The abnormal frequency island is referred to as an island in this report.
[2] NER clause 4.8.15
[3] NER clause 4.2.4
[4] ElectraNet is the Transmission Network Service Provider in South Australia.
[5] AGL is the operator or the Torrens Island Power Station in South Australia.
[6] EnergyAustralia is the operator of Cathedral Rocks wind farm in South Australia.
[7] The normal operating frequency band for an islanded system is 49.5 – 50.5 Hz. Refer to AEMC Reliability Panel's Frequency Operating Standards (Mainland).
[8] The frequency reached a maximum of 50.577 Hz, exceeding the upper limit of 50.5 Hz by 0.077 Hz.
[9] Constraints sets are mathematical equations used in the market dispatch calculation to represent power system operating limits. When a constraint equation violates, this means the power system may exceed technical limits following a contingency event. In this case, there was insufficient FCAS to contain, stabilise and recover the frequency (to 50 Hz) following a further contingency event in SA.

The SA power system was re-connected to the interconnected power system at 2226 hrs – 35 minutes after the trip of Line 1. This followed a delay of 26 minutes caused by frequency control problems within the islanded SA power system. At 2230 hrs AEMO gave permission to ElectraNet to restore all load, and by 2337 hrs most of the load had been restored.[10]

See Appendix A for a power system diagram illustrating the incident and Appendix B for a chronological log of the incident.

AEMO is required to review this incident for the following reasons:

1. Automatic UFLS was initiated as a result of this this incident. AEMO is required to review incidents where load shedding is initiated by UFLS.[11]
2. The power system was not in a secure operating state for 35 minutes due to a shortage of contingency FCAS in SA. AEMO is required to review incidents where the power system is insecure for more than 30 minutes.[12]
3. The trip of Line 1 is a non-credible contingency event; AEMO is required to review non-credible contingency events.[13] Generally transmission lines are expected to trip at both ends under fault conditions. This trip of a transmission line at one end is an unexpected event.

AEMO also considers the following events significant to power system operation and includes them as part of the review:[14]

1. The power system frequency in SA exceeded the NOFB for 92 seconds, which means the power system was not in a satisfactory operating state[15] for this period[16].
2. Frequency control problems in SA during island operation caused a delay in returning Line 1 to service.

The following four sections of this report (Sections 3, 4, 5 and 6) address separate aspects of the incident.

3. ELECTRANET REVIEW – TRIP OF LINE 1

ElectraNet is responsible for the transmission network in SA. This section summarises ElectraNet's assessment of the trip of the Line 1.

ElectraNet found that Line 1 tripped due to an incompatible protection relay configuration. The protection relay had been recently installed as part of the works associated with the SESS upgrade. The line tripped when an automated test signal was unexpectedly interpreted by the new relay as a trip signal. The routine[17] test signal was transmitted from Heywood Terminal Station (HYTS) to verify the integrity of a protection telecommunication channel between HYTS and SESS. As a result, the relay opened CBs 6603 and 8029 at SESS, which in turn off-loaded Line 1.

ElectraNet has reprogrammed the newly installed protection relays to prevent a reoccurrence of the trip.

[10] ElectraNet advised all load restored except for approximately 21 MW of pump load and a small amount of 11 kV load (due to distribution issues)
[11] Clause 6(d) of AEMC Reliability Panel's Guidelines for identifying reviewable operating incidents
[12] Clause 4 of AEMC Reliability Panel's Guidelines for identifying reviewable operating incidents
[13] Clause 4.8.15(a)(1)(i) of the NER, and Clause 1 the AEMC Reliability Panel's Guidelines for identifying reviewable operating incidents
[14] Clause 6(f) of AEMC Reliability Panel's Guidelines for identifying reviewable operating incidents
[15] NER Clause 4.2.2(a)
[16] AEMO is required, to the extent it is practicable, to operate the power system in a secure operating state – NER clause 4.3.1(a), 4.2.6(a), 4.2.4(a)(1).
[17] The test is an automated function that is sent periodically (in this case weekly).

4. GENERATION TRIP REVIEW – CATHEDRAL ROCKS

During a power system incident, generating plant and transmission elements remote from the incident are required to stay connected to the power system. This allows for affected plant to disconnect in a coordinated manner leaving the remainder of the power system intact.

During this incident, Cathedral Rocks wind farm tripped unexpectedly from 11 MW as a result of the Line 1 trip, when its rate of change of frequency protection operated. AEMO has determined that the rate of change of frequency in SA as a result of this incident was around 0.36 Hz/second. Generating units are normally expected to stay connected for rates of change of frequency below 1 Hz/second.

Due to the relatively small amount of generation disconnected, this trip did not have a significant impact on the incident. At the time of publication, AEMO and Energy Australia were still investigating whether the trip was in accordance with the Cathedral Rocks Performance Standards.

5. AEMO REVIEW – FREQUENCY CONTROL

AEMO reviewed the islanded SA power system operation from separation to reconnection. AEMO found that frequency control for the SA island, at times, did not operate as expected. This section summarises the issues AEMO considered and associated findings.

5.1 SA frequency standards

Power system frequency standards are set by the Reliability Panel[18] and apply to various power system conditions. For a separation event that results in the creation of an island the frequency standard is 49–51 Hz (Separation Event Frequency Standard).

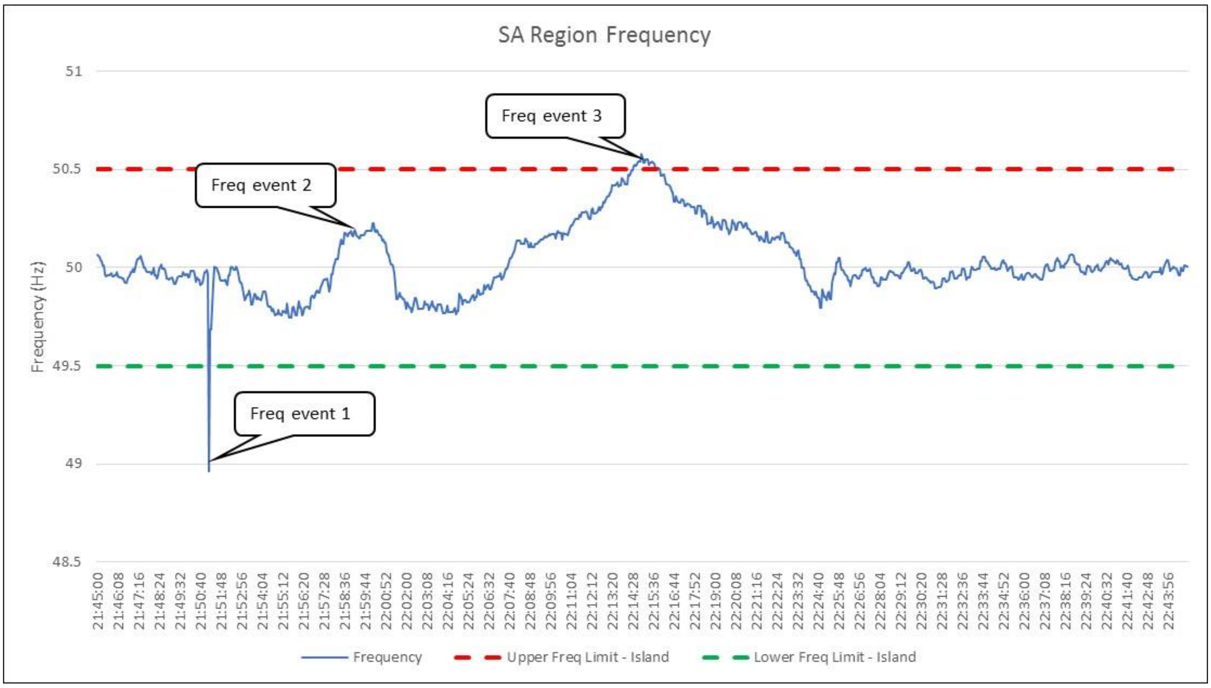
The SA government had, however, previously instructed AEMO, via a SA Jurisdictional System Security Coordinator notification, to amend the Separation Event Frequency Standard for SA to 47–52 Hz. This means the frequency in SA is allowed to operate within a wider band immediately following a separation event, and as a result less contingency FCAS is required.

On that basis, AEMO has determined that no contingency raise FCAS is required if flow on the Heywood interconnector is towards SA, as frequency will be maintained above 47 Hz by the operation of UFLS which starts at 49 Hz. Contingency lower FCAS may be required, however, if flow on the Heywood interconnector is towards Victoria at the time of separation. Following separation, during island operation, the NOFB[19] is 49.5–50.5 Hz.

For this incident, following separation, there were three frequency events (as shown in Figure 1). The first is associated with the actual separation, the second with the dispatch of non-scheduled generation, and the third with operation of contingency FCAS enabled units in SA. Each of these three events is separately discussed below.

[18] Refer to the AEMC Reliability Panel's Frequency Operating Standards (Mainland).
[19] No contingency event or load event - specified in AEMC Reliability Panel Frequency Operating Standards.

Figure 1 SA Frequency



5.2 Event 1 – SA separation event

As a result of the separation, SA frequency fell to a minimum of 48.96 Hz at 21:51:08 hrs and recovered to near 50 Hz within 12 seconds largely as a result of the operation of UFLS. The Frequency Operating Standards were not breached as a result of this event.

AEMO reviewed the operation of the SA UFLS scheme, and confirmed that it performed as designed. Approximately 105 MW of load was disconnected by the automatic UFLS scheme to assist frequency recovery. The rest of the 160 MW load disconnected during this event was not via UFLS, but tripped due to the frequency and voltage disturbances.

Although AEMO had not enabled any contingency raise FCAS in SA as a result of the planned outage, 10 MW of R6 was enabled on SA units (5 MW on each of Torrens Island B2 and B4) as part of the normal NEM R6 requirement. Based on data provided by AGL, AEMO has determined, in accordance with the Market Ancillary Service Specification (MASS), that the R6 response of these units as shown in Table 1 was adequate.

Table 1 FCAS R6 enablement and response.

Generating Unit	R6 enabled (MW)	R6 response (MW)
Torrens B2	5	36.9
Torrens B4	5	49.6

Although both R60 and R5 FCAS were also enabled, delivery of these was not required as the frequency recovered to 50 Hz within 12 seconds.

5.3 Event 2 – dispatch of non-scheduled generation

From around 2153 hrs, SA frequency fell below 49.85 Hz then increased to above 50.15 Hz, before it fell to below 49.85 Hz then recovered to above 50 Hz at 2207 hrs (See Figure 1). This frequency event, Event 2, was caused by the dispatch and subsequent shutdown of around 75 MW of non-scheduled generation in SA.

Although frequency did not exceed the NOFB for island operation, it is of interest as it should initiate a contingency FCAS response. This is because the contingency FCAS response[20] is based on a non-island NOFB of 49.85–50.15 Hz.

After the SA island was formed, AEMO invoked constraints sets from dispatch interval 2200, to enable contingency FCAS in SA, to ensure frequency was maintained within the Frequency Operating Standard. See Appendix C for details of the FCAS that was enabled.

AEMO has taken steps to analyse the contingency FCAS response in accordance with the MASS during this period. This proved impracticable, due to the small excursions from the 49.85–50.15 Hz frequency band, the low rate of frequency change, and the short duration of Event 2.

AEMO is satisfied, however, that all contingency FCAS enabled units responded in the correct direction to help correct frequency during Event 2. Dispatch of regulation FCAS by the AEMO Automatic Generation Control (AGC) also helped limit the frequency disturbance. Charts in Appendix D illustrate the response of contingency FCAS enabled units during this incident.

5.4 Event 3 – delivery of delayed lower FCAS

During Event 3, the maximum frequency was 50.58 Hz at 22:14:36 hrs and exceeded the upper limit of the NOFB for approximately 92 seconds. This meant the power system was not in a satisfactory operating state for this period.[21]

AEMO has not analysed delivery of L6 and L60 FCAS for Event 3. The slow rate at which frequency changed makes accurate analysis impracticable.

AEMO has analysed the delivery of the L5 FCAS, and the results are shown in Table 2. The performance of Northern power station (NPS) units was acceptable. The performance of Torrens Island B power station (TIPS B) was not as expected. Although not enabled to provide a response, both Torrens Island 'A' and Pelican Point power stations provided a delayed lower FCAS response.

Table 2 FCAS L5 enablement and response

Generating Unit	L5 enabled (MW)	L5 response (MW)
Northern 1	**7**	**36.5**
Northern 2	**15**	**41.9**
Pelican Point	0	12.3
Torrens Island A 4	0	37.6
Torrens Island B 2	16.5	0
Torrens Island B 4	16.5	0

Event 3 was not related to a contingency event. AEMO determined that Event 3 was related to an increase of around 35 MW in non-scheduled and semi-scheduled generation, and an incorrect contingency FCAS response from generating units 2 and 4 at TIPS B. In response to the low frequency during Event 2, the TIPS B units started delivering a contingency FCAS raise response. This response did not stop when the frequency had recovered to 50 Hz, but continued to increase in output. The total increase in output of the TIPS B units, from when frequency returned to 50 Hz after Event 2, was approximately 65 MW.

When the frequency exceeded 50 Hz, AGC was sending lower regulation signals to the TIPS B units. The units did not respond to these signals and continued to increase output.

Due to the high frequency in SA it was not possible to re-synchronise SA to the rest of the interconnected power system. At 2214 hrs AEMO asked the TIPS B units to switch off AGC and to follow dispatch targets manually. This resulted in frequency returning to near 50 Hz at 2223 hrs. The SA

[20] Refer to AEMO's Market Ancillary Service Specification.
[21] See NER Clause 4.2.2(a), 4.2.49(a) and the AEMC Reliability Panel's Frequency Operating Standards.

power system was reconnected to the interconnected power system at 2226 hrs. AEMO estimates this caused a 26 minute delay in reconnection.

Discussions between AEMO and AGL have determined the response from the TIPS B units during Event 3 is related to the governor control system of these units when multiple frequency events overlap within a short period. AEMO is continuing to work with AGL to resolve these issues.

6. AEMO REVIEW – POWER SYSTEM SECURITY

AEMO is required to use its reasonable endeavours to maintain the power system in a secure operating state and, wherever possible, return it to a secure operating state following a contingency event within 30 minutes.

This section assesses how AEMO managed power system security over the course of this incident.

6.1 Outage Planning

As part of AEMO's planning for the outage of Line 2, it was determined that regulation FCAS was required to be available in SA immediately post-separation to ensure SA remained in a satisfactory operating state. Constraint sets enabling 35 MW of raise and lower regulation FCAS in SA were invoked at commencement of the Line 2 outage.

Further information on this issue and the outage planning for Line 2 are available in the Market Event report published by AEMO on 11 December 2015.[22]

6.2 Trip of Line 1

When Line 1 tripped at 2151 hrs, automatic UFLS operated to arrest and stabilise the frequency of the islanded SA power system. AEMO then invoked the following constraint sets in relation to frequency control:

1. F-ESTN_ISLE – sets contingency FCAS requirements in the area outside of SA.
2. F-SA_ESTN_ISLE_REG – sets regulation FCAS requirements.
3. F-SA_ISLE – sets contingency FCAS requirements for SA.

These constraint sets were invoked at 2155 hrs and should have returned the SA power system, as an island, to a secure state.

6.3 High frequency

As discussed in Section 5.4 (Event 3), at around 2214 hrs SA frequency exceed the NOFB for an island. This meant that the SA power system was not in a satisfactory operating state.

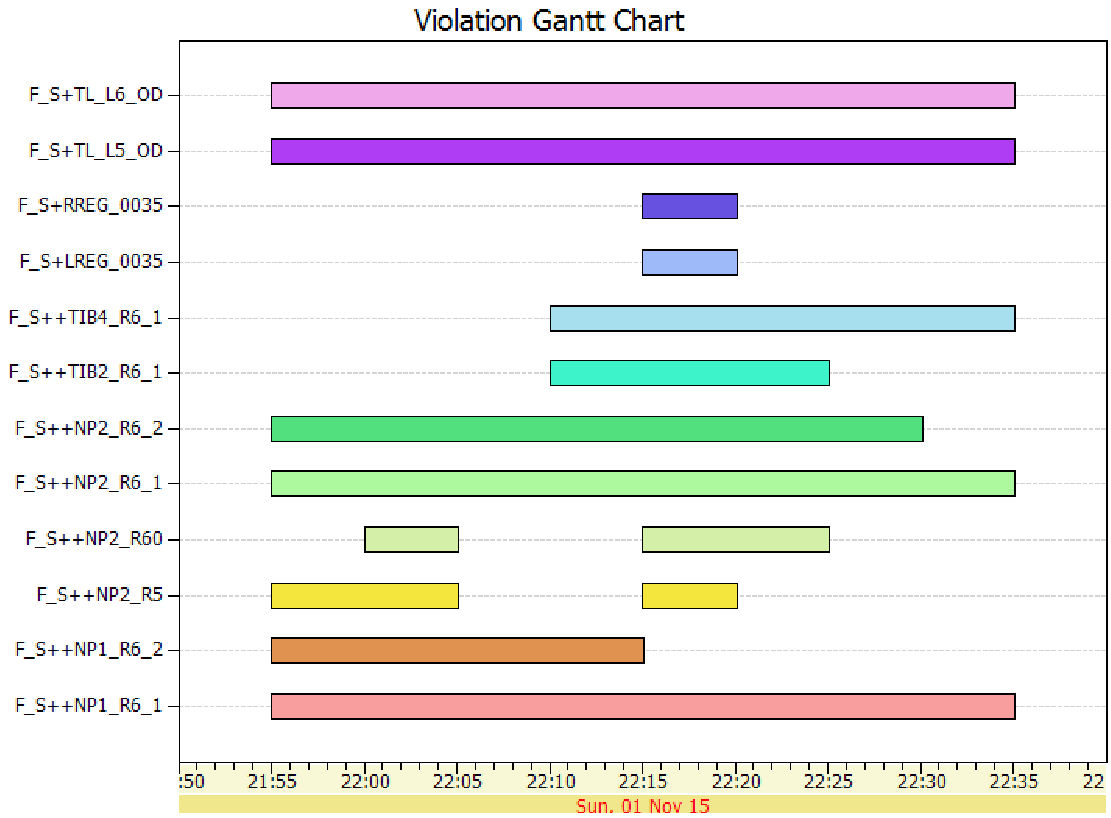
6.4 Violating FCAS constraint equations

For an islanded system, FCAS need to be sourced from within the island. As noted in Section 6.2, AEMO invoked a number of FCAS-related constraint sets between dispatch intervals 22:00 and 22:35. The third of these (F-SA_ISLE) is of interest, as a number of its constraint equations were violated for both raise and lower FCAS (as illustrated in Chart 1 below).

The following is an assessment of main FCAS constraint equations that violated during this incident.

[22] Available on the AEMO website at: http://aemo.com.au/Electricity/Resources/Reports-and-Documents/Market-Event-Reports/Market%20Event%20Report%20High%20FCAS%20Price%20in%20SA%20October%20and%20November%202015.

Chart 1 Violating contingency raise FCAS constraints



6.4.1 Contingency Lower services

The contingency lower FCAS requirements are based on managing the risk of the loss of the single largest load in SA. This is normally the loss of the Davenport – Olympic Dam West 275 kV line with a load of around 140 MW.

Constraint equation F_S+TL_L6_OD sets the L6 second requirements. This constraint equation violated as shown in Table 3.

Table 3 Violations for constraint equation F_S+TL_L6_OD

Dispatch Interval	Violation degree (MW)
22:00	25.33
22:05	25.72
22:10	25.42
22:15	47.73
22:20	60.22
22:25	70.13
22:30	45.15
22:35	42.99

Similarly, constraint equation F_S+TL_L5_OD sets the lower 5 minute requirements. This constraint equation violated as shown in Table 4.

Table 4 Violations for constraint equation F_S+TL_L5_OD

Dispatch Interval	Violation degree (MW)
22:00	11.41
22:05	31.85
22:10	8.14
22:15	12.43
22:20	0.9
22:25	32.27
22:30	36.26
22:35	24.46

These constraint equation violations indicate that insufficient L6 and L5 FCAS was available in SA. AEMO has procedures in place to manage the lack of contingency lower FCAS in SA, but these were not implemented due to the short duration of the outage.

6.4.2 Contingency Raise services

Contingency raise FCAS is based on the risk of the loss of the largest single generating unit in SA. Constraint set F-SA_ISLE includes equations to determine the contingency FCAS required to meet the loss of each generating unit in SA. Each of these equations is co-optimised, that is, the National Electricity Market Dispatch Engine (NEMDE)[23] will find the least cost option of enabling FCAS to match the output of the generating unit or to reduce its output to reduce the amount of FCAS required. If insufficient FCAS is available, NEMDE will reduce the generating unit output to a level where the risk meets the FCAS available.

Generally the largest single generating units in SA are the NPS units. This was the case during the separation event. A number of constraint equations associated with sourcing contingency raise FCAS (R6, R60 and R5) violated during the event. See Chart 1.

Table 5 provides an example of the contingency FCAS shortage in relation to R6. From dispatch interval 22:00, insufficient R6 was available to cover the loss of NPS 1 or 2, and the constraint equations were violated. In attempting to resolve this issue, NEMDE reduced the output of both units to reduce the risk and consequently the amount of R6 required. In doing so, however, NEMDE reduced NPS unit outputs to below where they could no longer provide R6, thus reducing the total amount of R6 available[24] – NPS was not available to provide R6 below a unit output of 170 MW.[25] From dispatch interval 22:15 there was insufficient R6 to cover the loss of an NPS unit or the loss of a TIPS B unit.[26]

Table 5 Violations for a sample of R6 constraint equations

Constraint and unit dispatch target	22:00	22:05	22:10	22:15	22:20	22:25	22:30	22:35
F_S++NP1_R6_1 violation (MW)	149.2	126.4	134.4	121.4	64.7	100.3	68.6	35.9
NPS 1 MW dispatch target	193.7	177.1	183	170	122	143	127	104
F_S++NP2_R6_1 violation (MW)	216	206	205	191	161	137	128	92
NPS2 MW dispatch target	241.6	234.7	233.8	219.6	190.8	170	170	144.9
F_S++TIB4_R6_1 violation (MW)				21.6	66.2	53.5	27.5	21.3

[23] National Electricity Market Dispatch Engine is the algorithm AEMO uses to determine dispatch outcomes.
[24] For context, NPS was providing a small amount of R6 (10 MW per unit) relative to the amount of further MWs required –see Row 1 in Table 5 (35–149 MW).
[25] At 170 MW output the available FCAS is zero, due to the shape of the registered FCAS trapezium.
[26] Normally NEMDE will not reduce the output of a generating unit to below where it can provide FCAS. However, if the actual output of the unit is seen by NEMDE to be below this level, then NEMDE can further decrease output.

Due to the lack of R6 in SA, NEMDE could not produce a feasible dispatch solution (one that would result in the secure operation of the power system). If NEMDE had held NPS output at a level whereby it could provide R6, the constraint equation would still have violated, because there was still insufficient R6. Therefore, due to the lack of R6 FCAS, the SA power system was not secure.

If the island had continued for an extended period, AEMO may have had to intervene in accordance with clause 4.8.9 of the NER to direct participants to restore power system security. Such directions may involve bringing additional generating units on line to provide FCAS and reducing the output of the largest generating units to reduce FCAS requirements.

6.4.3 Regulation FCAS

Regulation FCAS constraint equations violated for a single dispatch interval (22:20). This was consistent with AEMO requesting TIPS to switch off AGC and reduce outputs manually. TIPS was a provider of regulation FCAS at that time, however, with AGC switched off, regulation FCAS cannot be provided. Without TIPS providing regulation FCAS, there was insufficient regulation FCAS in SA, hence the constraint equations violated. The violations ceased the following dispatch interval when AGC was switched on.

All FCAS constraint violations (raise, lower and regulation) ceased when Line 1 was returned to service at 2236 hrs and the constraints were revoked. As SA was then reconnected to the interconnected system, this removed the need for FCAS services to be sourced in SA.

6.5 Reclassification of the incident

Following the return to service of Line 1, AEMO considered that the cause of the Line 1 trip was unknown, could potentially re-occur and was, therefore, an abnormal condition.[27] AEMO determined that, until the cause of the trip had been identified, it would limit power flow into SA. This was primarily to prevent a repeat of load shedding should Line 1 trip again. Following the return to service of Line 1, AEMO invoked a constraint set (I-VS_080) to limit the power flow into SA to 80 MW. AEMO later reduced this to 50 MW.

At this time, AEMO did not reclassify the incident as a non-credible contingency. Due to the number of control schemes in this part of the network and major augmentations at both HYTS and SESS, AEMO was unsure whether new or modified control systems may have caused the trip.

The following day, after further assessment, the cause remained unknown, so AEMO reclassified the trip of Line 1 at the SESS end as a credible contingency event.[28] The constraint sets and reclassification were removed four days later (5 November 2015), when ElectraNet had identified and resolved the cause of the incident.

6.6 Summary of Power System Security

Over the course of this incident, the power system was not in a secure operating state for 35 minutes. This was due to the lack of contingency FCAS and was exacerbated by the unexpected response of TIPS (Section 5.4 – Event 3).

Following the return to service of Line 1, AEMO took appropriate action by reclassifying the incident as a credible contingency event, until the cause of the incident was identified and resolved.

[27] See NER Clause 4.2.3A.
[28] AEMO is required to assess whether or not to reclassify a non-credible contingency event as a credible contingency – NER Clause 4.2.3A (c) – and to report how re-classification criteria were applied – NER Clause 4.8.15 (ca). AEMO has to determine if the condition that caused the non-credible contingency event has been resolved.

7. MARKET INFORMATION

AEMO is required by the NER and operating procedures to inform market participants about incidents. This section assesses how AEMO informed the market[29] over the course of this incident.

AEMO was required to inform market participants about the following matters:

1. A non-credible contingency event – AEMO must notify market participants within two hours of the event.[30]

   AEMO issued Market Notice (MN) 50258 at 2211 hrs to notify market participants that Line 1 had tripped.

2. New information update – AEMO must update a previous notification as it becomes aware of new information.[31]

   AEMO issued MN 50267 at 2238 hrs to notify market participants that Line 1 had returned to service.

3. Constraint set I-VS_080 invoked – notification of a variance to interconnector transfer limits.[32]

   In MN 50267 (point 2) AEMO also notified market participants the constraint set I-VS_080 had been invoked so the interconnector flow into SA would be limited to 80 MW.

4. Constraint set I-VS_050 invoked – notification of a variance to interconnector transfer limits.[32]

   AEMO issued MN 50269 at 2322 hrs to notify market participants that constraint set I-VS_050 had been invoked so the interconnector flow into SA would be limited to 50 MW.

5. Reclassification of the trip of Line 1 at the SESS end as a credible contingency event – AEMO must notify market participants as soon as practicable.[33]

   AEMO issued MN 50274 at 1326 hrs on 2 November 2015 to notify market participants of the reclassification.

6. Constraint set I-VS_050 revoked – notification of a variance to interconnector transfer limits.[32]

   AEMO issued MN 50340 at 1759 hrs on 5 November 2015 to notify market participants that constraint set I-VS_050 had been revoked so the interconnector flow into SA would not be limited to 50 MW.

7. Cancellation of the reclassification of the Trip of Line 1 at the SESS end as a credible contingency – AEMO must notify market participants as soon as practicable.[33]

   AEMO issued MN 5034 at 1759 hrs on 5 November 2015 to notify market participants that AEMO had cancelled the reclassification because the cause of the trip had been identified and a solution had been implemented to prevent a recurrence.

Over the course of this incident AEMO issued appropriate, timely and sufficiently detailed market information.

[29] AEMO generally informs the market about operating incidents as the progress by issuing Market Notices – see AEMO website.
[30] AEMO is required to notify the Market of a non-credible contingency event within two hours of the event - AEMO *Procedure SO_OP 3715*, *Power System Security Guidelines,* Section 10.3.
[31] AEMO is required to notify the Market as it becomes aware of new and material information – NER Clause 4.2.3A(d).
[32] For short term outage AEMO is required to notify the Market of variances to interconnector transfer limits: *AEMO Procedure SO_OP 3715, Power System Security Guidelines, Section 22.*
[33] AEMO is required to notify the market of a reclassification NER clause 4.2.3(g), details of the reclassification 4.2.3(c) and when AEMO cancels the reclassification 4.2.3(h).

8. CONCLUSIONS

AEMO has assessed this incident in accordance with clause 4.8.15(b) of the NER. In particular, AEMO has assessed the adequacy of the provision and response of facilities or services, and the appropriateness of actions taken to restore or maintain power system security.

AEMO concluded that:

1. An incompatible protection relay configuration led to the unexpected tripping of Line 1 that, in turn, islanded the SA power system.
2. UFLS operated as expected for this type of incident.
3. The islanded SA power system was not in a satisfactory operating state for 92 seconds during the incident. This was because the SA power system frequency exceeded the NOFB for 92 seconds.
4. The SA power system was insecure for 35 minutes due to insufficient contingency FCAS in SA. This was resolved when SA was reconnected to the interconnected system 35 minutes later.

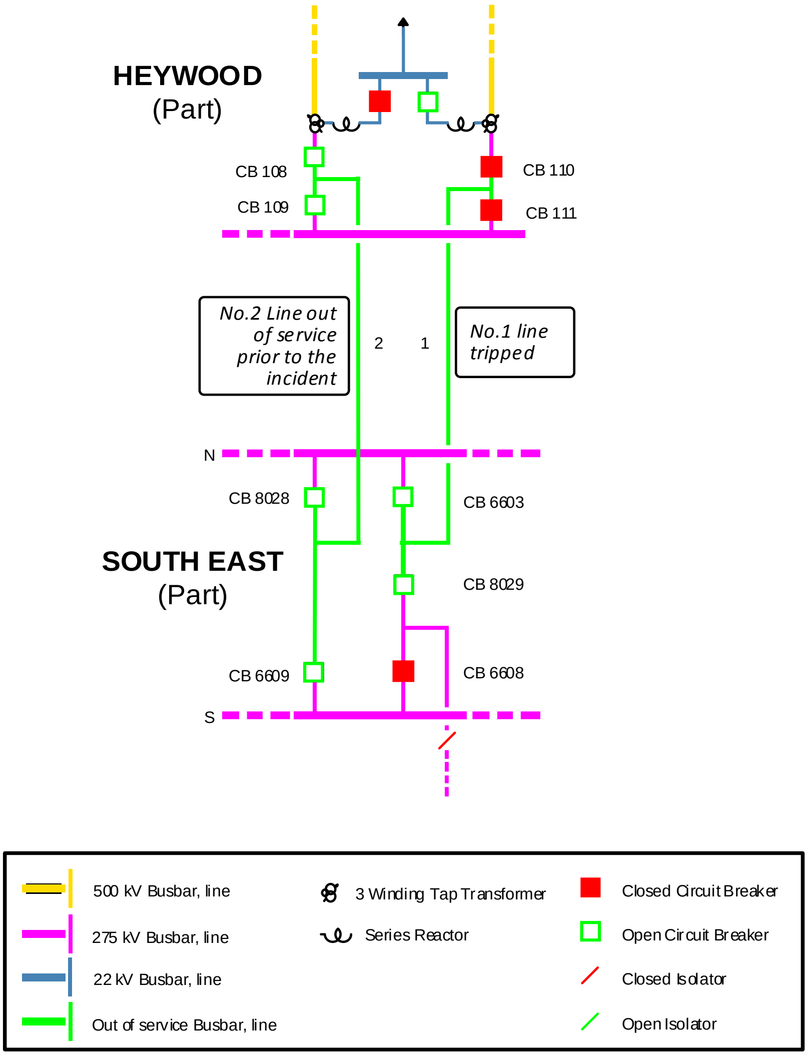
9. PENDING ACTIONS

The following issues have arisen as a result of this incident but are yet to be resolved (at publication of this report). AEMO tracks the progress of these issues until they are resolved.

1. Cathedral Rocks trip – AEMO and EnergyAustralia to resolve by 31 March 2016.
2. Governor control of Torrens Island – AEMO and AGL to resolve by 31 March 2016.

APPENDIX A. POWER SYSTEM DIAGRAM

This illustrates the status of affected power system elements immediately after the trip of Line 1.



APPENDIX B. INCIDENT EVENT LOG

This table provides a chronological log of the incident.

Time and Date	Event
0700 hrs Thur 29 Oct 2015	Line 2 taken out of service for a planned outage.
0700 hrs Thur 29 Oct 2015	AEMO invoked constraint sets F-I-HYSE, F-S_LREG_0035, F-S_RREG_0035, I-HYSE, V-HYTX.
2151 hrs Sun 1 Nov 2015	Line 1 tripped at the SESS end only(CBs 6603 and 8029 at SESS opened). SA frequency fell to a low of 48.964 Hz. UFLS operated at 49 Hz and disconnected 105 MW of customer load. SA frequency returned to within the NOFB, 49.5–50.5 Hz, in 4 s and to 50 Hz in 12 s. Cathedral Rocks windfarm tripped from 11 MW.
2155 hrs	AEMO invoked constraint sets F-ESTN_ISLE, F-SA_ESRN_REG, F-SA_ISLE and SA_ESTN_ISLE.
2200 hrs	AEMO gave permission to ElectraNet to return Line 1 to service.
2210 hrs	AEMO requested TIPS B Units 2 and 4 to switch AGC off.
2211 hrs	AEMO issued MN 50258: No.1 Line trip; separation of SA from the NEM; UFLS in SA.
2214 hrs	SA frequency exceed the NOFB for 92 seconds – maximum excursion to 50.577 Hz.
2215 hrs	AEMO requested TIPS B Units 2 and 4 to switch AGC on.
2226 hrs	CB6603 at SESS closed and Line 1 returned to service. SA reconnected.
2230 hrs	AEMO gave permission to ElectraNet to restore all customer load.
2235 hrs	AEMO invoked Constraint Set I-VS_080 to limit Vic to SA flow to a maximum of 80 MW.
2238 hrs	AEMO issued MN 50267. Notification that: • HYTS -SESS No.1 Line had returned to service. • Constraint set I:VS_080 had been invoked.
2255 hrs	AEMO revoked constraint set I-VS_080 and invoked constraint set I-VS_050 to limit Vic to SA flow to a Maximum of 50 MW.
2322 hrs	AEMO issued MN 50269: Notification that constraint set I-VS_050 had been invoked.
2337 hrs	ElectraNet notified AEMO that most of customer load had been restored.
1326 hrs Mon 2 Nov 2015	AEMO issued MN 50274. AEMO classified the trip of HYTS-SESS No.1 Line at SESS end as a credible contingency.
1541 hrs Thur 5 Nov 2015	ElectraNet notified AEMO that protection relays at SESS had been reconfigured to prevent a re-occurrence of the incident.
1759 hrs	AEMO issued MN 50340. AEMO revoked Constraint Set I-VS_050.
1759 hrs	AEMO issued MN 50341. AEMO cancelled reclassification in MN 50274.
1600 hrs Tues 10 Nov 2015	Line 2 returned to service.
1740 hrs Tues 10 Nov 2015	AEMO revoked constraint sets F-I-HYSE, F-S_LREG_0035, , F-S_RREG_0035, I-HYSE, V-HYTX.

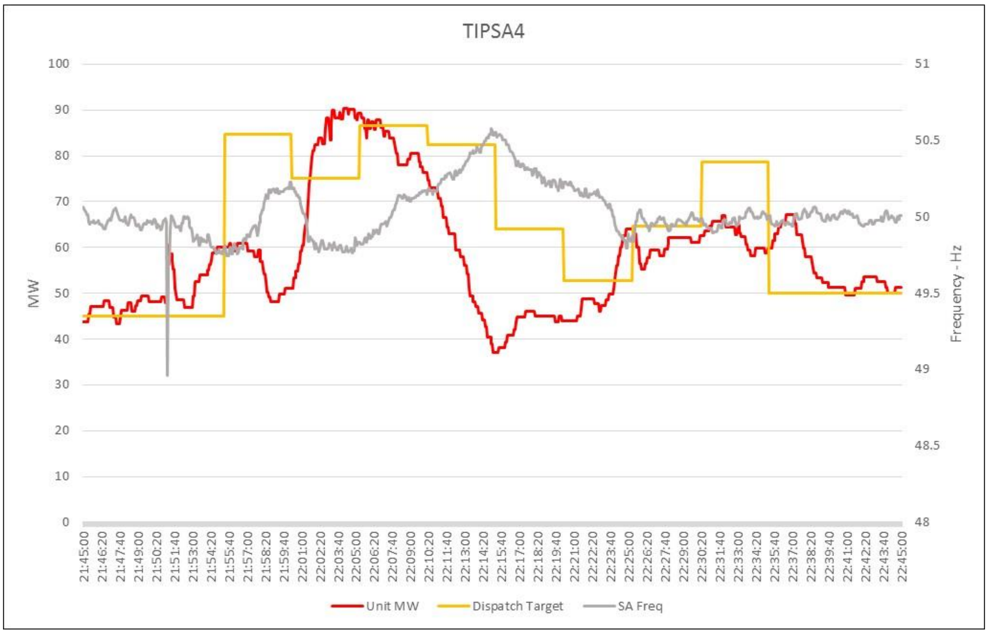
APPENDIX C. ENABLED FCAS

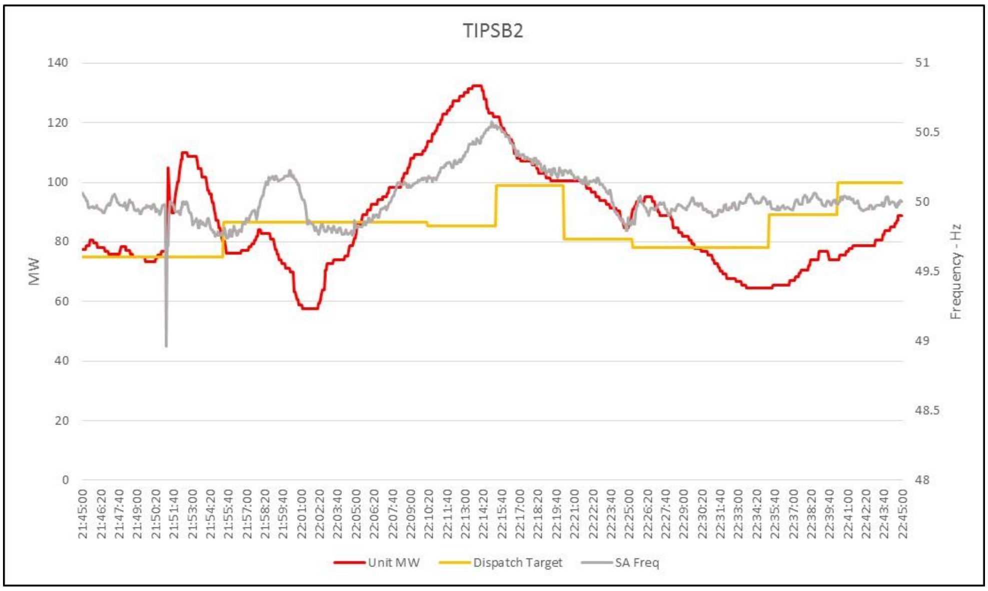
This table shows the FCAS enabled in SA over the course of the incident.

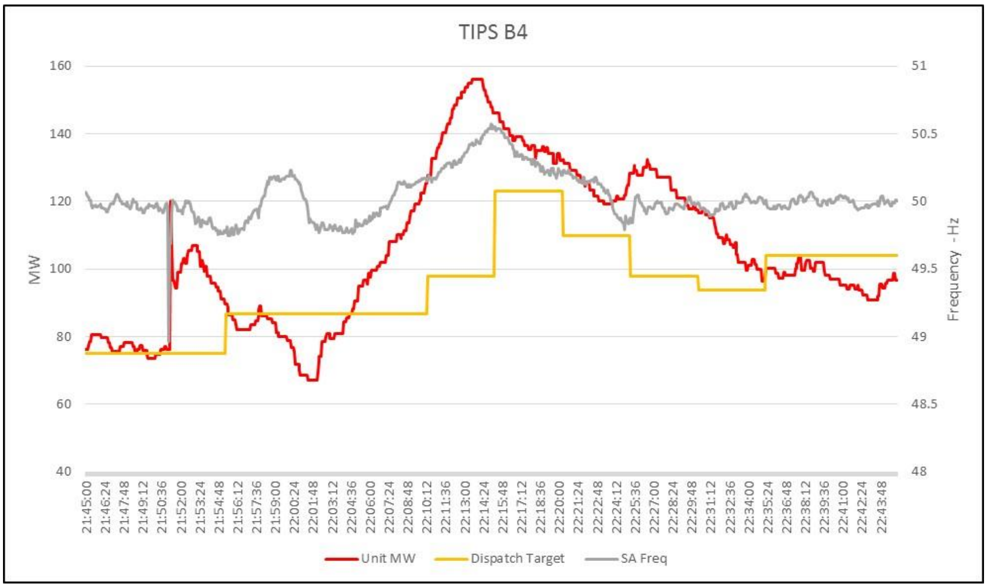
SETTLEMENT DATE	DUID	RREG	R6	R60	R5Min	LREG	L6	L60	L5Min
21:55 01/11/2015	NPS1	6	0	0	0	6	0	0	0
21:55	NPS2	6	0	0	0	6	0	0	0
21:55	PPCCGT	3	0	0	0	3	0	0	0
21:55	TORRA4	0	0	0	0	0	0	0	0
21:55	TORRB2	10	5	10	10	10	0	10	0
21:55	TORRB4	10	5	10	10	10	0	10	0
22:00	NPS1	10	5	19	18	0	5	10	13
22:00	NPS2	3	5	22	20	0	5	12	15
22:00	PPCCGT	29	17	15	0	19	17	15	0
22:00	TORRA4	0	10	25	0	10	10	11	0
22:00	TORRB2	0	20	50	50	0	20	20	27
22:00	TORRB4	40	15	38	50	10	15	20	17
22:05	NPS1	7	5	6	5	0	5	3	4
22:05	NPS2	6	5	25	20	0	5	13	15
22:05	PPCCGT	30	17	15	0	18	17	15	0
22:05	TORRA4	1	10	25	0	0	10	17	0
22:05	TORRB2	10	20	50	50	10	20	20	16
22:05	TORRB4	32	15	38	50	10	15	20	16
22:10	NPS1	10	5	10	10	0	5	5	7
22:10	NPS2	8	5	25	20	0	5	13	15
22:10	PPCCGT	20	17	15	0	27	17	15	0
22:10	TORRA4	4	10	25	0	11	10	15	0
22:10	TORRB2	20	20	50	50	10	20	20	16
22:10	TORRB4	40	15	38	50	10	15	20	16
22:15	NPS1	0	0	0	0	0	0	0	0
22:15	NPS2	10	5	25	20	0	5	15	15
22:15	PPCCGT	18	17	15	0	30	17	15	0
22:15	TORRA4	7	10	24	0	9	10	24	0
22:15	TORRB2	21	20	50	50	0	20	21	25
22:15	TORRB4	40	15	38	50	0	15	20	38
22:20	NPS1	0	0	0	0	0	0	0	0
22:20	NPS2	10	5	16	16	0	5	9	11
22:20	PPCCGT	18	17	15	0	30	17	15	0
22:20	TORRA4	0	0	0	0	0	0	0	0
22:20	TORRB2	0	20	50	50	0	20	35	39
22:20	TORRB4	0	15	38	50	0	15	38	50
22:25	NPS1	0	0	0	0	0	0	0	0
22:25	NPS2	0	0	0	0	0	0	0	0
22:25	PPCCGT	18	17	15	0	30	17	15	0
22:25	TORRA4	0	0	0	0	0	0	0	0
22:25	TORRB2	10	20	50	50	5	20	50	16
22:25	TORRB4	39	15	38	50	0	15	33	50
22:30	NPS1	0	0	0	0	0	0	0	0
22:30	NPS2	0	0	0	0	0	0	0	0
22:30	PPCCGT	20	17	15	0	30	17	15	0
22:30	TORRA4	0	10	11	0	3	10	11	0
22:30	TORRB2	10	20	50	50	8	20	47	10
22:30	TORRB4	37	15	38	50	0	15	20	38
22:35	NPS1	0	0	0	0	0	0	0	0
22:35	NPS2	0	0	0	0	0	0	0	0
22:35	PPCCGT	20	17	15	0	30	17	15	0
22:35	TORRA4	8	10	10	0	19	10	10	0
22:35	TORRB2	25	20	32	29	15	20	41	4
22:35	TORRB4	40	15	38	20	0	15	27	34

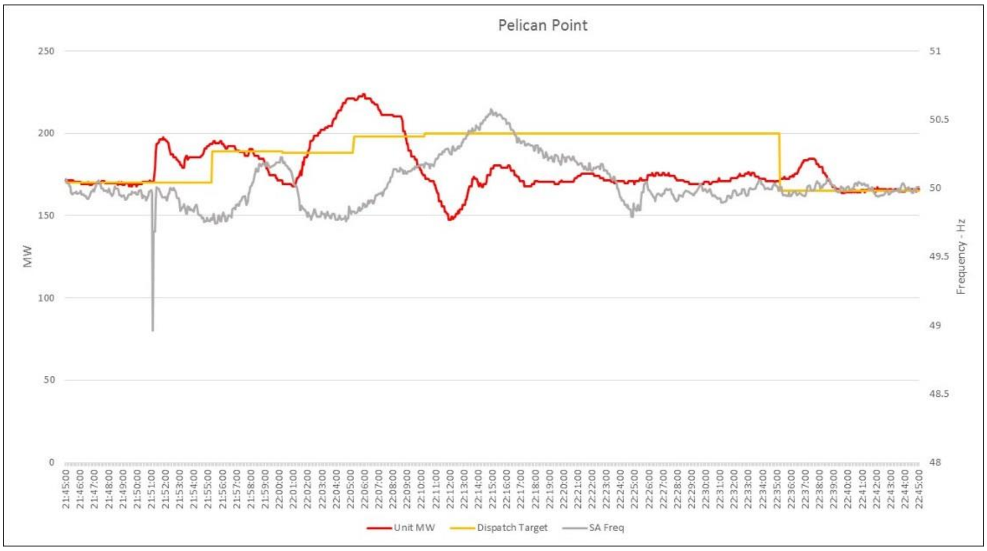
APPENDIX D. OUTPUTS OF FCAS ENABLED GENERATING UNITS

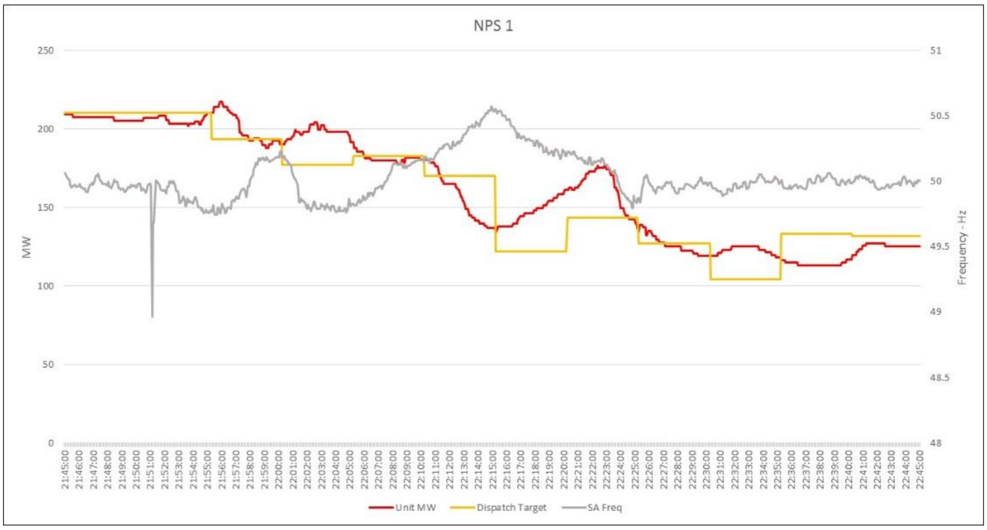
The following charts provide information on the response of FCAS enabled units during the SA islanding event.

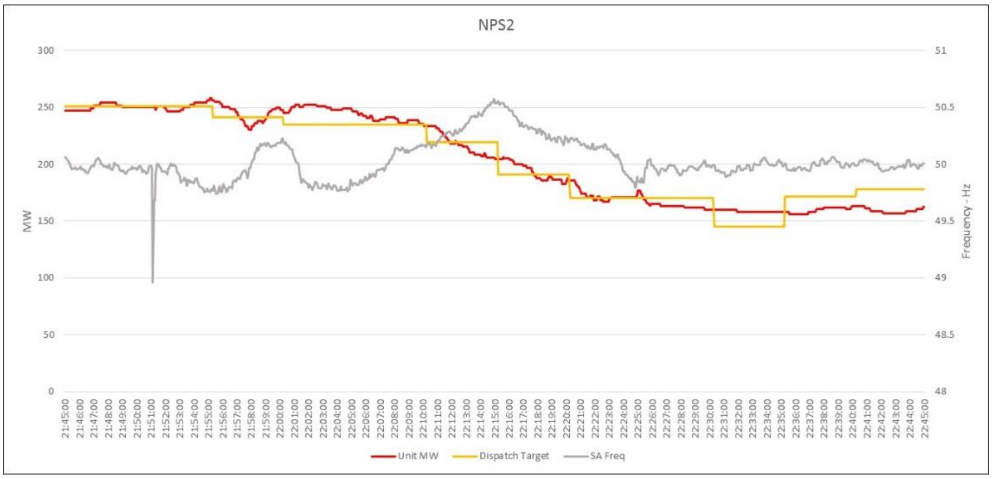





TIPS B4
MW
Frequency - Hz
Unit MW
Dispatch Target
SA Freq


Pelican Point
MW
Frequency - Hz
Unit MW
Dispatch Target
SA Freq


NPS 1
MW
Frequency - Hz
Unit MW
Dispatch Target
SA Freq


NPS2
MW
Frequency - Hz
Unit MW
Dispatch Target
SA Freq