Final Report – New South Wales and Victoria Separation Event on 4 January 2020

September 2020

A reviewable operating incident report for the National Electricity Market

Important notice

PURPOSE

AEMO has prepared this final report in accordance with clause 4.8.15(c) of the National Electricity Rules, using information available as at the date of publication, unless otherwise specified.

DISCLAIMER

AEMO has been provided with data by Registered Participants as to the performance of some equipment leading up to, during, and after the separation event, in accordance with clauses 3.14 and 4.8.15 of the Rules. In addition, AEMO has collated information from its own systems.

AEMO has made every reasonable effort to ensure the quality of the information in this report but cannot guarantee its accuracy or completeness. Any views expressed in this report are those of AEMO unless otherwise stated and may be based on information given to AEMO by other persons.

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ABBREVIATIONS

Abbreviation	Term
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
ARENA	Australian Renewable Energy Agency
Distributed PV	Distributed photovoltaic
kV	Kilovolt
LHS	Left Hand Side of a constraint equation. This consists of the variables that can be optimised by NEMDE. These terms include scheduled or semi-scheduled generators, scheduled loads, regulated Interconnectors, MNSPs or regional FCAS requirements.
LOR 2	Lack of Reserve level 2
FCAS	Frequency control ancillary service
FOS	Frequency Operating Standard
Hz	Hertz
LHS	Left Hand Side of a constraint equation. The LHS consist of controllable variables and their respective multiplying factors (or coefficients).
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
PASA	Projected Assessment of System Adequacy
pu	Per unit
RERT	Reliability and Emergency Reserve Trader
RHS	Right Hand Side of a constraint equation. The RHS is pre-calculated and presented to the solver as a constant; these terms cannot be optimised by NEMDE.
UFLS	Under frequency load shed
UNSW	University of New South Wales

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1. Overview

This is AEMO's final report about a multiple contingency event[1] that occurred on 4 January 2020 in the New South Wales region, that resulted in the separation of the Victorian and New South Wales regions during a major bushfire event in the Snowy Mountains area.

This incident resulted in the loss of 34 megawatts (MW) of generation and 43 MW of customer load, and a reduction of approximately 2,267 MW of generation availability. This reduction in generation availability, coupled with the loss of interconnection to Victoria, resulted in a Lack of Reserve Level Two (LOR 2) condition in New South Wales. In response to the LOR 2 condition, AEMO activated its Reliability and Emergency Reserve Trader (RERT) services in New South Wales.

Refer to Appendix A1 for diagrams of the power system prior to and after the separation event.

This final report is prepared in accordance with clause 4.8.15(c) of the National Electricity Rules (NER) and should be read in conjunction with AEMO's preliminary report published on 5 March 2020 (Preliminary Report)[2]. This final report provides further analysis of the following issues:

- The delivery of frequency control ancillary services (FCAS) immediately after the separation event.
- The availability of contingency raise FCAS in the Queensland/New South Wales island after the separation event.
- The frequency in the Victoria/South Australia and New South Wales/Queensland islands during the period of separation.
- The operation of protection schemes within the 132 kilovolt (kV) network between Wagga[3] and Yass substations.
- The ability of AEMO's Projected Assessment of System Adequacy (PASA) process to accurately calculate reserve levels under region separation conditions.
- The performance of generating units during the disturbance created by the separation event.
- The response of distributed photovoltaic (PV) generation to voltage and frequency disturbances during this event.
- Any potential or actual major security of supply issues during this incident.

AEMO's conclusions are summarised in Table 1 below. Each of these findings is discussed in further detail in the body of the report.

National Electricity Market (NEM) time (Australian Eastern Standard Time [AEST]) is used in this report.

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[1] As defined in clause 4.8.15 of the NER and the associated Reliability Panel Guidelines.

[2] AEMO. Preliminary Report – New South Wales and Victoria Separation Event on 4 January 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

[3] While the city is named Wagga Wagga, the substation is normally referred to as Wagga.

Table 1 Summary of conclusions

Finding	Actions recommended or underway
Several generating units did not fully deliver their enabled FCAS requirements.	Corrective action has been implemented for the majority of these generating units. AEMO is continuing to follow up with the remaining generators to ensure future compliance.
The power system was not in a secure operating state for 13 minutes between the trip of 051 line and 66 line.	AEMO recommends TransGrid review its policies for splitting the Wagga–Yass 132 kV network under certain operational configurations.
The power system was not in a secure operating state for up to 45 minutes after the islanding event due to a shortage of FCAS in the New South Wales/Queensland island.	AEMO will modify the constraint formulation to reduce the probability of reoccurrence.
The Frequency Operating Standard was met for this multiple contingency event.	No action required.
There was an unexpected frequency deviation within the normal frequency operating band in the Victoria/South Australia area shortly after the multiple contingency event	AEMO will conduct further analysis to determine the reason for this.
AEMO PASA tools did not correctly determine reserve levels in the New South Wales region after the islanding event due to the effective change in region boundaries.	AEMO is currently reviewing its PASA tools with changes expected to be implemented by mid-2021.
The majority of generating units operated as expected and in accordance with their Generator Performance Standard in response to the islanding event. Two generating units either increased or decreased output in relation to the frequency. AEMO has determined these units operated correctly.	No action required.
Distributed PV generation was observed to decrease output in New South Wales, Victoria and South Australia in response to the fault that resulted in the separation of New South Wales and Victoria. Approximately half of this response was related to disconnection of distributed PV. 40-50% of distributed PV systems demonstrated behaviours that were not consistent with the relevant standards (AS/NZS4777.2:2015). This represents a growing security risk as more distributed PV continues to be installed. Visibility of distributed resources is becoming increasingly important for assessment and management of power system security.	AEMO is working with stakeholders on a review of AS/NZS4777.2:2015 to implement requirements for improved disturbance ride-through capabilities and is investigating accelerated deployment of voltage ride-through testing in South Australia. AEMO is working with stakeholders to identify and address sources of non-compliance. AEMO (in collaboration with the Australian Renewable Energy Agency [ARENA], University of New South Wales [UNSW], Solar Analytics, WattWatchers, ElectraNet, TasNetworks and other stakeholders) is continuing work to improve data sources, analysis tools, and power system models to investigate and represent distributed energy resources accurately.

2. Incident overview

From approximately 1147 hrs on 4 January 2020, severe bushfire activity in the Snowy Mountains area resulted in a series of outages of multiple 330 kV transmission lines in the Snowy Mountains area.

Just before 1510 hrs on 4 January 2020, the power system in the southern New South Wales area was as shown in Figure 14 in Appendix A1, with the Lower Tumut – Wagga 051 330 kV line out of service and interconnection between Victoria and New South Wales maintained via the Murray-Tumut 66 330 kV line (66 line) and the combination of the Wodonga – Jindera 060 330 kV line, the Redcliffs – Buronga OX1 220 kV line and the 132 kV interconnection between Wagga and Yass.

At 1510 hrs on 4 January 2020, the 66 line tripped, resulting in the tripping of the 132 kV interconnection between Wagga and Yass and the separation of the Victoria and New South Wales regions but with the Wodonga- Jindera 060 330kV line remaining in service with load in the south west New South Wales area connected to Victoria. As a result of the loss of the 132 kV interconnection between Wagga and Yass, there was a loss of approximately 43 MW of customer load in southern New South Wales.

This separation resulted in the NEM being split into two islands:

- Queensland and New South Wales (except for the south-western part of New South Wales), and
- Victoria (including the south-western part of New South Wales), South Australia, and Tasmania.

Prior to this separation there was a power flow of approximately 618 MW from Victoria to New South Wales, and as a result of this separation the frequency in the Queensland/New South Wales island fell and the frequency in the Victoria/South Australia/Tasmania island rose.

Refer to the Preliminary Report for a detailed sequence of events leading up to the islanding event. Interconnection between the Victoria and New South Wales regions was restored at approximately 2156 hrs on 4 January when both the Murray–Tumut 65 line (65 line) and the 66 line were returned to service.

This event had several impacts on the power system including frequency response and the associated delivery of FCAS, reserve levels and reserve level calculations, and security of supply to areas in southern New South Wales. These issues are discussed in this report.

3. Frequency response

The Frequency Operating Standard (FOS) provides the following definitions:

- Network event – a credible contingency event other than a generation event, load event separation event or part of a multiple contingency event
- Separation event – a credible contingency event affecting a transmission element that results in an island.
- Multiple contingency event – either a contingency event other than a credible contingency event, a sequence of credible contingency events within five minutes, or a further separation event in an island.

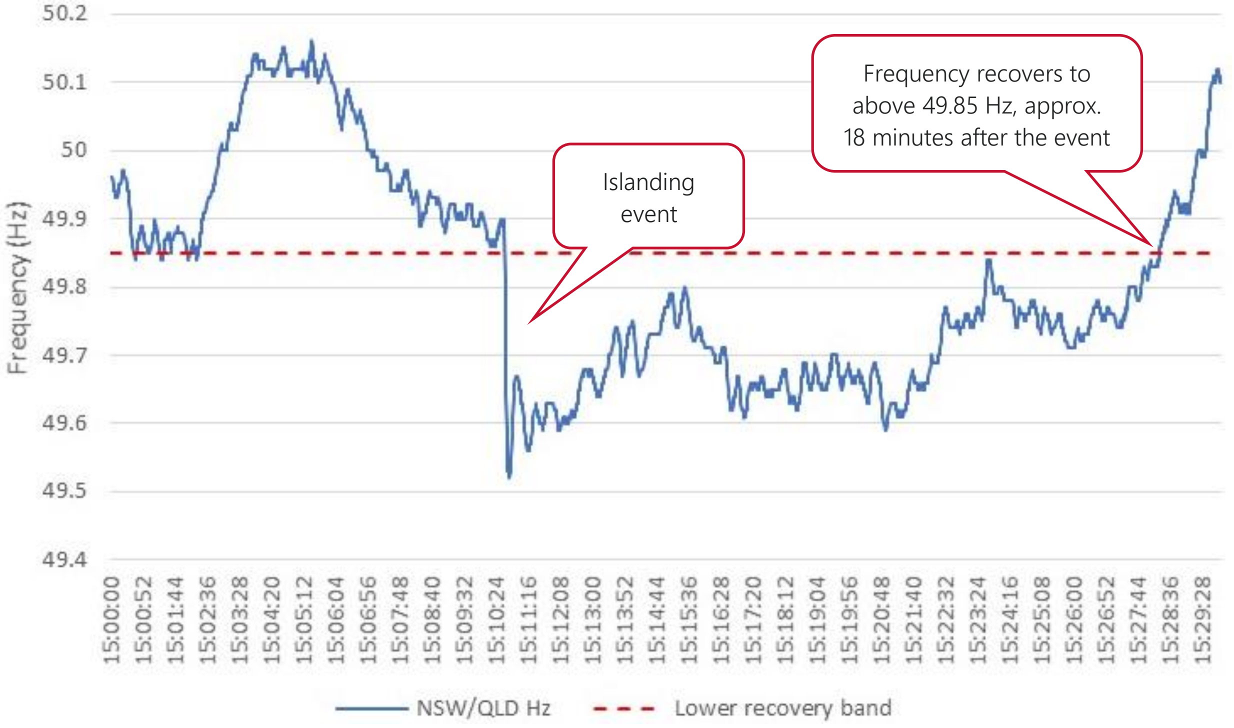
AEMO had reclassified the simultaneous loss of the 65 line and 66 line as a credible contingency at 1350 hrs on 31 December 2019[4]. However, given 65 line tripped at 1507 hrs on 4 January 2020 followed by 66 line three minutes later at 1510 hrs, the trips were not simultaneous. The trip of both 65 line and 66 line, combined with the previous outage of 051 line at 1501 hrs on 4 January, resulted in the creation of the Victoria/South Australia/Tasmania and New South Wales/Queensland islands. AEMO considers this, in the context of the FOS, a multiple contingency event.

Frequency in New South Wales/Queensland island

Figure 1 shows the frequency response in the New South Wales/Queensland island prior to and after the trip of 66 line.

[4] Market Notice 72238

Figure 1 Frequency in the New South Wales/Queensland island



The FOS for a multiple contingency event allows the frequency to fall to a minimum of 47 hertz (Hz) (containment) but the frequency should[5] return to above 49.5 Hz (stabilisation) within two minutes and to above 49.85 Hz (recovery) within 10 minutes.

For this event, the minimum frequency reached in the New South Wales/Queensland island was 49.52 Hz. The FOS was met in the New South Wales/Queensland island in relation to the containment and stabilisation frequencies, but – despite the considerable over-delivery of delayed raise FCAS in the New South Wales/ Queensland island as discussed in Section 3.1.2 – the frequency only returned to above the recovery frequency after approximately 18 minutes.

This is the result of the disparity in dispatch outcomes until the separation constraints were invoked at 1525 hrs. For example, for the dispatch interval ending 1520 hrs, the scheduled flow towards New South Wales on the Victoria – New South Wales interconnector was 450 MW, while actual flow was only 171 MW. That is, there was a deficiency of approximately 280 MW of generation in the New South Wales/Queensland island.

Once the separation constraints had been invoked, additional generation was dispatched in the New South Wales/Queensland island, and the frequency recovered.

Despite the delay in the frequency returning to within the recovery band, AEMO considers the FOS was met as all reasonable endeavours were taken to restore the frequency to within the recovery band as soon as possible.

Frequency in Victoria/South Australia/Tasmania island

Although referred to in this report as one island, this is in practice two islands, the Victoria/South Australia island and the Tasmania island. As Tasmania is connected to the mainland only by a direct current (DC) link and associated frequency controller, the frequency response in Tasmania to a contingency event will be different to that on the mainland.

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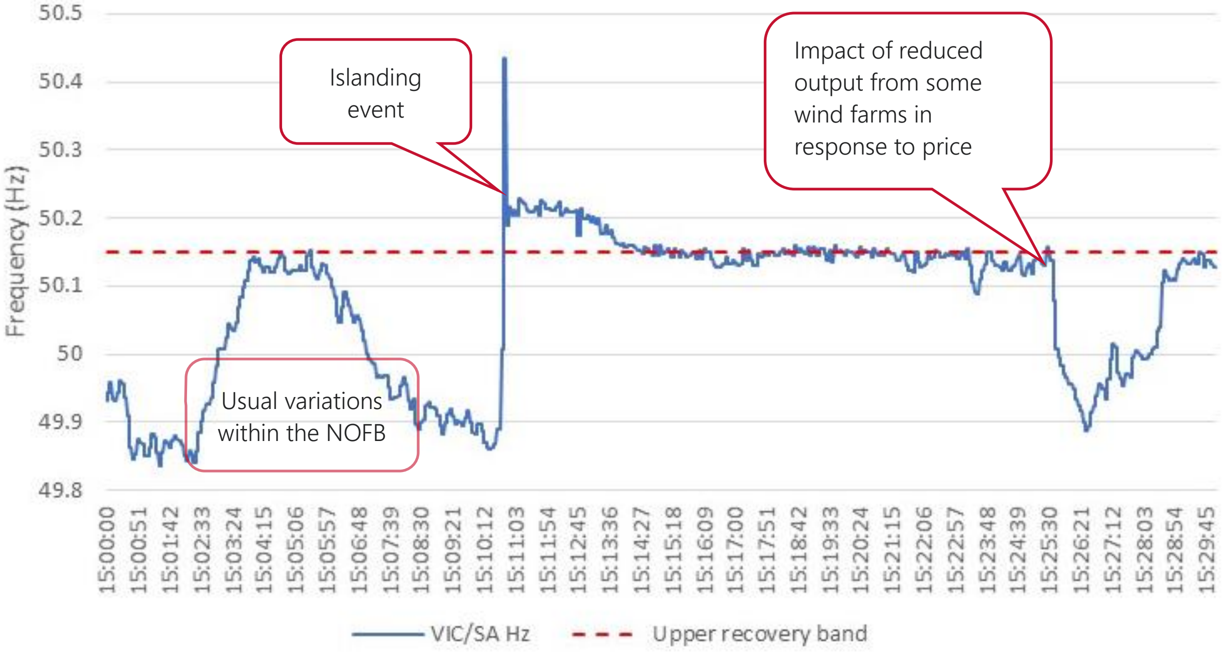
[5] The FOS states "reasonable endeavours".

The frequency response in both islands is discussed in this section.

Figure 2 shows the frequency response in the Victoria/South Australia island prior to and after the multiple contingency event.

Figure 2 Frequency in the Victoria/South Australia island



The FOS for a multiple contingency event allows the frequency to rise to a maximum of 52 Hz (containment), but the frequency should[6] return to lower than 50.5 Hz (stabilisation) within two minutes and to below 50.15 Hz (recovery) within 10 minutes.

For this event, the maximum frequency reached in the Victoria/South Australia island was 50.43 Hz. Despite a shortage of delayed lower FCAS delivery (see Section 3.1), frequency in the Victoria/South Australia island recovered to below 50.15 Hz within approximately six minutes. In the Victoria/South Australia island, the FOS was met but the frequency remained at approximately 50.15 Hz for a further 10 minutes. See Section 3.1.1 for more information.

There was a further reduction in frequency in the Victoria/South Australia island between approximately 1525 hrs and 1528 hrs. The minimum frequency was 49.88 Hz, which is within the normal frequency operating band. As shown in Figure 3 and Figure 4, this was caused by the rapid reduction in output of semi-scheduled wind farms in Victoria, as these generating units followed their dispatch caps in response to negative prices in Victoria immediately after the constraints to manage the system separation were invoked[7]. There was little reduction in semi-scheduled wind generation in South Australia, and similarly little reduction in semi-scheduled solar generation in both Victoria and South Australia, in response to the dispatch price. Although the wind farms in Victoria correctly followed their dispatch caps downwards, additional generation would have been dispatched to replace this reduction in generation to prevent a significant change in frequency. AEMO will conduct further analysis to determine why this dispatch of additional generation did not prevent a frequency deviation.

[6] The FOS states "reasonable endeavours".

[7] I_VN_Zero – VIC-NSW zero transfer limit in either direction, NQ_VST_ISLE – Separation between NSW/Queensland and VIC/SA/TAS

Figure 3 Reduction in wind farm output in Victoria

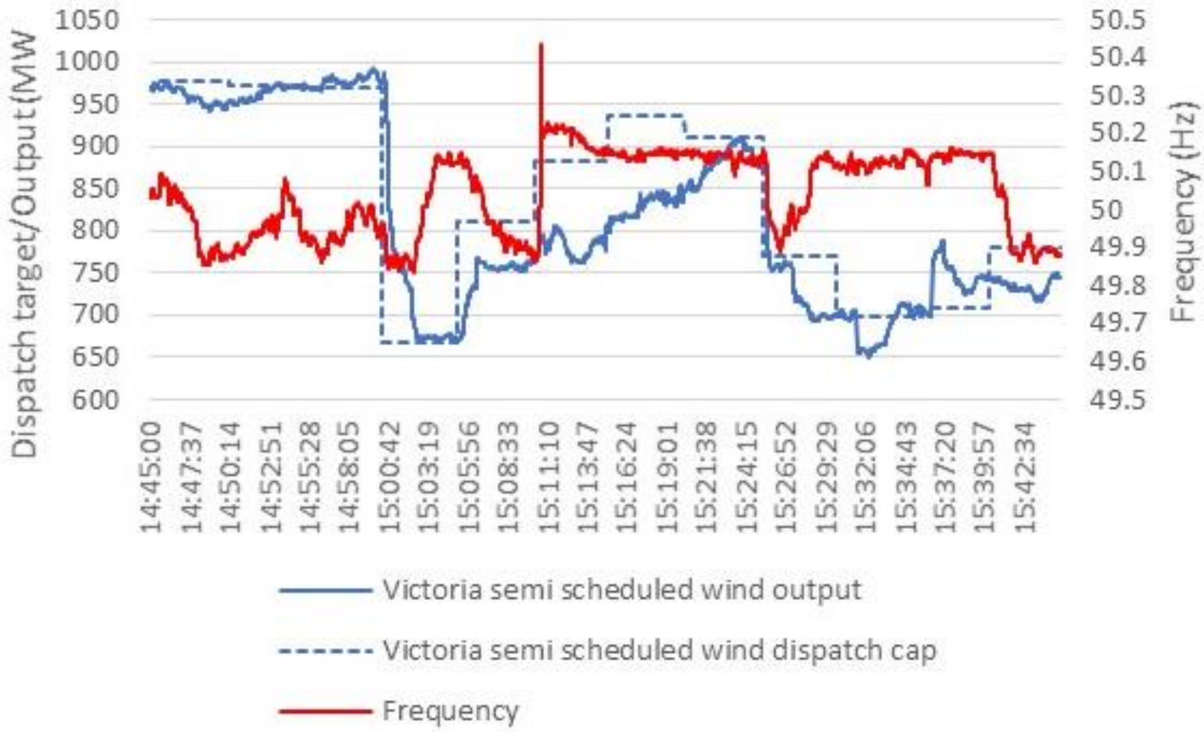


Figure 4 Dispatch price in Victoria and South Australia

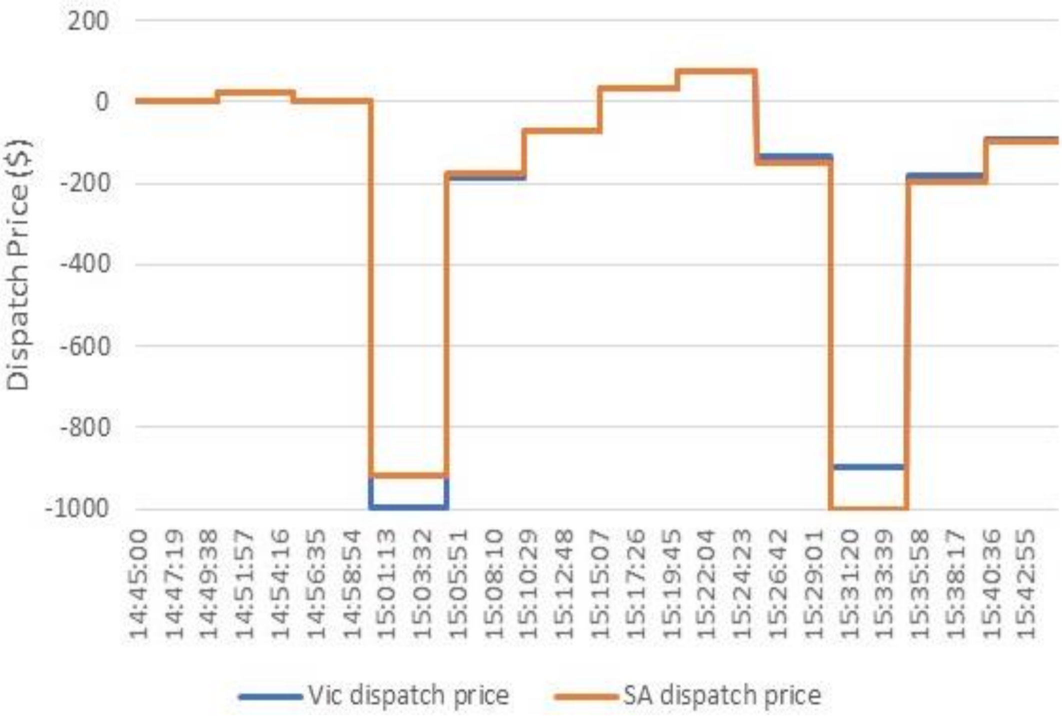
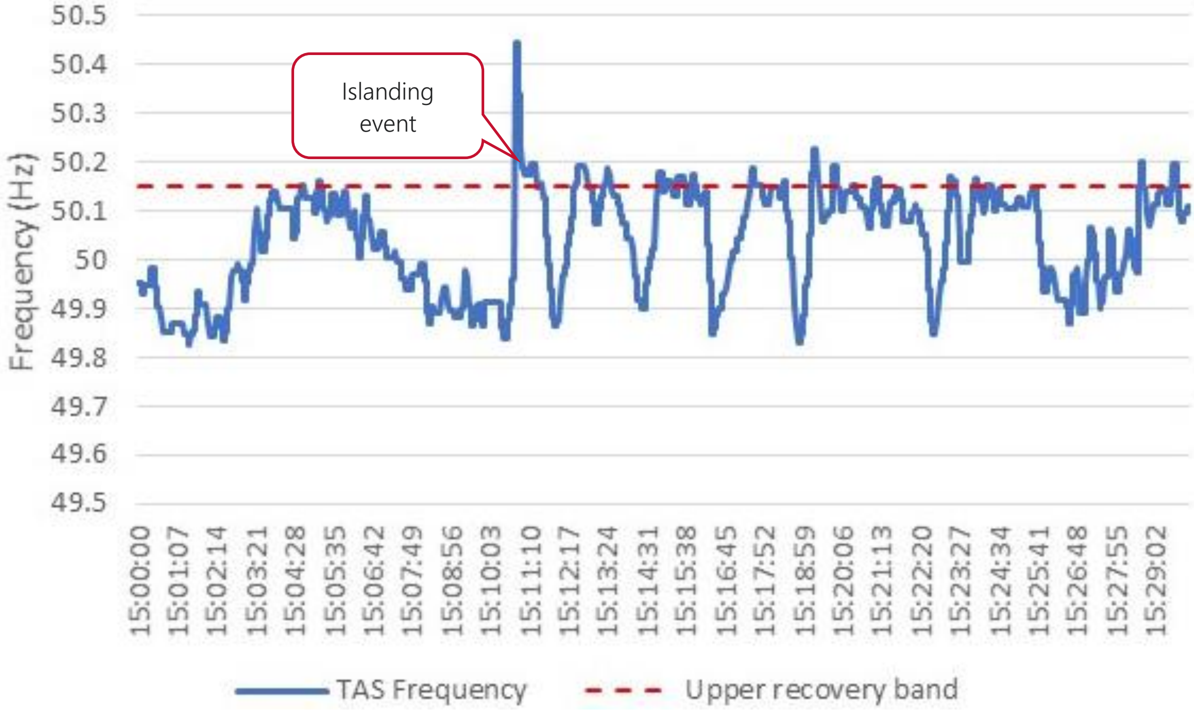


Figure 5 shows the frequency response in Tasmania prior to and after the separation event. The FOS in Tasmania for a multiple contingency event allows the frequency to rise to a maximum of 55 Hz (containment) and the frequency must return to lower than 52 Hz (stabilisation) within two minutes and to lower than 50.15 Hz (recovery) within 10 minutes. While the containment and stabilisation frequency were met, a post event oscillatory behaviour resulted in small short duration deviations above recovery frequency.

Figure 5 Frequency in Tasmania



These oscillations have been observed previously and appear to be related to the enablement of certain generating units in Tasmania to provide regulation FCAS and the interaction with the automatic generation control (AGC) system in Tasmania. While in general oscillatory behaviour in any power system quantity is undesirable, these frequency oscillations have been observed to be bounded and slow, and typically remain within the full normal operating frequency band of 49.75 to 50.25 Hz. AEMO does not see this as a material issue as it had no adverse impact on power system security.

Some AGC re-tuning has occurred in the past which has reduced the occurrences of this issue, and upcoming changes across the NEM to require all generation to provide primary frequency response may help further address these oscillations[8].

3.1 Delivery of FCAS

AEMO reviewed the delivery of FCAS, in accordance with the Market Ancillary Service Specification[9], in response to the frequency rise in Victoria and South Australia and the frequency reduction in New South Wales and Queensland.

Table 2 shows the amount of FCAS enabled in the NEM for the dispatch interval ending 1515 hrs on 4 January 2020, that is, just prior to the separation event. It should be noted that for an intact system FCAS is enabled on a NEM-wide basis; FCAS is not enabled in specific regions, except after separation events or where a single credible contingency event may result in a separation event.

[8] Mandatory Frequency Response Rule change. See AEMC website: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

[9] Available on the AEMO website at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/market-ancillary-service-specification-v50--effective-30-july-2017.pdf?la=en.

Table 2 NEM FCAS enablement

Service	Enabled (MW)
Fast raise	462
Slow raise	462
Delayed raise	320
Fast lower	224
Slow lower	309
Delayed lower	232

3.1.1 New South Wales/Queensland island

Table 3 shows the enablement and delivery of contingency raise FCAS in the New South Wales/Queensland island for the dispatch interval ending 1515 hrs on 4 January 2020[10].

Table 3 shows that a small number of generating units did not deliver the full enabled service. This is discussed further in Section 3.1.3. While some generating units did not fully deliver their enabled FCAS, the total amount of raise services delivered exceed the amount enabled, which assisted in the frequency recovery.

Table 3 New South Wales and Queensland raise FCAS (MW)

Generating unit	Fast raise enablement	Fast raise delivered	Slow raise enablement	Slow raise delivered	Delayed raise enablement	Delayed raise delivered
Enel X aggregated interruptible load (New South Wales)	29	50	18	33	12	28
Enel X aggregated interruptible load (Queensland)	2	6	3	6	2	4
Eraring 1	15	0	0	0	0	2
Eraring 3	7	Note 1	0	67	0	43
Gladstone 1	15	50	15	43	0	24
Gladstone 2	15	48	15	45	0	30
Gladstone 3	15	31	15	50	0	34
Gladstone 5	7	67	7	67	0	40
Gladstone 6	6	59	6	60	0	42
Mt. Piper 1	10	16	0	30	0	23
Mt. Piper 2	10	41	0	74	0	36
Stanwell 1	5	22	10	25	0	10

[10] Table 3 only includes generating units enabled to provide at least one of the contingency raise FCAS. Other generating units not enabled for FCAS may also have responded to the frequency change.

Generating unit	Fast raise enablement	Fast raise delivered	Slow raise enablement	Slow raise delivered	Delayed raise enablement	Delayed raise delivered
Stanwell 4	5	Note 1	10	23	0	16
Tarong 1	5	6	10	3	0	24
Tarong 2	5	4	10	0	0	17
Tumut 3	0	N/A	0	24	10	12
Vales Point 5	5	41	7	79	10	65
Vales Point 6	5	25	10	151	10	65
Totals	161	465	136	778	44	512

Note 1 – High speed data was not provided due to equipment failure. R6 analysis not conducted.

3.1.2 Victoria/South Australia/Tasmania island

Table 4 shows the enablement and delivery of contingency lower FCAS in the Victoria/South Australia/ Tasmania island for the dispatch interval ending 1515 hrs on 4 January 2020[11,12].

Table 4 shows that several generating units did not deliver the full enabled lower FCAS, with some generating units increasing output instead of reducing. This is discussed further in Section 3.1.3. However, the total delivered fast lower and slow lower services exceeded requirements, which assisted in frequency containment and stabilisation in the Victoria/South Australia/Tasmania island. For the delayed lower service, only one generating unit delivered at least the enabled amount, and the total delayed lower delivery was 95% of the enabled amount.

The FOS for a separation event allows the frequency in the mainland regions to rise to a maximum of 51 Hz (containment) but the frequency must return to lower than 50.5 Hz (stabilisation) within two minutes and to below 50.15 Hz (recovery) within five minutes. For this event the maximum frequency reached in the Victoria and South Australia was 50.43 Hz, as shown in Figure 2. Despite the shortage of delayed lower FCAS delivery, frequency in Victoria and South Australia recovered to below 50.15 Hz within approximately five minutes. In Victoria and South Australia, the FOS was met but the frequency remained at approximately 50.15 Hz for a further 10 minutes. This was caused by the lack of lower regulation FCAS enabled in the Victoria, South Australia and Tasmania at the time of separation.

Table 4 Victoria and South Australia lower FCAS (MW)

Generating unit	Fast lower enablement	Fast lower delivered	Slow lower enablement	Slow lower delivered	Delayed lower enablement	Delayed lower delivered
Hornsdale Battery Power reserve	61	51	18	15	40	33
Loy Yang B1	14	68	51	96	50	44
Loy Yang B2	14	107	100	113	50	39
Loy Yang A1	5	-8	5	84	7	5
Loy Yang A3	5	-9	5	0	10	0

[11] There was no contingency lower FCAS enabled in the Tasmania region prior to the separation event.

[12] Table 4 only includes generating units enabled to provide at least one of the contingency lower FCAS. Other generating units not enabled for FCAS may also have responded to the frequency change.

Generating unit	Fast lower enablement	Fast lower delivered	Slow lower enablement	Slow lower delivered	Delayed lower enablement	Delayed lower delivered
Loy Yang A4	5	8	5	66	10	1
Yallourn 4	25	52	20	73	15	51
Totals	129	270	204	437	182	174

Table 5 shows the amount of lower regulation FCAS enabled.

Table 5 Lower regulation FCAS enabled in Victoria/South Australia/Tasmania

Dispatch Interval ending	Lower Regulation FCAS enabled (MW)
1510 hrs	33
1515 hrs	36
1520 hrs	36
1525 hrs	51
1530 hrs	160

Additional lower regulation FCAS was enabled after the relevant system separation constraints were invoked and became effective from dispatch interval ending 1530 hrs. Rule changes[13] requiring all generation to provide a primary frequency response would have addressed this issue.

3.1.3 Analysis of non-compliant enabled FCAS providers

The Hornsdale Power Reserve (HPR) delivered less of the lower contingency services than had been expected due to a setting used to calculate the lower FCAS response required. AEMO has discussed this with the Generator, and the FCAS offers for HPR have been adjusted to reflect the actual capability.

Loy Yang A unit 1 and unit 3 failed to meet their fast lower and delayed lower FCAS requirements. Both units initially ramped up while the frequency was over 50.15 Hz and then reduced output. Loy Yang A unit 3 failed to meet its lower FCAS requirements because the frequency influence signal for the unit had been disabled by AGL. AGL has advised AEMO that the frequency influence signal has since been restored. Investigations are ongoing in relation to the performance of Loy Yang A unit 1. AGL has bid the contingency lower FCAS on Loy Yang A units 1 – 3 as unavailable until the FCAS capability of these units has been demonstrated.

Loy Yang A unit 4 did not sustain the delivery of the delayed lower contingency services for up to 600 seconds after the frequency disturbance time due to the FCAS response tapering off as the frequency returned to close to the upper recovery band..

Loy Yang B unit 1 and unit 2 met their fast and slow lower contingency FCAS requirements but only delivered between 78%-88% of the delayed lower service. AEMO is working with Alinta Energy to better understand the performance of the generating units to ensure compliance.

Eraring Unit 1 was enabled for 15 MW of the fast raise service and did not respond to the low frequency event. The plant was bid out of the FCAS market in the next dispatch interval when the operator became aware of a limitation on site which prevented the unit from responding to a contingency event. An assessment of the fast raise delivery from Eraring Unit 3 was not conducted because high speed data was unavailable due to a failure with the recording devices. Origin Energy has advised that this issue has been

[13] Mandatory Frequency Response Rule change. See AEMC website: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

rectified and the unit has since provided high speed data for other events. AEMO noted that Eraring Unit 3 did provide slow raise and delayed raise contingency services, despite not being enabled to do so in the dispatch interval ending at 1515 hrs.

An assessment of the fast raise delivery from Stanwell Unit 4 was not conducted because high speed data was unavailable due to a failure of the recording devices. Stanwell Corporation has advised that this issue has been rectified and the unit has since provided high speed data for other events.

Tarong Unit 1 and Unit 2 were enabled for both the fast raise and slow raise contingency services. However, while the units initially ramped up and largely delivered the fast raise service, the output of both units was unstable between six seconds and 60 seconds of the frequency disturbance time, resulting in an under-delivery of the slow raise service. Investigations by Stanwell Corporation have shown this was caused by unexpected governor action in response to the inertial contribution of the generating units after the rapid reduction in frequency. This behaviour has not been witnessed during previous testing of the generating units FCAS capabilities. Stanwell Corporation will continue to review the performance of the Tarong units to determine if modifications are required to governor settings to improve future FCAS performance.

3.2 Availability of FCAS

As noted in the Preliminary Report, several constraint equations associated with the provision of contingency raise FCAS in the New South Wales/Queensland island violated. A violated constraint equation means the required level of FCAS is not available and the power system may not be in a secure operating state.

The following constraint equations violated by varying amounts during the period 1530 hrs to 1740 hrs on 4 January 2020[14]:

- F_NQ+MG_R5 – raise 5-minute service requirement for a generation event in the separated New South Wales/Queensland island – violated for up to 20 minutes.
- F_NQ+MG_R6 – raise 6-second service requirement for a generation event in the separated New South Wales/Queensland island – violated for up to 45 minutes.
- F_NQ+MG_R60 – raise 60-second service requirement for a generation event in the separated New South Wales/Queensland island – violated for up to 40 minutes.
- F_Q++NIL+R5 – raise 5-minute service requirement to limit flow on QNI for loss of a 750 MW generating unit in New South Wales – violated for 20 minutes.

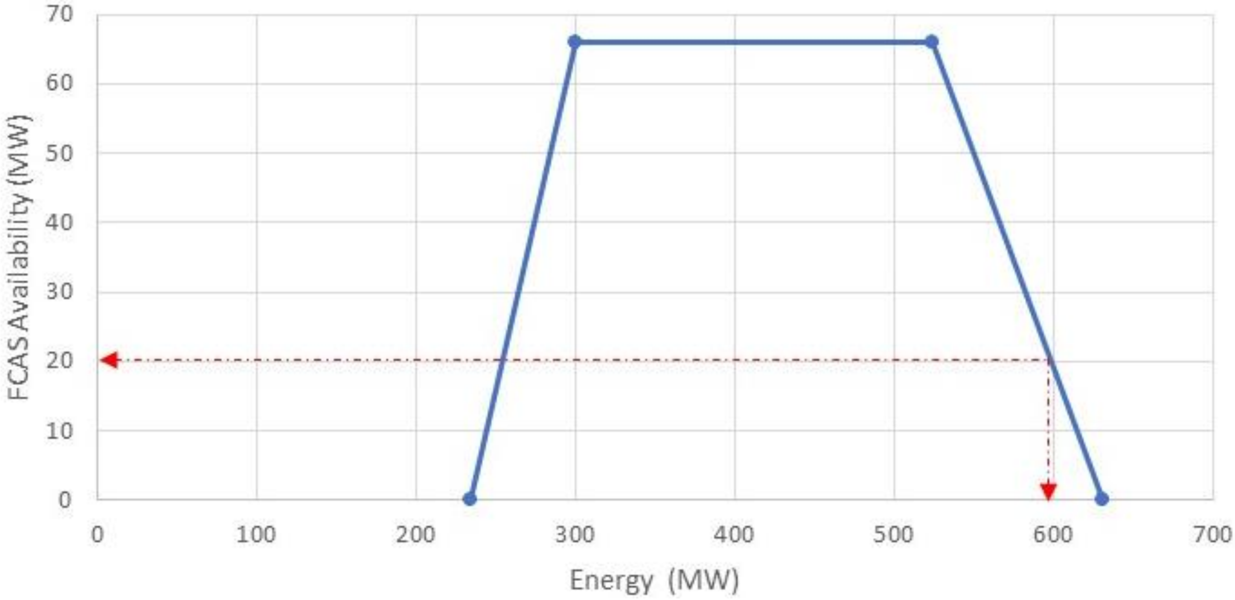
As there was a significant shortage of FCAS for up to 45 minutes, the power system in the New South Wales/Queensland island would not have been in a secure operating state for this period, as the FOS would not have been met on the trip of the largest generating unit in the island at the time.

Although sufficient FCAS was bid available to the market, a significant percentage of the available FCAS was not able to be dispatched due to the level of energy generating units were dispatched to.

To illustrate, Figure 6 shows a typical fast raise FCAS trapezium that is normally bid available for a large generating unit. For the dispatch interval ending 1545 hrs on 4 January 2020, the generating unit was dispatched for 598 MW of energy and 20 MW of fast raise FCAS. As shown in Figure 6, the maximum fast raise FCAS that this generating unit can provide at an output of 598 MW is only 20 MW. Similarly, for the dispatch interval ending 1605 hrs, the generating unit was dispatched for 630 MW of energy and therefore could not be dispatched for any fast raise FCAS. This type of scenario applied to multiple generating units, resulting in the shortage of FCAS available for dispatch.

[14] Refer to Appendix A2 for further details.

Figure 6 Typical fast raise FCAS trapezium



The constraint equations invoked as part of the islanding event aim to source enough FCAS to manage the loss of the single largest generating unit and are all constructed in a similar fashion. Using F_NQ+MG_R6 as an example, the construction is of the form:

> (R6 dispatched in Queensland and New South Wales) >= (size of the largest dispatched generating unit in Queensland or New South Wales) – (load relief).

In constraint terminology, the RHS is a fixed value and the LHS is variable; that is, the size of the largest generating unit becomes a fixed value and FCAS is dispatched to suit and if insufficient FCAS is available the constraint will violate.

However, under certain circumstances, AEMO can move the generating unit at risk to the LHS of the equation to allow generation to be co-optimised with the FCAS requirement. This construction is of the form:

> (R6 dispatched in Queensland and New South Wales) - (generating unit at risk) >= - (load relief).

That is, moving the generating unit at risk to the LHS allows the NEM Dispatch Engine to reduce the output of the generating unit at risk to reduce the FCAS requirement[15].

Although AEMO will modify these constraint equations to this format by 31 December 2020[16], constraints in this format may not necessarily have provided a complete solution in this instance. Reducing the output of generating units to match the FCAS availability would require other generating units to increase output. As most of the larger generating units are in New South Wales, reducing output from these units would potentially exacerbate the reserve issues, as noted in Section 5 of this report.

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[15] For further information on formulation of FCAS constraints refer to section 8 of AEMO Constraint Formulation Guidelines, available at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/constraint_formulation_guidelines_v10_1.pdf.

[16] Allowing sufficient time for due diligence and testing prior to implementation.

4. Operation of the Wagga–Yass 132 kV network

In the Wagga Wagga area there are three major substations:

- Wagga330 – has both 330 kV and 132 kV connections and is normally referred to as the Wagga substation.
- Wagga132 – is separate from the Wagga substation and has only 132 kV connections.
- Wagga North – is separate from both the Wagga and Wagga132 substations and has only 132 kV connections.

The transfer from Victoria to New South Wales is defined as the flow across the Wodonga–Jindera 060 330 kV line (060 line), Murray–Upper Tumut 65 330 kV line (65 line), Murray–Lower Tumut 66 330 kV line (66 line), Redcliffs–Buronga OX1 220 kV line (0X1 line), and Guthega–Munyang 979 132 kV line[17] (979 line).

Immediately prior to the trip of the 66 line, the transfer from Victoria to New South Wales was approximately 650 MW. With the trip of the 66 line, combined with the existing outages of 65 and 051 lines, this flow was transferred onto the OX1 and 060 lines and subsequently the three 132 kV connections between Wagga and Yass[18]. This network is not designed or expected to maintain synchronism between Victoria and New South Wales.

Approximately two seconds after the trip of the 66 line, the Wagga–Yass 990 132 kV line (990 line), Yass–Burrinjuck 970 132 kV line (970 line), and Murrumburrah–Wagga North 991 132 kV line (991 line) tripped, resulting in the separation of the Victoria and New South Wales regions, leaving the Wagga area load and generation connected to Victoria via the 060 line.

4.1 Wagga–Yass 132 kV interconnection

At times of high Wagga Wagga area load and high import from Victoria, the outage of 051 line may result in overloading of the transformers at Yass or the 132 kV lines between Wagga and Yass. Figure 7 provides an overview of the 132 kV connections between Wagga and Yass immediately after the islanding event.

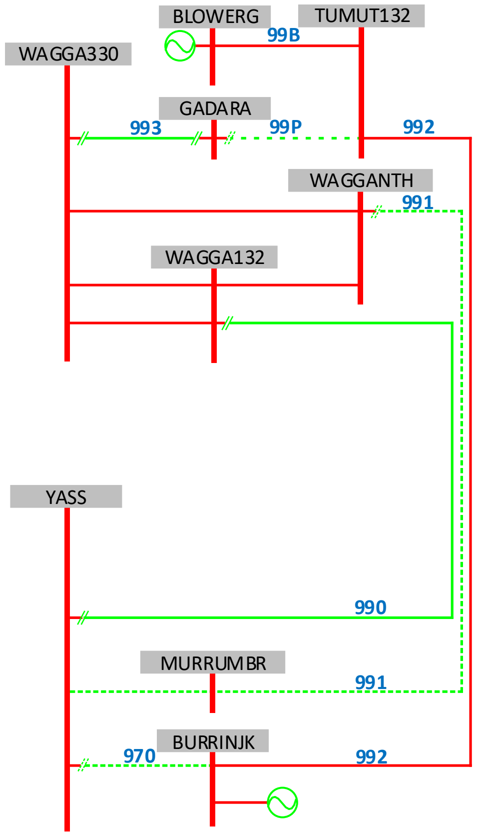
Prior to a planned outage of 051 line, TransGrid will, in accordance with its operating procedures, open the following lines to prevent post contingent overloads on the 132 kV network:

- Wagga–ANM 996 132 kV line (996 line).
- Wagga–Darlington Point 63 330 kV line (63 line).
- Darlington Point–Balranald X5 220 kV line (X5 line).
- 990 line.
- 991 line.
- Gadara–Tumut132 99P 132 kV line (99P line).

[17] 979 line is normally open at Guthega.

[18] Connection 1 = 993, 99P, 992 and 970 lines. Connection 2 = 991 & 99M lines. Connection 3 = 990 line

Figure 7 Wagga–Yass 132 kV connections



To cover the forced outage of 051 line under normal conditions when the rest of the 330 kV network in the Snowy area is intact, TransGrid has implemented the Yass overload tripping scheme. This automatic control scheme will open the 132 kV connections between Wagga and Yass in the event of an overload on the 970, 990, or 99M lines, or on either of the two 330/132 kV transformers at Yass.

If a trip and unavailability of 051 line results in a non-secure operating state, TransGrid would be expected to manage the 132kV network to restore the power system to a secure operating state, similar to what would be done for a planned outage of 051 line.

On the morning of 4 January 2020, and considering the conditions expected in the Snowy area later in the day, AEMO discussed with TransGrid the option of opening the Wagga–Yass 132 kV parallel. AEMO considered that constraining transfers from Victoria to New South Wales to manage this area was not reasonable due to the already low reserve levels in New South Wales. TransGrid replied that it did not consider this necessary at the time as there was no current impact on the power system in the area from bushfires and it would leave a number of loads on radial feeds and the Yass overload tripping scheme was expected to manage any post contingent overloading after a trip of 051 line. TransGrid also advised that if system conditions changed, it would then further consider opening the parallel pre-contingent.

At 1415 hrs, AEMO reclassified the simultaneous loss of both 65 and 66 lines as a credible contingency event. After this reclassification the power system remained in a secure operating state.

However, after the loss of 65 line at 1455 hrs and 051 Line at 1457 hrs, the power system was not in a secure operating state, as the subsequent trip of 66 line would result in large changes in the power flows in the Wagga–Yass 132 kV network and significant thermal overloading of lines in this area.

TransGrid did not have enough time to split the 132 kV parallel before 66 Line tripped at 1510 hrs. The power system was not in a secure operating state for 13 minutes.

AEMO recommends TransGrid review its procedures for splitting the 132 kV parallel during periods of high uncertainty such as during bushfire activity or other periods of multiple line outages.

Approximately two seconds after the trip of the 66 line, the 990 line tripped at both Yass and Wagga132, the 970 line tripped at Yass, and the 991 line tripped at Wagga North, to split the 132 kV network between Wagga and Yass. However, these line trips were not related to operation of the Yass Overload control scheme, as this scheme is based on thermal overloads and takes approximately 20 seconds to operate.

Instead, protection data indicates the presence of a power swing[19] passing through 970, 990, and 991 lines as a result of the loss of the 330 kV connection through the Snowy Mountains area. This power swing caused protection to operate at both the Wagga 132 and Yass end of 990 line, the Yass end of 970 line, and the Wagga North end of 991 line. Protection systems operated as expected under the power system conditions at the time.

Although TransGrid had not split the Wagga–Yass 132 kV parallel prior to or after the outage of 051 line, the resulting power system conditions after the trip of 66 line were essentially the same as if the parallel had been split manually.

Approximately three seconds after the trip of 970, 990, and 991 lines, the 990 line auto reclosed first at Wagga 132 and then at Yass, reconnecting Victoria and New South Wales briefly. This reclose was not successful because such a small single connection is not expected to keep the islands synchronised. The 990 line tripped again almost immediately after the Yass end reclosed, again due to a power swing.

4.2 Trip of 993 and 99P lines

After the initial trip of the 970, 990, and 991 lines, and before the auto-reclose on the 990 line, the Wagga–Gadara 993 132 kV line tripped at the Wagga end, auto-reclosed, and then tripped again at both ends. This created a third (small) island containing generation at Blowering (34 MW) and load at Tumut (20 MW) and Gadara (23 MW). Approximately 10 seconds later, the resulting generation/load imbalance resulted in operation of the under-frequency load shedding (UFLS) relays at Tumut, tripping 20 MW of load. At 15:11:20.043 hrs, the Gadara–Tumut 132 99P 132 kV line tripped at Gadara, resulting in the loss of the load at Gadara and the shutdown of the Blowering generating unit.

This second outage of 993 line was likely the result of the combined effects of heating from the fires in the vicinity of the line and increased current during the power swing that caused the previous trip causing the conductors to fail. A subsequent line patrol found conductors on the ground within the fire zone. TransGrid replaced several poles and five conductor spans prior to returning the line to service.

Although TransGrid could not conclusively determine the reason 99P line tripped, there is evidence of voltage collapse in the island formed around the Blowering generating unit after the trip of 993 line, resulting in the trip of 99P line at Gadara.

5. Reserve

5.1 Calculation of reserve levels

This separation event resulted in regional boundaries that differed from boundaries normally used for reserve calculations. This section considers the issues this caused with reserve calculations.

[19] A power swing is defined as an oscillation in active and reactive power flows on a transmission line in response to a fault or large disturbance. This oscillation in power and voltage levels result in changes in impedance which can be interpreted by protection relays as a line fault.

5.1.1 Reserve level calculations

AEMO calculates the expected reserve for each NEM region based on the defined network area within that region, and using the available supply, net import via interconnectors, and forecast demand within the region. This and other outputs are determined in the solution produced by AEMO's PASA model. Where AEMO identifies that there is a non-remote probability of load shedding due to a reserve shortfall, AEMO will declare the relevant LOR condition[20].

The boundary between the Victoria and New South Wales regions is defined in Section 4 of this report. However, after the separation event, the Wodonga–Jindera 060 330 kV line and the Buronga–Redcliffs OX1 220 kV line remained in service, with the 132 kV network split between Wagga and Yass. This resulted in a conceptual shift of the regional boundaries, with load and generation within the Wagga Wagga area 'shifting' from the New South Wales region to the Victoria region. Wagga Wagga area load was approximately 500 MW at the time. Wagga Wagga area generation[21], with a registered capacity of approximately 1,259 MW[22], initially remained connected to Victoria, but was constrained[23] to 0 MW as at 1540 hrs on 4 January 2020 for system security reasons as noted in the Preliminary Report.

The AEMO PASA model that determines reserve levels within each region is not dynamically configurable to modify regional boundaries to reflect changes within the interconnected network, because the requirements for such changes are rare.

Following the separation event, AEMO staff performed a forecast review and manual calculations to determine reserve levels for the (reduced) New South Wales region and (increased) Victoria region. AEMO adjusted the demand forecasts for each region so the PASA model was able to estimate reserve levels for subsequent reserve forecasts. This enabled determination of power system conditions and relevant response actions to manage these. This required additional effort by operational staff, however, the outcome was effective in managing conditions and was considered the relevant measure to take given the limitations of the PASA model. The adjustment to the demand forecast was removed following the synchronisation of the New South Wales and Victoria regions.

AEMO is currently working on a Short Term (ST) PASA Replacement Project, which will involve a holistic review of the Pre Dispatch (PD) and ST PASA methodology. Outcomes during this incident will be considered as part of this review. The project will include consideration of a full network model to enable more granular determination of reserve levels, and AEMO plans to implement this replacement system by mid-2022.

5.2 Reliability and Emergency Reserve Trader (RERT)

Reserve levels in New South Wales fell sharply after the separation from Victoria, due to the loss of import capability from Victoria, the constraint on generation in the Wagga Wagga area, and reduced capability from Tumut generation. Additionally, semi-scheduled and non-scheduled wind generation was de-rated and under-forecast during the day, primarily due to high wind de-rating and wind speed forecast variations.

AEMO declared an actual LOR 2 in New South Wales from 1600 hrs on 4 January 2020. In response to the LOR 2 condition, AEMO activated 68 MW of RERT and pre-activated an additional 300 MW of RERT. The LOR 2 condition was cancelled at 2106 hrs and all RERT was de-activated by 2145 hrs on 4 January 2020. A full report on the RERT activation and the reserve conditions leading up to the RERT activation is available on AEMO's website[24].

[20] Further details are provided in AEMO Reserve Level Declaration Guidelines, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf.

[21] Uranquinty, Coleambally Solar Farm (SF), Finley SF, Broken Hill SF, and Silverton Wind Farm (WF). Does not include any non-scheduled generation in the area.

[22] Actual bid capacity at the time was 744 MW.

[23] Constraint set: N-LTWG_RADIAL – Out = 051 line with 132 kV network split.

[24] Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q1 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2020/rert-quarterly-report-q1-2020.pdf?la=en.

6. Performance of generating units

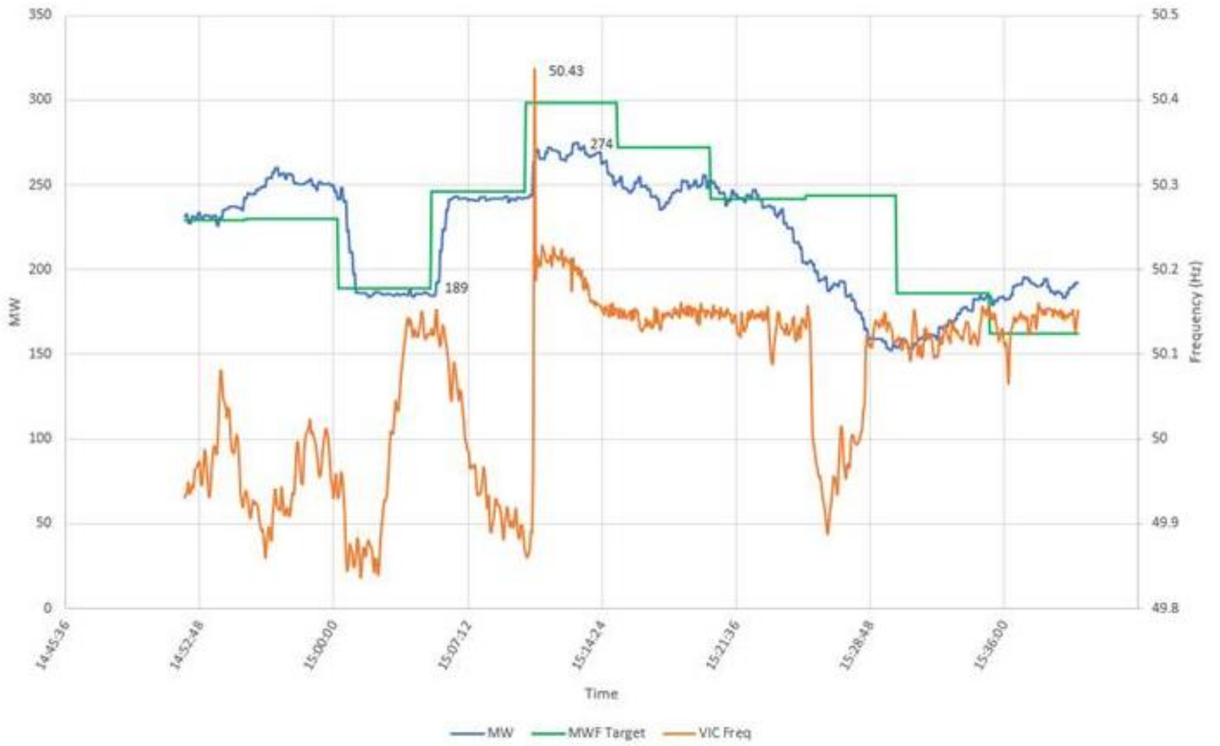
AEMO reviewed the response of generating units to the frequency change due to the separation event. The majority of generating units performed as expected. This section provides information relating to the performance of particular generating units assessed as part of this incident review.

6.1 Macarthur Wind Farm

Macarthur Wind Farm is in Victoria and would be expected to respond to frequency changes in Victoria. Immediately post separation, the frequency in Victoria rose, as shown in Figure 2 (in Section 3). In accordance with clause S5.2.5.11 of the NER, a generating system under relatively stable wind conditions must not increase its power transfer to the power system in response to a rise in frequency.

In response to the frequency change in Victoria, the output of Macarthur Wind Farm increased from approximately 245 MW to 275 MW. However, analysis has shown the wind farm was following dispatch targets at the time, as shown in Figure 8, and was therefore compliant with its Generator Performance Standard.

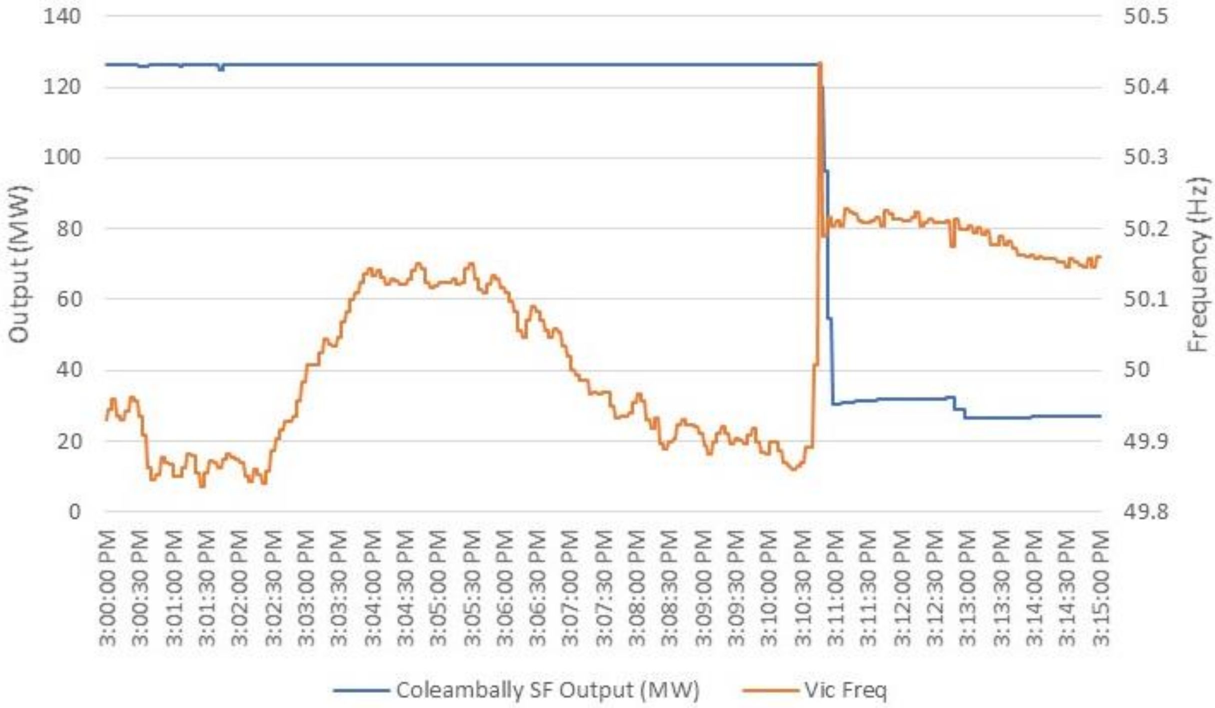
Figure 8 Output of Macarthur Wind Farm



6.2 Coleambally Solar Farm

Although Coleambally Solar Farm is in New South Wales, post separation it remained connected to the Victoria/South Australia island and therefore was exposed to the frequency in this island and reduced output from 126 MW to 30 MW, as shown in Figure 9.

Figure 9 Output of Coleambally Solar Farm

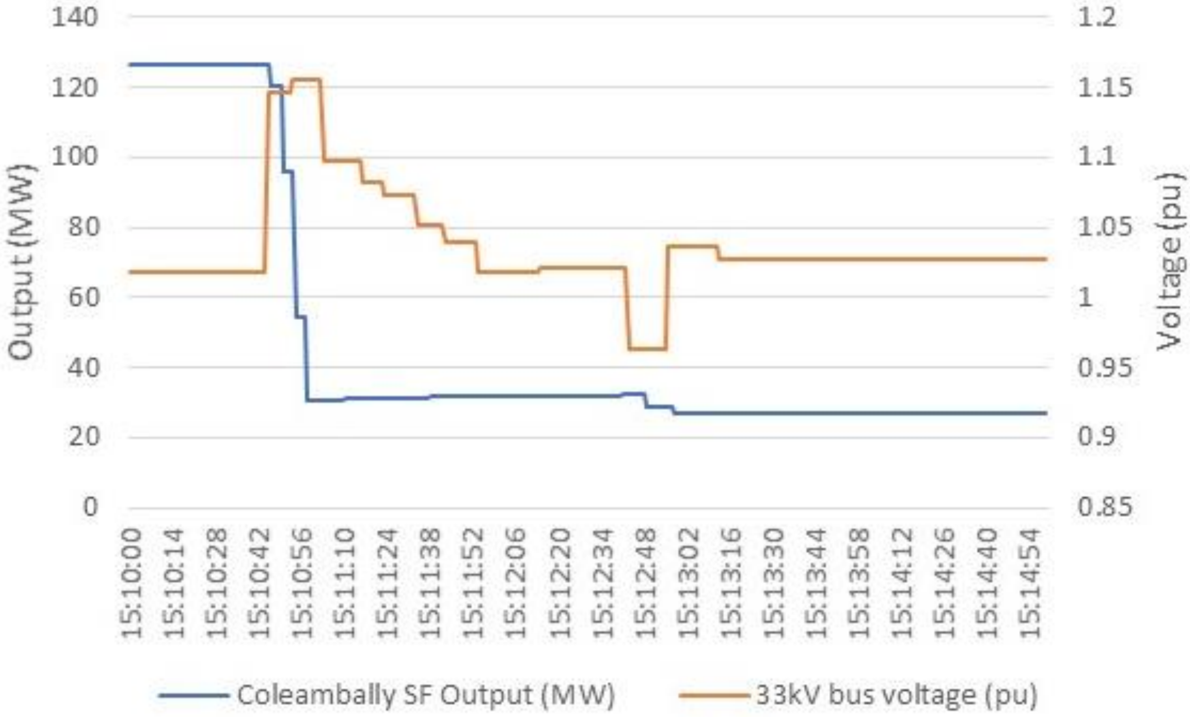


Although a reduction in output was expected due to the frequency response, the extent of the reduction was more than would be expected, as some of the inverters tripped. Further analysis shows the unit reduced output in response to high voltage at the generating unit terminals. The high voltage resulted from the sudden reduction in power flow through the 132 kV network post separation and was an expected outcome.

Post separation, the voltage at the generating unit 33 kV busbar was approximately 1.154 per unit (pu) (38 kV) and persisted for over three seconds, as shown in Figure 10[25].

[25] The 132 kV voltage reached a maximum of 1.124 pu or 148.4 kV.

Figure 10 Voltage response at Coleambally Solar Farm



The tripping of inverters in response to high voltages is consistent with the Generator Performance Standard, in that tripping of inverters is permissible if the terminal voltage exceeds 1.15 pu for greater than three seconds. Not all the inverters tripped, as not all inverters experienced the full three seconds of over-voltage. Approximately 30 MW of generation remained online. The additional loss of generation at Coleambally assisted in the frequency recovery and was compliant with its Generator Performance Standard.

7. Reliability of supply

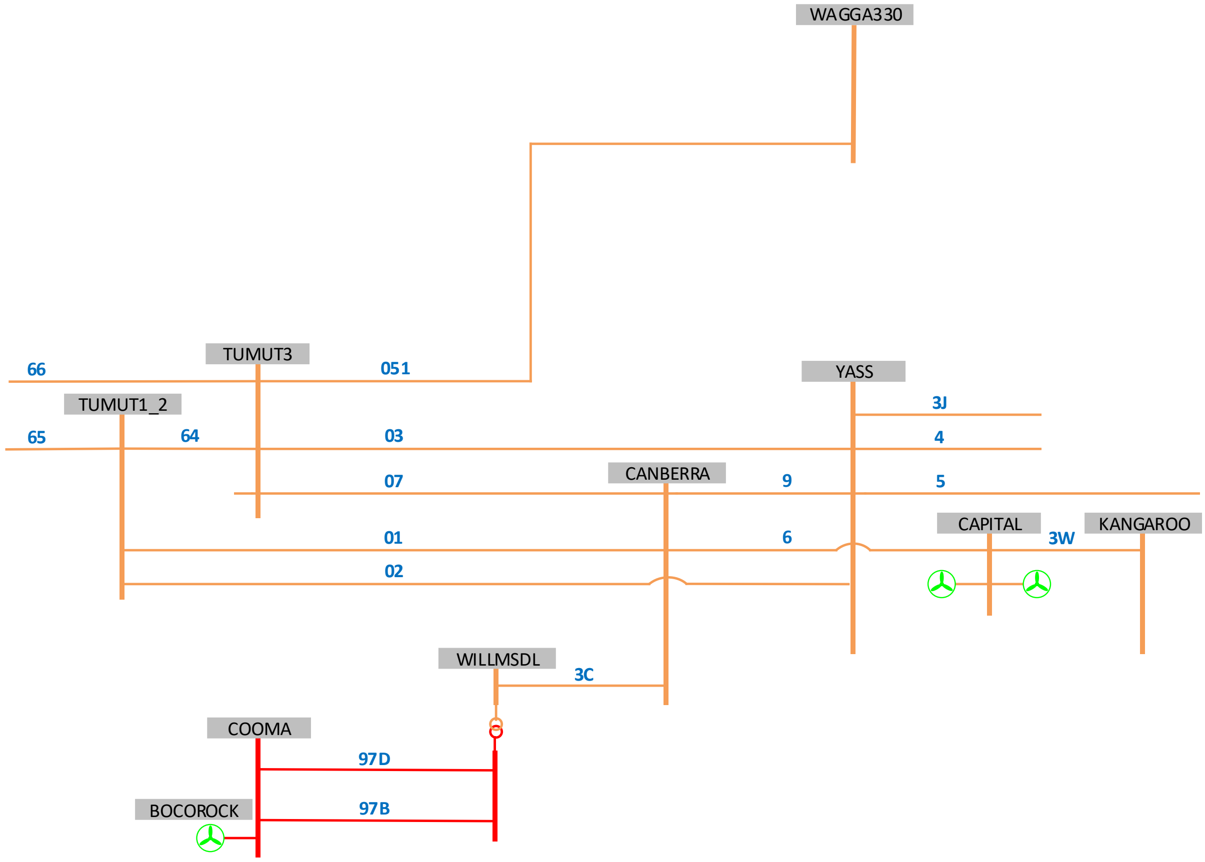
As noted in the Preliminary Report, despite the nature of this event, only 43 MW of customer load was lost as a direct result of this incident. This load was restored within approximately 40 minutes.

Of concern to AEMO during this event was supply to the Canberra area. As shown in Figure 11, the Canberra substation (which supplies most of the Australian Capital Territory load) is fed via four 330 kV lines; two are from the Snowy Mountains area, one from Yass, and one from Sydney South via Kangaroo Valley and Capital:

- Tumut1-2 – Canberra 01 330 kV line (01 line).
- Tumut3 – Canberra 07 330 kV line (07 line).
- Yass – Canberra 09 330 kV line (09 line).
- Capital – Canberra 06 330 kV line (06 line).

Apart from where the lines enter the Canberra substation these lines all run in separate easements.

Figure 11 Supplies to Canberra substation



During this event, there were numerous outages on the 01, 07, and Capital–Kangaroo 3W 330 kV (3W) lines. The only line supplying Canberra that did not trip during this incident was the 09 line. Apart from numerous outages of the various lines, the following multiple line outages also occurred:

- 01 and 3W – three occasions for a maximum outage duration of 10 minutes.
- 01 and 07 – three occasions with a maximum outage duration of 50 minutes.
- 01, 07, and 3W – two occasions with a maximum outage duration of 12 minutes.

With 01, 07, and 3W lines out of service, the only supply to Canberra substation is 9 line from Yass and 6 line to Capital, which connects generation from Capital and Woodlawn wind farms to Canberra. The load fed from the Canberra substation was approximately 530 MW at the time, with an additional 93 MW being supplied by Bocorock Wind Farm, which also connects into Canberra. The loss of 9 line under these conditions would leave Canberra islanded on generation at the Bocorock, Capital, and Woodlawn wind farms. The resulting large supply demand imbalance in this island would result in the trip of the three wind farms on low frequency with a complete loss of supply to Canberra.

Post-event studies for the loss of 6 line during the outage of 01 and 07 lines leaving Canberra fed via 9 line only show low voltage levels at Canberra and high flows on the remaining in-service line, but within acceptable limits.

Studies for the loss of 9 line during the outage of 01 and 07 lines, leaving only the 6, 3W, and 18 lines through to Dapto in service, show voltage levels at Canberra and line flows would similarly be within acceptable limits.

8. Response of distributed photovoltaic generation

Distributed PV[26] generation is now a significant component of the power system, and as such its aggregated behaviour can affect outcomes during system incidents. AEMO has traditionally had limited visibility of distributed PV behaviour.

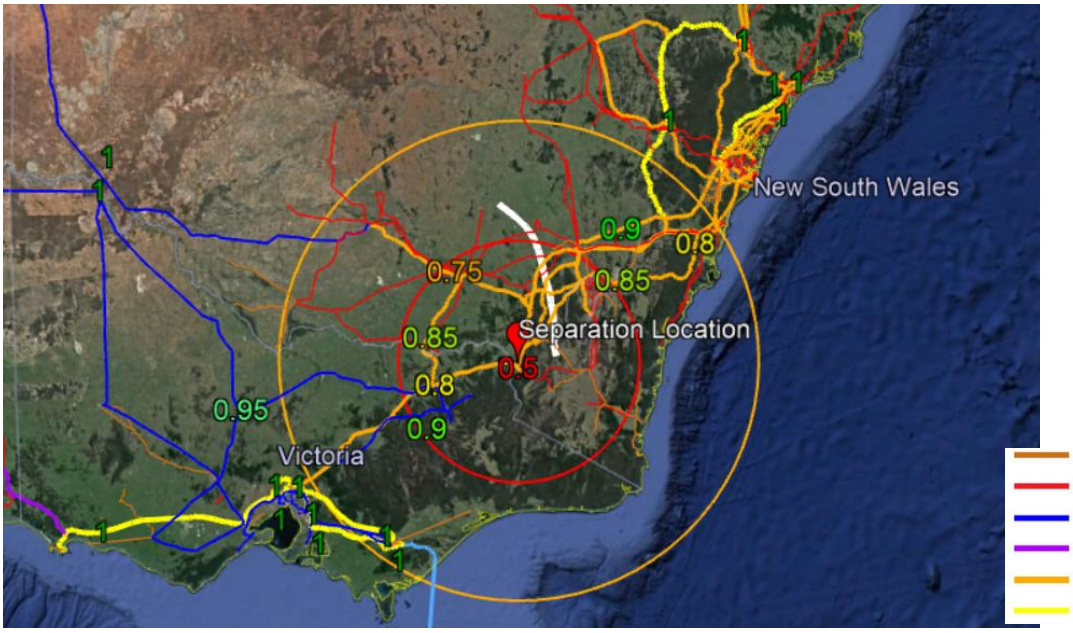
For analysis of the behaviour of distributed PV generation during this event, Solar Analytics[27] provided data from approximately 13,000 individual distributed PV systems in the NEM under a joint Australian Renewable Energy Agency (ARENA) funded project[28], with anonymisation to ensure that system owner and addresses could not be identified.

AEMO has reviewed this data in relation to the impacts caused by the trip of 66 line at 1510 hrs on 4 January 2020 that led to the separation of Victoria and New South Wales.

8.1 Distributed PV behaviour

Figure 12 shows the minimum voltages measured across the New South Wales and Victoria transmission network at the time of separation, as context for interpreting distributed PV responses.

Figure 12 Minimum voltages recorded (pu minimum on a single phase) at time of separation (1510 hrs)



Zone 1 includes all distributed PV systems within 150 km of the separation location, Zone 2 between 150 km and 300 km from the separation location, and Zone 3 covers all remaining distributed PV in New South Wales and Victoria.

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26 Distributed PV refers to any PV system connected to the distribution network. This includes rooftop PV, as well as small solar farms and commercial PV systems on buildings.

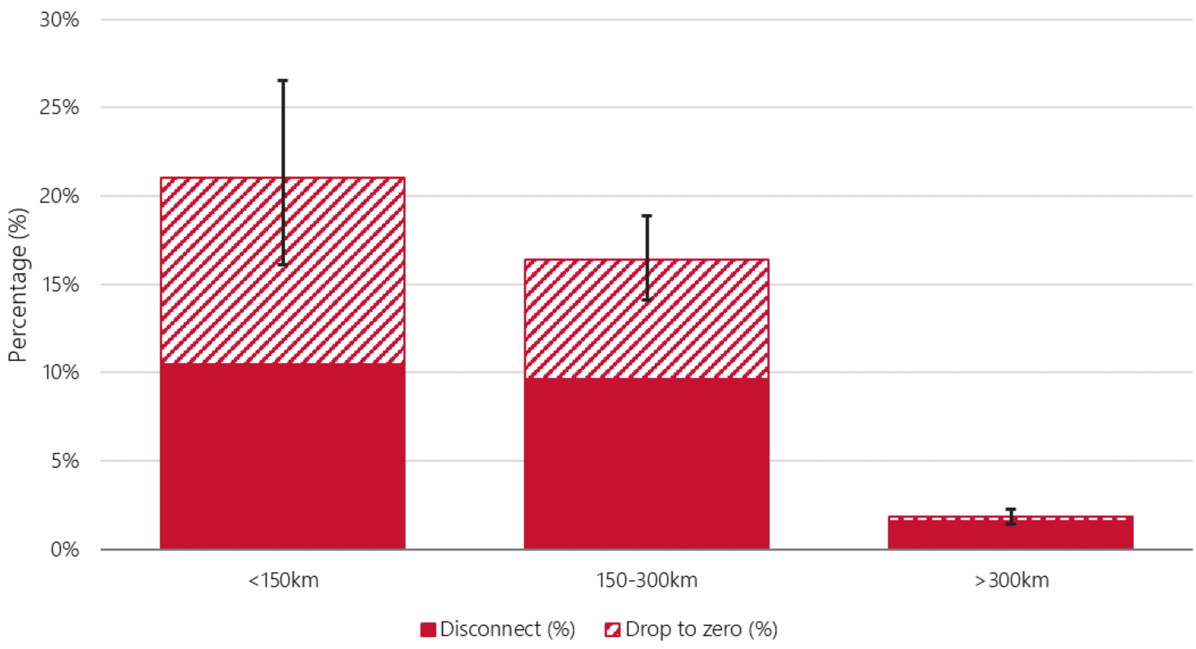
27 Solar Analytics Pty Ltd is a software company that designs, develops and supplies solar and energy monitoring and management services to consumers and solar fleet managers. Data was supplied with anonymisation to ensure system owner and address could not be identified.

28 Collaboration on ARENA-funded project "Enhanced Reliability through Short Time Resolution Data" with further details at https://arena.gov.au/projects/enhanced-reliability-through-short-time-resolution-data-around-voltage-disturbances/.

The location of the Murray–Tumut disconnection is shown by the red marker, and the bold white line demonstrates where the Victoria and New South Wales regions electrically separated. Everything to the right of the bold white line remained connected to the New South Wales region and experienced under-frequency to a minimum of 49.53 Hz, while everything to the left of the line remained connected to the Victoria region and experienced over-frequency to a maximum of 50.43 Hz. The zones indicated in red and yellow concentric circles were used to analyse distributed PV responses by proximity to the disturbance. As can be seen in the figure, voltages reached a minimum of 0.85 pu in south-east New South Wales, and 0.5 pu in the north east Victoria area (measured on a single phase).

Figure 13 shows the disconnection of distributed PV observed in each of the geographic zones illustrated in Error! Reference source not found. 12. A higher disconnection rate is observed closer to the separation location, consistent with the depth and geographic extent of voltage measurements recorded. Minimal distributed PV disconnections were observed in regions further than 300 km from the separation location (where the voltage disturbance was minimal), suggesting that the primary cause of disconnections closer to the event location was the voltage disturbance.

Figure 13 Distributed PV disconnection in New South Wales and Victoria relative to distance from the separation location



Values shown illustrate the proportion of distributed PV systems observed to reduce power to close to zero for at least two measurement intervals (termed "disconnection") and distributed PV systems observed to reduce power to close to zero for one measurement interval (termed "drop to zero"). Uncertainty estimates are based on sample sizes and observed number of disconnections, calculated at a 95% confidence level.

Estimates of how much distributed PV generation reduced in each region in response to the separation are shown in Table 6. As shown, part of the reduction in distributed PV generation in each region was related to disconnection of distributed PV ("PV shake-off", with much of this in New South Wales and Victoria likely due to the voltage disturbance), and part was attributable to the controlled over-frequency droop response of distributed PV inverters installed under the 2015 standard[29].

[29] 'The 2005 standard' refers to inverters installed before October 2015 under AS/NZS4777.3:2005. 'The 2015 standard' refers to inverters installed after October 2016 under AS/NZS4777.2:2015.

Table 6 Reduction in distributed PV estimated in each region, with likely causes

		New South Wales	Victoria	South Australia
Max/min frequency		49.53 Hz north of separation 50.43 Hz south of separation	50.43 Hz	50.43 Hz
Voltage disturbance		Significant	Significant	None
Reduction in distributed PV generation estimated for the region (MW)		90 MW (7%)	140 MW (13%)	50 MW (7%)
Proportion of reduction attributable to:	**Controlled over-frequency droop response of distributed PV inverters under the 2015 standard**	50%	25%	55%
	Disconnection of distributed PV under the 2015 standard	25%	15%	35%
	Disconnection of distributed PV under the 2005 standard	25%	45%	10%

In New South Wales, most of the reduction in distributed PV generation occurred south of the separation, in response to the over-frequency in that area, and in response to the voltage disturbance (based on comparison with previous events and inverter bench testing results). Minimal distributed PV response was observed on the north side of the separation, where only 2.5% of distributed PV systems disconnected (3% of 2005 standard and 2% of 2015 standard systems).

Distributed PV generation in Queensland was observed to be mostly unaffected by the under-frequency (which reached a minimum of 49.53 Hz). Distributed PV responses in Tasmania were not investigated due to insufficient data for a statistically meaningful assessment.

The over-frequency droop response of inverters on the 2015 standard is becoming an important contributor to power system security, assisting in minimising over-frequency excursions by reducing distributed PV generation by meaningful proportions. However, significant rates of non-compliance were observed, as shown in Table 7. The analysis found that 35% of distributed PV systems in South Australia and 46% of distributed PV systems in Victoria installed under the 2015 standard were observed to not respond as specified.

Table 7 Responses of distributed PV systems on the 2015 standard

	Victoria (and New South Wales south of the separation)	South Australia
Response as specified	24%	35%
Did not deliver any response	46%	35%
Partially responded	14%	20%
Disconnected or dropped to zero	11%	7%
Offline prior to the incident	3%	4%

AEMO is working with industry to implement a program to improve compliance with standards. Further details of the analysis can be found in Appendix A3.

A1. Status of major transmission circuits prior to and after separation

Figures 14 and 15 below show the status of the circuits of the transmission network in southern New South Wales and northern Victoria immediately prior to and immediately after islanding. The transmission circuits are shown as follows:

- Solid orange lines represent in-service 330 kV transmission circuits.
- Solid blue lines represent in service 220 kV transmission circuits.
- Solid red lines indicate Inservice 132 kV transmission circuits.
- Dotted red lines represent in service 132 kV connections to other 132 kV subsystems.
- Solid green lines represent deenergised 132 kV circuits.
- Dotted green lines represent 132 kV circuits which are energised but open at one end (that is, not carrying load).

The dotted blue line represents the boundary between the New South Wales and Victorian regions.

Figure 14 Status of major transmission circuits prior to islanding

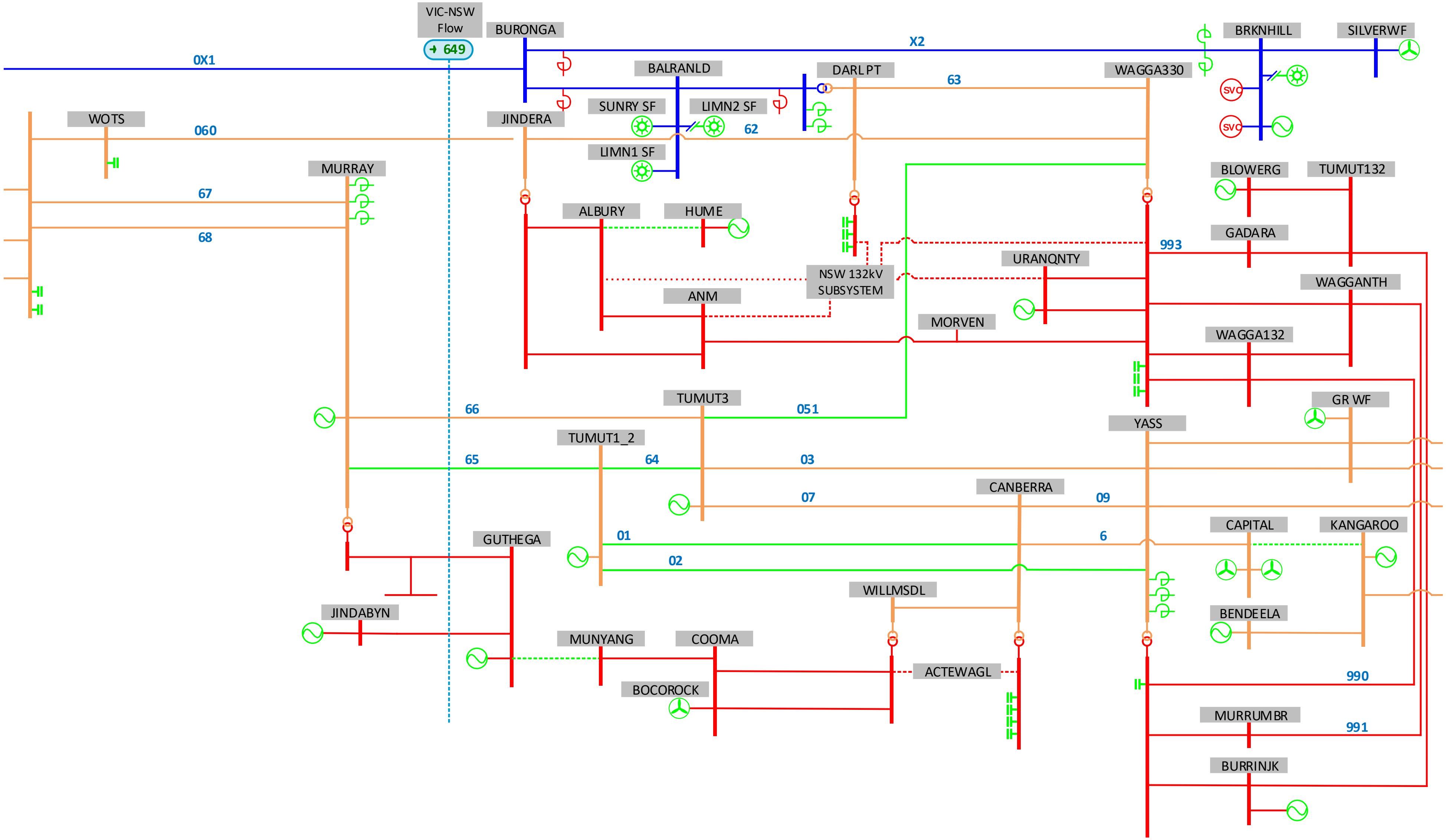
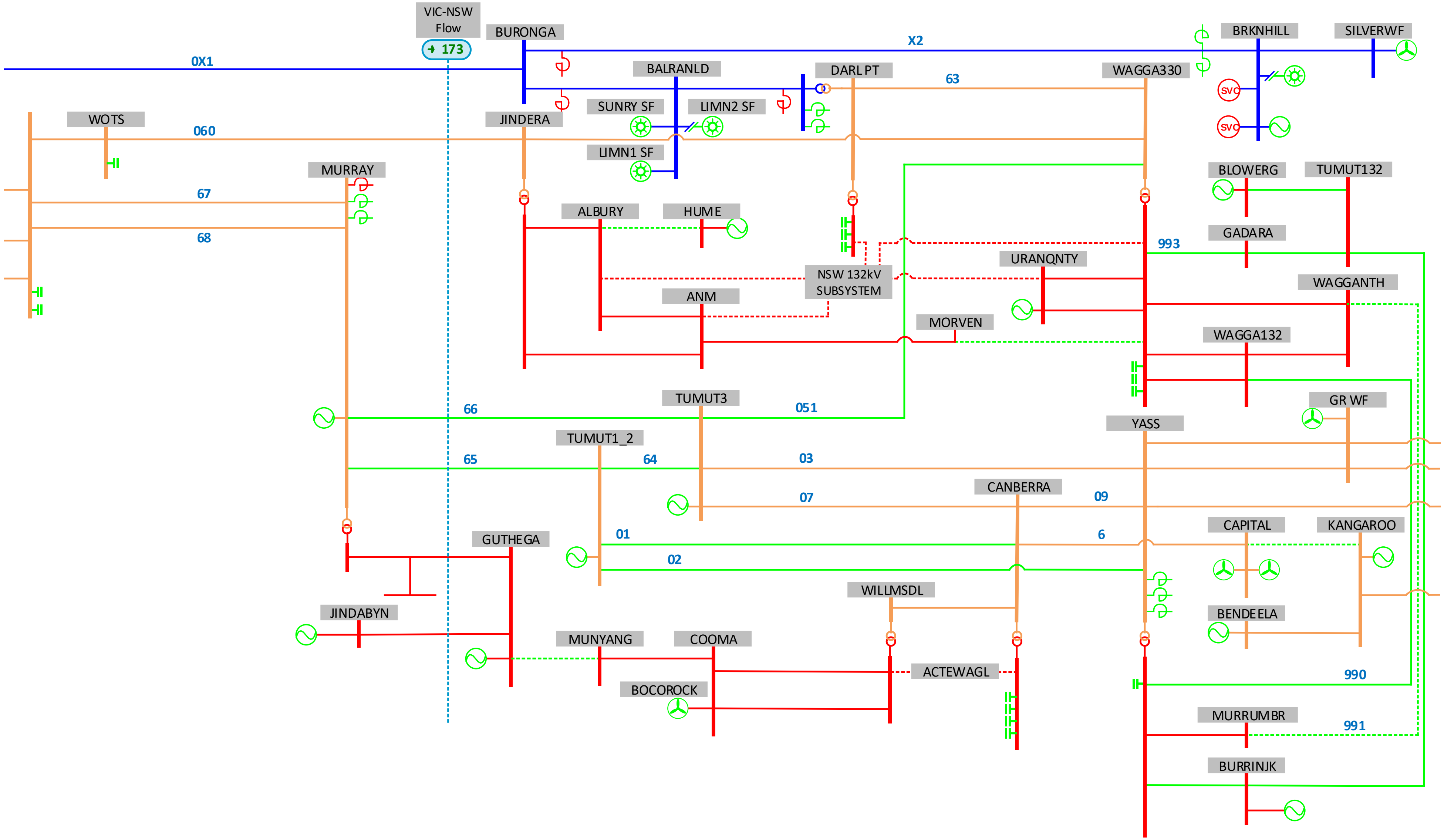


Figure 15 Status of major transmission circuits immediately after islanding



A2. FCAS constraint violations

CONSTRAINTID	SETTLEMENTDATE	RHS (MW)	VIOLATIONDEGREE (MW)
F_NQ+MG_R5	4/01/2020 15:50	605.92	-98.19
F_NQ+MG_R5	4/01/2020 15:55	613.99	-210.07
F_NQ+MG_R5	4/01/2020 16:00	616.01	-243.97
F_NQ+MG_R5	4/01/2020 16:05	625.50	-63.19
F_NQ+MG_R5	4/01/2020 16:10	611.31	-25.83
F_NQ+MG_R5	4/01/2020 16:15	620.91	-64.86
F_NQ+MG_R5	4/01/2020 16:30	618.93	-204.67
F_NQ+MG_R5	4/01/2020 16:45	612.65	-0.80
F_NQ+MG_R5	4/01/2020 16:55	611.49	-97.69
F_NQ+MG_R5	4/01/2020 17:00	611.94	-129.02
F_NQ+MG_R5	4/01/2020 17:05	612.11	-55.47
F_NQ+MG_R5	4/01/2020 17:25	605.61	-19.70
F_NQ+MG_R5	4/01/2020 17:35	606.82	-99.47
F_NQ+MG_R5	4/01/2020 17:40	610.34	-69.75
F_NQ+MG_R6	4/01/2020 15:30	549.95	-123.55
F_NQ+MG_R6	4/01/2020 15:50	524.53	-119.23
F_NQ+MG_R6	4/01/2020 15:55	532.64	-161.98
F_NQ+MG_R6	4/01/2020 16:00	535.47	-217.35
F_NQ+MG_R6	4/01/2020 16:05	545.01	-269.06
F_NQ+MG_R6	4/01/2020 16:10	531.55	-236.91
F_NQ+MG_R6	4/01/2020 16:15	540.43	-305.62
F_NQ+MG_R6	4/01/2020 16:20	542.20	-145.95
F_NQ+MG_R6	4/01/2020 16:25	531.53	-157.11
F_NQ+MG_R6	4/01/2020 16:30	538.31	-116.77
F_NQ+MG_R6	4/01/2020 16:55	530.61	-14.17
F_NQ+MG_R6	4/01/2020 17:00	530.61	-38.99
F_NQ+MG_R6	4/01/2020 17:35	525.85	-11.75
F_NQ+MG_R60	4/01/2020 15:30	549.95	-73.09
F_NQ+MG_R60	4/01/2020 15:50	524.53	-99.25
F_NQ+MG_R60	4/01/2020 15:55	532.64	-138.35
F_NQ+MG_R60	4/01/2020 16:00	535.47	-207.35
F_NQ+MG_R60	4/01/2020 16:05	545.01	-278.29
F_NQ+MG_R60	4/01/2020 16:10	531.55	-248.91
F_NQ+MG_R60	4/01/2020 16:15	540.43	-317.62
F_NQ+MG_R60	4/01/2020 16:20	542.20	-110.06
F_NQ+MG_R60	4/01/2020 16:25	531.53	-158.63
F_NQ+MG_R60	4/01/2020 16:30	538.31	-128.77
F_NQ+MG_R60	4/01/2020 16:55	530.61	-26.17
F_NQ+MG_R60	4/01/2020 17:00	530.61	-50.99
F_NQ+MG_R60	4/01/2020 17:35	525.85	-24.75
F_Q++NIL_R5	4/01/2020 16:00	1360.00	39.22
F_Q++NIL_R5	4/01/2020 16:05	1360.00	47.33
F_Q++NIL_R5	4/01/2020 16:10	1360.00	57.74
F_Q++NIL_R5	4/01/2020 16:15	1360.00	88.00

A3. Analysis of distributed PV generation

Just prior to separation, distributed PV was contributing an estimated 4.2 gigawatts (GW) of generation in the NEM. The analysis below explores the behaviour of distributed PV in response to the separation event at 1510 hrs.

A3.1 New South Wales and Victoria

Table 8 summarises the disconnection rates in New South Wales and Victoria, which are likely at least partially related to the voltage disturbance experienced, with voltages reaching a minimum of 0.85 pu in south-east New South Wales, and 0.5 pu in the north east Victoria area (measured on a single phase). A higher rate of disconnections was observed south of the separation, likely associated with lower voltages experienced in that part of the network.

Table 8 Disconnections/drop to zero observed for distributed PV systems in New South Wales and Victoria

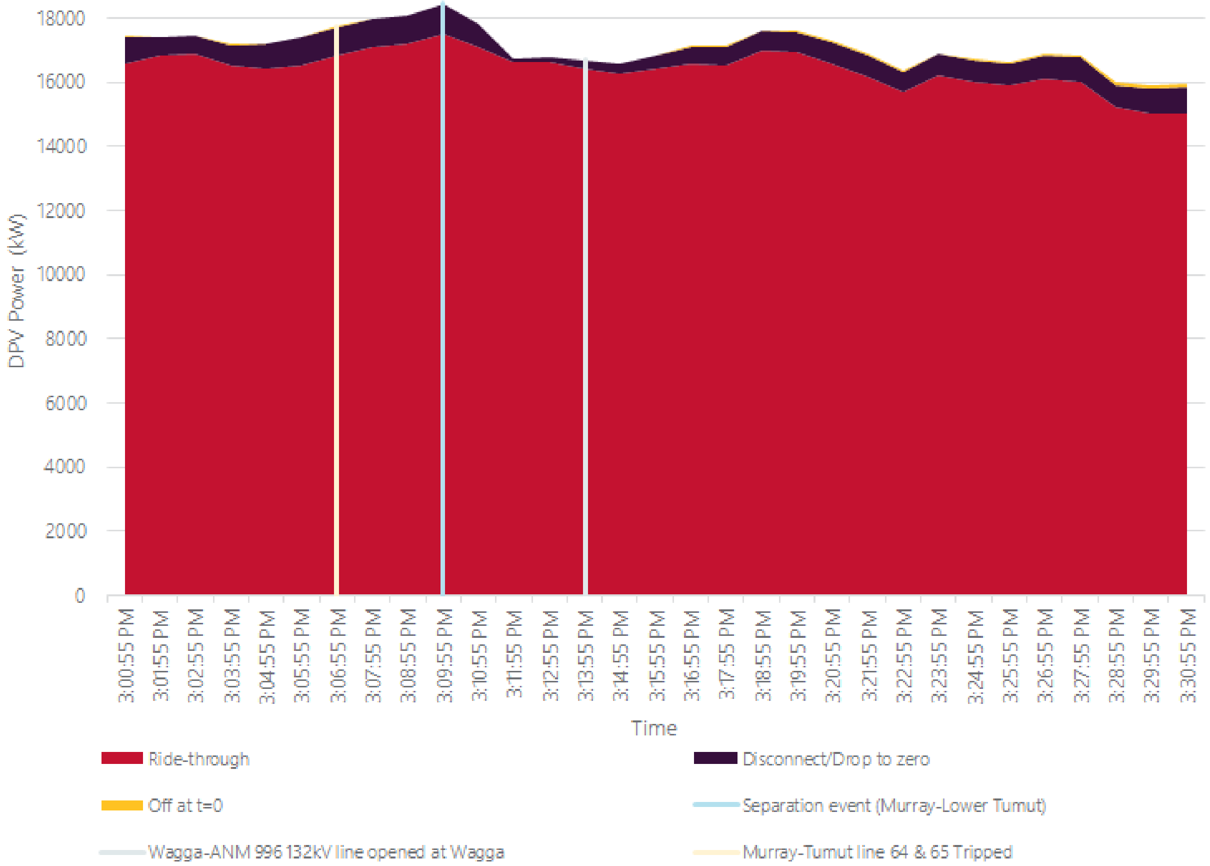
	2005 standard		2015 standard	
	<30 kW	30-100 kW	<30 kW	30-100 kW
New South Wales (north of separation)	3% (2% - 6%)	0% (0% - 10%)	1% (1% - 2%)	5% (4% - 7%)
Victoria (and New South Wales systems south of separation)	8% (4% - 15%)	13% (6% - 24%)	10% (8% - 12%)	16% (12% - 19%)

'2005 standard' refers to inverters installed before October 2015 under AS/NZ4777.3:2005. '2015 standard' refers to inverters installed after October 2016 under AS/NZ4777.3:2015. The window of disconnections measured was 3 minutes from 15:09:55, to capture only the 15:10 separation event, and not any other faults surrounding this event.

Generally, the rate of disconnections observed was higher for larger systems (30-100 kW) compared with smaller systems (<30 kW). This has also been observed in other events and other NEM regions. This may be related to distribution network protection systems applied for larger connections, and AEMO will investigate this possibility with distribution network service providers.

Figure 16 demonstrates the aggregate power for the distributed PV systems monitored in New South Wales and Victoria. The time stamps at 15:07, 15:10 and 15:14 are marked to indicate the times where faults on the network are known to have occurred. Distributed PV generation throughout the day was variable, perhaps related to bushfire smoke, but a clear drop in aggregate distributed PV generation occurred immediately after the 15:10 separation. Other faults that occurred immediately prior to and after the event did not cause clear drops in distributed PV generation. The voltage profile of the other faults in this observation window may have been milder, although high speed data is not available to confirm.

Figure 16 Aggregate power for Solar Analytics monitored systems in New South Wales and Victoria



Given that the separation event did not align with regional borders in this case, AEMO used a novel method for analysis of distributed PV behaviours in this event. The frequency data measured by the Solar Analytics systems at each distributed PV site was directly used to distinguish the systems that remained connected to the network north of the separation, versus south of the separation (since the frequency in each region post separation was different). AEMO is now integrating this new capability into standard tools for assessment of distributed PV behaviour and is continuing to improve methods for distributed PV analysis.

A3.2 South Australia – over-frequency

South Australia experienced an over-frequency excursion to a maximum of 50.43 Hz, with no voltage disturbance recorded on the transmission network. Table 9 summarises distributed PV disconnection behaviour. For distributed PV systems installed under the 2015 standard, disconnection behaviour is inconsistent with the specifications in the standard. Laboratory bench testing[30] shows that the majority of distributed PV systems tested on the 2015 standard behave consistently with specified over-frequency ride-through requirements, suggesting that this behaviour may be related to installation processes.

[30] UNSW project "Addressing Barriers to Efficient Renewable Integration", funded by ARENA, with partners ElectraNet, TasNetworks, and AEMO. Further information at https://research.unsw.edu.au/projects/addressing-barriers-efficient-renewable-integration, with inverter testing results at http://pvinverters.ee.unsw.edu.au/.

Table 9 Disconnections/drop to zero observed for distributed PV systems in South Australia

	2005 standard		2015 standard	
	<30 kW	30-100 kW	<30 kW	30-100 kW
South Australia	4% (1% - 11%)	0% (0% - 19%)	7% (7% - 8%)	1% (0% - 2%)

A3.3 Queensland – under-frequency

In Queensland, very minimal distributed PV disconnections were observed. There was minimal voltage disturbance recorded, and frequency reached a minimum of 49.53 Hz.

A3.4 Over-frequency droop response – South Australia and Victoria

After separation, Victoria and South Australia both experienced an over-frequency excursion, with a maximum frequency of 50.43 Hz. Inverters installed under the 2015 standard should demonstrate an over-frequency droop response when frequency exceeds 50.25 Hz and sustain that response until frequency falls below 50.15 Hz. In this event, frequency remained above that level for approximately 12 minutes. To provide a compliant response, inverters installed under the 2015 standard should have curtailed to 89% of their output immediately prior to the event.

Anonymised data of generation in each 60-second interval from 4,237 distributed PV systems installed after October 2016 in South Australia and Victoria (including the systems in New South Wales that were south of the separation) was analysed to investigate whether inverters are delivering this behaviour as specified, with findings as shown in Table 10.

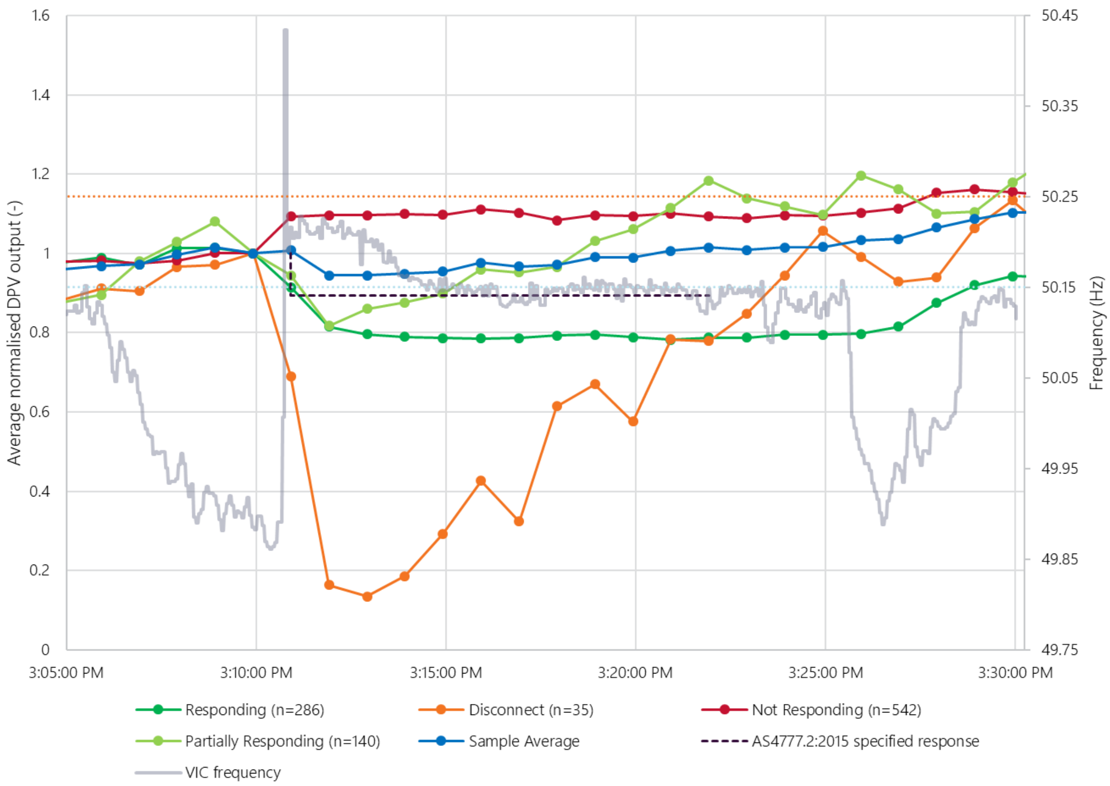
Table 10 Behaviour of sampled systems in South Australia and Victoria installed after October 2016

	South Australia	Victoria (plus systems in New South Wales south of separation)
Responding as specified **Distributed PV systems reduced power by at least 50% of the specified reduction for the whole response period.**	35%	24%
Partially responding **Distributed PV systems reduced power by at least 50% of the specified reduction for at least one measurement interval in the first two minutes.**	20%	14%
Not responding **Distributed PV systems did not demonstrate a significant reduction response.**	35%	46%
Disconnect **Distributed PV systems that reduced output power to less than 5% of the pre-event power for at least one measurement interval during the response period.**	7%	11%
Offline prior to incident **Distributed PV systems that were not operating prior to the incident occurring.**	45	35

The analysis found that 35% of distributed PV systems in South Australia and 46% of distributed PV systems in Victoria installed under the 2015 standard were observed to not respond as specified. In previous disturbances, 30-40% of distributed PV on the 2015 standard has shown similar non-compliance behaviour[31]. Bench testing of 16 inverters sold in the NEM as compliant with the 2015 standard showed that most demonstrated the specified over-frequency droop response under laboratory conditions[32]. This suggests that the cause of the inverters observed to not demonstrate this behaviour in the field is more likely related to installer processes, rather than manufacturer settings and design. AEMO is investigating this further with stakeholders and establishing a program of work to improve compliance.

Figure 17 and Figure 18 show the average normalised response[33] of distributed PV inverters installed under the 2015 standard in each response category listed in Table 10, in Victoria and South Australia. The black dotted line indicates the "specified response", based on the maximum frequency reached in South Australia and Victoria during this event (50.43 Hz). The normalised response of systems responding as specified is shown in green, and the systems that are not responding are shown in red. A proportion of systems also disconnect in response to the event (shown in orange). The total sample average is indicated in blue and shows a small reduction in generation.

Figure 17 Victoria – over-frequency droop response



[31] 25 August 2018 (https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf?la=en&hash=49B5296CF683E6748DD8D05E012E901C) and 16 November 2019.

[32] Conducted by UNSW as a part of a collaboration on ARENA funded project "Addressing Barriers to Efficient Renewable Integration" with further details at https://arena.gov.au/projects/addressing-barriers-efficient-renewable-integration/.

[33] The normalisation is calculated by dividing the output power from each system by output in the pre-event interval (such that power is shown as a percentage of power in the pre-event interval), and then averaging in each time interval across all systems in the relevant category.

Figure 18 South Australia – distributed PV over-frequency droop response