

NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

FOR THE NATIONAL ELECTRICITY MARKET

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IMPORTANT NOTICE

Purpose

AEMO has prepared the 2016 National Transmission Network Development Plan under clause 5.20.2 of the National Electricity Rules. This report is based on information available to AEMO up to 14 October 2016.

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EXECUTIVE SUMMARY

The *National Transmission Network Development Plan* (NTNDP) is an independent, strategic assessment of an appropriate course for efficient transmission grid development in the National Electricity Market (NEM) over the next 20 years. This assessment balances reliability, security, and cost considerations while meeting emissions reduction targets.

The NEM is moving into a new era for transmission planning:

- Transmission networks designed for transporting energy from coal generation centres will need to transform to support large-scale generation development in new areas.
- Transmission networks will increasingly be needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply.

High level modelling suggests positive net benefits for potential interconnection developments, if they are competitively priced:

- A new interconnector linking South Australia with either New South Wales or Victoria from 2021.
- Augmenting existing interconnection linking New South Wales with both Queensland and Victoria in the mid to late 2020s.
- A second Bass Strait interconnector from 2025, when combined with augmented interconnector capacity linking New South Wales identified above, although the benefits are only marginally greater than the costs.
- A Regulatory Investment Test for Transmission (RIT-T) will be required in each case to fully determine the optimal development to serve consumers.

Co-ordination and contestability can maximise the benefits of transmission investments across the NEM:

- Modelling shows greater total net benefits when these developments are combined, creating a more interconnected NEM. These benefits are projected to increase as the energy transformation accelerates.
- Geographic and technological diversity smooths the impact of intermittency and reduces reliance on gas-powered generation (GPG). Greater interconnection facilitates this diversity and delivers fuel cost savings to consumers.
- A more interconnected NEM can improve system resilience.
- Contestability in transmission should make development more competitively priced, reducing costs for consumers.

A **resilient power system** can withstand disturbances, including high impact, low probability events such as interconnector failures

Interconnection does not necessarily solve all challenges – local network and non-network options are also needed to maintain a reliable and secure supply:

- Synchronous condensers, or similar technologies, will be required to provide local system strength and resilience to frequency changes.
- AEMO modelling suggests benefits from augmenting transmission in western Victoria to accommodate over 4 gigawatts (GW) of projected new renewable generation capacity.

System strength is a measure of the stability of a power system under all reasonably possible operating conditions

What is driving the new era for transmission planning?

The next 20 years will be characterised by unprecedented transformation in the power industry as it transitions to a low carbon future.

Policy settings

This 2016 NTNDP assessment has incorporated Australia’s COP21 commitment¹, the Federal large-scale renewable energy target² (LRET), and the Victorian Renewable Energy Target³ (VRET).

The addition of COP21 and VRET assumptions this year has changed AEMO’s projections since the 2015 NTNDP, increasing the forecast scale and speed of the generation mix transformation.

A changing generation mix

AEMO projects Australia’s 2030 emissions reductions target will be met mostly by large-scale renewable generation replacing coal generation as it withdraws from service. GPG will be required to support intermittent renewable generation unless alternate technologies become cost-competitive.

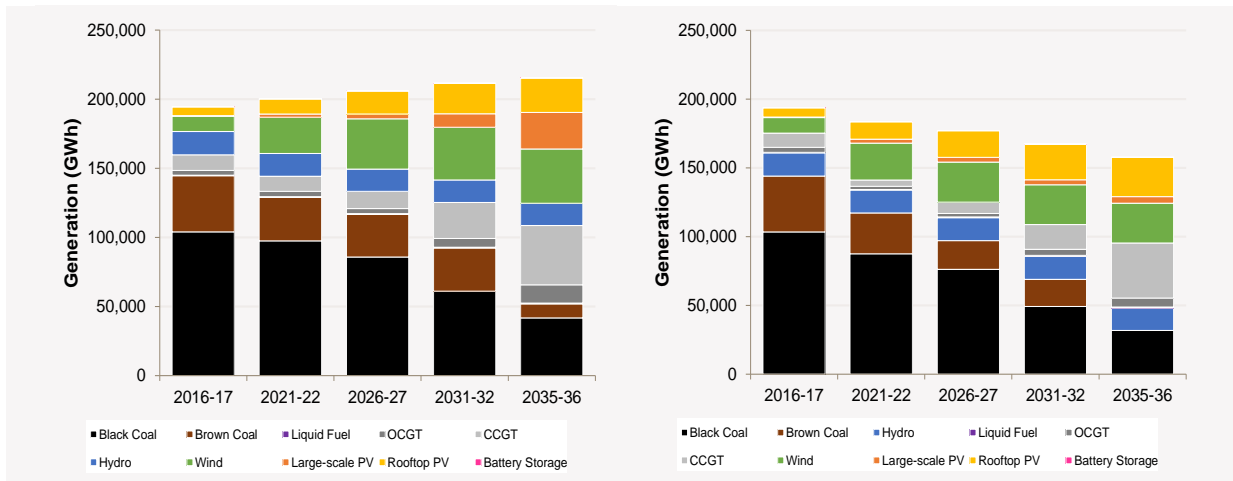
This transformation has ramifications for existing and future transmission needs. Transmission development will be required over the next 20 years to:

- Connect up to 22 GW of new large-scale wind and solar generation.
- Integrate this intermittent generation while maintaining a reliable and secure power system.

The transmission network was historically designed to transport large-scale synchronous generation (located close to major energy resources) to load centres. Renewable generation is expected to connect in areas with high wind and solar resources, which tend to be weaker parts of the grid designed to supply only local load.

The figure below shows AEMO’s projection that coal generation will reduce from 74% of NEM generation in 2016–17 to 24% in 2035–36, increasing the need for frequency and voltage support from other sources to maintain a reliable supply.⁴ While operational solutions can be developed to manage the most urgent challenges in the short term, network and non-network options will be more economic and effective in the longer term.

Figure 1 Projected NEM generation (GWh), Neutral (left) and Low Grid Demand (right) scenarios



¹ COP21 refers to Australia’s commitment at the 21st Conference of Parties to reduce greenhouse gas emissions. The Council of Australian Governments (CoAG) has recommended the NTNDP assume a 26% to 28% of emissions reduction below 2005 levels by 2030. This assessment assumed that the resultant trajectory of emissions reduction is continued between 2030 and 2036.
² A target for large-scale renewable generation across Australia of 33,000 GWh in 2020.
³ A target for renewable generation to produce 25% of total electricity generation in Victoria by 2020 and 40% by 2025.
⁴ Frequency control and system strength were highlighted as high priority challenges in AEMO’s *Future Power System Security Program: August 2016 update*. Available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability>.



Beyond 2030, the scale and timing of generation mix changes is highly uncertain and largely depends on the decisions of coal-fired generators and the ongoing direction of energy policy.

AEMO understands that approximately 9 GW of coal generation will reach its technical end of life in the 2030s. Whether coal generation is refurbished or replaced will depend on future climate change policy, technological advances, future gas prices and the level of consumer demand. This introduces a decade when investment decisions could have divergent implications for the energy system. To investigate this uncertainty further, two projections of timing of coal retirements were examined:

- The 2016 NTNDP examines a pathway of coal generation retirements based on assumed financial viability and announced intentions to close plant at the end of technical life.⁵ This results in a greater projection of GPG to support development of new renewable generation.
- The 2016 National Gas Forecasting Report (NGFR) examines how extending the technical life of some ageing coal plant could result in later coal generation retirements and a lower projection for GPG in the horizon to meet capacity needs.

The two projections approximately align to 2030 with 2 GW difference in installed GPG capacity and negligible difference in domestic annual gas consumption. By 2036 the forecasts diverge, with 10 GW difference in installed GPG capacity, and almost 50% difference in domestic annual gas consumption (excluding LNG).⁶

This signals the uncertainty towards the end of the 20-year horizon and the strong influence that timing of coal retirements could have on investment in the gas industry. Both of these GPG outlooks will be tested further in the 2017 GSOO along with implications for gas supply and reserves.

Demand uncertainty

AEMO's 2016 *National Electricity Forecasting Report* (NEFR)⁷ projected grid demand growth to be flat over the next 20 years. The drivers for transmission development have shifted from meeting demand to other requirements, including system support services to integrate new generation into the grid.

A number of factors could lead to demand from the transmission system being materially lower than forecast in the NEFR, including:

- Changing consumer technologies and behaviour. Distributed energy resources, energy-efficient devices, and innovative retail products are giving consumers increased control over their energy supply and changing the way they interact with the power system. Rooftop photovoltaic (PV) is projected to represent between 34% and 60% of new generation installations between the scenarios assessed.
- Continuing growth challenges for major energy-consuming business sectors. Sectors with projected growth, like services, use comparatively little electricity.

Maintaining a reliable and secure supply during extremely low demand periods is emerging as a new driver for transmission development.

The strategic outlook for transmission development

AEMO has modelled future development paths considering the expected transformation of the power system and the uncertainties that will challenge investment decision-makers. The 2016 NTNDP has examined transmission development under three scenarios:

- The Neutral scenario, considered the most likely estimate for demand growth.

⁵ AEMO, 2016. *Consultation paper for the 2016 National Transmission Network Development Plan*. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>.

⁶ When LNG is included the difference between the NTNDP and NGFR projections for annual gas consumption in 2035–36 is about 15%.

⁷ AEMO. 2016 *National Electricity Forecasting Report*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.



- The Low Grid Demand scenario, which considers a different, credible path to test how the low boundary for demand (falling 32% in 20 years) could impact transmission development.⁸
- The 45% Emissions Reduction scenario, which considers an accelerated emissions reduction trajectory towards 2030, based on the Neutral level of demand.

Responding to stakeholder interest, the 2016 NTNDP also examined a range of potential interconnector developments between all regions of the NEM.

This NTNDP has looked holistically at the potential market benefits of solutions required to maintain reliable, secure energy supply over the next 20 years. The assessment took a strategic approach, looking not only at the viability of individual solutions, but more broadly at a range of investments that may occur across the NEM. It also considered smaller-scale network or non-network alternatives that in combination may deliver a more cost-effective range of future reliability, security, and efficiency benefits for consumers.

In addition, the NTNDP investigates a range of power system phenomena and how they are expected to change as the generation mix evolves, specifically how:

- System strength is expected to decline, given the increase in inverter-connected generation coupled with synchronous generation withdrawals.
- Decreasing mainland and regional inertia will correspond to an increase in rate of change in frequency following a disturbance.
- Increasing generation variability will impact frequency regulation requirements.

Outlook insights

The 2016 NTNDP assessment indicates that:

- Inter-regional and intra-regional transmission development appear to be in the long-term interest of consumers if competitively priced. Regulatory Investment Tests for Transmission (RIT-Ts) are warranted to further explore these and non-network alternatives.
- Sufficient inertia is projected to be available over the next 20 years to maintain a secure and reliable supply, but only if the network remains interconnected following disturbances. Following a synchronous separation event, South Australia is already at risk of widespread outages unless mitigation measures are put in place.
- System strength is projected to materially decline across the NEM, particularly in areas of high inverter-connected generation, such as:
 - Much of South Australia, western Victoria, and Tasmania.
 - Emerging local areas of poor network strength in New South Wales and Queensland, where a high concentration of renewables is anticipated by 2035–36.
- To counteract the decline in system strength, improvements to either inverter-connected devices or supporting plant will become essential for these generators to operate reliably.

Benefits of further interconnection

The following table highlights the modelling results from the 2016 NTNDP interconnector studies. The potential interconnection options AEMO studied were found to deliver fuel cost savings by improving utilisation of renewable generation and reducing reliance on higher-cost gas generation. A large portion of the assessed benefits for a new South Australian interconnector are associated with avoiding major supply disruptions by improving system resilience. For the second Bass Strait interconnector, most of the assessed benefits are delivered by deferring the expected need for capital expenditure on GPG.

⁸ The Neutral case is equivalent to the 2016 NEFR Neutral sensitivity. The Low Grid Demand case adjusted the 2016 NEFR Weak sensitivity to include high uptake of rooftop PV, residential battery storage, and energy efficiency, creating a credible low boundary for 20-year grid demand.



The table also includes synchronous condensers, an alternative network option that may reduce the risk of major supply disruption in South Australia.

Table 1 NTNDP interconnection modelling – cost-benefit results over next 20 years

No.	Description	Indicative timing	NPV gross market benefits to 2035–36 (\$ million)	NPV of annualised cost to 2035–36 (\$ million)	Overall net benefit (\$ million)	Incremental net market benefits (\$ million)	Benefit to cost ratio
1	Augment existing interconnector capacity to NSW	Mid to late 2020s	170	47	123	0	3.62
2	New SA interconnector to VIC (325 MW) + option 1 above	2021	595	335	260	136	1.78
3	New SA interconnector to NSW (325 MW) + option 1 above	2021	583	335	248	124	1.74
4	Second Bass Strait interconnector (600 MW) + option 1 above	2025	531	387	143	20	1.37
5	Combination of options 1,2,4 or 1,3,4 above	As above	978	676	302	179	1.45
6	Synchronous condensers in South Australia + option 1 above	2021	459	314	145	22	1.46

Net Present Value (NPV) is calculated over 20 years, using a 7% discount rate. The NTNDP assessed new South Australian interconnectors (options 2 and 3) at capacities of 325 MW.

A combination of these potential interconnector developments was found to deliver positive net benefits in every scenario assessed. This indicates that these potential projects are likely to remain beneficial under a broad range of policy and grid demand uncertainties.

AEMO recommends that each potential development be thoroughly assessed through a RIT-T, to examine whether alternative (including non-network) options could deliver greater net benefits.

AEMO acknowledges that the current RIT-T process does not consider a potential range of broader economic benefits. Their inclusion could strengthen the case for investment, but would add another layer of complexity to the process. The RIT-T review by the Council of Australian Government (CoAG) Energy Council will report on aspects of the RIT-T process.⁹

Benefits of non-network solutions

Large-scale investments take years to implement, raising the risk of assets becoming underutilised or stranded, particularly given the broad range of future uncertainties.

Smaller-scale network or non-network solutions could be implemented more quickly to address immediate challenges. They also facilitate a more flexible approach to planning and managing the power system in the face of uncertainty:

- Operational measures, such as changing protection scheme settings, implementing control schemes, or applying network constraints to ensure the power system operates within its secure technical envelope, can be implemented quickly.¹⁰
- Operating more local synchronous plant in the short term, and installing more plant locally in the long term, would address reduced system strength and inertia as synchronous generation retires.

⁹ CoAG Energy Council, 2016. *Review of the Regulator Investment Test for Transmission*. Available: <http://scer.gov.au/sites/prod.energycouncil/files/publications/documents/RIT-T%20Review%20Consultation%20Paper.pdf>.

¹⁰ For example, after the 2016 Black System event in South Australia, a regulation restricted Heywood Interconnector transfers to limit the rate of change of frequency (RoCoF) at or below 3 hertz (Hz) per second. AEMO Electricity Market Notice 55358, 12 October 2016. Available: <https://www.aemo.com.au/Market-Notices>.



- Regulatory changes can vary in implementation time from a few months to years. Potential regulatory changes could include introducing new obligations into the connections performance standards, and changes to ancillary services markets.
- Technological advances could include changes to technical performance standards to use the advanced capabilities of inverters and wind farms to produce inertia, high inertia synchronous condensers, or battery storage.

AEMO is collaborating with the Australian Energy Market Commission (AEMC)¹¹ and the CoAG Energy Council¹² to examine a range of potential solutions in more detail.

Network Support and Control Ancillary services (NSCAS)

The NTNDP assesses whether further Network Support and Control Ancillary services (NSCAS) are required in the next five years. NSCAS are contracts procured by Transmission Network Service Providers (TNSPs), or AEMO as a last resort, for non-market ancillary services such as voltage support, inertia, and fault level provision.

In the 2015 NTNDP, a one-year NSCAS gap was identified in New South Wales. The 2016 NTNDP finds that this gap can now be managed through operational measures.

Based on currently available information, an NSCAS gap has been identified in South Australia. AEMO has determined that at least two large synchronous generating units must be online in South Australia to maintain a secure operating state.¹³ This is required to maintain system strength. AEMO will confirm this gap in early 2017 following completion of more detailed analysis.

AEMO notes that the regulatory framework does not allow for the identification and procurement of NSCAS to mitigate non-credible contingencies. The South Australian government has proposed a rule change to introduce a sub-category of non-credible events for which AEMO can plan emergency frequency schemes.¹⁴ AEMO will monitor this request and, if necessary, submit a separate rule change request to allow future NSCAS assessments to consider specific types of non-credible events and recommend NSCAS solutions.

Co-ordination and contestability could lead to more efficient development

Contestability should make transmission development more competitively priced, reducing overall costs for consumers.¹⁵ This is important given the speed at which the NEM is transforming, and the potential cost of the various transmission development projects being considered.

NTNDP modelling of potential interconnector developments showed greater net benefits when combined, highlighting the benefits of a co-ordinated approach to planning:

- Geographic and technology diversity smooths the impact of intermittency and reduces reliance on gas-powered generation (GPG). Greater interconnection facilitates this diversity and delivers fuel cost savings to consumers.
- A more interconnected NEM can also improve system resilience.

As the independent national transmission planner, AEMO has a responsibility to develop a national strategy for transmission development that is based on the long-term interests of NEM consumers. AEMO believes the NTNDP is the appropriate vehicle to bring together a range of industry stakeholders to facilitate a co-ordinated, national approach to long-term network planning. This has been the approach in 2016, and AEMO will expand this consultative and collaborative approach in 2017.

¹¹ AEMC, 2016. *System Security Market Frameworks review*. Available: <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

¹² Council of Australian Governments. *Energy Market Transformation*. Available: <http://www.scer.gov.au/current-projects/energy-market-transformation>.

¹³ AEMO, 2016. *Market Notice 56089*. Available: <https://www.aemo.com.au/Market-Notices?currentFilter=&sortOrder=&searchString=56089>.

¹⁴ AEMC, 2016. *Emergency under frequency control schemes*. Available: <http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen>. Viewed: 5 October 2016.

¹⁵ This aligns with the AEMC's draft determination on *Transmission connection and planning arrangements*, published on 24 November 2016. Available: <http://www.aemc.gov.au/Rule-Changes/Transmission-Connection-and-Planning-Arrangements#>.



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CHAPTER 1. ABOUT THE NTNDP

The *National Transmission Network Development Plan* (NTNDP) is an independent strategic plan for transmission development across the National Electricity Market (NEM) over the next 20 years.

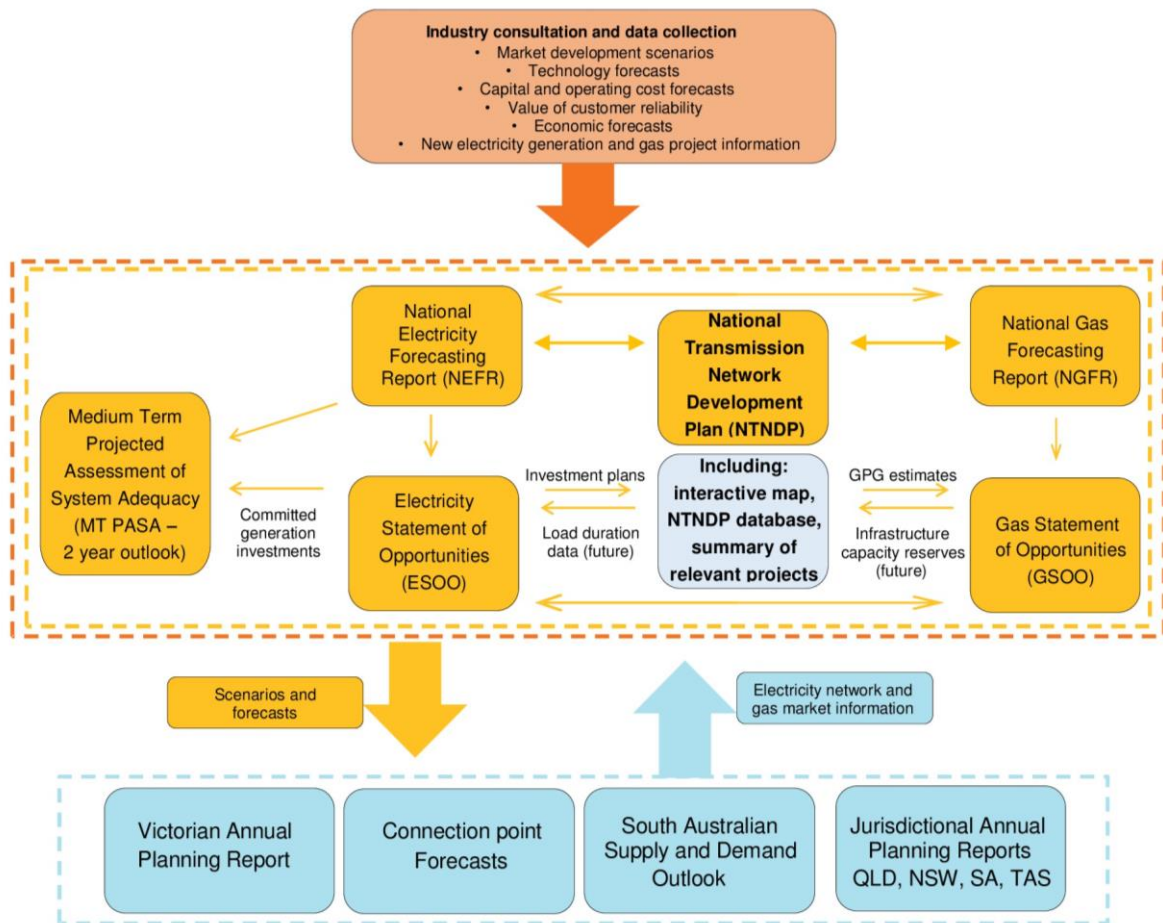
AEMO publishes the annual NTNDP as part of its role as national transmission planner under the National Electricity Law, in accordance with clause 5.20.2 of the National Electricity Rules (NER).

The 2016 NTNDP:

- Highlights the importance of strategically assessing the future needs of the NEM transmission grid.
- Provides an assessment of an appropriate course for the efficient development of the national transmission grid under a range of scenarios.
- Reflects on the evolution of transmission development, with the industry entering a new era for transmission planning.
- Examines how the changing generation mix could impact network development, power system security, and the utilisation of major transmission lines in the next 20 years.
- Proposes a range of possible solutions to effectively manage the power system into the future.
- Identifies whether further Network Support and Control Ancillary Services (NSCAS) are required to manage power system security and reliability in the next five years.

The NTNDP is part of AEMO’s suite of NEM planning publications, shown below.

Figure 2 AEMO planning publications





1.1 The NTNDP's planning approach

A key objective of transmission planning is to develop the power system as efficiently as possible while maintaining reliability and security to the standards set for the NEM.

In its role as National Transmission Planner, AEMO considers the National Electricity Objective (NEO)¹⁶, which is to:

Promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply of electricity, and the reliability, safety and security of the national electricity system.

Two key terms in this objective for transmission planning are:

- **Reliability** – sufficient generation and transmission capability to supply demand.¹⁷
- **Security** – the capability of the power system to continue operating within its technical limitations even after credible contingency events, such as single generation or transmission failures, and mechanisms to limit the impact of non-credible contingencies.

The challenge for efficient planning is to strike a balance in power system development that meets the long-term interests of consumers in relation to reliability, security, and cost.

At the fifth Energy Council meeting for the Council of Australian Governments (CoAG) in July 2016, Ministers recognised that Australia's energy markets are in a time of "significant change due to the transition to low-carbon emissions" and that they "must be reliable, affordable and sustainable. Business as usual is not an option".¹⁸

Australia's increasing focus on sustainability is reflected in its commitment at the 21st Conference of Parties to reduce greenhouse gas emissions by 26% to 28% below 2005 levels by 2030 (COP21 commitment).

The CoAG Energy Council has stated to AEMO that a 28% reduction from 2005 levels by 2030 is an appropriate constraint to use in its ongoing forecasting and planning processes. By incorporating the COP21 commitment, the 2016 NTNDP examines an appropriate path for transmission development in the NEM considering reliability, security and cost, while meeting emissions reduction targets over the next 20 years.

1.2 Stakeholder engagement

AEMO would like to acknowledge the great assistance of key stakeholders across the energy industry during its development of the 2016 NTNDP, including state and federal governments, generators, Transmission Network Service Providers (TNSPs), retailers, and research organisations.

The stakeholder engagement process has included:

- A formal consultation process, in accordance with clause 5.20.11 of the NER, beginning with a consultation paper published in January 2016¹⁹, to which stakeholders were invited to make submissions.
- An open-invitation consultation workshop held in February 2016.
- AEMO's written response to consultation submissions and key issues discussed at the workshop, published in July 2016.²⁰

¹⁶ The NEO can be read at: <http://www.aemc.gov.au/Energy-Rules/National-electricity-rules>.

¹⁷ The latest outlook for reliability is examined in AEMO's 2016 *Electricity Statement of Opportunities*. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

¹⁸ CoAG. "Energy Council Communique – 19 August 2016". Available: <http://www.scer.gov.au/publications/5th-coag-energy-council-meeting-communique-19-august-2016>. Viewed: 13 September 2016.

¹⁹ AEMO. *National Transmission Network Development Plan*. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>.

²⁰ AEMO, 2016. *Consultation paper for the National Transmission Network Development Plan*. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>.



- The NTNDP Technical Working Group, a group of technical specialists from across the industry with market modelling or strategic network planning expertise. The Technical Working Group has met at regular intervals throughout the project to discuss progress and key issues. Minutes of these meetings are available on the AEMO website.²¹
- Specific engagement with TNSPs to understand their committed projects, current and emerging network issues, and proposed solutions, as outlined in their Annual Planning Reports, and to discuss outcomes from the NTNDP studies in each region.

Two stakeholder enquiries were received after AEMO's formal consultation response was published. One enquiry, from AusNet Services, supported investigating a new interconnector between Victoria and South Australia to facilitate the South Australian energy transformation. This is addressed in the 2016 NTNDP through the HorshamLink interconnector case study, and a similar option has been included in ElectraNet's South Australian Energy Transformation RIT-T project consultation.²²

The other enquiry, from the University of Queensland, suggested including a high level analysis of a new interconnector between Queensland and South Australia. This request was received too late to be included in the analysis for the 2016 NTNDP, but AEMO notes that a similar route has been included as an option in the South Australian Energy Transformation RIT-T. AEMO will monitor the outcomes of this analysis on the possible route, and will examine it further if appropriate as part of the national transmission strategy in 2017.

²¹ AEMO. "NTNDP Technical Working Group". Available: <http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/NTNDP-Technical-Working-Group>.

²² ElectraNet. *South Australian energy transformation*. Available: <https://www.electranet.com.au/projects/south-australian-energy-transformation/>.



CHAPTER 2. A NEW ERA FOR TRANSMISSION PLANNING

The first Australian transmission line was a 100 km line linking Hobart with a hydro-electric power station in 1916.²³ It was the catalyst for 90 years of centralised generation and transmission development that culminated in 2006 when Tasmania was connected to the NEM via the Basslink Interconnector.

For many decades, the NEM has benefited from centralised generation within interconnected transmission systems, through:

- Economies of scale.
- The ability to exploit large primary energy resources such as coal.

The NEM is now moving into a new era for transmission planning, characterised by greater consumer engagement, and transformation of the generation mix to meet climate change policy objectives:

- Transmission networks, designed for transporting energy from coal generation centres, will need to transform to support large-scale generation development in new areas.
- Transmission networks will increasingly be needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply.

2.1 Historical drivers of transmission development

Maximum demand growth has historically been the main driver of transmission augmentation, to ensure the network can transport sufficient electricity to meet peak demand each year.

The first NTNDP, published in 2010, collated demand forecasts from each NEM TNSP that projected maximum demand of 2% per annum over the 20 years to 2030. This was expected to be driven mainly by population growth, economic growth, and rapid uptake of air-conditioning appliances.

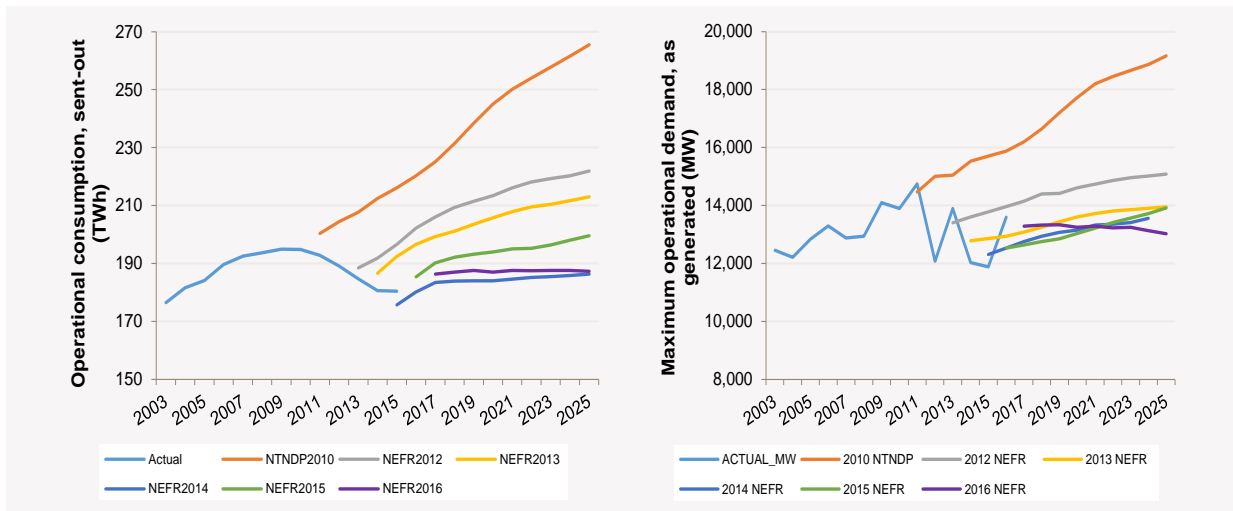
As a result, the 2010 NTNDP introduced a concept called NEMLink, a proposal for a large-scale alternating current (AC) interconnection running from Queensland, through New South Wales and Victoria, to South Australia, with an additional direct current (DC) link to Tasmania. While NEMLink was ultimately found not to be viable at the time, it was primarily conceptualised to address projected emerging network limitations due to expectations for strong growth in grid demand.

Since 2010, expectations for growth in both annual consumption of grid electricity (operational consumption) and maximum demand have changed.

The figures below show this change, and the 2016 NEFR forecasts for the next 10 years, which project annual consumption to remain flat, and maximum demand to decrease, across the NEM. Maximum demand forecasts are region-specific, not NEM-wide, so the New South Wales forecast is shown as an example.

²³ Brady, F. 1996. *A Dictionary on Electricity*. Available: http://www.ewh.ieee.org/r10/nsw/subpages/history/electricity_in_australia.pdf. Viewed: 1 December 2016.

Figure 3 Changing expectations for NEM operational demand (left) and NSW maximum demand (right)

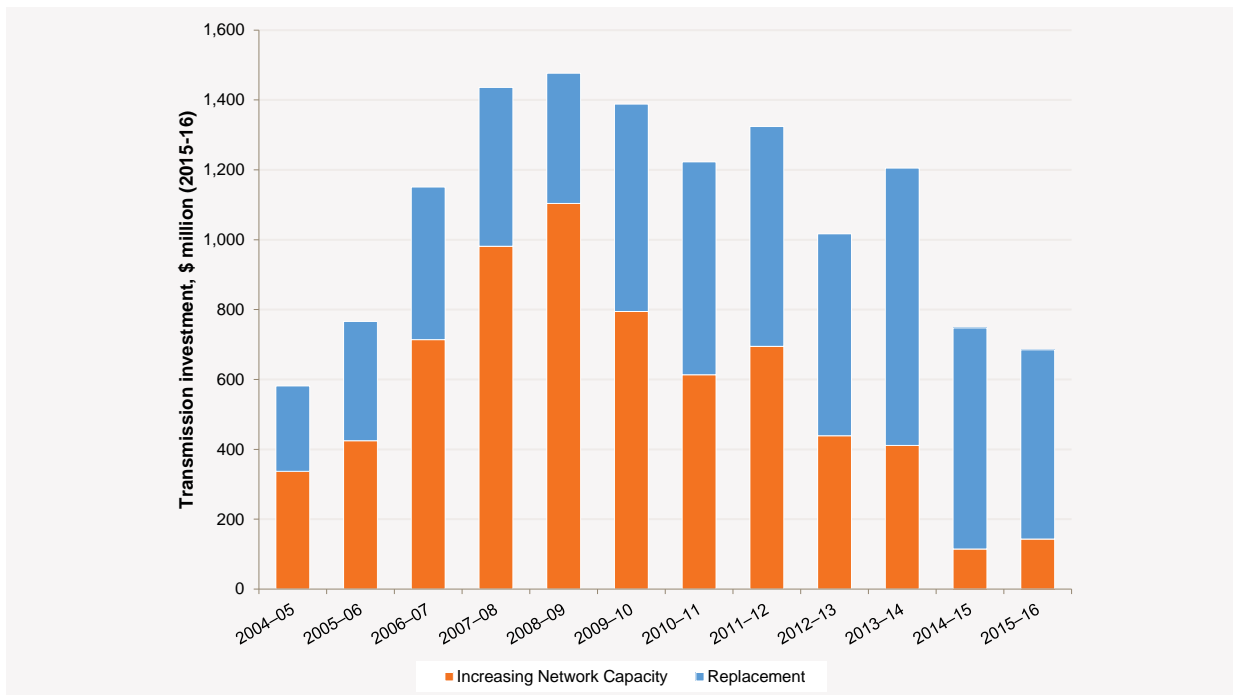


The primary factors contributing to this change in projected demand include:

- Rapid growth of rooftop photovoltaic (PV).
- Declining electricity-intensive manufacturing operations in the NEM regions.
- Energy efficiency initiatives, combined with more efficient appliances.
- Changing consumer behaviour.

As a result, the projections for transmission augmentation expenditure have also reduced in recent years, highlighting the link between demand growth expectations and transmission development, shown below.

Figure 4 Evolution of transmission investment, 2004–05 to 2015–16



Source: Transmission Network Service Provider revenue proposals and Australian Energy Regulator revenue determinations



The increase in replacement expenditure shown here can be broadly attributed to transmission assets built in the 1960s and 1970s approaching end of life. As these assets reach the end of their lifespan, critical decisions will need to be made whether:

- To replace them like-for-like.
- Other development options can deliver a better outcome for consumers.
- The assets could be relocated or retired.

The 2016 NTNDP includes a 20-year outlook for the utilisation of major transmission flow paths to help inform this assessment, which is discussed further in Chapter 3.

2.2 New drivers for transmission planning

Demand is no longer a driver for transmission development, as expectations for demand growth remain flat over the next 20 years, with uncertainties that could lead to material reductions from current expectations.

The 2016 NTNDP considers new drivers for transmission development, outlined below.

2.2.1 Ageing coal generation fleet

Of the existing coal generation fleet, almost 70% of the generation capacity will exceed 50 years from first operation by 2036, indicating that a large proportion of the fleet is approaching the end of its intended life.

The 2016 NTNDP projects that up to 63% of the fleet (15.5 gigawatts (GW)) may withdraw from service in the next 20 years under a Neutral economic growth scenario, of which 9 GW is projected to be withdrawn in the 2030s.

Whether coal generation is refurbished or replaced will depend on future climate change policy, technological advances, future gas prices, and the level of consumer demand. To investigate this uncertainty further, and at the request of stakeholders, AEMO has examined two projections of timing of coal retirements in its forecasting and planning processes:

- The 2016 NTNDP examines a pathway of coal-fired generation retirements based on assumed financial viability and announced intentions to close plant at the end of technical life.²⁴ This results in a greater projection of gas-powered generation (GPG) to support development of new renewable generation.
- The 2016 *National Gas Forecasting Report* (NGFR)²⁵ examines how extending the technical life of some ageing coal plant could result in later coal generation retirements and a lower projection for GPG in the horizon to meet capacity needs.

The GPG outlook in the two projections approximately aligns to 2030, with 2 GW difference in installed GPG capacity and negligible difference in domestic annual gas consumption.

By 2036, the GPG forecasts diverge, with 10 GW difference in installed GPG capacity, and almost 50% difference in domestic annual gas consumption (excluding LNG).²⁶

This signals the uncertainty towards the end of the 20-year horizon and the strong influence that timing of coal retirements could have on investment in the gas industry. Both these GPG outlooks will be tested further in the 2017 *Gas Statement of Opportunities* for eastern and south-eastern Australia²⁷, along with implications for gas supply and reserves.

²⁴ AEMO, 2016. *Consultation paper for the 2016 National Transmission Network Development Plan*. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>.

²⁵ AEMO, 2016. *National Gas Forecasting Report*. Available: <https://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report>.

²⁶ When LNG is included the difference between the NTNDP and NGFR projections for annual gas consumption in 2035–36 is about 15%.

²⁷ AEMO. *Gas Statement of Opportunities*. Available: <https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities>.



The timing and location of coal generation withdrawals will, therefore, impact when and where new generation and transmission development is required over the next 20 years. Limited notice of withdrawals at such a scale would not allow for coordinated planning and could compromise efficient NEM development.

2.2.2 Emissions reduction policies

All studies in the 2016 NTNDP assume that the NEM achieves at least a proportionate share of the COP21 commitment (28% emissions reduction). The mechanisms to meet the target, and any targets beyond 2030, have not yet been specified. The review of Australia's climate change policies in 2017 should provide more information on the potential mechanisms that will be applied to achieve it.²⁸

The proposed Victorian Renewable Energy Target (VRET) is also assumed to be met in all studies. The VRET specifies that renewable energy will represent 25% of total Victorian generation in 2020, rising to 40% by 2025.²⁹

AEMO acknowledges that other state governments have also announced aspirational renewable energy targets, of 50% by 2025 in South Australia³⁰, 50% by 2030 in Queensland³¹, and net zero emissions by 2050 in New South Wales.³² The VRET is included in the 2016 NTNDP and other state targets are not, because the Victorian government has defined the mechanism it intends to apply to reach the target, being a series of reverse auctions for renewable energy capacity. AEMO will incorporate other targets into future analysis as the mechanisms to achieve them are confirmed.³³

In response to stakeholder interest regarding the possible future expansion of emissions reduction policies, or the possibility that the electricity industry could be asked to contribute a greater than proportionate share of the COP21 commitment, the 2016 NTNDP has examined a "45% Emissions Reduction" scenario. This scenario explicitly models a 45% reduction in emissions by 2030 from 2005 levels, with the resultant trajectory continued to 2036.

The 2016 NTNDP modelling indicates that these emissions reduction policies, coupled with consumer investment trends, will be major drivers for transformation in the NEM generation mix, and for transmission development. This is discussed further in the next chapter.

2.2.3 Future consumer investment trends

In a period of rapid technological change, consumer investment trends could materially reduce future grid demand and change its daily profile. Behind the meter technologies (on consumers' sites) may also start delivering system support services, such as frequency control, to the NEM. Consumer investment trends that could materially impact the power system are explored below.

- **Rooftop PV** – Installed capacity is projected to exceed 20 GW by 2036, becoming the technology with most generation capacity in the NEM. Uptake could accelerate faster than projected if a variety of factors, such as further cost breakthroughs or material rises in electricity prices, combine to improve the economics of PV ownership.
- **Energy efficiency** – The 2016 NEFR projects that energy efficiency will reduce grid demand by 27,082 GWh in 2035–36 (greater than the projected generation from rooftop PV of 25,442 GWh in

²⁸ Australian Government, 2016. *Review of Australia's climate change policies*. Available: <https://www.environment.gov.au/climate-change/review-climate-change-policies>.

²⁹ Victorian government, 2016. "Victoria's renewable energy targets". Available: <http://earthresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets>. Viewed: 13 September 2016.

³⁰ South Australian government, 2016. "Renewables SA". Available: <http://www.renewablessa.sa.gov.au/>. Viewed 13 September 2016.

³¹ Queensland government, 2016. "A solar future: powering Queensland's renewable energy industries". Available: <https://www.dews.qld.gov.au/electricity/solar/solar-future>. Viewed: 13 September 2016.

³² New South Wales government, 2016. *NSW climate change policy framework*. Available: <http://climatechange.environment.nsw.gov.au/About-climate-change-in-NSW/NSW-Government-action-on-climate-change>.

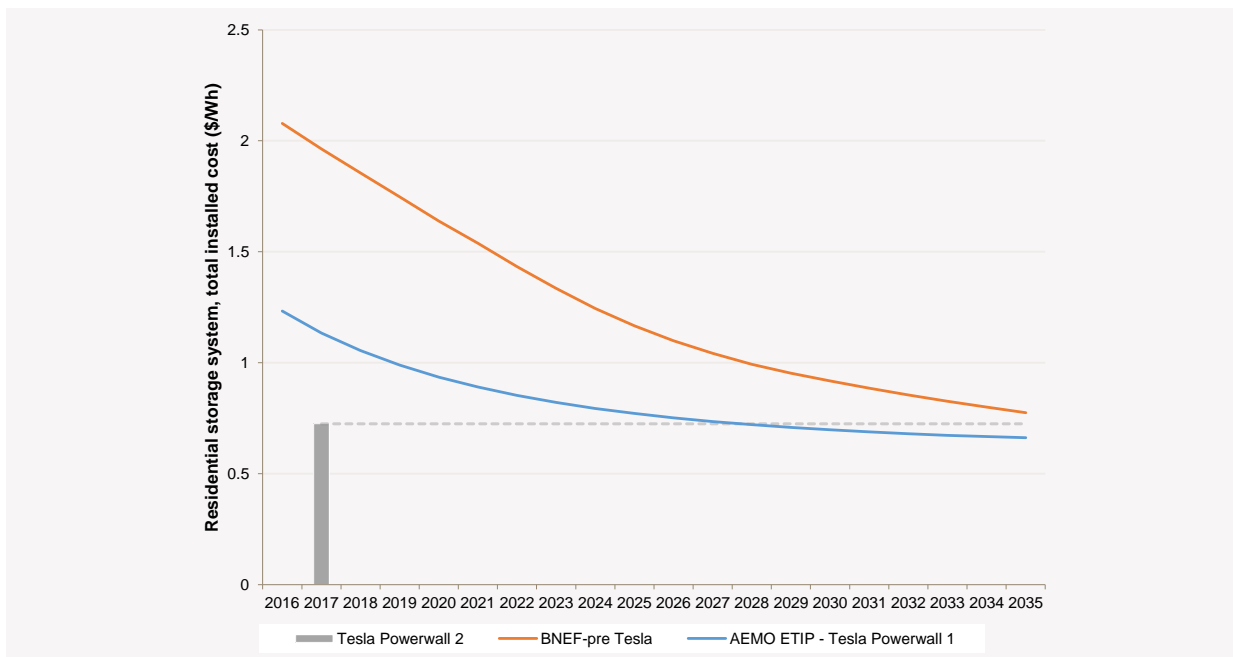
³³ AEMO acknowledges that the Queensland government has released a draft expert report recommending the reverse auction approach is applied to their target for 50% renewable energy by 2030.

the same year).³⁴ Further emphasis on energy efficiency, as a relatively cheap form of abatement to meet emissions reduction targets, could reduce grid demand by more than current expectations.

- **Behind the meter battery storage** – The 2016 NEFR projected residential storage uptake in the NEM of 7 GWh of installed capacity in 2036 (about 3 GW inverter capacity). The recent launch of Tesla’s Powerwall 2 represents a further step down the cost curve for residential battery storage. Tesla’s website indicates that a fully installed 14 kilowatt hour (kWh) system with integrated inverter is expected to cost \$10,150.³⁵

The figure below shows this cost plotted against the expected cost projections from AEMO’s 2015 *Emerging Technologies Information Paper*.³⁶ The cost projection from Bloomberg New Energy Finance before the announced costs of the first Tesla Powerwall is shown in orange.³⁷ AEMO combined this cost profile with the expected 2016 Australian cost of the first Powerwall to reach the projection shown in the blue line.

Figure 5 Residential battery storage system, total installed cost projection (\$/Wh)



The rapid reduction in system cost shows how quickly this market is progressing. A combination of further cost reductions, business model innovation, innovative tariffs, and potential electricity price rises could accelerate uptake of storage much quicker than was projected in the 2016 NEFR.

- **Demand side participation (DSP)** – Any incentive for customers to reduce their load at certain times is sufficient for DSP to take place. There are different forms of DSP, including:
 - Centralised control of appliances – for example, Energex is providing upfront discounts on air-conditioning units to allow them to remotely turn it down at maximum demand times, which they also do with electric hot water units.³⁸ Aggregated distributed battery storage also fits into this category.

³⁴ AEMO, 2016. *National Electricity Forecasting Report*. Available: <http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational>.

³⁵ Tesla Energy, 2016. Powerwall 2. Available: https://www.tesla.com/en_AU/powerwall. Viewed: 8 December 2016.

³⁶ AEMO, 2015. *Emerging Technologies Information Paper*. Available: <https://www.aemo.com.au/Media-Centre/2015-Emerging-Technologies-Information-Paper>.

³⁷ Bloomberg New Energy Finance. *Now or Never? The Economics of Residential PV and Storage in Australia*, 10 April 2015.

³⁸ Energex, 2016. *Peaksmart air-conditioning*. Available: <https://www.energex.com.au/home/control-your-energy/positive-payback-program/positive-payback-for-households/peaksmart-air-conditioning>.



- Interruptible loads – aggregated voluntary load shedding, typically by commercial and industrial consumers, can rapidly reduce demand after trigger events like frequency disturbances. International examples show that interruptible load services can deliver 135 MW of frequency raise service within 1 second of the trigger event, or 70 MW within 0.2 seconds.³⁹
 - Behavioural demand response – where consumer engagement applications can incentivise residential and commercial consumers to voluntarily reduce their load for peak events. United Energy ran a trial during the 2016 summer that resulted in a load reduction during peak events of greater than 30% among participating customers.⁴⁰
 - If DSP can materially reduce grid demand at critical times, it could defer the need for network augmentation expenditure or reduce the need for involuntary load shedding schemes that are indiscriminate and potentially costly for consumers.
- **Grid-connected microgrids and standalone power systems**
 - Microgrids combine Distributed Energy Resources (DER) to securely meet local demand, either in parallel with the grid or when operating in island mode (not grid-connected).
 - By intelligently managing DER, grid-connected microgrids can reduce grid congestion at critical times and improve power quality. This can enable networks to defer augmentation expenditure that would otherwise have been required, and provide cost savings to consumers. A recent ENA–CSIRO study found the effective rollout of DER could replace the need for up to \$16.2 billion in distribution network investment.⁴¹

Effective implementation of these technologies could drive a transformation in the distribution networks. If implemented at sufficient scale, it could reduce the requirements for large-scale development to improve power system resilience. The closer generation and system security services are to demand centres, the fewer factors risk disrupting that supply.

2.2.4 New challenges for transmission planning

The new drivers outlined above indicate the scale of changes that could occur in the next 20 years. Transmission planners will have to consider the impact of transformations at either end of the electricity supply chain (generation and distribution), and what that means for the future of transmission. They will also have to consider the range of uncertainties on how these changes will play out. The 2016 NTNDP has tackled some of these uncertainties through applying a scenario-based assessment.

2.3 2016 NTNDP scenarios

The 2016 NTNDP examines two demand forecasts – Neutral and Low Grid Demand – based on AEMO’s 2016 *National Electricity Forecasting Report* (NEFR).⁴² A further scenario – 45% Emissions Reduction – examines the impact of a greater emissions reduction target by 2030 on transmission development, assuming a target of 45% emissions reduction based on the Neutral level of demand.

A comparison of the scenarios is shown in the table below.

³⁹ Enernoc, 2016. Submission to the AEMC System Security Market Frameworks Review. Available: <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

⁴⁰ Bidgely, 2016. *Bidgely delivers industry leading demand response results of over 30 percent peak load reduction*. Available: <http://www.businesswire.com/news/home/20160503005628/en/Bidgely-Delivers-Industry-Leading-Demand-Response-Results-30>.

⁴¹ ENA, 2016. *Electricity Network Transformation Roadmap – unlocking value for customers*. Available: http://www.ena.asn.au/sites/default/files/unlocking_value_for_customers_october2016.pdf. Viewed: 8 October 2016.

⁴² AEMO. *National Electricity Forecasting Report*, June 2016. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.



Table 2 Comparison of NEFR vs NTNDP scenarios

Driver	NEFR and NTNDP Neutral	NEFR Weak ^b	NTNDP Low Grid Demand	NTNDP 45% Emissions Reduction
Population growth ^a	ABS projection B	ABS projection C	ABS projection C	ABS projection B
Economic growth	Neutral	Weak	Weak	Neutral
Consumer confidence	Average confidence and engagement	Low confidence and engagement	Low confidence and engagement	Average confidence and engagement
Rooftop PV and battery storage uptake	Neutral consumer in a neutral economy	Hesitant consumer in a weak economy	Confident consumer in a weak economy	Neutral consumer in a neutral economy
Energy efficiency uptake	Medium	Low	High	Medium
Emissions reduction requirement	Reduce greenhouse gas emissions by 28% below 2005 levels by 2030, with the resultant trajectory continued to 2036	Reduce greenhouse gas emissions by 28% below 2005 levels by 2030, with the resultant trajectory continued to 2036	Reduce greenhouse gas emissions by 28% below 2005 levels by 2030, with resultant the trajectory continued to 2036	Reduce greenhouse gas emissions by 45% below 2005 levels by 2030, with the resultant trajectory continued to 2036

^a Australian Bureau of Statistics, 2013. Population projections, Australia. Available: <http://www.abs.gov.au/ausstats/abs@.nsf/mf/3222.0>.

^b The NEFR Weak scenario is not considered in the 2016 NTNDP, and is provided here for comparison only.

A key distinction to make is that the NEFR is an economically consistent forecast of demand that analyses how economic factors such as population, consumer confidence, and business conditions could impact demand. The NTNDP Low Grid Demand scenario seeks to stress test generation and transmission development under the credible lower boundary of grid demand.

As a result, the NTNDP Low Grid Demand scenario applies high uptake of rooftop PV, distributed battery storage systems, and energy efficiency, which may not be consistent with low economic growth but creates a lower boundary for grid demand. Further, the 45% Emissions Reduction scenario seeks to understand the sensitivity of strategic transmission grid development to a more accelerated transformation of the generation mix, but does not include any feedback loop to consider electricity price implications for consumer demand.

2.4 A national strategy

The NTNDP produces an efficient development strategy of the entire NEM transmission grid. The full details of this assessment can be found in section 3.2.

Maintaining system security and reliability as the generation mix continues to evolve, consumption patterns change as a result of new products in the marketplace, and consumers are increasingly involved in their own energy decisions is not a trivial challenge. It requires broad, collaborative and innovative planning approaches, and a high level of coordination across the industry.

As discussed above, transmission planners will have to consider the impact of transformations at the household, distribution and generation levels, and what that means for the future of transmission. The availability of plant to deliver energy when needed, and capability to provide system support services, such as frequency and voltage support, are also key factors to consider when assessing future development needs of the transmission grid.

A key consideration of the NTNDP’s national development strategy is whether further transmission interconnection between NEM regions could be economically justified and warrant investigation (along with alternate network and non-network options) by TNSPs.

This year, the assessment provides a more holistic view of transmission interconnection benefits, by valuing potential improvements in system resilience. A resilient power system can withstand



disturbances, including high impact, low probability events such as interconnector failures. If unable to withstand such disturbances, major supply disruptions may result.

2.5 Contestability

Uniquely in the NEM, the Victorian regulatory framework provides for the contestable provision of major transmission augmentations. If a required transmission upgrade is separable from the existing shared network, AEMO conducts a competitive tender to procure the service. This approach has given rise to lower cost outcomes compared to the traditional model. In recent years there has been a noticeable increase in the level of competition in Victorian transmission augmentation tenders, with a corresponding reduction in costs to end users. For instance, a competitive process for the Victorian portion of the Heywood Interconnector upgrade meant that it was able to be procured at a lower cost than forecast in the RIT-T.

The competitive pressures apply to the design, construction, operation, and ownership of the network investment. It can also provide competition between the network solution and non-network solutions such as embedded generation and demand management.

Procuring new interconnected transmission infrastructure nationally through a contestable market would help apply competitive pressure to network costs, and increase the economic justification for investment in the long-term interest of consumers.

CHAPTER 3. NATIONAL TRANSMISSION OUTLOOKS

Key insights

- AEMO modelling shows net positive benefits for the following interconnector developments if competitively priced:
 - A new interconnector linking South Australia with either New South Wales or Victoria from 2021.
 - Augmenting the existing interconnectors linking New South Wales with both Queensland and Victoria in the mid to late 2020s, particularly as coal-fired generation retires.
 - A second Bass Strait interconnector from 2025, when combined with augmented interconnector capacity linking New South Wales identified above.
- Modelling has shown greater net benefits when interconnector developments are combined, highlighting the benefits of a more interconnected NEM. Geographic and technology diversity smooths the impact of intermittency and reduces reliance on GPG. To realise these benefits, a co-ordinated national planning approach is required.
- GPG is assumed to be located where coal retirements are likely to occur, to minimise additional transmission network development, subject to fuel availability and pipeline proximity. If new generation is not optimally located, further transmission upgrades might be required.
- Major transmission development (approximately \$1 billion to \$3 billion) is likely to be required to facilitate the connection of renewable generation to meet the VRET.
- Interconnector utilisation is projected to increase over the outlook period, as regions become more reliant on each other. This further highlights the value of a more interconnected NEM. Local network utilisation trends will be driven by changes to the generation mix within the region.

This chapter assesses and outlines an appropriate course for the efficient development of the national transmission grid over the next 20 years, under a range of scenarios.

The most appropriate course can be a combination of new interconnection, supporting plant, and new generation, and must:

- Maintain system security.
- Result in the transmission of sufficient generation to meet demand.
- Balance reliability, generation cost, network cost, and emissions targets.

This chapter presents the National Transmission Outlook in four sections:

- **The generation outlook**⁴³– projects the location and timing of new generation additions and withdrawals for each demand scenario and case study. This outlook focuses on efficient development to meet forecast demand, minimising the total generation and network investment cost over the next 20 years. Detailed results are presented on the interactive map.⁴⁴
- **The inter-regional transmission outlook** – an assessment of the impact and value of new transmission interconnections between NEM regions. This analysis is a precursor to a complete Regulatory Investment Test for Transmission (RIT-T) which would assess benefits of a wider range of credible network and non-network options. A detailed technical analysis of potential new interconnectors is addressed in Chapter 5 (for South Australia) and Chapter 6 (for Tasmania).

⁴³ While the *Electricity Statement of Opportunities* only considers generation which has been committed, the NTNDP generation outlook builds (assumes) sufficient generation to meet reliability standards in the most efficient manner.

⁴⁴ AEMO. *Interactive map*. Available: <http://www.aemo.com.au/aemo/apps/visualisations/map.html>.



- **The intra-regional transmission outlook** – assesses the capability for the transmission network to transfer power between generation and load centres within NEM regions. This analysis considers how thermal, voltage collapse, and stability limitations impact power transfer capability.
- **Changes to transmission network utilisation** – analyses how future transmission flow paths will be loaded relative to their thermal limits for the projected generation and load forecasts, to assist TNSPs in their strategic network planning processes.

The NTNDP assessment takes a strategic approach, and minimises generation and transmission network costs by locating new generation efficiently, with consideration of spare network capacity, network connection costs, the quality of local wind and solar resources (or availability of fuel sources for thermal plants), and power system reliability and security requirements.

AEMO acknowledges that a range of commercial factors influence where new generation developments are located, so the 2016 assessment has prioritised new generation installations in the first five years of the model to take into account connection applications received by AEMO.

The net market benefits discussed in this chapter are at the lower end of the cost range, assuming that investment will be competitively priced. Contestability in transmission would help ensure that developments are more competitively priced, reducing overall costs for consumers.⁴⁵ This is important given the speed at which the NEM is transforming, and the potential cost of the various transmission development projects being considered.

3.1 Generation outlook

This section presents the projected generation outlooks for each of the three scenarios described in Section 2.3 – Neutral, 45% Emissions Reduction, and Low Grid Demand.

3.1.1 Projected capacity mix

The generation mix of the NEM is projected to continue transforming over the next 20 years, driven by three key factors:

- Legislated and advanced emissions reduction policy objectives (Australia's COP21 commitment, LRET, and VRET).
- The reducing financial viability of ageing coal generation.
- Meeting forecast system operational consumption.

In the Neutral scenario, AEMO projects that:

- 63% (15.5 GW) of the existing coal generation fleet may retire by 2036.
- New installations of 49.5 GW of generation may be required by 2036, comprising wind generation (19%), large-scale PV (27%), GPG (24%), and rooftop PV (30%).⁴⁶

An increase in installed NEM capacity is forecast, despite a relatively flat demand projection under the Neutral scenario, as a result of an increase in penetration of intermittent generation installations. A balance of GPG is still required to ensure that supply meets demand at all times, particularly when wind and PV generation is low.

New GPG has been assumed to be located to utilise existing electricity transmission infrastructure, made vacant by coal generation withdrawals. However, new GPG capacity in these locations would require development of gas production and pipelines. Direct comparisons of network versus pipeline augmentation to determine optimal plant siting has not been conducted.

Uncertainty in the timing of retirements of the existing coal generation fleet, and future availability of gas supply, will directly affect GPG projections. Modelling did not consider the impact of increased GPG on

⁴⁵ This aligns with the AEMC's draft determination on *Transmission connection and planning arrangements*, published on 24 November 2016. Available: <http://www.aemc.gov.au/Rule-Changes/Transmission-Connection-and-Planning-Arrangements#>.

⁴⁶ This percentage is based on the effective installed capacity after taking into account a degradation factor, as applied in the 2016 National Electricity Forecasting Report.

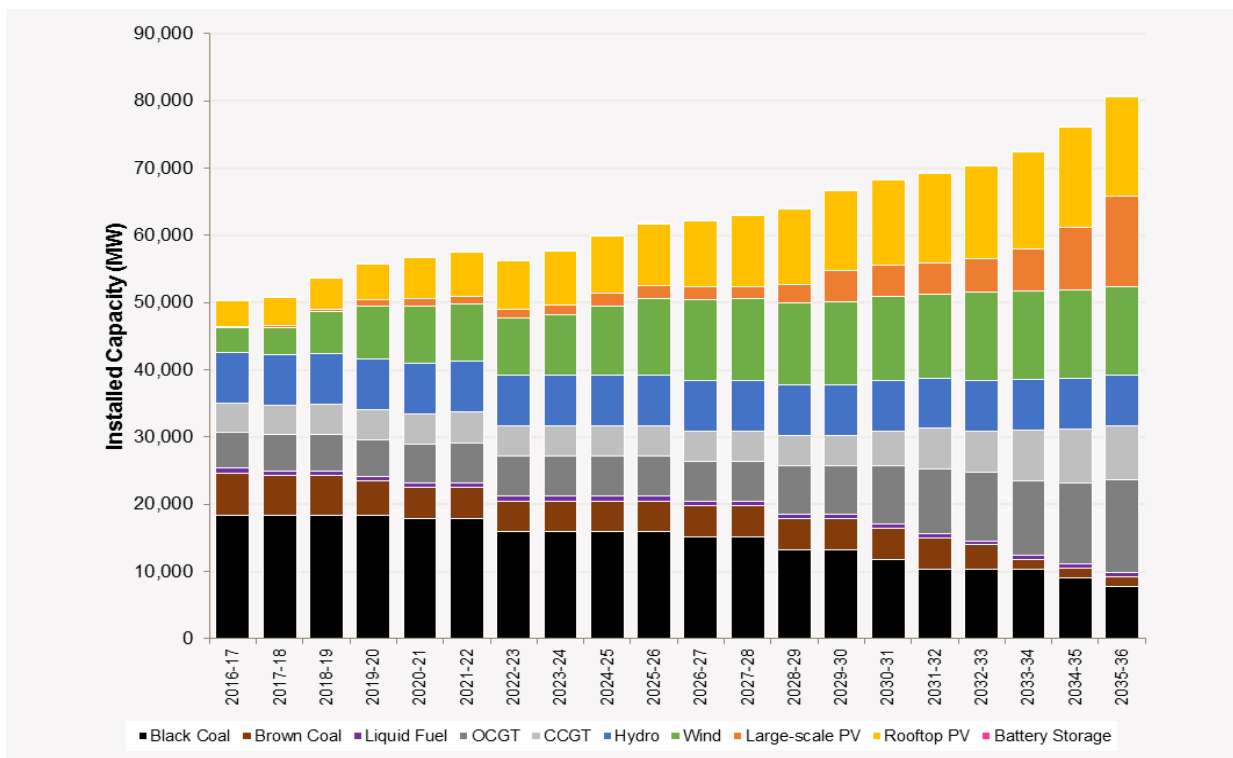
gas supply and demand, and ultimately gas price. Increases in gas prices, or investment risk due to future climate change policy, could make alternative fuel sources such as biogas or biomass, or emerging technologies, either grid-scale or distributed, more viable alternatives to GPG over the outlook period.

Compared to the Neutral scenario, AEMO projects that:

- The transformation of the generation mix is accelerated in the 45% Emissions Reduction scenario, due to the deeper cuts in emissions required by 2030. More coal-fired generation is retired, there is higher penetration of intermittent generation sources, and more battery storage is installed to assist in levelling intermittency of wind and solar generation, while also contributing to peak demand periods. The 45% Emissions Reduction scenario also includes the announced retirement of Hazelwood Power Station from 2017 and return to service of mothballed plant, consistent with AEMO’s NEM *Electricity Statement of Opportunities* (ESOO) update.⁴⁷
- The Low Grid Demand scenario projects that 3.3 GW additional coal plant may retire to 2035–36, due to the reducing financial viability of the coal plant associated with the more challenging demand environment. The scenario includes strong penetration of rooftop PV, projected to reach 36% of installed capacity by 2035–36. The support of GPG is not required to the same extent as under the Neutral scenario, due to lower grid demand.

Figures 6, 7 and 8 show installed capacity projected by fuel type over the next 20 years for the Neutral, 45% Emissions Reduction and Low Grid Demand scenarios respectively.

Figure 6 Total installed capacity by fuel type to 2035–36, Neutral scenario



⁴⁷ AEMO. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

Figure 7 Total installed capacity by fuel type to 2035–36, 45% Emissions Reduction scenario

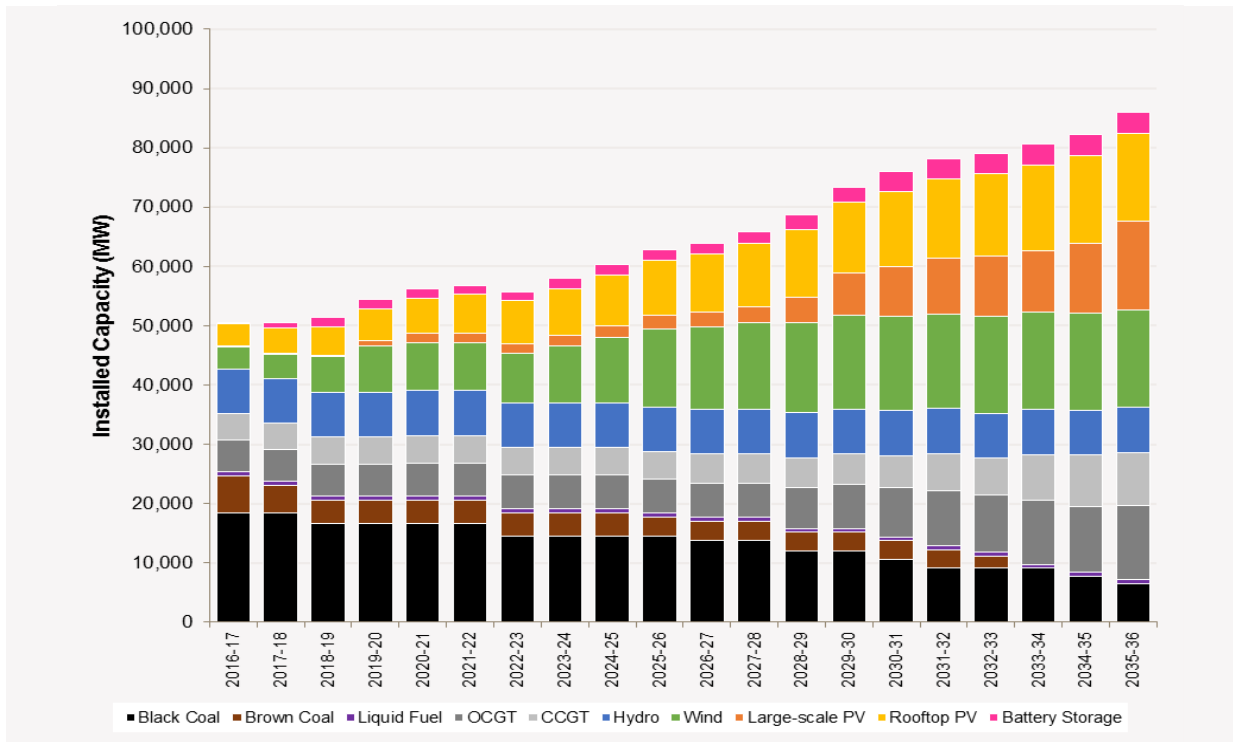
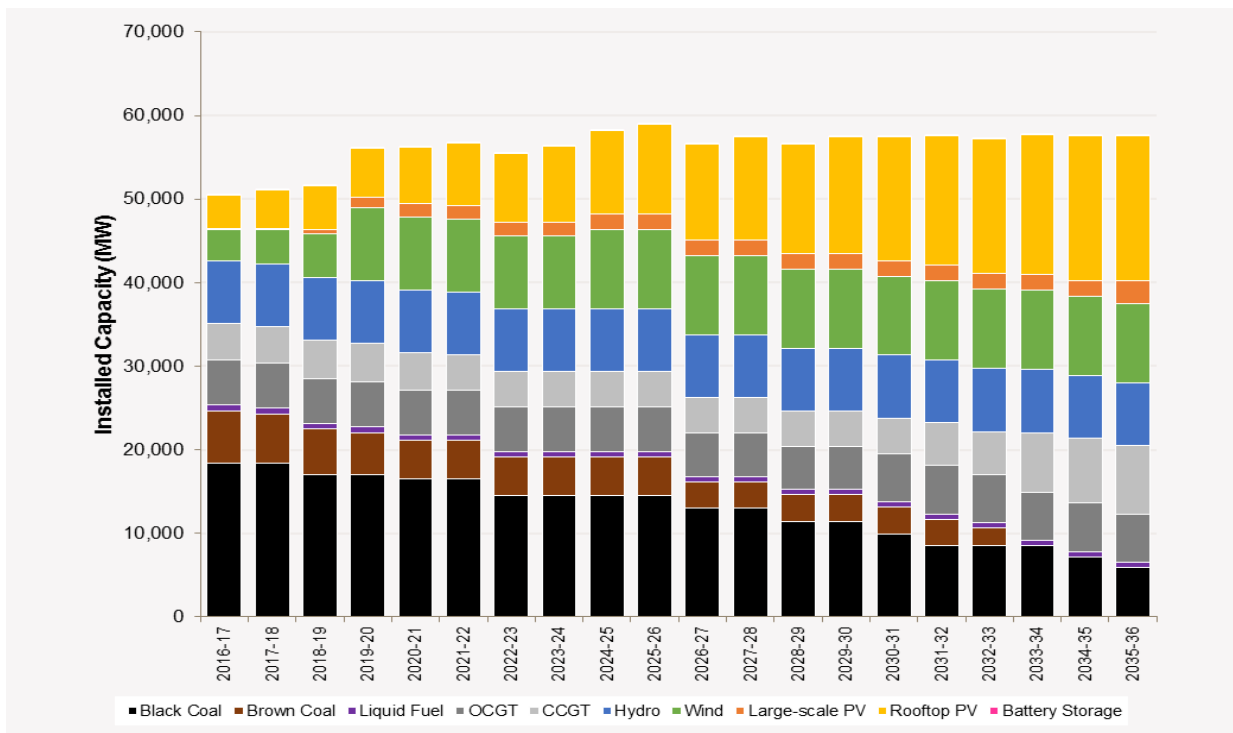


Figure 8 Total installed capacity by fuel type to 2035–36, Low Grid Demand scenario



3.2 Inter-regional transmission outlook

A number of possible augmentations to increase interconnection in the NEM were considered in the NTNDP transmission and generation outlooks.

The generation outlooks discussed above were co-optimised with interconnector augmentation, as increased interconnection has the potential to provide a range of benefits, including increased efficiency in generation production costs, greater reliability and security outcomes, and reduction in capital investment related to new generation.

This section examines the economic value of the interconnector options. This analysis does not meet the requirements of a full RIT-T assessment, but provides a high level overview of the potential benefits that each interconnector may provide, focusing on the allowable market benefits in a RIT-T.⁴⁸ The allowable market benefits assessed include:

- **Generation dispatch efficiencies** – changes in production cost arising through different patterns of generation dispatch and changes in network losses, including changes in fuel consumption and variable operations and maintenance expenditure. These have been calculated assuming perfect competition, with dispatch based on SRMC bidding. Network constraints have been included to capture operating costs under realistic network congestion.
- **Reliability benefits** – changes in voluntary and involuntary load curtailment, valued based on the value of customer reliability (VCR).⁴⁹
- **Capital investment efficiencies** – changes in capital investment for non-transmission elements, including savings associated with:
 - Differences in the timing of new plant.
 - Difference in capital cost.
 - Differences in fixed operational and maintenance costs.
- **Environmental scheme benefits** – changes in penalties paid or payable for not meeting the LRET.

This analysis also refers to “**resilience benefits**”. These relate to benefits derived from increasing the power system’s resilience to high impact, low probability events such as interconnector failures. Resilience benefits are not a separate category of benefits, but a subset drawn from existing categories of RIT-T allowable market benefits.

Potential resilience benefits are:

- For South Australia, the increased resilience to severe and widespread **involuntary load shedding** in the region following electrical separation of South Australia from the rest of the NEM.
- For Tasmania, the increased resilience to **generation dispatch inefficiencies** throughout the NEM associated with prolonged (year-long) failure of the existing Basslink Interconnector.

The following potential benefits have not been included in this assessment:

- Competition benefits.
- Changes in ancillary service costs (with the exception being the dispatch efficiency benefits associated with revoking the RoCoF constraint in cases where there is additional South Australian interconnection).
- Changes in any additional option value not covered by the above definitions.

The Net Present Value (NPV) of market benefits has been calculated over 20 years to 2035–36 using a 7% social discount rate. The interconnector costs have been annualised assuming a weighted average cost of capital of 8.76% and a 50 year asset life to provide a NPV comparison of costs over the same time period, and are assumed to be competitively priced.

The specific technical details of each case study on new interconnection, and how they can improve NEM resilience, are included in Chapter 5 for South Australia and Chapter 6 for Tasmania.

⁴⁸ Australian Energy Regulator. *Final regulatory investment test for transmission*. Available: <https://www.aer.gov.au/system/files/Final%20RIT-T%20-%2029%20June%202010.pdf>.

⁴⁹ AEMO, *Value of Customer Reliability*, \. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review>.

3.2.1 Interconnector options considered

This assessment considered numerous options for interconnector augmentations. The full list of options considered can be found in the NTNDP modelling data file in the 2016 NTNDP Database online.⁵⁰ The table below shows the interconnector augmentation options that have been examined in detail.

Table 3 Interconnector augmentation options considered in detail in the 2016 NTNDP

Interconnector	Projects	Forward direction	Increase from present limit (MW)		Cost estimate (2016–17 \$ million)
			Forward direction	Reverse direction	
New South Wales to Queensland interconnector (QNI)	Series compensation on the Bulli Creek – Dumaresq 330 kV line only. 2x200 MVA _r , 330 kV shunt capacitor bank at Armidale and uprating of Liddell – Muswellbrook – Tamworth and Liddell – Tamworth 330 kV transmission lines	NSW–QLD	450	300	136
Victoria to New South Wales interconnector (VIC–NSW)	Second South Morang 500/330 kV transformer, a braking resistor at Loy Yang, and uprating of the South Morang – Dederang 330 kV circuits.	VIC–NSW	170	0	74
New South Australia to Victoria interconnector (HorshamLink)	A new 275 kV link from Tailem Bend (SA) to Horsham (Vic), with a new 275 kV single circuit line from Tailem Bend to Tungkillo (SA). Combination of new line, uprating existing line, and new transformers, requiring power flow control (such as phase shifting transformers) and dynamic voltage support (such as synchronous condensers).	VIC–SA	325 to 650	325 to 650	500 to 750
New South Australia to New South Wales interconnector (RiverLink)	New 275 kV link between Darlington Point (NSW) and Robertstown (SA). Combination of new line, uprating existing line, and new transformers, requiring power flow control (such as phase shifting transformers) and dynamic voltage support (such as synchronous condensers).	NSW–SA	325 to 650	325 to 650	500 to 1,000
New Bass Strait Interconnector (2BSI)	New 400 kV mono-polar transmission system between Tyabb (Vic) and Smithton (TAS), and new 220 kV double circuit line between Smithton and Sheffield (TAS).	TAS–VIC	600	600	940

These interconnector projects were co-optimised with generation build to provide guidance on the timings and network configuration for each project. This modelling indicated that the QNI and VIC–NSW augmentations were the most cost-effective options, delivering the highest benefit to cost ratio, although interconnection options between other regions also showed merit. These QNI and VIC–NSW augmentations are therefore incorporated into the Base cases for all three 2016 NTNDP scenarios – Neutral, Low Grid Demand, and 45% Emissions Reduction:

⁵⁰ AEMO, 2016. NTNDP Database. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.



- Augmentation from Victoria to New South Wales (VIC–NSW) to increase transfer capability into New South Wales from 2029–30 in the Neutral and 45% Emissions Reduction scenarios and from 2023–24 in the Low Grid Demand scenario.
- Augmentation from New South Wales to Queensland (QNI) to increase transfer capability bi-directionally between New South Wales and Queensland from 2028–29 in the Neutral and 45% Emissions Reduction scenarios and from 2026–27 in the Low Grid Demand scenario.

These augmentation timings typically align with coal-fired generation retirements.

Following stakeholder interest, the 2016 NTNDP assessment also explicitly conducted case studies into a second Bass Strait interconnector (2BSI) and additional interconnection to South Australia, either with New South Wales or Victoria.

The interconnection options and timings shown in Table 4 were therefore modelled in detail in this year’s NTNDP.

Table 4 Timing of modelled interconnector augmentation

Augmentation option	Timing in Neutral	Timing in Low Grid Demand	Timing in 45% Emissions Reduction
QNI	2028–29	2026–27	2025–26
VIC–NSW	2029–30	2023–24	2029–30
HorshamLink	2021–22	2021–22	2021–22
RiverLink	2021–22	2021–22	2021–22
2BSI	2025–26	2025–26	2025–26

3.2.2 Market benefit analysis

The table below shows the NPV of total market benefit analysis for each interconnector study in the Neutral scenario over the modelled 20-year period.

It compares each interconnector development option against a ‘no interconnector options’ case, using time-sequential modelling and relevant cost inputs (outlined in the 2016 NTNDP Database⁵¹).

It also shows the incremental net market benefits, over and above the benefits attributable to the QNI and VIC–NSW interconnection augmentations.

An extended time horizon of analysis may alter the results of this market benefit analysis, strengthening (or weakening) the case for interconnection augmentations.

⁵¹ AEMO, 2016. NTNDP Database. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.

Table 5 Market benefit analysis to 2035-36, Neutral scenario (\$ million)

Case study	Dispatch efficiency benefits	Reliability benefits	Capital investment efficiency benefits	Environmental scheme benefits	Resilience benefits	NPV of gross market benefits to 2035-36	NPV of annualised cost to 2035-36	Overall net market benefit	Incremental net market benefits
Base case QNI VIC-NSW	\$117m	\$27m	\$31m	-\$4m	\$0m	\$170m	\$47m	\$123m	\$0m
2BSI + QNI VIC-NSW	\$202m	\$114m	\$165m	\$2m	\$48m	\$531m	\$387m	\$143m	\$20m
HorshamLink + QNI VIC-NSW	\$324m	-\$1m	-\$6m	\$117m	\$161m	\$595m	\$335m	\$260m	\$136m
RiverLink + QNI VIC-NSW	\$355m	-\$2m	-\$6m	\$75m	\$161m	\$583m	\$335m	\$248m	\$124m
HorshamLink then 2BSI + QNI VIC-NSW	\$451m	\$85m	\$111m	\$123m	\$209m	\$978m	\$676m	\$302m	\$179m

Base case QNI VIC-NSW

- Upgrades to QNI and VIC-NSW are estimated to deliver positive net market benefits of \$123 million, primarily from fuel cost savings, compared to the case where no interconnector augmentation is developed. These fuel savings are projected to occur predominately from the late 2020s as New South Wales and Victoria increase reliance on interconnection to better utilise generation resources across the NEM following coal generation retirements.
- This Base case projects capital investment efficiencies, as the link augmentations are projected to defer up to 300 MW of GPG installation in New South Wales through the 2030s.
- These upgrades deliver positive net market benefits under all three scenarios (\$281 million in the 45% Emissions Reduction scenario and \$86 million in the Low Grid Demand scenario).

HorshamLink and RiverLink

Studies into additional interconnection to South Australia, to increase transfer capability 325 MW in either direction from 2021-22, projected 714 MW of additional wind installations in South Australia in response to the development of the interconnector. This additional wind generation is forecast to relocate or defer installation of GPG and renewable generation in other regions.

Key insights from the Neutral scenario market benefit analysis over the outlook period to 2035-36 include:

- Additional interconnection between South Australia and either New South Wales or Victoria is projected to deliver net market benefits in the order of \$124 million to \$136 million over the next 20 years, compared to the Base case QNI VIC-NSW.
- A new interconnector would provide South Australia greater access to lower-cost fuel supplies at times when intermittent generation within the region was low (reducing exposure to high gas prices), delivering potential generation dispatch efficiency benefits of \$207 million under the HorshamLink case and \$239 million in the RiverLink case.
- An additional interconnector may reduce the likelihood of a widespread blackout in South Australia by mitigating the possibility of electrical separation from the rest of the NEM. The assessment estimates overall net economic benefits of \$161 million in resilience benefits in South Australia.
- A new interconnector would not necessarily provide all the services required to avoid electrical separation, and additional regional solutions would be needed to address areas of low system

strength and minimise the potential contingency size. Operating an interconnector below its maximum transfer limit can enable the interconnector(s) to remain connected following a larger contingency size, which decreases the risk of separation, but this can reduce available market benefits. Resilience of the South Australian system is discussed further in Chapter 5.

- Intra-regional congestion and interconnector limitations, combined with the constraint to limit Heywood Interconnector flow in low power system inertia conditions in South Australia⁵², results in some projected spill of wind generation in the Base case. Given this spill of wind, the LRET targets in the next five to 10 years are forecast to be at risk, with the LRET penalty price paid by some retailers. In the Neutral scenario, the market benefits of this interconnector case study include \$121 million benefits (for HorshamLink) associated with alleviating network congestion, reducing wind-spill and therefore reducing costs associated with LRET penalties. Environmental benefits for RiverLink are slightly lower (\$79 million) due to the intra-regional congestion differences in Victoria and New South Wales.
 - These differences are associated with the different flow paths of the new interconnectors, and the transmission works that may be necessary in Victoria to support renewable generation connections in response to the VRET. These developments are discussed further in Chapter 5 and Chapter 6.

Importantly, the assessment finds positive net market benefits under all three scenarios, suggesting the investment would be robust to uncertainties in demand and climate change policy.

Accelerated retirement of coal-fired generation increases the generation dispatch efficiencies provided by this interconnector, as improved renewable generation utilisation reduces reliance on higher cost gas fired generation. Net market benefits range between \$239 million and \$272 million under the 45% Emissions Reduction scenario (depending on route), and between \$142 million and \$178 million under the Low Grid Demand scenario.

Second Bass Strait

The development of the proposed 600 MW second Bass Strait interconnector is forecast to increase the financial viability of renewable generation in Tasmania by reducing the risk of being constrained off due to transmission limitations and increasing access to the broader NEM. Tasmania's relatively rich wind resources are more capable of export with a second link, while Tasmania's ability to import electricity during off-peak periods increases the flexibility available to the Hydro Tasmanian generation portfolio to maximise the value of stored water, and reduce NEM-wide system costs.

With a second Bass Strait interconnector, the modelling projects 365 MW of additional wind generation in Tasmania (instead of some large-scale PV in Queensland), relative to the Base case QNI VIC–NSW.

Under the Neutral scenario, the key insights from the market benefit analysis over the outlook period to 2035–36 include:

- A second Bass Strait interconnector is projected to deliver a positive net market benefit of \$20 million over the outlook period to 2035–36, compared to the Base case QNI VIC–NSW.
- Tasmania's ability to export hydro (and to a lesser extent wind generation) to support peak loads on the mainland would be increased in this case, and is projected to reduce demand curtailment costs for the NEM (\$87 million) and defer capital investment including deferral of between 300MW and 600MW of GPG capacity in New South Wales and Victoria from the late 2020s (\$134 million).
- More efficient utilisation of Tasmanian hydro and wind generation is also projected to deliver \$85 million in generation dispatch efficiency benefits, displacing some coal and gas fired generation.
- A second Bass Strait interconnector will provide \$48 million in market benefits associated with increased resilience of the network to potential interconnector failures. For Tasmania, the loss of the existing Basslink Interconnector can result in increased dispatch costs, as experienced in 2015–16. With Basslink out of service, generation costs will increase if GPG is required to return to

⁵² AEMO Electricity Market Notice 55358, 12 October 2016. Available: <https://www.aemo.com.au/Market-Notices>.

service in Tasmania, to supplement local hydro generation. The mainland will also no longer have access to generation from Tasmania, resulting in increased GPG production on the mainland. The development of the second interconnector therefore avoids the increased costs associated with the failure of the single interconnector.

- This was estimated based on the simulated differences in market costs with and without a second interconnector, if Basslink was unavailable for a prolonged period. The benefit itself is weighted using a 5% probability of occurrence, representing a 1-in-20-year expectation of a 12-month outage, or equivalent to a 1-in-10-year outage of six months' duration (as experienced in 2015–16). Long-term average hydro yields have been assumed in this assessment. Resilience benefits would be higher under low hydro storage conditions, but the probability of a prolonged Basslink outage coinciding with these conditions would also be lower.

The assessment finds positive net market benefits only under the Neutral scenario. Under both the Low Grid Demand and 45% Emissions Reduction scenarios, the net market benefits are negative (-\$147 million and -\$57 million respectively). While the generation dispatch efficiency savings increase under these scenarios due to accelerated retirement of coal generation, the capital deferral benefits decrease. In the Low Grid Demand scenario, there is less new generation investment required, whereas in the 45% Emissions Reduction scenario battery storage helps to smooth peak demand, reducing the need for some new peaking capacity.

This suggests that the benefits of a second Bass Strait interconnector are sensitive to uncertainties in future demand and climate change policy. It would therefore be prudent to test additional scenarios, including various future rainfall scenarios, to gain a greater understanding of the risks and potential benefits associated with this investment.

HorshamLink and second Bass Strait interconnector

The analysis indicates that synergies are achieved through greater interconnection, highlighting the importance of a national, strategic coordinated approach to planning in order to maximise benefits to consumers. The combined net market benefit of both an additional South Australian interconnector and the second Bass Strait interconnector is \$179 million, greater than the sum of each interconnector's separate effects.

Under the Neutral scenario, the key insights from the market benefit analysis over the outlook period to 2035–36 include:

- The forecast generation development is expected to be very similar to that of the HorshamLink case in the 2020s, and then similar to the 2BSI case, following the second link's development. Observed benefits in this case are approximately \$42 million greater than those expected by the HorshamLink case alone.
- This case study leads to an increase in South Australia wind production, relative to the second Bass Strait case, in addition to increased flexibility in Tasmanian hydro production, relative to the HorshamLink case. The increased geographic diversity of resources due to the addition of both interconnectors has a compounding effect, resulting in the lowest fuel costs of any case studied (\$334 million cost saving).
- The HorshamLink and 2BSI case increases the ability for hydro generation to export from Tasmania to support peak loads, particularly in Victoria and South Australia, deferring capital investment (\$80 million) as well as delivering resilience benefits for both South Australia and Tasmania (\$209 million).

Total project capital costs are about \$1.6 billion in this case, as it includes augmentation of QNI and NSW–VIC as well as the additional South Australia and Bass Strait interconnectors. This is equivalent to a NPV of \$676 million over the next 20 years, when costs are annualised assuming a weighted average cost of capital of 8.76% and a 50 year asset life. For comparison, the NPV of capital expenditure on new generation over the same period is estimated to be \$16.4 billion.

The combined interconnection option delivers positive net market benefits under two of the three scenarios. Under the Low Grid Demand scenario, it would be more beneficial not to proceed with the second Bass Strait Interconnector, as it delivers insufficient capital investment and dispatch efficiencies. Net market benefits are estimated to be \$397 million under the 45% Emissions Reduction scenario and -\$35 million under the Low Grid Demand scenario.

One advantage of this combined option is that there would be some flexibility in delaying the timing of the second interconnector if demand proved to be lower than forecast.

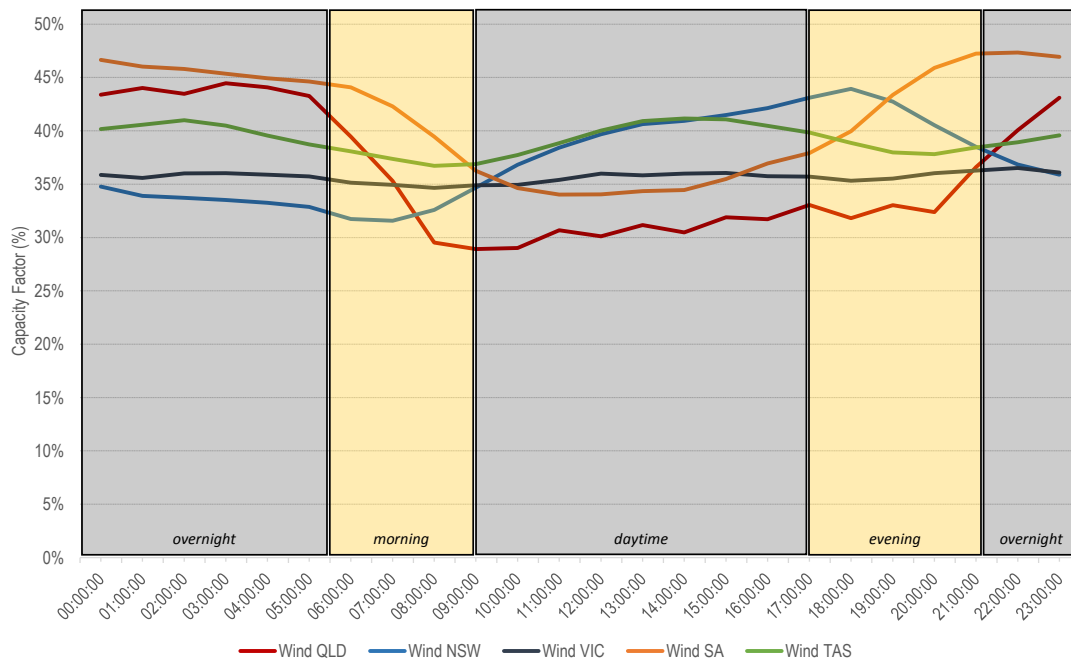
3.2.3 Benefits of geographic and technical diversity

The analysis has highlighted that interconnectors serve to exploit the geographic diversity of intermittent generation sources, leading to more efficient generation siting decisions from a resource perspective, and smoothing the intermittency in aggregate across the NEM. This reduces the need to dispatch higher marginal cost generation such as GPG at times when the renewable resources within a region are not available.

Further, as wind penetration increases in a particular region, there will be a diminishing return on further developments, as the correlation of generation in geographically near locations is relatively high. As such, increasing diversity of intermittent generator developments can deliver both dispatch and capital investment efficiency benefits. The value of this diversity is expected to increase as renewable energy penetration increases.

Figure 9 below shows the average time of day generation from wind farms available in different regions, based on historical data observed in 2013–14.⁵³

Figure 9 Average wind farm operation per region, by time of day



The figure shows that the resource profiles of wind farms across the regions are quite different. For example, while Tasmanian wind has greater daytime production, South Australia’s wind generation profile has greater operation near peak load times in the evening and overnight, and Queensland’s wind generation is lowest on average at times when rooftop PV generation across the NEM will be relatively high.

⁵³ The 2013–14 year has been used as the reference year for all the modelling - from which demand, solar and wind traces have been derived.



Wind farm generation in one region can therefore complement output in another region, or even PV generation, if there is adequate regional interconnection.

3.3 Intra-regional transmission outlook

The transmission outlook examines how the generation outlook could cause limitations in supply being transmitted to meet demand. These limitations can be driven from changes in either load or generation. Transmission development is no longer driven by rising NEM demand, as expectations are for overall grid demand to remain flat or trend towards a Low Grid Demand scenario that falls 32% by 2036. It will now be driven by the transforming generation mix to meet Australia's federal and state emissions reduction targets, as the transmission network will be required to:

- Connect and securely integrate up to about 35 GW of new large-scale generation to the power system. These projections reduce to around 13 GW of new large-scale generation in the Low Grid Demand scenario. When connecting large amounts of new generation, there should be economies of scale in creating new generation hubs to reduce the overall costs to consumers of connecting new generation. Powerlink and TransGrid are actively promoting this concept in Queensland and New South Wales.^{54,55}
- Meet the increasing need for system support services, such as frequency and voltage support⁵⁶, and solutions that complement renewable generation intermittency, as synchronous generation (coal, gas and hydro) in the NEM is projected to reduce from 91% annually in 2016–17 to 58% in 2035–36.

The transmission limitations that will drive projected developments are identified in the sections below.

This year's transmission outlook also explores how utilisation of NTNDP flow paths is expected to change over the outlook period. This projection will also depend heavily on generation changes.

This section of the transmission outlook investigates limitations for the Neutral and Low Grid Demand scenarios only. The intra-regional transmission outlook for the 45% Emissions Reduction scenario first requires a more detailed assessment of alternative interconnection options to increase the transfer capability between Victoria and New South Wales. This will be investigated in 2017.

3.3.1 Type of limitations identified

Three types of limitations are considered in the NTNDP transmission development outlook:

- **Reliability limitations** occur if, at the time of regional maximum operational demand, the network does not have enough capacity to meet demand.
- **Potential Reliability limitations** are limitations which may eventuate if new generation, particularly GPG, is not able to be located to utilise spare capacity of the transmission network.
- **Economic limitations** are where more expensive generation is dispatched ahead of cheaper generation to avoid network overloads.
- **VRET limitations** are economic limitations which may need to be addressed for sufficient renewable generation to be built in Victoria to meet the VRET.

The figure below shows the location of each type of network limitation on the main transmission network, as identified by the NTNDP modelling and TNSPs in their annual planning reports. Each limitation is identified by a locational reference code. These are also shown on AEMO's online interactive map.⁵⁷

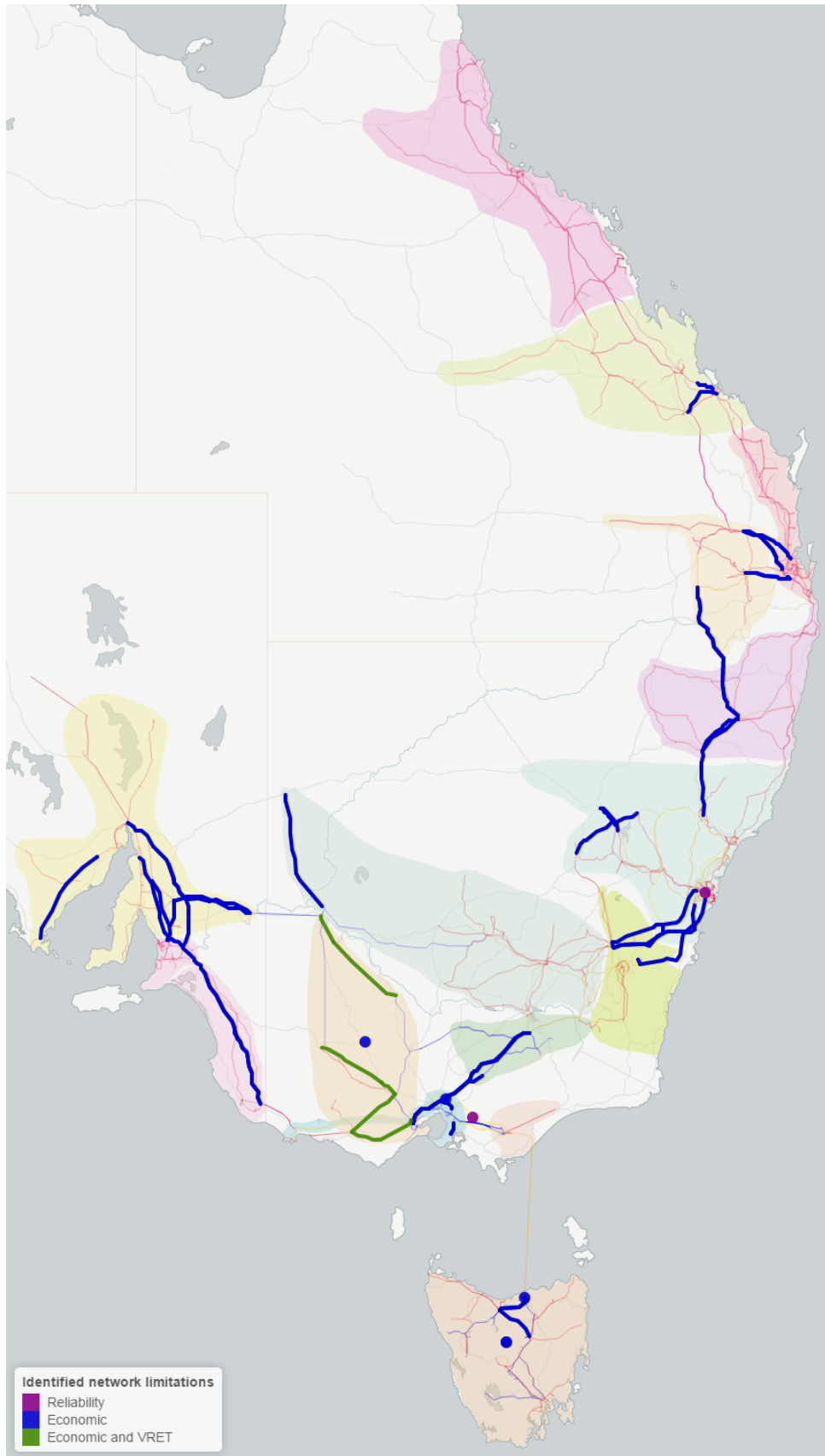
⁵⁴ Powerlink, 2016. *Transmission Annual Planning Report*. Available: https://www.powerlink.com.au/About_Powerlink/Publications/Transmission_Annual_Planning_Reports.aspx.

⁵⁵ TransGrid, 2016. *Renewable Energy Hub*. Available: <https://www.transgrid.com.au/news-views/lets-connect/consultations/current-consultations/Pages/Renewable-Energy-Hub.aspx>.

⁵⁶ Frequency control and system strength were highlighted as high priority challenges in AEMO's *Future Power System Security Program: August 2016 update*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability>.

⁵⁷ AEMO. Available: <http://www.aemo.com.au/electricity/planning/interactive-map/>.

Figure 10 Identified network intra-regional limitations, Neutral scenario



3.3.2 New South Wales

Reliability limitations

The 2016 NTNDP identifies one projected reliability limitation in the Sydney CBD area. This limitation is well known, and is already the subject of a joint RIT-T between TransGrid and Ausgrid, presently at the Project Specification Consultation Report (PSCR) stage.⁵⁸ TransGrid and Ausgrid have identified the need based on an assessment that the future value of unserved energy and environmental and operating and maintenance costs that can be avoided by undertaking the investment in 2021–22 exceeds the investment cost.

The limitation is due to a number of drivers, which are outlined in the PSCR as:

- *The deteriorating condition and reduced capability of assets (330 kV Cable 41 by TransGrid and a number of 132 kV cables by Ausgrid).*
- *The deteriorating condition of ageing oil-filled cables in the existing network and the derating of the 330 kV Cable 41 by TransGrid (in 2011 and 2016) and the derating of a number of 132 kV cables by Ausgrid (beginning in 2012).*
- *Ausgrid's planned retirement of three oil-filled cables in Inner Sydney in the next two years.*
- *The age-related deteriorating condition of a further eight oil-filled Ausgrid cables in the Inner Sydney area.*
- *An increase in forecast peak demand due to renewed economic activity within Inner Sydney.*

This limitation has been under close observation by both TransGrid and Ausgrid for a number of years, and was also identified in the 2015 NTNDP. The approximate cost to address this limitation is expected to be between \$435 and \$555 million⁵⁹, due to the size, location, and complexity of the limitation.

Potential reliability limitations

There is the potential for an additional reliability limitation to appear in New South Wales after 2030, when the bulk of NSW black coal generation retirement occurs. This occurs for both Neutral and Low Grid Demand Scenarios

New GPG in NSW is located to take advantage of the spare network capacity made available by the coal retirement, avoiding the need to augment the network in other areas. This is a cost-effective location for connecting new GPG, as additional generation can be delivered to the load centres using the spare capacity of the existing transmission network. If this was not possible, and the potential reliability limitation eventuated, an alternative solution could include:

- Additional generation being built outside the region, closer to an available fuel source.
- Sufficient transmission connection from regional and interregional generation into the 330 kV/500 kV transmission ring around the main New South Wales load centres. This would likely require several thousand MW of transmission capacity.
- Utility-scale energy storage batteries located in the Hunter Valley to make use of existing transmission infrastructure.
- Maintaining the existing supply of coal generation, with additional carbon abatement measures to ensure it Australia's COP21 commitment is met.

A combination of two or more of these options is likely to be the most cost-effective alternative. In-depth analysis of the potential has not been undertaken at this stage, and is likely to be the subject of future work.

⁵⁸ TransGrid, 2016. *Powering Sydney's future*. Available: <https://www.transgrid.com.au/powering-sydney-rit-t>.

⁵⁹ Refer to costs in PSCR, available: <https://www.transgrid.com.au/news-views/lets-connect/consultations/current-consultations/Documents/Powering%20Sydney%27s%20Future%20-%20RIT-T%20PSCR.pdf>.

Economic limitations

New South Wales has a number of economic limitations on the main 330 kV network which forms the transmission flow paths between Victoria and the Sydney region, and the Sydney region and Queensland.

These limitations are projected to become more binding in later years, with the majority of new utility-scale PV and wind generation expected to be located on or nearby these 330 kV lines, and New South Wales projected to become more reliant on interconnection after the retirement of black coal generation.

Table 6 Projected economic limitations in New South Wales

Zone	Potential transmission limitations	Dispatch scenario	Possible solution	Scenarios
CAN to NCEN	Transmission limitations on 330 kV cutset between Yass/Canberra and Sydney	High export Vic-NSW and high wind/PV generation in CAN zone	Upgrading Snowy to Sydney 330 kV network* <ul style="list-style-type: none"> • Upgrading line 01 and 02 to an operating temperature of 100°C • Upgrading line 39 to an operating temperature of 100°C • Upgrading lines 4 and 5 to an operating temperature of 100°C • Replacing terminal equipment on line 11 at Dapto and Sydney South • Replacing terminal equipment on line 17 at Avon and Macarthur • Upgrading line 18 to an operating temperature of 100°C. 	All
NNSW	Transmission limitations between 330 kV lines between Dumaresq and Liddell	High import from QLD and high wind/PV generation	Upgrading the Liddell to Dumaresq lines including*: <ul style="list-style-type: none"> • Upgrading the lines 83, 84, 85 and 88 from an operating temperature of 85°C to 120°C • New SVCs at Armidale, Dumaresq and Tamworth, and switched shunt capacitors at Dumaresq, Armidale and Tamworth substations. 	All
SWNSW	220 kV between Broken Hill and Buronga	High wind from Broken Hill	New 220 kV circuit between Broken Hill and Buronga	Neutral All
NCEN	132 kV Network around Wellington (e.g. Dubbo, Nyngan, Parkes etc.)	High PV penetration connected to 132 kV network	Upgrading of 132 kV network to Wellington where required	Neutral All

* Source: TransGrid APR. Available: <https://www.transgrid.com.au/news-views/publications/Documents/Transmission%20Annual%20Planning%20Report%202016.pdf>.

3.3.3 Queensland

Potential reliability limitations

There is a potential reliability limitation when some local black coal generating units are projected to retire in 2021 under the generation outlook in the Neutral scenario. The Calvale–Wurdong 275 kV line is projected to overload under some system normal conditions. The extent of the potential overload, and the economic impact, would depend on any changes to the generation dispatch pattern. In the Low Grid Demand scenario, there is no projected overload on the Calvale–Wurdong 275 kV line.

Economic limitations

The following table shows economic limitations projected under the Neutral and Low Grid Demand scenarios.

Table 7 Projected economic limitations in Queensland

Zone	Potential transmission limitations	Dispatch conditions	Possible Solutions	Scenarios
SWQ QNI	Transmission limitations between 330 kV lines between Dumaresq and Bulli Creek (part of the NSW-QLD interconnection)	Transient stability limits ⁶⁰ set the exporting limit from QLD to NSW	Increase RHS of transient stability limit, such as add new Capacitor banks. ⁶¹	Neutral, Low Grid Demand
SWQ/SEQ	Transmission limitations between SWQ and SEQ lines, currently considered as Tarong limitation	High export from SWQ to SEQ	Uprating of Mt England to South Pine 275 kV line or increase generation in CQ or NQ zone	Neutral
CQ	Transmission limitations on Calvale–Wurdong 275 kV line	High import from SWQ and reduced generation in CQ	Uprating of Calvale–Wurdong 275 kV circuit or install a second Calvale–Wurdong 275 kV circuit.	Neutral
CQ	Transmission limitations on Bouldercombe–Raglan–Larcom Creek–Calliope River 275 kV circuits	Reduced generation at Gladstone and Yarwun power stations	Raglan–Larcom Creek–Calliope River 275 kV circuits	Neutral

3.3.4 South Australia

Reliability limitations

No reliability limitations were identified in South Australia.

Economic limitations

Most economic limitations are in the Northern South Australia (NSA) zone, and relate to projected high levels of wind and solar generation. The potential economic limitations in South Australia that may arise and some possible solutions, assuming new generation development follows the least cost generation expansion plan, are summarised in the table below.

The level of potential congestions in the NSA zone and the feasible solutions depend on the penetration level and the concentration of wind and solar generation within the zone.

For example, connection of about 500 MW to 600 MW of new wind generation on any of the 275 kV lines between Davenport to Robertstown or Davenport to Para would require significant augmentation of the main 275 kV network in the NSA zone. These augmentations could include network reconfigurations at Belalie substation, Tungkillio substation, and rebuilding the existing Davenport – Brinkworth – Para 275 kV lines into double circuit lines.

⁶⁰ Transient stability constraint equations are Q:N_NIL_AR_2L-G Out=Nil, limit Qld to NSW on QNI to avoid transient instability for a 2L-G fault at Armidale, and Q:N_NIL_BI_POT Out=Nil, limit Qld to NSW on QNI to avoid transient instability on trip of a Boyne Island potline.

⁶¹ See Powerlink PSCR for further details: https://www.powerlink.com.au/Network/Network_Planning_and_Development/QNI_upgrade_study.aspx. Viewed 11 October 2016.

Table 8 Projected economic limitations in South Australia

Zone	Potential transmission limitations	Dispatch scenario	Possible solution	Scenarios
NSA	Transmission limitations on NSA-ADE 275 kV corridor	High levels of wind/solar generation in the NSA zone	Uprating the 275 kV lines between Davenport and Robertstown.	Neutral all
NSA	Transmission limitations on the 132 kV network in the Mid North region	High levels of wind/solar generation in the NSA zone	Uprating the relevant 132 kV lines in Mid North region and implement dynamic ratings.	Neutral all, Low Grid Demand Base case
NSA	Transmission limitations on the 132 kV network in the Riverland region	High levels of wind/solar generation in the NSA zone and high Murraylink export to VIC	New interconnector to SA. Install reactive support in the Riverland region to increase the transfer capacity of existing 132 kV network.	Neutral all, Low Grid Demand Base case
NSA	Transmission limitations on the 132 kV network in the Eyre Peninsula	High levels of wind/solar generation in Eyre Peninsula region of the NSA zone	Rebuild the 132 kV lines on the Eyre Peninsula as double circuit lines	Neutral all, Low Grid Demand all
SESA	Transmission limitations on the Tungkillo-Tailem Bend-South East transmission corridor	High levels of wind/solar generation in the NSA and ADE zone	Install the 2nd 275 kV circuit between Tailem Bend and Tungkillo. New interconnector to SA.	Neutral, Low Grid Demand Base case

3.3.5 Tasmania

Reliability limitations

No reliability limitations were identified in Tasmania.

Economic limitations

Economic dispatch limitations are caused by limitations on transmission line thermal capability and power system stability limits. Thermal limitations are projected during periods of high wind power generation and high export from Tasmania to Victoria. Power system stability limits may occur at times of high import from Victoria to Tasmania, high wind power generation in Tasmania and lack of hydro units online.

The economic dispatch limitations in the following table have been identified for the Neutral and Low Grid Demand scenarios.

Table 9 Projected economic limitations in Tasmania

Potential transmission limitations	Dispatch conditions	Possible solutions	Scenarios
Transmission limitations on the Palmerston – Sheffield 220kV line.	High wind generation in the North West Tasmania area. High import from VIC to TAS through second Bass Strait interconnector	Reduce wind and/or hydro generation from North West and West; Reduce import to Tasmania via second interconnector Uprating of existing Sheffield-Palmerston 220 kV circuit for a higher thermal rating, or a second Sheffield-Palmerston 220 kV circuit.	Neutral
Transmission limitations on the Georgetown – Sheffield 220kV line.	High wind generation from the North West and West Tasmania area and, high Basslink export from TAS to VIC.	Reduce wind and/or hydro generation from North West and West; Reduce Basslink export from TAS to VIC. Uprating of existing Georgetown – Sheffield 220 kV circuits for a higher thermal rating, or a third Georgetown-Sheffield 220 kV circuit.	All Neutral except 2BSI .
Voltage collapse at Georgetown	High export from TAS to VIC at times of no GPG units in Tamar Valley and reduced number of hydro units in northern	Reduce export from TAS to VIC; Constrain on generation in Tamar Valley and hydro units in northern Tasmania;	Neutral. Low Grid Demand



Potential transmission limitations	Dispatch conditions	Possible solutions	Scenarios
	Tasmania (current issue to continue to future)	Installation of additional reactive support at Georgetown substation.	
Transient over-voltage at Georgetown 220 kV	High export from TAS to VIC via Basslink at times of no GPG units in Tamar Valley and reduced number of hydro units in northern Tasmania (current issue to continue to future)	Reduce export from TAS to VIC; Constrain on generation in Tamer Valley and hydro units in northern Tasmania; Installation of additional dynamic reactive support at Georgetown substation.	Neutral. Low Grid Demand
Basslink inverter commutation instability due to low fault level at George Town 220 kV.	High import from Victoria to Tasmania via Basslink and low or no GPG units online in Tamar Valley and low or no hydro units in northern Tasmania (current constraint to continue).	Constrain on generation in Tamer Valley and hydro units in northern Tasmania; Operate existing GPG and hydro units as synchronous condensers. Installation of new synchronous condensers. Generation re-dispatch or constrain Basslink import into Tasmania.	Neutral Low Grid Demand
High rate of change of frequency (RoCoF)	High wind generation in Tasmania and/or increased import from Victoria to Tasmania and reduced Tasmania hydro units on line	Constrain on GPG and hydro units in Tasmania. Operate existing GPG and hydro units as synchronous condensers. Inertia support services from wind generation Non network solutions to provide fast frequency services.	Neutral
High rate of change of frequency (RoCoF)	Unavailability of existing frequency control ancillary support (FCAS) services with retirement of smelters in Tasmania.	Reduce Basslink import from Victoria to Tasmania.	Low Grid Demand all

3.3.6 Victoria

Reliability limitations

No reliability limitations were identified in Victoria.

Potential reliability limitations

There is the potential for an additional reliability limitation to appear in Victoria after 2030, when the bulk of brown coal generation retirement occurs.

New GPG in Victoria (up to 3,000 MW in the Neutral scenario) is located to take advantage of the spare network capacity made available by the coal retirement, avoiding the need to augment the network in other areas. This is a cost-effective location for connecting new GPG, as additional generation can be delivered to the load centres using the spare capacity of the existing transmission network. If this was not possible, and the potential reliability limitation eventuated, an alternative outlook could include:

- Building additional generation, outside the Latrobe Valley area, and augmenting the Victorian transmission network.
- Utility-scale energy storage batteries located in the Latrobe Valley to make use of existing transmission infrastructure.
- Maintaining the existing supply of coal generation, with additional carbon abatement measures to ensure it Australia’s COP21 commitment is met.

A combination of two or more of these options is likely to be the most cost-effective alternative. In depth analysis of the potential has not be undertaken at this stage, and likely the subject of future work.

Victorian Renewable Energy Target limitations

There are a large number network limitations which may result in generation being constrained off or curtailed. This depends heavily on the location of generation being built, as there is a balance between



the network capability and wind quality. The consequence of curtailment is that more installed renewable generation is required in order to meet the VRET.

The table below shows specific limitations identified during periods of high PV and wind farm output.

Table 10 Projected economic limitations relating to the VRET

Observed limitation	Network needs	Possible project/transmission development	Comments	Cost Estimate (\$M)
Ballarat – Waubra – Ararat – Horsham 220 kV lines	Reduce generation curtailment and meet VRET target	Double circuit lines Ballarat – Waubra – Ararat – Horsham 220 kV lines, replacing the existing single circuit lines	This development may be required if the total amount of new wind/solar generation to be connected to this line exceeds 800 MW. This development should be treated as indicative only. It is only one of the possible development options, and a cost-benefit assessment will be required to decide whether it is economically feasible.	\$163
Redcliffs – Weman – Kerang 220 kV lines	Reduce generation curtailment and meet VRET target	Double circuit lines Redcliffs – Weman – Kerang 220 kV lines, replacing the existing single circuit lines	This development may be required if the total amount of new wind/solar generation to be connected to this line exceeds 200 MW. This development should be treated as indicative only, is only one of the possible development options, and also a cost-benefit assessment will be required to decide whether it is economically feasible.	\$195
Ballarat – Terang – Moorabool 220 kV lines	Reduce generation curtailment and meet VRET target	Double circuit lines Ballarat – Terang – Moorabool 220 kV lines, replacing the existing single circuit lines	This development may be required if the total amount of new wind/solar generation to be connected to this line or Terang Terminal Station exceeds 500 MW. This development should be treated as indicative only, is only one of the possible development options, and a cost-benefit assessment will be required to decide whether it is economically feasible.	\$214
Deliver generation from Kerang / Horsham / Ballarat to load centres	Reduce generation curtailment and meet VRET target, and avoid load curtailment when support from neighbouring states is insufficient. Also accommodate HorshamLink (if required).	Double circuit 500 kV line from Kerang – Horsham – Ballarat – Moorabool	This development may be required if the total amount of wind/solar generation to be connected to the NWV zone (including new connection to the distribution network) exceeds 1500 MW. This development should be treated as indicative only, is only one of the possible development options, and a cost-benefit assessment will be required to decide whether it is economically feasible.	\$1587

Economic limitations

Many of Victoria’s projected economic limitations overlap with the VRET limitations described above.



Table 11 Projected economic limitations in Victoria

Zone	Potential transmission limitations	Dispatch conditions	Possible Solutions	Scenarios
NVIC	Transmission limitation on South Morang 500/330kV transformer	High export from Vic to NSW	2nd South Morang 500/330 kV transformer	All
NVIC	Transmission limitations on Dederang-South Morang 330 kV circuits	High transfer between VIC to NSW (export or import)	Up rate the existing DDTs – SMTS 330 kV line, or a third line	All
NVIC	Transmission limitations on Eildon-Thomastown 220 kV line	High import from NSW	Up rate the existing EPS – TTS 220 kV line, or replace it with a double circuit line	All
NVIC	Transmission limitations on Dederang - Mt. Beauty 220kV lines	High export to NSW	A new 500 kV line from KGTS – HOTS – BATS – MLTS	All
NWV	Transmission limitations on North West Victoria 220 kV network	High wind and solar generation (well over local demand) in the North West Victoria area.	Replace the existing single circuit RCTS – WETS – KGTS 220 kV lines with double circuit lines.	All
NWV	Transmission limitation on Red Cliffs - Wemen - Kerang 220 kV line	High wind and solar generation connected to North West Victoria, particularly the solar generation connected to the network around Red Cliffs, Wemen and Kerang.	Replace the existing single circuit BATS – WBTS – HOTS 220 kV lines with double circuit lines.	All
NWV	Transmission limitations on Ballarat-Horsham 220kV line	High wind generation connected between Ballarat and Horsham and/or between Horsham and Redcliffs	Replace the existing single circuit BATS – TGTS – MLTS 220 kV lines with double circuit lines.	All
SWV	Transmission limitations on Ballarat - Terang - Moorabool lines	High wind generation connected between Ballarat, Terang and Moorabool, and/or to Terang Terminal Station	Up rate the existing GTS – MLTS 220 kV line, or a new single circuit line from GTS – MLTS	All
SWV	Transmission limitations on Moorabool - Geelong lines	High wind generation connected between Ballarat, Terang and Moorabool, and/or to Terang or Moorabool Terminal Stations. This limitation is unlikely to cause any material market impacts before limitations in the NWV and SWV areas are relieved.	A new (third) GTS – KTS 220kV line	Neutral
MEL	Transmission limitations on Geelong - Keilor lines	High wind/solar generation connected to NWV and SWV zones.	Up rate the existing KTS – TTS 220 kV lines with high temperature conductors	Neutral
MEL	Transmission limitation on Keilor - Thomastown line	High wind/solar generation connected to NWV and SWV zones. This limitation is unlikely to cause any material market impacts before limitations in the NWV and SWV areas are relieved.	Up rate the existing TTS – RWTS 220 kV lines with high temperature conductors	Neutral
MEL	Transmission limitation on Thomastown - Ringwood line	High wind/solar generation connected to NWV and SWV zones. This limitation is unlikely to cause any material market impacts before limitations in the NWV and SWV areas are relieved.	Up rate the existing CBTS – TBTS 220 kV line, or a third line	Neutral

3.4 Changes to utilisation of flow paths

This section presents projections for the utilisation of major transmission flow paths across the NEM. A common driver of utilisation changes is the retirement of coal generation. Consequently, these trends depend heavily on the timing of these retirements, and the location and size of subsequent new generation required.⁶²

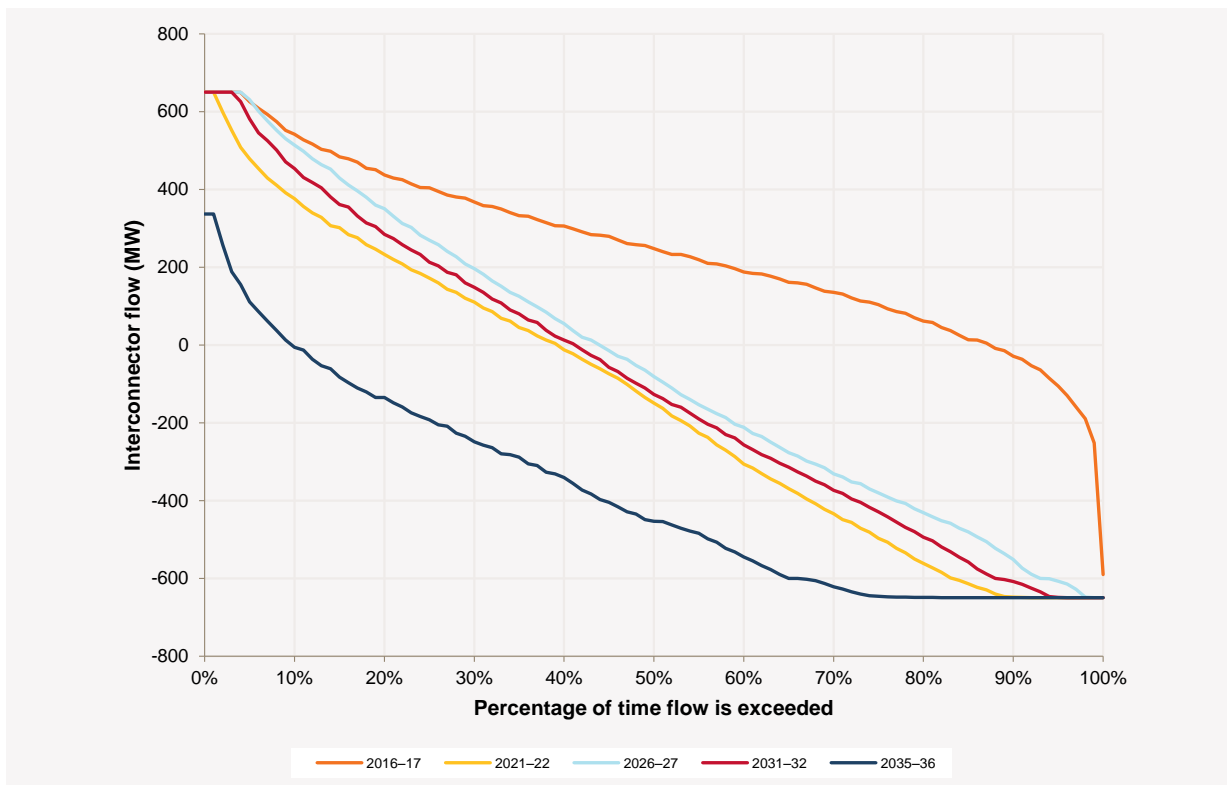
This section only presents data on the Neutral Scenario, and does not include the potential new interconnector projects for South Australia or Tasmania. For data and charts on Neutral and Low NTNDP scenarios, please see AEMO’s interactive map.⁶³

All interconnector flows are calculated based on hourly market simulation based on Nash-Cournot equilibrium modelling, and unit commitment as described in the *Market Modelling Methodology and Input Assumptions*.⁶⁴

3.4.1 Changes to interconnector flow (Neutral scenario)

Victoria – South Australia

Figure 11 Projected utilisation of the Victoria to South Australia interconnector (Heywood)



Interconnector flow for the VIC–SA interconnector is projected to change significantly from 2016–17 as renewable generation increases in both South Australia and Victoria, reducing the need for South Australia to import from Victoria. Another feature is the existing 3 Hz per second RoCoF constraint⁶⁵, which has the effect of reducing interconnector flows between Victoria and South Australia. As major

⁶² This analysis was performed prior to the announcement of the Hazelwood power station retiring in early 2017. In this analysis Hazelwood power station is fully retired by 2022.

⁶³ AEMO. *Interactive maps and dashboards*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards>.

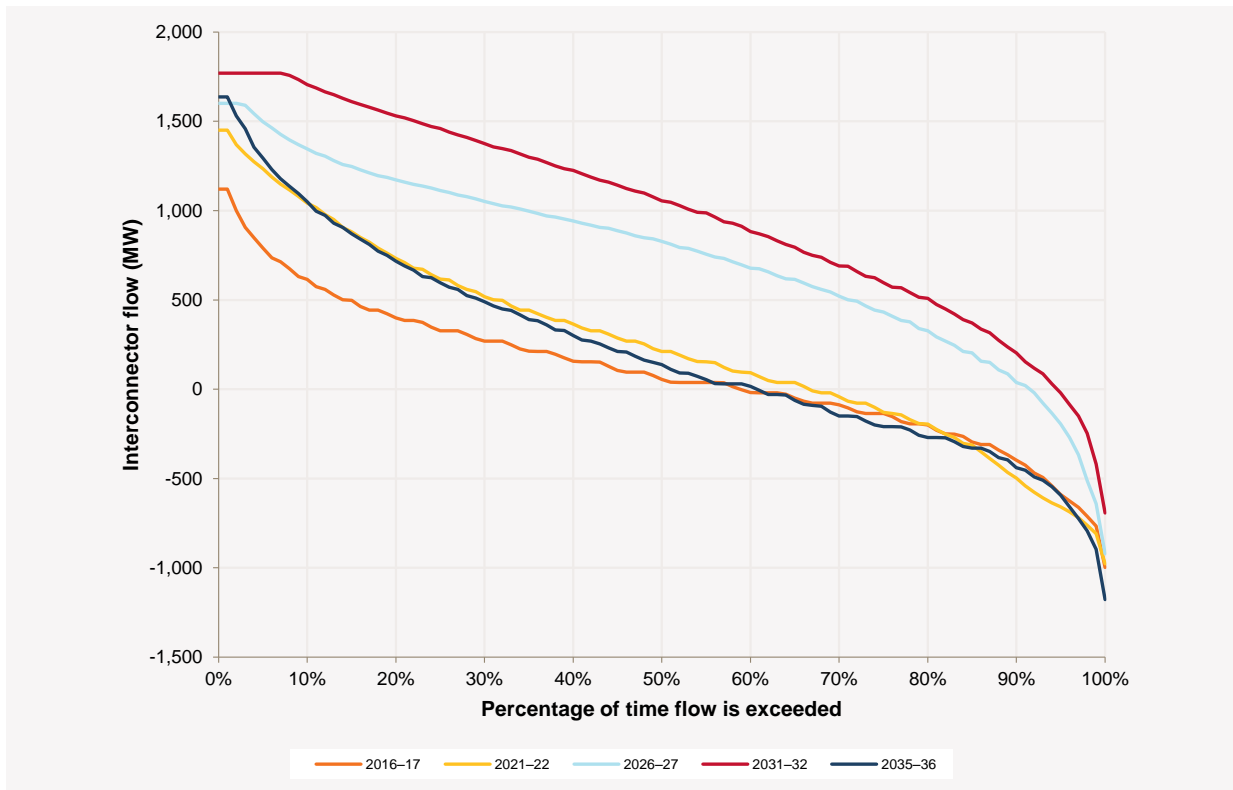
⁶⁴ AEMO, 2016. *Market Modelling Methodology and Input Assumptions*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.

⁶⁵ AEMO Electricity Market Notice 55358, 12 October 2016. Available: <https://www.aemo.com.au/Market-Notices>.

black and brown coal-fired generation retires in Victoria and New South Wales, interconnector flows from Victoria to South Australia are also expected to decrease.

Victoria – New South Wales

Figure 12 Projected utilisation of the Victoria to New South Wales interconnector



The VIC–NSW interconnector is initially projected to increase flow north to New South Wales as a consequence of increasing renewable generation in Victoria under the VRET, and black coal generation retirements in New South Wales (Liddell’s retirement has been announced for 2022–23).

By 2035–36, this trend is projected to be largely reversed and the flow from Victoria reduced, as significant black and brown coal-fired generation is expected to retire in both New South Wales (total of 8.8 GW by 2036) and Victoria (total of 4.8 GW by 2036)⁶⁶, and 9.9 GW of additional renewable generation is projected to be built in New South Wales by 2036. An increase in capacity is observed after 2026–27 following the projected augmentation of the VIC-NSW interconnector.

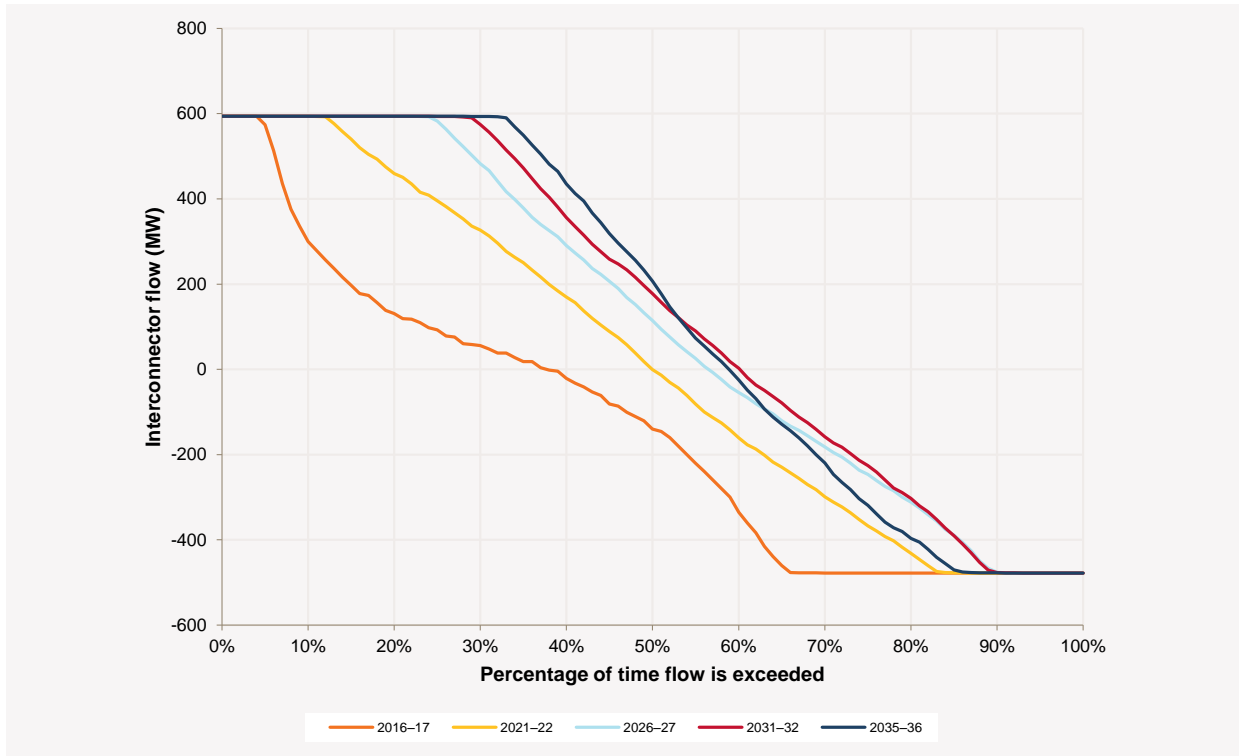
Tasmania–Victoria

The TAS–VIC interconnector is projected to experience an increase in flows in both direction (north and south), often to the interconnector’s limit.

Northward flow is mainly due to forecast increases of renewable energy in Tasmania and coal retirements on the mainland.

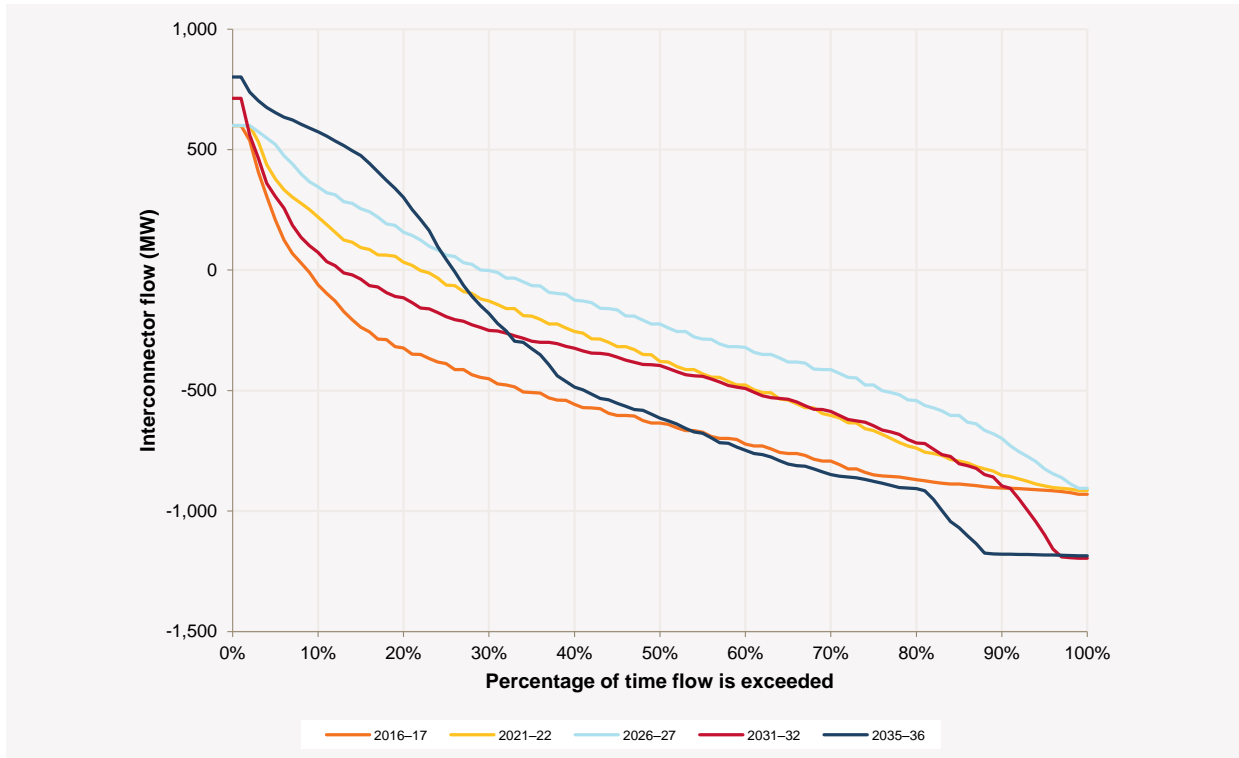
⁶⁶ This analysis was performed prior to the announcement of the Hazelwood power station retiring in early 2017. In this analysis Hazelwood power station is fully retired by 2022.

Figure 13 Projected utilisation of the Tasmania to Victoria interconnector



New South Wales – Queensland

Figure 14 Projected utilisation of the New South Wales to Queensland interconnector





Until 2031, NSW–QLD interconnector utilisation is projected to remain fairly constant, with flows tending to be slightly more southerly to support New South Wales. With black coal retirement, these southerly flows become more frequent as Queensland supports New South Wales. In 2035–36, AEMO projects an increase in the utilisation of the NSW–QLD interconnector in flows both north and south. This is attributable to the 9.9 GW of projected new renewable generation in New South Wales, combined with an upgrade to the interconnector capacity in 2028–29.

3.4.2 Regional utilisation trends (Neutral scenario)

This section describes the trends for major regional flow paths, and their potential drivers. Data and graphs are available on AEMO's interactive map.⁶⁷ In general AEMO projects utilisation to fluctuate depending on generation retirement and new generation installations. Utilisation in metropolitan areas is largely steady over the outlook period, as generation changes occur outside these areas.

For details on the methodology, please see Chapter 5 of the 2016 *NTNDP Methodology and Input Assumptions*.⁶⁸

New South Wales

A slight increase in average utilisation is forecast across the main New South Wales transmission network. This is due to coal retirements in northern New South Wales, and large growth in renewable generation which connects to the 330 kV network supply regional load centres and forms interconnection to other states. Specifically:

- Average utilisation in northern New South Wales fluctuates depending on the generation mix.
 - It remains steady between 2017 and 2022 due to limited generation projects in the north.
 - Average utilisation increases in 2027 due to the retirement of black coal generation causing more imports from Queensland.
 - Average utilisation then decreases in 2032 with more renewable projects being built in northern and western New South Wales. However, the peak utilisation increases and has a potential to overload 330 kV lines between Liddell and Tamworth as black coal retires and more reliance is placed on the surrounding network to supply load during peak times
- There is potential for overloading on the 132 kV parallel system between southern and western New South Wales (Yass – Wellington), due to a large number of generation projects connecting at Yass, Wellington, and Wallerawang.

Queensland

For the NTNDP outlook, the Queensland network utilisation generally decreases slightly. This can be attributed to forecasts for declining average demand, retirement of major generation centres, and a steady uptake of new generation evenly distributed across the state.

An exception to this general trend is that the average utilisation of flow paths connecting to metropolitan areas remains constant, but the utilisation becomes more 'peaky' with higher maximums and lower minimums. This reflects the load growth patterns in Queensland identified in the 2016 NEFR, and this area of the network's independence from changes to generation.

South Australia

The primary driver of utilisation trends in South Australia is 1,500 MW of additional wind generation (by 2022) and about 1,000 MW solar generation (by 2036) expected in the northern part of South Australia.

⁶⁷ AEMO. *Interactive maps and dashboards*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards>.

⁶⁸ AEMO, 2016. *2016 NTNDP Methodology and Input Assumptions*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.



This results in:

- A noticeable increase in the average utilisation of the 275 kV network between northern South Australia and Adelaide from 2022. The utilisation then remains largely unchanged until new solar generation appears toward end of the outlook period, which results in further increase in the utilisation.
- Moderate increase in the average utilisation of the southern South Australia to Adelaide transmission corridor, as the increase in the utilisation in the SA export direction is largely offset by the decrease in the utilisation in the SA import direction, due to new generation expected in South Australia as well as the continued decline of demand in South Australia.

Tasmania

The Tasmanian load forecast is relatively flat, however the dispatch of hydro and wind generation and the Basslink Interconnector are expected to affect 220 kV line loadings. With forecast higher transfers between Tasmania and Victoria in both directions, power flows on the Palmerston–Sheffield and Sheffield–Georgetown 220 kV transmission lines are projected to increase.

Victoria

Utilisation in Victoria is projected to change following the introduction of renewable generation to meet the VRET, and the subsequent retirements of brown coal in the Latrobe Valley. Specifically:

- A large decrease in peak and average utilisation is projected on the 500 kV system between Melbourne and the Latrobe Valley, due to the closure of Hazelwood.
- There is a decrease in average and minimum utilisation across the Moorabool transformers. This is largely due to around 2,000 MW of wind and solar expected in North West Victoria, and reduction along the 500 kV system due to the Hazelwood closure.
- Utilisation on the South Morang – Dederang 300 kV line is expected to increase, as more export to New South Wales is required.

3.5 Consideration of TNSP Annual Planning Reports

NEM TNSPs publish Annual Planning Reports to provide information on their committed projects, current and emerging networks issues, and proposed solutions. All committed and proposed projects reported by TNSPs are accounted for in the NTNDP and summarised in the 2016 NTNDP database.⁶⁹ The 2016 NTNDP assessment of transmission network adequacy does not include these matters, which are addressed by the TNSPs in their planning process:

- Transmission augmentations that may be required if future generation development follows an alternate path to those indicated in the generation outlook.
- Transmission augmentations based on TNSPs applying different planning criteria, such as additional security beyond N-1 planning criteria⁷⁰, that are not committed.
- Transmission network development not directly related to national flow paths. For example, local transmission augmentations driven by local demand growth, or the appearance of new or contracted loads, are not considered.
- The need to replace transmission assets approaching or exceeding their intended technical lifetime.

⁶⁹ AEMO, 2016. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.

⁷⁰ "N-1" planning criteria means there must not be any loss of load following an outage of a single element (line or transformer) during periods of high customer demand unless specifically agreed with the affected distribution network owner or directly connected end-use customer.

CHAPTER 4. EMERGING CHALLENGES AND OPPORTUNITIES

Key insights

- As frequency control is sourced system wide, sufficient inertia is projected to be available over the next 20 years to maintain a reliable and secure supply, as long as the NEM transmission grid remains interconnected following disturbances.
 - High RoCoF is currently a challenge for non-credible contingencies that separate South Australia from the rest of the NEM. This might also emerge as a challenge for Queensland if coal generation is replaced primarily with inverter-connected generation.
 - Growth in the need for regulation FCAS, and a reduction in the number of providers, could lead to a shortfall when areas are at risk of separation, unless inverter-connected generation is designed to provide frequency regulation response.
- System strength is projected to decline across the NEM, particularly in areas of high inverter-connected generation, such as North West Victoria and the northern parts of South Australia.
 - One method to counter this trend is to ensure local dynamic voltage support is installed at new generation sites, costing \$5 to \$10 million for a 150 MW inverter-connected generator.
 - In the absence of this support, or technological improvements, inverter-connected generation may become unstable and place system security at risk.
- Some technical solutions have the potential to simultaneously address a range of emerging challenges. AEMO discusses specific case studies in Chapters 5 and 6, where solutions are combined and evaluated.

The transforming generation mix is changing the operational characteristics of the power system, as:

- Synchronous generation is progressively being displaced by inverter-connected generation.
- Consumers are becoming more active about how their electricity demand is met and managed, resulting in increasing amounts of DER, such as rooftop PV.

This chapter summarises how these transformations are impacting the power system, and what challenges and opportunities exist. It specifically outlines:

- What is meant by “system security”, and how different disturbances affect power system security.
- Some important metrics of a power system’s resilience, including frequency control, system strength, and the ability to dispatch generation.
- How these challenges are changing over time, the potential solutions, and a high-level cost estimate of the more straightforward solutions.

Linkages with other programs of work

The selection of topics considered in this chapter has been informed by AEMO’s Future Power System Security (FPSS) program⁷¹, which applied a stakeholder consultation approach to identify the highest priority challenges and is linking with the Australian Energy Market Commission (AEMC) System Security Market Frameworks Review.⁷²

⁷¹ More information on the FPSS is available at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSS-Reports-and-Analysis>.

⁷² AEMC. *System Security Markets Frameworks Review*. Available: <http://aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

The 2016 NTNDP extends that analysis by quantifying, mostly for the Neutral scenario, how each challenge may develop over the next 20 years.

4.1 What is system security, and how is it affected by system disturbances?

Maintaining power system security:

- Requires the safe scheduling, operation, and control of the power system on a continuous basis within power system standards and applicable technical limitations of the system, in accordance with the principles set out in clause 4.2.6 of the NER.
- Involves processes designed to minimise the risk of commonly occurring events on the power system (such as the disturbances described below) triggering a cascade of failures resulting in major loss of supply.

4.1.1 What is a power system disturbance?

A disturbance occurs when the power system unexpectedly has a change in supply, demand, connectivity, or voltage. These disturbances can be external, such as a line tripping due to lightning, or internal, such as plant failure causing generation tripping.

Power systems are designed and operated to be able to withstand certain disturbances or events without further adverse effects. It would be unrealistic, and too costly, to design a power system to withstand any disturbance or series of disturbances.

Disturbances that are considered reasonably possible in prevailing conditions are called credible contingencies, while low probability events are referred to as non-credible. Following any contingency event (credible or otherwise), AEMO must take all reasonable actions to adjust the operating conditions to return the power system to a secure operating state as soon as practical, within 30 minutes at most.

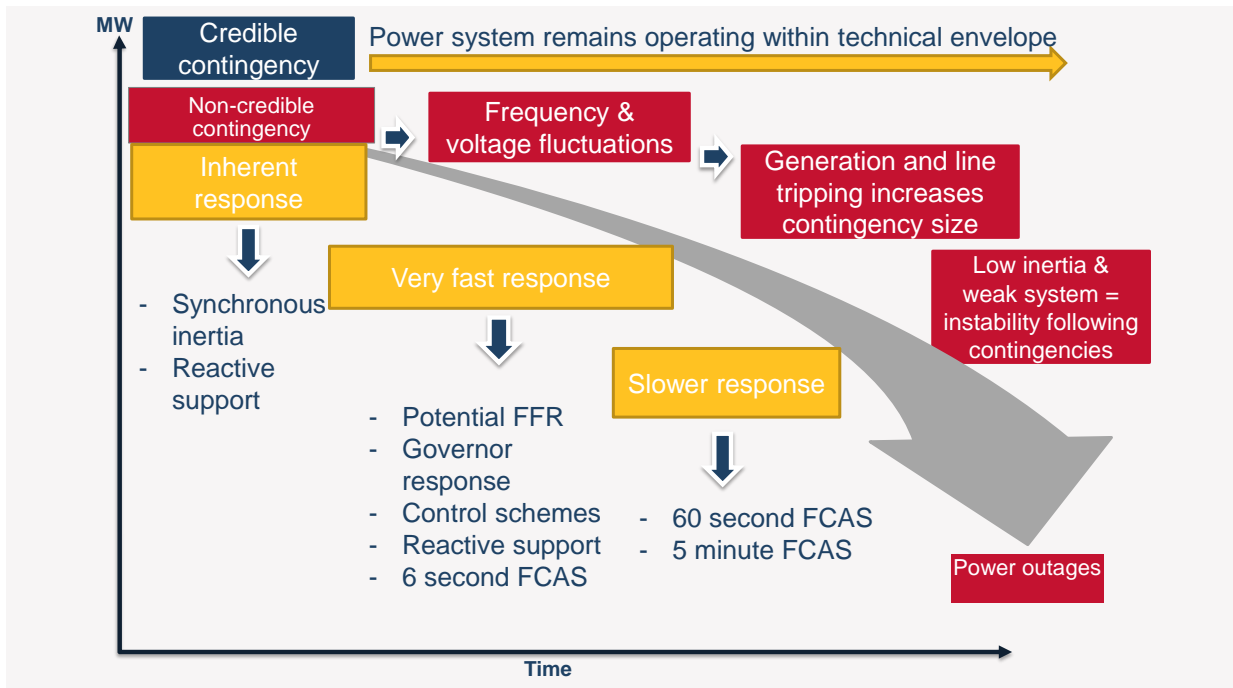
If the disturbance impacts the supply-demand balance, there must a mechanism to bring the system back within applicable tolerance limits almost instantaneously, or the imbalance will increase towards a tipping point.

If a contingency event is non-credible and sufficiently large, further disturbances may occur and it may not be possible to return the power system to a secure operating state.

4.1.2 How the power system responds to a disturbance

A power system's response to a disturbance can be broadly broken down into three stages, as shown in the figure below. For a power system to end in a satisfactory state, the power system must 'survive' each stage.

Figure 15 The potential impact of contingency events on the power system



Inherent response

This response starts from the instant of the disturbance, before any control system can operate, and can continue into the two other stages of response. The inherent response is determined by the characteristics of the power system, such as inertia, system strength, and network impedances. These characteristics are discussed in the sections below.

It is possible to minimise the size of the disturbance, and the likelihood of future cascading disturbances, by constraining generation to ensure the characteristics of the power system have enough operating margin (headroom) to withstand or minimise the initial disturbance.

Very fast response (detect and respond)

Various control systems detect and respond to events to bring supply and demand back into balance. Very fast response is not immediate, but can occur very quickly (typically in the order of hundreds of milliseconds). Examples include:

- Increasing or decreasing supply by changing generation output, currently through the governor responses of synchronous generation, but potentially in the future by fast frequency response (FFR) services (discussed further in Section 4.2.2).
- Decreasing load by disconnecting it automatically (load shedding scheme).
- Decreasing generation by disconnecting it automatically (generation tripping scheme).
- Disconnecting equipment or separating the network to stop it cascading into the rest of the power system.

Slower response

The slower response typically involves market mechanisms to assign generators or loads to autonomously respond to a range of potential contingency events.

Contingency Frequency Control Ancillary Services (FCAS) markets respond within 6 seconds, 60 seconds, and 5 minutes of a contingency⁷³, with each response playing a role in returning the power system to a secure operating state. These markets are dependent on sufficient controllable generation being online to meet FCAS requirements (discussed below).

4.2 Frequency stability

Frequency is important to the security of the power system. It is a measure of the instantaneous balance between supply and demand – if supply exceeds demand, frequency will increase, and vice versa. The NEM operates at a nominal frequency of 50 hertz (Hz). The Frequency Operating Standards are set by the Reliability Panel, and prescribe allowable frequency deviations for different types of events.⁷⁴

To maintain system frequency, AEMO enables FCAS that are provided by generation or load to correct imbalances when they occur.

There are two main types of FCAS:

- Regulation FCAS is used to correct minor imbalances in electricity supply and demand within 5-minute dispatch intervals.
- Contingency FCAS is used to correct a sudden, unexpected loss of generation or load.

“Lower” FCAS are used to correct an excess of generation, while “raise” services are used to correct an excess of demand.

4.2.1 Inertia and Rate of Change of Frequency (RoCoF)

When a contingency results in a supply demand imbalance, system frequency will begin to deviate from 50 Hz. The initial RoCoF will depend on both:

- The size of the contingency (scale of load or generation lost).
- The amount of synchronous inertia operating in the power system at the time.

Synchronous inertia is an inherent property of synchronous generation (examples of which include coal, gas, hydro, biomass, geothermal, and solar thermal generation). Inverter-connected generation (such as wind and PV generation) does not currently contribute significant synchronous inertia.

As inverter-connected generation displaces synchronous generation, the inertia in the system reduces, meaning the system experiences higher RoCoF after a contingency event.

High RoCoF levels make it increasingly difficult to manage frequency disturbances, because the FCAS acting to correct the imbalance must operate more rapidly to arrest the frequency change. If the RoCoF level is unacceptably high, it can result in a cascading trip of load or generation. For very large, rare events that produce very high RoCoF, emergency frequency control systems (such as under frequency load shedding (UFLS) schemes) may not be fast enough to prevent widespread supply disruption.

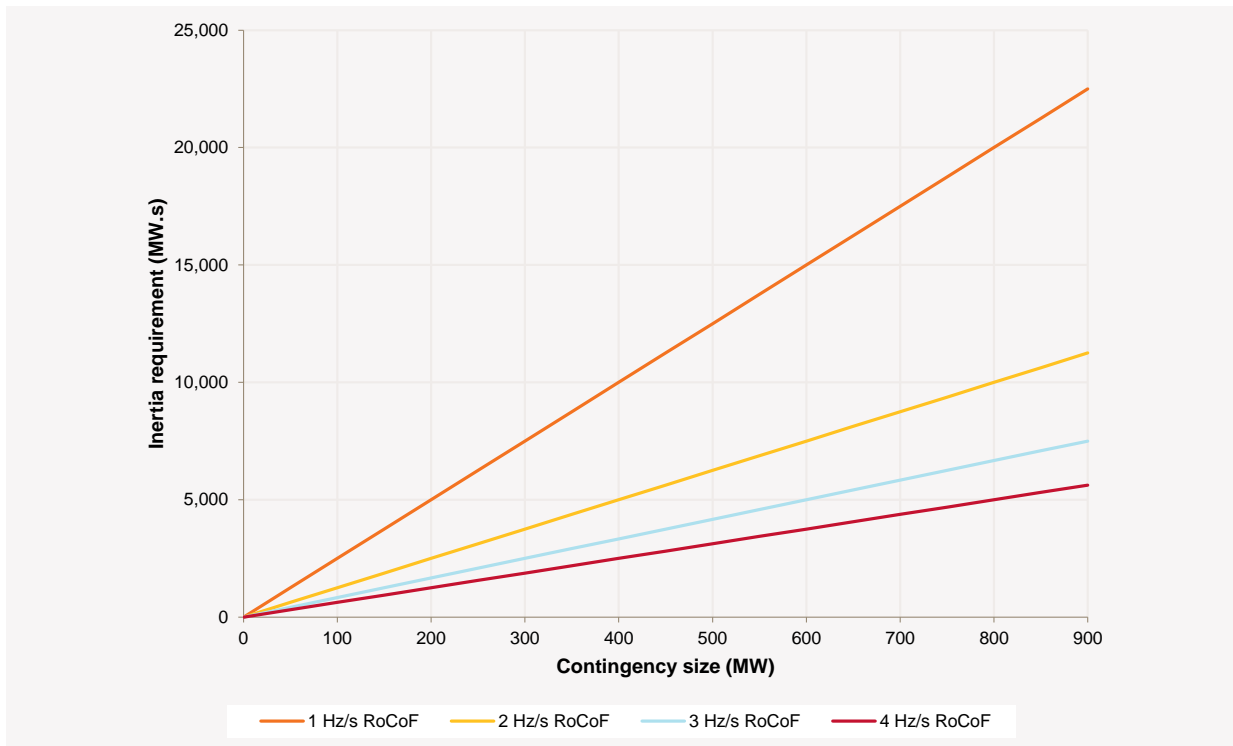
Generator performance standards relating to response to frequency disturbances are described in the NER (S5.2.5.3). Since 2007, the standards have required generating units to remain online for a RoCoF of 1 Hz per second (Hz/s) for 1 second as a minimum, and up to 4 Hz/s for 0.25 seconds to meet the standard for automatic connection.

The figure below shows the amount of inertia required to limit instantaneous RoCoF for different contingency sizes.

⁷³ AEMO, 2015. *Guide to ancillary services in the National Electricity Market*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services>.

⁷⁴ AEMC, 2009. *Frequency Operating Standards (Mainland)*. Available at: [http://www.aemc.gov.au/Australias-Energy-Market/Market-Legislation/Electricity-Guidelines-and-Standards/Frequency-Operating-Standards-\(Mainland\)](http://www.aemc.gov.au/Australias-Energy-Market/Market-Legislation/Electricity-Guidelines-and-Standards/Frequency-Operating-Standards-(Mainland)).

Figure 16 Inertia requirement for RoCoF limits



AEMO is conducting an assessment of the secure technical envelope for RoCoF, through the FPSS program.⁷⁵ This work will inform the manner in which the power system must be operated in future, to increase the likelihood of the system returning to a secure state following non-credible contingency events.

Inertia is effectively sourced ‘NEM-wide’. This means that, in an AC interconnected system, all inertia from operating units contributes to slowing the RoCoF in any part of the network. However, if a region becomes separated from the rest of the NEM, it can only access inertia from local units operating in that region. A separation can occur as a result of a direct disconnection of the interconnector (perhaps due to failure of network components), or as a result of a large contingency event in a region causing the interconnector to exceed its limits, and subsequently disconnecting.

The analysis presented in the following sections illustrates the inertia levels and RoCoF exposure projected for the NEM (and regions of the NEM that have only one AC interconnector with other regions). All results presented are based on the Neutral scenario Base case with competitive bidding and unit commitment modelled to more accurately approximate generator dispatch.⁷⁶

NEM mainland – inertia and RoCoF to 2036

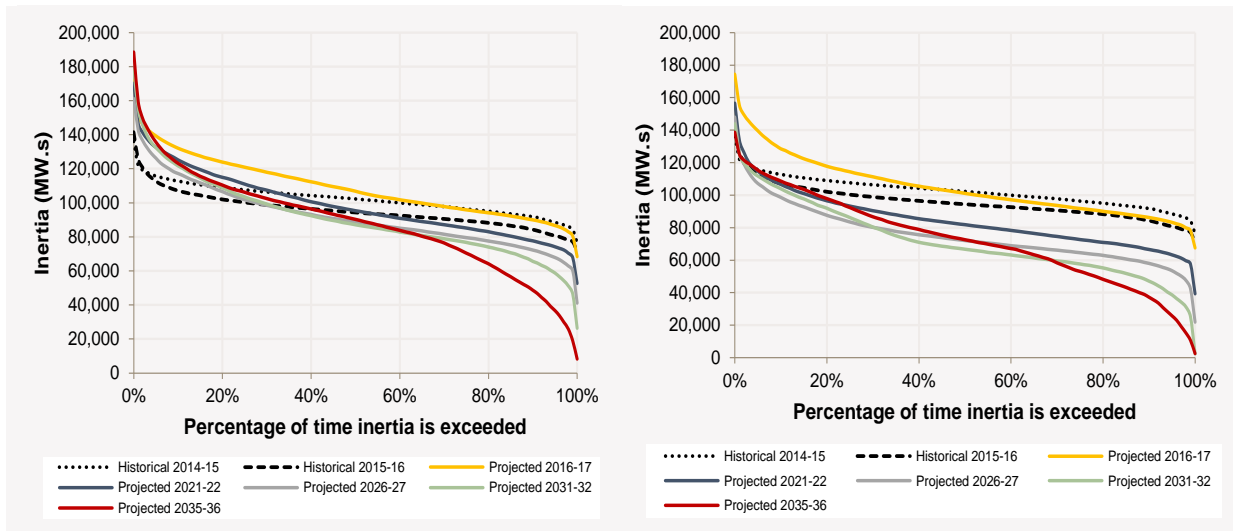
Inertia on the NEM mainland is projected to gradually reduce over the outlook period, as illustrated in the following figure.

Tasmania is excluded from this analysis, since it is connected via a DC link which does not transfer inertia. Inertia on the mainland is projected to reach a minimum of less than 10,000 megawatt seconds (MWs) by 2035–36 in the Neutral scenario Base case, and around 2,500 MWs by 2031–32 in the Low Grid Demand scenario, unless a higher minimum is ensured through a new mechanism.

⁷⁵ <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

⁷⁶ Unit commitment was based on economic dispatch. No regional minimum inertia limits were applied in this modelling.

Figure 17 Mainland NEM inertia excluding Tasmania, Neutral (left) and Low Grid Demand (right)



AEMO uses contingency FCAS to reduce the risk of load shedding following credible contingencies. However, AEMO has limited powers to manage the consequences of non-credible contingencies. To date, non-credible events have largely been managed via UFLS, which is an “emergency” mechanism that initiates involuntary load shedding to prevent complete system collapse. As RoCoF levels escalate (due to decreasing system inertia), a point will be reached where UFLS cannot operate successfully to prevent system collapse.

Therefore, it is important to project the future RoCoF exposure for a range of non-credible events that are plausible (although rare), to provide a basis for determining when these mechanisms may no longer be sufficient or appropriate.

Figure 18 illustrates the RoCoF exposure on the mainland NEM (excluding Tasmania), calculated based on the simultaneous loss of the two largest units at a single station.

This event is classified as “non-credible” in the NER, since it involves the loss of multiple units. This means AEMO has limited powers to manage the consequences of this event.

For this contingency event, RoCoF on the mainland NEM is shown to remain well below 1 Hz/s until 2035–36. This suggests that managing this type of contingency event (loss of two largest units at a single station) is unlikely to cause RoCoF challenges on the NEM mainland in the near future.

Figure 18 Mainland NEM RoCoF for loss of the two largest units at a single station (non-credible and plausible)

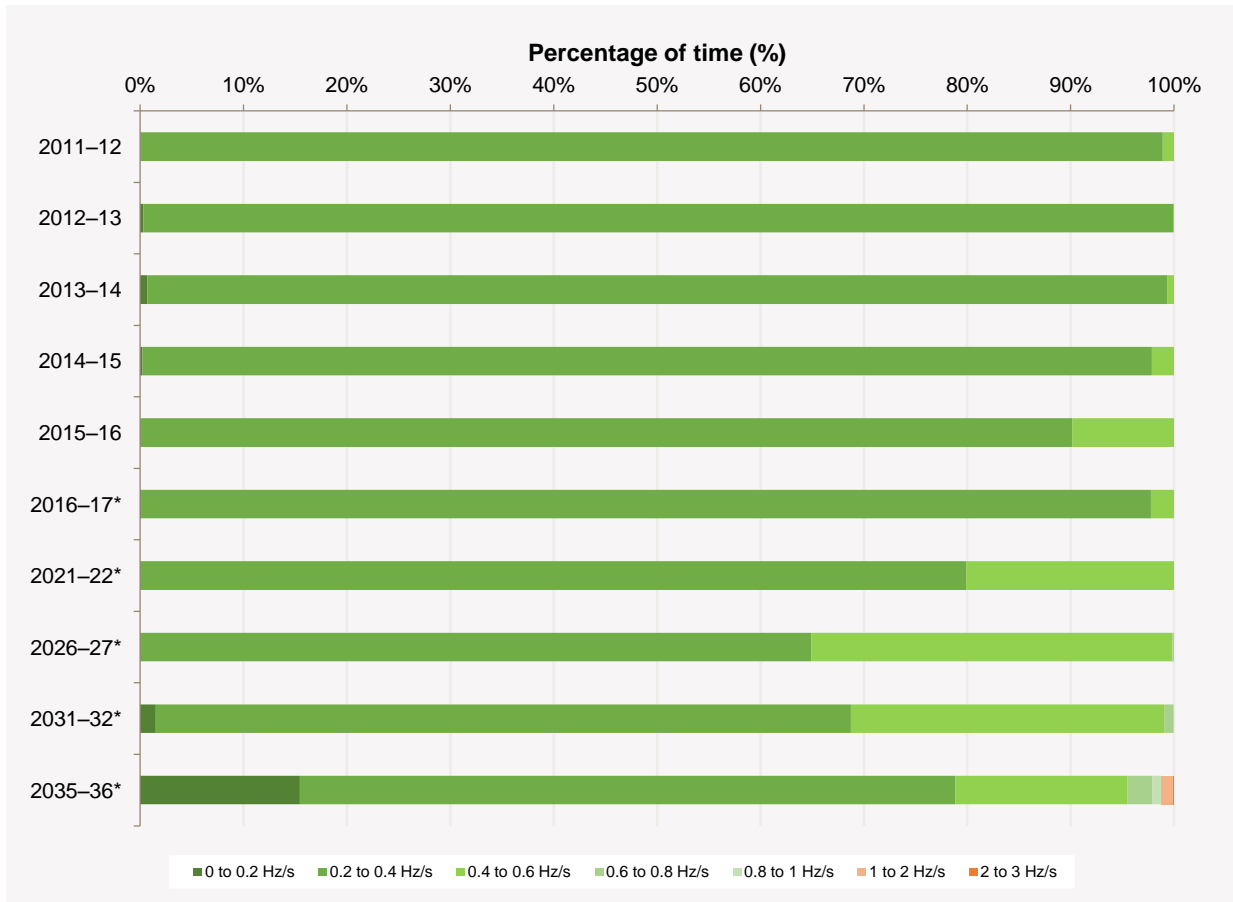


Figure 19 shows the RoCoF exposure calculated for a more extreme non-credible event – the loss of a whole power *station* (simultaneous loss of all units) – based on the operating level of the largest power station online on the mainland NEM in each hour.

This is also defined as non-credible in the NER (since it involves simultaneous loss of multiple generating units).⁷⁷ This could be considered a very extreme event.

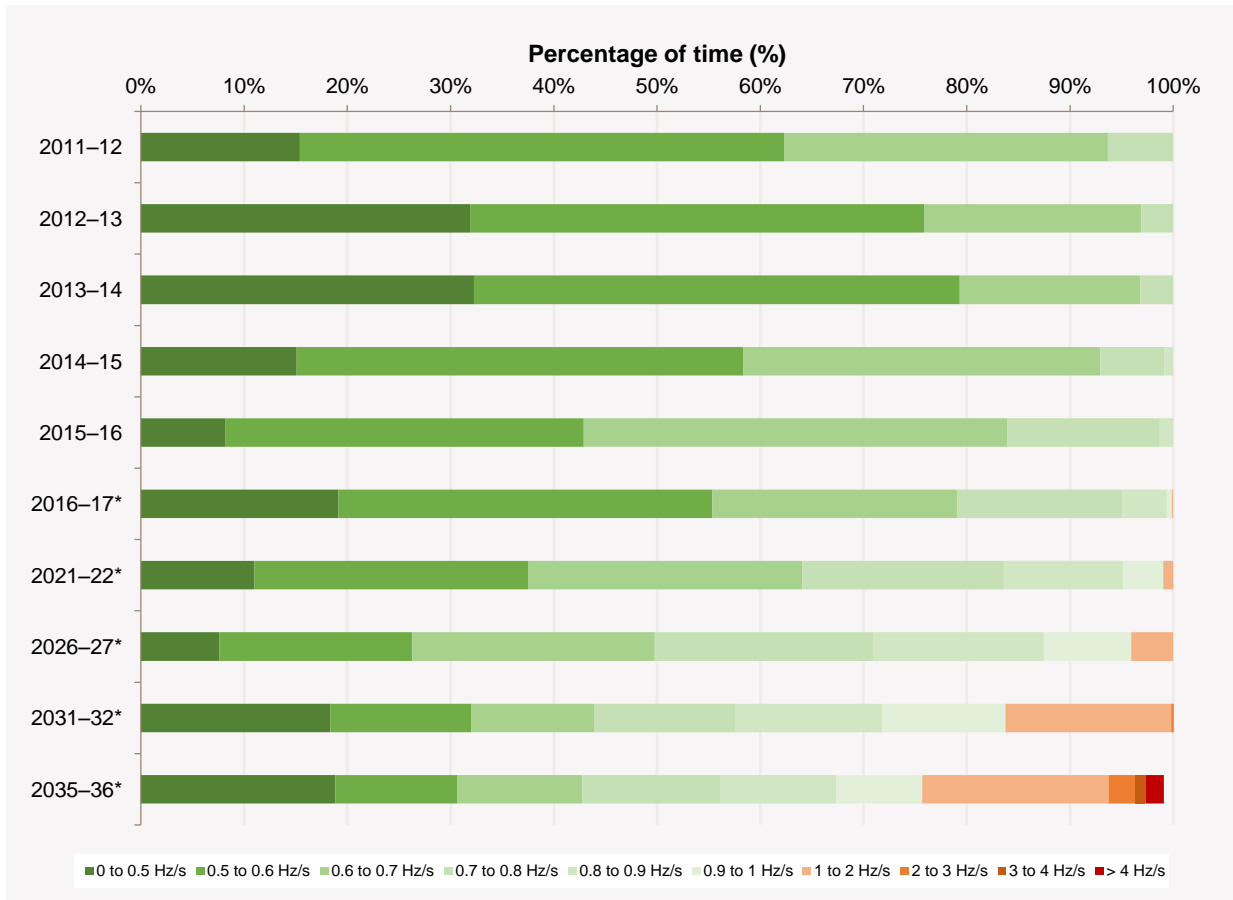
The figure shows that, even for this extreme contingency event, RoCoF would have remained below 1 Hz/s in recent years.

Some increase is projected in future, with RoCoF exceeding 1 Hz/s almost 5% of the time by 2026–27, and more than 20% of the time by 2035–36. RoCoF exposure is projected to exceed 3 Hz/s around 3% of the time in 2035–36.

At this level, UFLS is unlikely to operate successfully to prevent system collapse, in the event of a (rare) non-credible contingency. Importantly, however, a contingency event of this magnitude is considered extremely unlikely.

⁷⁷ The separation of South Australia or Queensland was also considered as a possible non-credible event, which would involve loss of the inertia operating in that region, as well as the contingency size associated with the flows on the relevant interconnector. However, this was found to be generally associated with a much slower RoCoF than the loss of a whole station (which can be of the order of 2GW, far exceeding the flow limits on QNI and Heywood), and therefore was not used as a basis for this assessment.

Figure 19 Mainland NEM RoCoF for loss of the largest power station (non-credible and extreme)



South Australia – inertia and RoCoF to 2036

In South Australia, the main challenge relating to high RoCoF is associated with the loss of the AC Heywood Interconnector—which could occur as a consequence of multiple contingencies in Victoria or South Australia.

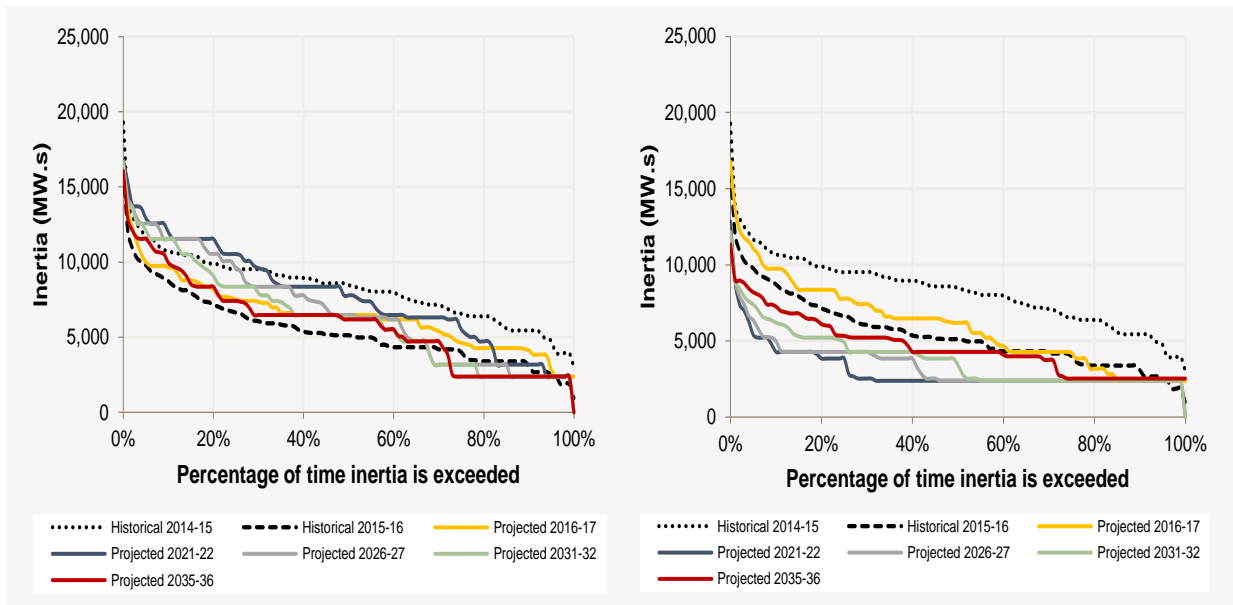
If the interconnector fails, South Australia becomes separated from the rest of the NEM, and no longer has access to the synchronous inertia in other regions. This means South Australia’s RoCoF exposure upon separation will be dependent upon the local inertia in South Australia. The flows on the interconnector can be large (in comparison with the amount of synchronous inertia in South Australia), potentially causing a large contingency event with high RoCoF.

The evolution of inertia in South Australia is illustrated in Figure 20. This analysis did not consider AEMO’s recently determined requirement for at least two large generating units to remain online in South Australia.⁷⁸ Inertia levels reduced between 2014–15 and 2015–16 due to the retirement of Northern Power Station. Inertia levels in South Australia on 13 November 2016 were observed at less than 1,000 MWs (associated with only one synchronous unit operating).

Minimal change in the distribution of inertia levels in South Australia is projected in the Neutral scenario (with no retirement of synchronous generation modelled in South Australia). If synchronous units do retire, or if market participants elect to operate these units differently in future, these levels could reduce, as shown in the Low Grid Demand scenario.

⁷⁸ AEMO. *Secure Operation of South Australia*. Available at: http://www.aemo.com.au/-/media/Files/Media_Centre/2016/SA-System-Strength.pdf.

Figure 20 South Australia inertia, Neutral (left) and Low Grid Demand (right)



The potential RoCoF exposure in South Australia is discussed further in Chapter 5.

Tasmania – inertia and RoCoF to 2036

In Tasmania, the loss of the Basslink Interconnector is considered credible at all times (since it is a single line). It is managed with a special protection scheme, which very rapidly trips load when loss of the interconnector is detected. Also, a range of hydro units in Tasmania have the ability to operate as synchronous condensers, providing inertia and other system services, without generating energy. As credible contingencies are relatively large compared to the system, constraint equations are also used to manage RoCoF for credible contingencies in Tasmania.

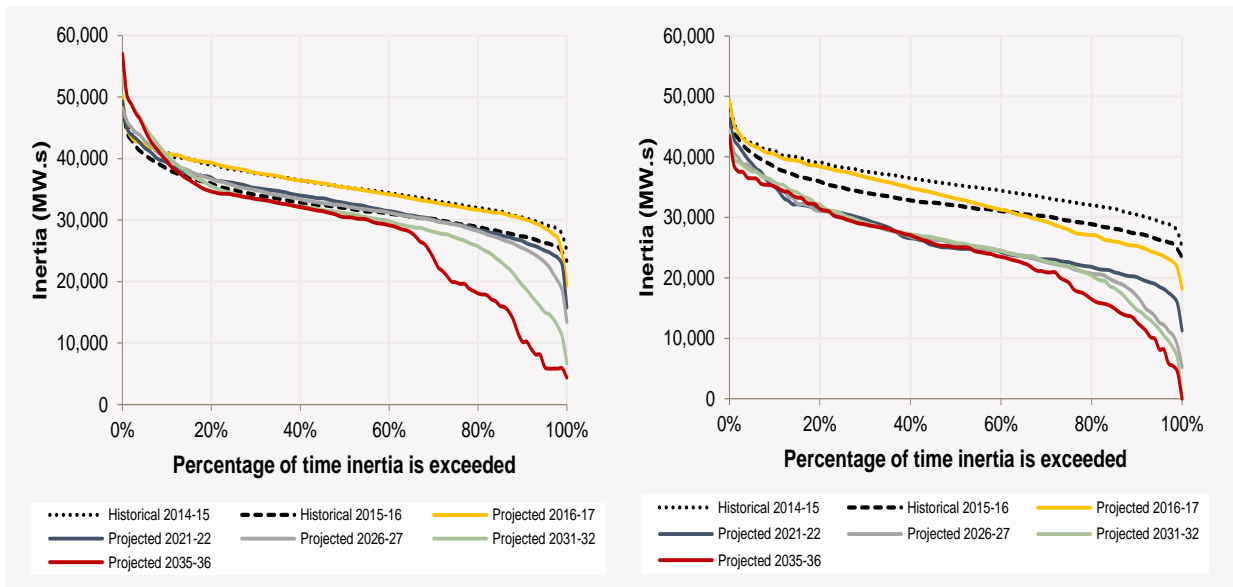
This means that RoCoF in Tasmania can be managed by a number of mechanisms, meaning there is less need for AEMO to intervene to maintain system security. Frequency control in Tasmania is discussed further in Chapter 6.

Queensland – inertia and RoCoF to 2036

In Queensland, the main challenge relating to high RoCoF is associated with the non-credible loss of the double circuit AC QNI interconnector. If the interconnector fails, Queensland becomes separated from the rest of the NEM, and no longer has access to the synchronous inertia in other regions. This means Queensland's RoCoF exposure upon separation will be dependent upon the local inertia in Queensland.

Projected inertia levels in Queensland for the Neutral scenario are illustrated below, assuming that no limitation is placed on Queensland unit commitment. Minimal change is projected until 2031–32, when the incidence of much lower levels of inertia is projected to occur in some periods.

Figure 21 Queensland inertia, Neutral (left) and Low Grid Demand (right)



The size of the contingency event, upon separation from the NEM, will be dependent upon the flows on the QNI interconnector. When there is a credible risk of separation (for example, due to one of the lines being out of service), contingency FCAS services are enabled in Queensland to protect against the loss of the interconnector. This is co-optimised, trading off the cost of procuring local FCAS against the cost of limiting interconnector flows.

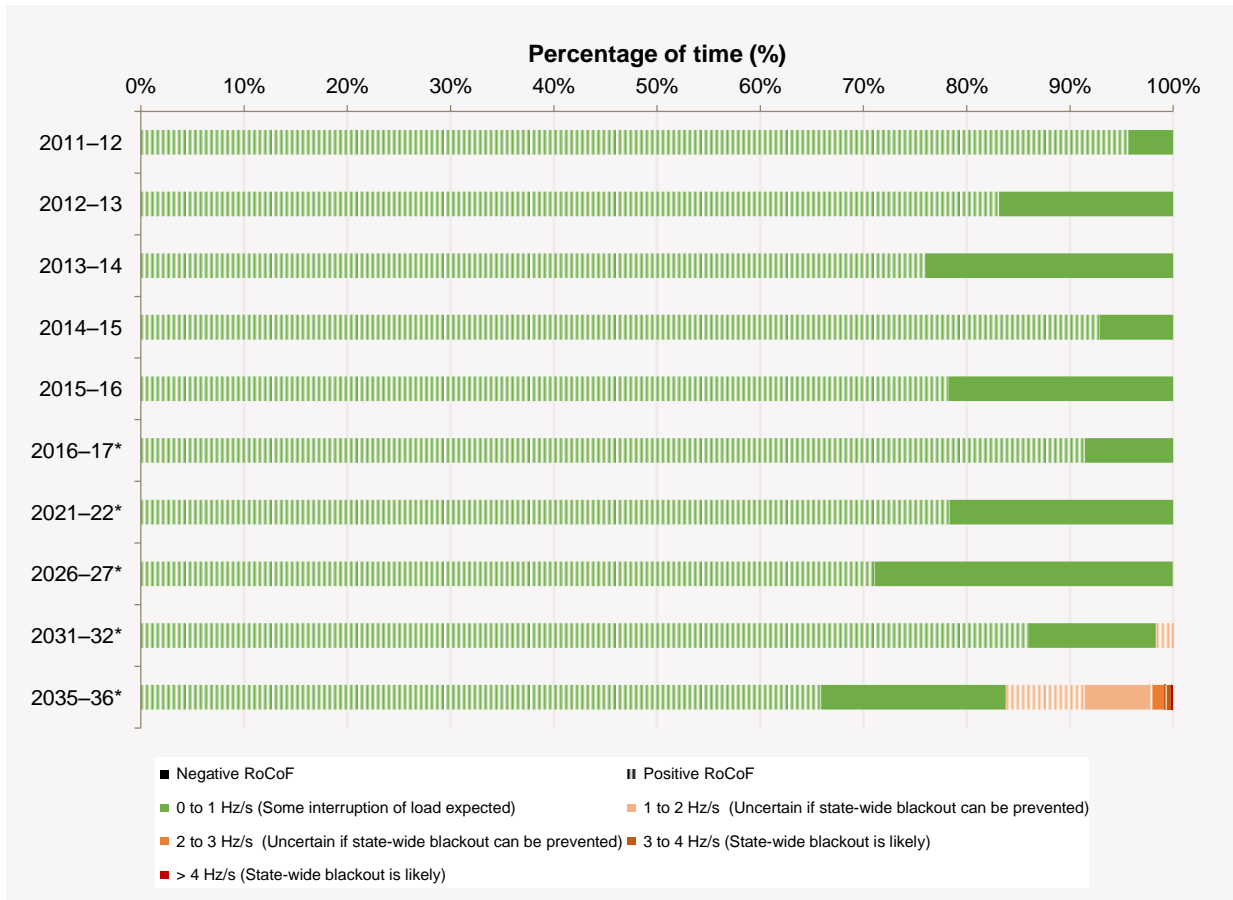
This means flows on QNI are typically significantly reduced during periods of credible separation, limiting the potential contingency size (and potential RoCoF).

AEMO has limited powers to proactively manage the likelihood and consequences of a non-credible separation event. In this case, flows on QNI are not influenced by the need to enable local contingency FCAS, and can be significantly higher.

The future RoCoF exposure for non-credible loss of the QNI interconnector was calculated as illustrated below for the Neutral scenario.

This incorporates periods of positive RoCoF (rising frequency), which is related to periods with flows on QNI exporting out of Queensland. Periods of negative RoCoF (falling frequency) are related to periods with flows on QNI importing into Queensland.

Figure 22 Queensland RoCoF for non-credible loss of QNI interconnector



The figure above shows that RoCoF in Queensland associated with non-credible loss of QNI remains slower than 1 Hz/s for the majority of the outlook period. By 2035–36, RoCoF exceeds ± 3 Hz/s (the level where UFLS is unlikely to operate successfully) around 1% of the time, and exceeds ± 1 Hz/s (the level where it is uncertain if state-wide blackout can be prevented) more than 15% of the time.

This analysis suggests that Queensland may eventually be vulnerable to a state-wide blackout, upon the non-credible loss of QNI. However, this is not projected until late in the outlook period (associated with significant retirement of coal-fired plant). Options for potential solutions to this challenge are outlined in the following section.

4.2.2 Possible solutions to mitigate high RoCoF

This section identifies a range of possible solutions to mitigate high RoCoF. These have been classified as short-term solutions or long-term solutions.

Short-term solutions

These options could mitigate high RoCoF in the immediate future, but may be less efficient than longer-term solutions after two to three years.

Reduce interconnector flows

Present concerns relating to high RoCoF in the NEM are primarily associated with a specific potential event – the loss of a major interconnector, causing separation of a region. The interconnector loss can



isolate a part of the network which may have very low levels of synchronous inertia at the time, and can represent a comparatively large contingency event (depending on the flows on the interconnector).

Reducing the flows on the interconnector can minimise the size of the possible contingency event.

In South Australia, the flows on the Heywood Interconnector are reduced when the loss of the interconnector is considered credible (for example, when one of the two lines is out for maintenance). The relevant constraint equation calculates the total amount of synchronous inertia online in South Australia, and reduces the flows on Heywood to maintain the possible RoCoF below ± 1 Hz/s.

When loss of the Heywood Interconnector is considered non-credible, flows are reduced to prevent RoCoF exceeding ± 3 Hz/s.

Similarly, in Tasmania, constraint equations are used to protect against high RoCoF. These constraint equations limit both generation and interconnector flow to manage RoCoF for loss of the largest generator in Tasmania.

Operate existing synchronous generation more frequently

RoCoF is directly reduced by operating a larger quantity of synchronous generation. The amount of synchronous generation that needs to be operating at any particular time to adequately mitigate RoCoF will depend on:

- The size of the largest contingency (which could be determined by the flows on the interconnector).
- The RoCoF withstand capabilities of the system at the time (which may depend on the RoCoF withstand capabilities of the individual units operating at the time).

Operating synchronous generation more frequently would displace the operation of inverter-connected generation (wind and PV), possibly leading to energy spilling in some periods.

The AEMC is considering possible frameworks for implementing this solution in the System Security Market Frameworks Review.⁷⁹

Longer-term solutions

In the longer term, a wider range of solutions could be considered, some of which could be incentivised via the introduction of a mechanism to procure inertia services. Potential solutions to high RoCoF are being considered by the AEMC in the System Security Market Frameworks Review⁸⁰, including:

- New interconnectors.
- Special protection schemes.
- High inertia synchronous condensers.
- Retrofitting retiring synchronous units as synchronous condensers.
- Installing new synchronous generation.
- Installing new synchronous generation that can operate as synchronous condensers.

New interconnectors

A new AC interconnector would alleviate high RoCoF concerns, because it would make the islanding of that region less likely (noting that the system would need to be designed and operated such that the loss of one interconnector did not lead directly to overloading and loss of the second interconnector).

This means the region is much more likely to remain connected to the rest of the network, and therefore retain access to the synchronous inertia in the rest of the network.

⁷⁹ AEMC. *System Security Market Frameworks Review*. Available: <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

⁸⁰ <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

Special protection schemes

A special protection scheme is a mechanism designed to act very rapidly to counteract a contingency event. Typically, a large industrial load or generator close to the interconnector would agree to be tripped when the failure of the interconnector was detected, correcting the power imbalance.

Because the event of interest (the failure of the interconnector) is detected directly (rather than via the resulting change in frequency), the response can be very rapid and more robust on very short timescales. The flows on the interconnector are constantly monitored to calculate the amount of load to be tripped, and “pre-arm” the response, to avoid control logic latencies and allow for very rapid and accurate response.

A special protection scheme has been successfully used for many years to manage the loss of the Basslink Interconnector to Tasmania. A similar scheme could be developed for South Australia, to protect against the loss of the Heywood Interconnector.

The design and implementation of this scheme is complex, and would need to be carefully tailored to ensure it would capture all possible failure pathways, and would not be vulnerable to false triggering. This would be expected to take several years, to ensure a robust and reliable response.

A similar scheme could be developed for Queensland if it becomes vulnerable to high RoCoF.

High inertia synchronous condensers

Synchronous condensers are a type of network element that contribute synchronous inertia, as well as other services (such as system strength). Some manufacturers are now offering synchronous condensers specifically designed to have higher inertia, targeted at addressing RoCoF challenges.

Synchronous condensers do not contribute active power, and therefore do not displace inverter-connected generation when they operate.

High inertia synchronous condensers are estimated to cost in the order of \$50 million for the addition of 1,000 MWs of inertia.

Retrofit synchronous generating units as synchronous condensers

In some cases, it may be possible to retrofit retiring synchronous generation to operate as a synchronous condenser. This would allow these assets to continue to provide valuable system services (including synchronous inertia).

The inertia provided by the unit is somewhat reduced during the conversion process, and the costs of the conversion would depend on the individual characteristics of each unit.

Install new synchronous generation

A range of potential new entrant generation types could contribute synchronous inertia, including solar thermal, gas turbines, hydro, biomass, and geothermal.

Install new synchronous generation that can operate as synchronous condensers

Some types of synchronous generation can incorporate a clutch, which allows them to transition as required between operating as a synchronous condenser (providing synchronous inertia and other system services, but no active power), and generating electricity (providing active power as well as synchronous inertia and other system services). This allows significant flexibility to contribute the services required, without displacing inverter-connected generation.



International review of frequency control adaptation

In October 2016, AEMO published a report by DGA Consulting which provided an international review of frequency control adaptation.⁸¹ The review found very few large power systems (500 MW or more) experiencing issues related to high RoCoF, with notable exceptions in Ireland and Great Britain where investigations into RoCoF are breaking new ground.

An emerging potential solution to high RoCoF may be FFR, or “synthetic inertia”. Inverter-connected technologies, such as wind and PV generation, flywheels, batteries, and some other types of energy storage, can provide a rapid active power injection to correct a supply demand imbalance following a contingency event. Rapid tripping of demand-side resources could have a similar effect. This can help to rapidly arrest the frequency decline, and provide time for conventional power system governors to act.

Preliminary analysis suggests that adding a sufficient quantity of appropriately delivered FFR can reduce the amount of synchronous inertia required to maintain frequency within the required levels.

The executive summary of the DGA Consulting report states that:

The international literature is clear that FFR alone is not sufficient. It is currently not possible to operate a large power system without any synchronous inertia, and synthetic inertia does not provide a direct replacement.

In future, it may be possible to manage a power system without any synchronous inertia, using inverter-connected devices to set and maintain frequency. Such a service would be different from FFR as it would involve constantly and instantaneously maintain frequency, rather than just responding to a contingency event. This suggests that any inertia procurement mechanism introduced in the NEM should be designed to transition over time as new technologies emerge.

If designed with the capability, inverter-connected devices are able to deliver a very fast response (in some cases as fast as 10–20ms). However, from a power system perspective there are likely to be complex challenges around the very fast measurement and identification of high RoCoF events, to ensure the response is sufficiently robust (avoiding false triggering) and properly controlled. Implementation of services of this nature in international markets is fledgling at present.

The potential for an FFR service in the NEM is being explored by AEMO through the FPSS program⁸², and by the AEMC through its System Security Market Frameworks Review.⁸³

4.2.3 Impact of increasing generation variability on frequency regulation

With continued growth in variable generation (such as wind and PV), the size and number of continuous minor supply demand imbalances is expected to grow. This means more regulation FCAS may be required in future to manage increasing system variability and uncertainty.

The market has historically attracted regulation and contingency FCAS from synchronous generation. If this synchronous generation is displaced from dispatch (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources, which the market has not attracted to date.

These two factors (growth in the need for regulation FCAS, and reduction in the number of providers of FCAS) could lead to a shortfall in regulation FCAS capability in future, creating a system security challenge. To quantify the nature and timing of this potential challenge, this section presents analysis estimating the future need for regulation FCAS services, based on the Neutral scenario.

⁸¹ DGA Consulting, 2016. International review of frequency control adaptation. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

⁸² <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

⁸³ <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

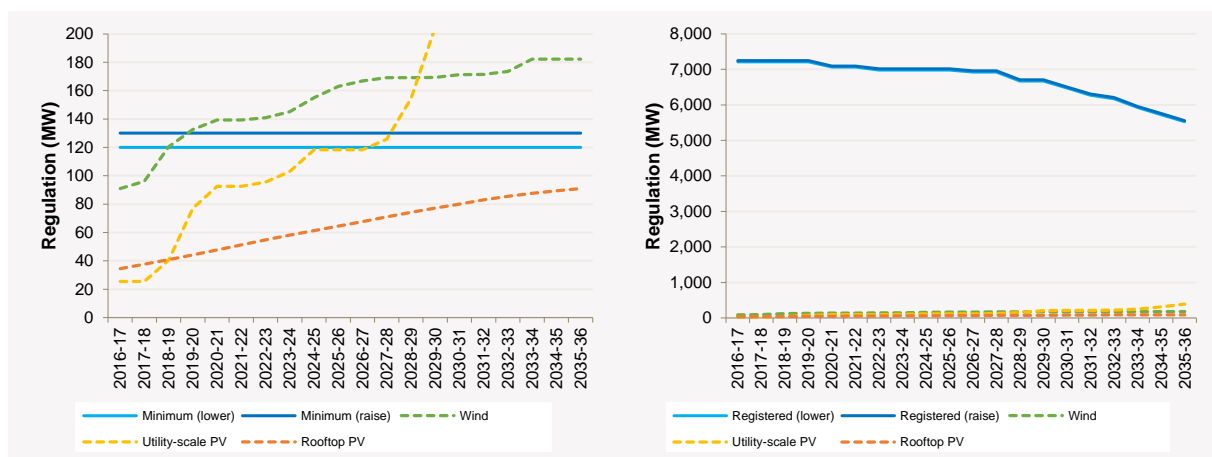
Projections of NEM-wide regulation FCAS requirements

The figure below (left) shows a projection of the total amount of regulation FCAS required in the NEM in the 20-year outlook period, highlighting estimated future regulation FCAS needs associated with the variability of utility-scale PV (orange), wind (yellow), and rooftop PV (red). These projected needs are compared with the minimum amount of regulation FCAS enabled in all periods at present, shown in blue (130 MW raise, and 120 MW lower).

It indicates that:

- The variability from wind remains below the minimum level of regulation FCAS enabled until about 2020. At around that time, approximately 7 GW to 8 GW of installed wind capacity is forecast, and the amount of regulation FCAS required to manage the variability from wind may exceed the minimum amount, and require more regulation FCAS to be enabled in some periods.
- For utility-scale PV, this point occurs around 2028 and is associated with about 2 GW of capacity.
- The short-timescale variability from rooftop PV is projected to be relatively small by comparison. Even in 2036, with more than 19 GW of rooftop PV installed, the amount of regulation FCAS required to manage variability from rooftop PV is forecast to remain below the current minimum enablement. This is due to the significant geographic diversity inherent in rooftop PV generation.

Figure 23 Estimate of future regulation FCAS needs for the NEM, compared with minimum regulation FCAS enablement (left) and registered supply of regulation FCAS (right)



The figure on the right shows the forecast total registered supply of regulation FCAS in the NEM, for comparison with the projected level of regulation FCAS required.

At present, the regulation FCAS capacity registered in the NEM is 7,245 MW (raise) and 7,213 MW (lower).⁸⁴ With modelled generation retirements, this is projected to reduce to approximately 5,500 MW of raise and lower regulation FCAS by 2036, if no new entrants register to provide regulation services. Modern wind and utility-scale PV plant have the capability to provide regulation FCAS services, but to date none have registered to do so in the NEM.

The figure shows that the quantity of registered supply for regulation FCAS across the NEM is projected to remain far in excess of forecast requirements. Even in the most extreme case, in 2036, with about 13 GW of utility-scale PV installed, the associated regulation FCAS requirement is estimated to be about 450 MW. This remains far below the registered capacity of providers of regulation FCAS in the NEM, even taking into account the reduction in supply from the retirements modelled. This suggests that shortfalls in regulation FCAS are unlikely, on a NEM-wide basis, over the 20-year outlook.

⁸⁴ At 22 September 2016.

Projections of regulation FCAS requirements – regions with a single interconnector

Three regions (South Australia, Queensland, and Tasmania) can separate individually from the rest of the NEM because they are only connected to one other region. When this occurs, local regulation FCAS providers must supply the necessary services. Therefore, it is important to consider the regulation FCAS requirements for each of these regions individually.

South Australia

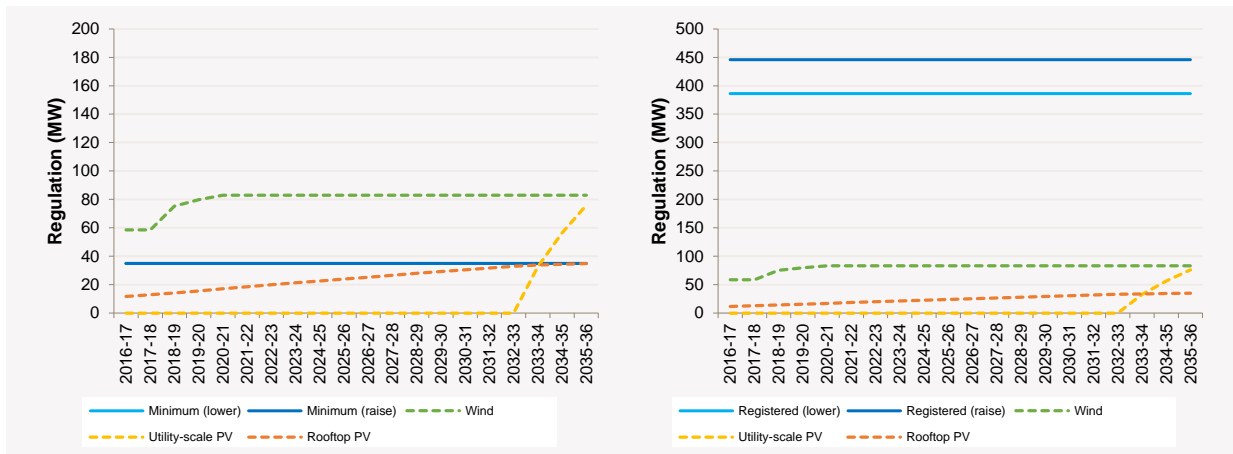
South Australia has a minimum regulation FCAS enablement of 35 MW, applied in periods when it is operating as an island, or has a credible risk of separation from the NEM (for example, when only one Heywood Interconnector line is in service). The historical incidence of a credible risk of separation in South Australia averaged about 7% to 8% of the time in the five years to 2015–16, as shown in the table below. Regulation FCAS must be provided locally at these times.

Table 12 Historical periods of credible separation for Heywood Interconnector

Calendar year	Credible separation (% of time)	Credible separation (Hours)
2011–12	11.37%	998.7
2012–13	11.96%	1047.7
2013–14	2.68%	235
2014–15	1.56%	136.7
2015–16	8.45%	742.3

The figure below shows the regulation FCAS projection for South Australia, highlighting the requirements associated with different sources of variable generation, and compares it to projected supply.

Figure 24 Estimate of future regulation FCAS needs for South Australia, compared with minimum regulation FCAS enablement (left) and registered supply of regulation FCAS (right)



This analysis indicates that wind generation is an increasing source of variability in South Australia. Any growth in wind generation in South Australia may cause a need for increasing the amount of regulation FCAS enabled, in periods where wind is contributing to increased variability. The Neutral scenario projects large-scale PV growth in South Australia from 2034, which also rapidly increases the regulation FCAS requirement beyond the minimum amount enabled at present.

South Australia currently has a total registered capacity of providers of regulation FCAS of 446 MW for raise, and 386 MW for lower.⁸⁵ There is no projected retirement of plant registered to provide FCAS in South Australia, and the registered supply of regulation FCAS remains above projected requirements, even with substantial forecast growth in wind and utility-scale PV.

However, the units registered to provide regulation FCAS services (Torrens Island, Pelican Point, and Quarantine) must be online and operating at a favourable set point to deliver these services. This indicates that system security needs for regulation FCAS may increasingly influence dispatch in South Australia, during periods of credible separation risk.

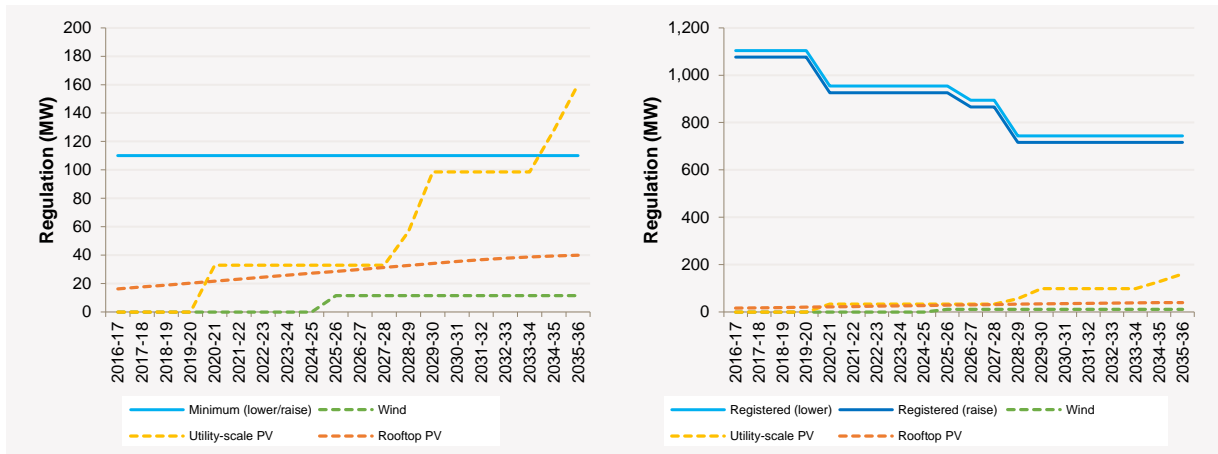
This represents a potential opportunity for new entrants to register to provide regulation FCAS, increasing the available supply in South Australia.

Queensland

Regulation FCAS is only enabled locally within Queensland when an actual separation event occurs, and Queensland must be managed as an island. In this case, Queensland has a minimum regulation FCAS enablement of 110 MW.

Figure 25 (left) shows future projected regulation FCAS needs in Queensland (when operating as an island), based on modelled growth in wind and PV. Utility-scale PV is projected to grow to more than 2 GW in Queensland by 2035, with an associated regulation FCAS requirement of approximately 130 MW. By 2036, with further growth in utility-scale PV to approximately 4 GW, the regulation requirement may reach approximately 200 MW. This suggests that the amount of regulation FCAS enabled in Queensland, when operating as an island, may need to increase from around 2035, in periods when utility-scale PV is operating.

Figure 25 Estimate of future regulation FCAS needs for Queensland, compared with minimum regulation FCAS enablement (left) and registered supply of regulation FCAS (right)



There is currently 1,076 MW (raise) and 1,104 MW (lower) of regulation FCAS capacity registered in Queensland.⁸⁶ The figure on the right above illustrates the impact of modelled retirements on the available capacity of registered regulation FCAS (assuming no new entrants).

Despite modelled retirements, the registered capacity of regulation FCAS is forecast to remain far above projected requirements, suggesting that a shortfall is unlikely in Queensland unless there is significant growth in utility-scale PV and this growth does not coincide with the registration of new entrants to provide regulation FCAS.

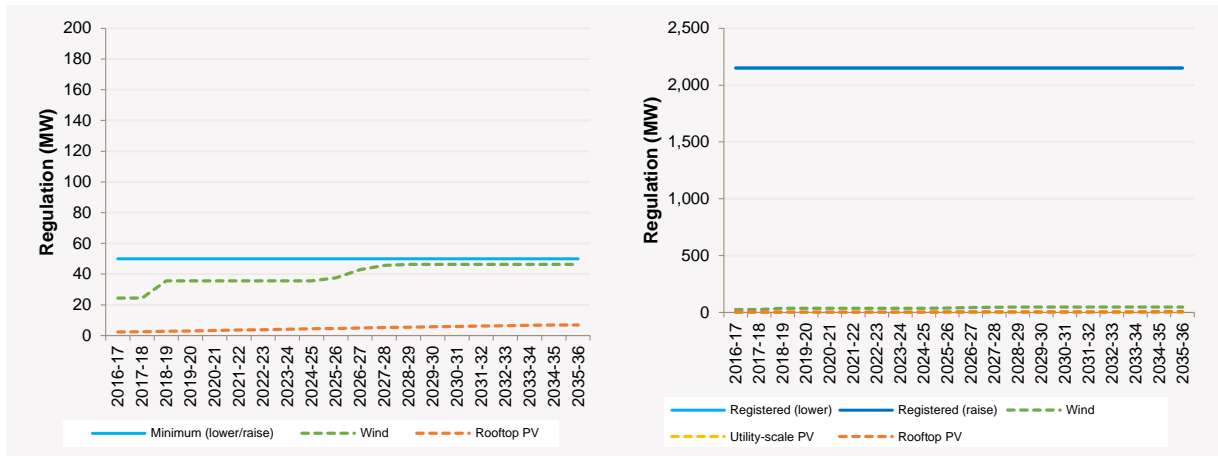
⁸⁵ At 22 September 2016.
⁸⁶ At 22 September 2016.

Tasmania

The figure below shows the projected regulation FCAS requirement in Tasmania for the Neutral scenario, highlighting requirements associated with wind and rooftop PV. This modelling does not project any installation of utility-scale PV in Tasmania.

The analysis indicates that projected growth in variable generation is unlikely to significantly influence the need for further regulation FCAS in Tasmania.

Figure 26 Estimate of future regulation FCAS needs for Tasmania, compared with minimum regulation FCAS enablement (left) and registered supply of regulation FCAS (right)



Possible technical solutions

If designed to do so, modern wind and utility-scale PV plant are able to ramp rapidly, over most of their available capacity. Manufacturers of these products have advised AEMO that, with the appropriate control systems, these generation types are capable of contributing to FCAS requirements in all markets.

Providing raise services (increasing generation to increase system frequency) will require wind and PV generation to operate at a reduced output to allow “headroom”. This means the plant would be spilling energy to provide these services, foregoing energy payments for that reduced capacity.

No wind or PV plant is registered to provide FCAS at present in the NEM, although AEMO will engage with interested new entrants to those markets. AEMO’s FPSS program includes work to identify and address any possible barriers to the participation of emerging technologies in FCAS markets.

At present, the amount of regulation FCAS enabled in any particular period is increased in response to accumulated frequency errors (measured via the “time error”). The time error provides an indication that the frequency has been away from the nominal 50 Hz target for a period of time, suggesting that more regulation is needed to manage the prevailing system conditions. This mechanism could be used to dynamically enable more regulation in future, in periods when it is required.

Alternatively, the FCAS framework could be adapted to allow pre-emptive enablement of more regulation FCAS when required, based upon anticipated variability calculated from the system conditions and other relevant factors. This is also being explored through AEMO’s FPSS program.⁸⁷

⁸⁷ More information about the FPSS is available at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

4.3 System strength

System strength is an inherent characteristic of any power system. It is important, as it can materially impact the way a power system operates.

Higher fault levels, or high currents following a fault, are typically found in a stronger power system, while lower fault current levels are representative of a weaker power system.⁸⁸

During system normal conditions, a low Short Circuit Ratio (SCR) or weak system is very sensitive to active/reactive power injections (or absorptions). That means the system voltage changes rapidly as the amount of reactive power injected (or absorbed) changes. It is therefore difficult to stabilise the system voltage on a weak system, and a weak system generally requires a voltage control system with supplementary stabilisation control.

A strong system is largely unresponsive to reactive power injections (and absorptions), and the system voltage is not significantly influenced by changes in the network.

During fault conditions:

- Synchronous generation (when online) typically provides additional current, many times its typical long-term maximum power output.
- Inverter-connected generation typically only provides between 0 and 100% of its typical maximum long-term power output during a fault.

A high fault level could be viewed as the generation on the grid responding strongly to the drop in voltage at the fault, trying to restore the situation. Fault currents vary around the grid both by location and by voltage level. The fault currents are higher in areas close to synchronous generation, and lower in areas further away from this generation.

Unlike RoCoF, which can be managed globally in an interconnected system, system strength must be provided near to the weak system. This is because, the higher the impedance between the synchronous plant and the weak network, the lower the impact or support provided by the synchronous plant.

4.3.1 Future system strength

System strength reduces as synchronous generation is replaced with increasing amounts of inverter-connected generation.

The NTNDP's 20-year generation outlook for the Neutral scenario projects a reduction of around 15 GW of synchronous plant, and the connection of over 22 GW of large-scale inverter-connected generation, not including rooftop PV.

The Low Grid Demand scenario projects a reduction of almost 19 GW of synchronous plant and connection of about 8 GW of large-scale inverter-connected generation.

This displacement of synchronous generation is projected to greatly reduce system strength across the NEM, as shown in the figure below. The areas of biggest expected change are where there are high concentrations of inverter-connected plant such as wind and utility-scale PV.

AEMO has performed a high-level assessment to locate areas where system strength is an existing or emerging challenge. An area of the grid is generally considered weak if the SCR drops below three.⁸⁹ For this assessment, the weighted⁹⁰ SCR was calculated for possible connections to determine network strength.

⁸⁸ A fact sheet on system strength is located on the AEMO website. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

⁸⁹ Y Zhang, S Huang, J Schmall, J Conto, J Billo, E Rehman, "Evaluating System Strength for Large-Scale Wind Plant Integration", PES General Meeting | Conference & Exposition, 2014 IEEE.

⁹⁰ Weighted short circuit ratio takes into account the interaction between inverter-connected generation on the short circuit ratio.

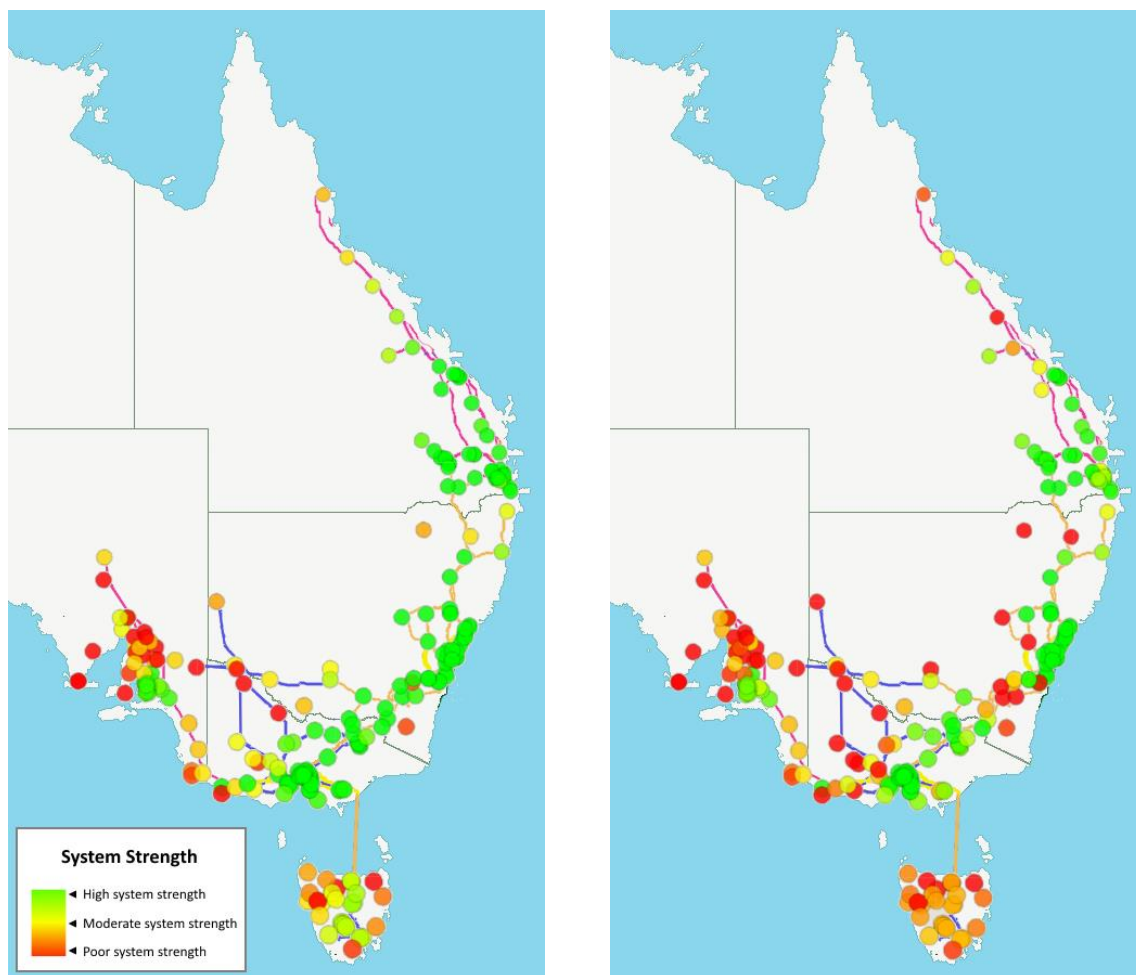
The results of this assessment are illustrated in the figure below, which highlights:

- Poor network strength is projected to decline further in much of South Australia, western Victoria, and Tasmania.
- Emerging local areas of poor network strength in New South Wales and Queensland, where high concentration of renewables are anticipated by 2035–36.

The figure illustrates how system strength is a local phenomenon. In South Australia, synchronous generation in the Adelaide area is projected to maintain system strength throughout the outlook period, while the remainder of South Australia, particular the northern parts of the state, remains weak. AEMO has identified an NSCAS gap to improve the low system strength in South Australia (see section 7.2.3).

High capacity AC interconnection does not necessarily make an area strong. For example, it is the presence of synchronous generation (such as Murray and Tumut) for the VIC–NSW interconnector that provides the fault current, resulting in a strong system.

Figure 27 System strength assessment in 2016–17 (left) and 2035–36 (right)



4.3.2 Voltage management

Voltage management (steady-state voltage stability) deals with the response of the power system to small changes in the network within the normal voltage range (generally between 90% and 110% of the nominal voltage).⁹¹

⁹¹ This kind of assessment is generally provided through P-V and Q-V analysis.



As noted above, the voltage in a weak system is sensitive to both active and reactive power changes. A strong system, however, is largely unresponsive to reactive power injections (and absorptions) and the system voltage is only marginally influenced by changes in the network.

An ongoing reduction in the number of online synchronous generators, and the resulting weakening effect, makes the impact of switching events more pronounced as the fault level reduces. This can result in voltages deviating beyond the normal operating range.

Operating under weak grid conditions results in a higher likelihood of steady-state instability for existing inverter-connected generation. Although future improvements to power electronics might increase the stability of new renewable generation connections, existing generation would need to be upgraded to cater for nearby connections.

4.3.3 Voltage dip

A voltage dip (also called a voltage sag) is a brief drop in network voltage following a fault or switching event. It can have varied impacts on the operation of motors and sensitive electronics, such as computers, depending on its magnitude and duration.

In a weak network area, voltage dips are deeper, more widespread, and can last longer than in a strong network. For example, the transient voltage dip resulting from a short circuit event will be more severe, more widespread, and slower to recover in a weak system than in a strong system. This condition will generally last until the network fault is cleared by protection systems (see Table S5.1a.2 in the Rules for fault clearance time requirements).

Section 5.2.1 presents an assessment of the spread and depth of voltage dip during transmission faults in South Australia.

The impact of fault ride-through

The ability of generators to maintain stable operation following a fault is an important aspect of power system security. With the increasing depth, spread, and duration of voltage dips, this capability is more important than ever.

Schedule 5.2.5.5 of the NER defines the requirements for a generating system to remain in continuous uninterrupted operation following a disturbance in the power system. This capability can be negotiated between the generator and the TNSP, although a minimum capability is required.

For wind farms, depending on the wind turbine design, a low voltage ride-through threshold is generally defined in the range of 80% to 90% of its nominal voltage.⁹² When the turbine voltage drops below this threshold, the turbine suspends normal operation and starts injecting reactive current. Most existing wind turbines are designed to withstand zero voltage at their terminals for 150 milliseconds or longer.⁹³

During a network fault, generators tend to reduce their active power generation and supply reactive power. Following fault clearance, the generating systems are designed to immediately resume active power generation (depending on the capability of the generator and the kind of fault). This capability is important to ensure generation is available after the network fault is cleared.

In a weak system, where the impact of the network fault is widespread, a large amount of generation can enter fault ride-through during the brief period before a fault is isolated, resulting in a power imbalance. This imbalance can result in the system frequency deviating to a point where it cannot remain connected following isolation of the fault, and where the frequency is too low to recover by UFLS schemes. To limit the frequency impacts of fault ride-through in weak systems, the system strength must be improved.

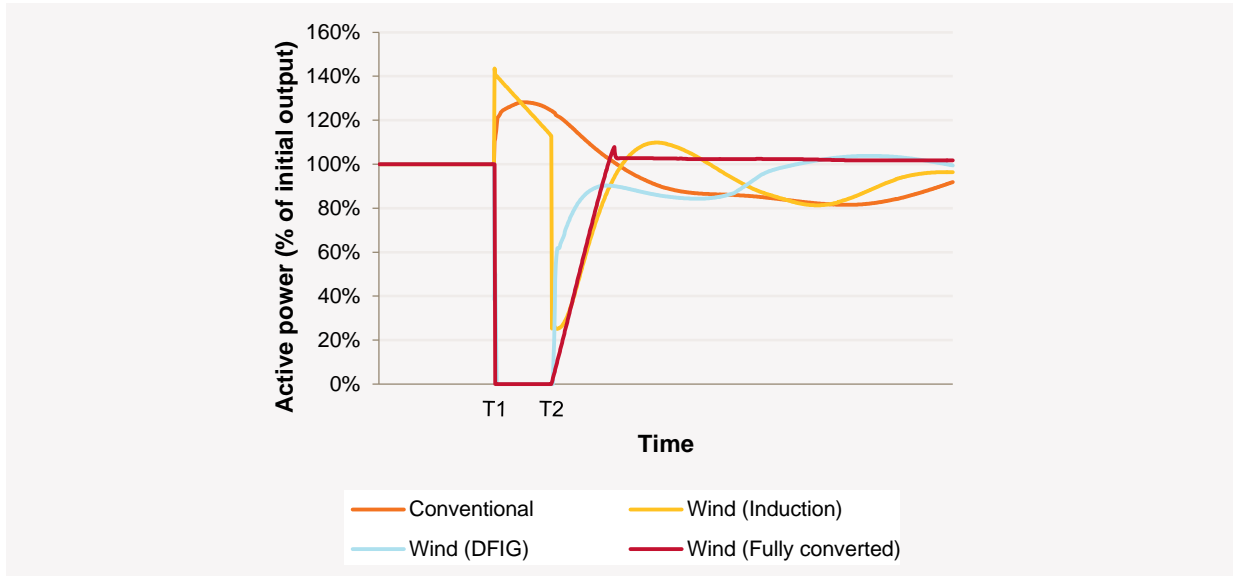
⁹² Accounting for interconnecting lines and cable impedances, and network and collector grid transformers, a 100% voltage drop at the point of common coupling (PCC) would translate into residual voltage in the order of 10 to 15% at the wind turbine generator terminals.

⁹³ AEMO. *Wind Turbine Plant Capabilities Report*, 2013. Available at: http://www.aemo.com.au/-/media/Files/PDF/Wind_Turbine_Plant_Capabilities_Report.pdf.

The following figure provides an indication of how different kinds of generation respond to fault conditions. In this example, a network fault occurs at time T1, and is cleared at time T2.

This shows that some synchronous generation and induction-based wind farms (known as “type 1” or “type 2”) provide current to feed the fault (supporting frequency), while others (like full converter and Doubly Fed Induction Generators (DFIG)) provide little to no active power response until after a fault is cleared. An abundance of generators that do not supply fault current can exacerbate frequency instability during fault conditions (described in the previous section).

Figure 28 Illustrative example of active power response during fault ride-through



4.3.4 Power quality

Power quality refers to the power system’s ability to supply a smooth and consistent supply of power.⁹⁴ For the same consumer demand, voltage harmonics and unbalance are higher in weak systems than in strong systems. This can result in large over-voltages lasting for several seconds, potentially exceeding the withstand capability of local generation. Because synchronous generators act as a sink for harmonics and voltage unbalance, displacement of synchronous generators with inverter-connected generation diminishes power quality.

4.3.5 Operation of protection

In the NEM, a combination of over-current, distance, differential, and loss of synchronism (also known as “out-of-step”) protection systems ensure short circuits and instabilities can be isolated from the system. These protection systems generally operate by measuring the current that flows through the different phases on a circuit. If the current becomes very high, if it deviates materially over the distance of the line, or if the line impedance reduces, then the protection system can locate and isolate a fault from the network.

The trend of decreasing system strength will result in fault current being reduced, which makes it more difficult for protection systems to detect and isolate faults:

- Over-current protection will operate more slowly in areas with a lower fault level, and may have difficulty discerning between high load current and fault current.
- Distance protection may fail to operate for high impedance faults.

⁹⁴ Good power quality requires well balanced and near sinusoidal waveforms of voltage and current at a stable frequency. A weak power system exhibits a higher equivalent impedance and lower dominant resonance frequencies compared to a strong power system.



- Differential and out-of-step protection may require fine tuning to operate under a range of fault conditions.
- If local areas of the transmission network continue to weaken, protection systems will need to be reconfigured and redesigned to ensure correct operation.

4.3.6 Improving system strength

System strength cannot be imported, and must be supplied locally.

Solutions to improve system strength include:

- Synchronous condensers.
- Synchronous machines (synchronous generators).
- Static synchronous compensators (STATCOMs), or other voltage source converter (VSC) technology, with energy storage or transfer.

In the absence of improving system strength, renewable generator capabilities and protection design may need to be updated to accommodate further decreases in system strength in some areas of the network.

Cost of addressing system strength

The exact requirements to improve system strength depend heavily on the specific location and network characteristics. For example, some existing wind farms were required to install small synchronous condensers to increase local system strength.

As a reasonable estimate, for an additional 150 MW wind connecting in a weak area of the network would require around 30 MVar of synchronous condensers at an approximate cost of \$5 million to \$10 million.

4.4 Visibility and control of the power system

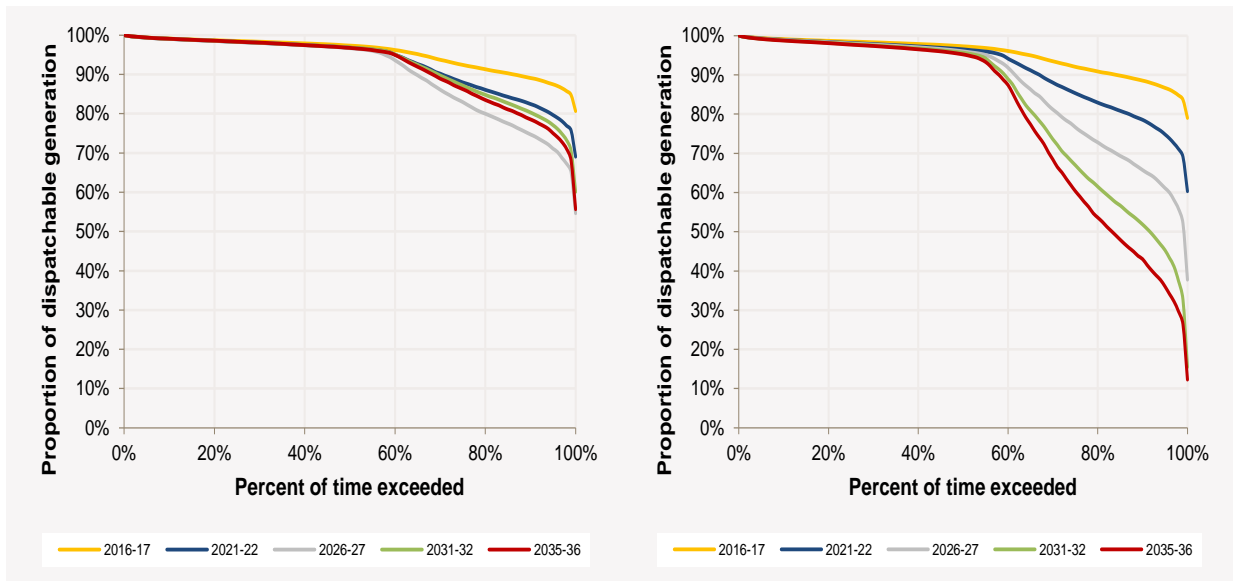
Managing power system security involves the constant balancing of supply and demand to ensure power flows remain within the technical limits of the grid (the technical envelope). Reactive plant must also be deployed to ensure voltages across the grid meet the required profile.

To achieve this balance, AEMO continuously determines and revises the limitations on the system, taking into account the prevailing power system and plant conditions, short-term forecasting of non-dispatchable generation (wind and PV), and predicting the impacts of potential contingency events.

This process requires sufficient information and data about the power system and its components to effectively model how the power system might respond to a range of system events.

As non-dispatchable, inverter-connected generation comprises a greater proportion of total generation over the next 20 years, as shown in the figures below, the visibility and control of the power system is expected to reduce.

Figure 29 Proportion of dispatchable generation in the NEM, Neutral (left) and Low Grid Demand (right)



The chart shows that, for over half the year, almost 100% of generation online is dispatchable, which is the same throughout the outlook period. This alignment represents night time hours when PV does not generate. The progressive divergence over the outlook for the remainder of each year represents the growing penetration of non-dispatchable PV, which effectively reduces grid demand.

While AEMO has always had limited visibility of the demand side, load has traditionally been easier to predict as it is correlated with factors such as weather, time of day, day of week, and economic drivers.

More importantly, an underlying diversity in the behaviour of consumers means that, on an average day, they use their appliances at different times and in different ways. In instances when they don't, such as the utilisation of air-conditioners, the material increase in demand can be anticipated through weather patterns, and AEMO puts in place operational measures to manage these instances.

To date, the diversity in “passive” demand has allowed AEMO to forecast the aggregate demand with sufficient accuracy to operate the power system securely. This included an understanding of how the load as a whole would respond to power system disturbances.

The presence of large volumes of DER has the potential to challenge this underlying diversity. This is particularly likely when DER is combined with storage technologies that could shift between being load or generation in an instant, based on different commercial drivers such as tariff signals or network support contracts.

This means the traditional relationships and diversity AEMO has relied on to accurately forecast load and determine the technical envelope will no longer hold, in the presence of significant uptake of DER, without enough information to accurately model the aggregated behaviour of DER.

In the absence of sufficient data, AEMO would need to apply very conservative limits on the technical envelope to mitigate potential system security risks of unpredictable swings in supply and demand. This would result in more stringent constraints in the dispatch process, creating market inefficiencies that would end up having economic consequences for both consumers and participants.

As part of the FPSS program⁹⁵, AEMO will publish a paper in early 2017 on the visibility of DER, which will discuss the information AEMO requires and the reasons why in more detail. AEMO is also conducting a Consultation on developing DSP information guidelines. These guidelines will enable

⁹⁵ AEMO. Future Power System Security program. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

AEMO to collect specific information on DSP to improve the accuracy of its load forecasting processes across different timeframes, from the pre-dispatch forecast to the 20-year NEFR forecast.⁹⁶

4.5 Ramping requirements of dispatchable generation

The variability of non-dispatchable wind and PV generation requires flexible management of the supply demand balance over different timeframes throughout the day.

The one-hour time resolution of the NTNDP market model does not capture the intra-minute and intra-hour volatility of wind and PV generation. Section 4.2, however, discusses this increasing variability and whether more regulation FCAS might be required to manage it.

The NTNDP analysis examined changes in non-dispatchable generation over the course of the day, and found an increasing need for dispatchable generation to ramp up and down throughout the day to balance supply as wind and PV generation changes.

For the Neutral scenario, the following figure shows NEM-wide consumer demand less rooftop PV and non-scheduled wind generation, which equates to generation dispatched, over the course of the projected maximum and minimum demand days in five year intervals to 2035–36.

Figure 30 Projected NEM-wide dispatched generation on maximum and minimum demand days

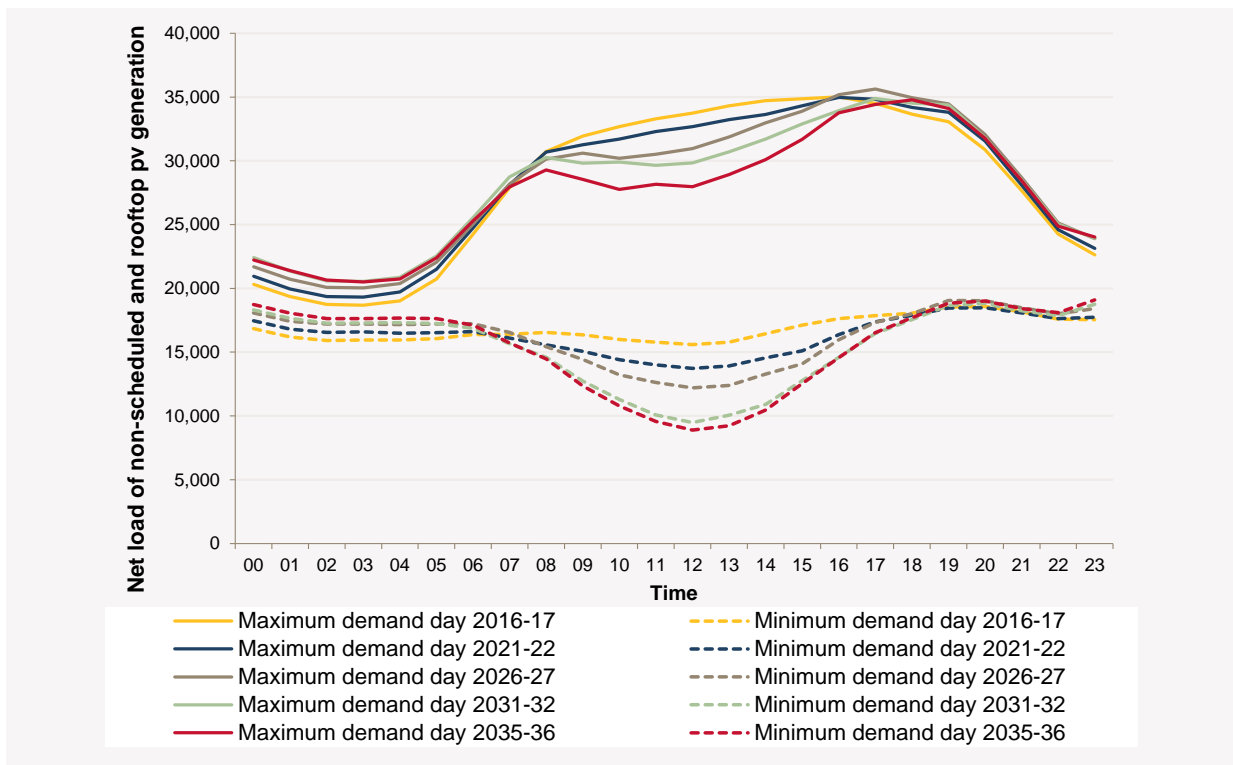


Figure 30 indicates that the dispatchable generation required to meet the supply demand balance is decreasing at times of high rooftop PV generation. The “lip” shaped contours of dispatched generation on maximum and minimum days show the variability that dispatchable generation is likely to exhibit in future. On low demand days, the amount of consistent “base load” generation required throughout the day is expected to decrease.

⁹⁶ AEMO, 2016. *NEM demand side participation information guidelines consultation*. Available: <https://www.aemo.com.au/Stakeholder-Consultation/Consultations/NEM-Demand-Side-Participation-Information-Guidelines-Consultation>.

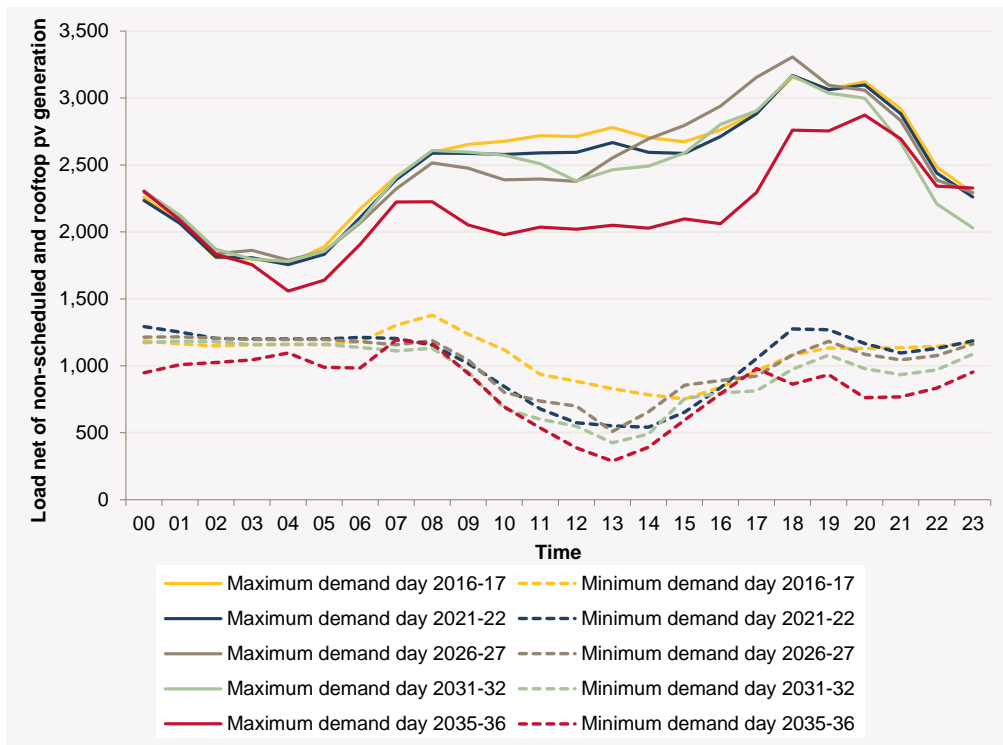
It follows that these trends are likely to reduce the financial viability of generation that incurs greater costs (in terms of equipment degradation) from ramping its output up and down, such as coal generation.

The ramping rates caused by rooftop PV on a NEM-wide scale do not appear to be greater than the ramping rate required to meet the morning peak in demand or the drop down in demand after the evening peak. It is important to note, however, that a greater degree of intra-day variability is expected in regions with particularly high levels of non-dispatchable generation.

Figure 31 shows the projected dispatched generation on minimum demand days in South Australia over the next 20 years. The intra-day variability in South Australia is more pronounced than the NEM-wide average due to its higher penetration on non-dispatchable generation.

When considering that dispatchable generation includes semi-scheduled wind generation, which can be constrained down through the dispatch process, it is likely that scheduled demand will become negative on low demand days in South Australia during the next 20 years. This possibility was first projected in AEMO’s 2015 NEFR.⁹⁷

Figure 31 Projected dispatched generation on minimum demand days in South Australia



4.6 Reduction in stability limits

A stability limit defines the maximum power transfer allowable through a point in the power system before system stability is at risk following a credible contingency or in steady-state.

All three scenarios explored in the 2016 NTNDP project a steady decline in synchronous generation as investment in renewables increases. This will result in a decline in inertia (see section 4.2.1), which will likely result in a reduction of transient stability limits which reduce capability of the network to transfer power across major transmission flow paths. Voltage stability limits may also be affected by the withdrawal of synchronous generation, although the impact will depend on the specific location of new generator connections, and their reactive power capability.

⁹⁷ AEMO, 2015. *National Electricity Forecasting Report*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

CHAPTER 5. IMPROVING SOUTH AUSTRALIAN POWER SYSTEM RESILIENCE

Key insights

- Following both the closures and decreasing availability of synchronous power stations, there is now an increased risk that a non-credible contingency will result in a state-wide blackout in South Australia. AEMO has only limited operational mechanisms to protect the power system against these non-credible contingencies.⁹⁸
- The emerging power system resilience challenges in South Australia relate primarily to system strength and stability. Based on a projection of historical events and an estimation of their impact, the economic benefit from improving South Australian power system resilience is estimated to be approximately \$472 million per event.
- Increasing interconnection between South Australia and the eastern states will increase South Australian power system resilience if system strength and stability are also addressed. This solution will also deliver fuel cost savings by increasing transfer capability between South Australia and the eastern states. Costing between \$500 million and \$1 billion, a new interconnector could deliver positive net market benefits of approximately \$260 million.
- A combination of services (providing system strength, inertia, FFR, and frequency regulation) could comprise a lower-cost alternative approach to improving South Australia's resilience to non-credible contingencies without additional interconnection. This option is estimated to cost approximately \$455 million, and will be cheaper if synchronous generators offer inexpensive services. This is estimated to result in marginally positive net market benefits (\$20 million).
- AEMO's 2016 NTNDP investigation was a high-level pre-feasibility study, which found multiple credible solutions with positive net market benefits. A detailed assessment and consultation, as a part of a RIT-T, is recommended to determine the most cost-effective way to improve South Australia's power system resilience. In November 2016, ElectraNet initiated a RIT-T process to determine a preferred solution.⁹⁹ The first stage of this RIT-T is currently under consultation.

5.1 Background on South Australia's emerging power system resilience challenges

The 2015 NTNDP¹⁰⁰ highlighted South Australia's exposure to frequency stability challenges due to low levels of synchronous generation, and having only one AC interconnector.

In February 2016, AEMO and ElectraNet explored the impacts of high RoCoF¹⁰¹ on frequency stability.¹⁰² This study reinforced the increasing importance of the Heywood Interconnector for the secure and reliable operation of the South Australian power system.

In May 2016, the closure of the Northern Power Station continued the trend for decreasing synchronous generation in South Australia. Following this closure, AEMO produced an update on emerging power system resilience challenges.¹⁰³ Among other topics, this update explored system strength and the

⁹⁸ AEMO will comply with specific regulations under the Essential Services Act, which may relate to protecting against specific threats.

⁹⁹ ElectraNet. South Australian Energy Transformation Project Specification Consultation Report. Available at: <https://www.electranet.com.au/projects/south-australian-energy-transformation/>

¹⁰⁰ AEMO. 2015 National Transmission Network Development Plan (NTNDP). Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>

¹⁰¹ Rate of Change of Frequency (RoCoF) is explored in section 4.2.1.

¹⁰² AEMO and ElectraNet. *Update to Renewable Energy Integration in South Australia*, 2016. Available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/CACEB2122362436DAC2CDD6E8D3E70D0.ashx>

¹⁰³ AEMO. *Future Power System Security Progress Report*, 2016. Available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx>

potential impacts of South Australia separating from the eastern states following the closure of Northern Power Station. Through its FPSS program¹⁰⁴, AEMO is working to identify any underlying RoCoF limits of the power system, and exploring alternative ways of managing RoCoF through new measures, such as an FFR service or other frequency control mechanisms.

In August 2016, AEMO published the *South Australian Electricity Report*¹⁰⁵, noting:

- A high risk of a region-wide blackout in South Australia following the rare event of the unexpected concurrent loss of both Heywood Interconnector lines.
- That South Australia had separated from the rest of the NEM due to such non-credible contingency events four times since 1999, and the likelihood that a region-wide blackout might result from a non-credible separation event had increased as the amount of synchronous generation within South Australia decreased¹⁰⁶ and the capacity of the interconnector increased.

On 28 September 2016, South Australia blacked out following multiple transmission faults and a rapid reduction in generation output within South Australia.^{107,108} This resulted in a rapid increase of imports on the Heywood Interconnector, which activated Heywood's automatic loss of synchronism protection mechanism, leading to the disconnection of the Heywood Interconnector. As a result, approximately 900 MW of supply from Victoria over the Heywood Interconnector was immediately lost, and the remaining generation in South Australia was unable to meet the load. The sudden and large deficit of supply caused the system frequency to collapse more quickly than the UFLS scheme was able to act.

In accordance with South Australian jurisdictional requirements imposed after the blackout, AEMO has implemented constraints to limit flow on the Heywood Interconnector to maintain the anticipated RoCoF of the South Australian power system at or below 3 Hz/s in the event of a non-credible coincident trip of both circuits of the Heywood Interconnector.

ElectraNet published a Project Specification Consultation Report (PSCR) in October 2016, initiating the regulatory process to implement solutions for the emerging power system resilience challenge.¹⁰⁹ ElectraNet's RIT-T incorporates an assessment of the competition benefits resulting from a lower wholesale electricity price in South Australia.

This chapter considers the feasibility of three possible solutions to improve South Australian power system resilience:

- South Australia to New South Wales interconnector.
- South Australia to Victoria interconnector.
- Locally provided services (without increasing South Australian interconnection).

This chapter explores the possible solutions to deliver a system resilience benefit to South Australia, and the range of other benefits that a solution might capture. AEMO's investigation was high-level, and found multiple credible solutions that might deliver positive net market benefits. A detailed assessment and consultation, such as ElectraNet's South Australian Energy Transformation RIT-T, is recommended to determine the most cost-effective way to improve South Australia's power system resilience.

¹⁰⁴ More information on the program is available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability>.

¹⁰⁵ AEMO. *South Australian Electricity Report (SAER)*, 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

¹⁰⁶ As outlined in Chapter 4, synchronous generation increases system strength and improves frequency stability.

¹⁰⁷ AEMO, 2016. *Preliminary operating incident report into the South Australian state-wide power outage*. Available: <https://www.aemo.com.au/Media-Centre/Media-Statement-South-Australia-Interim-Report>.

¹⁰⁸ AEMO, 2016. *Update to: preliminary operating incident report into the South Australian state-wide power outage*. Available: <https://www.aemo.com.au/Media-Centre/Update-to-report-into-SA-state-wide-power-outage>.

¹⁰⁹ ElectraNet. *South Australian Energy Transformation*. Available at: <https://www.electranet.com.au/projects/south-australian-energy-transformation/>.

5.2 The driver for augmentation

The primary driver for considering augmentation is to deliver a net positive benefit to the market by:

- Improving the resilience of the South Australian power system, especially to withstand non-credible contingencies, and
- Decreasing fuel costs.

Emerging power system resilience issues in South Australia are being driven by a changing generation mix. While this has not increased the likelihood of non-credible contingencies occurring, it has impacted the capacity of the power system to manage the potential consequences.

5.2.1 Improving the resilience of South Australia's power system

The primary goal of the solutions considered in this chapter is to significantly reduce the risk of a South Australian blackout on the occurrence of a non-credible contingency by building more redundancy and strength into the power system:

- A network solution would improve resilience by increasing inter-network redundancy and enhancing network strength (see Section 4.3.6), aiming to minimise the possibility of a separation event.
- A locally provided solution would improve resilience by enhancing system strength (see Section 4.3.6) and providing a geographically distributed response, aiming to minimise the likelihood of a state-wide blackout following a separation event.

All solutions must address:

- Frequency stability (transfer inertia and contingency services from the eastern regions, or provide sufficient inertia such that frequency stability is maintained).
- Frequency regulation (provided through interconnection or within South Australia).
- Transient and voltage stability during and after a separation event.
- Emerging issues relating to system strength.

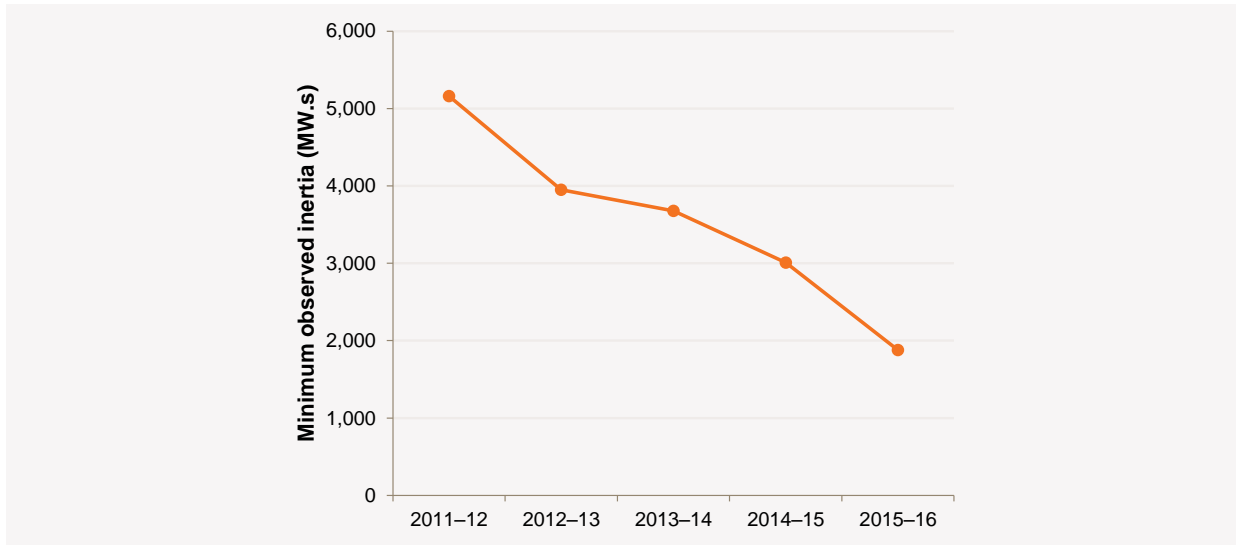
Depending on the solution, additional benefits relating to fuel cost savings (economic dispatch) may also be realised.

Maintaining frequency stability

Frequency stability is emerging as an important property of how the South Australia power system might respond to becoming suddenly electrically separated from the eastern states. Following the closure and decreasing availability of synchronous power stations, the South Australian power system has become more susceptible to frequency instability following a separation event. The general principles of frequency stability are described in Section 4.2.

The following figure shows historical minimum inertia levels in South Australia over the past five years, illustrating the trend of a clear decline in the annual minimum amount of inertia in the region.

Figure 32 Minimum historic and projected inertia in South Australia



In four of the five non-credible events where South Australia has separated from Victoria since 1999, a sudden loss of generation (around 500 MW) in South Australia resulted in a rapid increase of imports before protection systems disconnected the interconnector. Analysis of these events suggests that the interconnector’s protection will operate at approximately 900 MW, depending on system conditions.¹¹⁰

AEMO has performed an assessment to determine the historic and projected exposure of the South Australian system to high RoCoF conditions following a separation event.¹¹¹

Figure 33 below shows the RoCoF levels which would result from this rare event. Where a loss of interconnection results in frequency increasing, RoCoF is shown with vertical fill effects in the figure. Where frequency would fall in response to a loss of interconnection, RoCoF is shown with solid fill effects in the figure.

The RoCoF risk increased after the upgrade of the Heywood Interconnector, and again after the closure of Northern Power Station. Emergency frequency control schemes in their current form (such as standard UFLS) are increasingly unlikely to maintain frequency stability. This could result in a black system across South Australia from a non-credible separation event.

There is a large percentage of time where it is unknown how the South Australian power system would respond to a non-credible separation event. As outlined in section 4.2.1, the capability of the South Australian network to withstand different levels of RoCoF is currently being investigated.

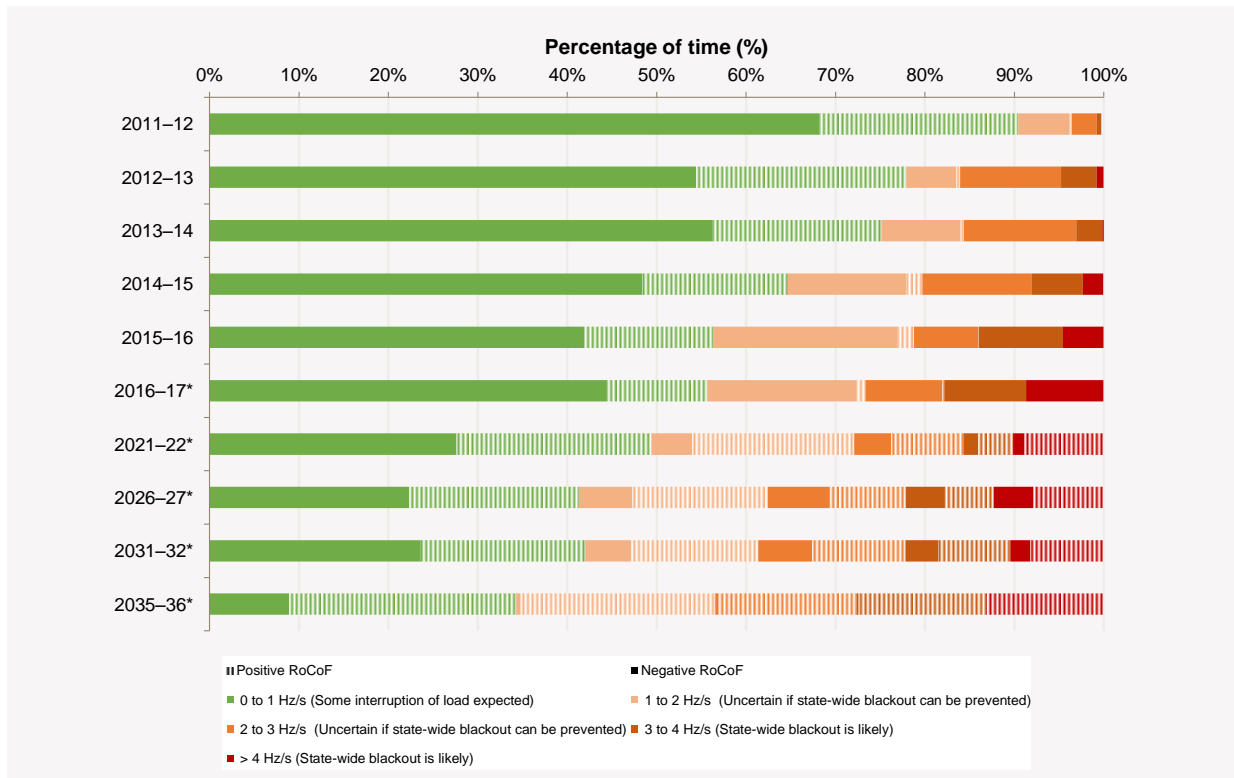
Following a large non-credible contingency event in South Australia:

- A network solution would provide frequency stability by transferring frequency support through the interconnector.
- A local solution may not prevent separation, but would rely on a combination of fast control schemes and inertia within South Australia to prevent frequency instability.

¹¹⁰ AEMO does not protect against this contingency size. Rule change proposals relating to AEMO’s ability to protect against these contingencies are presented in section 5.3.4.

¹¹¹ For this RoCoF assessment, the sudden interruption of 500 MW of generation is included in the contingency for instances where it would result in Heywood flow exceeding 900 MW.

Figure 33 RoCoF and the projected risk of frequency instability following a loss of interconnection



Inertia requirement following separation

The UFLS scheme in South Australia is designed to trip customer load to restore the balance of supply and demand following a non-credible event. The current UFLS design in South Australia is likely to be capable of restoring the balance of supply and demand when RoCoF is up to 3 Hz per second.

To contain RoCoF to 3 Hz per second (so that UFLS has sufficient time to operate successfully), following a generating contingency that results in the Heywood Interconnector rapidly increasing flow to 900 MW before separating, approximately 7,500 MWs of inertia is required (see section 4.2.1 for more information on inertia and RoCoF).

Providing frequency regulation

In the event of South Australia losing synchronous interconnection, assuming the system remains intact, the capability to regulate frequency will depend on the capability of generators online at the time (existing generators with this capability are slow to start).

To ensure ongoing power system security, a solution that aims to improve South Australia’s resilience to a synchronous separation (rather than preventing it) must be capable of providing sufficient frequency regulation within a short time after a separation event. This could include:

- Upgrading the Murraylink DC interconnector to provide and respond to frequency regulation requirements (transferring regulation FCAS from Victoria).
- Batteries or other storage devices.
- Contracting or otherwise incentivising the availability of generation that can rapidly respond to frequency regulation signals.



Ensuring transient and voltage stability

Largely as a result of the decreasing operation of synchronous generation (resulting in decreasing inertia) and increasing interconnector flows, the South Australian power system will at times be at risk of transient and voltage instability following either:

- The loss of both Heywood Interconnector lines.
- A contingency event involving multiple generators in South Australia.

For solutions where additional interconnection provides network redundancy and increased transfer capacity from South Australia to the eastern states, the design of a new link would be required to survive the loss of the existing one. At periods of high transfer, this contingency will result in a rapid power swing on the remaining interconnector. The design of a special protection scheme will likely be required to quickly balance the supply and demand in South Australia (rapid load shedding or generation tripping), such that voltage does not collapse and the remaining link is not overloaded.

To improve power system resilience, any proposal that is designed to provide frequency stability must also ensure transient and voltage stability. The following table highlights generic solutions to transient and voltage stability limitations.

Table 13 Technical solutions for transient and voltage stability

Technical Solution	Transient stability	Voltage stability
Synchronous condenser	Suitable	Suitable
Synchronous condenser with flywheel	Suitable	Suitable
SVC, DVAR or STATCOM	Suitable	Suitable
Special control scheme	Suitable	Suitable
Braking resistor	Suitable for over-frequency	Not suitable
Battery storage	Suitable	Not suitable

Ensuring system strength

Declining system strength is emerging as a major challenge for the South Australian power system. Although building long circuits can assist in some aspects of frequency management, in this instance it will provide little benefits to system strength. Any proposal to improve South Australia’s power system resilience must be accompanied with provisions that increase system strength. See Section 4.3.6 for more information on improving system strength.

Emerging challenges in South Australia resulting from declining system strength include:

- Voltage dip.
- Generator fault ride-through.
- Voltage management.
- Power quality.
- Correct operation of protection.

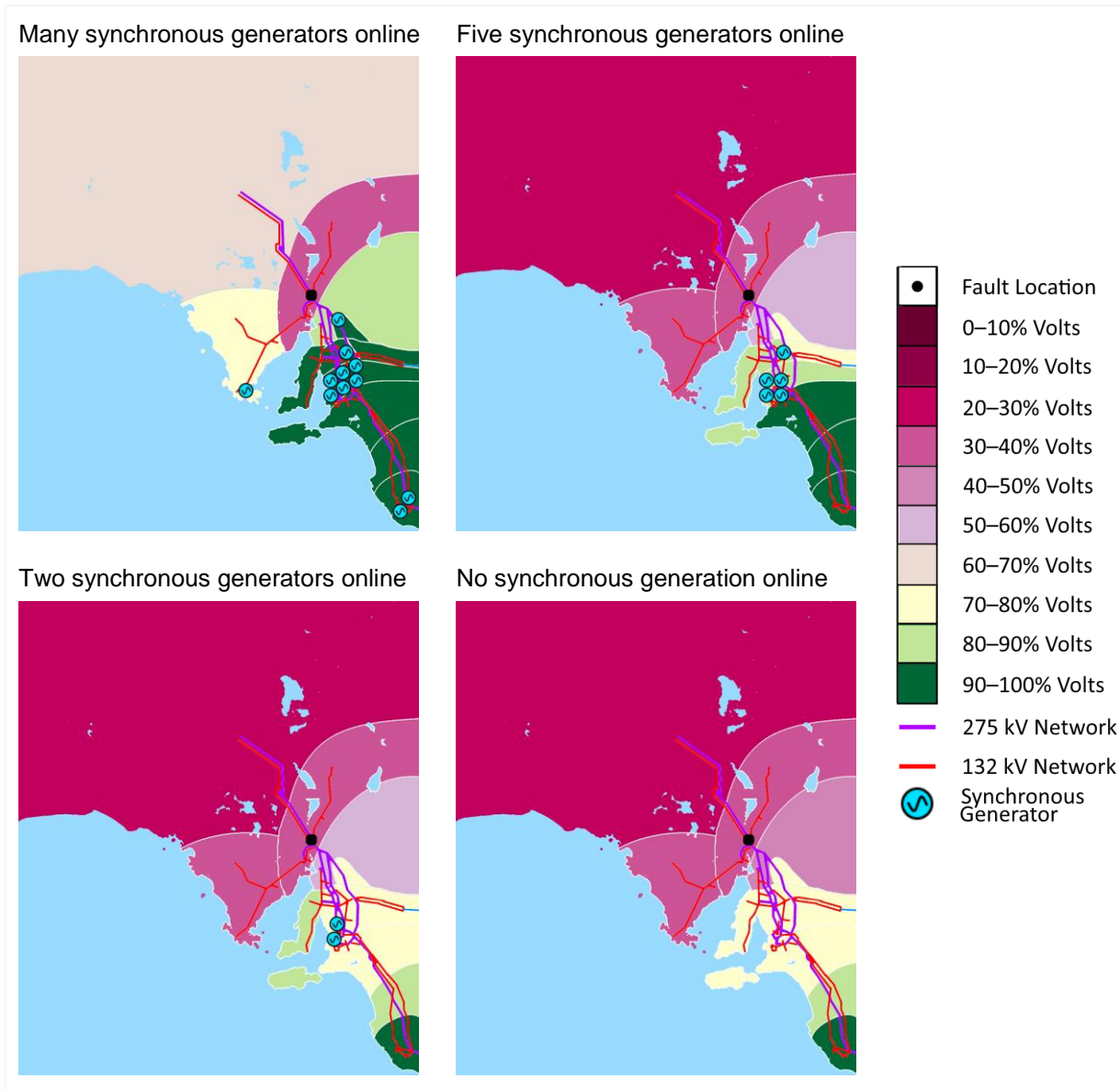
Voltage dip

In a weakening South Australian network, the impacts of a network fault are increasing in terms of depth, spread, and duration. See section 4.3.3 for general information on voltage dip.

The following figures illustrate the depth and spread of voltage dip during a simulated two-phase to ground fault at Davenport. The number of online synchronous generators is illustrated on each map.¹¹² Comparing these figures, it can be observed that the online synchronous generators act to limit the spread of voltage dips, as they supply both fault current and dynamic reactive power support.

¹¹² Small generators are grouped as one for illustrative and comparative purposes.

Figure 34 Transmission network voltage dip during a two-phase to ground fault at Davenport



Although the main transmission network can experience severe and widespread voltage dips, there are lower voltage pockets where dynamic reactive plant limits the reach of the voltage dip. This design is important for inverter-connected generation, such as wind or solar farms, where a voltage dip can initiate fault ride-through mode (discussed in the following section).

Inverter-connected generation and fault ride-through mode

The spread and depth of a voltage dip can have significant implications for power system security and resilience. Many inverter-connected generator connections will temporarily halt active power generation when their voltage drops below 80% to 90% of nominal voltage.^{113,114} This is known as fault ride-through mode, and will often last for approximately 500 milliseconds.

¹¹³ AEMO. Wind Turbine Plant Capabilities Report. Available at: https://www.aemo.com.au/-/media/Files/PDF/Wind_Turbine_Plant_Capabilities_Report.ashx.

¹¹⁴ Accounting for interconnecting lines and cable impedances, and network and collector grid transformers, a 100% voltage drop at the PCC would translate into residual voltage in the order of 10 to 15% at the wind turbine generator terminals.

In the case of South Australia, and in the above voltage dip illustrations, under some conditions the spread of the voltage dip can be observed below 80% of nominal voltages throughout much of the South Australian transmission network. Fortunately, many wind farms in South Australia are supported by local dynamic reactive support, which often prevents the voltage dip from being observed at the wind turbine terminals.

The presence of dynamic reactive support (such as DVAR, STATCOM, SVC, or a synchronous condenser) close to the point of connection for inverter-connected generation is increasingly important to prevent wide areas of generation from entering fault ride-through mode simultaneously.

A solution that improves system strength (provides fault current) and provides voltage support will limit the spread and depth of voltage dips, improving power system resilience in South Australia.

Voltage management

The voltage in some parts of South Australia is very sensitive to both active and reactive power changes. In contrast, strong systems are largely unresponsive to reactive power injections (and absorptions) and the system voltage is only marginally influenced by changes in the network.

In South Australia, an ongoing reduction in the number of online synchronous generators and the resulting weakening effect makes the impact of switching events more pronounced as the fault level reduces. This can result in operating voltages deviating beyond the normal operating range.

See section 4.3.2 for more information on voltage management.

Power quality

Power quality refers to the power system's ability to supply a smooth and consistent supply of power. In South Australia, poor power quality issues may arise if system strength continues to decline. This could result in an increase in network losses, a reduction in supply reliability, and damage to equipment. See section 4.3.4 for more information on power quality.

Operation of protection

In the NEM, a combination of overcurrent, distance, differential, and loss of synchronism (also known as "out-of-step") protection systems ensure that short circuits and instabilities can be isolated from the system. If local areas of the transmission network continue to weaken, protection systems will need to be reconfigured and redesigned to ensure correct operation. See section 4.3.5 for more information on the operation of protection in weak systems.

Solutions to improving South Australia's power system resilience

A range of very different solutions exist to improve South Australia's power system resilience. The remainder of this chapter presents and assesses:

- Two interconnector paths, which primarily aim to reduce the risk of South Australia disconnecting from the eastern states.
- A local solution, which aims to increase the resilience of the South Australia power system to events that include separation.

The following section outlines some of the key benefits that could be used to economically justify these projects under a RIT-T. A RIT-T that focuses on the need to improve South Australia's power system resilience would explore solutions in more detail, and potentially consider additional options or refinements to those presented here.

Estimating the benefit of improving power system resilience

The benefits of improving power system resilience in South Australia largely relate to preventing a state-wide blackout.



To estimate this benefit, the following high-level approach was taken:

1. Estimate the likelihood of a separation event.
2. Estimate the probability that a separation event will result in a state-wide blackout.
3. Estimate the total customer supply interrupted for a single state-wide blackout.
4. Estimate the overall benefit of improving power system resilience.

Estimating the likelihood of a separation event

There have been five non-credible separation events resulting in the loss of the Heywood Interconnector since the NEM started 17 years ago.¹¹⁵ Although three of these events involved the trip of the Northern Power Station, which is no longer relevant (it closed in May 2016), the resulting decrease in system strength and resilience has left the South Australian system more susceptible to smaller events.

Although there is no evidence that the separation risk has changed in recent years, the likely impact of a separation event has significantly increased in severity, due to the changing energy mix and increased interconnector flow. For the purpose of this assessment, South Australia is estimated to separate from the eastern states every 3.4 years (29% probability per year).

Estimate the probability that a separation event will result in a state-wide blackout

In the event of a loss of synchronous separation, the South Australian power system must rely entirely on its own generation fleet and automatic protection systems to balance supply and demand. Although there are several instabilities that must be addressed to avoid a wide-spread blackout, frequency stability (high RoCoF) will often be the most limiting factor. Simulated interconnector flow and unit commitment was used to determine the frequency stability impacts of a loss of separation. In recent years, the decreasing availability of synchronous power stations in South Australia and the increase in interconnector capacity has resulted in a greater risk of frequency instability in South Australia following a loss of interconnection (see Figure 33).

For this assessment, it is assumed that no load shedding will occur in response to a separation event where frequency changes at 1 Hz/s or less, and that the entire South Australian system will be blacked out for a separation event resulting in at least 4 Hz/s.¹¹⁶ The annual results from this approach are listed in Table 15.

Estimate the total customer supply interrupted for a single state-wide blackout

To estimate the impact on customer demand, AEMO reviewed historic state-wide demand and analysed international blackouts of similar size. The average underlying South Australian customer demand is approximately 1,500 MW, and is forecast to be relatively flat.

The following table provides data¹¹⁷ for four blackout events that are somewhat similar to a South Australian blackout. The events have been averaged to provide an estimate for the duration of a South Australian blackout. The estimated duration of a blackout event for South Australia used for this purpose is approximately 12 hours.

¹¹⁵ AEMO. Future Power System Security (FPSS) Progress Report. Available at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx>.

¹¹⁶ For this study, the estimated impact on South Australian load shedding is linearly interpolated for separation events with RoCoF between 1 Hz/s and 4 Hz/s. For example, it is assumed that half of South Australian demand will be shed in response to a 2.5 Hz/s separation event.

¹¹⁷ AEMC Reliability Panel (prepared by DGA Consulting). International Comparison of Major Blackouts and Restoration. Available at: <http://www.aemc.gov.au/getattachment/144f4579-f61f-41ea-803f-2048e2eb695d/DGA-Consulting-International-comparison-of-major-b.aspx>.



Table 14 International blackout events similar to a hypothetical South Australian interruption

Blackout Event	Load interrupted (MW)	Duration (hours)
2013 Sarawak, Malaysia	1,600	8.5
2008 Oahu, Hawaii, USA	1,000	18 [†]
2011 San Diego, California, USA	8,000	12
2016 South Australia, Australia	1,553	9.2 [‡]

[†] This figure relates to the time until approximately 90% to 95% of load was given permission to be restored.

[‡] Extensive storm damage slowed restoration north of Adelaide. This duration projects the approximate time for customer demand to be restored if the restoration rate didn't slow due to network damage.

The rate at which customer demand is restored can also impact the cost-benefit assessment. Restoration data from a wide-scale blackout in Turkey¹¹⁸ and from the recent South Australian blackout indicate that load restoration begins slowly, speeds up, and is completed slowly (that is, restoration follows a sigmoid or “S” shaped curve).

Using the assumptions above, a state-wide blackout in South Australia would result in a total interruption of approximately 9,000 megawatt hours (MWh) of customer energy.

Estimate the overall benefit of improving power system resilience

In 2014, AEMO completed a review of its VCR.¹¹⁹ After adjusting for CPI, the average national planning VCR for South Australia is currently \$34,965/MWh.

The VCR application guide highlights that the VCR may not accurately estimate the impacts of widespread or prolonged outages¹²⁰, and that additional offsets might be required to extrapolate the VCR. With the data currently available, a sensitivity where VCR is doubled was used as a proxy to capture the direct and indirect economic impacts. This approach broadly aligns with the South Australian Council of Social Service (SACOSS), which used AEMO’s VCR and a sensitivity based on the economic impacts of a similar event, resulting in a multiple approximately 2.42 times the current VCR.¹²¹

Using the two VCRs and the total interruption size (presented in the previous section), the economic impact of a single South Australian blackout is estimated between \$315 million and \$629 million. This results in an average of \$472 million, which is well aligned with the “default blackout cost” of \$476 million that was estimated by Deloitte for the Reliability Panel’s review of system restart ancillary services (SRAS) standards.¹²²

Using the results from the frequency stability assessment, the annual risk of a state-wide blackout can be approximated, and are listed in the table below.

¹¹⁸ Project Group Turkey. *Report on Blackout in Turkey on 31st March 2015*. Available at: https://www.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/20150921_Black_Out_Report_v10_w.pdf.

¹¹⁹ AEMO. *Value of Customer Reliability*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review>.

¹²⁰ The VCR approach was based on customer surveys. Respondents were not expected to have a good understanding of the social and safety impacts related to widespread or prolonged outages.

¹²¹ SACOSS. *Looking Around the Corner—A discussion on Current South Australian Power System Risks*. Available at: <https://www.sacoss.org.au/looking-around-corner-discussion-current-south-australian-power-system-risks>.

¹²² Deloitte Access Economics. *Economic assessment of System Restart Ancillary Services in the NEM*. Available at: <http://www.aemc.gov.au/getattachment/6e6ad6c7-584c-4993-98f3-7589fec6b506/Deloitte-Access-Economics-Economic-Assessment-of-S.aspx>

Table 15 Annual benefits from improving South Australia’s power system resilience

Year	Likelihood of state-wide blackout ^a	Probability weighted economic cost of blackout risk
2016–17	8%	\$37 million
2021–22	8%	\$39 million
2026–27	11%	\$52 million
2031–32	11%	\$54 million
2036–37	13%	\$60 million

^a This projection is based on a combination of historic and forecast data, and is intended for economic analysis only.

5.3 Solutions to improve South Australian power system resilience

The feasibility of two interconnector options, and one local solution, are presented in the following sections.

The 2016 NTNDP analysis has found that there is no “silver bullet” solution that addresses the challenges relating to a low carbon future. Operational measures and non-network options will play an important role in this transition, and local development will be required to ensure sufficient system strength in each region.

Operating an interconnector below its maximum transfer limit can improve system resilience, which decreases the risk of separation, but this trades off other market benefits

5.3.1 Expanding the VIC–SA interconnector: “HorshamLink”

HorshamLink is a proposal to upgrade the existing VIC–SA interconnector by adding a parallel link between Tungkillo in South Australia and Horsham in Victoria.

This new link could be single or double circuit, and would increase the capability of the West Victorian transmission network to connect renewable generation. In 2017, AEMO will initiate a RIT-T in West Victoria, in response to the large number of proposed generation connections.

The following figure illustrates the proposed location of the HorshamLink. The solid green lines illustrate the path of proposed new circuits, and the dashed green line highlights an upgrade that is under investigation for an upcoming RIT-T (the West Victoria upgrade mentioned in the 2016 VAPR).

Figure 35 Proposed HorshamLink path



The following table summarises the high-level costs, dates, and capacity for two options that utilise the HorshamLink path.

Table 16 HorshamLink options summary

Interconnector	Capacity	Cost	Commissioning date
Single circuit	325 MW	Approximately \$500 million	2021
Double circuit	650 MW	Approximately \$750 million	2021

While feasibility studies have been completed, detailed technical studies are required to establish that the single or double circuit HorshamLink options are likely to deliver the full system resilience benefit.¹²³ The market benefit assessment in Chapter 3 focuses on the single circuit option. A double circuit option is more likely to maintain interconnection during severe events, and will deliver greater fuel cost benefits due to its higher capacity.

Augmentation details

The proposed HorshamLink comprises:

- New single or double circuit between Tungkillo and Horsham at 275 kV to provide increased interconnection.
- Phase-shifting transformer or other high impedance control on each new circuit (above), to balance flows between the proposed link and the existing Heywood link.
- 275 kV / 220 kV transformers at Horsham to facilitate a connection of the two networks.

¹²³ For the purpose of this economic assessment, AEMO has assumed that a double circuit option will capture the full system resilience benefit once commissioned, while a single circuit option will capture half that benefit.



- Stringing and commissioning the vacant 275 kV circuit between Tailem Bend and Tungkillo.
- Dynamic reactive support and fault contribution along the 275 kV network in South Australia (such as synchronous condensers).
- Dynamic reactive support and fault contribution in North West Victoria (such as synchronous condensers).
- Very fast special control scheme to protect lines from thermal overload and protect against voltage collapse in the event of a double circuit outage.
- This project is estimated to cost between approximately \$500 million and \$750 million.

Connecting renewables

The HorshamLink proposal would deliver benefits relating to facilitating renewable generator connections in West Victoria, and between Tailem Bend and Horsham. AEMO has already indicated that a RIT-T will be commencing to accommodate the high number of renewable energy connections between Horsham and Ballarat.

Reactive power and system strength requirements

Preliminary studies have found a need for both reactive support and fault contribution along the 275 kV network near Robertstown in South Australia, and in North West Victoria. These needs can be met simultaneously with synchronous condensers.

These preliminary studies indicate that this requirement can be met with a combination of:

- Synchronous condenser at Tailem Bend.
- Synchronous condenser at Horsham.
- Synchronous condenser at Red Cliffs.

Special protection scheme

To improve South Australian power system resilience, a key design criteria for any new interconnector is the ability to withstand a possible loss of the parallel interconnector. To achieve this criteria, a special protection scheme may be required to rapidly shed load or generation following the loss of one double circuit link.

High level cost-benefit

Based on simulated market conditions and generation expansions in the Neutral scenario, the HorshamLink interconnector proposal is projected to deliver positive gross market benefits of approximately \$425 million. The system resilience benefits account for about 38% of these benefits (\$161 million). See section 3.2 for further details.

5.3.2 The SA–NSW interconnector: “RiverLink”

The RiverLink proposal would connect the South Australian network from Robertstown to Buronga in New South Wales (via the Riverland region). This new link could be single or double circuit, and would increase the capability of the South West New South Wales transmission network to connect renewable generation in Eastern South Australia and Southern New South Wales.

Geographic diversity is an important quality of any interconnector proposal, because it will reduce the risk of separation due to weather events (such as bushfire, storm, or cyclone). The RiverLink proposal provides better geographic diversity than HorshamLink, because it provides an entirely distinct path, whereas HorshamLink meets the existing interconnector at Tailem Bend.

The following figure illustrates the location of the proposed RiverLink.

Figure 36 Proposed RiverLink path



The following table summarises some high-level attributes of these options.

Table 17 RiverLink options summary

Interconnector	Capacity	Cost	Commissioning date
Single circuit	300 MW	Approximately \$500 million	2021
Double circuit	650 MW	Approximately \$1 billion	2021

Detailed technical studies are required to prove that the single or double circuit RiverLink options would deliver the system resilience benefit (for example, ensure that it would remain connected in the event of a loss of interconnection at Heywood).¹²⁴

Augmentation details

The major components proposed for RiverLink are:

- Single or double circuit between Robertstown and Buronga at 275 kV to provide increased interconnection.
- Phase-shifting transformer or other high impedance control on each new circuit (above), to balance flows between the proposed link and the existing Heywood link.
- Up-rating of Darlington Point to Buronga to 275 kV to avoid thermal congestion in South West New South Wales.
- Two 330 / 220 kV transformers at Darlington Point to deliver supply to the existing connection.
- Two 275 / 220 kV transformers at Buronga to deliver supply to the existing connection.

¹²⁴ For the purpose of this economic assessment, AEMO has assumed that a double circuit option will capture the full system resilience benefit once commissioned, while a single circuit option will capture half that benefit.

- One 275 kV / 22 kV transformer at Balranald to deliver supply to the existing connection.
- Line upgrades between Red Cliffs and Buronga to avoid thermal congestion or damage in the event of an outage.
- Stringing and commissioning the vacant 275 kV circuit between Taillem Bend and Tungkillo (for the double circuit option only).
- Dynamic reactive support and fault contribution along the 275 kV network in South Australia (such as synchronous condensers).
- Dynamic reactive support and fault contribution in North West Victoria (such as synchronous condensers).
- Very fast special control scheme to protect lines from thermal overload and protect against voltage collapse in the event of a double circuit outage.

This project is estimated to cost between approximately \$500 million and \$1 billion.

Reactive power and system strength requirements

High-level studies have found a need for both reactive support and fault contribution along the 275 kV network near Robertstown in South Australia, in North West Victoria, and near Buronga in New South Wales. These needs can be met simultaneously with synchronous condensers.

High-level studies indicate that this requirement can be met with a combination of:

- Synchronous condenser at Robertstown.
- Synchronous condenser (or SVC) at Buronga.
- Synchronous condenser at Bendigo.

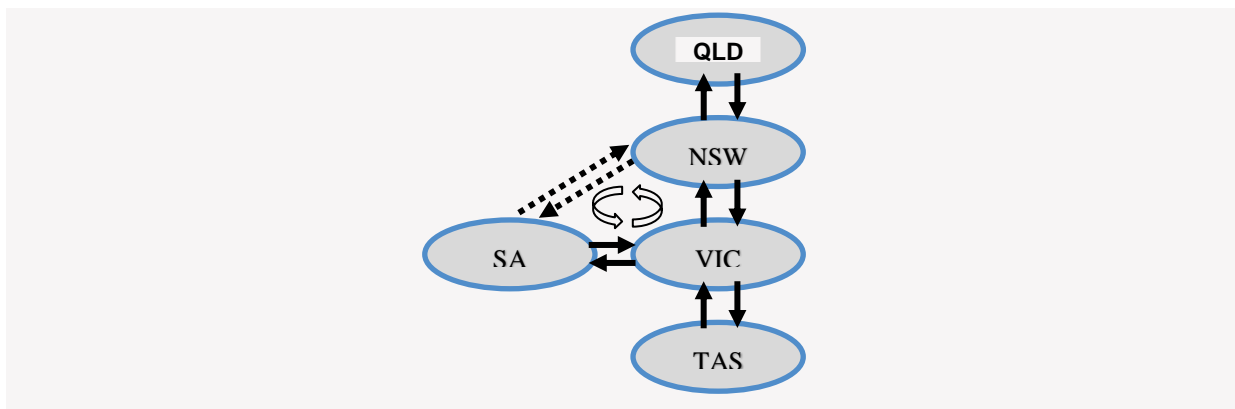
Special protection scheme

To improve South Australian power system resilience, a key design criteria for any new interconnector is the ability to withstand a possible loss of the parallel interconnector. To achieve this criteria, a special protection scheme may be required to rapidly shed load or generation following the loss of one double circuit link.

Loop flows

A connection between South Australia and New South Wales would create a loop between regions (see figure below), which can affect operation of the electricity market. Although the current design has parallel interconnectors between Queensland and New South Wales, and between South Australia and Victoria, one of each pair is DC and is separately dispatchable. Creating a separate AC link between South Australia and New South Wales (see figure below) will require a review of NEM market design.

Figure 37 Loop flow resulting from SA to NSW connection

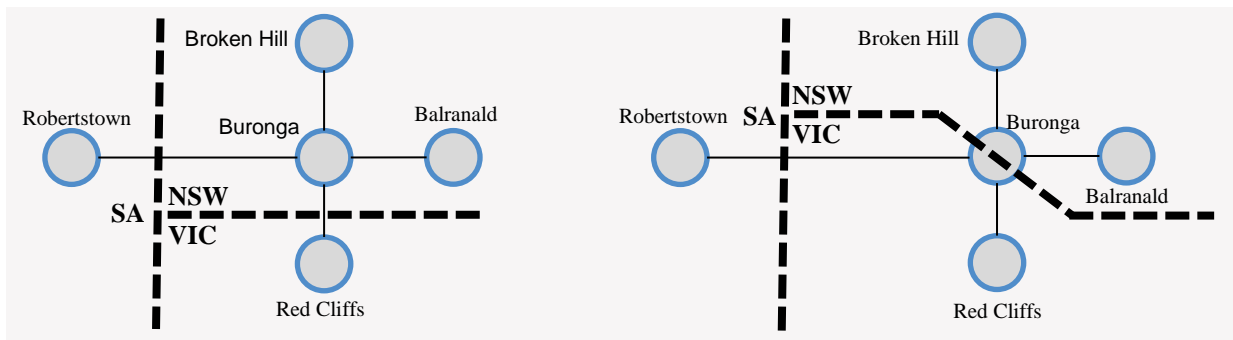


This loop in major transmission paths would require several key considerations:

- Separate AC interconnectors are physically related (via Kirchhoff’s law – power will take the path of least resistance), and cannot be separately dispatched based on market forces. Some form of flow-based market coupling would be required to ensure the physical relationship between the two interconnectors was maintained.¹²⁵
- Models that determine transmission losses will become complex and may necessitate design changes to the NEM dispatch engine.
- Under some constrained conditions, market prices can increase above the prices bid by generators (the “spring washer effect”¹²⁶).
- Inter-regional settlement residues will become more complex and may require market design solutions.

Although creating a separately dispatchable parallel AC interconnector is feasible, for this study the loop flow issues have been avoided by redefining the existing VIC-SA interconnector as a combination of Heywood and the RiverLink. This involves shifting the Victoria to New South Wales boundary slightly so that where the RiverLink interconnector connects in Buronga is defined as being in Victoria (see figure below).

Figure 38 Region boundary before (left) and after (right) possible boundary shift



High level cost-benefit

Based on simulated market conditions and generation expansions in the Neutral and Low Grid Demand scenarios, the RiverLink interconnector proposal is projected to deliver gross market benefits of approximately \$413 million. The system resilience benefits account for about 39% of these benefits (\$161 million). See section 3.2 for further details.

5.3.3 A local solution (synchronous condensers)

A local solution could be designed to improve the resilience of the South Australian power system. Because a non-network solution would involve services that might be contracted from existing generation, it is difficult to estimate the cost of a solution without completing a formal tender. As part of their RIT-T, ElectraNet has initiated an expression of interest to determine the feasibility of this kind of option.

A non-network option will not materially increase the import or export capability of South Australia, and will therefore not deliver the same range of benefits captured by an increase in interconnection. Rather than preventing load shedding, this solution aims to limit the extent of load shedding so that it can be

¹²⁵ This might be achieved by creating constraint equations that link the flow on one interconnector directly to the flow on the other. Alternatively, the two interconnectors could be dispatched as one if the New South Wales region boundary is shifted.

¹²⁶ When pricing regions are connected with a closed loop, the possibility arises of distorted prices due to multiple power flow paths between generation and the load. AEMO has studied this effect, also called the spring washer effect, and determined that significant but not expensive alterations would be required to the dispatch algorithm to counter the effect.



quickly restored. Because of this, the local solution is estimated to capture approximately 90% of the system resilience benefit presented in Section 5.2.1.

As detailed in Section 5.2.1, the solution to South Australia's emerging system resilience must address:

- Frequency stability.
- Frequency regulation.
- Transient and voltage stability during and after a separation event.
- System strength so that renewable generation can ride through a fault, protection systems can correctly operate, and voltages can be effectively managed.

The approximate cost of this local collection of solutions is estimated at \$455 million, and would be cheaper if scheduled generators offered to provide services at a more economic price. The net benefits attributed to this solution is estimated at \$21 million.

Frequency stability requirement

Following a sudden loss of interconnection, South Australia will have a power imbalance. To maintain frequency stability post separation, a minimum amount of inertia is required so protection and control schemes can operate before the power imbalance reaches a point of no return.

In 2015–16, the inertia in the South Australian power system ranged from 1,880 MWs to 19,086 MWs, with an average of 7,374 MWs. To limit RoCoF to 3 Hz/s at periods of high interconnector flow, approximately 7,500 MWs of inertia is required (see section 5.2.1).

The approximate cost of achieving this inertia with high-inertia synchronous condensers is \$350 million to \$400 million, and therefore accounts for the majority of the cost the local solution.

Frequency regulation requirement

In the event that the South Australian power system withstands the immediate loss of separation, frequency must be regulated so supply and demand can be balanced. Currently, at least 35 MW of regulation FCAS is required to perform this task. AEMO can only procure this service when there is a credible risk of separation.

The most likely solutions to provide frequency regulation are:

- Synchronous generation (online prior to separation).
- Upgrading the Murraylink DC interconnector to regulate frequency.
- Scheduled battery storage (commercial or distributed).
- Wind farm control systems, which can provide both raise¹²⁷ and lower frequency regulation, if designed to do so (this capability does not currently exist within the current fleet).

Transient and voltage stability, and system strength requirements

A sudden imbalance of power in a region, such as that caused by a loss of interconnection, can cause transient instability or voltage collapse. A non-network solution that provides inertia will likely also improve transient and voltage stability, and system strength (because inertia is generally provided by synchronous machines which support these stability limits).

Any specific combination of services that can deliver a system resilience benefit will need to undergo detailed analysis to determine the resilience to transient and voltage stability, and their impact on system strength.

¹²⁷ Currently, there are no wind farms in the NEM that provide frequency regulation. To provide raise regulation, the wind farm would likely need to operate below its capability and respond to frequency needs.



5.3.4 Interim solutions to improve South Australian power system resilience

The long-term solutions detailed in the previous sections have lead times up to five years. For this reason, it will likely be economic to provide an interim solution that improves South Australian power system resilience.

To be effective, and to limit distortion to the electricity market, operational solutions will be most effective when paired with a special protection scheme that rapidly disconnects a portion of load or generation in South Australia following a separation event. This scheme would reduce the impact and period of any possible interruption following a separation event.

Several recent rule change proposals have suggested possible mechanisms to deliver system security for events such as a Heywood separation. In response to these rule change proposals, the AEMC initiated a system security market frameworks review.¹²⁸ AEMO is working closely with the AEMC to coordinate the analysis and implementation of a range of measures to maintain future power system security (see Section 4.2.2).

5.3.5 Other solutions not presented

This study did not consider further upgrades to the existing Heywood Interconnector, because they would not provide geographic diversity to the existing link. This would still leave South Australia at a risk of separation due to weather events that might affect the area between Sydenham (Victoria) and Tailem Bend (South Australia).

The possibilities of connecting the South Australian network directly to Queensland or Tasmania were not considered in depth. The distances involved in these options result in higher costs, especially when stations are added to facilitate generator connections. AEMO will continue to evaluate the merits of these options in the long-term strategic development of the NEM.

A detailed RIT-T might explore these options in further detail.

¹²⁸ AEMC. System Security Market Frameworks Review. Available at: <http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review>.

CHAPTER 6. TASMANIAN TRANSMISSION DEVELOPMENT OPTIONS

Key insights

- A second Bass Strait Interconnector may provide net market benefits, but the outcomes are sensitive to assumptions on future grid demand, climate change policy, and uptake of large-scale battery storage. A second Bass Strait Interconnector is projected to deliver:
 - Positive net market benefits of \$20 million in the Neutral scenario
 - Negative net market benefits of -\$147 million and -\$57 million in the Low Grid Demand and 45% Emissions Reductions scenarios respectively.
- A second Bass Strait Interconnector delivers greatest net market benefits when combined with additional interconnection between other NEM regions (including additional South Australian interconnection), by facilitating greater utilisation of Tasmanian hydro generation resources, and taking advantage of geographic diversity in intermittent generation.
- While a second Bass Strait Interconnector may support power system resilience by facilitating FFR services and FCAS, these support services are already provided more efficiently by existing hydro generators in Tasmania and Victoria.
- Adding more renewable generation into Tasmania may reduce system inertia and system strength in that region. This could be addressed by utilising existing hydro and GPG operating as synchronous condensers, or implementing new network or non-network solutions such as new synchronous condensers, fast frequency services from wind generation, and battery storage.
- A second interconnector would require transmission network extension from Sheffield to Smithton (in Tasmania) and connection at Tyabb (in Victoria), which has been included in the cost of the interconnector. There are no other material differences in intra-regional transmission network augmentation needs across the NEM, with or without a second Bass Strait Interconnector.

6.1 Background

On 20 December 2015, the Basslink Interconnector experienced a fault that led to the cable being out of service until 13 June 2016.¹²⁹ The combination of the Basslink outage and record low rainfall over the period before and during the outage meant that Tasmania experienced one of the most significant energy challenges in its history.

During the Consultation process for the 2016 NTNDP, stakeholders highlighted an interest in a high level assessment of an additional interconnector between Victoria and Tasmania to examine whether a second Bass Strait interconnector could lower overall electricity costs in the NEM, improve Tasmania's energy security, and facilitate renewable energy investment in the state.¹³⁰

The existing Basslink Interconnector facilitates imports of electricity into Tasmania when there is a shortage of local generation (low water storages and wind generation), and/or low wholesale energy prices in Victoria. Exports occur when there is excess local generation (high water levels or wind generation) and/or high wholesale energy prices in Victoria. A second Bass Strait interconnector would expand these capabilities and may take advantage of changes in the NEM generation mix.

¹²⁹ Basslink, 2016. Available: <http://www.basslink.com.au/media/>.

¹³⁰ Tasmanian Energy Security Taskforce, 2016. *Consultation paper*. Available: http://www.stategrowth.tas.gov.au/tasmanian_energy_security_taskforce/consultation_paper.

AEMO has taken a strategic approach to this assessment, including consideration of how the NEM is likely to evolve in the future and what effects a second Bass Strait interconnector, or other interconnectors, would have on this evolution and on power system operation.

AEMO has assessed:

- The market benefits of a second interconnector between Tasmania and Victoria.
- The network augmentations and other power system changes required to facilitate the concurrent development of a second interconnector and substantial additional wind generation in Tasmania.
- The potential benefits of further interconnector developments between Victoria and South Australia, and the concurrent development of a second Bass Strait interconnector.

6.2 The driver for augmentation

Notwithstanding the six-month outage of the Basslink Interconnector in early 2016, the primary benefits of a second Bass Strait interconnector do not relate to providing redundancy for Basslink, but rather to:

- Deferring the need for peaking generation capacity investments in the mainland NEM.
- Reductions in fuel and variable operating and maintenance costs, due to production from hydro and wind generation in Tasmania displacing natural gas generation in the mainland NEM.

A second interconnector would also provide reliability benefits (improve energy security) in the rare event that the Basslink Interconnector is out of service, and these are also included in the analysis.

The cost-benefit assessment does not include any potential benefits related to increasing competition, variations in rainfall in Tasmania, or any potential change in ancillary service costs. A more detailed study would be necessary to assess these benefits, which is out of scope for this NTNDP.

6.3 Interconnector configuration

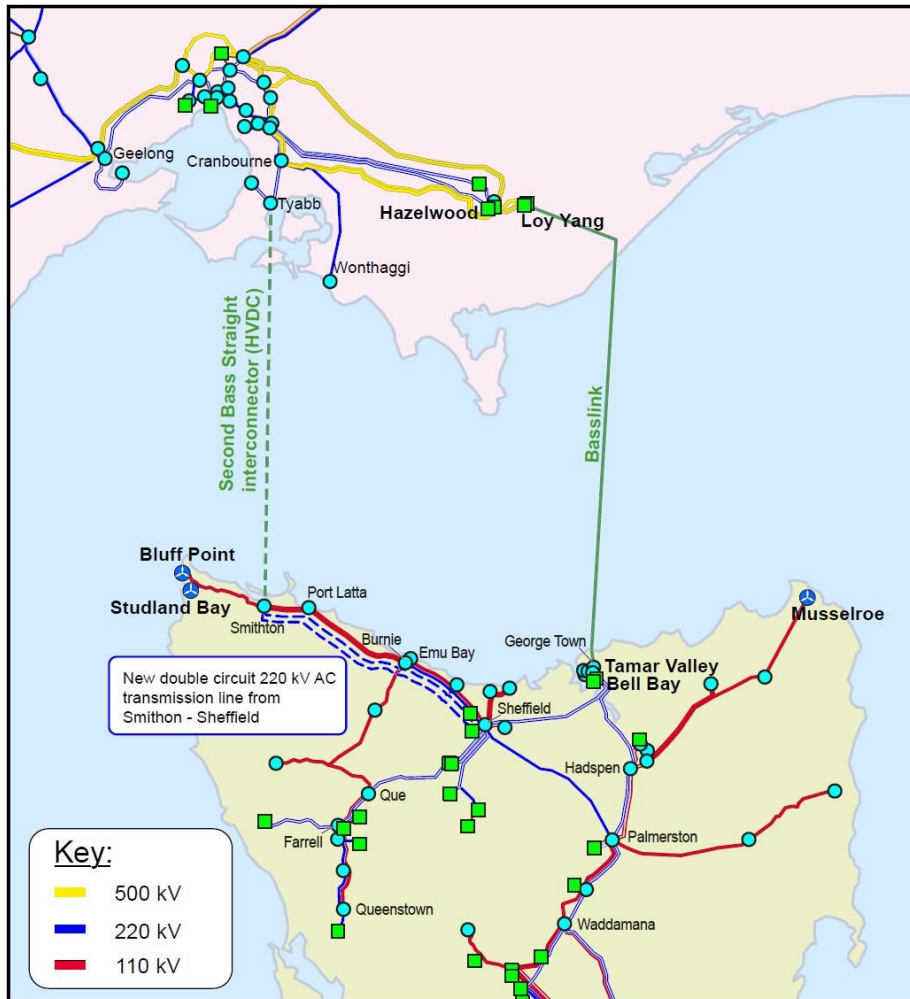
A second Bass Strait interconnector was modelled with 600 MW transfer capacity between Victoria and Tasmania. The only feasible option to transfer 600 MW over an approximately 300 km distance across the Bass Strait is high voltage direct current (HVDC) technology.

In this high level assessment, HVDC based on Voltage Source Converter (VSC) technology was considered, with an operating voltage of ± 320 kV. HVDC VSC technology has the ability to connect to the weaker power system.

There are number of possible routes for the second HVDC submarine cable and connection points in Victoria and Tasmania. In this study, a route between Smithton (in north-west Tasmania) and Tyabb (south-east of Melbourne) has been modelled. Smithton has large wind power generation potential with relatively high capacity factor compared to wind power generation from other locations. Tyabb is closer to the major load centre in Victoria.

Figure 39 below shows the route of the modelled second interconnector. A number of separate routes are possible for the connection of a second interconnector. A detailed RIT-T type of studies may consider other possible routes and connection points.

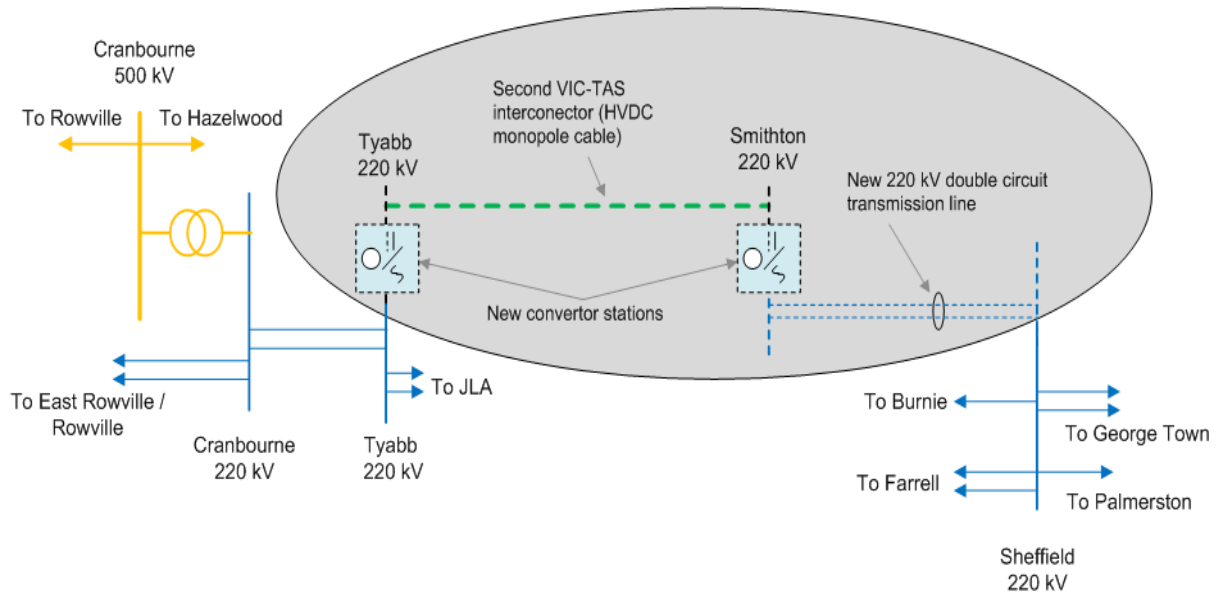
Figure 39 Second Bass Strait interconnector route and connection points



An additional 220 kV double circuit transmission line from Sheffield to Smithton (approximately 130 km) would be required to facilitate the connection of a second Bass Strait interconnector. This 220 kV line is also required to accommodate large amount of wind power generation in North-West Tasmania. A new substation and converter station would be required at Smithton or in the North-West Tasmania. The existing network in Victoria could accommodate additional transfer between Tasmania and Victoria. A new converter station would be required at or close to Tyabb.

Figure 40 below shows the network configuration for the connection of the proposed second Bass Strait interconnector.

Figure 40 Second Bass Strait interconnector – electrical connection



6.4 Assessment of net benefits

The full details of the net benefits assessment can be found in Section 3.2. The assessment found positive net benefits for a second Bass Strait interconnector in the Neutral scenario (\$20 million), but not in the Low Grid Demand or 45% Emissions Reduction scenarios. Nonetheless, the interconnector may still warrant further investigation in a RIT-T, particularly in combination with other interconnector developments.

6.5 Network limitations in Tasmania associated with a new interconnector

The potential network limitations in Tasmania associated with the second Bass Strait interconnector are shown in Section 3.3.5.

In both Neutral and Low Grid Demand scenarios, a projected economic dispatch limitation was identified on the Sheffield–Palmerston 220 kV circuit, as it exceeded continuous ratings during system normal operation. This constraint is projected to be driven by high generation in Southern Tasmania, coupled with high export via the second interconnector.

Options to address this thermal limitation would include line uprating of existing 220 kV circuits for a higher thermal rating or a second Sheffield to Palmerston 220 kV circuit.

No network thermal limitations were identified to meet maximum demand, in any of the three scenarios.

6.6 Power system security considerations

Greater interconnection with the mainland will provide hydro generation with more flexibility to generate at times of greater value, either during high demand periods or when renewable generation is low. This is likely to result in peakier utilisation of hydro and increase the period of time where no hydro plant is generating, especially at times of high imports from the mainland. Additional wind generation in Tasmania will amplify this change in hydro utilisation.

The lack of hydro generation at certain times may lead to power system security challenges such as reduced system inertia, FCAS capability, and system strength in the Tasmanian power system. As a consequence, frequency and voltage control is expected to become more challenging in Tasmania.



A number of existing hydro generators and GPG in Tasmania could provide inertia services and system strength services by operating in synchronous condenser mode, but there are currently no market-based incentives for these services.

There is a market mechanism to procure adequate FCAS capability through the NEM Dispatch Engine (NEMDE). This mechanism would result in rescheduling generation in Tasmania, and transfer on the Bass Strait interconnectors, to increase FCAS availability in Tasmania.

Retirement of coal generation in the mainland would reduce available FCAS in the NEM. As discussed in Section 4.2.3, sufficient sources of FCAS capability are projected on the mainland and through the existing Basslink Interconnector, without the need for additional interconnection.

In the Low Grid Demand scenario, a number of large industrial loads are projected to retire in the NEM, including in Tasmania. In this case, the unavailability of large industrial load is projected to affect the existing frequency control special protection scheme (FCSPS) and lead to frequency control challenges. To address this without a second Bass Strait interconnector, imports from Victoria to Tasmania would need to be reduced. With FCSPS not in service, a second interconnector could improve frequency control and allow increased imports from Victoria to Tasmania.

CHAPTER 7. NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

Key insights

This chapter identifies whether any further Network Support and Control Ancillary Services (NSCAS) are required in the NEM over the next five years.

AEMO's 2016 NSCAS assessment identified:

- A potential NSCAS gap in South Australia based on currently available information. AEMO has determined that at least two large synchronous generating units must be online in South Australia to maintain a secure operating state.¹³¹ This is required to maintain system strength, avoid fast voltage collapse, and ensure transient voltage stability. AEMO will confirm this gap in early 2017 following completion of more detailed analysis.
- All NEM regions have identified other security issues that can be managed operationally within the five-year outlook period. No NSCAS gaps exist when these operational measures are available.

7.1 Types of NSCAS

NSCAS¹³² are non-market ancillary services that may be procured by TNSPs (or by AEMO as a last resort) to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

There are currently three types of NSCAS:

1. Network Loading Ancillary Service (NLAS):

- Maintains power flow in transmission lines within capacity ratings following a credible contingency event; and maintains or increases the power transfer capability of that transmission network, by allowing increased loading on transmission network components.

2. Voltage Control Ancillary Service (VCAS):

- Maintains the transmission network within voltage stability limits, and
- Maintains or increases the power transfer capability of that transmission network, by improving voltage control and voltage stability.

3. Transient and Oscillatory Stability Ancillary Service (TOSAS):

- Controls power flow into or out of the transmission network, to maintain the transmission network within its transient or oscillatory stability limits, and
- Maintains or increases the power transfer capability of that transmission network, by improving transient or oscillatory stability.

¹³¹ AEMO, 2016. *Market Notice 56089*. Available: <https://www.aemo.com.au/Market-Notices?currentFilter=&sortOrder=&searchString=56089>.

¹³² NSCAS information, procedures, and guidelines are available at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines>.

7.2 NSCAS gaps for maintaining power system security

The following sections present the outcomes from the 2016 NSCAS assessments.

7.2.1 New South Wales

Under low demand conditions, over-voltages can occur at the Kangaroo Valley and Bendeela 330 kV buses as a result of a credible contingency. The over-voltage can be mitigated by other operational measures. Therefore no NSCAS gap for maintaining power system security is projected in New South Wales over the outlook period.

7.2.2 Queensland

South East Queensland may experience transmission line overloads or high bus voltages during certain operating conditions. These issues can be managed by line switching. Therefore, no NSCAS gap for maintaining power system security is projected in Queensland over the outlook period.

7.2.3 South Australia

The 2016 NSCAS assessment for South Australia has identified one NSCAS gap relating to system strength, and one potential challenge relating to high voltages for which no NSCAS gap is identified as it can be managed operationally.

System strength

On 13 November 2016, the South Australian power system was operating with one synchronous generating unit in service.¹³³ AEMO has completed a preliminary analysis of the period, and concluded that two large synchronous generating units are required to be online in South Australia to ensure a secure operating state as defined in clause 4.2.2 of the NER.

Preliminary analysis by AEMO concluded that the following generator combinations can meet this requirement:

- Two Torrens Island B generating units.
- One Torrens Island B unit and eight Hallett Power Station generating units.
- One Torrens Island B unit, one Torrens Island A unit, one Quarantine 5 unit, and one other Quarantine generating unit.
- One Torrens Island B unit and one Pelican Point CCGT generating unit.
- One Torrens Island B unit, one Pelican Point GT unit, and two Quarantine 1-4 generating units.
- One Pelican Point CCGT unit and eight Hallett Power Station generating units.
- One Torrens Island A unit, one Quarantine 5 unit, one other Quarantine unit, and eight Hallett Power Station generating units.
- In all relevant combinations, one Torrens Island B unit can be substituted by two Torrens Island A units.

This operational requirement may demonstrate the existence of a new NSCAS gap. Because this operational requirement was recently identified, a detailed investigation is still in progress. AEMO will publish a report in early 2017 to further explore the requirement, and will collaborate with ElectraNet to confirm the existence, size, and trigger date of the NSCAS gap. If the market mechanisms are not successful in meeting the minimum requirement and the latest time to intervene has been reached, AEMO will intervene in the market by issuing a direction to maintain power system security.

¹³³ AEMO. SA System Strength. Available: http://www.aemo.com.au/-/media/Files/Media_Centre/2016/SA-System-Strength.pdf.



High voltages in northern South Australia

Following the closure of Northern Power Station, the South Australian transmission network may experience high voltages in the northern South Australia region and Adelaide metro region during low demand conditions. The same areas have a risk of inadequate reactive power support during high demand conditions.

These issues can be managed operationally, and no NSCAS gap for maintaining power system security is projected in South Australia over the outlook period, while these operational measures are available.

ElectraNet is current progressing a RIT-T to improve voltage control in the northern South Australia region.¹³⁴

7.2.4 Tasmania

The Tasmanian network can experience low system inertia, and – around the George Town area – difficulty with voltage control. Currently, system inertia is maintained at secure levels using a constraint equation that manages the Tasmanian generation mix and Basslink transfer levels. Voltage control can be managed using various control schemes, voluntary generator dispatch from Hydro Tasmania, or by constraining Basslink transfer levels.

Therefore, no NSCAS gap for maintaining power system security will occur in Tasmania over the outlook period, while the same operational measures are available.

7.2.5 Victoria

Under low demand conditions, over-voltages can occur around the Portland area as a result of a credible contingency. The over-voltage can be mitigated by line switching.

No NSCAS gap for maintaining power system security will occur in Victoria over the outlook period, while these operational measures are available.

7.3 NSCAS gaps for maximising market benefits

7.3.1 Queensland, New South Wales, South Australia, and Victoria

The market benefit assessment showed insufficient benefits to NEM consumers from addressing constraints using NSCAS in these regions.

7.3.2 Tasmania

AEMO identified two constraints in Tasmania that have been binding significantly compared to previous years, since Basslink was re-energised in June 2016. These are presented in the table below.

Table 18 NSCSPS constraint equation

Constraint ID	Constraint Description	Marginal Value
T>>T_NIL_BL_EXP_6E	Out = Nil, avoid O/L a Sheffield to Georgetown 220 kV line (flow to Georgetown) for trip of the parallel Sheffield to Georgetown 220 kV line considering NCSPS action.	\$65,729
T>>T_NIL_BL_EXP_7C	Out = Nil, avoid O/L a Farrell to Sheffield 220 kV line for trip of the parallel Farrell to Sheffield 220 kV line considering NCSPS action.	\$41,206

The constraint binding hours have increased due a high volume of hydro generation in Tasmania’s west coast, while other generators in the Central and North West regions have low water levels. This

¹³⁴ For more information, see <https://www.electranet.com.au/projects/northern-south-australia-region-voltage-control/>.

constraint will not result in security issues, but may continue to have a high market impact. AEMO will continue to monitor these constraints to determine if the problem is ongoing.

7.4 Status of NSCAS gaps identified in prior NTNDPs

AEMO procured two VCASs (Voltage Control Ancillary Service) but did not procure any NLAS (Network Loading Ancillary Service) or Transient and Oscillatory Stability Ancillary Service (TOSAS) for the 2015–16 financial year.

The table below shows the costs for NSCAS services procured between the 2014–16 financial years.

Table 19 NSCAS services and costs from 2014–16

Facility	Benefitting region	NSCAS service	Quantity (MVar)	Cost 2013–14	Cost 2014–15	Cost 2015–16
Combined Murray and Yass substations	NSW	VCAS	800	\$3,195,62	\$9,896,698	\$10,055,572
Combined Murray and Tumut power stations	NSW	VCAS	700	\$41,301,706	\$134,494	\$171,797
Total				\$44,497,327	\$10,031,191	\$10,227,368

The VCAS at Murray and Yass substations is based on a fixed quantity and cost per month.

The VCAS from Murray and Tumut Power Stations is based on an enabling charge per generating unit that is payable for each trading interval when the service is enabled.

7.5 AEMO’s 2016–17 NSCAS acquisition

No additional NSCAS gaps have been identified for 2016–17.

7.6 AEMO’s current NSCAS agreements

AEMO has procured NSCAS under the two following agreements for the period from 30 June 2013 to 30 June 2019, as indicated in Table 19.

7.6.1 Agreement for generation support

AEMO has an NSCAS agreement for the provision of VCAS by generation units running as synchronous condensers from 1 July 2013 to 30 June 2018. This provides both absorbing and supplying reactive power as a bundled reactive capability.

VCAS costs are based on actual usage of the service, which has been progressively reduced since TransGrid commissioned its first reactor at Yass 330/132 kV Substation.

7.6.2 Agreement with TransGrid

AEMO has procured 800 MVar absorbing VCAS from TransGrid, primarily using new network assets, including reactors at Murray Switching Station and Yass Substation. Provision of full VCAS service under this agreement commenced from 31 March 2014 and will end by 30 June 2019. TransGrid is expected to apply to include the relevant network assets in its regulated asset base, and continue to provide the required voltage absorbing capability as a prescribed transmission service, after the expiry of this agreement.

VCAS costs are based on availability of TransGrid’s NSCAS equipment at a fixed cost per trading interval, regardless of usage.

APPENDIX A. GENERATION OUTLOOK

A.1 Introduction

AEMO's generation outlook simulated the future generation mix by incorporating a least-cost expansion of large-scale generation of the NEM over a 20-year outlook period, from 2016–17 to 2035–36. The objective of the expansion plan is to identify the least-cost mix of generation to ensure adequate supply to meet demand at the current NEM reliability standard. The outlook projects the generation mix by fuel type, location, and timing of investments and withdrawals.

The methodology that underpinned the generation outlook is briefly described in section A.2. More detail is in the *Market Modelling Methodology and Input Assumptions*.¹³⁵

Relationship to the National Transmission and Network Development Plan

The generation outlook was an input to the 2016 NTNDP, providing a view of zonal generation required to meet forecast maximum demand and operational consumption.

A unique generation outlook was required for each of the scenarios and interconnector case studies modelled in the NTNDP. For more detailed regional results from each outlook, please refer to the NTNDP webpage¹³⁶ and interactive map.¹³⁷

A.2 Generation outlook methodology

Over the projection period, the generation outlook optimised generation investments, withdrawals, and operational cost, taking into account requirements to:

- Dispatch generation to meet operational maximum demand plus minimum reserve level across each year.
- Ensure sufficient generation reserve is available to meet the reliability standard.
- Meet legislated and advanced policy objectives (Australia's COP21 commitment, LRET, and VRET).

Operational maximum demand requirements

Forecast maximum demand and assumed minimum reserve levels determine the future generation and interconnector capacity required. Annual consumption and the demand profile affect the generation mix that is used to meet demand. The NTNDP:

- Used AEMO's 2016 NEFR¹³⁸ to provide consumption forecasts for each NEM region.
- Assumed minimum capacity reserves set to the size of the largest online generator and to ensure the reliability standard would be met.

Generation requirements

In determining the efficient generation mix required in the outlook, AEMO assumed that all generators were offering to generate (bidding) at their short run marginal cost (SRMC). Each generator's assumed SRMC was based on the information published on AEMO's online NTNDP Database.¹³⁹ This assumed

¹³⁵ AEMO. *Market Modelling Methodology and Input Assumptions*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.

¹³⁶ AEMO. Available: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan>.

¹³⁷ AEMO. Available: <http://aemo.com.au/aemo/apps/visualisations/map.html>.

¹³⁸ AEMO. *National Electricity Forecasting Report*, June 2016. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

¹³⁹ AEMO. *NTNDP Database*. Available: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.



perfect competition in the market, and that generators would be fully flexible to respond to market signals.

Interconnector upgrade scenarios

Analysis of a number of interconnector upgrade options, discussed in Chapter 3, revealed a net market benefit of upgrading existing interconnector capacity linking New South Wales with both Queensland and Victoria. The timing of these upgrades occurs in the 2020s to support increased intermittent generation and supplement New South Wales supply as existing generators retire (specifically, Liddell in 2022–23 and Vales Point 2028–29, both in New South Wales) under the Neutral scenario. These upgrades have been considered in all market modelling for the 2016 NTNDP.

Market benefit analyses of the HorshamLink interconnector, RiverLink interconnector, and second Bass Strait interconnector have been conducted in addition to the upgrade of interconnection capacity between New South Wales and both Queensland and Victoria.

For the purpose of the generation outlook, the HorshamLink and RiverLink interconnector options were considered under the same expansion plan. Dispatch differences between these options were modelled using alternative network constraints to reflect the differing network capabilities of the two alternatives in time-sequential modelling.

Preliminary modelling of all scenarios was conducted, allowing for incremental interconnector upgrades to gain an understanding of the most likely timing of the link augmentation. This timing was subsequently locked down into the simulations.

Emissions reduction objectives

A number of emissions reduction policies were modelled in the 2016 NTNDP, including the COP21 commitment, the LRET, and the VRET.

- The COP21 commitment requires a 26–28% reduction of national emissions by 2030 based on the 2005 emission level.
- The LRET is modelled using updated Large-scale Generation Certificate (LGC) inventories. The policy defines a target renewable generation level in 2020, with liabilities persisting up until 2030 and penalties paid for any non-compliance.
- The Victorian government is in the process of legislating the VRET, which incentivises at least 25% of generation from the region to be sourced from renewable technologies by 2020, and at least 40% by 2025. The developments incentivised by the policy to 2020 are expected to contribute to the LRET objective, while developments beyond 2020 are expected to have their large-scale generation certificates (LGCs) voluntarily surrendered. Beyond 2020, therefore, the policy should contribute to a higher overall renewable penetration than the LRET requires (as is the case with existing Australian Capital Territory reverse auction outcomes). This advanced policy also requires an 80%–20% split between new wind and new solar technologies installed to meet the policy.

Generation dispatch methodology

The primary purpose of the generation outlook is to simulate efficient installation and retirement of generation and transmission investment. Some short-term operational issues, such as the hourly chronology of generation dispatch, transmission network congestion, and hydro-storage coordination, have not been taken into account. This necessitated running a time-sequential model to validate the plausibility of the results of the generation outlook model.

A time-sequential model used the results of the generation and transmission outlook, and a forecast of network limitations, to simulate hour-by-hour generation dispatch across the NEM. This highlighted network congestion that may arise from retiring or building generation in a certain location, as well as other issues the generation outlook model is not designed to capture.



The modelling followed an iterative process, whereby the generation outlook was modified to alleviate some of the network limitations that arose from retiring or building generation in particular locations.

The time-sequential model considered generator operational costs only in dispatching the market, as investment decisions were captured by the generation outlook model. This simulated a perfectly competitive market using an SRMC bidding model, rather than a reflection of strategic bidding behaviours influenced by the portfolio considerations.

In practice, offers from generators will be influenced by a number of real-world factors for the business owning the generator, including:

- Bids for other generators in the portfolio.
- The generator's start-up times and costs.
- The generator's flexibility to respond to signals.
- The retail load being supplied by the business.
- The business' wholesale contract prices and position, and risk profile.

The 2016 NTNDP also used a competitive bidding time-sequential model to simulate levels of inertia, dispatch, and fault levels on the network over the outlook period. The model provides an improved approximation of generation levels as compared to the SRMC model.

Both time-sequential models in the 2016 NTNDP incorporate the regulation currently in place to maintain the expected Rate of Change of Frequency (RoCoF) of the South Australian power system, in relation to the non-credible double circuit trip of the Heywood Interconnector, at or below 3 Hz per second.¹⁴⁰ Flow limits on the Heywood Interconnector were based on the total inertia online in the South Australian region, to ensure the South Australian power system could continue operating after a double circuit outage of the Heywood Interconnector. In cases where an additional AC link between South Australia and either Victoria or New South Wales was built, the constraint limiting flow on the Heywood interconnector was revoked.

¹⁴⁰ AEMO Electricity Market Notice 55358, 12 October 2016. Available: <https://www.aemo.com.au/Market-Notices>.



MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GW	Gigawatt
GWh	Gigawatt hours
Hz	Hertz
Hz/s	Hertz per second
MW	Megawatt
MWh	Megawatt hours
MWs	Megawatt seconds

Abbreviations

Abbreviation	Expanded name
2BSI	Second Bass Strait Interconnector
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COP21	Council of Parties 21
DER	Distributed Energy Resource
DSP	Demand Side Participation
DVAR	Dynamic Volt-Amp. Reactive
FCAS	Frequency Control Ancillary Services
FPSS	Future Power System Security
GPG	Gas-powered generation
HVDC	High Voltage Direct Current
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MRET	Mandatory Renewable Energy Target
NEFR	National Electricity Forecasting Report
NEM	National Energy Market
NPV	Net Present Value
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
OFGS	Over Frequency Generation Shedding
POE	Probability of Exceedance
PV	Photovoltaic
QNI	Queensland-New South Wales Interconnector (upgrade)
R&D	Research and Development
RIT-T	Regulatory Test for Investment - Transmission
RoCoF	Rate of Change of Frequency
SCR	Short Circuit Ratio
SRAS	system restart ancillary services



Abbreviation	Expanded name
SRES	Small-scale Renewable Energy Scheme
STATCOM	Static synchronous compensator
SVC	Static VAr Compensator
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding
VAPR	Victorian Annual Planning Report
VIC-NSW	Victoria-New South Wales Interconnector (upgrade)
VRET	Victorian Renewable Energy Target
VSC	Voltage Source Converter
WSCR	Weighted Short Circuit Ratio



GLOSSARY

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

Term	Definition
active power	Also known as electrical power. A measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts.
ancillary services	Services used by AEMO that are essential for: <ul style="list-style-type: none"> • Managing power system security. • Facilitating orderly trading. • Ensuring electricity supplies are of an acceptable quality. This includes services used to control frequency, voltage, network loading and system restart processes, which would not otherwise be voluntarily provided by market participants on the basis of energy prices alone. Ancillary services may be obtained by AEMO through either market or non-market arrangements.
annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
capacity for reliability	The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard. Capacity for reliability = 10% probability of exceedance (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
capacity limited	A generating unit whose power output is limited.
committed project	Committed transmission projects include new transmission developments below \$5 million that are published in the TNSPs' Annual Planning Reports, or those over \$5 million that have completed a Regulatory Investment Test. Committed generation projects include all new generation developments that meet all five criteria specified by AEMO for a committed project.
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-registered customer or franchise customer.
constraint equation	The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome. See also network constraint equation.
contingency	An event affecting the power system that is likely to involve an electricity generating unit's or transmission element's failure or removal from service.
consumer	A person or organisation who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
credible contingency	Any outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults.
customer	See consumer.
demand	See electricity demand.
demand-side management	The act of administering electricity demand-side participants) possibly through a demand-side response aggregator).
demand-side participation	The situation where consumers vary their electricity consumption in response to a change in market conditions, such as the spot price.
distribution network	A network which is not a transmission network.
electrical energy	Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period.



Term	Definition
	Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses. In large electric power systems, electrical energy is measured in gigawatt hours (GWh) or 1,000 megawatt hours (MWh).
electrical power	Electrical power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts. Also known as active power.
electricity demand	The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes: <ul style="list-style-type: none">• The electrical power consumed by the consumer load.• Distribution and transmission losses.• Power station transformer losses and auxiliary loads.• The ESOO reports demand as half-hourly averages.
embedded generating unit	A generating unit connected within a distribution network and not having direct access to the transmission network.
embedded generator	A generator who owns, operates or controls an embedded generating unit.
energy	See electrical energy.
generating system	A system comprising one or more generating units that includes auxiliary or reactive plant that is located on the generator's side of the connection point.
generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
generation	The production of electrical power by converting another form of energy in a generating unit.
generation capacity	The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions. The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer.
generation expansion plan	A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions.
generator	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity.
impedance	Electrical impedance represents how much opposition a conductor poses to the flow of electricity.
inertia	Produced by synchronous generators, inertia dampens the impact of changes in power system frequency, resulting in a more stable system. Power systems with low inertia experience faster changes in system frequency following a disturbance, such as the trip of a generator.
installed capacity	Refers to generating capacity (in megawatts (MW)) in the following context: <ul style="list-style-type: none">• A single generating unit.• A number of generating units of a particular type or in a particular area.• All of the generating units in a region.
interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
interconnector flow	The quantity of electricity in MW being transmitted by an interconnector.
Large-scale Renewable Energy Target (LRET)	See national Renewable Energy Target scheme.
limitation (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another networks or the amount of electrical power delivered at a defined instant at a connection pint, or aggregated over a defined set of connection points.



Term	Definition
maximum demand	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also National Electricity Law.
national transmission flow path	That portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres. Generally refers to lines of nominal voltage of 220kV and above.
national transmission grid	See national transmission flow paths.
National Transmission Network Development Plan (NTNDP)	An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
National Transmission Planner	AEMO acting in the performance of National Transmission Planner functions.
National Transmission Planner (NTP) functions	Functions described in section 49(2) of the National Electricity Law.
net market benefit	Refers to market benefits of an augmentation option minus the augmentation cost. The market benefit of an augmentation is defined in the regulatory investment test for transmission developed by the Australian Energy Regulator.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to consumers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider.
network capability	The capability of the network or part of the network to transfer electricity from one location to another.
network congestion	When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.
network constraint equation	A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also 'constraint equation'.
network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings.
network limitation	Network limitation describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also network congestion.
network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
network service provider	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER).
non-credible contingency	Any outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involved demand-side participation (including post contingent load relief) and new generation on the load side for the limitation.
power	See 'electrical power'.
power station	In relation to a generator, a facility in which any of that generator's generating units are located.



Term	Definition
power system	The National Electricity Market's (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
power system reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.
power system security	The safe scheduling, operation, and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 (of the NER).
reactive energy	A measure, in varhour (varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power	<p>The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAR (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as:</p> <ul style="list-style-type: none"> • Alternating current generators. • Capacitors, including the capacitive effect of parallel transmission wires. • Synchronous condensers. <p>Management of reactive power is necessary to ensure network voltage levels remains within required limits, which is in turn essential for maintaining power system security and reliability.</p>
region	An area determined by the AEMC in accordance with Chapter 2A (of the NER), being an area served by a particular part of the transmission network containing one or more major load centres of generation centres or both.
regulatory investment test for transmission (RIT-T)	<p>The test developed and published by the AER in accordance with clause 5.6.5B, including amendments.</p> <p>The test is to identify the most cost-effective option for supplying electricity to a particular part of the network. It may compare a range of alternative projects, including, but not limited to, new generation capacity, new or expanded interconnection capability, and transmission network augmentation within a region, or a combination of these.</p>
reliability	The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.
Reliability and Emergency Reserve Trader (RERT)	<p>The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when:</p> <ul style="list-style-type: none"> • Reserve margins are forecast to fall below minimum reserve levels (MRLs), and • A market response appears unlikely.
renewable energy target (RET)	See 'national Renewable Energy Target scheme'.
rooftop photovoltaic (PV)	Includes both residential and commercial photovoltaic installations that are typically installed on consumers' rooftops.
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
security	Security of supply is a measure of the power system's capacity to continue operating within defined technical limits even in the event of the disconnection of a major power system element such as an interconnector or large generator.
substation	A facility at which two or more lines are switched for operational purposes. May include one or more transformers so that some connected lines operate at different nominal voltages to others.
supply	The delivery of electricity.
synchronous condenser	Synchronous condensers are synchronous machines that are specially built to supply only reactive power. The rotating mass of synchronous condensers will contribute to the total inertia of the network from its stored kinetic energy.



Term	Definition
trading interval	A 30 minute period ending on the hour (EST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
transmission network	<p>A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus:</p> <ul style="list-style-type: none">• Any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network.• Any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.
under frequency load shedding (UFLS)	Load shedding takes place if the power frequency falls below a set threshold.
voltage instability	An inability to maintain voltage levels within a desired operating range. For example, in a 3-phase system, voltage instability can lead to all three phases dropping to unacceptable levels or even collapsing entirely.