NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

FOR THE NATIONAL ELECTRICITY MARKET

Published: **November 2015**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared the 2015 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 31 August 2015.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all participants in providing data and information used in this publication.

EXECUTIVE SUMMARY

The National Transmission Network Development Plan (NTNDP) is an independent, strategic view of the development of the national transmission grid in the National Electricity Market (NEM) over the next 20 years.

Key insights of the 2015 NTNDP

The role of the transmission grid is evolving, from the secure transportation of bulk power generation, to include the secure integration of renewable generation and emerging technologies. This reflects a changing paradigm characterised by declining electricity consumption from the grid, an increasing focus on renewable and embedded generation, and withdrawal of thermal synchronous generation (such as coal and gas-fired generation).

- Continuing the trend observed in recent years, expenditure to replace ageing transmission network infrastructure currently outweighs investment in new network capacity. This is expected to continue for the next 20 years.
- Based on the current Large-scale Renewable Energy Target (LRET), the NTNDP modelled up to 6,700 megawatts (MW) of additional large-scale renewable generation investment across the NEM by 2020. Minimal new transmission network infrastructure is required to deliver this generation to consumers, provided generation is located to balance fuel source availability and network costs. There is a risk that concentration of this generation in the same location will cause local transmission congestion due to network limitations.
- New power system infrastructure may be required to provide frequency control and network support services. Currently, regions with high renewable penetration rely heavily on interconnection to provide these services. In future, alternative solutions may need to be explored if higher penetrations of renewable and embedded generation are to be integrated across the NEM.
- As the proportion of behind-the-meter[1] generation increases, detailed information on the location, extent and operation of embedded technologies (including rooftop photovoltaics (PV), battery storage or electric vehicles) will be needed to accurately forecast operational consumption and manage the supply demand balance on the system.

A scenario-based assessment of efficient network development

Each year the NTNDP uses a range of scenarios to examine the efficient development of the national transmission grid. This year, the scenarios reflect the changing use of transmission networks, and take account of current carbon policy incentives, as follows:

- **Gradual Evolution scenario:** assumes operational consumption continues to increase in line with the 2015 National Electricity Forecasting Report (NEFR)[2] medium scenario, and there is a gradual penetration of residential electricity storage to 8 Gigawatt hours (GWh) installed by 2035 as forecast in AEMO's 2015 Emerging Technologies Information Paper.[3]

[1] Behind-the-meter refers to generation, storage and other technologies on consumers' premises, for on-site use.
[2] AEMO, 2015 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 19 October 2015.
[3] AEMO, 2015 Emerging Technologies Information Paper. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information. Viewed: 19 October 2015.

- **Rapid Transformation scenario:** assumes that operational consumption follows the 2015 NEFR low scenario, and is lowered further by greater rooftop PV uptake (33.3 GW installed capacity by 2034–35, compared to 20.9 GW in the Gradual Evolution scenario) and a 40% penetration of residential battery storage (19.1 GWh installed capacity) by 2035. This scenario also assumes 20% of households own an electric vehicle (over 2 million electric vehicles) by 2035.

A sensitivity assuming lower large-scale PV costs is applied to both scenarios, to reflect the possibility of large-scale PV becoming more cost-competitive with wind generation. The Rapid Transformation sensitivity also includes a higher penetration of large-scale renewable generation.

Emerging challenges in managing the power system

As wind and PV generation increases (possibly combined with battery storage), and withdrawal of thermal synchronous generation continues, secure operation of the grid will become more challenging, particularly when demand is low and output from renewable generation is high. These challenges include:

- **Less dispatchable generation:** Increasing rooftop PV in the generation mix will reduce the proportion of total generation controllable through the central dispatch process. For example, under the Gradual Evolution scenario, for 10% of the time, less than 2,030 MW of South Australian generation is expected to be controllable in 2016 (that is, about 60% of total local generation supply, including rooftop PV). By 2025, this is forecast to drop to about 1,540 MW (38% of total local generation supply). Decreasing levels of controllable generation, combined with limited information on the location, extent and operation of embedded technologies (such as battery storage or electric vehicles), will make it increasingly difficult to:
  - Forecast demand, supply and the behaviour of the power system.
  - Balance supply and demand in real time.
  - Control the flows on the grid to remain within secure limits.
- **Inertia and frequency control requirements:** Regions with high proportions of large-scale renewable and embedded generation become dependent on interconnection to other regions for inertia and network support services that maintain power system security.

  Inertia, produced by synchronous generators, 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.

  Through interconnection, inertia and network support services from other regions are currently available to manage unexpected and sudden power system disturbances. As more thermal synchronous generators withdraw from the NEM, there is a risk that there may be insufficient inertia and network support services available to be shared across all regions.
- **Voltage stability during faults:** Synchronous generators provide dynamic voltage support to the power system, particularly during and immediately following network faults. Withdrawal of these generators reduces voltage stability in the surrounding area, meaning there are larger voltage fluctuations during network faults. Most wind and large-scale PV generators in areas with poor voltage stability will struggle to remain connected to the network during network faults, and their power output may need to be restricted to manage this risk.

Proposed work

A program of work is ongoing to evaluate the current and future impact of these challenges on power system operation. This work will also identify feasible solutions to assist in maintaining power system security and reliability. In December 2015, AEMO will publish a joint report with ElectraNet on the power system implications of a changing generation mix, focusing on South Australia. Further studies will be completed in 2016.

New power system infrastructure may be part of the solution. Developments that may be required to manage system security will be factored into future NTNDPs. The 2016 NTNDP will present potential network and non-network options to address the emerging challenges identified in this 2015 NTNDP, and in the forthcoming renewable integration studies.

Minimum demand – Network Support and Control Ancillary Services requirements

At times of minimum demand drawn from the grid, managing high voltage in the transmission network becomes an operational risk in maintaining system security.

The 2015 NEFR, for the first time, included a forecast for minimum demand in South Australia. It projected the growth of rooftop PV would continue to reduce minimum demand levels, and that rooftop PV generation could exceed demand in South Australia during some midday periods from 2023–24.

Within five years, Network Support and Control Ancillary Services (NSCAS) may be required to address high voltage in both South Australia and New South Wales.

NSCAS are non-market ancillary service contracts designed to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. These services are procured by Transmission Network Service Providers (TNSPs), or AEMO as a last resort, to maintain power system security and reliability where operational measures, such as switching lines out of service, are no longer feasible.

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CHAPTER 1. ABOUT THE NTNDP

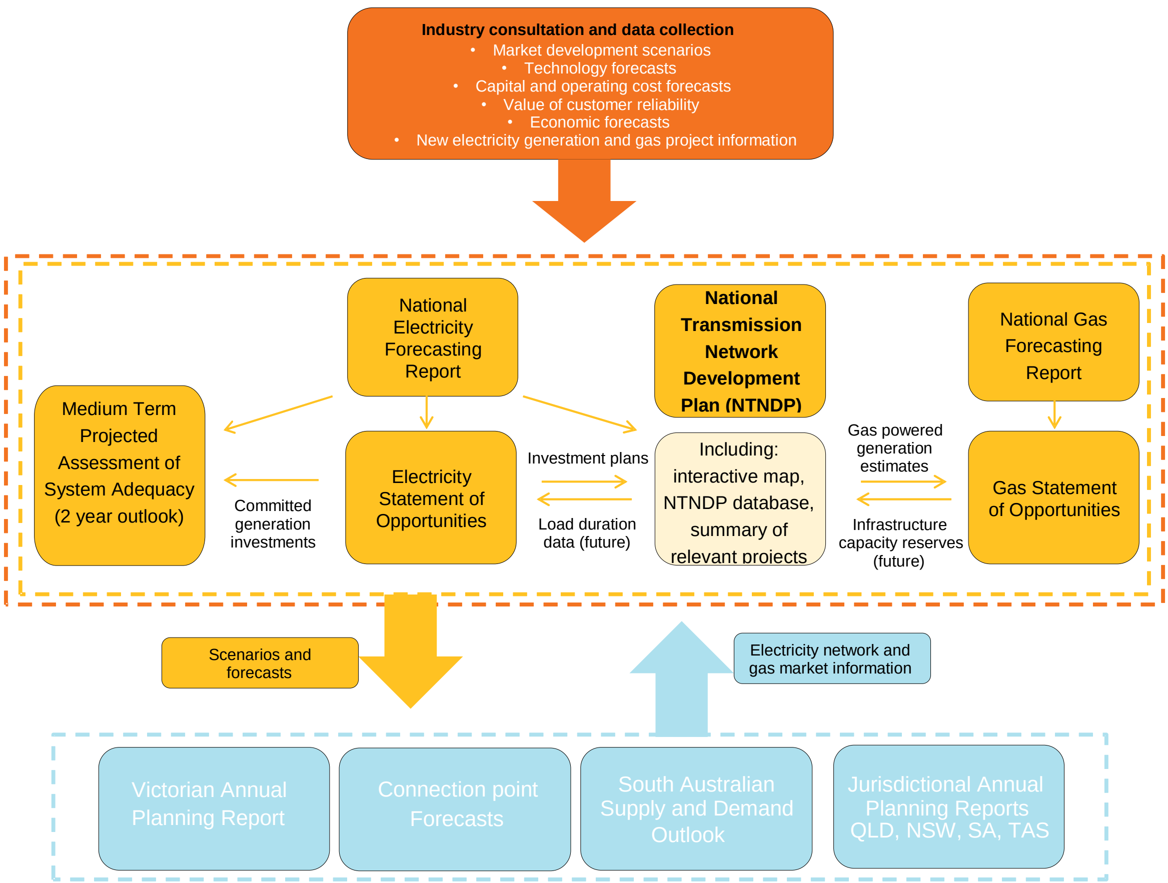
The National Transmission Development Plan (NTNDP) provides an independent, strategic view of the long-term development of the national transmission grid over a 20-year planning horizon. AEMO publishes the annual NTNDP as part of its role as national transmission planner under the National Electricity Law, in accordance with clause 5.20.2 of the National Electricity Rules (the Rules).

This year's NTNDP:

- Reflects on current network investment trends and how these are evolving.
- Examines the thermal capability of transmission flow paths that connect supply sources to population and industrial centres in the NEM.
- Discusses factors impacting power system security, such as levels of inertia and the proportion of total generation managed through the dispatch process.
- Identifies network support and control ancillary service (NSCAS) gaps which may occur in the next five years. These are services that may be needed to manage the security and reliability of the NEM in the near term.

The NTNDP is part of a comprehensive suite of AEMO's planning publications, an overview of which is shown below.

Figure 1 AEMO planning publications



AEMO is also undertaking separate work examining the integration of renewable generation in the NEM, including under specific system operating conditions such as system separation events. A list of relevant completed and proposed work is contained in Appendix D.

A list of supplementary information published with the NTNDP is contained in Appendix E.

The NTNDP contains a number of technical terms and concepts that are defined in the Glossary.

1.1 2015 NTNDP scenarios considered

The NTNDP assesses the need for transmission development under a range of credible scenarios over a 20-year period. These scenarios consider future demand, and the type, location and associated costs of large-scale generation, as well as levels of embedded generation such as rooftop photovoltaic (PV) and demand-side management.

A number of recent events and trends are likely to impact the use, operation and development of transmission networks:

- Reducing residential consumption per capita and less electricity-intensive manufacturing.
- Agreement of the adjusted Large-scale Renewable Energy Target (LRET).
- Announced withdrawals of thermal synchronous generation (coal and gas-fired generation).
- Continued growth of rooftop PV, at both residential and now commercial scales.
- Increased consumer awareness of battery storage and electric vehicles.

For the 2015 report, AEMO has developed scenarios and sensitivities (see Table 1 below) that reflect these changes. The Gradual Evolution scenario is designed to reflect a future where there are no major cost reductions or additional incentives to drive the uptake of new technology. The Rapid Transformation scenario is designed to reflect a future where new embedded technologies have experienced rapid uptake, possibly driven by significant cost reductions and/or new policy incentives. Both scenarios consider only current federal climate change policies in market modelling, such as the LRET and the Emissions Reduction Fund. It is assumed that no new coal-fired generation is installed.

Table 1 **NTNDP 2015 scenarios**

Scenario	Description	Cases	Code[d]
Gradual Evolution	Consumer demand growth continues in line with medium forecasts [a] Gradual penetration of rooftop PV (21 GW total residential and commercial rooftop PV by 2035) and residential electricity storage (8 GWh by 2035)[b]	Base scenario	G
		Sensitivity – lower large-scale solar costs	GS
Rapid Transformation	Consumer demand continues on a low trajectory [a] High penetration of embedded technologies, including residential PV at saturation[c] (33 GW total residential and commercial rooftop PV by 2035), 40% of households with residential battery storage (19 GWh by 2035) and 20% of household with electric vehicles (about 2 million vehicles)	Base scenario	R
		Sensitivity – lower large-scale solar costs and a higher amount of large-scale renewable generation	RS

[a] Medium and low demand forecasts published in AEMO's 2015 National Electricity Forecasting Report (NEFR).
[b] Using the outcomes in the Emerging Technologies Information Paper that was published as a supplement to the 2015 NEFR.
[c] Saturation occurs when all households that can take advantage of rooftop PV have a system installed. It includes separate houses, semi-detached row or terrace houses, and townhouses, but is discounted by 25% in consideration of dwellings subject to building restrictions, roof shading, or a lack of incentive for rented properties.
[d] These codes are used to reference the scenarios and sensitivities outlined in charts and tables throughout this report.

The sensitivity applied to both scenarios assumes lower large-scale PV costs, to reflect the possibility of large-scale PV becoming more cost-competitive with wind generation. The Rapid Transformation sensitivity also tests the network impacts if more large-scale renewable generation is built.

CHAPTER 2. RECENT EVOLUTION OF TRANSMISSION INVESTMENT

A shift in the nature of transmission investment has been observed since 2009, moving away from augmentation to increase network capacity, and towards replacement of ageing assets.

This shift coincides with a period of declining consumption drawn from the grid (operational consumption) resulting from a restructuring of industry away from electricity-intensive manufacturing, and changing consumer behaviour due to increasing electricity prices, energy efficiency initiatives, and rooftop PV incentives. Operational consumption forecasts have reduced over time to reflect these changes.

Transmission development has also been impacted by an increasing focus on large-scale renewable generation, driven by various climate change policy incentives. These factors are explored below.

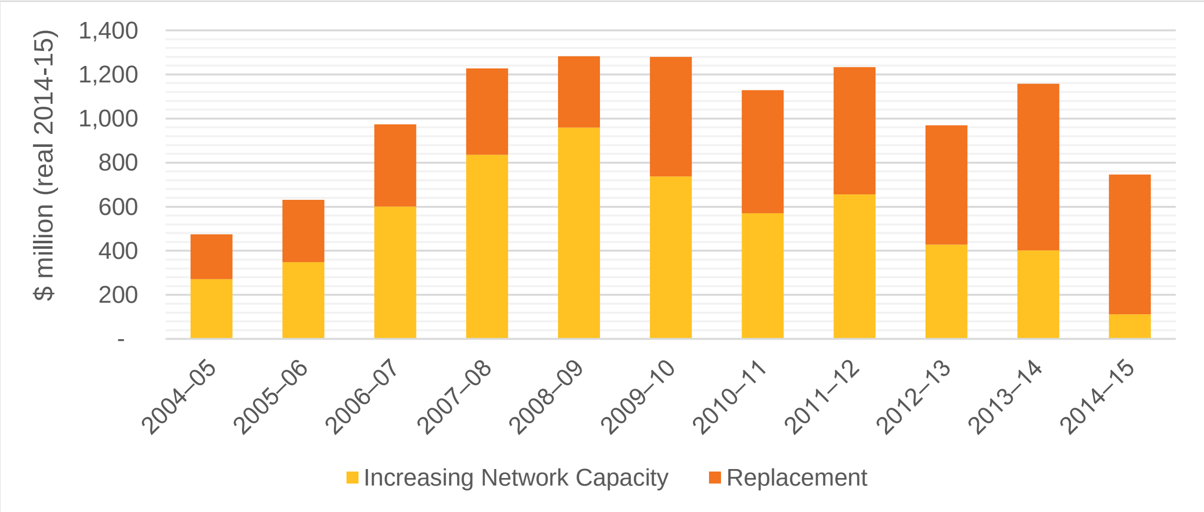
2.1 Shifting nature of transmission investment

Since 2009, TNSPs have been investing more capital to replace ageing network assets, and less on network augmentation:

- Total annual investment in transmission networks across the NEM has decreased, from $1,282 million in 2008–09 to $745 million in 2014–15 (2014–15 dollars).
- The proportion of total investment to increase network capacity has fallen from 75% in 2008–09 to 15% in 2014–15.
- Average annual replacement expenditure was around $600 million between 2009–10 and 2014–15, compared to about $315 million from 2004–05 to 2008–09.

Figure 2 shows the annual volume of transmission investment, and the relative proportions of expenditure on increasing network capacity and replacing network assets, over the last decade.

Figure 2 Evolution of transmission investment



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

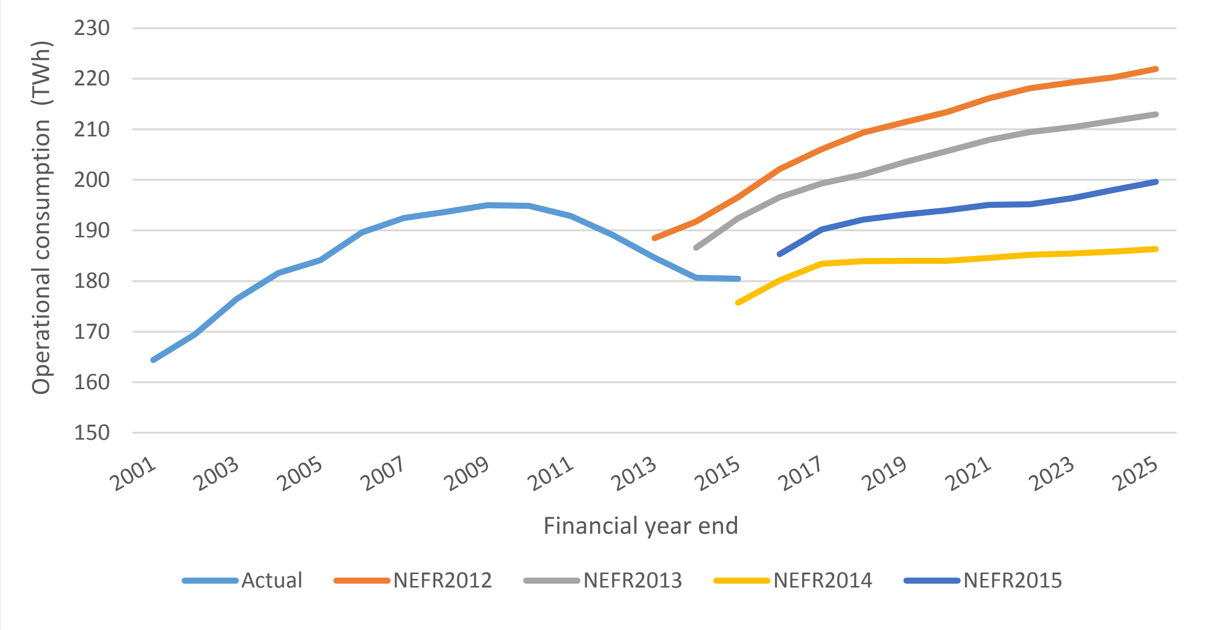
As identified in the 2014 NTNDP, AEMO expects transmission network investment to focus on replacement rather than augmentation for the next 20 years. Given the significance of this shift, the

Australian Energy Regulator (AER) is considering whether regulatory investment tests should be applied to replacement expenditure in addition to augmentation.

2.2 Declining energy supplied through the grid

Prior to 2010, operational consumption was increasing across the NEM. The expectation that this trend would continue contributed to significant investments to increase network capacity between 2005 and 2009. Figure 3 shows how operational consumption forecasts have changed since 2012.

Figure 3 Actual operational consumption and AEMO forecasts[4]



A number of factors contributed to this change in outlook, including:

- The rapid growth of rooftop PV.
- Decreasing electricity-intensive manufacturing operations in Australia.
- Increasing retail electricity prices that gave consumers more incentive to reduce their energy use.
- Energy efficiency initiatives across NEM regions, combined with more efficient appliances.

2.3 Growth of rooftop PV

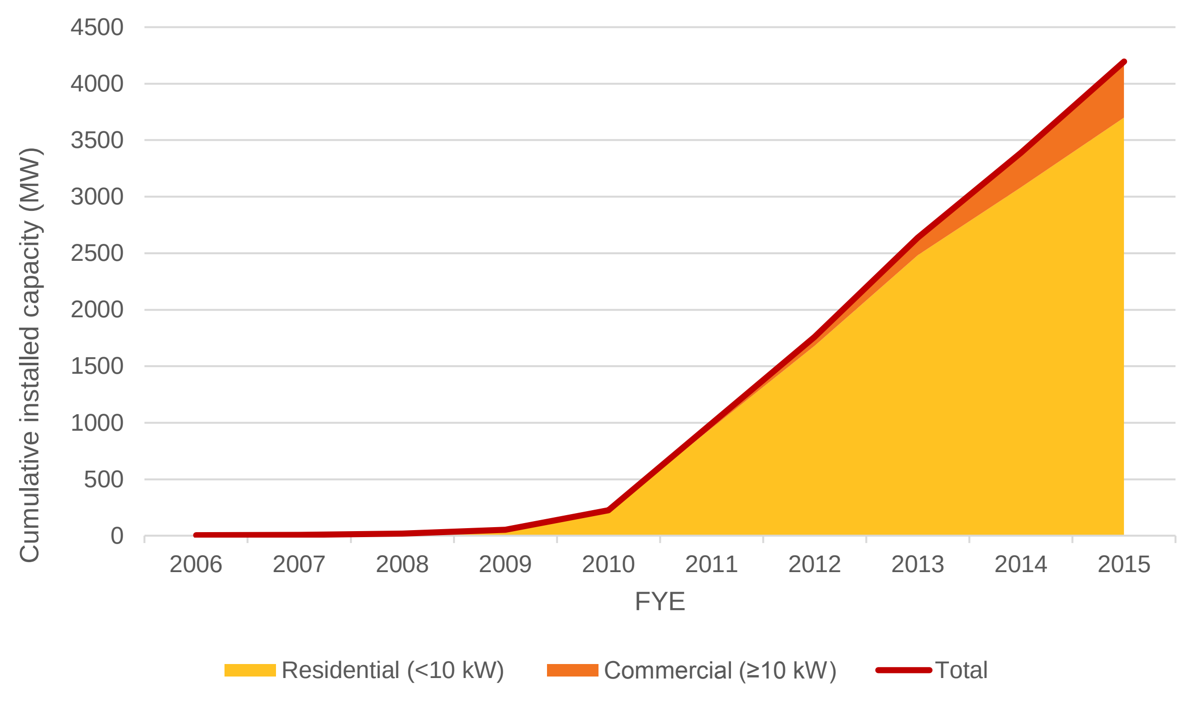
Residential rooftop PV across the NEM has grown from very low numbers in 2009 to the highest penetration in the world (as a percentage of all households)[5], initially driven by generous policy incentives.

Figure 4 shows the rapid growth of rooftop PV (including both residential and commercial) across the NEM, and the growth is expected to continue. In the Gradual Evolution scenario an additional 9,600 MW of rooftop PV is expected to be installed between now and 2024–25.

[4] AEMO, National Electricity Forecasting Reports. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting. Viewed: 28 October 2015. The first National Electricity Forecasting Report was published in 2012. Before this, forecasting information was produced by AEMO for South Australia and Victoria, and by the TNSPs in other regions.

[5] ESAA, 2015. Renewable energy in Australia, how do we really compare? Available: http://www.esaa.com.au/Library/PageContentFiles/14251626-ae50-48a1-8fb0-70841eae409f/ESA002_factsheet_renewables.pdf. Viewed: 23 October 2015.

Figure 4 Rooftop PV uptake across the NEM



To date, AEMO has forecast demand drawn from the grid (operational consumption) by subtracting estimated rooftop PV from its underlying demand projections. Accordingly, there is a direct correlation between the accuracy of rooftop PV forecasts and operational consumption forecasts.

In the 2015 NTNDP, and in future NTNDP publications, rooftop PV will be presented as a type of generator to provide a clear indication of how rooftop PV contributes to total generation in the NEM.

2.4 Increasing focus on renewable generation

The Mandatory Renewable Energy Target (MRET) was first introduced in 2001, targeting 9,500 GWh of extra renewable generation by 2010. In 2010, the MRET was replaced with the LRET, increasing the target for large-scale renewable generation to 41,000 GWh by 2020, and introducing the solar credits scheme that incentivised rooftop PV.[6] Rooftop PV was further incentivised by various state-based feed-in tariffs that paid up to 66 cents per kilowatt hour.[7]

The LRET was a major driver of network development plans for the 2010 NTNDP and in the network development plans of subsequent NTNDPs.

In 2015, the LRET was reduced to 33,000 GWh per year by 2020, but the solar credits scheme continued unchanged. The future of climate change policy settings, particularly beyond 2020, remains uncertain. Australia's Paris 2015[8] commitment is to reduce greenhouse gas emissions by between 26% and 28% below 2005 levels by 2030, and state governments are targeting increasing levels of renewable generation, but the instruments to achieve these targets are yet to be determined.

[6] Parliament of Australia. Mandatory Renewable Energy Target. Available: http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/Browse_by_Topic/ClimateChange/Governance/Domestic/national/Mandatory. Viewed: 23 October 2015.
[7] Parliament of Australia, Feed-in Tariffs. Available: http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/Browse_by_Topic/ClimateChange/Governance/Domestic/national/tariffs. Viewed: 27 October 2015.
[8] For the 21st Conference of the Parties for the United Nations Framework Convention on Climate Change.

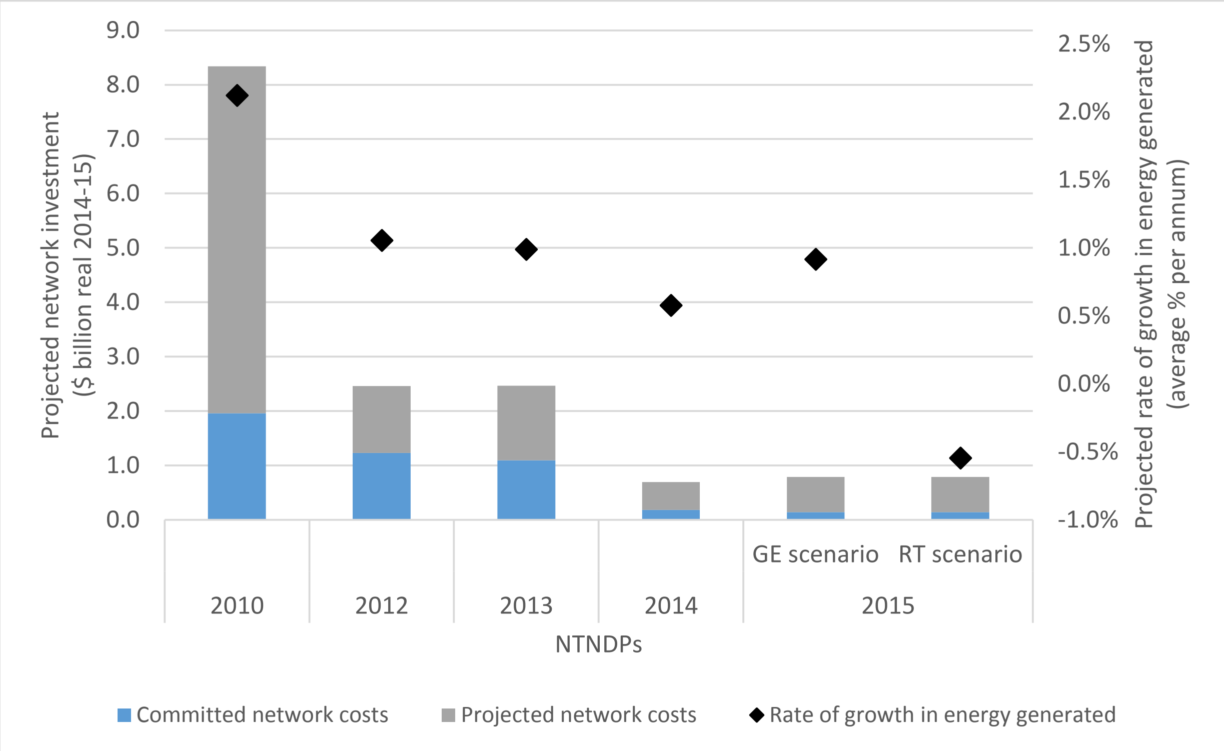
As the focus on renewable generation increases, the role of the transmission network is also shifting, from transporting bulk power to securely integrating large-scale and embedded renewable generation into the NEM.

2.5 Impact on transmission development needs

As a result of the factors described above, NTNDP projections for new infrastructure to address transmission network capacity limitations have fallen in recent years (shown in Figure 5).

In the 2015 NTNDP, minimal new transmission infrastructure expenditure is projected over the next 20 years ($800 million), as discussed in Chapter 3.

Figure 5 Estimated cost of addressing main transmission network limitations identified in previous NTNDPs



The chart uses these scenarios: 2010 (Decentralised World – Medium), 2012 (Planning scenario), 2013 (Carbon Price), and 2014 (Medium).

CHAPTER 3. NATIONAL TRANSMISSION OUTLOOK

This chapter identifies potential limitations on the national transmission flow paths, to help consider and assess a course for the development of the national transmission grid over the next 20 years. Potential limitations are identified using the scenarios and sensitivities outlined in section 1.1.

This assessment combines two key outlooks:

- The generation outlook[9], which projects the location and timing of new generation additions and withdrawals for each scenario and sensitivity. This outlook focuses on efficient development to meet forecast demand, minimising the total generation and network investment cost over the next 20 years.
- The transmission outlook, which describes any identified thermal network limitations on the main transmission flow paths. The generation outlook heavily influences the transmission development outlook.

To minimise generation and transmission network costs, new generation is assumed to be located efficiently, considering spare network capacity, network connection costs and the quality of the local wind and solar resources (or availability of fuel sources for thermal plants).

Based on the scenarios considered, minimal new transmission network infrastructure is required to deliver generation to consumers, continuing the trend seen in NTNDPs since 2012. This relies on generation being located efficiently, as described above. There is a risk that concentration of generation in the same location could cause local transmission congestion due to network limitations.[10]

3.1 Generation outlook

Based on the current LRET, the NTNDP modelled between 4,200 MW and 6,700 MW of forecast additional large-scale renewable generation installed across the NEM by 2020. Wind and large-scale PV provide the majority of this renewable generation.

Between 3,125 MW and 8,565 MW of coal-fired generation is modelled as withdrawn between 2015–16 and 2034–35, including the announced withdrawal of Northern and Liddell Power Stations. More coal withdrawals are projected in the Rapid Transformation scenario, as the forecast lower operational consumption drives down the utilisation of these power plants to a point where it is no longer cost-effective to operate.

Rooftop PV provides the highest contribution to additional generation capacity under all scenarios and sensitivities. By 2034–35, the Gradual Evolution scenario projects 17,656 MW of additional rooftop PV (20,890 MW total) installed, based on the uptake in the 2015 NEFR.[11] The Rapid Transformation scenario assumes a trajectory towards saturation of residential rooftop PV in 2035, resulting in additional 30,095 MW installed by 2034–35 (33,329 MW total). More rooftop PV typically reduces transmission congestion, as it reduces operational demand.[12]

[9] While the ESOO only considers generation which has been committed, the NTNDP generation outlook builds sufficient generation to meet reliability standards in the most efficient manner.

[10] The market design already provides some signals to intending generators to internalise the broader network costs into their investment decision, via regional pricing, nodal loss factors and volume congestion. The AEMC has, however, recommended to COAG that, should material congestion emerge, the Optional Firm Access reform will be implemented. This would provide generator investors with the same locational incentive as our modelling presumes.

[11] AEMO, 2015 National Electricity Forecasting Report, page 17. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 29 October 2015.

[12] In some situations, very high levels of rooftop PV in a particular location may also cause congestion when simultaneously feeding into the local network.

Figure 6 and Figure 7 show rooftop PV and NEM generation capacity additions and withdrawals under the Gradual Evolution and the Rapid Transformation scenarios.

Figure 6 Generation capacity additions and withdrawals – Gradual Evolution scenario and sensitivity

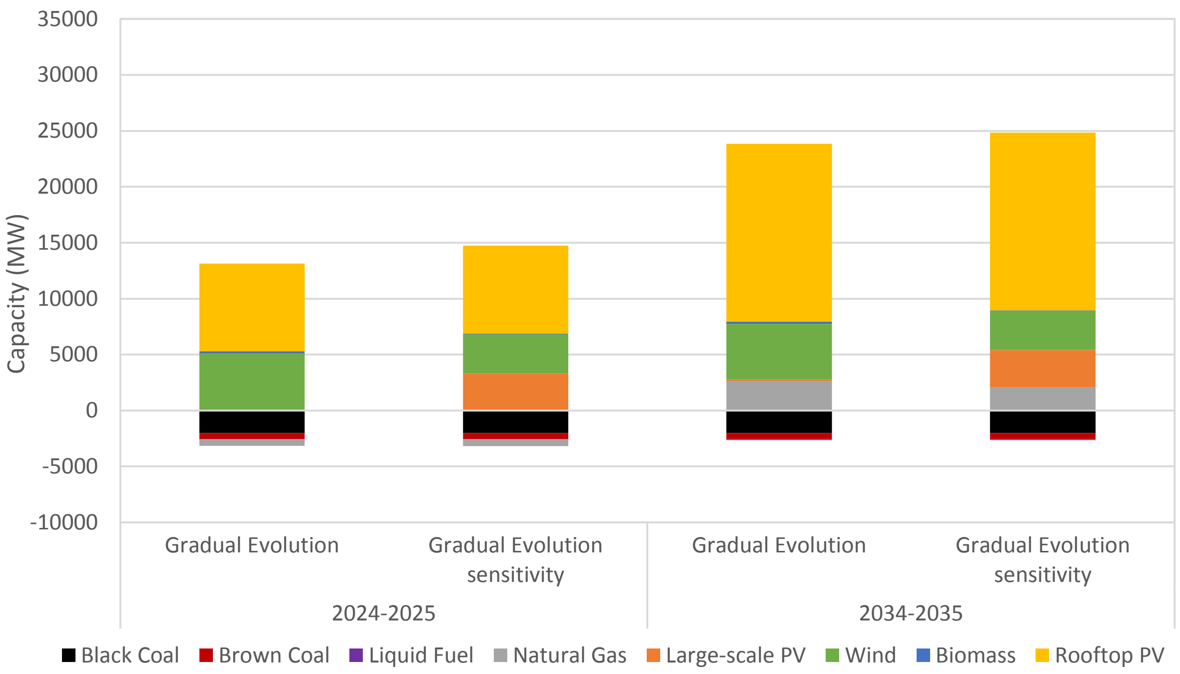
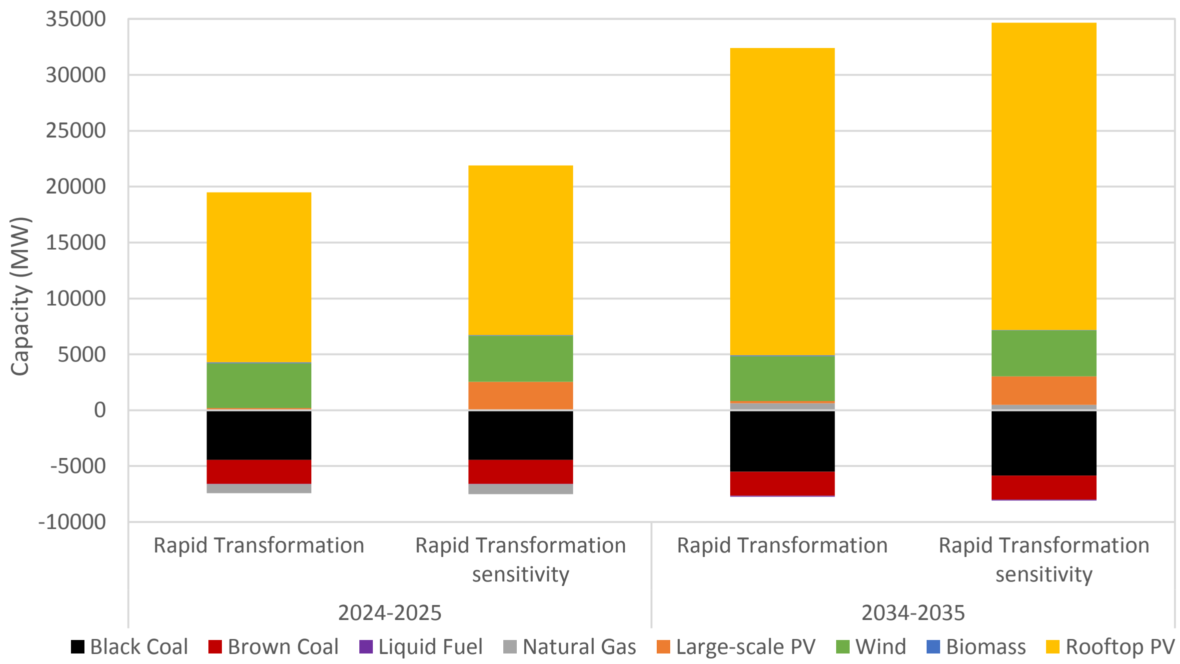


Figure 7 Generation capacity additions and withdrawals – Rapid Transformation scenario and sensitivity



Under the Gradual Evolution scenario, a need for peaking capacity is forecast toward the end of the outlook period, to meet maximum demand growth and provide back up for intermittent generation. This does not arise in the Rapid Transformation scenario, due to lower forecast demand and the impact of 40% residential storage penetration on smoothing the residential peaks in demand. The effect battery storage has on the household electricity demand profile is consistent with the 2015 Emerging Technologies Information Paper.[13]

It is important to note that, although residential battery storage can reduce regional demand peaks when the residential and regional peaks coincide, it could also increase regional peaks if the tariff is not cost-reflective. For example, if the regional peak occurs during the middle of the day, and the residential storage is charging from rooftop PV, this reduces the rooftop PV available to contribute towards meeting the regional peak. How storage operates in relation to both residential and regional demand profiles is likely to be driven by the tariff structure.

Where new generation capacity is required, without defined carbon abatement initiatives after 2030, the generation outlook shows gas-fired generation being built.[14] Demand-side participation, or new technologies such as electricity storage, may provide an equivalent service in circumstances when the capacity is only required to meet demand peaks.

Both sensitivities (with lower large-scale PV costs) show more renewable generation capacity installed in total. Large-scale PV typically operates at a lower capacity factor than wind, so more capacity is required to produce the same amount of generation. By design, the Rapid Transformation sensitivity also targets more renewable generation to test the impact on the national transmission grid.

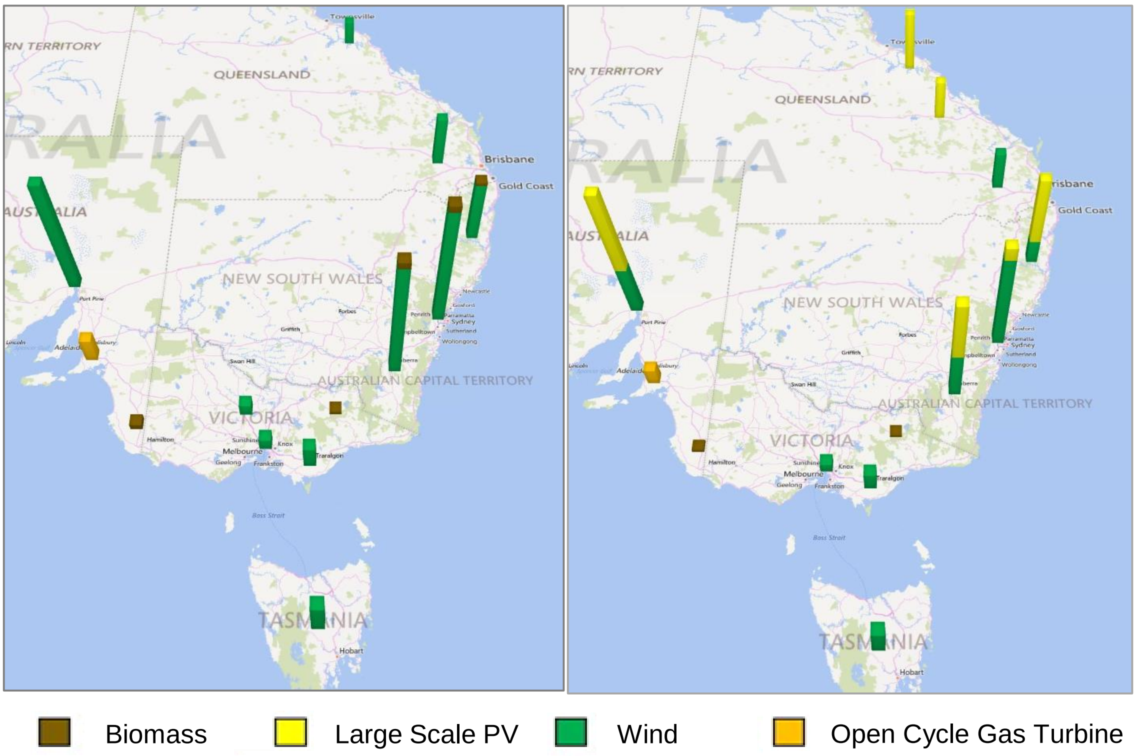
The location of generation is a major factor in the efficient development of the transmission network. Due to widespread natural resources there are many possible sites for wind and PV generation, meaning that, in theory, new generation of this type can connect in locations that have spare network capacity. In reality, developers of new generation consider a range of commercial factors that may result in concentration of generation assets in particular areas.

For the Gradual Evolution scenario and sensitivity, the efficient development plan locates the majority of new generation in the central New South Wales and Canberra regions, as shown in Figure 8 below. New generation is modelled at similar locations in the Rapid Transformation scenario and sensitivity.

[13] AEMO, 2015 Emerging Technologies Information Paper. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information. Viewed: 19 October 2015.

[14] Due to the financial and environmental risk, the NTNDP assumes no additional coal plants will be built in the NEM.

Figure 8 Additional generation location by 2024–25 – Gradual Evolution scenario (left) and sensitivity



3.2 Transmission development outlook

The NTNDP transmission development analysis primarily assesses the adequacy of the national transmission grid to reliably support major power transfers between supply and demand centres (referred to as NTNDP zones).

Key observations for transmission development are:

- Minimal new transmission network infrastructure is required to transport power to consumers, provided new generation is located efficiently to balance the quality and availability of the fuel source, and network costs.
- There is a risk that concentration of this generation in the same location will cause local transmission congestion due to network limitations. This is discussed further in section 3.2.2.

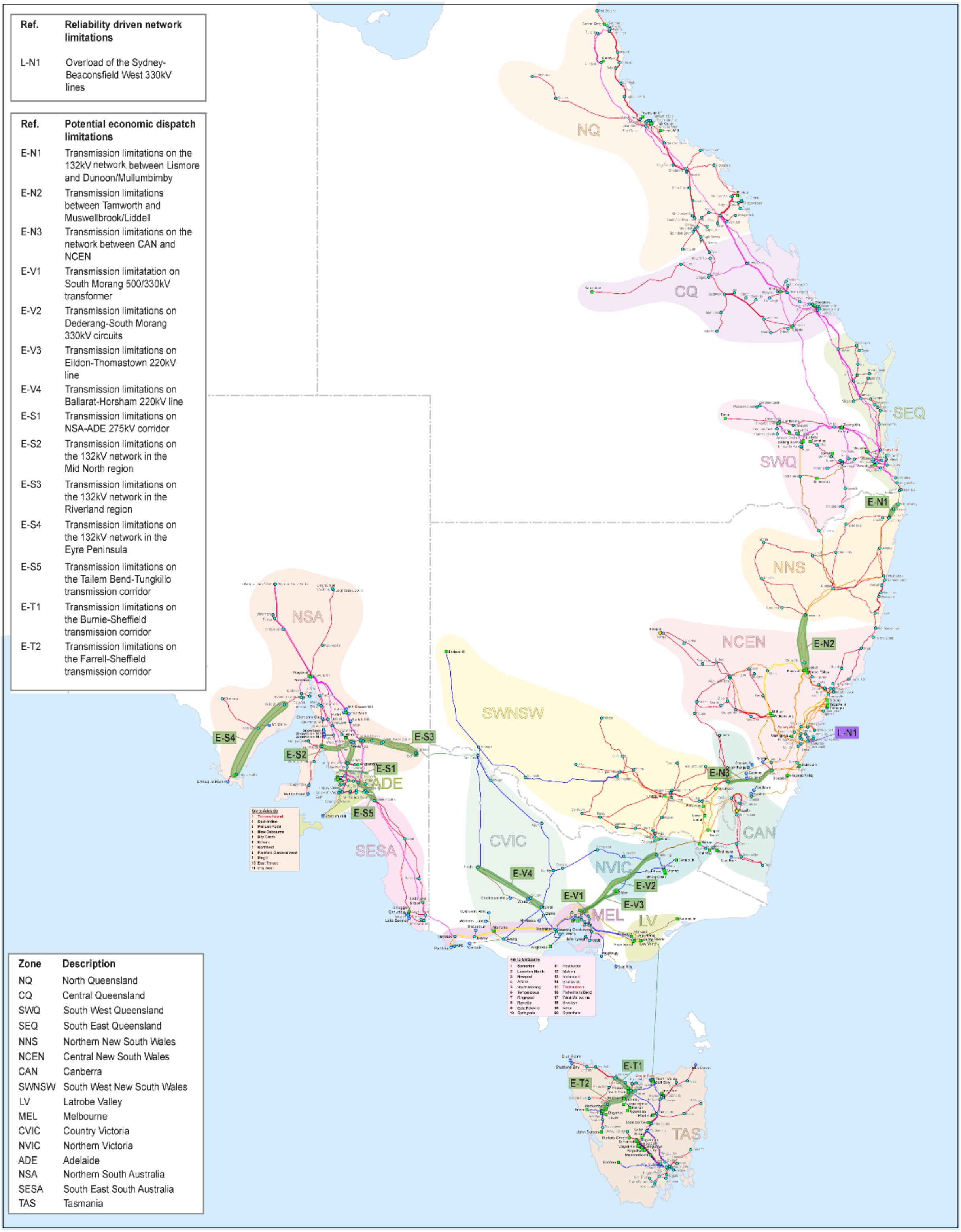
3.2.1 National transmission flow paths

Two types of limitations are considered in the NTNDP transmission development outlook: reliability limitations, and economic limitations.

- **Reliability limitations** occur if, at the time of regional maximum operational demand, the network does not have enough capacity to meet demand.
- **Economic limitations** are where more expensive generation is dispatched ahead of cheaper generation in order to avoid network overloads.

Figure 9 shows the location of network limitations on the main transmission network, as identified by the NTNDP modelling and TNSPs in their annual planning reports. These include both reliability-driven network limitations and potential economic dispatch limitations. Each limitation is identified by a locational reference code.

Figure 9 Identified network limitations



Further details about these limitations are provided in Table 2 and Table 3, and on the interactive map on AEMO's website.[15]

[15] AEMO. Available: http://www.aemo.com.au/electricity/planning/interactive-map/.

Reliability limitations

The 2015 NTNDP identifies only one reliability limitation, in Sydney. This limitation appears in all the scenarios and sensitivities (Table 2). It was one of three limitations identified in the 2014 NTNDP, and TransGrid identified it in their 2015 Annual Planning Report. The shortfall in supply capacity is expected to occur in the early to mid-2020s and is primarily dependent on the timing of AusGrid 132 kV cable retirements in Sydney.[16] The other two reliability limitations in the 2014 NTNDP have been addressed since the publication of 2014 NTNDP. Information on these can be found on AEMO's website.[17]

Table 2 **Reliability driven network limitations identified through NTNDP modelling**

Reference	Region	Timing	Observed limitation	Network needs	Scenarios
L-N1	New South Wales	2020–21 to 2024–25	Overload of the Sydney – Beaconsfield West 330 kV line for an outage of the Sydney South – Haymarket 330 kV line	Non-network solution and/or a new supply to the Beaconsfield West substation from another 330 kV supply point	G,GS
		2025–26 to 2029–30			R, RS

Economic dispatch limitations

Connecting wind and large-scale PV generation is expected to create network congestion, particularly at times of high wind and/or solar generation output. This may result in restricting wind, solar and/or low cost thermal generation and dispatching higher cost generation. The limitations caused under such circumstances are called economic dispatch limitations.

The 2015 NTNDP identifies the location of potential economic dispatch limitations that may arise in all scenarios over the next 20 years, if new generation development occurs in line with the generation outlook in section 3.1. These are listed in Table 3. The majority of these limitations already exist in the network, and those relating to wind generation are expected to become more prominent if more wind generation is connected in these zones.

Table 3 **Potential economic dispatch limitations**

Reference	Region/Zone	Potential transmission limitations	Dispatch scenario	Scenarios
E-N1	NSW NNS	Transmission limitations on the 132 kV network between Lismore and Dunoon/Mullumbimby	High wind generation in NNS zone when power flows from New South Wales to Queensland[18]	G,GS, R, RS
E-N2	NSW NNS	Transmission limitations between Tamworth and Muswellbrook/Liddell	High wind generation in NNS zone when power flows from NNS zone to NCEN zone	G,GS, R, RS
E-N3	NSW CAN	Transmission limitations between CAN and NCEN	High wind generation in the CAN zone when power flows from the SWNSW zone to CAN zone	G,GS, R, RS
E-V1	VIC MEL	Transmission limitation on South Morang 500/330 kV transformer	High export from Victoria to New South Wales	G,GS, R, RS
E-V2	VIC MEL	Transmission limitations on Dederang – South Morang 330 kV circuits	High transfer between Victoria and New South Wales (export or import)	G,GS, R, RS

[16] Transgrid. Available: https://www.transgrid.com.au/news-views/publications/transmission-annual-planning-report/Documents/Transmission%20Annual%20Planning%20Report%202015.PDF. Viewed: 6 November 2015.
[17] Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. Viewed: 3 November 2015.
[18] This assumes Directlink is fully available for 180 MW. Although Directlink capability is currently reduced due to outage, in the long term it is assumed to return to full capability. This limitation is unlikely to appear if the capability of Directlink were to remain reduced.

Reference	Region/Zone	Potential transmission limitations	Dispatch scenario	Scenarios
E-V3	VIC MEL	Transmission limitations on Eildon–Thomastown 220 kV line	High transfer between Victoria and New South Wales (export or import)	G,GS, R, RS
E-V4	VIC CVIC	Transmission limitations on Ballarat–Horsham 220 kV line	High wind generation connected between Ballarat and Horsham and/or between Horsham and Redcliffs	G
E-S1	SA NSA	Transmission limitations on NSA–ADE 275 kV corridor	High wind/solar generation in the NSA zone	G,GS
E-S2	SA NSA	Transmission limitations on the 132 kV network in the Mid North region	High wind/solar generation in the NSA zone	G,GS, R, RS
E-S3	SA NSA	Transmission limitations on the 132 kV network in the Riverland region	High wind/solar generation in the NSA zone	G,GS, R, RS
E-S4	SA NSA	Transmission limitations on the 132 kV network in the Eyre Peninsula	High wind/solar generation in the NSA zone	G,GS, R, RS
E-S5	SA SESA	Transmission limitations on the Tailem Bend – Tungkillo transmission corridor	New generation in SESA zone or high import from Victoria	R,RS
E-T1	TAS	Transmission limitations on the Burnie–Sheffield transmission corridor	High wind generation in North-west Tasmania	G,GS
E-T2	TAS	Transmission limitations on the Farrell–Sheffield transmission corridor	High wind generation in West Tasmania	G,GS

The timing and scope of any projects required to address potential economic dispatch limitations will depend on detailed market assessment of the costs and benefits of any solution. AEMO will monitor these limitations and work with the relevant TNSPs as needed to address them.

Further information on the transmission outlook can be found on the AEMO website.[19]

3.2.2 Risk of local congestion

There is a risk that, if new generation is located in areas without spare network capacity, additional local network limitations will emerge, resulting in the power output of some generators being restricted.

Case study – regions with high concentrations of large-scale renewable generation

North-West Victoria: AEMO has received inquiries from wind farm developers interested in connecting to the Ballarat–Waubra–Horsham 220 kV transmission line (BATS–WBTS–HOTS). If any of these developments proceed, the current thermal limit of the line between BATS and WBTS could be exceeded in some circumstances. If the loading on the BATS–WBTS line threatened to exceed the thermal limit, the amount of generation output that could flow onto that line would be restricted. Therefore, some wind farms located on the BATS–WBTS–HOTS line, and potentially also between HOTS and Red Cliffs (RCTS), would be dispatched at less than their full output. This problem would be exacerbated if more wind farms were connected to the line over time.

[19] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

AEMO is keeping the situation under review, and if appropriate will assess whether the capacity of the line should be augmented in future. This could only be justified if there would be sufficient net benefits to the market more broadly.

3.2.3 Consideration of TNSP Annual Planning Reports

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 the TNSPs are accounted for in the NTNDP, and are summarised in the 2015 NTNDP database.[20]

The 2015 NTNDP assessment of transmission network adequacy does not include:

- Transmission augmentations that may be required if future generation development does not follow an efficient path, as indicated in the generation outlook.
- Transmission augmentations based on TNSPs applying different planning criteria, such as additional security beyond N-1 planning criteria (for information about the NTNDP planning criteria see Appendix A).
- Transmission network development not directly related to national flow paths. This means that local transmission augmentations driven by local demand growth, or the appearance of new or contracted loads, are not considered.
- The need to replace aged transmission assets.

These matters are addressed by the respective TNSPs in their planning process.

[20] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

CHAPTER 4. EMERGING CHALLENGES

Operating the network securely will become more challenging as thermal synchronous generation is withdrawn and large amounts of wind, large-scale PV and rooftop PV generation (possibly combined with battery storage) are installed on the system. It will be particularly difficult at times when operational demand is low and renewable generation is high. The challenges relate to how the system behaves during disturbances, and how much generation can be dispatched in order to match supply and demand. A disturbance is a supply demand imbalance, which can be caused by the trip of a generator, load or a transmission line.

Specifically, this NTNDP examines:

- Reductions in dispatchable generation associated with high levels of PV and battery storage.
- Frequency stability of low inertia systems and the importance of interconnection.
- Low fault level impacts on protection schemes and voltage stability during disturbances.

4.1 Background on emerging challenges, and focus on South Australia

Many of these challenges to network security and reliability emerge from fundamental differences in the physical generating equipment between synchronous and certain renewable generation technologies:

- Synchronous generators (most coal, gas and hydro generators) produce power through directly connected alternating current machines, rotating at a speed synchronised to power system frequency. These generators produce inertia, which 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 or load.
- Modern wind turbines and PV systems are connected to the power system through the use of power electronic converters. These are seen by the grid as asynchronous generation and most do not inherently contribute inertia.

These challenges are influencing potential transmission development. Historically, it was expected that there would be large amounts of synchronous generation in the NEM, and the capacity of individual transmission flow paths to transport power from generation to demand centres was the main driver influencing development of the transmission network.

However, given the changing load and generation mix, other aspects of power system security are emerging as major challenges, now and throughout the outlook period. As these challenges emerge, the role of the transmission system is evolving to focus more on providing widespread access to inertia and network support services between regions across the interconnected system.

Rooftop PV and other generation technologies located behind-the-meter (that is, on the consumer's premises) also contribute to the challenges described in this chapter. These devices are typically not registered and controlled in the same way large generators are. Information on the location, extent and operation of these technologies will be needed to accurately forecast operational consumption, manage the supply/demand balance on the system and plan the power system for the future.

South Australia is most exposed to these challenges, due to its high levels of wind and rooftop PV generation, and the region having only one AC interconnector (comprising two circuits) to other regions. At present, South Australia has about 1,470 MW of installed wind generation and around 530 MW of rooftop PV generation. This represents about 50% and 17% respectively of the NEM's total installed wind and rooftop PV capacity, in a region that constitutes only 8.5% of the NEM's operational demand.

By 2024–25, in the Gradual Evolution sensitivity, the total amount of wind and PV generation (both large-scale and rooftop) in South Australia is projected to exceed 4,500 MW, which represents 65% of total generation capacity in the region (increasing from 42% today). Combined with the recent and announced withdrawals of 1,505 MW[21] of coal and gas fired generation in South Australia by 2017, this substantially increases South Australia's reliance on synchronous generation and frequency control ancillary services (FCAS)[22] from Victoria, via the Heywood Interconnector.

This increasing reliance on the interconnector presents a system security risk for South Australia.[23] Since 2011, AEMO has undertaken considerable work to understand these implications for the power system (see Appendix D). AEMO is continuing to build on this work to develop a deeper understanding of the issues surrounding the withdrawal of synchronous generation and increasing renewable generation in the power system.

4.2 Less dispatchable generation

Consumer demand and availability of intermittent generation varies throughout the day. This variation is relatively gradual compared to a disturbance, and is presently managed by AEMO through the central dispatch process. If the supply demand balance is not maintained accurately, the power system will operate beyond its frequency and voltage safety limits, which will compromise power system security and can result in equipment failures.

There are three classifications for registered generators in the NEM: scheduled, semi-scheduled and non-scheduled. Non-registered generators are also described below.

Scheduled generation: typically, generating systems larger than 30 MW that are not intermittent are controlled through the central dispatch process to achieve a supply demand balance. Directly connected synchronous generation is generally able to increase or decrease power output on demand.

Semi-scheduled: Intermittent generating systems larger than 30 MW, including most wind farms and large-scale PV plants, generate at the level dictated by the amount of wind or sunlight available. It is, however, possible for these generators to be dispatched below their maximum available generation if required.

Non-scheduled: Most generating systems smaller than 30 MW, including some pre-2008 wind farms, are not dispatched through the central process.

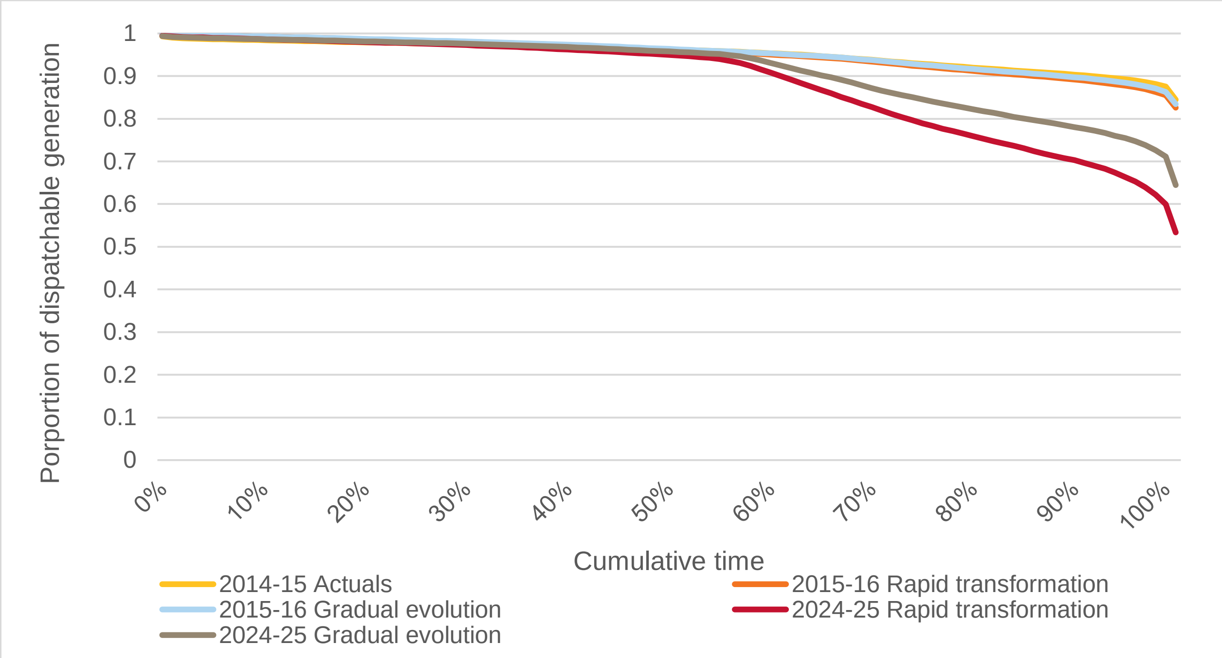
Non-registered: Most generating systems smaller than 5 MW, including behind-the-meter generation (such as rooftop PV) are not required to be registered in the NEM, and are not part of the central dispatch process.

We can evaluate the controllability of the power system by looking at the ratio of scheduled and semi-scheduled generation to total generation (including non-registered generation).

Figure 10 shows this ratio for the entire NEM over a year, for both the Gradual Evolution and Rapid Transformation scenarios. The ratio changes as load and generation varies over the year.

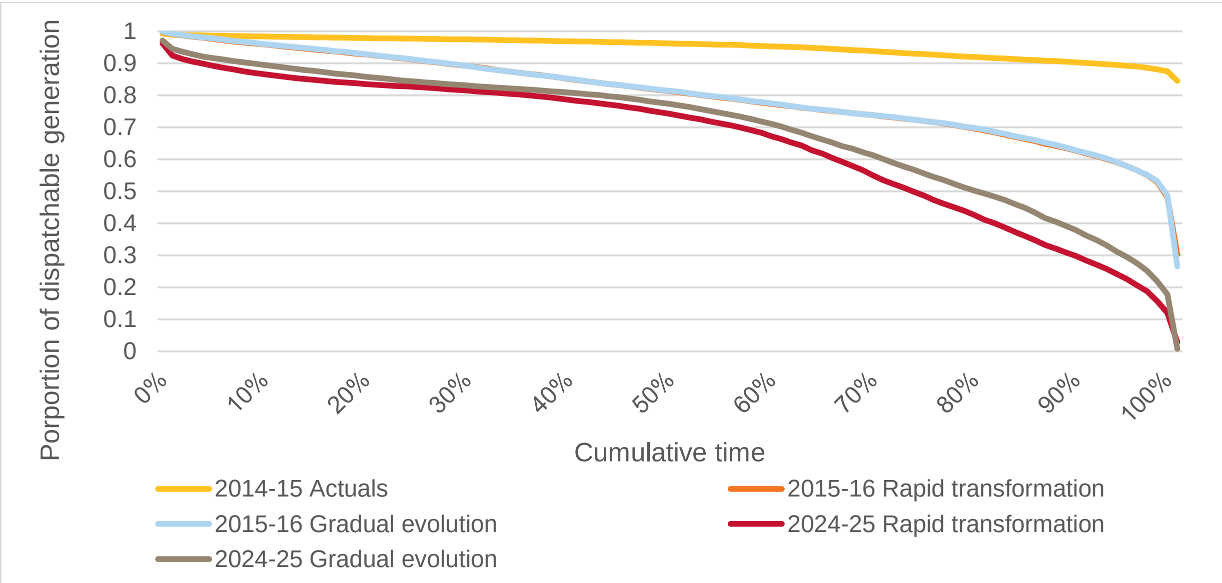
[21] AEMO, Generation Information. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. Viewed: 30 October 2015.
[22] Presently only synchronous generators have chosen to register to provide FCAS in the NEM.
[23] AEMO notes the incident on 1 November 2015 that impacted electricity supply from Victoria to South Australia via the Heywood Interconnector. Approximately 160–170 MW of load was lost as a result of this incident, causing electricity supply disruptions across regions of South Australia. AEMO is working with ElectraNet, SA Power Networks, and the South Australian Government on this matter.

Figure 10 Scheduled and semi-scheduled generation compared to total generation in the NEM



In 2014–15, South Australia is the NEM region with the largest proportion of installed non-scheduled and non-registered generation capacity. The continuing growth of rooftop PV in South Australia means that the ratio of scheduled and semi-scheduled generation to total generation is reducing. Figure 11 shows this trend for both NTNDP scenarios, comparing 2015–16 and 2024–25.

Figure 11 Scheduled and semi-scheduled generation compared to total generation in South Australia



The difference between the 2014–15 actuals and 2015–16 modelled outcome is largely due to the modelled outcome relying more on imports from Victoria to meet demand in South Australia than has been observed in recent history. Factors contributing to this difference are explained in section 4.5.

Decreasing levels of dispatchable generation will make it increasingly difficult to balance supply and demand in real time. Low levels of dispatchable generation will also make it difficult to manage the power system via constraint equations through the central dispatch process.

AEMO continues to investigate the challenges posed as dispatchable generation reduces in the power system (see Appendix D).

4.2.1 Forecasting the operational behaviour of "behind-the-meter" technologies

Behind-the-meter technologies, such as rooftop PV, electric vehicles and battery storage, connect to the power system through power electronics, providing limited visibility on how these technologies operate, and less understanding of how they may behave.

Power electronics have the ability to very quickly change rates of consumption or production. Large blocks of non-dispatchable electric vehicles or battery storage systems responding simultaneously to market or tariff signals could lead to large swings in operational demand. Any resulting supply demand imbalance would be difficult to manage if not visible or predictable.

This year the Australian Energy Market Commission (AEMC) completed a rule change (Improving demand side participation information provided to AEMO by registered participants[24]). This should help increase the level of behind-the-meter information available for forecasting purposes, although information issues may still arise where relevant data is not controlled or collected by NEM registered participants. Access to real time information will also become increasingly important to maintain power system security.

4.3 Frequency stability of low inertia systems

The spinning mass of synchronous generators provides inertia to the power system. Inertia works to maintain system frequency, especially immediately after a disturbance.

Presently, synchronous machines with inherent inertia are primarily responsible for arresting the change in frequency immediately following a disturbance. Power electronic interfaced technologies (such as rooftop PV, electric vehicles and battery storage), do not inherently contribute inertia. Following a disturbance, a system with low inertia would experience:

- Larger frequency excursions from nominal 50 Hz. These excursions trigger protection systems that disconnect loads or generation.
- Higher rate of change of frequency which can result in malfunction of power electronic interfaced technologies.

Synchronous generation may not always be the primary means of arresting the change in frequency immediately following a disturbance. Other options include synchronous condensers, under frequency load shedding and synthetic inertia. Synthetic inertia can be provided by specialised power electronic interfaced technologies that can rapidly change their power output in response to how fast frequency is changing.

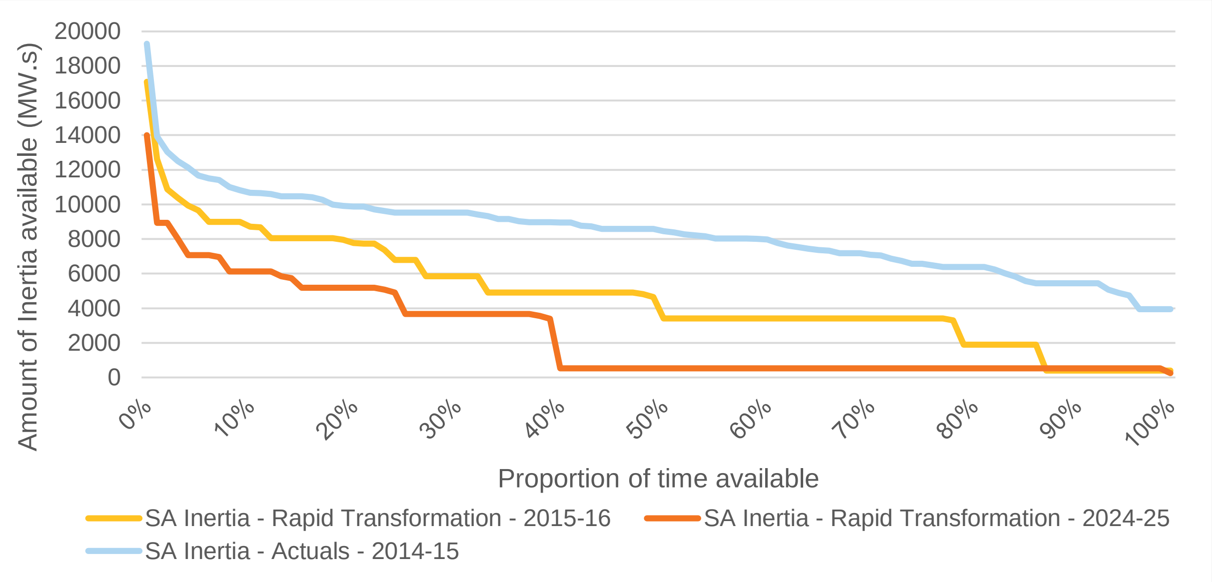
In both the NTNDP Gradual Evolution and Rapid Transformation scenarios, there is sufficient inertia provided by synchronous machines available across the NEM for the power system to operate securely, assuming all interconnectors are in service.

During system normal conditions, South Australia has access to the inertia produced by generation in other states, via interconnection (Heywood Interconnector). If this interconnector fails, or is unavailable, South Australia must source all its inertia requirements locally.

[24] AEMC, reference ERC0174. Available: http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr#. Viewed: 5 November 2015.

Figure 12 shows the amount of inertia available from within South Australia in 2014–15, and the projection for 2015–16 and 2024–25 under the Rapid Transformation scenario. It reflects the announced withdrawal of 1,505 MW of synchronous generation (by 2017). In 2024–25, for more than half the year, the levels of inertia in South Australia are below 600 megawatt seconds (MWs). The Rapid Transformation scenario has particularly low levels of inertia, as operational consumption is lower in this scenario. When combined with the projected growth of renewable generation, this means less synchronous generation needs to be dispatched to meet demand.

Figure 12 South Australia inertia for Rapid Transformation scenarios



Given the reduction of synchronous generation within South Australia, the Heywood Interconnector will continue to play a critical role in maintaining power system security and providing ancillary services from other regions. Lower levels of system inertia present a challenge for the future which AEMO will continue to examine.

4.4 Voltage stability challenges in weak networks

Synchronous generators provide dynamic voltage support to the power system, particularly during and immediately following network faults. Synchronous generators provide considerably more fault current to the power system than modern PV and wind turbines connected via power electronics. Fault current helps maintain voltage stability during network faults.[25] The withdrawal of synchronous generators reduces the fault current and can lead to a “weak” system, characterised by challenges including:

- Greater risk of DC/AC converters not remaining operational through network faults.
- Inability to achieve steady-state stability during system normal.
- Protective relays unable to distinguish between system normal load current and fault current leading to an inability to detect and clear faults on the system.
- Slow rate of recovery following network faults.

[25] Fault current is not beneficial in all circumstances. There are upper limits to the amount of fault current a network can manage, and excessive fault current will pose a safety risk and damage equipment.

The strength or weakness of a power system can be characterised by the short circuit ratio (SCR) index. In simple terms, this is the ratio of short circuit fault current to maximum load current. A system is generally considered weak if the SCR drops below 3.[26]

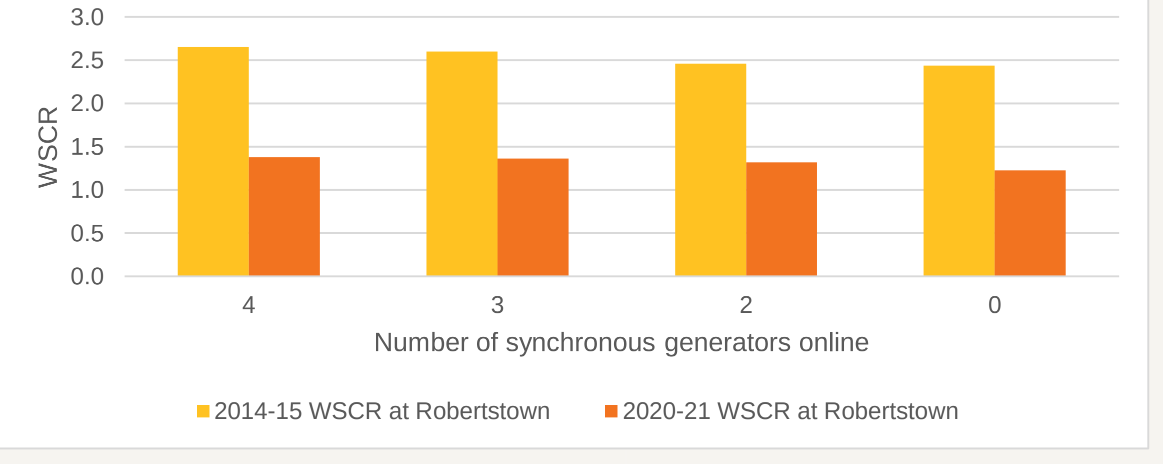
In areas with poor voltage stability and a low SCR, most power electronic devices (like wind and large-scale PV generation) will struggle to remain connected to the network during a nearby fault. Additionally, poor voltage stability and a low SCR make it difficult for power electronic devices to achieve a steady state in system normal, and their power output may need to be restricted to achieve a steady state.

Therefore, the SCR of a connection point may limit the amount of wind generation able to be connected in a weak part of the network because, in simple terms, the more wind turbine generators connected, the less fault current available. The minimum operable SCR defined at the low voltage (LV) terminals of the wind turbines is typically in the range of 1.5 to 2.5.[27] This is explored further in the case study below.

Case study – changes to the short circuit ratio at Robertstown in South Australia

Figure 13 shows the reduction in weighted[28] SCR estimated at the Robertstown connection point (in the South Australian transmission network) under the Rapid Transformation scenario. This part of the network is already considered weak, due to high network impedance[29], synchronous generation withdrawals in South Australia (Playford power station and 50% of capacity at Pelican Point power station), and increased wind and PV generation in the area.

Figure 13 Weighted short circuit ratio (WSCR) at Robertstown in South Australia



During times of low operational demand, less synchronous generation is likely to be dispatched, resulting in lower weighted SCRs. The results show the weighted SCR is less than 1.5 in 2020−21. If more wind generators were to be added in this area, the weighted SCR would reduce further.

Consequently, the SCR is likely to be a limiting factor in the amount of wind generation able to connect in this section of the transmission system.

[26] 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.
[27] Depending on the converter design.
[28] Weighted short circuit ratio takes into account the interaction between separate wind farms on the short circuit ratio.
[29] Impedance represents how much opposition a conductor poses to the flow of electricity. Long, thin transmission line conductors typically used in remote areas tend to have high impedance.

4.5 Modelling limitations

The NTNDP market modelling used for this analysis assumes that all generators are offering to generate (bidding) at their short run marginal cost (SRMC) based on the AEMO database of costs, with no allowance made for start-up costs. This implies there is perfect competition in the market and that generators are fully flexible to respond to market signals.

In practice, the offers from generators will be influenced by a number of real-world factors, including bids for any other generation in the portfolio, start-up times and costs, flexibility to respond to signals, wholesale contract prices and position of the business, any retail load being supplied by the business, and the risk profile of the business.

It is likely that these factors will lead to a greater number of synchronous generators being dispatched in the market than is predicted by SRMC bidding. As a result, the modelling probably underestimates the future levels of inertia, dispatchability and fault levels, however the trends still highlight that inertia levels are expected to fall further over time.

4.6 Proposed work

AEMO is continuing a program of work to evaluate the current and future impact of the challenges described in this chapter on power system operation across the NEM. An element of this work will identify feasible solutions to assist in maintaining power system security and reliability.

In December 2015, AEMO will publish a joint report with ElectraNet on the power system implications of a changing generation mix, focusing on South Australia. Further studies will be completed in 2016. See Appendix D for more information.

An intended focus area for the 2016 NTNDP will be to identify possible network and non-network solutions to manage system security across the national transmission network, addressing these emerging challenges.

CHAPTER 5. NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

The NTNDP is required to identify any NSCAS gap[30] based on the NSCAS need forecast to arise within a planning horizon of at least five years.

Network Support and Control Ancillary Services (NSCAS) are non-market services designed to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. These services are procured by TNSPs (or AEMO as a last resort) where operational measures, such as switching lines out of service, are no longer feasible.

An **NSCAS need** is defined under chapter 10 of the Rules as:

Network support and control ancillary service required to:

a) *maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard; and*

b) *maintain or increase the power transfer capability of that transmission network so as to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market.*

For more information on NSCAS, see Appendix C.

5.1 Security driven NSCAS

Controlling high voltage in the transmission network becomes a challenge in managing system security at times of minimum operational demand. The 2015 NEFR, for the first time, included a forecast for minimum operational demand in South Australia. It projected the growth of rooftop PV would continue to reduce minimum operational demand levels, and that rooftop PV generation could exceed operational demand in South Australia during some midday periods from 2023–24.

Based on AEMO’s minimum operational demand forecast for South Australia in the next five years, AEMO has identified an NSCAS gap for absorbing reactive power capability[31] of up to approximately 100 MVAr within the next five years, with a trigger date of December 2017.

AEMO has also identified an NSCAS gap of approximately 150 MVAr absorbing reactive power capability to manage potential high voltage, likely to occur in Kangaroo Valley, New South Wales, triggering in July 2018. This NSCAS gap is projected under low demand conditions and low interconnector transfers from Victoria to New South Wales. This is currently being managed through a five-year NSCAS contract which expires in 2018. More details are provided in Appendix C.

Similar challenges will arise in other regions if minimum operational demand continues to fall. Collaboration with industry stakeholders is required to identify operational solutions and/or additional reactive support to maintain power system security and reliability into the future.

5.2 Reliability driven NSCAS

AEMO’s 2015 Electricity Statement of Opportunities reported that the Reliability Standard[32] may be breached in South Australia in 2019–20.

[30] Any NSCAS need that AEMO forecasts will arise at any time within a planning horizon of at least 5 years from the beginning of the year in which the most recent NTNDP applies.
[31] Reactive power is needed for networks to manage voltages. Absorbing reactive power is required when voltage is too high.
[32] The Reliability Standard is a measure of sufficiency of installed capacity to meet demand. The Reliability Standard (National Electricity Rules clause 3.9.3C) requires that a maximum of 0.002% of all operational consumption can go unserved for any region in any financial year.

NSCAS need is currently defined to include services required to maintain power system security and reliability of supply of the transmission network in accordance with the reliability standard.

The issue in South Australia therefore constitutes an NSCAS gap under the Rules. However, in this instance the reliability of the transmission network is not deteriorating. What is required is additional transmission or generation capacity. This could be met by stand-by generation acquired as Non Market Ancillary Services through NSCAS, but AEMO believes that this issue is dealt with more appropriately through the Reliability and Emergency Reserve Trader mechanism[33] if left unaddressed.

AEMO is working with the AER to determine if this forecast Reliability Standard breach should be addressed through NSCAS.

[33] AEMO notes that rule 3.20 is due to expire on 30 June 2016, however there has been discussion of extension. AEMO will continue to monitor, as the situation is not yet certain.

APPENDIX A. SCENARIOS, KEY INPUTS AND MODELLING APPROACH

A.1 NTNDP scenario assumptions

The 2015 NTNDP scenarios drew heavily on the 2015 NEFR forecasts. For further details, please see Chapter 2 of the 2015 NEFR[34], and the 2015 NEFR Emerging Technologies Information Paper.[35] An overview of other scenario assumptions are provided in the tables below and in the following sections. A detailed list of the assumptions and corresponding input data is contained in the NTNDP inputs and assumptions page on the AEMO website[36] (which constitutes the NTNDP database).

A.1.1 Gradual Evolution

Key driver	Gradual Evolution (aligned with 2015 NEFR medium scenario)
Economic activity and population growth	Australia's economic activity and population growth continues according to market expectations from current levels, consistent with the Reserve Bank of Australia's (RBA) economic activity expectations and historical population growth reported by the Australian Bureau of Statistics (ABS).
Domestic gas production and global Liquefied Natural Gas (LNG)	Domestic gas production and global LNG markets continue as per current market expectations and are consistent with current growth in Australia's production levels.
Energy-intensive industrial sectors	Energy-intensive industrial sectors continue their current energy consumption levels. Any publicly-announced changes in operations have been accounted for, including the manufacturing sectors.
Research and development (R&D)	Slow to moderate R&D funding.
Distributed generation	Distributed generation penetration is anticipated to be moderate, with 20.9 GW of rooftop PV installed by 2035. 8 GWh of residential batteries is installed by 2035 (refer to the 2015 NEFR Emerging Technologies Information Paper). This projection was based on models of economic benefit, not consumer behaviour, and considered only new installations of rooftop PV and battery storage together, not retrofitting battery storage to existing rooftop PV.
Energy efficiency	Energy efficiency is aligned to the 2015 NEFR medium scenario.
Climate change policy	Up to and including 2020−21: the climate change policy is implemented through the Emissions Reduction Fund (ERF), with most abatement achieved outside the energy industry and therefore with zero implicit carbon cost. After 2020−21: Effect of ERF crediting in the energy industry and/or a tightening safeguard mechanism leads to an implicit cost on carbon aligned with European Emission Allowances.
The Large-scale Renewable Energy Target (LRET)	Target of 33 terawatt hours (TWh) of Australia's energy from renewable sources by 2020, with that level maintained until 2030.
The Small-scale Renewable Energy Scheme (SRES)	The maximum size of a PV installation for SRES remains at 100 kW.
Electric Vehicles	5% of households own an electric vehicle (around 0.5 million electric vehicles) by 2035 (refer to the 2015 NEFR Emerging Technologies Information Paper).

[34] AEMO, 2015 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 3 November 2015.
[35] AEMO, 2015 Emerging Technologies Information Paper. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information. Viewed: 3 November 2015.
[36] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

A.1.2 Rapid Transformation

Key driver	Rapid Transformation (aligned with 2015 NEFR low scenario)
Economic activity and population growth	There is a lower rate of growth in domestic and international economic activity than in the Gradual Evolution scenario. Domestic gas production is more difficult than expected. Australia's international competitiveness is lower than the Gradual Evolution scenario. Fuel substitution hurdles discourage fuel switching between electricity and gas. Global LNG demand is weaker than the Gradual Evolution scenario and there is low penetration of gas as a transport fuel.
Domestic gas production and global LNG	Energy-intensive industrial sectors, including smelters and the manufacturing sector, decrease their output.
Energy-intensive industrial sectors	There is a lower rate of growth in domestic and international economic activity than in the Gradual Evolution scenario.
Research and development (R&D)	R&D in new low-emission generation technologies is well-funded and co-ordinated internationally. The strong emphasis on R&D, pilot, and large-scale technology demonstration projects globally sees new, low-emission technologies move rapidly down the learning curves. New technologies are successfully integrated into the energy sector on a commercial scale.
Distributed generation	Distributed generation penetration is anticipated to be very high, with residential rooftop PV at saturation (25.5 GW installed capacity), total residential and commercial rooftop PV at 33 GW installed capacity, and a 40% penetration of residential battery storage (19.1 GWh installed capacity) by 2034-35.
Energy efficiency	Energy efficiency is aligned with the 2015 NEFR low scenario.
Climate change policy	Up to and including 2017−18: the climate change policy is implemented through the ERF, with most abatement achieved outside the energy industry and, therefore, with zero implicit carbon cost. After 2017−18: higher implicit cost of carbon relative to the Gradual Evolution scenario to reflect a tightening safeguard mechanism or additional carbon abatement policies.
The Large-scale Renewable Energy Target (LRET)	Target of 33 terawatt hours (TWh) of Australia's energy from renewable sources by 2020, with that level maintained until 2030.
The Small-scale Renewable Energy Scheme (SRES)	The maximum size of a PV installation for SRES remains at 100 kW.
Electric Vehicles	20% of households own an electric vehicle (over 2 million electric vehicles) by 2035.

A.2 Key inputs

This section provides a high-level description of the key inputs used in the NTNDP generation and transmission expansion modelling.

Annual energy and maximum demand forecasts

The 2015 NTNDP demand projections for the two scenarios were based on the regional projections provided as part of AEMO's 2015 National Electricity Forecasting Report (NEFR), medium and low scenarios. These projections are used to grow the respective demand traces in accordance with the Demand Trace Development Methodology.[37]

For information about the regional annual energy and maximum demand projections for each scenario see the 2015 NTNDP Assumptions and Inputs webpage.[38]

[37] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.
[38] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

Generation inputs

Information about the key operational parameters of current generating units and future generation projects derived from a number of sources[39], and included the following:

- Committed projects.
- Generating unit capacities.
- Hydroelectric models and water storage assumptions.

For more information see the AEMO Generation Information webpage[40] and the Planning Assumptions webpage.[41]

AEMO applied fuel cost projections for natural gas, brown coal, and bituminous (black) coal for new entry generating units, and estimates of the costs and other parameters for a range of new generation technologies.

The information sources included:

- Core Energy for fuel costs projections for natural gas.
- Bloomberg New Energy Finance (BNEF) for large-scale solar generation costs applied in both sensitivities.
- ACIL Allen report for all other fuel cost projections, estimates of the costs, and other parameters for other generation types (brown coal, and bituminous (black) coal). It also evaluates a range of new generation technologies and includes the following information for each:
  - Capital costs.
  - Fixed and variable operating and maintenance costs.
  - Regional annual build limits.
  - Thermal efficiency factors.
  - Emissions factors.

All the information listed above is available on the Planning Assumptions page on the AEMO website.[42]

A.3 Modelling approach

The 2015 NTNDP modelling framework comprised a combination of least-cost expansion models, transmission network power flow studies, and time-sequential market simulations.

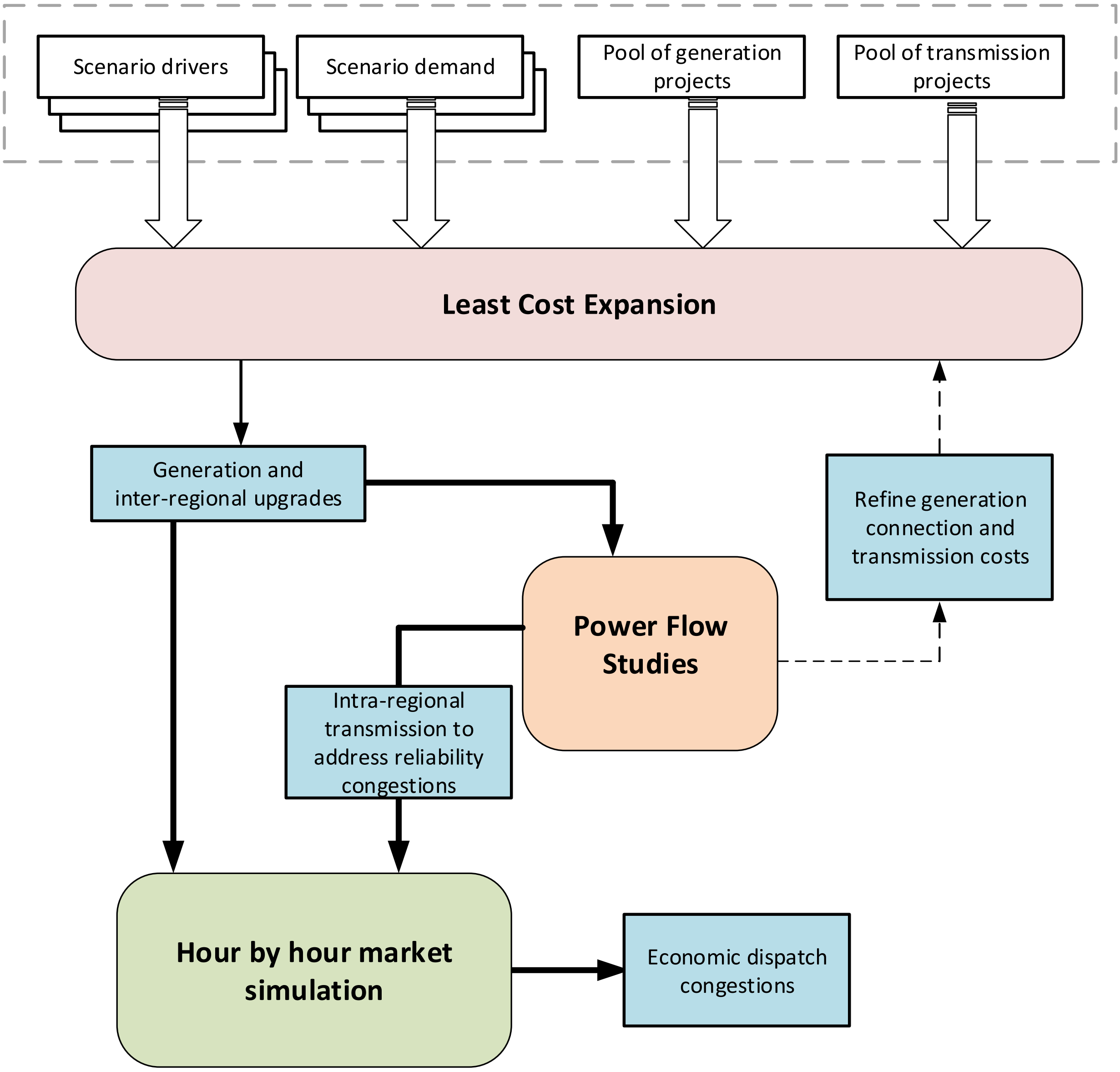
Figure 14 shows the relationships and data flows between these modelling activities. In particular, the 2015 NTNDP used these activities iteratively to ensure feasible and economically justifiable results:

- The least-cost expansion models produce a co-optimised expansion plan considering generation and interregional network options, which minimise overall capital and operating costs (subject to meeting reliability requirements).
- Initial power flow studies identify major intra-regional constraints. Cost estimates[43] for intra-regional network augmentations are used to refine the least cost expansion modelling assumptions so further simulations account for these costs, and the model can choose to keep the same generation expansion or alter it to reduce total expansion costs.

[39] Including AEMO's analysis, consultants, generators, and potential generation investors.
[40] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.
[41] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.
[42] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.
[43] Cost estimates sourced from TNSP's annual planning reports.

- The transmission network power flow studies identify intra-regional network constraints and the development required to maintain reliability of supply under the assumed load growth and generation expansion results.
- The time-sequential market simulations identify intra-regional constraints to meet the peak demand and transmission constraints caused to limit economic dispatch of generation.

Figure 14 Modelling approach overview



A.3.1 Scope of transmission developments considered by the NTNDP

Taking a long-term NEM-wide view, the NTNDP focuses on the ability of the national transmission network[44] to reliably support major power transfers between generation and demand centres in the

[44] This generally refers to lines of nominal voltage of 220 kV and above.

NEM. AEMO confined the scope of this analysis to transmission network thermal limitations arising during diversified regional peak demands.

System conditions

Load flow analysis was carried out to assess the transmission network adequacy for conditions matching regional 10% probability of exceedance (POE)[45] maximum demand, which were based on AEMO's 2015 NEFR.[46] Economic dispatch of NEM-wide generation was used to meet the 10% POE maximum demand. This involved modelling the economic dispatch of generation in a given region and inter-regional transfers to meet the 10% POE maximum demand in that region and corresponding demand in other regions.

Each point of connection was represented with diversified load at the time of AEMO's 10% POE maximum demand at a region-wide level. Individual connection points can experience a local load higher than the load at the time of the regional maximum demand. The 2015 NTNDP did not assess local transmission network adequacy to meet localised peak demand at times outside the 10% POE regional maximum demand.

Although network adequacy was assessed assuming wind power generation at historical levels of contribution during maximum demand, higher wind power generation can occur. To identify main transmission network limitations to accommodate high wind power generation, additional load flow studies were undertaken with 70–80% of wind power generation and moderate demand levels.

Planning criteria

AEMO undertook power system simulation studies and monitored the loading of main transmission lines and transformers under the following conditions:

- System intact (pre-contingency, when all other equipment is in service).
- A potential single credible contingency (N-0-1 criterion).[47]

The monitored transmission lines and transformers form part of the main transmission network supporting major NEM power transfers, although in some cases the monitoring was extended to lower voltages, particularly in areas where the transmission network at lower voltage levels was parallel to the main transmission network at voltage levels of 220 kV and above.

Network limitations were identified by comparing network loadings of monitored transmission lines and transformers against their summer continuous ratings. Winter continuous ratings were also considered for Tasmania, because Tasmania experiences its 10% POE maximum demand in winter.

Short-term ratings, generation rescheduling, and the application of existing control schemes were also taken into account to manage observed limitations. To identify a co-optimised generation and transmission plan, further investigations were carried out to check whether the limitations can be eliminated by the economic relocation of new generation (whether additional generation costs at the alternative location were outweighed by the costs of the avoided transmission).

The identification of network limitations did not consider the unavailability of generation plant combined with transmission plant outages.

[45] A probability of exceedance (POE) refers to the likelihood that a maximum demand forecast will be met or exceeded. A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10, while 50% and 90% POE projections are expected to be exceeded, on average, five years in 10 and nine years in 10 respectively.

[46] AEMO. "National Electricity Forecasting Report (NEFR) 2015". Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report . Viewed 5 November 2015.

[47] Where 'N' refers to the total number of plant, '0' refers to no prior outage, and '1' refers to a potential unplanned outage of one plant.

APPENDIX B. GENERATION OUTLOOKS

B.1 Introduction

AEMO's generation outlook simulated the future generation mix by incorporating a least cost expansion of large-scale generation in the National Electricity Market (NEM) over a 20-year outlook period, from 2015–16 to 2034–35, 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 described in section B.2.

Relationship to the National Transmission and Network Development Plan

The generation outlook is an input to the 2015 National Transmission and Network Development Plan (NTNDP), providing a view of zonal generation required to meet expected demand and operational consumption. A unique generation outlook is required for each of the two scenarios and associated sensitivities modelled in the NTNDP. A description of each outlook, including key insights, is in sections B.3 to B.6. For more detailed regional results from each outlook, please refer to the NTNDP webpage[48] and interactive map.[49]

B.2 Generation outlook methodology

Over the projection period, the generation outlook optimises generation investments and withdrawals taking into account requirements to:

- Dispatch generation to meet consumption across each year.
- Ensure sufficient generation reserve is available to meet the reliability standard.
- Meet legislated policy objectives (LRET target).

Consumption Requirements

Forecast maximum demand and minimum reserve levels determine the future generation capacity required. Annual consumption and the demand profile affect the generation mix that is used to meet demand. The NTNDP used AEMO's 2015 National Electricity Forecasting Report (NEFR)[50] to provide consumption forecasts for the NEM and by NEM region. Minimum capacity reserves were assumed to ensure the reliability standard would be met and are set to the size of the largest generator.

Generation Requirements

In determining the generation 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 described in Appendix A and published on AEMO's planning assumptions page.[51] No allowance was made for start-up costs. This implies there is perfect competition in the market and generators are fully flexible to respond to market signals. The NTNDP assumed no additional coal plants would be built in the NEM.

In practice, the offers from generators will be influenced by a number of real-world factors for the business owning the generator, including the bids for other generators in the portfolio, the start-up times

[48] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.
[49] AEMO. Available: http://www.aemo.com.au/electricity/planning/interactive-map/.
[50] AEMO. 2015 National Electricity Forecasting Report. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed 25 September 2015.
[51] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

and costs of the generator, the flexibility of the generator to respond to signals, the retail load being supplied by the business, and the business' wholesale contract prices and position, and risk profile.

It is likely that these factors will lead to a greater number of generators being dispatched in the market than is predicted by SRMC bidding. As a result, the modelling is likely to underestimate the levels of inertia, dispatch and fault levels.

B.3 Gradual Evolution scenario generation outlook

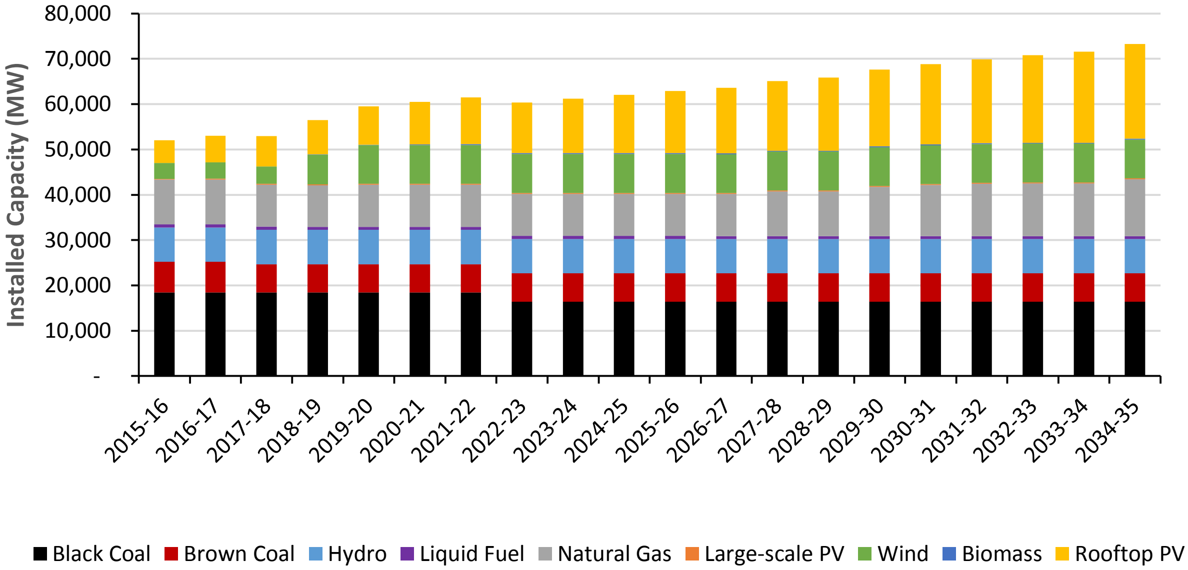
Overview

The Gradual Evolution scenario outlook assumed demand from centralised sources equal to the NEFR medium scenario. The medium demand was overlaid by a medium penetration of distributed energy resources equal to that described in the Emerging Technologies Information Paper published by AEMO supplementary to the 2015 NEFR.[52]

NEM total installed capacity by fuel type

Figure 15 illustrates that NEM-installed capacity is forecast to increase 44% from 50,864 MW to 73,264 MW by 2034–35. The forecast increase is largely due to the increase of 17,656 MW of rooftop PV accounting for about 67% of new capacity installations. The increase in rooftop PV can decrease maximum operational demand. However the NEFR forecasts an increase in maximum operational demand which cannot be met with rooftop PV alone, therefore an increase in scheduled generation installation is required.

Figure 15 Gradual Evolution scenario – total installed generation capacity by fuel type (NEM regions)



Key observations are:

- Large-scale PV increases by 94% (102 MW) by 2016–17 and remains steady until 2034–35.
- Rooftop PV increases by 546% (17,656 MW) by 2034–35.
- Wind generation increases 139% (4,985 MW) by 2019–20 and remains steady until 2034–35.

[52] Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information. Viewed 25 September 2015.

- Natural gas-powered generation (GPG) increases 27% (2,677 MW) by 2034–35.
- Coal-fired generation decreases by 12% (3,125 MW) by 2022–23 and remains steady until 2034–35.

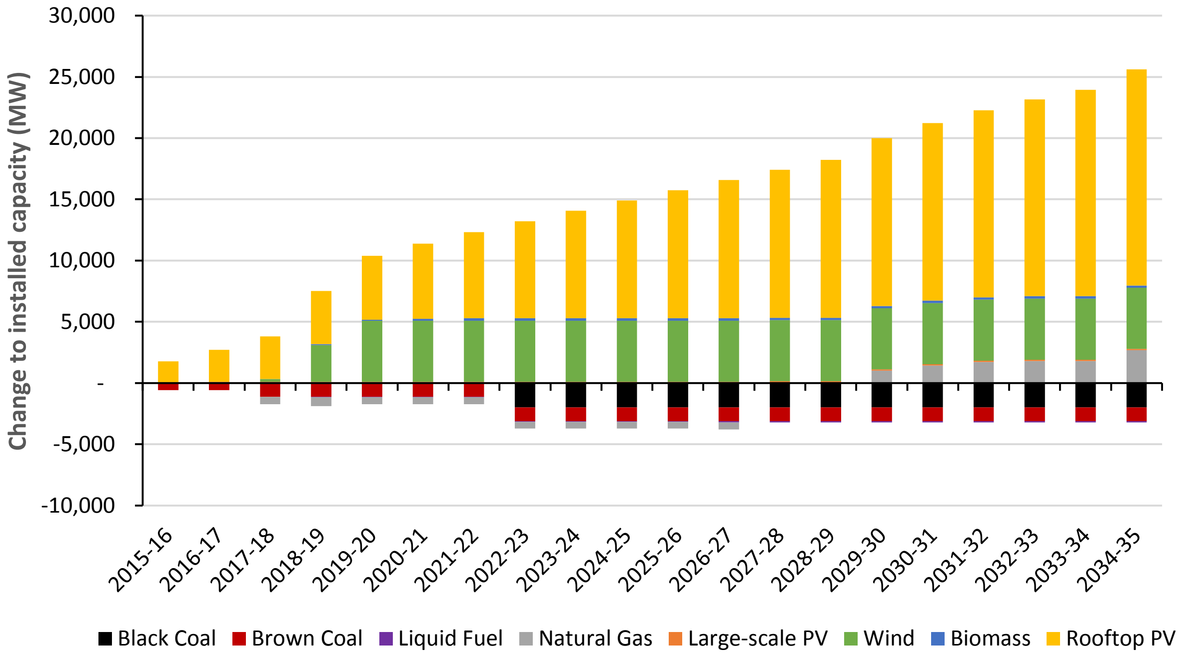
NEM capacity changes by fuel type

Figure 16 illustrates forecast cumulative generation capacity installations and withdrawals in the NEM over the 20-year outlook. The forecast additional installed generation is 22,400 MW (from 50,864 MW in 2015–16 to 73,264 MW by 2034–35), with 26,349 MW of new generation installed and 3,949 MW of generation withdrawn. This additional installed generation can refer to either new plant or return to service of plant that has already been withdrawn.

Key observations are:

- 4,985 MW of new wind generation installed between now and 2019–20.
- 17,656 MW of new rooftop PV installed by 2034–35.
- 2,677 MW of new GPG capacity (which may include GPG capacity currently planned to be withdrawn) is added by 2034–35 to meet reliability standards.
- 3,125 MW of coal-fired generation capacity withdraws in 2022–23.
- Residential storage capacity is forecast to increase by 3,850 MW from 8 MW by 2034–35. It may be inaccurate to represent the installed capacity in instances of combined PV and battery storage installations as the straight sum of the PV and battery capacity. This is because the inverter may be the factor limiting capacity, depending on the electrical configuration at the site.

Figure 16 Gradual Evolution scenario – cumulative generation capacity installations and withdrawals (NEM regions)



Regional capacity changes by fuel type

Table 4 provides the location of major changes in net generation capacity over the 20-year outlook period as a result of AEMO's market modelling. This table does not include projects that are already committed, however it does include announced withdrawals. Major changes in generation capacity includes net changes over 250 MW per fuel type per region. For more detail on changes in net generation changes per region please refer to the NTNDP database.

Table 4 **Gradual Evolution scenario – projected major changes in net generation capacity**

Region	Fuel type	Net change to generation capacity installed from 2015-16 to 2034–35 (MW)
New South Wales	Wind	2,500
	Rooftop Solar	4,660
	Storage	1,201
	Natural Gas	1,592
	Black Coal	-2,000
	Total	**7,953**
Queensland	Wind	588
	Rooftop Solar	5,561
	Storage	986
	Natural Gas	488
	Total	**7,623**
Victoria	Wind	400
	Rooftop Solar	4,845
	Storage	1,344
	Brown coal	-339
	Natural Gas	456
	Total	**6,706**
South Australia	Wind	936
	Rooftop Solar	2,077
	Brown coal	-786
	Natural Gas	320
	Total	**2,547**
Tasmania	Wind	320
	Rooftop Solar	513
	Total	**833**

B.4 Gradual Evolution sensitivity generation outlook

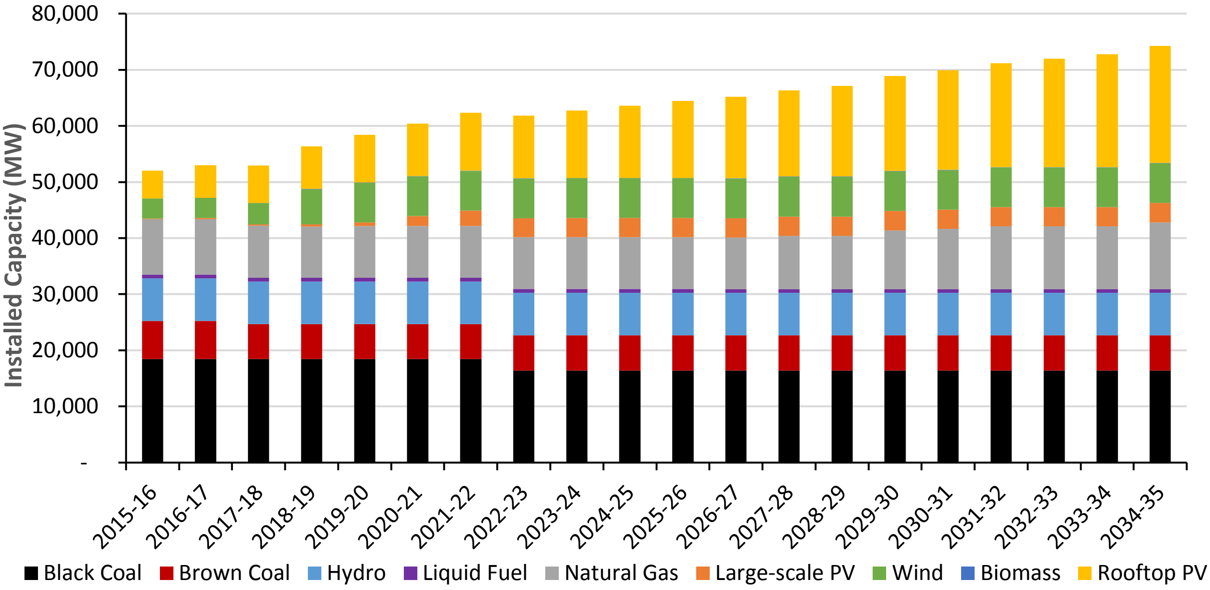
Overview

The Gradual Evolution sensitivity reflects the inputs and assumptions under the Gradual Evolution scenario, but introduces a lower cost for large-scale PV.

NEM total installed capacity by fuel type

Figure 17 illustrates that NEM-installed generation capacity is forecast to increase by 46% from 50,864 MW to 74,270 MW by 2034–35. The relative increase of 2% compared to the Gradual Evolution scenario is due to the shift from wind generation to large-scale PV. Typically, large-scale PV has a lower coincidence to regional maximum demand compared to wind, therefore more capacity is required to meet maximum demand requirements.

Figure 17 Gradual Evolution sensitivity – total generation capacity by fuel type (NEM regions)



Key observations are:

- Wind generation capacity increases by 98% (3,496 MW) by 2019–20 and remains steady until 2034–35.
- Large-scale PV increases by 3,051% (3,325 MW) by 2034–35.
- Rooftop PV increases by 546% (17,656 MW) by 2034–35.
- GPG increases by 21% (2,100 MW) by 2034–35 to meet reliability standards.
- Coal-fired generation decreases by 12% (3,125 MW) by 2022–23 and remains steady until 2034–35.

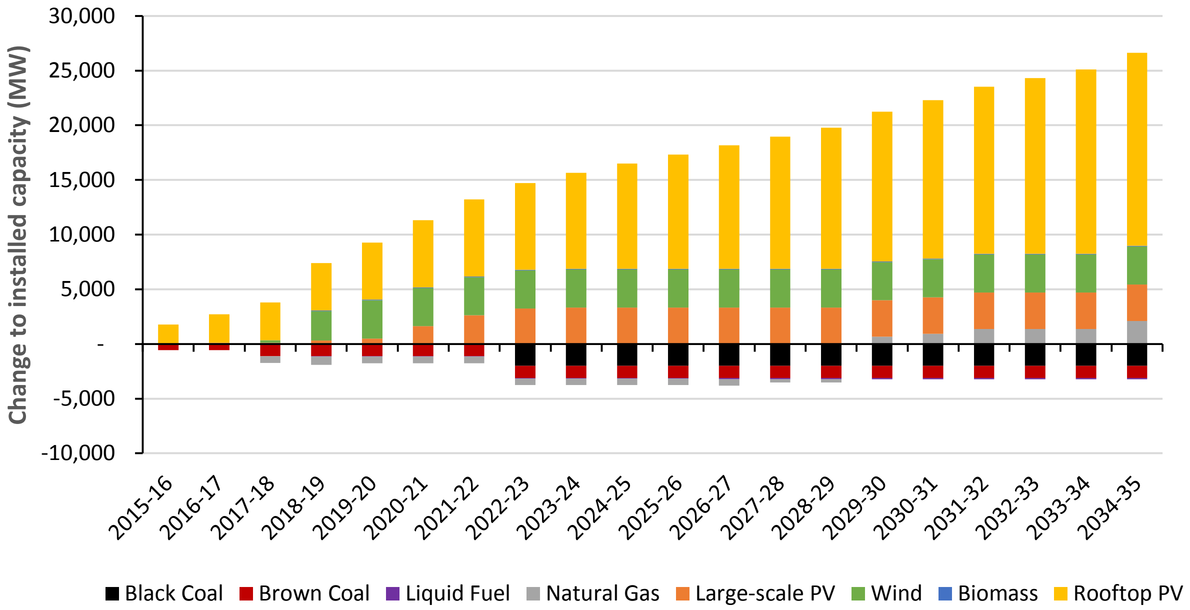
NEM capacity changes by fuel type

Figure 18 illustrates forecast cumulative generation capacity installations and withdrawals over the 20-year outlook. The forecast net installed new generation is 23,406 MW (from 50,864 MW in 2015–16 to 74,270 MW by 2034–35), with 27,381 MW of new generation installed and 3,975 MW of generation withdrawn. This additional installed generation can include either new plant or return to service of plant that has already been withdrawn.

Key observations are:

- 3,496 MW of new wind generation installed by 2019–20.
- 3,325 MW of new large-scale PV installed by 2023–24.
- 17,656 MW of new rooftop PV installed by 2034-35.
- 2,100 MW of new GPG capacity (which may include GPG capacity planned for withdrawal) is required by 2034–35 to meet reliability standards.
- 3,125 MW of coal-fired generation capacity withdraws in 2022–23.
- Residential storage capacity increases from 8 MW in 2015–16 to 3,858 MW by 2034–35.

Figure 18 Gradual Evolution sensitivity – cumulative generation capacity installations and withdrawals (NEM regions)



Regional net capacity changes by fuel type

Table 5 provides the location of major changes in net generation capacity over the 20-year outlook period as a result of AEMO's market modelling. This table does not include projects that are already committed, however it does include announced withdrawals. Major changes in generation capacity include net changes over 250 MW per fuel type per region.

For more detail on changes in net generation per region, please refer to the Generation and Transmission outlook on the NTNDP website.[53]

[53] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

Table 5 **Gradual Evolution sensitivity – projected major changes in net generation capacity**

Region	Fuel type	Net change to generation capacity installed from 2015–16 to 2034–35 (MW)
New South Wales	Wind	1,750
	Utility Solar	1,412
	Rooftop Solar	4,660
	Storage	1,201
	Natural Gas	1,356
	Black Coal	-2,000
	Total	**8,380**
Queensland	Wind	386
	Utility Solar	1,000
	Rooftop Solar	5,561
	Storage	986
	Natural Gas	273
	Total	**8,205**
Victoria	Wind	300
	Rooftop Solar	4,845
	Storage	1,344
	Brown Coal	-339
	Natural Gas	289
	Total	**6,439**
South Australia	Wind	500
	Utility Solar	811
	Rooftop Solar	2,077
	Natural Gas	360
	Brown Coal	-786
	Total	**2,962**
Tasmania	Wind	320
	Rooftop Solar	513
	Total	**833**

B.5 Rapid Transformation scenario generation outlook

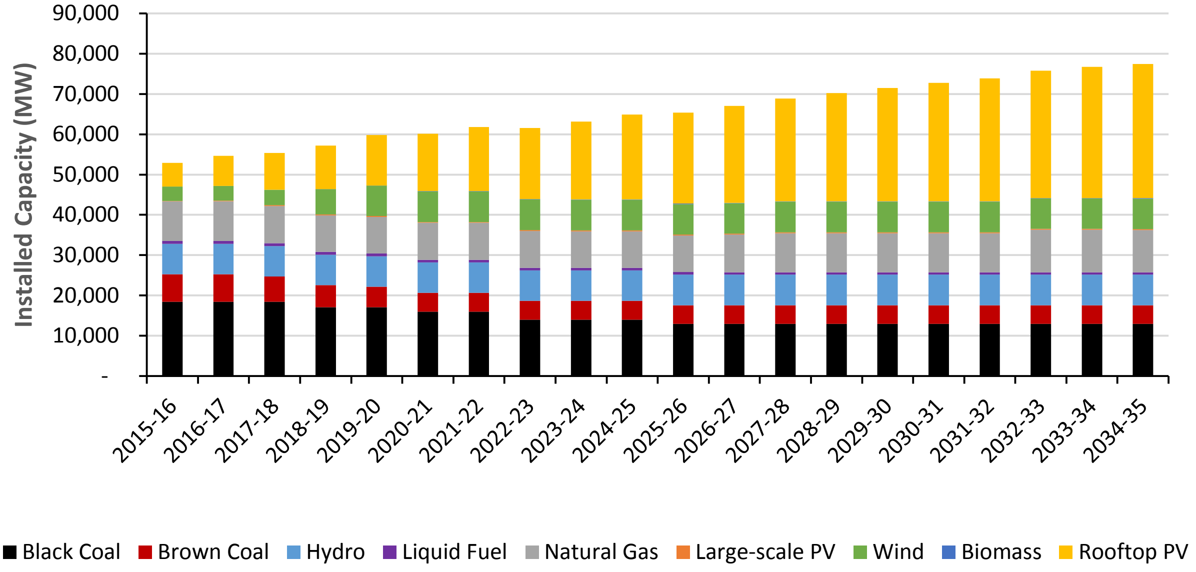
Overview

The Rapid Transformation scenario assumes a high penetration of distributed energy resources, and low demand from centralised sources, taking its input demand from AEMO's 2015 NEFR low scenario.

NEM total installed capacity by fuel type

Figure 19 shows that NEM-installed capacity is forecast to increase 52.3%, from 50,864 MW in 2015–16 to 77,468 MW by 2034–35. The majority of this increase is attributed to rooftop PV.

Figure 19 Rapid Transformation scenario – total installed generation capacity by fuel type (NEM regions)



Key observations are:

- Large-scale PV increases by 94% (102 MW) by 2016–17 and remains steady until 2034–35.
- Rooftop PV increases by 931% (30,095 MW) by 2034–35.
- Wind generation increases 112% (3,997 MW) by 2019–20 and remains steady until 2034–35.
- Coal-fired generation decreases by 32% (8,215 MW) by 2025–26 and remains steady until 2034–35.

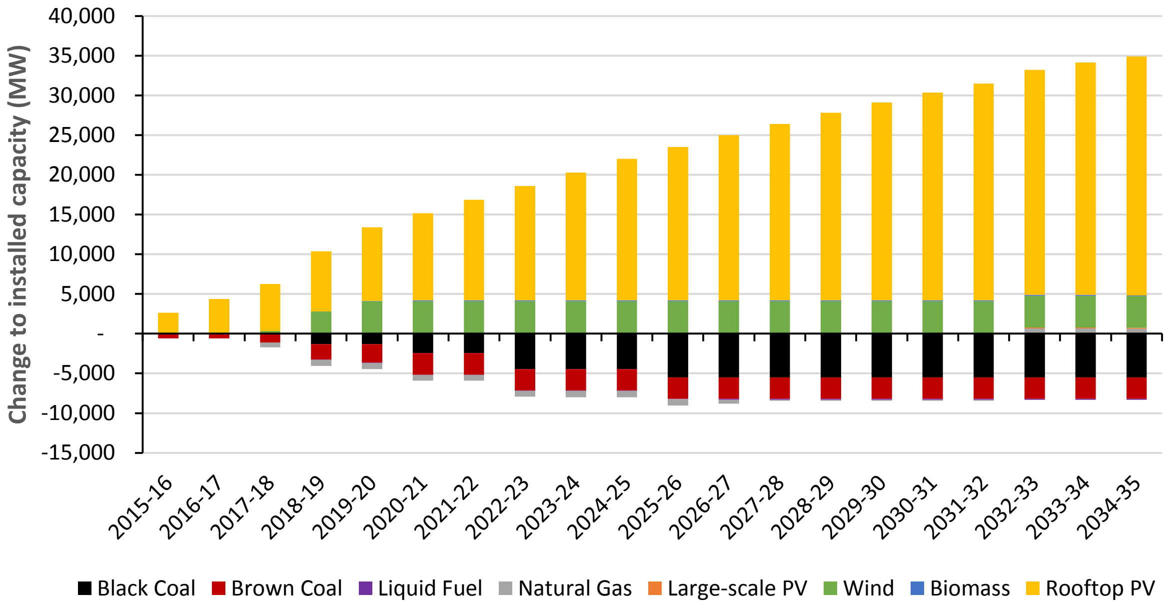
NEM capacity changes by fuel type

Figure 20 shows forecast cumulative generation capacity installations and withdrawals over the 20-year outlook. The forecast net installed generation is 26,604 MW (from 50,864 MW in 2015–16 to 77,468 MW by 2034–35), with 35,773 MW of additional generation installed and 9,169 MW of generation withdrawn. This additional installed generation can refer to either new plant or return to service of plant that has already been withdrawn.

Key observations are:

- 3,997 MW of new wind generation installed by 2019–20.
- 30,095 MW of new rooftop PV installed by 2034–35.
- 8,215 MW of coal-fired generation capacity withdraws in 2025–26.
- Residential storage capacity to increase to 11,188 MW by 2034–35.

Figure 20 Rapid Transformation scenario – cumulative generation capacity installations and withdrawals (NEM regions)



Regional net capacity changes by fuel type

Table 6 provides the location of major changes in net generation capacity over the 20-year outlook period as a result of AEMO's market modelling. This table does not include projects that are already committed, however it does include announced withdrawals. Major changes in generation capacity include net changes over 250 MW per fuel type per region. For more detail on changes in net generation changes per region please refer to the NTNDP database.

Table 6 **Rapid Evolution scenario – projected significant changes in generation capacity by state**

Region	Fuel type	Net change to generation capacity installed from 2015–16 to 2034–35 (MW)
New South Wales	Wind	2,271
	Rooftop Solar	10,076
	Storage	3,873
	Black Coal	-3,320
	Total	**12,900**
Queensland	Wind	400
	Rooftop Solar	7,807
	Storage	2,856
	Black Coal	-2,170
	Total	**8,893**
Victoria	Wind	300
	Rooftop Solar	8,857
	Storage	3,256
	Natural Gas	1,148
	Brown Coal	-1,939
	Total	**11,622**

Region	Fuel type	Net change to generation capacity installed from 2015–16 to 2034–35 (MW)
South Australia	Wind	786
	Rooftop Solar	2,680
	Storage	934
	Natural Gas	-480
	Brown coal	-786
	Total	**3,134**
Tasmania	Rooftop Solar	675
	Storage	270
	Total	**944**

B.6 Rapid Transformation sensitivity generation outlook

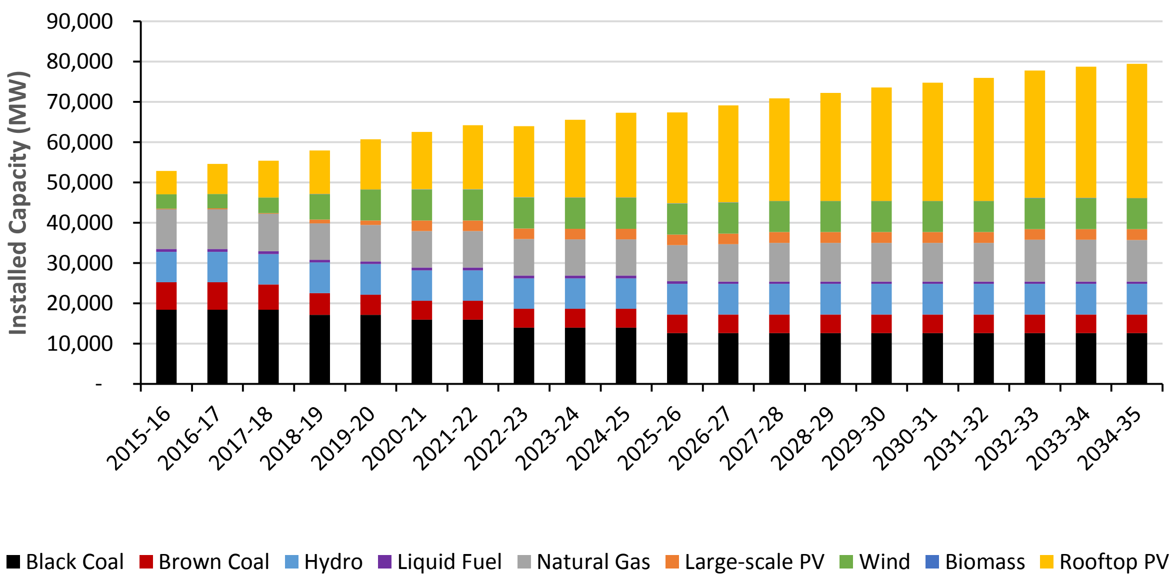
Overview

The Rapid Transformation sensitivity reflects the inputs and assumptions under the Rapid Transformation scenario, but assumes a lower cost for large-scale renewable generation.

NEM total installed capacity by fuel type

Figure 21 shows that NEM-installed capacity is forecast to increase 56.3%, from 50,864 MW in 2015–16 to 79,482 MW by 2034–35, due to the increase in distributed energy resources.

Figure 21 Rapid Transformation sensitivity – total installed generation capacity by fuel type (NEM regions)



Key observations are:

- Large-scale PV increases by 2,334% (2,544 MW) by 2020–21 and remains steady until 2034–35.
- Rooftop PV increases by 931% (30,095 MW) by 2034–35.
- Wind generation increases by 115% (4,120 MW) by 2019–20 and remains steady until 2034–35.

- Coal-fired generation decreases by 33% (8,565 MW) by 2025–26 and remains steady until 2034–35.

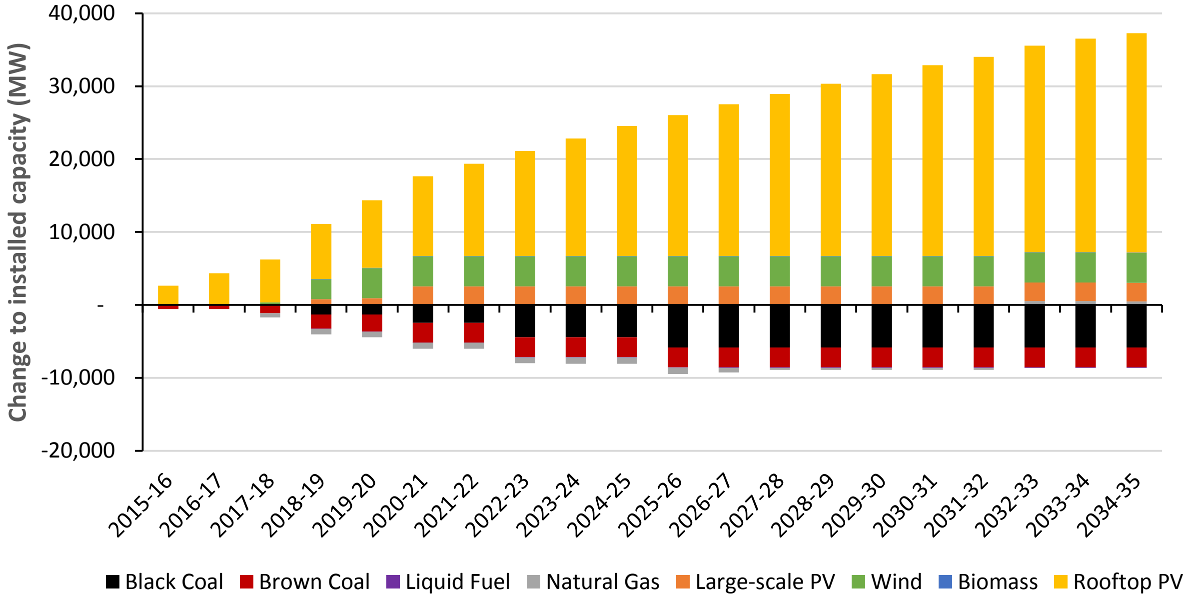
NEM capacity changes by fuel type

Figure 22 shows forecast cumulative generation capacity installations and withdrawals over the 20-year outlook. The forecast net installed generation is 28,619 MW (from 50,864 MW in 2015–16 to 79,482 MW by 2034–35), with 38,227 MW of generation installed and 9,608 MW of generation withdrawn. This additional installed generation can refer to either new plant or return to service of plant that has already been withdrawn.

Key observations are:

- 4,120 MW of new wind generation installed by 2019–20.
- 2,544 MW of new large-scale PV installed by 2020–21.
- 30,095 MW of new rooftop PV installed by 2034–35.
- 8,565 MW of black coal-fired generation capacity withdraws by 2025–26.
- Residential storage capacity increases to 11,188 MW by 2034–35.

Figure 22 Rapid Transformation sensitivity – cumulative generation capacity installations and withdrawals (NEM regions)



Regional net capacity changes by fuel type

Table 7 provides the location of major changes in net generation capacity over the 20-year outlook period as a result of AEMO's market modelling. This table does not include projects that are already committed, however it does include announced withdrawals. Major changes in generation capacity include net changes over 250 MW per fuel type per region. For more detail on changes in net generation changes per region please refer to the NTNDP database.

Table 7 **Rapid Transformation sensitivity – projected significant changes in generation capacity**

Region	Fuel type	Net change to generation capacity installed from 2015–16 to 2034–35 (MW)
New South Wales	Wind	2,352
	Utility Solar	901
	Rooftop Solar	10,076
	Storage	3,873
	Black Coal	-3,320
	Total	**13,882**
Queensland	Wind	400
	Utility Solar	1,000
	Rooftop Solar	7,807
	Storage	2,856
	Black Coal	-2,520
	Total	**9,543**
Victoria	Wind	300
	Rooftop Solar	8,857
	Storage	3,256
	Natural Gas	1,143
	Brown Coal	-1,939
	Total	**11,618**
South Australia	Wind	828
	Utility Solar	541
	Rooftop Solar	2,680
	Storage	934
	Brown Coal	-786
	Natural Gas	-480
	Total	**3,716**
Tasmania	Rooftop Solar	675
	Storage	270
	Total	**944**

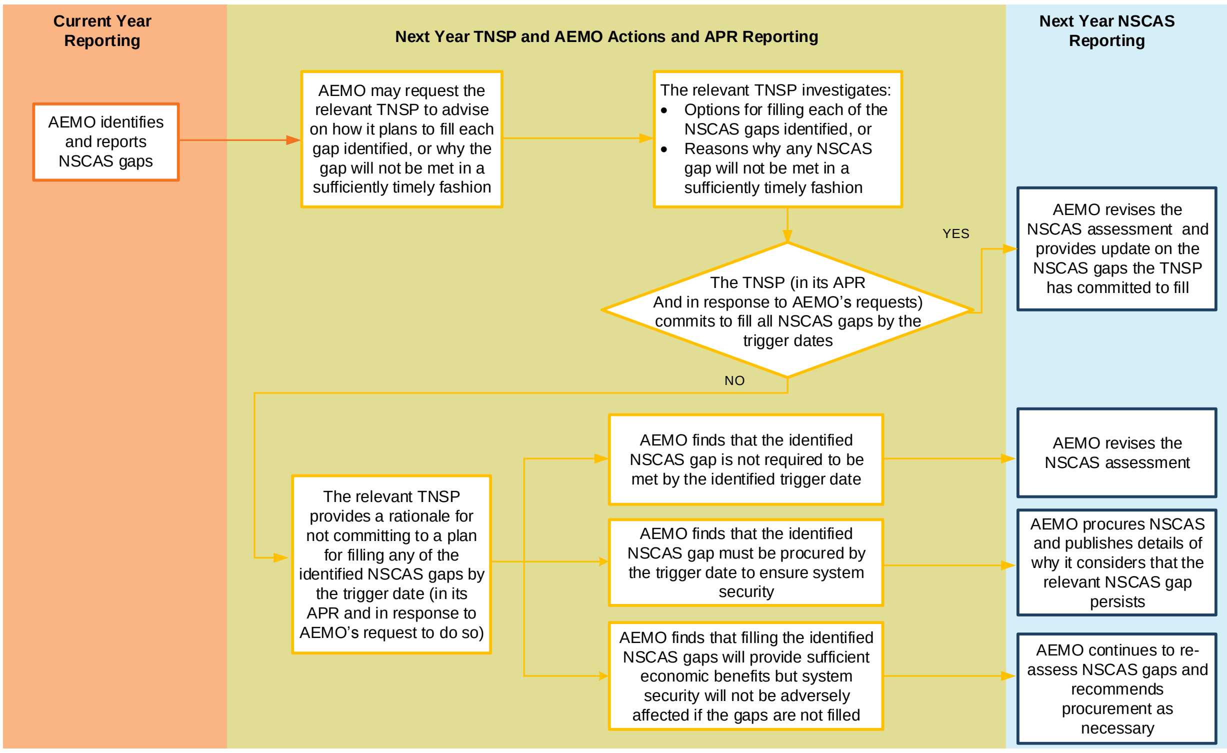
APPENDIX C. NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

NSCAS are non-market ancillary service contracts designed to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

TNSPs have primary responsibility for acquiring NSCAS. Each year, AEMO identifies any NSCAS need forecast to arise over a five-year horizon (NSCAS gap). This assists TNSPs with decision-making about their NSCAS procurement.

As required by clause 3.11.3 of the Rules, AEMO may ask a TNSP to advise the arrangements the TNSP will have in place to meet an NSCAS gap identified in an NTNDP. If no arrangements are in place, AEMO will acquire the necessary NSCAS to prevent any adverse impact on power system security and reliability.

Figure 23 Process for meeting NSCAS gaps identified by AEMO



More information is in the NSCAS description and NSCAS quantity procedure on AEMO's website.[54]

[54] AEMO, NSCAS Description and Quantity Procedure. Available at: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure. Viewed 6 October 2015.

C.1 NSCAS assessment outcome

AEMO's forecasts of NSCAS gaps in the next five years (2015–16 to 2019–20) are detailed below.

Controlling high voltage in the transmission network becomes a challenge in managing power system security during times of low demand. AEMO has identified a need to provide additional absorbing reactive power to manage high voltage in the next five years in New South Wales and South Australia.

Table 8 **Summary of challenges in maintaining power system security**

Region	Potential NSCAS gaps [a]	Comment	Potential Trigger date[55] /Tender date[56]
Queensland	None	The south-east Queensland network may continue to experience high voltages under light load conditions. This will be managed with operational solutions. AEMO and Powerlink will continue to monitor the situation.	None
New South Wales	About 150 MVAr absorbing reactive power	AEMO has identified an NSCAS gap of about 150 MVAr absorbing reactive power capability to manage potential high voltage likely to occur in Kangaroo Valley after the expiry of one of the two existing NSCAS agreements in June 2018. This NSCAS gap was identified on the assumption that the absorbing reactive power capability provided by TransGrid's existing NSCAS agreement, remains unchanged. AEMO and TransGrid will continue to monitor the situation. (See Section C.4 for more information on the existing NSCAS agreements.)	July 2018/ January 2017
Victoria	None	High voltages are likely to appear in the Victorian 500 kV network under certain system operating conditions. This will be managed by operational solutions. AEMO will continue to monitor the situation.	None
South Australia	Up to about 100 MVAr absorbing reactive power	The South Australian transmission network may experience high voltage during times of low demand. Currently, these high voltage issues are managed by operational solutions. Based on AEMO's minimum demand forecast for South Australia,[57] which projects that minimum demand in South Australia will continue to decline, AEMO has identified an NSCAS gap for absorbing reactive power capability of up to about 100 MVAr within the next five years. AEMO and ElectraNet will continue to monitor the situation.	December 2017/ June 2016
Tasmania	None	The George Town voltage control issues reported in the 2013 NTNDP have been resolved following the commissioning of two voltage control schemes by TasNetworks in 2014.	None

a. MVAr (megavolt amperes reactive) is a unit of reactive power, as megawatts are to active power. Reactive power is a necessary component of alternating current electricity. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which in turn is essential for maintaining power system security and reliability.

A component of NSCAS involves investigating whether a service to maintain or increase network power transfer capability will maximise the present value of net economic benefit to the NEM. In consultation with TNSPs, AEMO also investigated network constraints binding in 2014 with an annual market impact of greater than $50,000.[58] A constraint equation's annual market impact is determined by summating the marginal values from a marginal constraint cost (MCC) re-run over one year. For more information about the MCC re-run, see AEMO's annual NEM constraint report.[59] The 2015 NSCAS assessment

[55] Trigger date means for any NSCAS gap identified in clause 5.20.2(c)(8)(i) of the Rules, the indicative date that the NSCAS gap first arises
[56] Tender date means for any NSCAS gap identified in clause 5.20.2(c)(8)(i) of the Rules, the indicative date that AEMO would need to act so as to call for offers to acquire NSCAS to meet that NSCAS gap by the relevant NSCAS trigger date in accordance with clause 3.11.3(c)(4) of the Rules.
[57] AEMO. National Electricity Forecasting Report. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 6 October 2015.
[58] A $50,000 MCC threshold is used as a trigger to consider whether the market benefits limb of the NSCAS need may be met. Refer to 2012 market modelling at: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/Network-Support-and-Control-Ancillary-Services-Assessment-2012. Viewed: 9 November 2015.
[59] AEMO, NEM constraint report. Available: http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report.

found that the previously identified New South Wales to Victoria voltage stability limitation (detailed in Table 9) was the only limitation that had an annual market impact greater than $50,000 in 2014, and that may viably be addressed using NSCAS.

TNSPs are responsible for undertaking cost benefit analysis on emerging limitations, in addition to this preliminary assessment.

C.2 Status of NSCAS gaps identified in previous NSCAS assessments

Table 9 below provides an update on the status of the NSCAS gaps identified in 2012.[60] The 2013[61] and 2014[62] NSCAS assessments did not identify any additional potential NSCAS gaps.

Table 9 **Status of NSCAS gaps identified in 2012**

Potential NSCAS gap identified in 2012	Status
A need for voltage control ancillary service (VCAS)[a] to provide absorbing reactive power to avoid over-voltages in the Snowy and Kangaroo Valley areas in NSW.	AEMO acquired NSCAS to address this gap in 2012–13. See Section C.4 for details.
Potential NSCAS gap in relieving the Robertstown – North West Bend line loading limitation.	This limitation has been addressed through ElectraNet's committed projects and Network Capability Incentive Parameter Action Plan (NCIPAP)[63].
Potential NSCAS gap in relieving the New South Wales to Victoria voltage stability limitation.	Due to the low demand growth forecasts in both Victoria and New South Wales, and the newly installed capacitor banks at Canberra and Yass, the potential to deliver positive net market benefits by alleviating the New South Wales to Victoria voltage stability limitation foreseen in the 2012 NSCAS assessment has diminished. As part of AEMO and TransGrid's normal joint planning process, AEMO and TransGrid will continue to explore economical solutions to release the potential market benefits associated with this limitation.

a. VCAS maintains voltage within specific limits and avoids voltage instability for system security purposes or improves power transfer limits for net market benefit purposes. For more information, see the NSCAS description in http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure.

C.3 AEMO's 2014–15 NSCAS acquisition

AEMO did not acquire any additional NSCAS in 2014–15.

C.4 AEMO's current NSCAS agreements

Table 10 lists the NSCAS that AEMO acquired in 2012–13 for Voltage Control Ancillary Services (VCAS). No additional NSCAS was acquired in 2013–14.

Table 10 **NSCAS AEMO acquired in 2012–13**

Region	NSCAS type	NSCAS acquired
New South Wales	VCAS (absorbing)	800 MVAr

60 AEMO. Network Support and Control Ancillary Services (NSCAS) Assessment Report. Available at http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/Network-Support-and-Control-Ancillary-Services-Assessment-2012. Viewed: 6 October 2015.

61 AEMO. National Transmission Network Development Plan. Appendix B. Available at http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2013/2013_NTNDP.pdf.ashx. Viewed: 6 October 2015.

62 AEMO. National Transmission Network Development Plan. Appendix B. Available at http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2014/NTNDP%202014%20%20main%20document.ashx. Viewed 2 December 2014.

63 AER. Final decision – Early application of the network capability component of the service target performance incentive scheme for ElectraNet. Available at: http://www.aer.gov.au/system/files/AER - final decision - ElectraNet early application of the network capability component_0.pdf (Table 1). Viewed: 6 October 2015.

AEMO has procured NSCAS under the two following agreements for the period from 30 June 2013 to 30 June 2019.

- **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.

- **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. It is expected that TransGrid will 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 D. WORK ON INTEGRATION OF RENEWABLE GENERATION IN SOUTH AUSTRALIA

Published reports

After publishing the 2011 NTNDP, AEMO began extensive investigations – with government and industry stakeholders – into the challenges of integrating renewable generation in the NEM. This work has focused particularly on the emerging issues in South Australia.

Key initiatives have included:

- Wind Integration Investigation, consisting of five work packages published over 2011 and 2012:
  - Work package 1: Wind Integration in Electricity Grids: International Practice and Experience.
  - Work package 2: International Experience: Review of Grid Codes.
  - Work package 3: Wind Integration in Electricity Grids: Simulation using Historical Wind Data.
  - Work package 4: Lessons learned from International Wind Integration Studies.
  - Work package 5: Wind Integration in Electricity Grids: Market Simulation Studies.
- Wind Integration Studies Report, published in 2013.
- Wind Turbine Plant Capabilities Report, published in 2013.
- Renewable Energy Integration in South Australia – Joint AEMO and ElectraNet Report, published in 2014.

Renewables roadshows

In August 2015, AEMO also ran a series of renewables roadshows in all NEM capital cities and Canberra. The roadshows explored energy industry, government, research, regulator and consumer perspectives about how to best manage a NEM that includes increasing amounts of renewables, and the withdrawal of gas and coal-fired generation.

The key points were:

- South Australia is already one of the world leaders for global renewables penetration.
- No issues were identified with managing the South Australian power system under system normal conditions.
- AEMO is required to operate the power system such that it is, and will remain, in a secure operating state, including following credible (but not non-credible) contingency events. A requirement for AEMO to manage non-credible contingency events would require a change in policy.
- Procedures and processes have been updated to ensure it can manage the system following a credible contingency trip of the Heywood Interconnector.
- With the reduction in inertia in the system due to the changing mix of generation in South Australia, it may not be possible to manage the power system in South Australia following a non-credible trip (loss of both lines) of the Heywood Interconnector.

Proposed work

In 2015–16 AEMO is:

- Continuing to build on this work on renewables integration to develop a deeper understanding of the implications of a changing generation mix.

- Developing a systematic and comprehensive approach to studying the operating limits of the power system as the generation mix changes. As part of this, AEMO will review the analysis tools and models currently used to analyse performance of a power system, to ensure it has the appropriate tools to model a power system with little or no synchronous generation.
- Reviewing and revising its operating procedures to ensure it is well placed to manage credible contingency events and the possibility of South Australia becoming separated from the NEM.
- In conjunction with ElectraNet, reviewing the performance of the Under Frequency Load Shedding (UFLS) scheme in the presence of increasing penetration of rooftop PV and investigating the introduction of an Over Frequency Generation Shedding (OFGS) scheme in South Australia which would coordinate the tripping of generators following an over frequency event.

APPENDIX E. WHERE TO FIND MORE INFORMATION

AEMO has published the following supporting information for the 2015 NTNDP on its website:

- The NTNDP database comprising a comprehensive set of input data to enable stakeholders to undertake their own modelling.
- Spreadsheets with detailed modelling results and graphs.

The table below provides links to additional information provided either as part of the 2015 NTNDP accompanying information suite, or other related AEMO planning information.

Table 11 **Links to supporting information**

Information source	Website address
2015 National Transmission Network Development Plan – report and modelling results	http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan
AEMO Planning Assumptions page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions
AEMO Planning Interactive Map	http://www.aemo.com.au/electricity/planning/interactive-map/
2015 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report
Generator Information page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information
Maps and network diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Network Support and Control Ancillary Services (NSCAS) Description and Quantity Procedure	http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure
AEMO Integrating Renewable Energy page	http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy
ElectraNet 2015 Transmission Annual Planning Report	http://www.electranet.com.au/network/transmission-planning/transmission-annual-planning-report/
TransGrid 2015 Transmission Annual Planning Report	https://www.transgrid.com.au/news-views/news/2015/Pages/2015-Transmission-Annual-Planning-Report-released.aspx
Powerlink 2015 Transmission Annual Planning Report	https://www.powerlink.com.au/About_Powerlink/Publications/Transmission_Annual_Planning_Reports/Transmission_Annual_Planning_Report_2015.aspx
TasNetworks 2015 Annual Planning Report	http://www.tasnetworks.com.au/our-network/planning-and-development/annual-planning-program
AEMO 2015 Victorian Annual Planning Report	http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GW	Gigawatt
GWh	Gigawatt hours
MW	Megawatt
MWh	Megawatt hours
MWs	Megawatt seconds

Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BNEF	Bloomberg New Energy Finance
FCAS	Frequency Control Ancillary Services
GPG	Gas-powered generation
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MRET	Mandatory Renewable Energy Target
NEFR	National Electricity Forecasting Report
NEM	National Energy Market
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
OFGS	Over Frequency Generation Shedding
POE	Probability of Exceedence
R&D	Research and Development
SCR	Short Circuit Ratio
SRES	Small-scale Renewable Energy Scheme
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding
WSCR	Weighted Short Circuit Ratio

GLOSSARY

Key terms used in the 2015 NTNDP are listed below. Many of these terms have meanings defined in the National Electricity Rules (the Rules), but are included here for convenience.

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: • 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.

Term	Definition
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. 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: • 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 Rules) and, for the purposes of Chapter 5 (of the Rules), the term includes a person who is required to, or intends to register in that capacity.

Term	Definition
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: • 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.
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 Rules.
National Electricity Rules (the Rules)	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.

Term	Definition
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 Rules).
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.
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 Rules).

Term	Definition
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	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: • Alternating current generators. • Capacitors, including the capacitive effect of parallel transmission wires. • Synchronous condensers. 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.
region	An area determined by the AEMC in accordance with Chapter 2A (of the Rules), 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)	The test developed and published by the AER in accordance with clause 5.6.5B, including amendments. The test is to identify the most cost-effect 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.
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)	The actions taken by AEMO in accordance with clause 3.20 (of the Rules) 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: • 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.

Term	Definition
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.
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	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: • 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	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.