NATIONAL TRANSMISSION NETWORK DEVELOPMENT PLAN

FOR THE NATIONAL ELECTRICITY MARKET

Published: **December 2014**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

This document is published under clause 5.20.2 of the National Electricity Rules. This publication is based on information available to AEMO as at November 2014, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the national electricity market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (including information and reports from third parties) should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Acknowledgment

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

Australian Energy Market Operator Ltd ABN 94 072 010 327 www.aemo.com.au info@aemo.com.au

NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA

EXECUTIVE SUMMARY

AEMO publishes the annual National Transmission Network Development Plan (NTNDP) in its role as the national transmission planner. The purpose of the NTNDP is to facilitate the development of an efficient national electricity network that considers forecast of constraints on the national transmission flow paths. The NTNDP provides industry participants, the Australian Energy Regulator (AER), Australian Energy Market Commission (AEMC) and policy-makers with an independent, strategic view for the efficient development of the national transmission grid, over a 20-year planning horizon.

The 2014 NTNDP considers the challenges and opportunities for transmission network development over the next 20 years. It focusses on the transmission network assets connecting large-scale generation to population and industrial centres in the National Electricity Market (NEM).

The current environment

The consumption of electricity sourced from transmission networks in the NEM has been declining since 2009–10.[1] Maximum demand growth has slowed over this period and is forecast to slow over the next decade.[2] This is attributed to structural shifts in the Australian economy away from energy-intensive industries, consumer response to high prices, energy efficiency initiatives, and increasing generation at the local level.

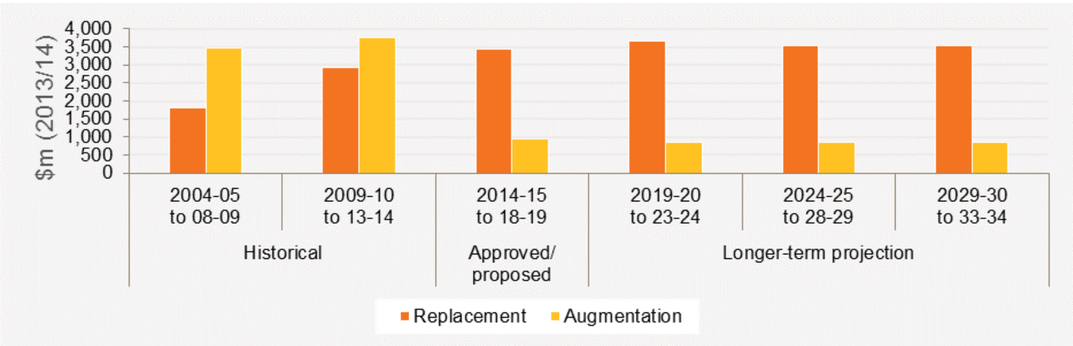
Transmission network investment profile

Historically, transmission development has been driven by forecast demand growth and prescriptive transmission network reliability standards in a number of NEM jurisdictions. More recently, reliability standards across the NEM have begun to converge towards an approach which explicitly considers customer's reliability need.

Future transmission network development plans reflect slowing forecast maximum demand growth. Transmission network augmentation needs are reducing and transmission network asset replacement is becoming the most common form of network development. Historically, 60% of the $11.9 billion of transmission network investment over the last decade was driven by the need to augment network capacity to meet expected maximum demand growth. AEMO forecasts that over the next 20 years, transmission network service providers (TNSPs) may invest between $9 billion and $18 billion in network infrastructure. It is estimated that 75%–85% of this expenditure will go towards replacing ageing assets rather than augmenting existing transmission network capacity.

Figure 1 presents the projected network investment profile for TNSPs across the NEM for the next 20 years, compared against historical investment over the last decade. Estimates to 2018-19 are derived from approved and proposed regulatory capital expenditure allowances, and 2014 transmission annual planning reports. These investment patterns are assumed to continue beyond 2018-19.

Figure 1 Transmission network capacity augmentation and asset replacement expenditure profile[3]



[1] AEMO. *2014 National Electricity Forecasting Report*. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 20 November 2014.
[2] AEMO. *2014 National Electricity Forecasting Report*. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 20 November 2014.
[3] Source: TNSP revenue proposals, AER determinations and draft determinations for TransGrid and TasNetworks (November 2014), 2014 transmission annual planning reports.

The significantly lower proposed augmentation investment over the next five years reflects current expectations for slower maximum demand growth. Against this backdrop, it is reasonable for consumers to expect asset replacement investment to also fall. This continued focus on asset replacement as shown in the graph presents an opportunity for policy-makers to address these expectations by implementing stronger criteria around asset replacement decisions in the long-term interests of consumers.

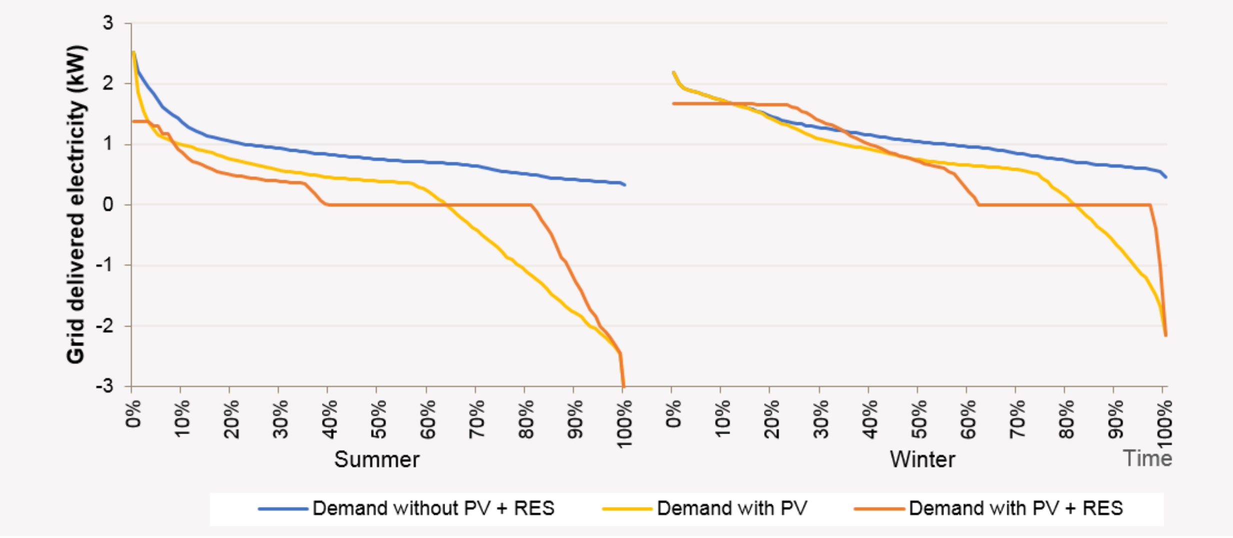
The changing environment

Emerging technology and potential changes

Emerging technology such as battery storage and rooftop photovoltaic (PV) will be a factor for the size and scope of future transmission networks in the medium to long term. Figure 2 demonstrates the impact of combining a time-of-use tariff with solar PV and residential energy storage (RES) installations on a typical household's demand for grid delivered electricity.[4] It shows:

- Adding a 5 kWh RES system to an existing solar PV system reduces the household maximum demand by 45% in summer and 23% in winter.
- Households with battery storage could be self-sufficient for 60% of the time in summer and 40% in winter.

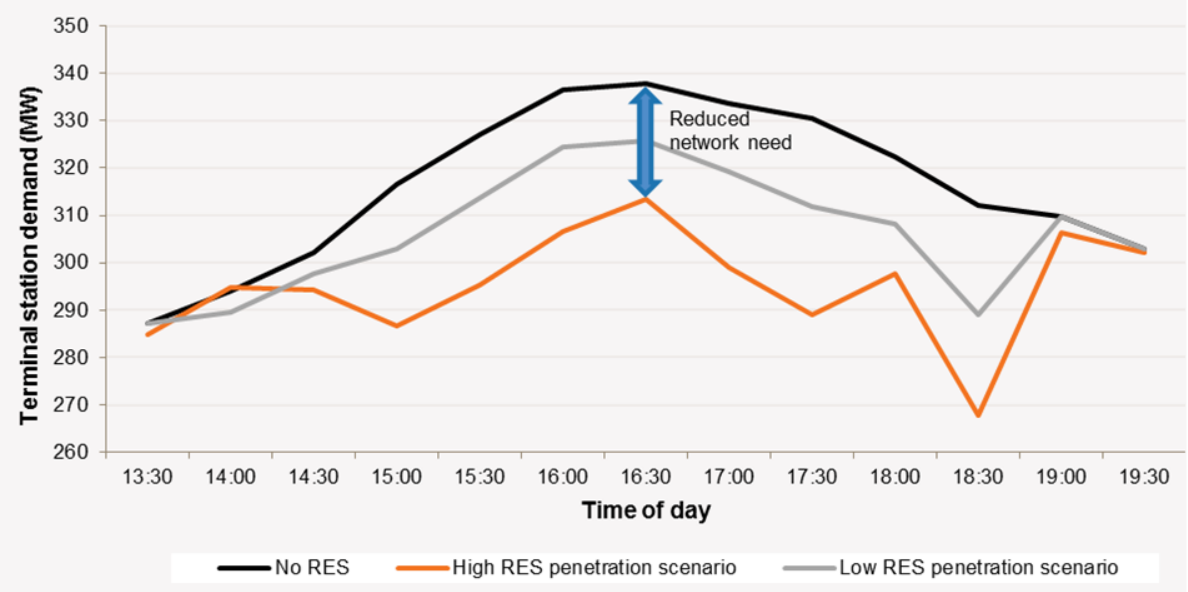
Figure 2 Change in individual load duration curves with a 4 kW solar, 5 kWh RES



The penetration of battery storage technology may further defer the need for augmentation and may affect the size and scope of any need for asset replacement. Figure 3 demonstrates the potential impact of battery storage on the load profile at a typical transmission substation during the maximum demand day in 2013. Under the high storage penetration scenario, plausible within the next 10 years, applying a critical peak capacity tariff could reduce maximum demand by up to 30 MW.

[4] The figure shows the average load duration of 299 suburban consumers in Melbourne with an average annual load of 8,033 kWh, using data on an hourly resolution.

Figure 3 Example of effects of battery storage on network utilisation



Emerging opportunities

Policy-makers and industry have a range of options to facilitate efficient transmission network development in the long-term interest of consumers. These include:

- Extending the life of a network asset by aligning its serviceable engineering life and regulatory life. Given changing consumption patterns, replacement of ageing assets on a like-for-like basis may not always be necessary. An economic cost-benefit approach to asset replacement decisions would encourage whole-of-life asset management practices and may defer network asset replacement expenditure. This would be consistent with the ongoing shift in network planning standards across the NEM from prescriptive capacity redundancy requirements, towards cost-benefit approaches balancing costs of supply with consumers' willingness to pay.
- Rewarding network businesses for delivering services valued by customers rather than building assets. There is an opportunity for the regulatory framework to shift from the current inputs-based approach guaranteeing a return on network investment, towards a focus on services. This would promote efficient operation of existing network assets and build flexibility into planning processes by encouraging targeted, incremental alternatives to significant investment in network infrastructure. Network businesses would be incentivised to broaden their business models to provide services such as energy, reactive capability or redundancy.
- Facilitating competition wherever possible. Existing arrangements in Victoria allow for contestability in the provision of major transmission augmentations. Transmission network upgrades that have been subject to a competitive tender process have given rise to lower cost outcomes compared to the traditional model.
- Broadening the range of credible solutions. Improving communication of network constraint information by the network service providers would help remove potential barriers to entry and encourage competition in the provision of non-network alternatives to network investment such as embedded generation and demand-side options.
- The introduction of cost-reflective network tariffs at the distribution level would align network costs with revenue generation while providing consumer choice to reduce household electricity costs. Such tariffs could incentivise the progress of complementary emerging technologies such as battery storage, encourage efficient operation of both distribution and transmission networks, and possibly defer costly augmentation of network capacity by shifting demand from peak times.

AEMO acknowledges that there are commercial realities to be considered, and that there will be a period of transition in moving towards a new framework.

CONTENTS

TABLES

FIGURES

CHAPTER 1. ABOUT THE NTNDP

The NTNDP provides industry participants and policy-makers with an independent, strategic view of the long-term development of the national transmission grid. It focuses on transmission network assets that connect large-scale generation to population and industrial centres in the NEM over a 20-year planning horizon.

The 2014 NTNDP considers the implications of the rapidly changing energy environment on transmission network development in the NEM. It examines opportunities to strengthen planning, regulatory and pricing frameworks to facilitate efficient network development that will meet the energy needs of consumers into the future.

1.1 The NTNDP in the energy planning context

AEMO publishes the annual NTNDP as part of its role as national transmission planner under the National Electricity Law.[5] As the national transmission planner, AEMO provides a national strategic perspective for transmission planning and co-ordination in the NEM. [6]

The NTNDP is one of a suite of annual publications AEMO produces to support efficient transmission network investment in the NEM. These include:

- The National Electricity Forecast Report (NEFR),[7] which provides electricity consumption and maximum demand forecasts.
- The Electricity Statement of Opportunities (ESOO) [8] and Gas Statement of Opportunities (GSOO) [9], which investigate supply-side reliability and provide information about energy resources affecting eastern and south-eastern Australia.

1.2 NTNDP inputs and modelling

AEMO consults with stakeholders on the assumptions relating to generation costs, location, carbon price, demand forecasts and other factors to be used as inputs to the NTNDP. Issues raised by stakeholders and AEMO's response and actions are outlined in the 2014 Planning Studies Response to Consultation document.[10] AEMO uses these inputs in preparing the NTNDP, and also considers (as required by the NER):[11]

- The pattern of electricity flow and constraints on national transmission flow paths in the preceding year.
- Forecast flows, network losses and constraints over the outlook period.
- Projected capabilities of the national transmission grid and any network support and control ancillary services (NSCAS) required to support that capability.
- Any intra-jurisdictional developments or incremental works needed to coordinate national flow path planning with regional planning.
- The most recent transmission annual planning reports published by TNSPs.
- The most recent NEFR, ESOO and GSOO.
- Current TNSP revenue determinations.

Given the forecast economic climate and potential impact of emerging technologies, AEMO considered two of the three scenarios published in the 2014 Planning and Forecasting Scenarios report[12] as credible scenarios for the

5 National Electricity Law, s49(2).
6 National Electricity Law, s49(2)(d).
7 AEMO. *2014 National Electricity Forecasting Report*. Available: http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 17 October 2014.
8 AEMO. *2014 Electricity Statement of Opportunities*. Available: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities. Viewed: 25 November 2014
9 AEMO. *2014 Gas Statement of Opportunities*. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Viewed: 25 November 2014
10 Available at: http://www.aemo.com.au/Electricity/Planning
11 National Electricity Rules, cl 5.20.2(b)
12 AEMO. *2014 Planning and Forecasting Scenarios.* Available at: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx.

2014 NTNDP. These are the medium energy consumption from centralised sources scenario (medium scenario), and the low energy consumption from centralised sources scenario (low scenario).

AEMO's transmission development outlook for the medium scenario is presented in Appendix A.

In the low scenario, while electricity consumption is projected to decrease in all regions, no further thermal constraints which would require new network investment were identified beyond those already identified in the medium scenario. Accordingly the low scenario is not discussed in detail in the NTNDP.

AEMO's assessment of NSCAS gaps over the next five years is presented in Appendix B.

CHAPTER 2. THE CHANGING ENVIRONMENT

2.1 Changing consumption patterns

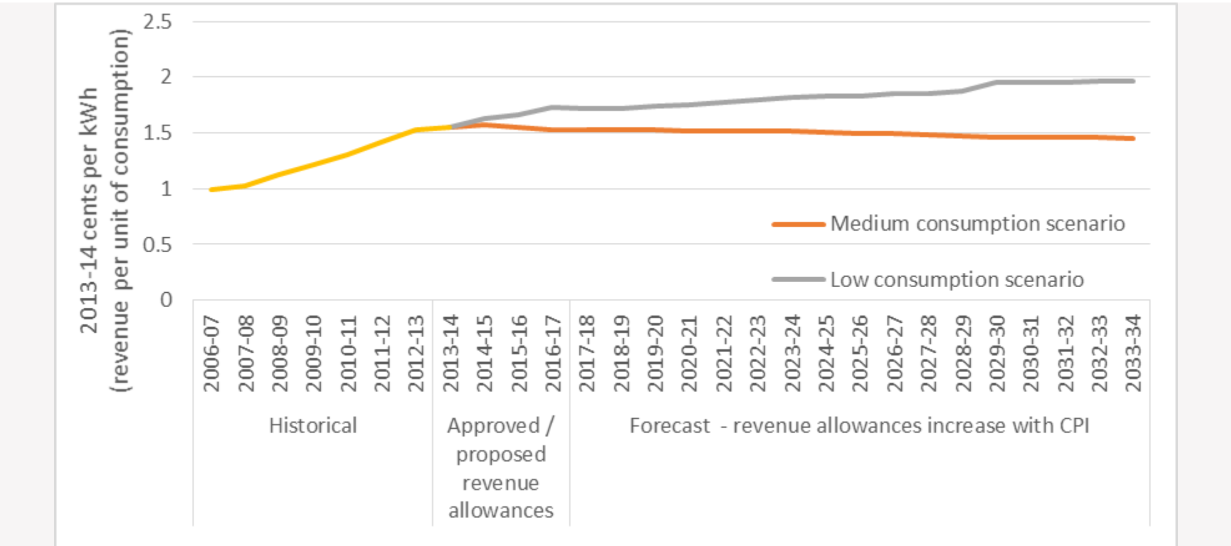
Electricity consumption from transmission networks across the NEM has been falling since 2009–10. This is due to structural shifts in Australia's economy away from energy-intensive industries, consumer reaction to high electricity prices, energy efficiency initiatives, and increasing generation at the consumer level (primarily rooftop PV).

Maximum demand growth has slowed over this period and is forecast to slow over the next decade. AEMO forecasts a continued decline in consumption over the next three years[13] before flattening in the longer term. This does not take into account the potential effect of emerging technologies discussed in Section 2.3.

The 2013 NTNDP identified that the combination of falling consumption and slowing maximum demand growth is contributing to falling transmission network asset utilisation and higher prices for consumers. Under the low energy consumption scenario, this continues into the future as transmission network businesses in the NEM recover approximately $8.9 billion of proposed or approved revenue allowances over the next three years (2014-15 to 2016-17). Transmission network businesses in the NEM operate under a regulated revenue cap, meaning that falling consumption results in higher prices as the allowed revenue is recovered from a declining consumption base.

This outcome is reflected in Figure 4, which explores the 20-year outlook for average transmission network revenue charges in the NEM under both medium and low energy consumption scenarios. This analysis assumes that revenue allowances beyond the current regulatory periods remain static in real terms.

Figure 4 20-year outlook of average NEM transmission charges under medium and low consumption scenarios[14]



2.2 Transmission network investment profile

AEMO forecasts between $9 billion and $18 billion of transmission network investment in the NEM over the next 20 years. This includes forecast augmentations and asset replacement. Appendix A provides details.

[13] Aside from some growth in Queensland as a result of liquefied natural gas projects.
[14] AER. TNSP Revenue Determinations. Available: http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements?sector=4&segment=9&region=All&status=All. Viewed: 28 October 2014. Based on: historical revenue allowances to 2012-13, approved allowances for ongoing regulatory periods, proposed allowances for TransGrid and TasNetworks 2014-15 to 2018-19, and CPI increases thereafter.

Figure 5 presents the projected network investment profile for TNSPs across the NEM for the next 20 years. A breakdown of this forecast is detailed in Table 1. Estimates to financial year 2018-19 are derived from approved and proposed regulatory capital expenditure allowances, and 2014 transmission annual planning reports.[15]

Table 1 presents longer-term estimates (beyond 2018-19) in a range, to account for inherent uncertainties about the full impacts of declining energy consumption and slowing maximum demand growth.[16]

Figure 5 Transmission network capacity augmentation and asset replacement expenditure[17]

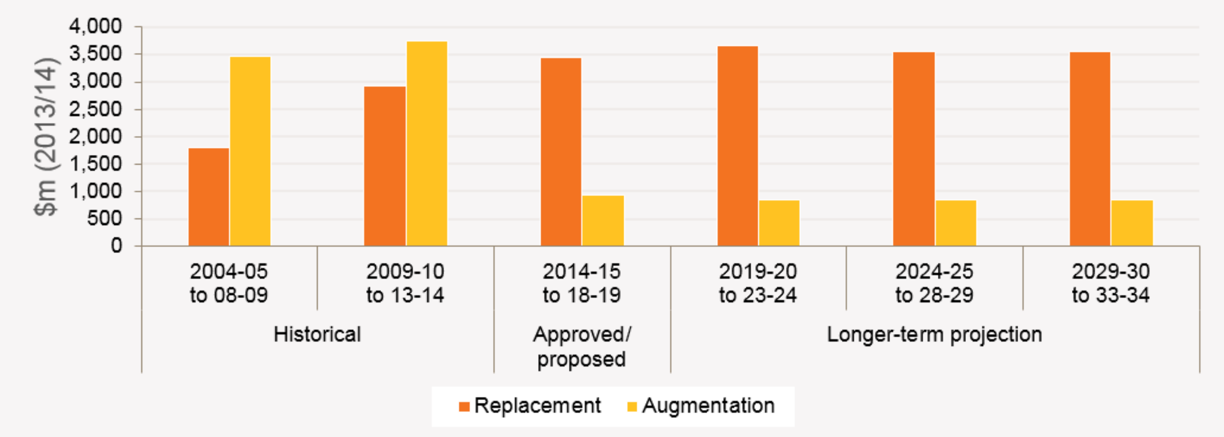


Table 1 Projected transmission network investment profile ($2013-14 billion)[18]

Network investment type	Historical		Proposed	Estimated range			
	2004–05 to 2008–09	2009–10 to 2013–14	2014–15 to 2018–19	2019–20 to 2023–24	2024–25 to 2028–29	2029–30 to 2033–34	Total 2014–15 to 2033–34
Asset replacement	1.8	2.9	3.4	1.8 to 3.7	0.9 to 3.5	0.9 to 3.5	7.0 to 14.2
Capacity augmentation	3.5	3.8	0.9	0.5 to 0.8	0.3 to 0.9	0.3 to 0.9	2.1 to 3.5
Total	**5.3**	**6.6**	**4.4**	**2.3 to 4.5**	**1.2 to 4.4**	**1.2 to 4.4**	**9.1 to 17.7**

Around 60% of the $11.9 billion of transmission network investment over the last decade was driven by the need to augment network capacity to meet expected maximum demand growth. The sharp reduction in proposed network augmentation investment over the next five years reflects current expectations for slower maximum demand growth.

The forecast projects continued investment in asset replacement to 2033-34.

Against this backdrop of slowing maximum demand growth, it is reasonable for consumers to expect asset replacement investment to fall in line with any reductions in asset utilisation in the future. As asset replacement becomes the dominant investment type in the future, there is an opportunity for policy-makers to address these expectations by implementing stronger criteria around asset replacement decisions in the long-term interests of consumers.

2.3 Emerging technology and potential changes

Consumer uptake of load-shifting technologies has the potential to significantly affect transmission networks in the NEM within the 20-year NTNDP planning horizon. Emerging technologies such as energy storage can provide an array of benefits to the energy system, including reductions in maximum demand, infrastructure investment

[15] Proposed network investment plans for the next five years are available in all five 2014 TNSP transmission annual planning reports. ElectraNet and AusNet Services have provided 10-year network investment plans in their transmission annual planning reports. More details in Appendix A.
[16] Longer-term upper and lower limits of the range were calculated as percentages of TNSP forecast proposed network expenditure over the next five years.-Upper (lower) limits for longer-term expenditure are assumed to be 100% (25%) of proposed expenditure for the next five years.
[17] Source: TNSP Revenue proposals, AER determinations, and 2014 transmission annual planning reports.
[18] Discrepancies in totals due to rounding.

deferral, power quality management and system security improvement. According to the International Energy Agency[19], some of these energy storage technologies are mature or near maturity, and some smaller-scale systems are already cost competitive in remote community and off-grid applications.

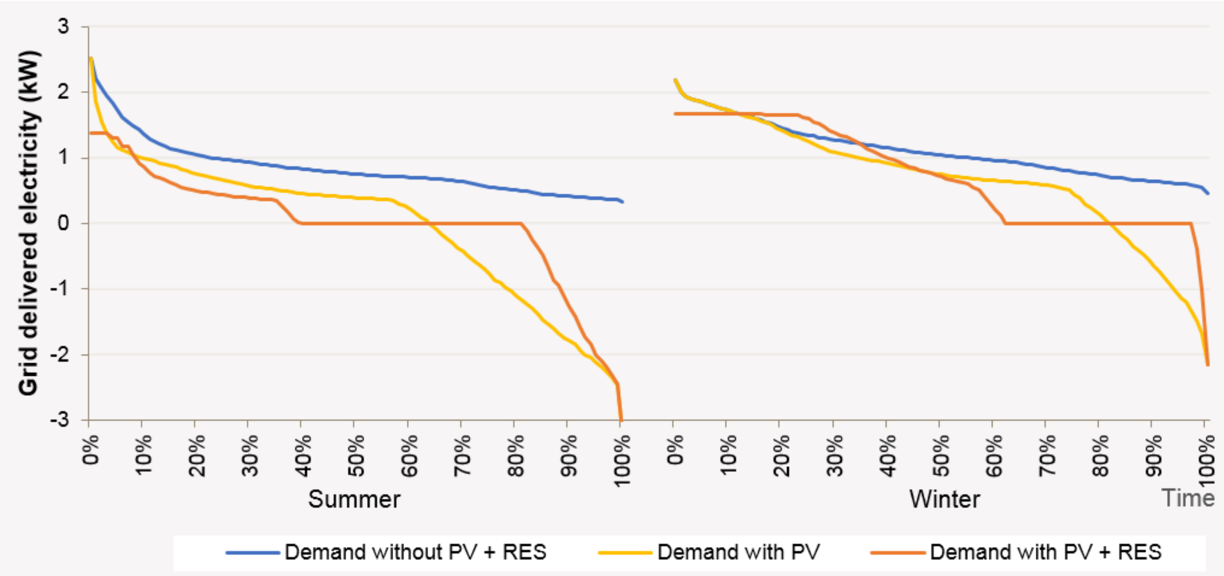
AEMO is monitoring the development and potential applications of energy storage technologies in Australia, and investigating the various impacts they are likely to have on future energy demand in the NEM.

Potential impact on residential load profiles

The figure below demonstrates how a combination of a time-of-use tariff, rooftop PV, and residential electricity storage (RES) installation may reduce household demand for electricity sourced from the grid.[20]

Although installing rooftop PV does not typically reduce the level of household maximum demand, adding a 5 kWh RES system could reduce household maximum demand by 45% in summer and 23% in winter. Figure 6 also shows that households with RES could be self-sufficient for 60% of the summer period and 40% of winter. Adding RES to household systems would also reduce energy exports from rooftop PV into the network. Appendix C provides further details and assumptions.

Figure 6 Change in individual load duration curves with a 4 kW solar, 5 kWh RES



Opportunities and network challenges

High penetration of RES in a local network dominated by households could:

1. Reduce maximum demand and enable the existing infrastructure to support more consumers.
2. Reduce rooftop PV energy exports to the grid allowing higher rooftop PV penetration in the area.
3. Shift residential consumption into off-peak (overnight) hours when combined with a time-of-use tariff, enabling increased network utilisation as the consumer population grows.

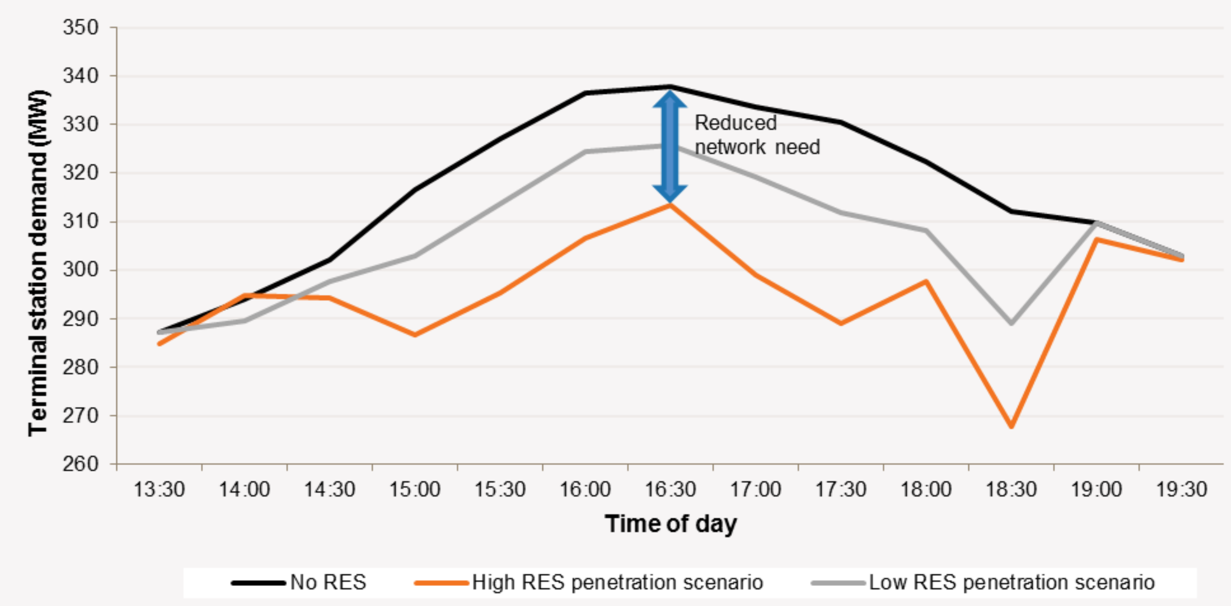
Figure 7 demonstrates the potential impact of RES on maximum demand at one transmission connection point.[21] Applying a critical peak capacity tariff, maximum demand at this terminal station could reduce by 7.3% and 3.2% under high and low RES penetration scenarios respectively.

[19] International Energy Agency (IEA). Technology Roadmap, Energy Storage. Available http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapEnergystorage.pdf

[20] The chart depicts the average load duration of 299 suburban consumers in Melbourne with an average annual load of 8,033 kWh. These load duration curves show the frequency at which a particular level of demand is exceeded (on an hourly resolution) throughout a full calendar year.

[21] The chart is based on the load profile at Templestowe Terminal Station in Victoria during the maximum demand day in 2013.

Figure 7 Potential impact of RES on maximum demand at a transmission connection point



The net effect of these findings is that, if advances in rooftop PV penetration and RES technology continue, network augmentation could be deferred or avoided at both the distribution and transmission levels. This would allow existing transmission and distribution network capacity to accommodate future demand growth.

While payback periods for RES technology do not currently appear to be financially viable for grid-connected consumers, the prospect of falling RES costs, rising electricity prices, and electricity tariff reforms could significantly improve the economic benefits of installing RES in the future. A combined investment in rooftop PV and RES should become economically viable for grid-connected consumers within the 20-year NTNDP planning horizon. See Appendix C for more details.

High rooftop PV and RES penetration will further reduce grid consumption in the future. In Figure 6 the positive areas under the graphs represent annual sales of grid-delivered electricity to households, with and without rooftop PV and RES. The example in Figure 6 shows that installing rooftop PV reduces household purchases of electricity from the grid by 36%, and the addition of RES could lead to a further reduction of 14%.

If RES technology is shown to bring long-term benefits to consumers through reduced maximum demand levels, more efficient operation of existing networks, and lower overall costs, it follows that the regulatory environment should incentivise network businesses to integrate this technology into their existing and planned infrastructure. This would help accommodate consumer expectations around network pricing and service levels, while promoting investment in efficient network development.

It is also possible that the markets for RES technology and electric vehicles could grow concurrently, as increased manufacturing capacity for battery producers reduces battery costs. Penetration of electric vehicles in Australia should increase demand for electricity network services, as electricity displaces liquid fuel, potentially reversing the trend of falling demand.

Evolving technologies and changing consumer patterns represent a development opportunity for network service providers as flexible pricing arrangements would enable them to control the timing and level of maximum demand in their networks. Such control would see network businesses maximise efficient infrastructure operation, ultimately benefiting consumers. Therefore it is important that any modifications to the current regulatory environment allow for the efficient integration of emerging technologies in circumstances of both falling and rising demand for grid electricity.

CHAPTER 3. EMERGING OPPORTUNITIES

Policy-makers and industry have a range of options to facilitate efficient transmission network development in the long-term interest of consumers. AEMO acknowledges that there are commercial realities to be considered and that there will be a period of transition in moving towards new frameworks. However, some of the options are outlined in this section.

3.1 Economic approach to asset replacement decisions

Electricity network assets must be maintained within acceptable operating condition and health and safety standards. Reduced network utilisation is behind the shift in transmission network investment from augmentation to asset replacement (see Section 2.2 for more information). Changing patterns of grid electricity consumption and slowing growth of maximum demand mean that replacing network assets with like-for-like may not always be appropriate.

In its revenue proposal for the 2014–15 to 2018–19 regulatory period, TransGrid identified three substantial condition-driven asset replacement projects with the potential to reduce capacity. AEMO estimates around $73 million in savings can be realised from these projects.[22]

The current Regulatory Investment Test–Transmission (RIT-T) applies to transmission augmentation projects over A$5 million. AEMO believes that applying a similar cost-benefit analysis to asset replacement proposals would contribute to more efficient investment outcomes. Such an approach would assess the need for the asset and fully explore alternative network and non-network options, and may defer network asset replacement expenditure in circumstances of lower demand.

Taking an economic approach to asset replacement would be consistent with the ongoing shift in network planning standards across the NEM – away from prescriptive capacity redundancy requirements, towards cost-benefit approaches that balance supply costs with consumers' willingness to pay.

3.2 Incentivising delivery of services above assets

Under the current regulatory framework, network service providers earn a guaranteed return that is determined by the value of their asset base. This return on assets represents approximately 60% of current approved transmission network revenue allowances across the NEM.[23] In the six years to 2014, transmission network investment programs have increased regulated asset bases by approximately $3.5 billion[24] while electricity consumption from the grid has reduced by 7.9%.[25,26]

Transmission network businesses in the NEM operate under a regulated revenue cap, so falling consumption will result in higher prices as the allowed revenue is recovered from a declining consumption base. Continued diminishing demand threatens the sustainability of the existing regulatory process that determines both the level of network revenues and the ways they are recovered. Growth of distributed generation (including rooftop PV) and RES could accentuate the current market complications caused by falling demand for grid electricity.

An opportunity exists for the regulatory framework to focus more on services, whereby network businesses are rewarded for services delivered. This could help encourage targeted, incremental investment in new network infrastructure rather than on large transmission investments, accommodate non-network solutions and promote efficient operation of existing network assets. A service focus may incentivise network businesses to:

[22] TransGrid. *Revenue proposal 2014/15 – 2018/19.* Available: https://www.aer.gov.au/sites/default/files/TransGrid%20-%20Revenue%20Proposal%202014-19%20-%20May%202014.pdf Viewed: 28 October 2014 p. 96-97

[23] AER. TNSP Revenue Determinations. Available: http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements?sector=4&segment=9&region=All&status=All. Viewed: 28 October 2014.

[24] AER. *State of the energy market 2008.* Available: http://www.aer.gov.au/node/6314 Viewed: 28 October 2014 p. 120, 142-3; AER. *State of the energy market 2013.* Available: http://www.aer.gov.au/node/23147. Viewed: 28 October 2014 pp.62-3. Nominal regulated asset base for transmission networks converted to real 2013/14 dollars.

[25] AEMO. 2012 Electricity Statement of Opportunities. Available http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-Electricity-Statement-of-Opportunities. Viewed: 25 November 2014. Figure 2.4.

[26] AEMO. 2014 National Electricity Forecasting Report. Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 25 November 2014. Table 3.

- Create more flexible planning processes by examining cost-effective solutions that include alternatives such as control and protection schemes, demand-side participation, and generation support.
- Adopt a cost-benefit approach to asset replacement decisions, taking into account the possibility of reduced utilisation in the future.
- Broaden their business models to provide services such as energy, reactive capability, or redundancy.

3.3 Facilitating competition

Reforms that encourage competition should benefit end-use consumers by lowering electricity prices and delivering innovative services. Competitive tender processes are intended to ensure that the most appropriate investment decisions are made in consumers' long-term interests.

Victoria's current arrangements allow for contestability in the provision of major transmission augmentations. Transmission network upgrades that have been subjected to a competitive tender process typically deliver lower cost outcomes. For example, the Heywood Terminal Station upgrade attracted tenders from three TNSPs, enabling AEMO to procure the Victorian element of the project at a lower price than forecast in the project justification.

Network businesses currently earn a guaranteed rate of return on capital investment that is regulated and implemented by the AER. There is scope to explore opportunities for infrastructure projects to be financed by capital markets using a contestable procurement process. Contestability could help to reduce margins and manage risk putting downward pressure on prices for consumers.

3.4 Broadening the range of credible solutions

Network augmentation is traditionally a capital-intensive process involving large, irreversible investment in infrastructure that is designed to last several decades. The capital investment is recovered over the regulated life of the high voltage asset, typically 30 to 60 years. Given the current market environment, changing future demand, and energy growth patterns, such high cost investments could find themselves stranded or underutilised.

Flexibility of non-network options

Non-network options can be implemented more quickly and flexibly in response to changing demand conditions, mitigating the risk of stranded network infrastructure in the future. This is increasingly relevant in an environment where transmission networks are constrained only a few days a year and there is increased technological capability to control loads by rescheduling generators including embedded generators. Tariff reform and the emergence of battery storage are also likely to improve maximum demand management capability.

Non-network options also provide network planners and businesses with greater opportunities for staging capital investment by creating plans that better respond to changing demand and generation expectations. For example, AEMO considered a staged generation support alternative in its analysis of credible options for the Regional Victorian Thermal Capacity Upgrade published in June 2014. This non-network alternative allowed the timing of subsequent stages to change under different plausible scenarios, minimising the risk of stranded assets in the future, relative to the network option.[27]

TNSPs are increasingly investigating opportunities to implement a combination of network and non-network solutions to address network constraints. Powerlink has proposed such a combination to address emerging limitations on the transmission network supplying the Bowen Basin coal mining area in Queensland.[28] TransGrid is pursuing demand management procurement to address the expected retirement of 132 kV cables and potential demand growth in the Sydney Inner Metropolitan Area.[29]

[27] AEMO. *Regional Victorian Thermal Capacity Upgrade*. Available: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Regional-Victorian-Thermal-Capacity-Upgrade. Viewed: 28 October 2014.
[28] Powerlink. *Transmission Annual Planning Report 2014*. Available: http://www.powerlink.com.au/About_Powerlink/Publications/Transmission_Annual_Planning_Reports/Documents/2014/Transmission_Annual_Planning_Report_2014_(complete_report).aspx. Viewed: 27 November 2014 p. 75
[29] TransGrid. *Transmission Annual Planning Report 2014*. Available: http://www.transgrid.com.au/network/np/Documents/TransGrid%20Transmission%20Annual%20Planning%20Report%202014-web.pdf. Viewed: 27 November 2014 p. 74.

Communication of network constraint information

Improving network service providers' communication of network constraint information would help remove potential barriers to entry and encourage better planning and more competition in the provision of non-network alternatives to network investment, such as embedded generation and demand-side options.

AEMO is developing an online electricity network mapping tool for Victoria that will highlight current and expected network constraints and identify likely development needs, some of which could be met by non-network solutions.

3.5 Cost-reflective network tariffs

Network investment is driven by the need for sufficient network capacity during peak usage periods. The AEMC's 2012 Power of Choice review highlighted that current residential network pricing structures do not efficiently align tariffs with the underlying cost of providing network services.[30]

This review recommended numerous initiatives to increase the options available to consumers for the way they use electricity. One recommendation was to introduce more efficient and flexible pricing for residential and small business consumers through cost-reflective distribution network pricing structures.

On 1 December 2014 the AEMC introduced a rule amendment introducing a network pricing objective that tariffs should reflect the efficient costs of providing distribution network services to retail customers.[31]

Introducing cost-reflective network tariffs at the distribution level would align network costs with revenue generation while providing consumers with a real opportunity to reduce household electricity costs.

Tariff reform that increases energy prices at times of maximum demand would incentivise a shift in consumption away from these periods. Emerging technologies, such as battery storage and advanced metering, could contribute to this in the future. The case studies discussed in Section 2.3 demonstrate that integrating emerging technologies with cost reflective pricing could reduce maximum demand. This would affect demand on both distribution and transmission networks and would:

- Free up capacity in existing distribution and transmission networks to accommodate consumer population growth.
- Encourage efficient operation of both distribution and transmission networks.
- Defer augmentation of network capacity by shifting demand from peak times.

[30] AEMC. Power of Choice review, chapter 6. 2012. Available: http://www.aemc.gov.au/getattachment/2b566f4a-3c27-4b9d-9ddb-1652a691d469/Final-report.aspx. Viewed: 5 November 2014.

[31] AEMC. National electricity amendment (distribution network pricing arrangements) rule 2014 no. 9. Available at: http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements/Final/AEMC-Documents/Final-rule.aspx. Viewed 4 December 2014

APPENDIX A. NATIONAL TRANSMISSION OUTLOOK

The projected need for new large-scale generation and transmission investment in the NEM has reduced since publication of the 2013 NTNDP.

A.1 Transmission development outlook

A.1.1 Factors driving transmission development

Projected transmission network development in the NEM reflects expectations for slowing demand growth, increases in new renewable generation and withdrawal of existing coal-fired and gas-powered generation capacity.

Underlying these key drivers are:

- The Large-scale Renewable Energy Target (LRET), which incentivises additional renewable generation capacity.
- Declining projected consumption, reducing the need for additional supply sources.

The coincidence of these two factors is projected to lead to the changing operation, dry storage, or retirement of some existing coal-fired and gas-powered generation.

New renewable generation is forecast to increase until 2020 due to the LRET, after which no further generation investment is required to meet projected maximum demand until around 2030. Peaking gas-powered generation capacity then becomes an economic way to meet peak demand growth to the end of the study horizon.

After 2020 the key drivers for transmission development are expected to be further retirement of coal-fired and gas-powered generation, and continued slow demand growth. These factors may ease current oversupply conditions but are not sufficient to trigger the need for further development of the national transmission grid.

The medium energy consumption scenario’s carbon pricing and gas price assumptions are not sufficient to incentivise a transition from coal-fired to gas-powered generation within the NTNDP's 20-year study period.

More details about the generation expansion plans modelled in the 2014 NTNDP is in the Generation Expansion Plan.[32] A description of the assumptions that form the basis of the medium energy consumption scenario is in the 2014 Planning and Forecasting Scenarios report.[33]

A.1.2 Transmission development outlook

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

Key observations are:

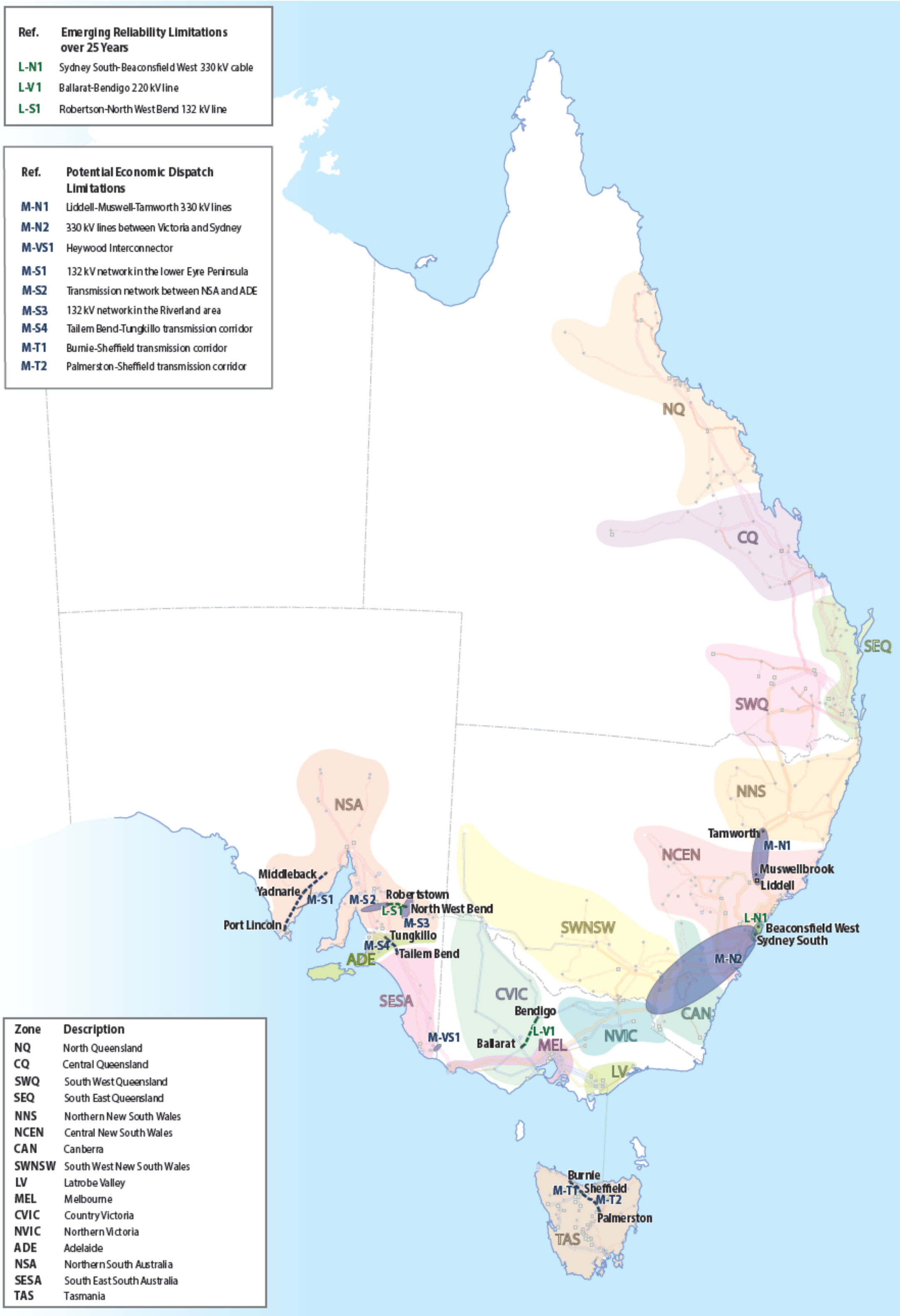
- Compared to the 2013 NTNDP, reduced maximum demand for electricity from the grid results in fewer network limitations in all regions.
- The NTNDP modelling does not identify a requirement for major investment in inter-regional augmentations.

Figure 8 shows the location of identified network limitations on the main transmission network. These include both reliability-driven network limitations identified through NTNDP modelling, and potential economic dispatch limitations. Each limitation is identified by a reference code. Further details about these limitations are provided in Table 2 and Table 3.

Projects proposed by TNSPs in their Annual Planning Reports (APR) are set out in the APR projects summary on AEMO’s 2014 NTNDP webpage.[34]

[32] AEMO. Generation Expansion Plan. Available at: http://www.aemo.com.au/Electricity/Planning.
[33] Available at: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx.
[34] TNSP APR projects summary sheet. Available at: http://www.aemo.com.au/Electricity/Planning.

Figure 8 NTNDP network limitations on the main transmission network by 2033–34



AEMO's least-cost modelling approach locates new generation to minimise overall generation and transmission costs. If generation development differs from the projected expansion, other network limitations may arise and would need to be addressed.

Increases in renewable generation can create operational and power system security challenges. AEMO and ElectraNet's October 2014 Renewable Energy Integration in South Australia Report[35] and AEMO's September 2013 Integrating Renewable Energy—Wind Integration Studies Report[36] outline these issues and recommend actions to support the integration of forecast wind generation.

Connecting wind generation to the power system is expected to contribute to network congestion, particularly at times of high wind generation output; this affects economic generation dispatch. The NTNDP identifies the location of potential network congestion that may arise if new generation development occurs in line with the least-cost modelling.

The reliability-driven network limitations lead to a loss of supply that cannot be resolved by rescheduling generation. The economic dispatch limitations arise because network capability limits the amount of generation that can be dispatched in a particular location, leading to the dispatch of more expensive plant ahead of less expensive plant.

Table 2 lists the transmission network limitations identified as affecting network ability to reliably supply customer load. These may not include limitations on lower-voltage networks (below 220 kV) or in supplying local load at times outside of the regional maximum demand.

Table 2 Reliability-driven network limitations identified through NTNDP modelling

Reference	Region	Zone	2013 Timing	2014 Timing	Observed Limitation	Network needs
L-V1	Vic	CVIC	2013–14 to 2017–18	2014-15 to 2018-19	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.[37]	Non-network solution and/or uprate Ballarat-Bendigo 220 kV line.
L-N1	NSW	NCEN	2013–14 to 2017–18	2014–15 to 2023-24[38]	Overload of the Sydney South – Beaconsfield West 330 kV cables 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.
L-S1	SA	NSA	2013–14 to 2017–18	2014–15 to 2018-19	Overload of Robertstown – North West Bend 132 kV No.1 circuit for the outage of Robertstown – North West Bend 132 kV No.2 circuit (via MWP3, MWP2 and MWP1) during times of peak load conditions in the Riverland area when Murraylink is not importing into South Australia.	Non-network solution and/or additional transmission capability along the Riverland region 132 kV transmission corridor.

Table 3 lists the transmission network limitations identified as affecting the economic dispatch of generation. These limitations are identified mainly during times of high wind generation output and do not lead to a loss of supply to customers.

The timing of any projects required to address potential economic dispatch limitations will depend on detailed market assessment. AEMO will monitor these limitations and work with the relevant TNSPs to address them should they become material.

35 AEMO and ElectraNet. Available at: http://www.electranet.com.au/assets/Reports-and-Papers/RenewableEnergyIntegrationinSouthAustraliaAEMOElectranetReportOct2014.pdf.
36 AEMO. Available at: http://www.aemo.com.au/Electricity/Planning/Integrating-Renewable-Energy. Viewed 4 December 2013.
37 AEMO has recently undertaken a RIT-T investigation for this limitation. Available at: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Regional-Victorian-Thermal-Capacity-Upgrade
38 The need is contingent on future demand growth, distribution of load and demand management levels in inner Sydney area and ratings of underground cables.

Table 3 Potential economic dispatch limitations

Reference	Region	Zone	Observed limitation	Dispatch scenario
M-N1	NSW	NNS	Transmission limitations on the Liddell–Muswell–Tamworth 330kV lines - power transfer to Northern NSW and QLD	Following the retirement of Redbank Power Station the power flow on the 330 kV lines between Liddell and Tamworth may become congested at times of high northward flows on the QNI Interconnector.
M-N2	NSW	CAN	Transmission limitations on the network between Victoria and Sydney at times of peak demand. Generation in SWNSW and import from Vic may be constrained.	High levels of generation in the southern NSW (CAN and SWNSW zones) combined with high import from Vic.
M-VS1	Vic and SA	MEL–SESA	Transmission limitations on the South East – Heywood transmission corridor.	High levels of SA import from Vic at times of peak demand in SA or high levels of SA export to Vic during times of high wind generation levels in SA.
M-S1	SA	NSA	Transmission limitations on the 132 kV network in the lower Eyre Peninsula.	High levels of wind generation in lower Eyre Peninsula.
M-S2	SA	NSA	Transmission limitations on the network between NSA and ADE.	High levels of wind generation in the NSA zone.
M-S3	SA	NSA	Transmission limitations on the 132 kV network in the Riverland area of SA.	High levels of wind generation in the NSA zone.
M-S4	SA	SESA	Transmission limitations on the Tailem Bend – Tungkillo transmission corridor.	New generation east of Adelaide or high import from Vic.
M-T1	Tas	TAS	Transmission limitations on the Burnie–Sheffield transmission corridor.	High levels of wind generation in North-west Tasmania.
M-T2	Tas	TAS	Transmission limitations on the Palmerston–Sheffield transmission corridor.	High levels of wind generation in Central Tasmania.

A.2 Forecast transmission network investment

The 2014 NTNDP capital investment estimates in Section 2.2 include:

- Transmission network augmentations identified through NTNDP modelling in Table 2.
- Replacement of ageing assets.
- Transmission needs to address local demand growth.

Table 4 presents a forecast investment profile over the next 20 years. AEMO forecasts between $9 billion and $18 billion of capital investment in NEM transmission networks over this period for both augmentations and asset replacement. Estimates to 2018 are derived from approved and proposed regulatory capital expenditure allowances, 2014 transmission annual planning reports and NTNDP findings.

Beyond 2018, longer-term estimates are given as a range, to account for inherent uncertainty about the potential impact of declining energy consumption and slowing maximum demand growth. These estimates are derived from the five TNSP transmission annual planning reports.[39] ElectraNet and AusNet Services provided 10-year network investment plans, while other TNSPs provided a five-year investment plan.

Beyond these periods, the upper and lower limits of the range were estimated as percentages of TNSPs' proposed capital expenditure over their current five or 10-year outlook. The upper limit is assumed to be 100% of proposed capital expenditure, and the lower limit is assumed to be 25% of proposed expenditure.

[39] Powerlink. Transmission Annual Planning Report 2014. Available: http://powerlink.com.au/About_Powerlink/Publications/Transmission_Annual_Planning_Reports/Transmission_Annual_Planning_Report_2014.aspx. Viewed: 25 November 2014; TransGrid. Transmission Annual Planning Report 2014. Available: http://www.transgrid.com.au/network/np/Documents/TransGrid%20Transmission%20Annual%20Planning%20Report%202014-web.pdf. Viewed: 25 November 2014; AEMO. 2014 Victorian Annual Planning Report. Available: http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report. Viewed: 25 November 2014; ElectraNet. Transmission Annual Planning Report. Available: http://www.electranet.com.au/network/transmission-planning/transmission-annual-planning-report/. Viewed: 25 November 2014; TasNetworks. Transend Transmission Annual Planning Report 2014. Available: http://www.tasnetworks.com.au/our-network/planning-and-development/annual-planning-program. Viewed: 25 November 2014

Table 4 Projected transmission network investment profile ($2013–14 billion)[40]

TNSP	Investment type	Historical		Proposed	Estimated range			
		2004–05 to 08–09	2009–10 to 13–14	2014–15 to 18–19	2019–20 to 23–24	2024–25 to 28–29	2029–30 to 33–34	Total 2014–15 to 33–34
Powerlink (Qld)	Asset replacement	0.50	1.10	0.90	0.23 – 0.90	0.23 – 0.90	0.23 – 0.90	1.58 – 3.60
	Capacity augmentation	1.85	0.89	0.17	0.04 – 0.17	0.04 – 0.17	0.04 – 0.17	0.30 – 0.69
	Total	**2.35**	**2.00**	**1.07**	**0.27 – 1.07**	**0.27 – 1.07**	**0.27 – 1.07**	**1.88 – 4.29**
TransGrid (NSW)	Asset replacement	0.41	0.54	1.44	0.36 – 1.44	0.36 – 1.44	0.36 – 1.44	2.51 – 5.75
	Capacity augmentation	1.00	2.00	0.20	0.05 – 0.20	0.05 – 0.20	0.05 – 0.20	0.35 – 0.80
	Total	**1.41**	**2.54**	**1.64**	**0.41 – 1.64**	**0.41 – 1.64**	**0.41 – 1.64**	**2.86 – 6.54**
AusNet (Vic)	Asset replacement	0.47	0.63	0.63	0.93	0.19 – 0.78	0.19 – 0.78	1.95 – 3.12
	Capacity augmentation	0.15	0.16	0.34	0.04	0.16 – 0.16	0.16 – 0.16	0.69 – 0.69
	Total	**0.62**	**0.79**	**0.96**	**0.97**	**0.35 – 0.94**	**0.35 – 0.94**	**2.64 – 3.81**
ElectraNet (SA)	Asset replacement	0.22	0.35	0.33	0.25	0.07 – 0.29	0.07 – 0.29	0.72 – 1.15
	Capacity augmentation	0.27	0.33	0.17	0.38	0.07 – 0.27	0.07 – 0.27	0.68 – 1.08
	Total	**0.49**	**0.68**	**0.50**	**0.62**	**0.14 – 0.55**	**0.14 – 0.55**	**1.40 – 2.23**
TasNetworks (Tas)	Asset replacement	0.20	0.23	0.15	0.04 – 0.15	0.04 – 0.15	0.04 – 0.15	0.25 – 0.58
	Capacity augmentation	0.18	0.36	0.06	0.01 – 0.06	0.01 – 0.06	0.01 – 0.06	0.10 – 0.22
	Total	**0.38**	**0.59**	**0.20**	**0.05 – 0.20**	**0.05 – 0.20**	**0.05 – 0.20**	**0.35 – 0.81**
NEM wide	Asset replacement	1.80	2.85	3.44	1.80 – 3.66	0.89 – 3.55	0.89 – 3.55	7.01 – 14.20
	Capacity augmentation	3.46	3.75	0.93	0.52 – 0.84	0.33 – 0.85	0.33 – 0.85	2.11 – 3.48
	Total	**5.25**	**6.61**	**4.37**	**2.32 – 4.50**	**1.22 – 4.40**	**1.22 – 4.40**	**9.12 – 17.67**

[40] Totals in table may not match due to rounding.

APPENDIX B. NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES

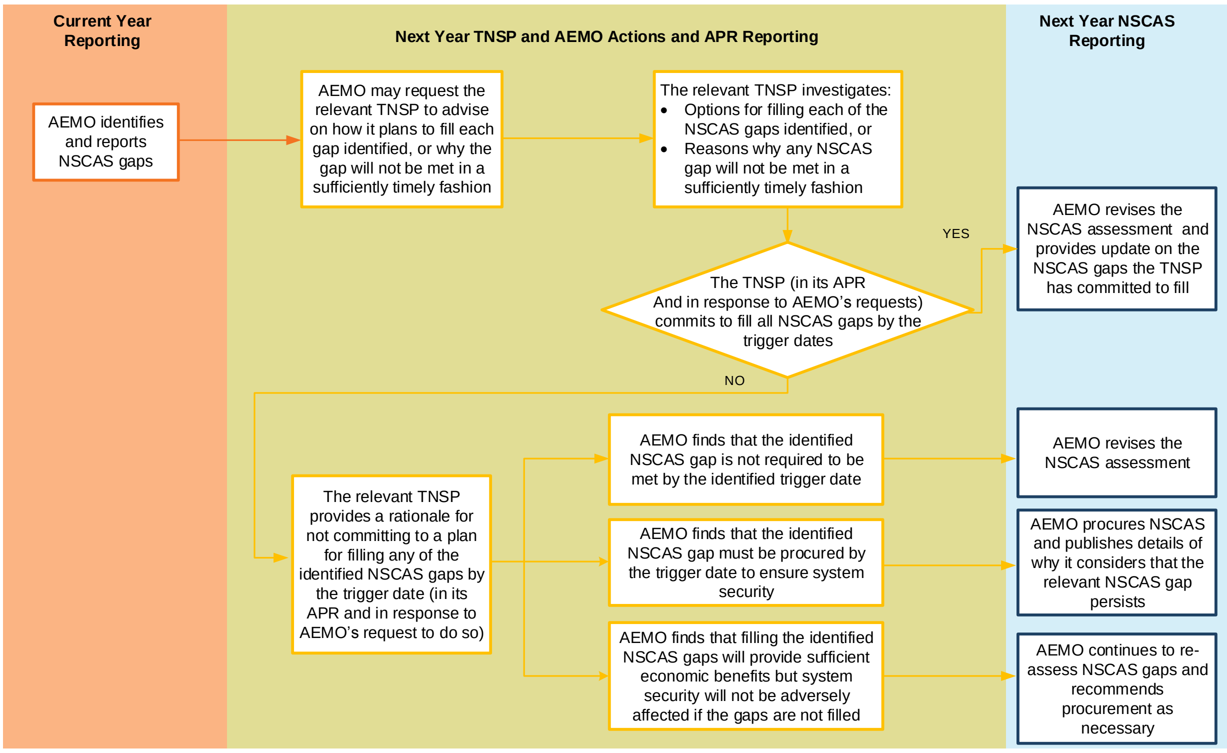
Network Support and Control Ancillary Services (NSCAS) may be procured to maintain power system security and reliability, and to maintain or increase the power transfer capabilities of the network.

TNSPs have primary responsibility for acquiring NSCAS. Each year AEMO identifies any NSCAS needs forecast to arise over a five-year horizon (NSCAS gaps); this assists TNSP decision-making with respect to NSCAS procurement.

If requested by AEMO, the TNSP is required to consider whether to make arrangements to meet an identified NSCAS gap. If the relevant TNSP does not commit to meeting the gap and AEMO considers it necessary to acquire NSCAS to prevent any adverse impact on power system security and reliability, AEMO will acquire NSCAS to meet the gap.

The figure below is a summary of the process for addressing any NSCAS gaps identified by AEMO.

Figure 9 Process for meeting NSCAS gaps identified by AEMO



Refer to the NSCAS description and NSCAS quantity procedures on AEMO's website for additional information.[41]

[41] 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 3 November 2014.

B.1 NSCAS gaps for maintaining power system security

In its 2014 NSCAS assessment, AEMO did not identify any NSCAS gaps to be met in order to avoid adverse power system security or reliability impacts over the next five years. The table below provides a summary of the 2014 NSCAS assessment results for each NEM region.

Table 5 Summary of NSCAS gaps for maintaining power system security

Region	NSCAS gaps	Comment
Queensland	None	The south-east Queensland network may experience high voltages under light load conditions. This will be managed with network switching operations. AEMO and Powerlink will continue to monitor the situation.
New South Wales	None	Ongoing NSCAS arrangements in New South Wales (Section B.5) are adequate for managing the potential voltage control issue at Kangaroo Valley and in the Snowy area.
Victoria	None	High voltages are likely to appear in the Victorian 500 kV network under certain system operating conditions. This will be managed with network switching operations. AEMO will continue to monitor the high voltages in Victorian 500 kV network.
South Australia	None	The static var compensators (SVCs) in South Australia were observed to be operating near limits under some light load operating conditions. This will be managed by operation solutions. AEMO and ElectraNet will continue to monitor the situation.
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 June and August 2014 respectively.

B.2 NSCAS gaps for maximising market benefits

No further NSCAS gaps for maximising market benefits in maintaining or improving power transfer capability were identified as part of AEMO's 2014 NSCAS assessment, although the gap identified in the 2012[42] and 2013 NSCAS[43] assessments remains.

In line with the NSCAS quantity procedure, AEMO consulted with TNSPs to assess the 66 binding constraint equations with summated marginal values higher than $50,000 for 2013. The assessment found that except for the Robertstown to North West Bend loading limitation, it is unlikely that addressing any other constraint using NSCAS in the next five years (2014–15 to 2018–19) could deliver sufficient economic benefits to be considered viable.

The 2012 and 2013 NSCAS assessments flagged potential market benefits by relieving the Robertstown to North West Bend line loading limitation if NSCAS could be acquired at an appropriate cost. ElectraNet and AEMO are currently finalising a joint planning study on this limitation (Section B.3).

B.3 Status of NSCAS gaps identified in 2012 and 2013

The table below provides an update on the status of the NSCAS gaps identified in 2012. The 2013 NSCAS assessment did not identify any additional potential NSCAS gaps.

[42] 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 2 December 2014.
[43] 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 2 December 2014.

Table 6 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 B.5 for details.
Potential NSCAS gap in relieving the Robertstown – North West Bend line loading limitation.	In its 2014 Transmission Annual Planning Reports (TAPR), ElectraNet proposed two small projects to address this limitation. AEMO and ElectraNet are finalising a joint planning study on this limitation.
Potential NSCAS gap in relieving the NSW to Victoria voltage stability limitation.	AEMO has been managing this limitation by reactive power support procured through VCAS procured from generating units running as synchronous generators. Both AEMO's and TransGrid's TAPRs commit to jointly investigating suitable economic options to meet this NSCAS gap.

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.

B.4 AEMO's 2013–14 NSCAS acquisition

AEMO did not acquire any additional NSCAS in 2013–14.

B.5 AEMO's current NSCAS agreements

The table below lists the NSCAS AEMO acquired in 2012–13 for VCAS.

Table 7 NSCAS AEMO acquired in 2012–13

Region	NSCAS type	NSCAS acquired[a]
NSW	VCAS (absorbing)	800 MVAr

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 security and reliability.

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

Agreement for generator 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

Under this agreement AEMO contracted 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 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 the NSCAS agreement.

VCAS costs are based on availability of TransGrid's NSCAS equipment at a fixed cost per trading interval, regardless of usage.

APPENDIX C. STORAGE CASE STUDIES

During 2014 research studies were undertaken at AEMO examining how residential battery storage technologies could affect the NEM.[44]

Case study 1: The economics of residential electricity storage[45]

This study used a detailed mathematical modelling approach (using a mixed integer linear program) to identify the financial viability of combined rooftop PV and battery storage systems for an average residential consumer in Melbourne.

To provide an indication of rooftop PV and battery storage payback periods for consumers over the next decade, the research used actual data for consumer demand, weather, cost and electricity tariff inputs together with assumptions about future retail electricity prices and system cost reductions.

Figure 6 shows how combining a time-of-use tariff with rooftop PV and a residential electricity storage (RES) installation is likely to affect household demand for grid-delivered electricity.[46] The load duration curve assumptions in this figure are shown in Table 8 below.

Table 8 Assumptions for analysis depicted in Figure 6

Assumptions	Description
Consumer demand	Average of 299 smart meter traces, hourly resolution for 2012 calendar year, annual load 8,033 kWh.
Weather data	Actual measurements from the Bureau of Meteorology weather station at Melbourne Airport. One minute data aggregated to an hourly resolution for the 2012 calendar year.
Retail tariff	Dodo time of day tariff (post carbon repeal) from the distribution area corresponding to demand data[47]
System performance	All system performance metrics such as RES depth of discharge and inverter efficiencies are taken from manufacturer specifications.[48]

Figure 10 below indicates the possible payback periods for combined 4 kW rooftop PV and 5 kWh RES system, using the assumptions in both Table 8 and Table 9. The payback periods shown represent a high RES uptake scenario using assumptions that indicate high electricity price rises, high cost reductions in RES over time and low costs of rooftop PV.

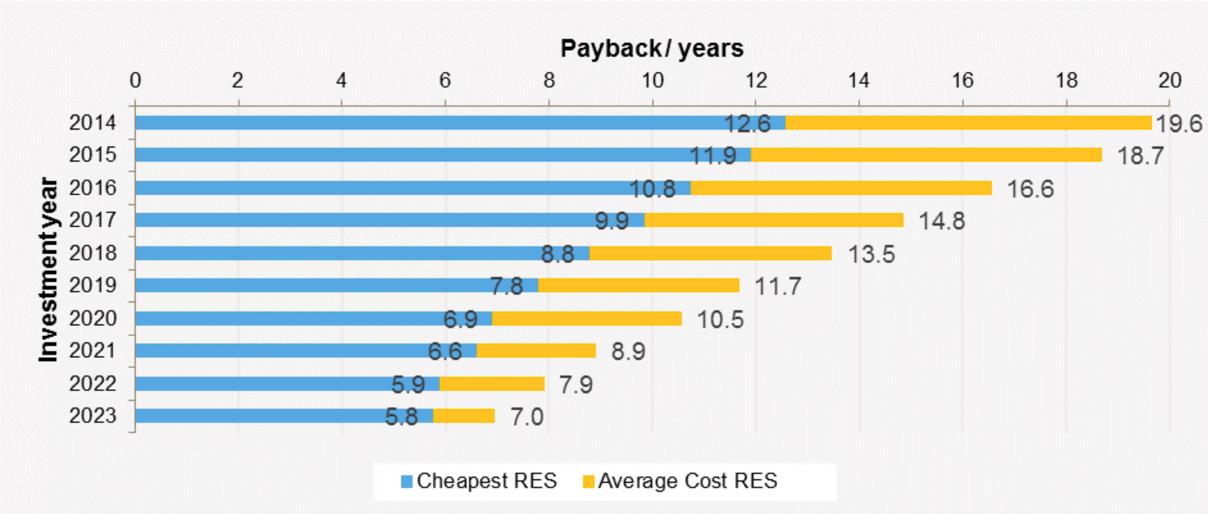
Table 9 Assumptions for analysis depicted in Figure 10

Assumptions	Description
Rooftop PV cost	Solar Choice solar PV price index – July 2014, Melbourne low 4 kW “low” price.[49]
RES system cost	Estimated installed cost of the cheapest and average priced consolidated RES systems in Australia, obtained from public information and speaking to relevant manufacturers.
Electricity prices	Future electricity price rises are taken from the 2014 NEFR high electricity price rise scenario.[50]
Future system costs	Based on a review of relevant literature[51] storage costs are assumed to fall by 40% for the cheapest and 60% for the average cost system to 2023 (linear trajectory). Rooftop PV and inverter costs are assumed to fall by 30% on the same basis.

[44] This research was conducted for AEMO by post-graduate students from the University of Melbourne and University College London.
[45] Based on an MSc research project ‘The economics of residential electricity storage in Victoria, Australia’, Matt Armitage, University College London, Australia (2014)
[46] The chart depicts the average load duration of 299 suburban consumers in Melbourne with an average annual load of 8,033 kWh. These load duration curves show the frequency that a particular level of demand occurs, on an hourly resolution, throughout a full calendar year.
[47] Dodo. Available at: https://connectto.dodo.com/Electricity/PPIS.aspx?postcode=3150&SignUpType=r. Viewed 21 November 2014.
[48] The RES system used in Figure 7 is manufactured by Sunsink and uses specifications stated on their website. In Figure 10 this represents the cheapest system in the market. For comparison the average cost scenario uses the same Sunsink system specifications; only the costs were updated. Sun-sink information can be found at: http://www.sunsink.com.au/. Viewed: 4 December 2014.
[49] Solar Choice. Available at: http://www.solarchoice.net.au/blog/solar-power-system-prices-sydney-melbourne-perth-canberra-adelaide-july-2014. Viewed 18 November 2014.
[50] AEMO. National Electricity Forecasting Report 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 11 December 2014.
[51] CSIRO summarised current thought leadership on cost reductions for electricity storage and projected a trajectory of 50% cost reduction by 2030. Change and choice – the Future Grid Forum’s analysis of Australia’s potential electricity pathways to 2050, 2013, page 30-31. Available at: http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure.aspx. Viewed 4 December 2014.

Assumptions	Description
Discount factor	5%. It is assumed that most consumers could include a rooftop PV and RES investment in their mortgage

Figure 10 Payback periods for 4 kW rooftop PV, 5 kWh RES when investing in next decade



The calculated payback periods shown in Figure 10 are for combined rooftop PV and RES investments. The payback period reduces over time with the forecast reduction in RES costs and the assumed increase in electricity prices. As the payback period lessens it is anticipated that there should increased penetration of RES in the NEM.

An important distinction is made in the research paper between the payback periods for a combined rooftop PV and RES investment (highlighted in Figure 10) and those relating to the incremental value that RES can provide to a consumer who has already installed rooftop PV. These paybacks are deemed to be considerably longer under current market conditions and may limit the uptake of RES.

Case study 2: Distribution network tariff design and emerging technologies[52]

This study examined the potential impact of cost-reflective distribution tariffs and the adoption of RES on network load profiles.

Using an adapted version of the model developed in the case study 1, Figure 7 shows the potential impact of RES on the load profile of Templestowe Terminal Station for the maximum demand day in 2013. Assumptions used in this analysis are as follows:

Table 10 Assumptions for analysis depicted in Figure 7

Assumptions	Description
Demand profile	Load profile for Templestowe terminal station on the maximum demand day in 2013.
RES system	5 kWh RES system.
Electricity tariff	Devised critical peak capacity tariff from the distribution network, passed on in full by retailers. This tariff structure consists of a significant difference between critical peak and off-peak charges
Network revenue	Although different tariffs were modelled in this research, each tariff raised the same overall revenue for the distribution network (simulating a revenue cap) before the solar PV and RES system was added.
Consumer demand	It is assumed that the consumer demand profile does not change.

[52] Based on research project 'Distribution network tariff design and emerging technologies – energy storage systems', Peter Young, University of Melbourne, Australia (2014)

Assumptions	Description
RES uptake scenarios	High and low penetration scenarios were developed for the uptake of RES systems. Each scenario assumes a 50% uptake rate among consumers where RES is economically viable.[53] The low penetration scenario represents an annualised cost of $350 for a 5 kWh RES system, while the high penetration scenario represents a cost of $300 per annum, assumed to be possible by 2025.[54]

[53] Defined when the projected annual household cost of electricity is cheaper with a solar PV and RES system than without it.
[54] Based on a possible price of batteries in 2025 of $160/kWh. McKinsey& Company. *Disruptive technologies: advances that will transform life, business any the global economy*. 2013. McKinsey Global Institute.

APPENDIX D. WHERE TO FIND MORE INFORMATION

AEMO has published the following supporting information for the 2014 NTNDP on its website:

- The NTNDP database comprising a comprehensive set of input data to enable stakeholders to undertake their own modelling.
- Generation Expansion Plan.
- Spreadsheets with detailed modelling results and graphs.
- A consolidated assessment of how the main transmission projects in transmission network service provider Annual Planning Reports relate to limitations observed in the 2013 NTNDP.

The table below provides links to additional information provided either as part of the 2014 NTNDP accompanying information suite, or other related AEMO planning information.

Table 11 Links to supporting information

Information source	Website address
2014 National Transmission Network Development Plan – report and modelling results	http://www.aemo.com.au/Electricity/Planning
2014 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report
Generation Expansion Plan	http://www.aemo.com.au/Electricity/Planning
2014 Planning and Forecasting Scenarios	http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx
2014 Planning Methodology and Input Assumptions	http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/consultations/nem/2014_Planning_Consultation_Methodology_and_Input_Assumptions_30_jan_14.ashx
2013 National Transmission Network Development Plan	http://www.aemo.com.au/Electricity/Planning
2013 Wind Integration Studies Report	http://aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/Integrating%20Renewable%20Energy%20-%20Wind%20Integration%20Studies%20Report%202013.pdf.ashx
AEMO Transmission connection point forecasting page	http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting
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
Planning Assumptions page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions
Renewable Energy Integration in South Australia	http://aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/Renewable_Energy_Integration_in_South_Australia_AEMO_Electranet_Report_Oct_2014.ashx

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GW	Gigawatts
GWh	Gigawatt hours
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt hours
MW	Megawatts
MWh	Megawatt hours
MVAr	Megavolt-amperes reactive
$	Australian dollars

Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
DSP	Demand-side participation
ESOO	Electricity Statement of Opportunities
GSOO	Gas Statement of Opportunities
GPG	Gas powered generation
JPB	Jurisdictional planning body
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MD	Maximum demand
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	National Electricity Market
NSCAS	Network support and control ancillary services
NTNDP	National Transmission Network Development Plan
NTP	National transmission planner
PV	photovoltaic
QNI	Queensland/New South Wales Interconnector
RAB	Regulated asset base
REC	Renewable Energy Certificate
RES	Residential electricity storage
RET	Renewable Energy Target

RIT-T	Regulatory Investment Test for Transmission
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
STPIS	Service Target Performance Incentive Scheme
SVC	Static VAr compensator
TAPR	Transmission Annual Planning Report
TNSP	Transmission network service provider
VCAS	voltage control ancillary service
VCR	Value of Customer Reliability

GLOSSARY

Many of the listed terms are already defined in the National Electricity Rules (NER), version 66.[55] These are marked with a double asterisk (**). Terms marked with a single asterisk (*), although defined in the NER, have a specific meaning when used in this report.

Term	Definition
active power*	Also known as 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.
ancillary services*	Services used by AEMO that are essential for: • Managing power system security • Facilitating orderly trading, and • 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 exceedence (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	A committed project is any new generation development or non-regulated transmission development that meets all five criteria specified by the AEMO for a committed project – generation.
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 'FCAS constraint equation', 'invoked constraint equation', and 'network constraint equation'.
consumer	See customer.
critical peak capacity tariff	A type of distribution network tariff that places a very high charge on the peak rate of electricity consumption during a critical time for the network. Such times are declared in advance by the distribution company on specific days during the year.
customer (electricity)*	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.

[55] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules

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 (DSP)	The situation where customers 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.
distribution network service provider (DNSP)**	A person who engages in the activity of owning, controlling, or operating a distribution system.
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 plant**	In relation to a connection point, includes all equipment involved in generating 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.

Term	Definition
generator**	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity.
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.
jurisdictional planning body (JPB)**	An entity nominated by the relevant Minister of the relevant participating jurisdiction as having transmission system planning responsibility (in that participating jurisdiction) as follows: • Queensland – Powerlink Queensland. • New South Wales – TransGrid. • Victoria – AEMO. • South Australia – ElectraNet. • Tasmania – TasNetworks.
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 (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also 'National Electricity Law'.
national transmission flow path**	That portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres. Generally refers to lines of nominal voltage of 220kV and above.
national transmission grid*	See 'national transmission flow paths'

Term	Definition
National Transmission Network Development Plan (NTNDP)*	An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
National Transmission Planner	AEMO acting in the performance of National Transmission Planner functions
National Transmission Planner (NTP) functions**	Functions described in section 49(2) of the National Electricity Law
net market benefit	Refers to market benefits of an augmentation option minus the augmentation cost. The market benefit of an augmentation is defined in the regulatory investment test for transmission developed by the Australian Energy Regulator.
network**	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (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. See also ‘ratings’.
network limitation	Network limitation describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also ‘network congestion’.
network service**	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
network service provider**	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER).
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involved demand-side participation (DSP) (including post contingent load relief) and new generation on the load side for the limitation.
power	See ‘electrical power’.
power station**	In relation to a generator, a facility in which any of that generator’s generating units are located.

Term	Definition
power system**	The National Electricity Market's (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
power system reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.
power system security**	The safe scheduling, operation, and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 (of the NER).
reactive energy**	A measure, in varhour-(varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power*	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, and • 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 NER), being an area served by a particular part of the transmission network containing one or more major load centres of generation centres or both.
regulatory investment test for transmission (RIT-T)**	The test developed and published by the AER in accordance with clause 5.6.5B, as in force from time to time, and includes amendments made in accordance with clause 5.6.5B.
regulatory test*	The test promulgated by the Australian Energy Regulator (AER) to identify the most cost-effect option for supplying electricity to a particular part of the network The test may also 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. After 1 August 2010, projects are assessed under the RIT-T (subject to transitional arrangements).
regulatory control period**	In respect of a Transmission Network Service Provider, a period of not less than 5 regulatory years in which a total revenue cap applies to that provider by virtue of a revenue determination.
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.

Term	Definition
Reliability and Emergency Reserve Trader (RERT)*	The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when: • 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'.
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.
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.
summer	Unless otherwise specified, refers to the period 1 November – 31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).
supply**	The delivery of electricity.
time of use tariff	A pricing structure consisting of different charges on the volume of electricity consumed at different times during the day, depending on the typical network utilisation at those times.
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.
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.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).

LIST OF COMPANY NAMES

The following table lists the full name and Australian Business Number (ABN) of companies that may be referred to in this document.

Company	Full company name	ABN
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator	92 072 010 327
AusNet	AusNet Services (Transmission) Ltd	48 116 124 362
CSIRO	Commonwealth Scientific and Industrial Research Organisation	41 687 119 230
Dodo Power & Gas	M2 Energy Pty Ltd	15 123 155 840
ElectraNet	ElectraNet Pty Limited	41 094 482 416
Powerlink Queensland	Queensland Electricity Transmission Corporation Limited	82 078 849 233
Redbank Power	Redbank Project Pty Limited	34 075 222 561
Snowy Hydro	Snowy Hydro Limited	17 090 574 431
Sun-Sink	Vulcan Energy Pty Ltd	45 060 161 891
TasNetworks	Tasmanian Networks Pty Limited	24 167 357 299
TransGrid	TransGrid	19 622 755 774