TransGrid

New South Wales

Transmission Annual Planning Report

2015

Contents

Appendix 1 TransGrid's network planning approach

Appendix 2 Asset replacement projects

Appendix 3 Individual bulk supply point projections

Appendix 4 Load profiles and load at risk

Appendix 5 Line utilisation report

Appendix 6 Transmission constraints

Appendix 7 Planning proposals for future connection points

Appendix 8 Progress of developments reported in TAPR 2014

Appendix 9 Results of December 2014 survey

Appendix 10

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Version	Date issued	Comment
0	30 June 2015	Original issue

Foreword by the Managing Director

This Transmission Annual Planning Report (TAPR) 2015 provides an assessment of the capabilities of and constraints facing TransGrid's network for the upcoming 10 year period. It outlines the process and outcomes of our annual planning review and provides advance information to our stakeholders, including market participants, on the nature and location of emerging constraints in our network.

We publish a TAPR every year. When read together with similar documents published by the three NSW distributors (Ausgrid, Essential Energy and Endeavour Energy), ActewAGL and the Australian Energy Market Operator (AEMO), this report is intended to provide a meaningful picture of the network planning activities and related opportunities across NSW and the ACT.

Forecast electricity supply and use have a direct influence on how TransGrid's network will evolve into the future. We take into account AEMO and the distributors' forecasts, as well as information provided by our directly connected customers and our own analysis and modelling to understand the preferences of energy users across NSW and the ACT.

Those preferences are driven by a range of factors. In recent years we have seen changes in trends for energy consumption and maximum demand. For example, overall energy consumption has declined. This has largely been driven by the impact of global economic conditions on major industry and consumer confidence, consumer responses to government energy policies and electricity price increases. However, the latest forecast from AEMO and the distributors indicates that both consumption and maximum demand[1] are likely to increase, albeit at more modest rates than past trends.

A period of lower growth requires a high level of agility and we have taken steps to ensure that our planning processes continue to reflect this.

First, we apply rigorous testing to a potential project's need as soon as it is identified, as well as in our exploration of the options for efficiently addressing it. As part of this, we proactively engage with stakeholders and have opened our planning processes to include a range of energy perspectives to help us evaluate and deliver the most appropriate solution.

A great example of this in action was the Powering Sydney's Future project. The project concerned whether action needed to be taken to reinforce the long-term power supply to Sydney's Central Business District and surrounding suburbs. Throughout 2014 we embarked on a major community consultation program to consider whether doing so would be appropriate and, if so, what actions should be taken. In the end, the moderating load forecast meant that TransGrid was able to defer the project, saving customers over $200 million.

Second, we continue to work hard to maximise the value from our existing assets. TransGrid was recently accredited to the global ISO55001 asset management standard and we are strengthening our condition based approach to asset maintenance. This year we have introduced a chapter on asset management to explain our asset strategies in more detail.

1 Maximum demand is the highest total load on TransGrid's network measured over a half hour period. This is the load that TransGrid must be able to supply whenever called upon to do so.

TransGrid has embraced the changing energy landscape and continued to enhance our business operations to become a more agile and responsive network providing safe, secure, reliable and economically efficient transmission services to New South Wales (NSW), the Australian Capital Territory (ACT) and the National Electricity Market (NEM).

Our Asset Renewal Program, a process by which we replace or refurbish parts of the network or individual pieces of equipment as an outcome of a comprehensive risk-based assessment, has enabled us to minimise our capital expenditure in the current regulatory period. We are also making more granular, targeted investment decisions. This includes, for example, implementing best practice dynamic line ratings and removing low clearances on individual transmission line spans rather than whole lines. Both projects aim to maximise the capacity of existing assets to deliver the electricity demanded by customers at the most efficient cost.

Finally, we continue to explore innovative non-network alternatives to address our customers' needs. The evolution of the demand management market is bringing new opportunities for us to work collaboratively with participants in that market to find solutions that will benefit consumers through lower transmission prices. We are investigating the potential for grid scale energy storage solutions and trialing the integration of network and non-network technologies. These initiatives will help shape the future of the grid and ignite new ways of delivering a reliable and sustainable electricity supply.

I'd like to highlight two other important things.

First, from the above, you'll have seen that TransGrid remains committed to safely, securely and reliably serving the needs of our customers at the lowest efficient cost. Like other electricity networks, TransGrid is a capital intensive business that delivers those services using predominantly long-lived assets. It is therefore important that efficient cost is understood to mean sustainably efficient.

The maximum revenues that TransGrid may earn for providing prescribed services are approved by the Australian Energy Regulator (AER). As part of its recent determination, the AER reduced our replacement capital expenditure for the years until 2017/18 by 29% from the amount we had submitted as being prudent. We are concerned that the regulator's decision may impact on the business's ability to deliver those services sustainably in the longer term. TransGrid is looking very carefully at how it rations both its capital and operating expenditure to best manage in this regard and we will continue to work closely with our customers, consumers and other stakeholders in doing so.

Second, in publishing this year's TAPR, we've put forward the best picture we have today of where we expect the network to be over the next ten years. Over the last year we have consulted with our stakeholders on the format and content of the report and made a number of improvements based on the feedback we received. This also includes changes made as the result of discussions held with the AER.

Ongoing improvement is an integral part of our business and I look forward to continuing an open conversation with you to ensure that TransGrid is best placed to meet your service expectations now and into the future.

Peter McIntyre
Managing Director
June 2015

Executive summary

Chapter 1

Introduction

TransGrid owns and operates the high voltage network connecting generators, distributors and major end users in NSW and the ACT. Along with the NSW and ACT electricity distributors, we are required to conduct an annual planning review to identify future needs and possible solutions over a ten year planning horizon. We publish our findings as a Transmission Annual Planning Report (TAPR).

We plan our network to meet our customers' needs safely, securely and reliably and at the most efficient long run cost. We explore and encourage non-network solutions to those needs wherever this is more cost efficient than a network option.

We continually seek to improve how we communicate our planning information, including the TAPR, to stakeholders and have taken into account recommendations for improvement received from both stakeholders and the Australian Energy Regulator (AER).

Chapter 2

Projections for factors affecting network capacity

The forecasts that TransGrid relies upon indicate that annual electricity consumption in the NSW region (including the ACT) is likely to grow on average by 1% annually over the next ten years driven mainly by lower energy prices, population growth and increased income.

By way of comparison, the projected annual growth rate in last year's TAPR 2014 was 0.4%. Maximum demand is projected to grow at 1.2% per annum in summer and 1.4% in winter, based on 50% Probability of Exceedance conditions under AEMO's medium economic growth scenario.

In recent years, it has become more difficult to confidently predict electricity consumption and maximum demand. Over this period, actual levels (not corrected for weather) for both have been below predictions. While it is possible that the forecasts set out above may not eventuate, we are nevertheless required to deliver a system capable of meeting those forecasts safely, securely, reliably and at efficient cost.

The only areas in which load growth is expected to lead to network limitations are the Gunnedah/Narrabri area and the Beryl/Mudgee area.

It is possible that some existing coal fired generation will be retired and that new renewable, likely wind, generation may be commissioned during the planning horizon. The latter would be likely to occur in areas remote from the major load centres of Newcastle, Sydney and Wollongong. Their development would therefore be likely to increase the loading on our network in those areas and between those areas and the major load centres.

The reliability standards and technical performance standards that we are required to operate, have not changed since last year's TAPR. However the NSW and other State and Territory governments are considering moves to harmonise the expression of the reliability standards across the NEM in coming years.

Chapter 3

Non-network solutions

Non-network solutions can offer alternatives to expanding our network and we consider such options whenever we face an investment need. This is because they can defer or avoid capital costs. Such solutions can typically be better tailored to local needs and enable us to adapt quickly to changing operating conditions. Currently, there appears to be only limited options for using non-network solutions within the ten year TAPR planning horizon.

We will continue to trial new demand management technologies and collaborate with market participants. This is because developing the demand management market is an important way to provide for efficient long term outcomes for customers.

Chapter 4

Asset management

As demand for electricity in the NSW region is expected to increase only moderately over the planning horizon, we expect to spend significantly less augmenting the network than we have in the past and instead place a greater emphasis on maximising the value to customers from our existing assets. In addition, a growing number of our assets are approaching the end of their serviceable lives increasing the importance of providing for their orderly retirement.

Our asset management system allows us to address these issues according to international best practice standards (ISO55001).

The AER's revenue determination is likely to impact our ability to do this, increasing the associated risks, including risks to customer service levels. We are carefully managing our expenditure including re-scoping and prioritising key programs such as dynamic line ratings (DLR) and low span remediation works in order to manage those risks.

TransGrid plans its network to meet its customers' needs safely, securely and reliably and at the most efficient long run cost.

Chapter 5

Completed, committed and planned developments

In the last financial year, 12 projects were completed that alleviated previously identified constraints. These include the Western Sydney Supply project, line 97G remediation, transformers at Newcastle, Griffith and Yanco and capacitor bank installations at Canberra and Yass.

25 projects progressed to, or are at, the committed stage including the redevelopment of the Orange substation, the DLR, quality of supply monitoring and point on wave switching control programs, the strategic acquisition of Riley Street, a future substation site in Surry Hills and a number of major substation rebuilds.

Eight projects are planned including the construction of the ACT Stockdill Drive switching station, the refurbishment of the Vales Point substation and partial rebuild of the Wagga 132 kV substation.

Some asset replacement projects progressed from the 'within 5 years' category from last year, including the Taree and Haymarket secondary systems projects.

Projects delayed or deferred during the review period included the Hume secondary systems replacement, multiple contingency protection scheme, Wallerawang – Orange 132 kV line retirement and the Vineyard – Cattai strategic site acquisition.

Chapter 6

Constraints and possible network developments

Possible projects in the next five years include augmentation in the Gunnedah/ Narrabri area as well as condition based works at Tamworth, Central Sydney, Munmorah/Doyalson area, Canberra, Burrinjuck and the multiple contingency protection scheme.

Possible developments in the next five to ten years include Hunter Valley – Tamworth – Armidale line capacity, Northern NSW voltage control, Newcastle substation condition, Marulan – Avon, Marulan – Dapto, Kangaroo Valley – Dapto line capacity and the Wallerawang – Orange 132 kV line condition. Other than for the Newcastle substation condition and the Wallerawang – Orange 132 kV line, these would be based on market benefits being achieved.

Some possible developments reported in last year's TAPR 2014 are now expected to arise further into the future because of moderating load forecasts. These include the Queensland – NSW Interconnector (QNI) upgrade and associated projects, development of supply to the Sydney inner metropolitan area and development of the Snowy to Sydney network capacity.

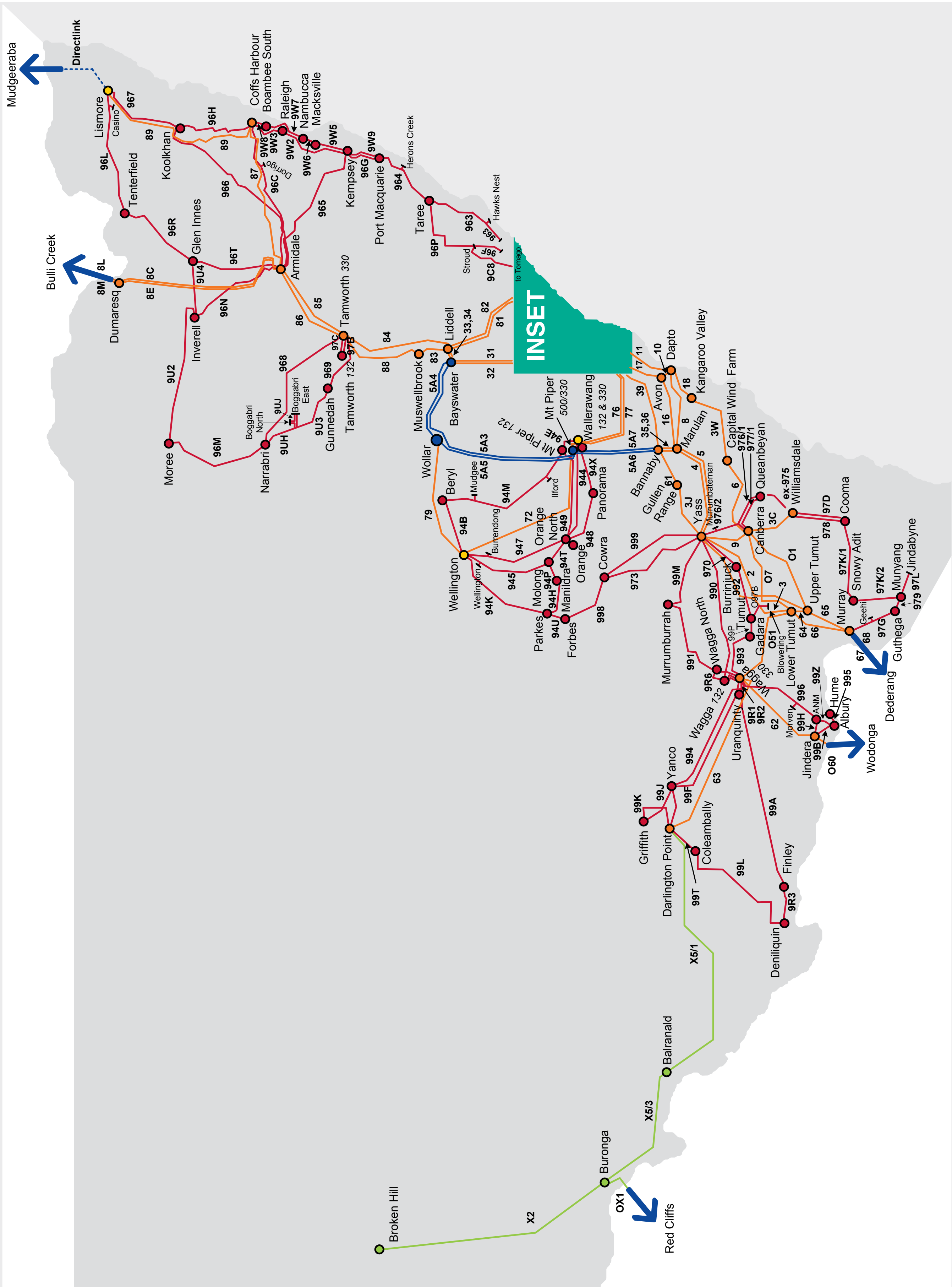
Some asset replacements, such as Sydney North and Albury secondary systems, Beaconsfield transformer and Buronga reactor replacements, have progressed and are now committed projects. Others have modified scopes and timeframes as a result of our regular review of needs and options.

Chapter 1

Introduction

- We own and operate the NSW high voltage network connecting generators, distributors and major end users in NSW and the ACT
- Along with the NSW and ACT electricity distributors, we are required to conduct an annual planning review to identify future needs and possible solutions over a ten year planning horizon. We publish our findings as a Transmission Annual Planning Report (TAPR)
- We plan our network to meet our customers' needs safely, securely and reliably and at the most efficient long run cost. We explore and encourage non-network solutions to those needs wherever this is more cost efficient than a network option
- We continually seek to improve how we communicate our planning information, including the TAPR, to stakeholders and have taken into account recommendations for improvement received from both stakeholders and the Australian Energy Regulator (AER).

FIGURE 1.1 – TransGrid's electricity network map



1.1 About TransGrid

Our network comprises 99 substations and nearly 13,000 kilometres of transmission lines and cables. Interconnected to Queensland and Victoria, it provides a strong electricity system that makes energy trading possible between Australia's three largest states along the east coast and supports the competitive wholesale National Electricity Market (NEM).

The network operates primarily at voltage levels of 500 kilovolts (kV), 330 kV, 220 kV and 132 kV. Our substations are normally located on land owned by us with the transmission lines and underground cables generally constructed on easements acquired across private or public land.

Staff are strategically located throughout NSW in order to meet day-to-day operation and maintenance requirements and to provide emergency response services. We have offices in Sydney, Western Sydney, Newcastle, Orange, Tamworth, Wagga Wagga and Yass.

TransGrid's network is shown in Figures 1.1 and 1.2. Figure 1.3 sets out where TransGrid sits within the electricity supply chain.

FIGURE 1.2 TransGrid's electricity network map – Inset

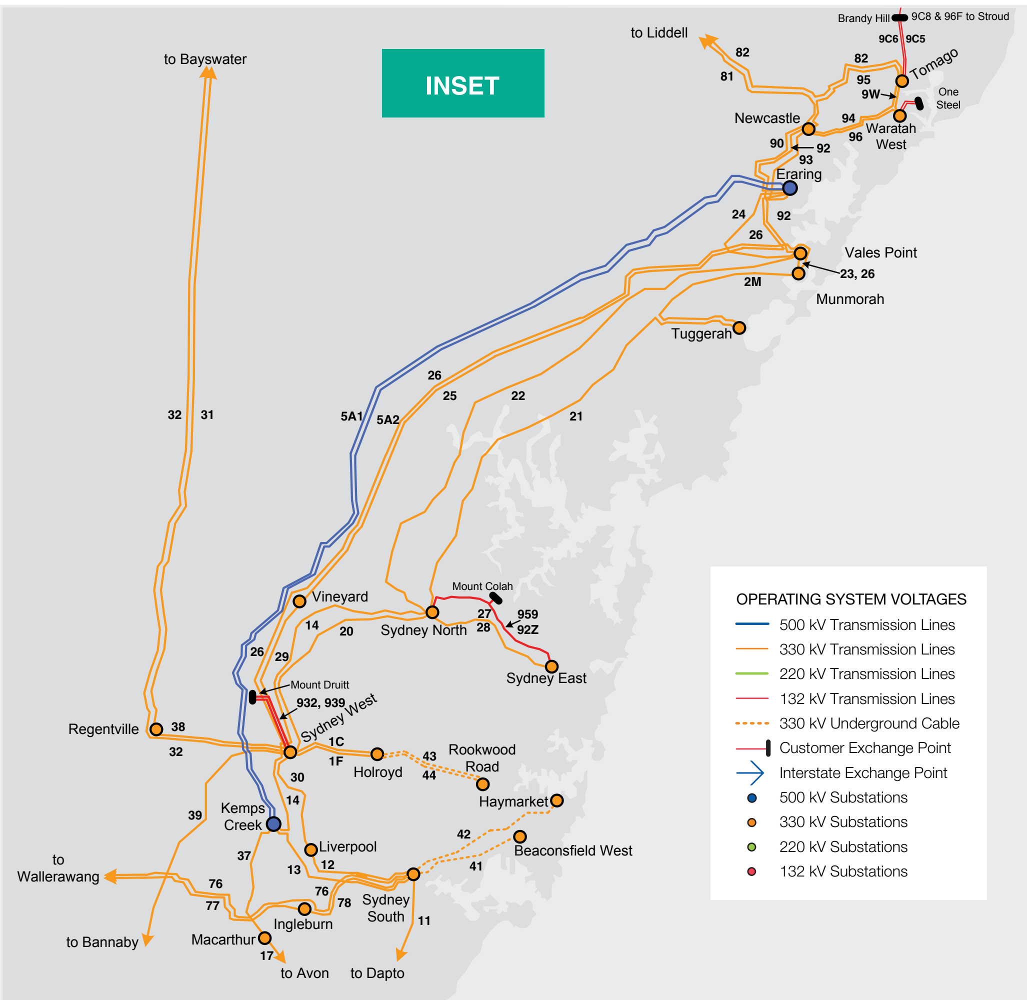
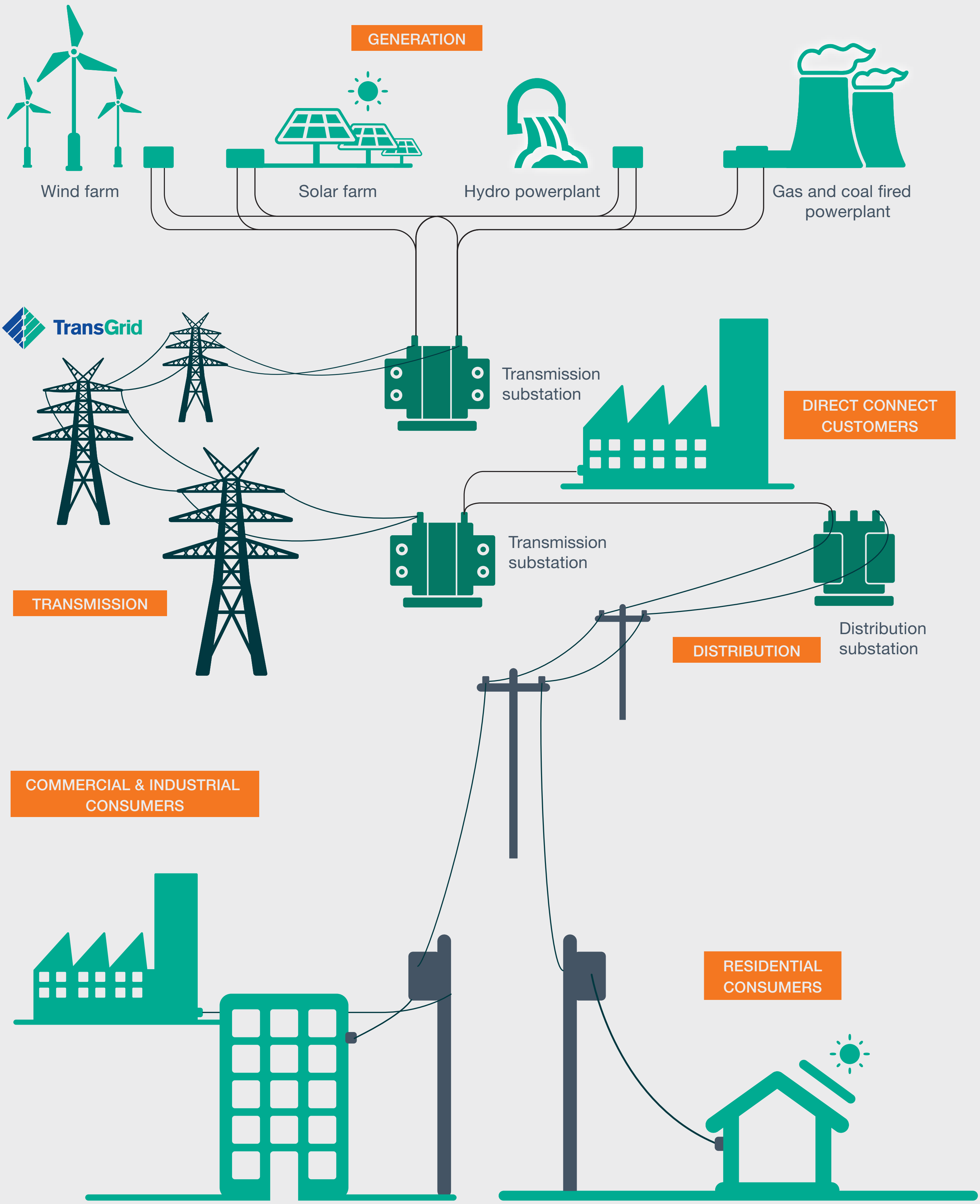


FIGURE 1.3 TransGrid within the electricity supply chain



Interconnected to Queensland and Victoria, our network provides a strong electricity system that makes energy trading possible between Australia's three largest states along the east coast and supports the competitive wholesale National Electricity Market (NEM).

1.2 About this TAPR

The National Electricity Rules (NER) requires us to undertake an annual planning review. The purpose of the review is to identify an optimum level of transmission investment so that we deliver our services at long run efficient cost.

The review identifies the emerging constraints within the network and possible options to overcome them. The review is also designed to provide information to interested parties so that they may propose options to meet those needs at lower costs where feasible. This may involve components of demand management and local generation.

Our annual planning review involves joint planning with each of the distribution network owners within NSW and the ACT (Ausgrid, Endeavour Energy, Essential Energy and ActewAGL) as well as with Powerlink and the Australian Energy Market Operator (AEMO). The objective of joint planning is to work together to develop the overall network in the most efficient way.

Our planning review began in October 2014 with a request by us for the distributors to provide their updated bulk supply point load forecasts. These forecasts take into account electrical loads experienced during the preceding summer and winter. Based on these revised load forecasts and AEMO's demand forecast for the NSW (including ACT) region of the NEM, we have updated our short term (one, three and five years) and longer term analyses of present and emerging network constraints and have summarised the results in this document.

This Transmission Annual Planning Report (TAPR) 2015 presents the results of our annual planning review. It:

- Identifies emerging constraints in NSW transmission networks over appropriate planning horizons
- Provides advance information on the nature, quantification and location of the constraints. The level of information included in this document is intended to encourage market participants and interested parties to formulate and propose options to relieve the constraints, including those that may include components of demand management and local generation or other options that may provide economically efficient outcomes
- Discusses options that have been identified for relieving each constraint including network, local generation, demand management and other options
- Indicates, where possible, if and when we intend to issue a Request for Proposals (RfP) for non-network alternatives to relieve a constraint
- Provides summary information for proposed augmentations
- Provides summary information for proposed replacement transmission network assets
- Provide a basis for annual reporting to the NSW Minister for Industry, Resources and Energy (the Minister) on the outcome of the annual planning review.

Under the NER, we must publish our TAPR by 30 June each year. We then hold a public forum to consider the report and related transmission matters and report to the Minister on the matters arising from the consultation process.

As the Jurisdictional Planning Body for NSW appointed by the Minister, we must also provide input to AEMO's Electricity Statement of Opportunities (ESOO) and National Transmission Network Development Plan (NTNDP). Broadly the ESOO considers the adequacy of generation in the NEM. The NTNDP provides an overview of the adequacy of key parts of the interconnected transmission networks serving the NEM. Both of these reports serve as inputs into our TAPR and we must also report to the Minister on any matters relevant to the TAPR arising from them.

1.3 How we plan

Our network investment process is designed to respond to the changing needs of stakeholders and deliver our capital program effectively. The process includes:

> An integrated, whole of business approach to capital program management

> Optimisation of investments to meet augmentation and asset replacement/ renewal requirements

> Early resolution of key risk areas such as environmental approvals, property acquisition and scope definition in the project delivery process

> Structured documentation around options evaluation and project scoping to enhance the transparency of decision making

> Early engagement with stakeholders throughout the planning cycle to involve end users and impacted communities in decisions.

The key processes and steps, including where and how we engage stakeholders, are set out below.

FIGURE 1.3 – How TransGrid plans the network

Stage		Transgrid planning process	Stakeholder involvement
STAGE 1	Identify need	Look at demand forecasts, expected generation patterns and the condition of existing assets. Will there be a shortfall in supply if we do nothing?	Sense-check forecasts with • Distributors • Directly connected customers • AEMO. Seek feedback from end users and their representatives on need assessment.
STAGE 2	Review options	Identify possible network and non-network options to fulfil the need, including: • Demand management • Local or distributed generation • Network infrastructure optimised to expected requirements.	Input from large users, service providers and experts on potential for non-network options. Communicate with local community that may be impacted by network infrastructure.
STAGE 3	Plan in detail	Request proposals and undertake investment analysis on most viable options.	Encourage proposals from market participants for non-network options. Engage impacted communities in network corridor selection, if relevant. Involve end users and their representatives in final investment decision.
STAGE 4	Implement solution	Enter into contracts for network or non-network solutions. Build network infrastructure, if required.	Work with impacted community to support best local outcomes. Report progress in meeting identified need to end users and their representatives.

1.3.1 Requirements

1.3.1.1 Design standards

The NSW Government has directed us to implement the *Transmission Network Design* and *Reliability Standard for NSW,* December 2010 in developing our plans. Broadly, the standard requires TransGrid to provide N–1 reliability[1] unless otherwise agreed with connected customers.

Details of our approach to network planning are provided in Appendix 1.

We have been awarded a utility services licence to provide electricity transmission services within the ACT. This licence requires, inter alia, a second 330 kV supply point to the ACT. The provision of Stockdill 330 kV switching station is part of the solution to fulfil this requirement.

We are also now responsible for procuring Network Support and Control Ancillary Services (NSCAS) in NSW and the ACT. NSCAS are those non-market ancillary services required to maintain power system security and reliability and maintain or increase the power transfer capability of the transmission network. NSCAS are discussed in Appendix B of AEMO's 2014 NTNDP.

1.3.1.2 The State Owned Corporations Act 1989

In planning to the above standards, it is relevant to note that TransGrid is currently a State Owned Corporation (SOC) under the *State Owned Corporations Act 1989*, with its principal objectives stated in Section 6B of the *Energy Services Corporations Act 1995 No 95*. That Act requires TransGrid to:

> Be a successful business, and, to this end:
  - Operate as efficiently as any comparable businesses
  - Maximise the net worth of the State's investment in it
  - Promote social responsibility by having regard to the interests of and engaging with the community in which it operates.

> Protect the environment by conducting its operations in compliance with the principles of ecologically sustainable development specified in Section 6 (2) of the *Protection of the Environment Administration Act, 1991*

> Minimise the environmental impact of its activities on easements for transmission facilities created in favour of the energy transmission authority

> Demonstrate responsibility towards regional development and decentralisation in the way in which it operates

> Operate efficient, safe and reliable facilities for the transmission of electricity

> Promote effective access to these transmission facilities.

1.3.2 Regulatory investment test for transmission (RIT-T)

For significant augmentation investments, we are required by the NER to also follow a RIT-T consultation process. This is a process designed to inform stakeholders of the investment need and proposed network or non-network option to address it, test the market for more efficient solutions and advise stakeholders of the outcome of the selected solution.

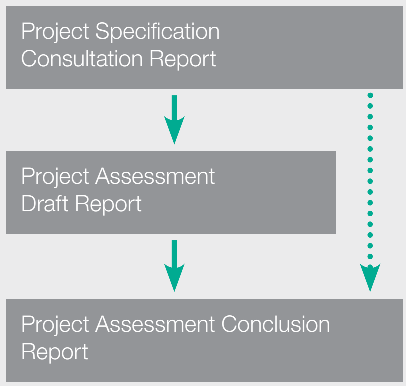
The RIT-T applies to transmission network investments where the cost of the most expensive credible option is greater than $5 million. It does not apply to investments relating to maintenance, replacement or urgent and unforeseen investments.

The RIT-T consultation process generally involves the issuing of three documents: the Project Specification Consultation Report (PSCR), the Project Assessment Draft Report (PADR) and the Project Assessment Conclusion Report (PACR).

Minimum consultation periods following publication of the PACR and PADR are specified and there is a requirement for the consideration of submissions received in response to these documents.

The PADR can be omitted where the preferred option costs less than $38 million, where there are no material market benefits and where the PSCR has identified the preferred option.

FIGURE 1.4 – RIT-T consultation documents



1 This requires the network to be able to supply the forecast load with one network element out of service.

The preferred option under the RIT-T is the credible option that maximises the net market benefit, taking into account the direct cost of the option and the market benefits arising from that option.

The process considers all credible options that are technically and economically feasible, including non-network options. The location and performance requirements that a non-network option would be required to deliver, including the size of the load reduction or additional supply required, are detailed during this process.

A new 'replacement transmission network asset' category was defined for network replacement projects with costs expected to exceed a threshold of $5 million. For this category there is a requirement to disclose information in TAPRs that includes a brief project description, when they are expected to become operational, other reasonable options considered (if any) and the estimated cost. This information is provided in Section 6.2.11.

Chapter 6 reports on RIT-T consultations completed since last year's TAPR. There are no RIT-T consultations currently underway.

1.3.3 Non-network options

Where non-network options are being considered to address a network constraint, the NER include requirements to indicate:

> When the constraint is expected to occur and the megawatt (MW) reduction at a connection point required to relieve the constraint for 12 months, and the locations at which that reduction could be made

> Plans and dates to issue a Request for Proposal (RfP) for a non-network alternative.

This information is included in Chapter 6. Additional information for one near-term augmentation need (supply to the Gunnedah/Narrabri area) is provided in Appendix 4. More general information on our approach to non-network options is included in Chapter 3.

1.4 Structure of this document

The rest of this document sets out:

> Forecast load, generation and other changes that may impact on the capacity of our network over the TAPR planning horizon (Chapter 2)

> How we look for and investigate options for meeting customer needs in ways that don't require us to build additional network infrastructure (Chapter 3)

> How TransGrid manages its assets to ensure that customers obtain the maximum value from them over their full lifecycle (Chapter 4)

> Completed, committed and planned developments (Chapter 5)

> Constraints and possible future developments (Chapter 6).

1.5 Continuous improvement

Our planning and operating decisions impact consumers across NSW and the ACT. We consider it is our responsibility to be as proactive, honest and transparent as possible in sharing information about our plans with our stakeholders.

We remain focused on improving our planning consultation processes, including this TAPR, to deliver more timely and cost effective solutions to meet our customer and other stakeholder needs. As part of this, late in 2014, we undertook a fourth annual survey of stakeholders and engaged with the AER on how the TAPR's effectiveness may be improved.

The survey allowed us to measure our performance through feedback provided by 66 employees of customer organisations who had contact with our staff in the preceding 12 months. The overall customer experience rating has increased by 3% this year, taking the score to 71%. Most TAPR users believed that their needs were being met. A summary of the results of the consultation are given in Appendix 9.

In early 2014, the Australian Energy Regulator (AER) undertook a review of the TAPRs produced by all transmission network service providers (TNSPs) within the NEM. The review was based on the AER's interpretation of both the NER requirements and the intentions of the rule makers when the relevant sections of the NER were being developed. The review led to the AER asking us to provide additional information in our TAPR.

There were a number of load forecast-related data items proposed to be included in the TAPR by the AER. Discussions with the distributors this year regarding their load forecasts revealed that some of that data is not available.

1.5.1 Changes made to TAPR 2015

TransGrid has made some changes to the content of this year's TAPR as detailed below.

> Results of the December 2014 TAPR survey have been included

> The load forecast data can be downloaded in spreadsheet form from our website

> Section 6.4 lists those developments that previously sat within, but this year have been deferred beyond, the 10 year timeframe. Many projects from last year have been deleted with a few moved into this section this year

> This TAPR takes into account the AER's recent final revenue determination for our 2014/15-2017/18 regulatory control period. The implications of the regulator's decision on how we are likely to be able to manage our assets to safely, securely and reliably deliver the services expected by customers is discussed in Chapter 4

> This TAPR 2015 is available in downloadable PDF form on our website.

1.5.2 Where to find further information and provide feedback

An important function of our consultation and information documents, including this TAPR, is to provide non-confidential information to enable interested parties to make informed decisions and contributions to our planning processes. Unfortunately, it is not always possible to predict the precise nature and depth of the information that those parties may require.

When additional information is sought, we generally hold discussions with the relevant party to determine what additional information is required. This enables us to tailor the additional information provided to the specific needs of that party.

We believe that this approach is well suited to the TAPR, which covers a wide range of subjects and cannot, by its nature, provide detailed information on all subjects covered. In line with this approach, rather than repeating detail that is available in other publicly available documents, the TAPR provides references to those documents.

A less targeted approach was considered, which would rely less on comments/submissions by providing additional information initially. However this was not adopted as:

> It would not be certain that the exact information required would be provided

> There is a greater risk that the information required by particular parties may be obscured by other information that is not relevant to them.

Comments on any aspect of this TAPR and particularly on our approach are welcome. Contact details are provided on the inside of the back cover.

We remain focused on improving our planning consultation processes, including this TAPR, to deliver more timely and cost effective solutions to customer and other stakeholder needs.

Chapter 2

Projections for factors affecting network capabilities

- Annual energy consumption in the NSW region (including the ACT) is forecast to grow on average by 1% annually over the next ten years due to lower electricity prices, population growth and increased income. The projected annual growth rate in last year's TAPR 2014 was 0.4%
- Maximum demand is projected to grow at 1.2% per annum in summer and 1.4% in winter (50% Probability of Exceedence conditions under AEMO's medium economic scenario)
- In recent years, it has become more difficult to confidently predict annual electricity consumption and maximum demand. Over this period, actual levels (not corrected for weather) for both have been below predictions. While it is likely that the future will vary from the forecasts, we are nevertheless required to deliver a system capable of meeting those forecasts safely, securely, reliably and at efficient long run cost
- The only areas in which load growth is expected to lead to network limitations are the Gunnedah/Narrabri area and the Beryl/Mudgee area
- It is possible that some existing coal fired generation will be retired and/or new renewable, likely wind generation commissioned during the planning horizon. New generation would be likely to occur in areas remote from the major load centres of Newcastle, Sydney and Wollongong. Their development would therefore be likely to increase the load on our network in those areas, and between those areas and the major load centres
- The reliability standards and technical performance standards that we are required to operate have not changed since last year's TAPR. However the NSW and other State and Territory governments are considering moves to harmonise the expression of the reliability standards across the NEM in the coming years.

2.1 Introduction

This chapter provides information regarding the likely impact of energy and demand forecasts and other factors on our transmission system over the ten year TAPR planning horizon.

Limitations on TransGrid's network, which restrict its ability to meet customer requirements, can arise from the following factors, either alone or in combination:

> Changes in loads (the magnitude of existing loads and/or geographical location of new loads)

> Changes in generation (particularly retirement of existing generators and development of new generators, although changed bidding behaviour can also be significant)

> Changes in network capability (for example retirement of network assets once they reach the end of their serviceable lives) and

> Changes in the service standards to be met.

We rely significantly on forecasting information published by AEMO and provided by the distribution businesses, and our directly connected customers, to understand changes in loads. We also take into account information published by AEMO to understand changes in generation and identify potential constraints regarding the capability of our network.

Forecasting is inherently uncertain. However, in recent years, it has become more difficult to confidently predict annual electricity consumption and maximum demand. Over this period, actual levels (not corrected for weather) for both have been below predictions. While it is likely that the future will differ from the forecasts provided by AEMO and the other parties referred to above we are nevertheless required to deliver a system capable of meeting those forecasts safely, securely, reliably and at efficient cost.

To help address the consequences of the uncertainty, we:

> Consider 'high loading', 'medium loading' and 'low loading' cases, which can be combinations of load patterns/magnitudes and generation patterns

> Undertake planning studies to consider the consequences of the retirement of major elements of our network.

The NSW region forecasts are provided by AEMO and those for bulk supply points by the distributors and customers directly connected at those locations.

2.2 Changes in loads

2.2.1 Introduction

Changes in how electricity is used can affect loads (the demand for electricity). While there is no clear demarcation between them, it can be useful to think of changes in loads being of two broad types. 'Organic' changes are the overall result of many small changes, either increases or decreases, across an area. 'Spot loads' are more localised, generally larger changes often associated with new developments or, in the case of load reductions, closure of a facility. The closure of the Kurri Kurri smelter in 2012 is a good example of a 'spot' reduction in load.

In recent years, the larger spot load increases have primarily been due to new or expanded mining activities. Two new mines in the Boggabri area, between Gunnedah and Narrabri, have recently been connected to our network. Mines in the Ulan area, which are supplied via Essential Energy's network from Beryl 132/66 kilovolt (kV) substation, are also expanding. There are also other prospective mining spot loads in the Gunnedah/Narrabri area and the Lithgow/Kandos area.

To understand the likely changes in loads, we look at forecast annual energy use for the NSW region and forecast maximum demands for the NSW region (including the ACT) and individual bulk supply points. The NSW region forecasts are provided by AEMO and those for bulk supply points, by the distributors and customers directly connected at those locations.

Energy use measures total energy throughput over a period of time in kilowatt hours (kWh) or, typically described in Gigawatt hours (GWh) at the transmission level. We are required to plan our network to be able to meet forecast maximum demand, not energy. However, energy forecasts can usefully reflect broader drivers that may impact the future use of the network. Those drivers include:

> Economic conditions — increasing levels of economic activity have traditionally been associated with higher levels of energy use (although this may be changing with a greater focus on energy efficiency)

> Government policies — for example, the Federal Government's Renewable Energy Target (RET) and energy efficiency programs

> Emerging technologies — for example, the ability for customers to self-generate electricity by using solar panels or store it using battery systems.

We reproduce AEMO's NSW regional energy forecast contained in its National Electricity Forecasting Report (NEFR) 2015. The NEFR considers three economic scenarios, broadly corresponding to high, medium and low growth. AEMO doesn't provide the likelihoods of its scenarios occurring. However, the medium scenario is usually considered to be the 'central' scenario as overall, it has lesser deviations from present trends in macro-economic variables than the high and low scenarios. As smaller deviations from present trends are more likely than larger deviations, the medium scenario is considered to be more likely than either the high or low scenarios. Consistent with this, AEMO has in the past referred to its medium scenario as the 'baseline' scenario.

Maximum demand is the highest total demand at a single point in time [1]. It is measured in watts, typically described in Megawatts (MW) at the transmission level. The forecasts we use for planning our network are based upon:

> The NSW region summer and winter maximum demand forecasts published by AEMO in its NEFR 2015[2] and

> The bulk supply point forecasts provided by the four NSW and ACT distribution businesses and our directly connected customers.

Details of AEMO's forecasts and the methodologies it uses are available from AEMO's website [3]. Note that the NEFR gives forecasts for 'operational'[4] quantities, which differ slightly from the 'native' values given here. The correlation between the two sets of values is given in the spreadsheet associated with the NEFR on the AEMO website.

1 For electricity networks, maximum demand is the highest average demand over a half hour period.

2 The responsibility for NSW region electricity forecasts was transferred from us to AEMO in 2012.

3 http://www.aemo.com.au/Electricity/Planning/Forecasting

4 'Operational' quantities: Operational consumption includes residential, commercial and large industrial consumption. It includes contributions from scheduled and semi-scheduled generation plus that from significant intermittent non-scheduled generators. It does not include contributions from small non-scheduled generation. 'Native' quantities include all of the above.

5 http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx

2.2.2 Forecast energy use

Table 2.1 and Figure 2.1 show the native annual energy usage projections for energy provided for the NSW region for each of AEMO's three scenarios. Details of the scenarios are given on the AEMO website[5].

The key inputs to AEMO's economic scenarios (namely high, medium and low) are assumptions on economic growth, population increase and future changes in electricity prices in the NSW region. Assumptions regarding these inputs drive the differences amongst the three economic scenarios.

The high economic scenario assumes high economic growth, high population growth but lower electricity prices. The low economic scenario, on the other hand, assumes lower economic growth, lower population increase and higher electricity prices.

The assumption of future growth rates for the variables (economic growth, population, electricity price) for the medium economic scenario lie between the high and low economic scenarios.

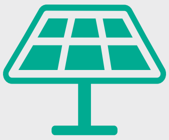
TABLE 2.1 – NSW region annual energy projections (GWh)

Actual		AEMO high	AEMO medium	AEMO low
2005/06	73,365			
2006/07	74,691			
2007/08	74,750			
2008/09	75,391			
2009/10	75,278			
2010/11	74,950			
2011/12	72,318			
2012/13	68,826			
2013/14	67,238			
2014/15 Est.	68,377			
2015/16		70,095	68,578	66,672
2016/17		71,056	69,177	67,052
2017/18		72,003	69,574	61,823
2018/19		73,004	70,013	59,043
2019/20		74,174	70,525	58,629
2020/21		75,458	71,432	58,399
2021/22		76,796	72,314	58,143
2022/23		78,183	73,233	57,961
2023/24		79,613	74,281	57,966
2024/25		81,043	75,300	58,062
Annual Average Growth Rate 2015/16 – 2024/25		**1.6%**	**1.0%**	**-1.5%**

Energy drivers

Economic conditions

Government policies



Emerging technologies

There has been a decline in NSW region energy consumption in the last five years. However, this trend may have reversed given that the energy consumption in 2014/15 is estimated to be 1.7% higher than that of the previous year.

In the short term (2015/16 to 2019/20), energy consumption in NSW is forecast to increase at an annual average rate of 0.7%. This increase is driven by an increase in residential and commercial consumption in response to lower electricity prices, and a slight increase in industrial consumption.

In the medium to long term (2015/16 to 2024/25), energy consumption is forecast to increase at an average annual rate of 1.0%, reflecting an increase in residential and commercial consumption.

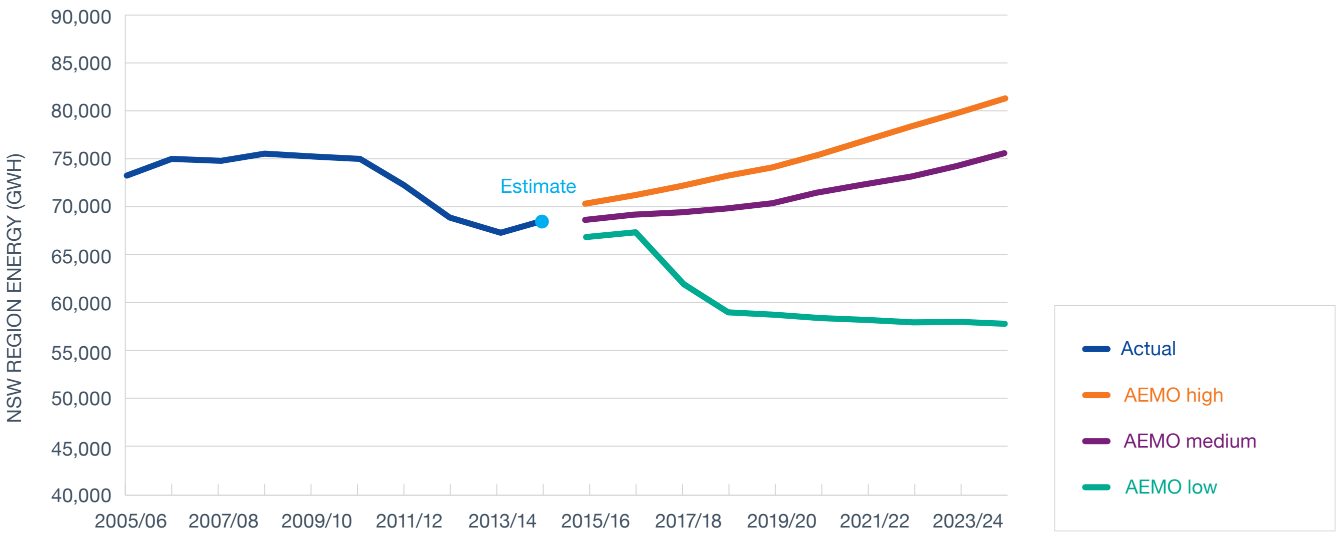
In the 2015 NEFR, AEMO advised that the energy forecasts are on average higher than last year. AEMO attributes this to the following:

> The NSW and ACT economy is expected to recover strongly growing by around 3% in 2014/15 in all economic scenarios. In the short-term, the recovery in the NSW and ACT economy is underpinned by strong dwelling investment and a recovery in business investment

> Electricity prices are expected to fall initially (from 2013/14 to 2014/15) due to the assumed removal of the carbon price. In the medium economic scenario, projected retail prices are expected to be relatively flat in real terms given the new AER draft determinations on network charges

> Industrial consumption in the long term is higher than those in the 2014 NEFR due to changes in AEMO's industrial forecasting methodology. In the 2014 NEFR, there was an assumption of gradually declining industrial production as mines depleted reserves and the economic outlook was less optimistic. Since then, industrial growth outlook seems to have recovered mainly driven by the depreciation of the Australian dollar against the United States dollar and higher aluminium prices. However, in the low economic scenario, Tomago Aluminium Smelter has been assumed to shut down in November 2017.

FIGURE 2.1 – NSW region energy projections [6]



6 AEMO has advised that the large drop in forecast energy consumption after 2017/18 for the AEMO Low Scenario reflects the assumption of the closure of the Tomago Aluminium Smelter plant in NSW after the expiry of its contract in response to less favourable economic conditions.

2.2.3 Forecast maximum demand

2.2.3.1 AEMO region forecast

AEMO's native summer and winter demand projections for the NSW region are given here on an as-generated basis[7]. Table 2.2 gives the historical summer and winter peak demands (not weather-corrected) and Table 2.3 shows the projections for a 10%, 50% and 90% probability of exceedance (POE) maximum demands over the next 10 years for each of the AEMO scenarios.

TABLE 2.2 – NSW region summer maximum demand projections (MW)

Actual		AEMO high			AEMO medium			AEMO low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2005/06	13,353									
2006/07	12,916									
2007/08	12,983									
2008/09	14,203									
2009/10	14,039									
2010/11	14,907									
2011/12	12,207									
2012/13	13,997									
2013/14	12,169									
2014/15	12,046									
2015/16		14,135	12,910	11,853	13,978	12,715	11,739	13,865	12,520	11,509
2016/17		14,385	13,058	12,003	14,086	12,824	11,803	13,897	12,552	11,588
2017/18		14,576	13,198	12,195	14,268	12,942	11,934	13,387	11,982	10,943
2018/19		14,730	13,375	12,349	14,457	13,039	12,009	12,979	11,542	10,581
2019/20		14,965	13,614	12,514	14,666	13,221	12,140	12,964	11,554	10,537
2020/21		15,288	13,845	12,760	14,887	13,405	12,301	12,862	11,517	10,493
2021/22		15,618	14,062	12,942	15,086	13,596	12,476	12,875	11,436	10,458
2022/23		15,947	14,345	13,182	15,219	13,750	12,643	12,943	11,486	10,456
2023/24		16,206	14,651	13,466	15,457	13,901	12,713	12,885	11,529	10,472
2024/25		16,563	14,942	13,728	15,756	14,096	13,021	13,016	11,536	10,522
Annual average growth rate 2015/16 – 2024/25		**1.8%**	**1.6%**	**1.6%**	**1.3%**	**1.2%**	**1.2%**	**-0.7%**	**-0.9%**	**-1.0%**

7 'As generated' maximum demand is measured at the point of generation (before 'power' leaves the generators to enter the transmission network).

TABLE 2.3 – NSW region winter maximum demand projections (MW)

Actual		AEMO high			AEMO medium			AEMO low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2006	13,116									
2007	13,917									
2008	14,339									
2009	13,128									
2010	13,493									
2011	13,052									
2012	12,302									
2013	11,773									
2014	11,667									
2015		13,056	12,457	11,973	13,027	12,397	11,908	12,779	12,221	11,736
2016		13,272	12,704	12,224	13,115	12,572	12,114	12,891	12,334	11,852
2017		13,502	12,913	12,422	13,287	12,750	12,272	13,007	12,420	11,939
2018		13,700	13,110	12,626	13,465	12,881	12,380	12,452	11,887	11,406
2019		13,953	13,331	12,845	13,636	13,027	12,544	12,088	11,546	11,049
2020		14,237	13,625	13,083	13,833	13,236	12,732	12,172	11,590	11,048
2021		14,514	13,874	13,351	14,054	13,463	12,877	12,156	11,566	11,036
2022		14,791	14,137	13,569	14,234	13,588	13,062	12,127	11,520	11,012
2023		15,127	14,447	13,895	14,434	13,811	13,258	12,137	11,563	11,058
2024		15,414	14,763	14,179	14,665	14,049	13,473	12,234	11,638	11,117
Annual average growth rate 2015/24		**1.9%**	**1.9%**	**1.9%**	**1.3%**	**1.4%**	**1.4%**	**-0.5%**	**-0.5%**	**-0.6%**

In the medium to long term (2015/16 to 2024/25), energy consumption is forecast to increase at an average annual rate of 1.0%, reflecting an increase in residential and commercial consumption.

Figure 2.2 shows the historical electricity maximum demand in summer to 2013/14 and the AEMO 10% and 50% POE demand projections. Figure 2.3 shows the corresponding data for winter.

FIGURE 2.2 – NSW region 2015 summer maximum demand projections and actual demands

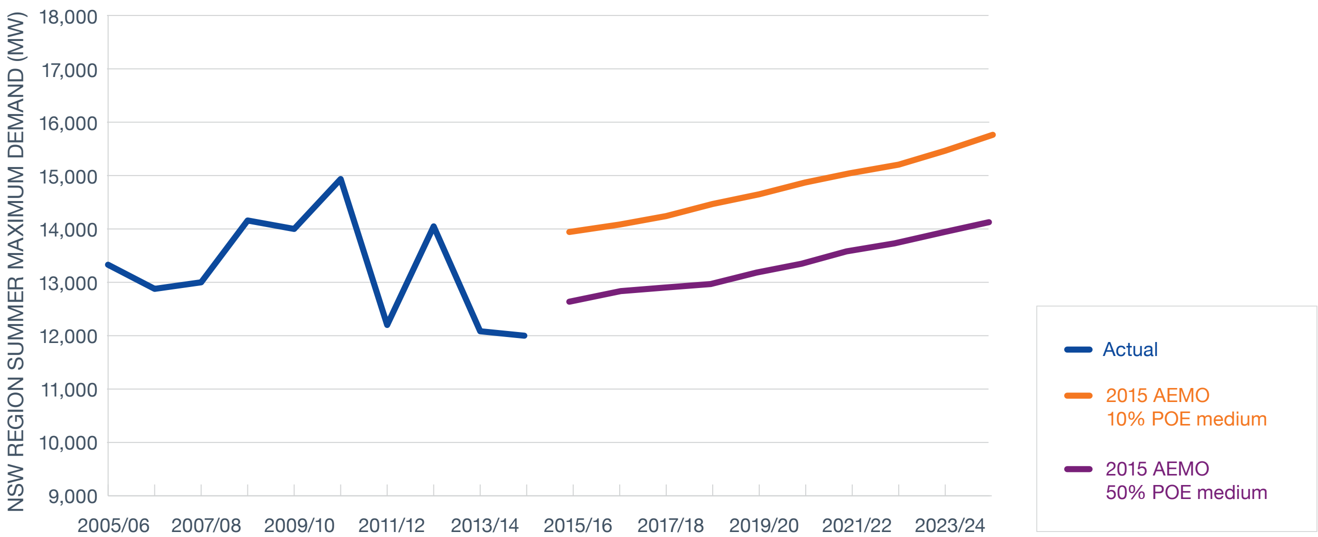


FIGURE 2.3 – NSW region 2015 winter maximum demand projections and actual demands

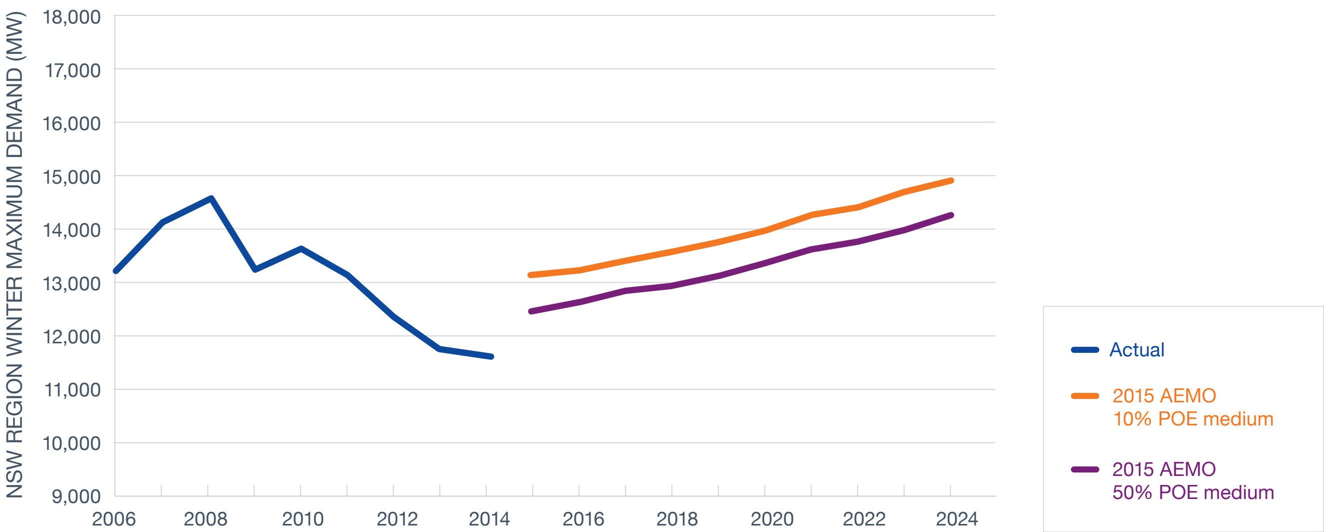


Figure 2.4 and Figure 2.5 show AEMO's forecasts produced in 2014 and 2015 for summer and winter maximum demands, respectively, together with actual (not weather and day-type corrected) maximum demands.

FIGURE 2.4 – AEMO's 2014 and 2015 summer maximum demand forecasts

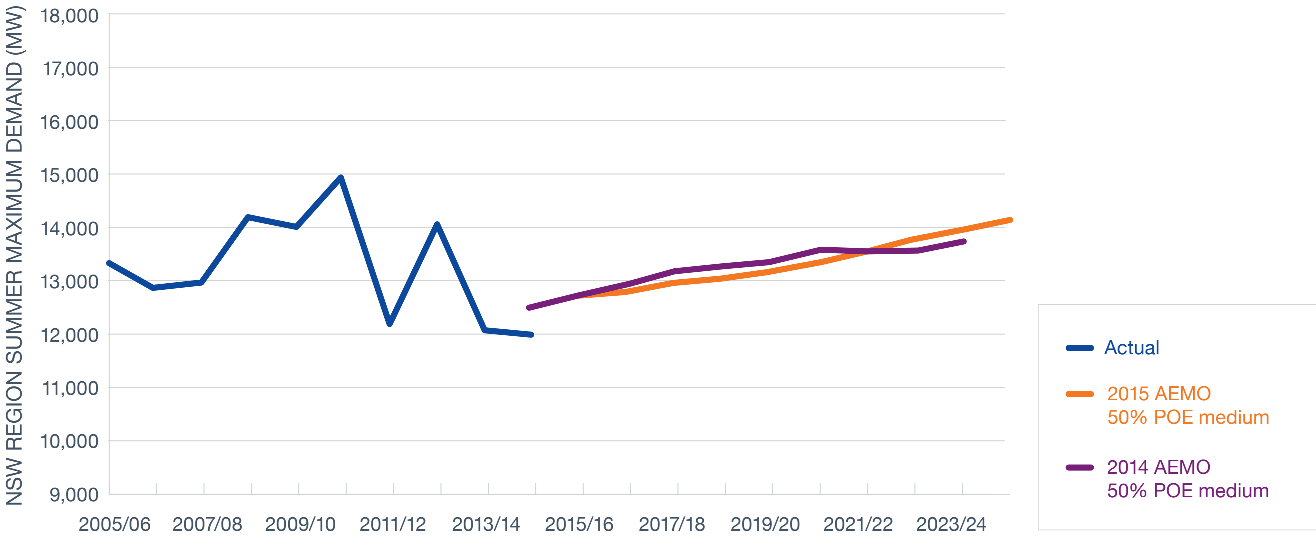
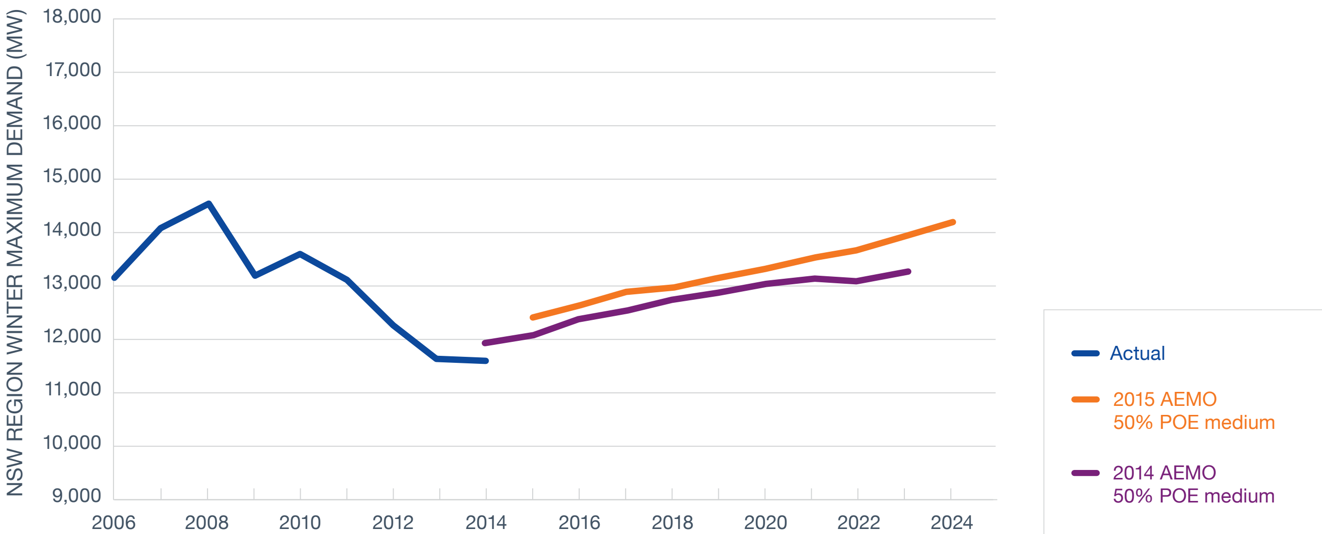


FIGURE 2.5 – AEMO's 2014 and 2015 winter maximum demand forecasts



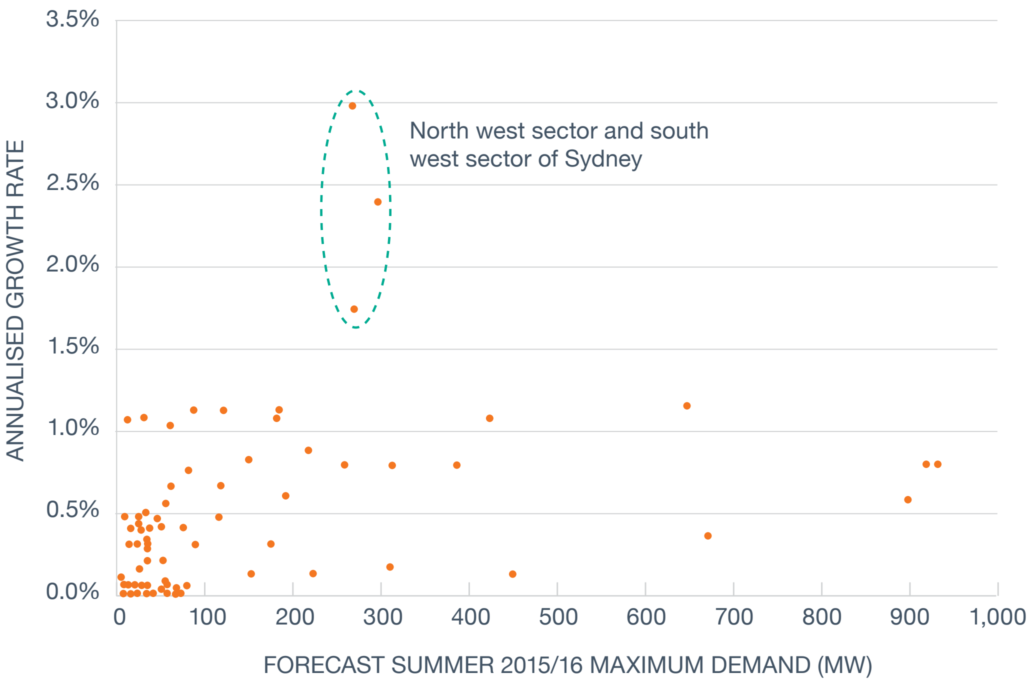
AEMO's 2015 summer forecasts are similar to those it produced in 2014. Those for winter are on average 2.4% above those it produced in 2014. The summer and winter forecasts are of a similar magnitude. In terms of network loadings, summer conditions are likely to be more onerous due to lower equipment ratings and generally worse power factors in summer.

2.2.3.2 Bulk supply point forecasts

Generally, the load changes at bulk supply points are 'organic'. However, where there are spot loads, they will be included in the relevant forecasts. The bulk supply point forecasts incorporate the 'local knowledge' of the distributors and directly connected customers. Macroeconomic data is generally not available at a bulk supply point level. Consequently, it is generally not possible to develop macro-economic models for individual bulk supply points and to produce forecasts for different economic scenarios. In practice, the bulk supply point forecasts are produced in a variety of ways, reflecting the amount of data available and the nature of the loads. These issues and how we have attempted to address them are discussed in the balance of this section.

Figure 2.6 and Figure 2.7 show the forecast growth rates, excluding the impact of spot loads, for bulk supply points serving the Distribution Network Service Providers (DNSPs)[8] in summer and winter. The growth rates are annualised. The detailed year on year forecasts of summer and winter maximum demands at the individual BSP level are set out in Appendix 3. Consistent with AEMO's forecasts for the NSW region, winter growth rates are generally higher than those for summer.

FIGURE 2.6 – Bulk supply point summer forecast growth rates



8 Our other directly connected customers, apart from the recently connected mines in the Boggabri area, are not expected to materially alter their operations.

The bulk supply points having the highest growth rates in summer or winter are those serving:

> The south west sector of Sydney (Macarthur and Liverpool)

> The north west sector of Sydney (Vineyard)

> The Central Coast (Tuggerah, Munmorah and Vales Point)

> The north eastern part of Sydney (Sydney East).

The capacities of the parts of our network supplying these areas of higher growth are expected to be adequate until beyond the ten year forecast period as the following developments have been completed in the past decade:

> Additional or larger transformers have been installed at Liverpool (2005), Tuggerah (2008), Sydney East (2013), Vales Point (2006) and Vineyard (2011)

> Macarthur substation was commissioned in 2009.

Overall, the only areas in which load growth is expected to lead to network limitations during the TAPR forecast period are the Gunnedah/Narrabri area and the Beryl/Mudgee area[9]. Options for addressing the Gunnedah/Narrabri area limitation is discussed in detail in Section 6.2.1 and Appendix 4.

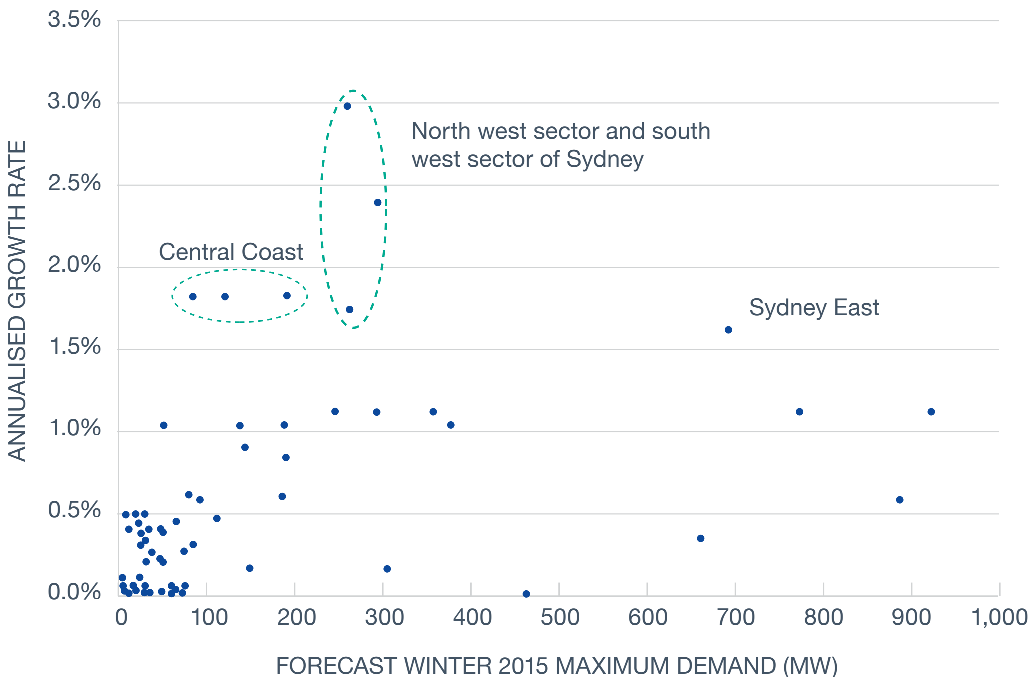
2.2.3.3 Comparing the AEMO and bulk supply point maximum demand forecasts

The bulk supply point forecasts are not produced on the same basis as the overall NSW projections produced by AEMO. For example:

> The underlying economic conditions may not be the same as those used by AEMO

> They may have been based on historical data with a timeframe different to that used by AEMO

FIGURE 2.7 – Bulk supply point winter forecast growth rates



9 The Gunnedah/Narrabri limitation relates to line ratings being exceeded. The Beryl/Mudgee limitation relates to the ability to maintain acceptable voltage levels.

> They indicate the likely maximum demand at that location, whenever it may occur, rather than the contribution to the overall NSW maximum demand

> They generally assume that only scheduled embedded generation is operating at the time of maximum demand.

Unlike the AEMO projections, none of the bulk supply point loads, by definition, include transmission losses or power used by generator auxiliaries. Despite this difference, the individual bulk supply point projections for each season can be aggregated to provide a useful point of comparison with the overall NSW seasonal demand projections.

We attempt to account for some of the aforementioned limitations by:

> Using 50% POE forecasts where they are available, and where they are not available, by assuming that individual bulk supply point projections are likely to have been based on enough historical data to converge towards an approximate 50% POE projection

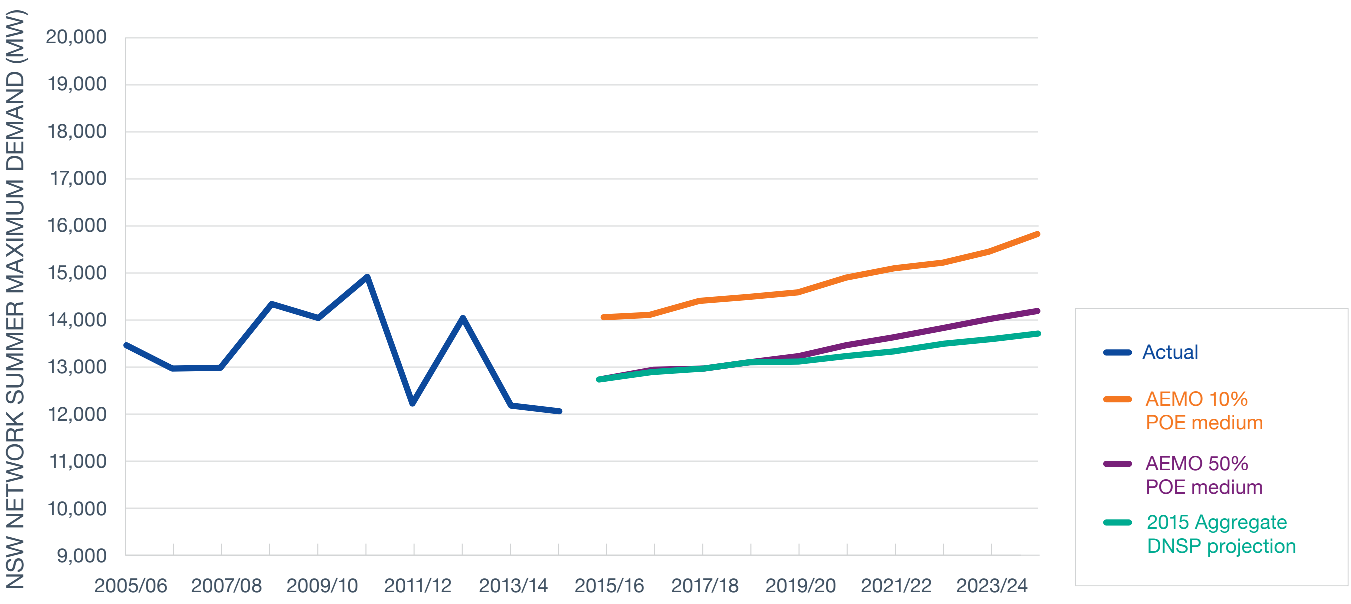
> 'Diversifying' individual bulk supply point projections to allow for the time diversity observed between historical local seasonal maximum demand and NSW maximum demand

> Adding forecast aggregate industrial loads not included in the bulk supply point forecasts

> Incorporating loss factors, which are also derived from historical observations, into the aggregate bulk supply point projections.

Figure 2.8 shows the comparison between the aggregated DNSP projections and AEMO's 10% POE and 50% POE medium scenario maximum demand projections for summer. Figure 2.9 shows the equivalent data for winter.

FIGURE 2.8 – AEMO and aggregate DNSP projections of NSW summer maximum demand



The aggregate bulk supply point forecasts and AEMO forecasts differ slightly, as expected for forecasts developed on different bases. Although the comparisons do not indicate which forecast is more accurate, they allow a high-level comparison to be made.

There is good alignment between the summer forecasts but the aggregate bulk supply point forecasts for winter are lower than AEMO's forecasts. Given that summer is the more onerous season for network capacity, due to lower equipment ratings and generally poorer power factors, the good alignment between the summer forecasts is comforting.

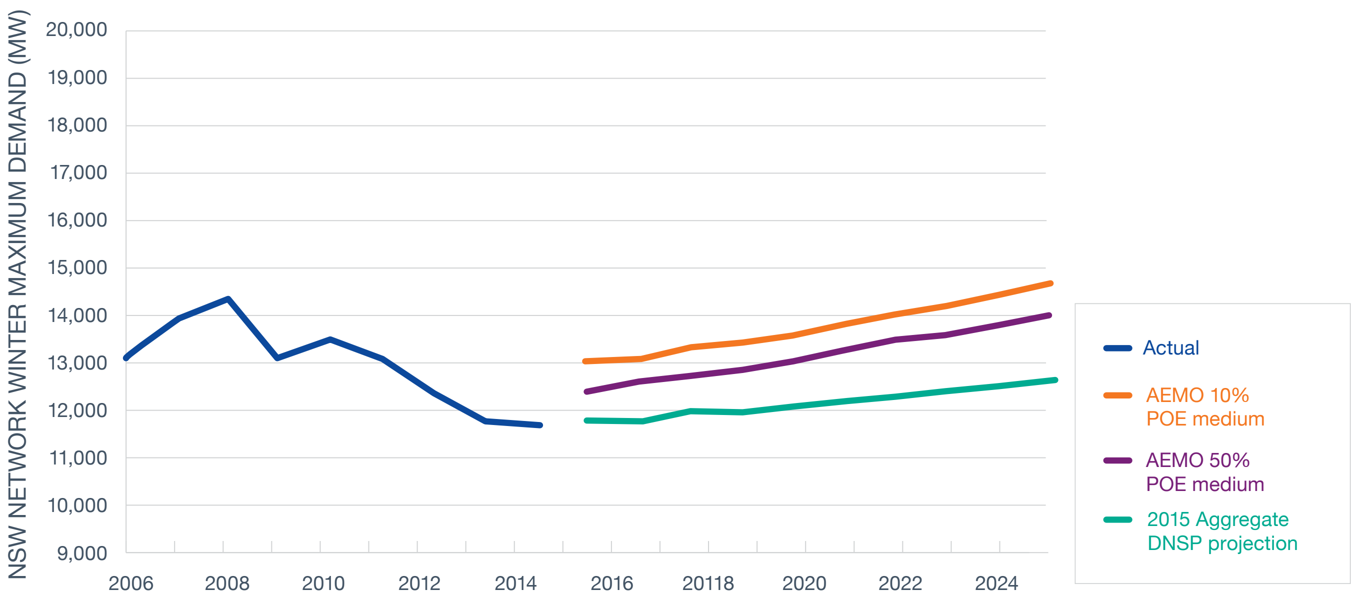
2.2.3.4 Management of load growth

As part of our normal planning processes, we consider non-network options to manage network limitations. Those options aim to reduce network loadings at critical times through modification of loads and/or embedded generation.

In a low growth environment there are fewer opportunities for non-network options to mitigate the effects of load growth. However, when such opportunities do arise, non-network options can be effective as the reductions in network loading which they give, can relieve limitations for longer than would have been the case in a higher growth environment.

Further information on non-network options is provided in Chapter 3. Also, to assist proponents of non-network options, Appendix 4 contains more detailed information on the Gunnedah/Narrabri area. As required by the NER, Section 6.5 provides information on our intention to issue requests for proposals for non-network options.

FIGURE 2.9 – AEMO and aggregate DNSP projections of NSW winter maximum demand



2.3 Changes in generation

To understand the changes in generation that have the potential to impact on our network's ability to meet our customers' needs, we take into account two documents published by AEMO. These are the 2014 ESOO and the National Transmission Network Development Plan (NTNDP) 2014. The NTNDP focuses on the opportunities and potential problems that the national transmission network serving the NEM (including much of our network) is likely to face over the next twenty years.

In recent years, five coal fired generators at Munmorah, Wallerawang and Redbank have been retired [10]. Any further retirements would be likely to increase loadings on parts of our network as generation from sources in other (probably more remote) locations is brought to the major load centres of Newcastle, Sydney and Wollongong.

AEMO's 2014 ESOO reported that, over the period to 2023/24, '… provided that existing generation remains available, new generation is not required to maintain system reliability under high, medium and low scenarios'. It also noted that within NSW there were 'publicly announced' generation proposals totalling over 8,500 MW of which wind projects comprised roughly half.

The key findings of NTNDP 2014 were that:

> Renewable generation, mostly wind generation, driven by the Large-Scale Renewable Energy Target (LRET [11]) will dominate the generation mix to 2020

> After 2020, it is expected that no further investment in generation is required to meet projected maximum demand until around 2030

> Coal fired generation will continue to provide the bulk of energy generation but is expected to reduce by about 2,000 MW in NSW.

Table 2.4 summarises the forecast changes in generation mix.

In June 2015, the Federal Government revised the current LRET target down from 41,000 GWh to 33,000 GWh by 2020. At this point, it is unclear the extent to which this policy change will impact on the above and future renewable energy generation projects.

The most prospective wind resources tend to be along the Great Dividing Range in Yass/Bungendore/Taralga area in the south of the state and the Glen Innes/Inverell/Tenterfield area in the north. These areas are remote from the major load centres of Newcastle, Sydney and Wollongong. The development of generation there would be likely to increase the loading on our network in those areas and between those areas and the major load centres.

Further information is provided in Section 6.3.7 which covers Snowy – Sydney capacity and Section 6.3.1 on the recent consultation process for uprating QNI capacity [12], the conclusion of which was to continue to monitor the need for possible additional capacity.

We have recently proposed the construction of renewable energy hubs to facilitate the connection of these clusters of prospective wind generators to our backbone network, at the lowest overall cost. Potentially, each hub could include technology designed to address the intermittency issues associated with wind generation. Development of the hubs would require close interaction with wind generation proponents as well as support from government and renewable energy agencies.

The 2014 NTNDP identified less need for additional capacity on single interconnectors due to the significant reduction in the growth of national electricity demand since 2010 and the then expected, suppressed growth in the future economic outlook.

TABLE 2.4 – NTNDP major generation amendments

Fuel type	Generation capacity increase (MW)	Generation capacity reduction (MW)	Anticipated timing
Wind	2,000	-	By 2020/21
Black Coal	-	-2,015	By 2018/19
Gas	-	-178	By 2021/22

10 These five generators had a combined capacity of approximately 2,000 MW. Prior to their retirement there were 21 major coal fired generators in NSW, having a combined capacity of approximately 12,000 MW.

11 Large-Scale Renewable Energy Target: A target set by the Australian Government which provides financial incentives for renewable energy generation.

12 QNI RIT-T can be found at http://www.transgrid.com.au/network/consultations/Pages/CurrentConsultations.aspx

We have recently proposed the construction of renewable energy hubs to facilitate the connection of clusters of prospective wind generators to our backbone network at the lowest overall cost.

2.4 Changes in network capability

This section discusses three further matters related to potential limitations on the existing network:

- Constraints — either reliability or market benefits types and how they have been/ may be alleviated
- Network system control and ancillary services (NSCAS) needs
- Asset management — how we manage our assets can have an impact on network capability.

2.4.1 Constraints

Constraints are of two types: those where relieving them can bring benefits to customers by providing for greater wholesale market competition, and those where the ability to meet reliability or power quality requirements may be at risk.

Regarding the former, we monitor network limitations which have bound or have been close to binding in the past (refer to Appendix 6). That analysis shows the impact of changed generator behaviour in preventing particular constraints from binding. A figure showing this as a 'spike' in the time spent at flows just below a constraint binding, appears in Appendix 6.

The NTNDP 2014 identified two potential market benefits constraints under the most likely development scenarios. These are the transmission network capacities between Liddell and Tamworth (constraint M-N1) and between Yass/ Canberra and the Sydney Area (constraint M-N2 concerning the Snowy-Sydney transmission system). These possible constraints are discussed in Sections 6.3.3 and 6.3.7, respectively.

The NTNDP 2014 identified one transmission reliability constraint occurring within five years. This is an overload of the Sydney South – Beaconsfield West 330 kilovolt (kV) cable for an outage of the Sydney South – Haymarket 330 kV. (L-N1). We are addressing the constraint for supplying the Sydney metropolitan area (L–N1). Details are given in Section 6.3.5.

A number of other constraints identified in the NTNDP 2014 either have already been, or are committed to being, addressed by our projects. Those projects are summarised in Table 2.5.

TABLE 2.5 – NTNDP comparison to TAPR 2015

Category	Ref	Project	TAPR 2015
Committed main transmission projects	C–N1	Second supply to ACT > Establish a new 330 kV switching substation at Wallaroo > Form 330 kV circuits from Yass to Wallaroo and from Wallaroo to Canberra > Construct a short section of 330 kV line from Wallaroo to the route of the Canberra – Williamsdale 330 kV line > Connect the new line at Wallaroo and to the Canberra – Williamsdale 330 kV line. This project relates to our licence obligations to provide a second point of supply to the ACT (for reliability purposes).	Section 5.4.1 (Now Stockdill)
	C–N2	Implement an optimised combination of SCADA and protection based multiple contingency schemes to protect the NSW power system from potential cascading failure. This project is for system security.	Section 6.2.10
	C–N3	Replace circuit breakers of 27 shunt capacitor banks with point-on-wave closing control. This project relates to quality of supply.	Section 5.3.1

Line loading can provide a leading indicator of future constraints. While loads within NSW have moderated in recent years, parts of our network remain heavily loaded. Appendix 5 shows the utilisation of our transmission lines relative to their contingency ratings during the period from May 2014 to March 2015. During that period, approximately 10% of the transmission lines in our network would have been loaded at or above [13] their capacity, should a critical outage have occurred. This is broadly consistent with a similar analysis reported in the TAPR 2014, for the period from May 2013 to April 2014 which showed approximately 15% of our lines in this category. The 330 kV lines north from Liddell were in this heavily loaded category in both these analyses.

2.4.2 NSCAS needs

NSCAS are ancillary services procured in order to prevent adverse security of the power system or negatively affect reliability. Under the NER, AEMO identifies NSCAS needs in NSW and is required to procure NSCAS services to address them. AEMO effectively has a backup role in terms of procuring NSCAS, where we are unable to do so.

The NTNDP 2014 did not identify any current NSCAS needs. Ongoing NSCAS arrangements in NSW are adequate for managing the potential voltage control issue at Kangaroo Valley and in the Snowy Mountains area. The NSCAS assessment in NTNDP 2014 did not identify any further means of maximising market benefits for maintaining or improving power transmission capability.

The potential gap identified in the NSCAS assessment for alleviating the constraint on voltage stability between NSW and Victoria has been managed through reactive power support procured through voltage control ancillary service (VCAS), a type of NSCAS, between AEMO and a generator. Although the main purpose of this agreement is to maintain system security, it also provides net market benefits before a more economical solution is identified and implemented. AEMO contracted 800 megavolt amperes reactive (MVAr [14]) absorbing VCAS from us, primarily using new network assets including reactors at Murray switching station and the Yass substation. Provision of a full VCAS service under this agreement runs from 31 March 2014 to 30 June 2019.

TransGrid and AEMO have jointly investigated this potential gap identified in the NSCAS assessment as follows:

> Analysing the performance of the NSW to Victoria voltage stability constraint equation and usage under the contract between April 2014 and March 2015

> Assessing the effect of the newly installed capacitor banks at Canberra and Yass on reducing the gap.

The investigation found that:

> We have installed additional capacitor banks at Canberra and Yass since August 2014 that can increase the stability limit of the NSW to Victoria voltage, and therefore reduce the gap

> There were periods within the past 12 months when using the contract to address the gap delivered net market benefits, including some periods after the commissioning of our new capacitor banks

> In the future, dynamic reactive power support will likely be required to address the gaps in the NSCAS assessment, due to the coexistence of voltage stability issues and high voltage issues during the periods of high levels of transfer from NSW to Victoria.

Based on the findings of the investigation, we have decided not to commit to a plan to address the gap. We will continue to monitor the NSW to Victoria voltage stability constraint and review the decision as necessary.

13 For parts of our network where loadings can be changed by re-dispatching generation, short time line ratings (which exceed the contingency ratings) are used. Where this has occurred, the analysis shows utilisations above 100% of the line contingency rating.

14 Mega Volt Amp reactive is a unit of reactive power.

2.4.3 Asset management

As part of our asset management processes we monitor the condition of our major items of equipment commensurate with their value, time to replace and their criticality to the network. In some cases where its loading may adversely affect the remaining life of the asset, its rating may be reduced. An example of this is the recent reduction in the rating of the 41 Sydney South – Beaconsfield West cable, to reflect degradation of the cable backfill material and ground temperatures greater than those used in the original design. Section 6.2.3 sets out additional information on works proposed to better define the extent of degradation of the backfill which will inform development of options to manage it.

Where major items of plant are approaching the end of their serviceable lives, the option of retiring them without replacing them is considered. While this is generally not possible due to the magnitude of the associated change in network capacity, there are some cases where it is.

Examples include:

> Retirement of a capacitor at Wellington. The capacitor was originally installed to defer the construction of a transmission line. The eventual construction of the transmission line removed the need to replace the capacitor at the end of its life

> The closure of the Kurri Kurri smelter has allowed one of the transformers at Newcastle substation, which was approaching the end of its serviceable life, to not be replaced

> The establishment of Williamsdale substation to meet the requirements of the ACT government will allow one of the transformers at Canberra substation to not be replaced, once it reaches the end of its serviceable life

> The lower forecasts for loads in the Sydney inner metropolitan area will allow one of the two 330/132 kV transformers at Beaconsfield, which are approaching the end of their serviceable lives, to not be replaced. Refer to Section 6.3.5.

The majority of our network has a 'mesh' configuration, with substations being connected, directly or indirectly, by multiple transmission lines. While this increases the resilience of our network, it makes the 'connectivity' provided by substation busbars very important, resulting in limited opportunities to avoid replacing busbars when they reach the end of their serviceable lives. A similar situation applies to substation secondary systems [15] which are essential for the substations to function.

We are also investigating the benefits of a number of strategic property acquisitions to accommodate future end-of-life asset replacements and network developments. One example of this is the acquisition of a property on Riley Street in Surry Hills from Ausgrid, to cater for the end of life replacement of the Haymarket substation. Refer to Section 5.3.1.

Information on our asset management process is included in Chapter 4. Information on condition based replacement projects is included in Chapters 5 and 6 and Appendix 2.

15 These include protection systems, control systems and communications facilities which are essential for substations to function safely and in an orderly manner.

2.5 Changes in service standards

Changes in service standards can arise from changes in technical standards or in reliability criteria. At this stage, we are not aware of any changes to the technical standards which may change the service standards we are required to meet.

Reliability criteria can be thought of as a description of the consequences that a society is prepared to insure against. There are moves to harmonise the 'expression and reporting of reliability' across the NEM. As part of this, it is possible that the reliability criteria applying to our network, and to which we must plan, will change.

2.6 Summary of factors affecting network capability

Loads within NSW have generally moderated over the past several years. This has resulted in the times at which network limitations are expected to arise, being further into the future. Apart from some locations with spot loads, such as the Beryl/Mudgee area and the Gunnedah/Narrabri area, load growth is presently not a major factor in the onset of network limitations. Should the reliability standards our network must meet be relaxed, load growth would be a less important factor for longer.

At present, the main contributor to known future network limitations, is the retirement of major transmission assets at the end of their serviceable lives, although the retirement of existing generators and the establishment of new generators have the potential to be major contributors.

In terms of the limitations described in Chapters 5 and 6, the most important are:

> Those relating to reliability of supply (the Beryl/Mudgee area and the Gunnedah/Narrabri area)

> Those relating to the possible retirement of major generation (the Snowy to Sydney network and the network north of Liddell). The impact of any retirements would depend on how much generation is retired and it's location. For smaller amounts the impacts may be just on generation dispatch. For larger amounts, supply reliability could be impacted

> Those relating to the retirement of major substations at the end of their serviceable lives. These substations generally perform a pivotal role in 'connecting' multiple transmission lines, with that connectivity being essential for our meshed network to function

> Those relating to the retirement of secondary systems at the end of their serviceable lives, as those systems are essential for substations to function.

Chapter 3

Non-network solutions

- Non-network solutions can offer alternatives to expanding our network and we consider such options whenever we face an investment need. This is because they can defer or avoid capital costs. Such solutions can also be tailored to local needs as well as allow us to adapt quickly to changing operating conditions
- Currently, there appears to be only limited options for using non-network solutions within the ten year TAPR planning horizon
- We will continue to trial new demand management technologies and collaborate with market participants. This is because developing the demand management market is an important way to provide for efficient, long term outcomes for customers.

3.1 Introduction

Non-network solutions can provide value to customers. This reflects the fact that investment in transmission networks is typically 'lumpy'. That is, augmenting the network normally involves the addition of major pieces of equipment that provide material changes in capacity. Where smaller increments are required, non-network solutions can prove cost effective in deferring or even avoiding network investment. This is particularly so where load growth is modest, as is currently forecast to be the case. The cost effectiveness of non-network solutions also partly reflects the fact that, typically, they can be more finely tailored to address local needs.

We have procured demand management in this way twice in the recent past. Approximately 350 Megawatts (MW) of network support was obtained for the summer of 2008/09 in the Newcastle–Sydney–Wollongong area, and joint planning with Ausgrid resulted in network support to cover 40 MW for operational risk mitigation over the summer of 2012/13 in the Sydney inner metropolitan area.

Under the most recent forecast, the network supplying the Sydney inner metropolitan area is expected to be adequate until the mid-2020s. Refer to Section 6.3.5.

There are two broad kinds of non-network solutions:

> Load curtailment where the consumer agrees to reduce usage during times of high demand [1] in exchange for a financial benefit. Typically, high demands occur on the afternoons of hot summer days and the evenings of cold winter days

> On-site or local generation and storage: Consumers generate their own electricity to offset their impact on the network and possibly provide supply for other consumers during peak times. Grid scale connections of generation and storage can also achieve an equivalent outcome.

The NER stipulates that we and other network businesses must consider non-network options when proposing to augment the existing transmission network and where the cost of a credible option exceeds $5 million. Such investments are subject to the RIT-T public consultation process described in Chapter 1.

1 There is an important distinction between demand management and energy efficiency solutions. Demand management is about temporarily reducing demand for electricity. Energy efficiency is about permanently avoiding (or removing) that demand. While supportive of energy efficiency, TransGrid's role is to minimise the long run costs of delivering the electricity that customers want. Shifting the timing of that demand to minimise those costs is part of this role. Permanently reducing electricity demand is not necessarily part of this role.

3.2 Current opportunities

As noted in the previous chapter, NSW and ACT electricity demand is expected to increase only modestly during the ten year planning horizon covered by this TAPR. This means that there are also likely to be relatively few opportunities to implement non-network solutions.

Chapter 6 identifies where there are likely to be network constraints. Where relevant, the feasibility of a non-network solution deferring capital expenditure in the network is discussed. Appendix 2 is a table of network asset replacement needs, which also discusses the feasibility of non-network solutions.

3.3 The importance of demand management

We are strongly committed to exploring and implementing non-network alternatives, wherever it is technically feasible and cost efficient to do so. This commitment is also important because we expect that the way Australians generate, supply and use electricity, will significantly evolve over the longer term. Straightforward continuing growth can no longer be assumed and networks must become more flexible and scalable to be able to provide the services that customers want at efficient prices.

We see the integration of non-network solutions as an important part of how we will conduct our core business in the future. Historically, transmission networks have procured non-network solutions in the form of generator support contracts. More recently, as noted above, we have been able to procure load reduction through financial agreements with our customers, either contracting directly or via a third party known as a demand response aggregator. Because of the magnitude of desired demand reductions at the transmission level, these arrangements generally involve larger directly connected customers. However, demand management can also be effective when aggregating a larger number of smaller customers. We intend to explore ways to both leverage that greater scale and integrate it into operational timeframes.

An independent market research company found that more than 80% of consumers supported this kind of investment. The research report noted that 'Overall participants felt that potential benefits to both the future of the electricity system and, for some, the environment as well, could be well worth an investment that most regarded as trivial.' (Newgate Research, 2013).

The Australian market for demand management solutions is relatively new. Policy makers have recognised that network businesses, such as TransGrid, have a role in helping to grow that market to ensure that suitable cost effective non-network opportunities are available. This policy intent has been given effect through the Demand Management Innovation Allowance. This is funding that the AER permits the networks to recover for undertaking projects that are likely to expand the range and cost effectiveness of demand management alternatives in the future.

The amount of this funding is relatively limited, particularly in terms of the larger scale projects appropriate for transmission networks. We are therefore exploring mechanisms, such as research agreements and joint funding arrangements, to ensure that our customers are able to derive the benefits of robust demand management alternatives when the needs arise.

We are strongly committed to exploring and implementing non-network alternatives wherever it is technically feasible and cost efficient to do so.

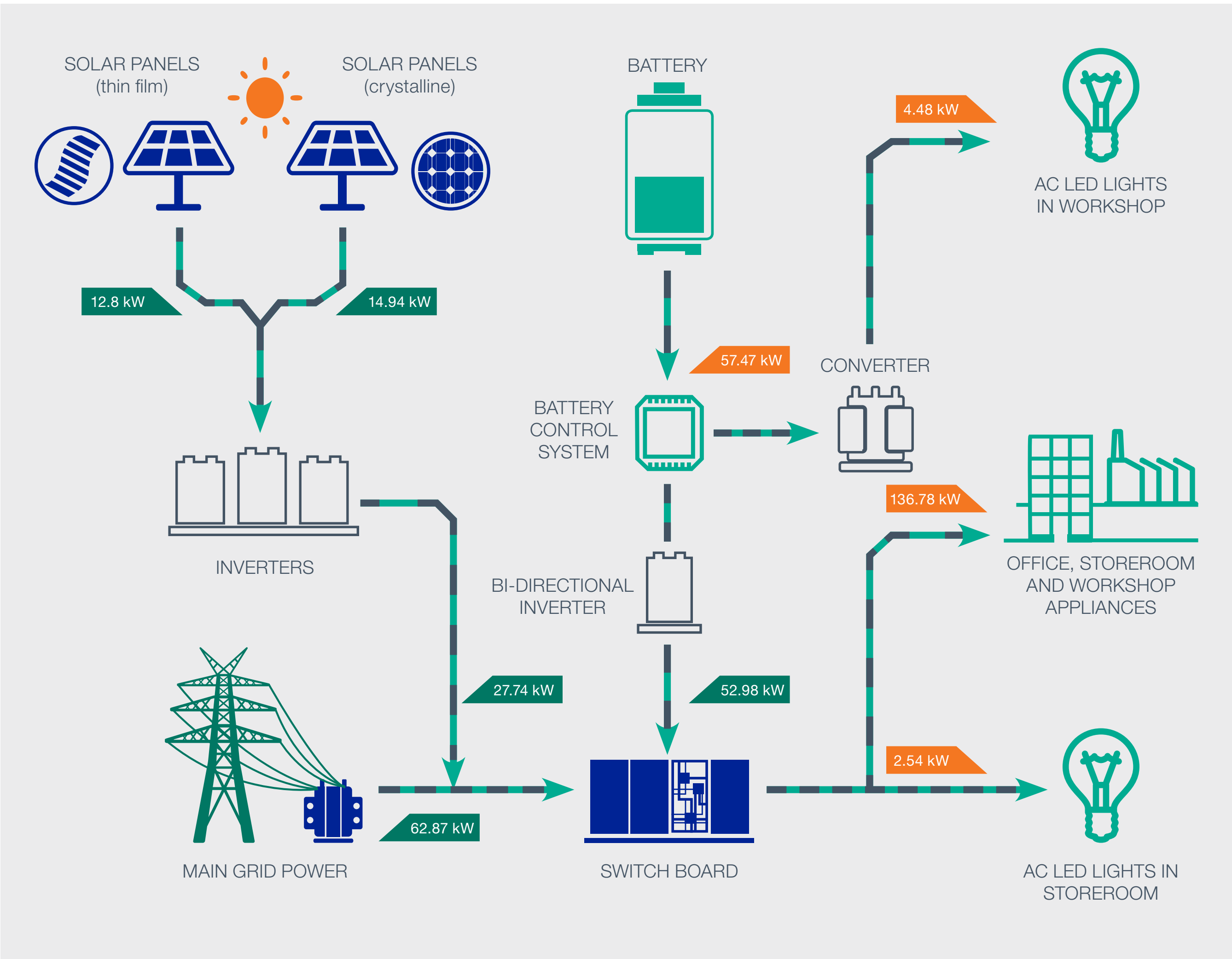
3.3.1 Recent innovation activities

The four key demand management innovation activities undertaken by us in 2014 are:

> Commissioning RMIT University to undertake research into co-managing home energy demand. The project sought to determine how residential electricity consumers conceptualise peak demand, how they respond to various demand management programs enabled by smart meters and smart grids, and what types of demand management incentives are most and least effective. RMIT published[2] its final project report in the middle of 2014. Through this research, we have aimed to enhance understanding of household demand, and to provide a firmer basis for future demand management initiatives. The main findings can be summarised as:

- Households are confused about the overall structure of the electricity system and are distrustful of a system they don't understand
- Householders receive significant misinformation from the media which

FIGURE 3.1 – Live monitor for the iDemand system



contributes to feelings of anxiety and mistrust

- When householders understand peak demand issues, they demonstrate a willingness to participate in demand management initiatives
- Customers are interested in the broader benefits of reducing peak demand
- Dynamic peak pricing achieves the highest peak demand reduction.

> In September 2014, hosting a Demand Management Innovation Forum to facilitate collaboration on emerging demand management needs and innovation projects. Participants included representatives from AEMO, the Australian Energy Market Commission (AEMC), demand response aggregators, major electricity consumers, network businesses and academics

> Commissioning the iDemand management system. iDemand facilitates research into demand management, and promotes development of, and education in, demand management in NSW. The system was commissioned at our Sydney West site in October 2014 and has the target of reducing electrical demand by 50%. The iDemand system consists of a 400 kilowatt-hour energy storage system, almost 100 kilowatts of solar generation capacity (including some thin film technology and some polycrystalline panels), energy efficient LED lighting, and a web portal that provides iDemand's live status and historical data for download. The focus is now to use the system to achieve definitive results in grid innovation. We are in discussion with several academic and industry bodies about formalising research agreements. Two distinct streams of research are emerging from these discussions. To find out more about iDemand visit: www.transgrid.com.au/iDemand

> Network Opportunity Maps — we are a partner in the Institute of Sustainable Futures at the University of Technology Sydney's Network Opportunity Maps project, funded by ARENA. The purpose of this project is to develop online maps of network constraints that are freely available and updated annually. The maps will include planned investment, the potential value of renewable energy, and demand management and decentralised energy generation resources. In this way, the maps will serve as an indicator of the initiatives for deferring or avoiding network investment across the NEM. These maps will facilitate initiatives in demand management by showing where expenditure is being proposed on the network. They will provide an estimate of the magnitude of demand management, distributed energy or renewable energy required, to defer or avoid network investment. In this way, the maps will increase the range of demand management alternatives in an area that experiences capacity constraint. Sample maps are now being prepared, and the maps will be released to the public in late 2015.

3.3.2 Future innovation activities

As part of its revenue proposal to the AER, we requested an allowance to continue demand management innovation in the 2014/15 to 2017/18 regulatory control period. In response, the Regulator allowed $1 million per annum for this purpose.

We are currently planning to use this allowance to target activities in three broad key areas:

> **Collaboration:** to improve consumer understanding of demand management, capture synergies across different industry participants' activities and to reduce regulatory barriers.

> **Market understanding and development:** to achieve greater understanding of the demand management market in NSW and promote information flows between relevant parties.

> **Technology trialling:** to overcome practical barriers to the application of demand management tools and technologies, both in the market and in integrating demand management into our regular business operations and practices.

2 The report is available at: http://www.transgrid.com.au/network/nsdm/Pages/default.aspx

Chapter 4

Asset management

- As demand for electricity in the NSW region is expected to increase only moderately over the planning horizon, we expect to spend significantly less than we have in the past augmenting the network and instead place a greater focus on maximising the value to customers from our existing assets
- A growing number of our assets are approaching the end of their serviceable lives, increasing the importance of providing for their orderly retirement
- Our asset management system allows us to address the above issues consistent with international best practice standards (ISO55001)
- The AER's revenue determination is likely to impact our ability to deliver services safely, securely and reliably, increasing the associated risks, including risks to customer service levels
- We are carefully managing our expenditure to minimise those risks. This includes re-scoping and prioritising key programs such as dynamic line ratings and low span remediation works.

4.1 Maximising the value of our existing assets

As demand for electricity in the NSW region is expected to increase only moderately over the planning horizon, we expect to spend significantly less augmenting the network and instead place a greater emphasis on maximising the value to customers out of our existing assets.

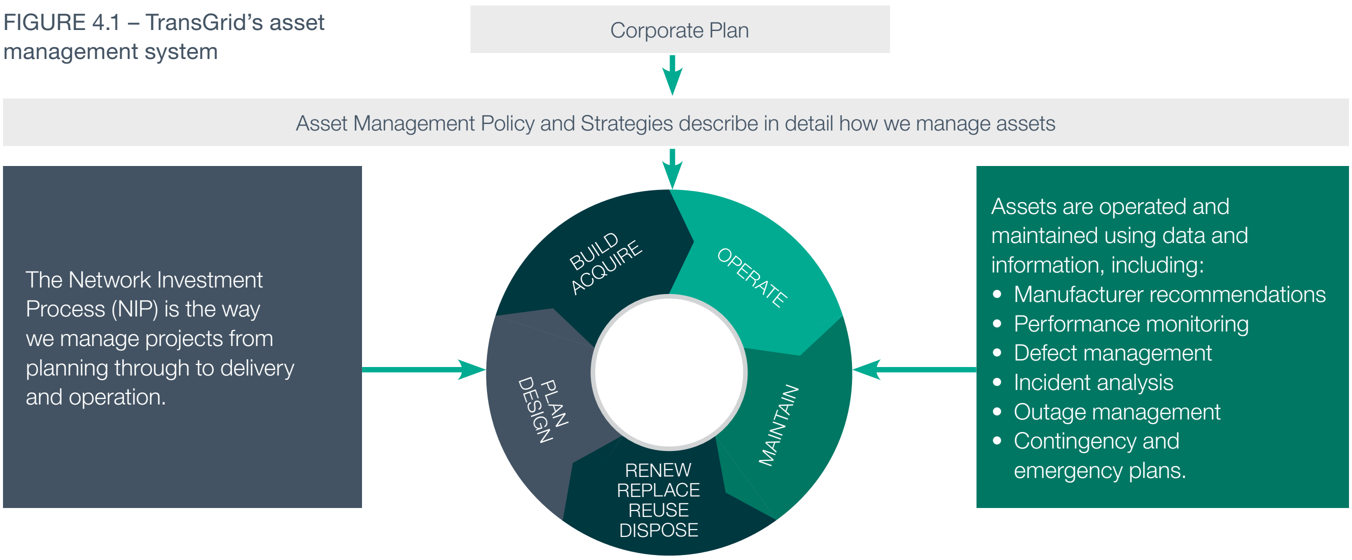
Part of this involves reviewing the configuration of our network to ensure that each element continues to be utilised effectively. In addition, many of the assets, such as substations, transmission lines and underground cables, that were built in the 1950s and 1960s and are nearing the end of their serviceable lives. Further information regarding the challenges that arise from the current condition of our network assets is provided in Section 4.3 below. Thus, we are also increasingly focused on how best to maintain, replace and refurbish those assets in a way that ensures the safe, secure and reliable delivery of services to our customers and consumers.

4.2 Our asset management system

Our asset management system provides a framework for effectively managing our transmission network assets over their complete life cycle. Assets are managed from the planning stage through to operation and then to decommissioning. The service life of an asset is extended, where appropriate, with components being replaced as needed. Our Asset Renewal Program comprises the most economic combination of replacement and refurbishment options. Our approach to asset management encompasses our jurisdictional requirements and obligations to meet the service level requirements of our customers, consumers and other stakeholders.

The asset management landscape has undergone a significant shift with the release of the new ISO 55001 asset management standard last year. In preparation for assessment against the new standard, we enhanced our asset management framework through alignment to internationally recognised asset management standards. As part of this process we improved our asset management strategy by strengthening our decision making criteria, with a particular focus on risk-based decision making. Our system was independently reviewed against the standard and we received certification in November 2014. A high level overview of our asset management system is set out in Figure 4.1.

FIGURE 4.1 – TransGrid's asset management system



4.3 Current condition of network assets

The following sections outline the key factors that influence how the major components of TransGrid's transmission network (substations, lines, cables and secondary systems) are managed.

4.3.1 Substations

The overall condition of TransGrid's substations can be influenced in a number of ways. For example:

> Substations designed in the past were built to less stringent safety and environmental standards, potentially resulting in installations breaching current requirements

> The technology used in substations advances with time, resulting in expertise and support for older technologies no longer being available

> The demands made on a substation may change over time, causing the design to be compromised to meet load requirements that were not originally anticipated

> The basic substation construction, or its components, can deteriorate with age.

Substations contain a range of electronic and mechanical components with widely differing service lives. As electronic components have a service life of about 15 years, such components integrated into high-voltage equipment can limit the life of the primary plant. Electronic technologies change rapidly and support for electronic components is not usually available after 10 years.

Our substations are located throughout NSW in climatic conditions that range from coastal to rural, sub-tropical to dry-desert, sea level to high altitude, and corrosive locations to stable atmospheres. Substations in coastal areas are more prone to accelerated deterioration.

4.3.2 Transmission lines

Transmission lines are categorised by nominal operating voltage and structure type, as follows:

> The voltage of a transmission line gives an indication of the robustness of the design, with transmission lines of a higher operating voltage generally being more robust in design

> The structure type gives an indication of the type of problem that can arise. Generally, transmission lines operating at above 132 kilovolt (kV) are carried by steel lattice towers, where transmission lines operating at 132 kV or below are predominantly carried by poles made from wood, concrete or steel.

Transmission line components at all voltage levels can be broken down into the three main elements: fittings, electrical conductors and support structures.

A common compliance issue with transmission lines relates to the clearance between the electrical conductors and the ground. The minimum clearance is stipulated in AS/NZS 7000:2010 Overhead Line Design – Detailed Procedures.

Transmission lines may breach clearance requirements as they age for the following reasons:

> Design temperatures – the metallic conductors expand and contract as they heat and cool, causing them to sag. Transmission lines are generally designed for a maximum operating temperature that accommodates the sag in the conductor while maintaining ground clearances. If the operating temperature exceeds the design temperature, the conductor may sag lower than the minimum clearance requirements. This is a common problem with older transmission lines that were constructed to British standards, which are based on lower operating temperatures

> Conductor creep – when a transmission line is constructed, the electrical conductors are tensioned at a level that will maintain minimum ground clearance. As the electrical conductors age, they stretch under this tension, causing them to sag. The conductor may breach the ground clearance if the creep exceeds the amount allowed for in the design

> Vegetation growth – transmission line routes require ongoing maintenance to prevent the vegetation from growing within the minimum clearances.

The most common problem affecting transmission lines in coastal and high-pollution areas is corrosion. Corrosion affects all metals, including the steel towers and fittings, and the aluminium conductors. Corroded structures can be considered for remediation, but corroded fittings and conductors often cannot be restored, meaning that end-of-life replacement is the only option if the line is to remain in service.

Managing transmission lines operating in corrosive environments involves replacing the fittings, and cleaning and repainting the structures before any of the structural members have severely deteriorated. These measures can delay the corrosion and extend the life of the structure. Where the remaining service life or structural integrity does not justify remediation, the structures are replaced as they reach the end of their service life.

4.3.3 Underground cables

Current and emerging issues concerning underground cables are:

- Cable overheating — degradation of the thermal bedding surrounding an underground cable results in the heat dissipation being significantly lower than the original design value. The cable may then operate at temperatures above its design maximum operating temperature, causing the insulation to deteriorate and the probability of a failure to increase
- Cable joint failure — the movement of the electrical conductors in a cable (which expand and contract as their temperature varies) is a common cause of failure in underground cable joints
- Deterioration of tunnels and structures for the underground cables.

Additionally, our underground cable assets are supported by associated cable monitoring systems (CMS), whose service life differs from that of the cables. The service life of the CMS is limited due to the computer components and operating systems becoming unsupported or obsolete. Some operating system and computer components need to be replaced five years after they are commissioned.

4.3.4 Secondary systems

Issues due to the aging of assets specific to substation automation systems include ongoing manufacturer support, deterioration due to wear and tear and exposure to the elements, and the fact that more modern construction and health and safety standards may be higher than the standards that applied during the original construction. Telecommunications assets are also affected by these issues as well as technological obsolescence.

TransGrid ensures that all secondary systems are kept up to date in order to deliver the services required by customers at the most efficient sustainable cost.

4.4 The AER revenue determination and TransGrid's approach

Applying our asset management approach to TransGrid's fleet of network assets generates an ongoing program of refurbishment and replacement capital works. Our programs for the first three years of the TAPR 2015 ten year planning horizon, formed a key component of our revenue proposal for the 2014/15-17/18 regulatory control period submitted to the AER in June 2014. Elements of those programs were updated when a revised proposal was lodged in January 2015.

The AER published its final revenue determination in May 2015. As part of that decision, the AER reduced our total refurbishment and replacement (including security and compliance related) capital expenditure from the proposed $1,028 million to $733.8 million, a difference of over $294 million or around 29%.

We are concerned that the AER's large reduction in this expenditure category may prevent the business from delivering services safely, securely and reliably in the longer term. We are looking very carefully at how we ration our capital and operating expenditure to best manage in this regard, and will continue to work closely with our customers, consumers and other stakeholders in doing so.

The asset management related capital projects set out in Chapters 5 and 6 have been revised in light of the AER's determination. They include a number of innovative programs. We have also committed to fully funding particular programs despite the AER's cuts. This is on the basis that to spend only what the AER has implicitly allowed for such programs would lead to an unacceptable level of risk.

We are looking very carefully at how we ration our capital and operating expenditure to best manage the AER's decision to reduce our refurbishment and replacement capital expenditure by 29%, and will continue to work closely with our customers, consumers and other stakeholders in doing so.


Chapter
5

Completed, committed and planned developments

- In the last financial year, 12 projects were completed that have alleviated previously identified constraints. These include the Western Sydney Supply Project, line 97G remediation, transformer and reactor replacements at Newcastle, Griffith and Yanco and capacitor bank installations at Canberra and Yass
- 25 projects progressed to, or are at the committed stage, including the redevelopment of the Orange substation, the Dynamic Line Rating (DLR), quality of supply monitoring and point on wave switching control programs, the strategic acquisition of Riley Street, a future substation site in Surry Hills, and a number of major substation rebuilds
- Eight projects are planned including the construction of the ACT Stockdill Drive switching station, the refurbishment of Vales Point substation and partial rebuild of the Wagga 132 kV substation
- Some asset replacements progressed from the ‘within 5 years’ category from last year including the Taree and Haymarket secondary systems projects
- Projects delayed or deferred included the multiple contingency protection scheme, Wallerawang to Orange 132 kilovolt (kV) line rebuild and Vineyard – Cattai strategic site acquisition.

5.1 Introduction

This chapter is structured around the following project classifications:

> 'Completed' projects are those that have alleviated constraints that were identified in previous TAPRs

> 'Committed' developments are those where we have made a financial and contractual commitment to undertake them and they are under development

> 'Planned' developments have completed the regulatory process but do not (yet) meet the criteria above for committed developments.

Within each classification, projects are broadly divided into major (typically entire lines, cables or substations) and minor developments.

All the developments referred to are the subject of proposals that have been recorded in previous TAPRs or regulatory consultations.

5.2 Completed developments

5.2.1 Major developments

Boggabri East switching station
The Boggabri Coal Mine requested a connection to the 132 kV transmission network for its expansion. The 9U3 Gunnedah – Narrabri line was cut and 12.5 kilometres of looped connection line was constructed to supply Boggabri East 132 kV switching station.

These works were completed in September 2014.

Boggabri North switching station
Maules Creek Coal Mine requested a connection to the 132 kV transmission network for their mine. The 9UH Narrabri – Boggabri East line was cut and three kilometres of looped connection line was constructed to supply Boggabri East 132 kV switching station.

These works were completed in April 2015.

Western Sydney Supply Project
We, Endeavour Energy and Ausgrid undertook work to increase the capacity of the transmission system supplying the Sydney inner metropolitan area to meet current and emerging constraints. The major components included:

> Construction of sections of a new double circuit 330 kV line and conversion of parts of an existing double circuit line, to operate at 330 kV between Sydney West 330/132 kV substation and the new Holroyd 330/132 kV substation

> Construction of the new Holroyd substation and associated connections to the existing 132 kV network

> Construction of the new Rookwood Road 330/132 kV substation and associated connections to the existing 132 kV network

> Installation of two 330 kV cables between the new Holroyd substation and the new Rookwood Road substation.

Holroyd substation and work on the double circuit 330 kV line were completed in March 2014.

Installation of the two 330 kV cables and construction of the new Rookwood Road 330/132 kV substation was completed in September 2014.

Disconnection of Munmorah Power Station
Delta Electricity has retired Munmorah Power Station. Disconnection of the 330 kV generator connections was completed in August 2014.

Transposition work on Line 76/77 Wallerawang – Sydney South/Ingleburn double-circuit 330 kV line
Prior to the establishment of the Ingleburn 330/66 kV substation, the 330 kV double-circuit lines 76 and 77 connected Sydney South and Wallerawang substations.

Following the establishment of the Ingleburn substation, line 77 (Wallerawang – Sydney South) was cut into Ingleburn 330 kV switchyard, resulting in two new lines:

> Line 77 (Wallerawang – Ingleburn)

> Line 78 (Ingleburn – Sydney South).

An analysis of the system revealed that at times of high power transfer from Wallerawang, the loss of line 78 could produce an unusually high negative-sequence voltage level at Ingleburn substation. This was due to the overall configuration of the 330 kV network and particularly due to the phasing of the Wallerawang – Ingleburn-Sydney South 330 kV double-circuit lines 76, 77 and 78.

On-site measurements confirmed that, following the opening of line 78 (Ingleburn – Sydney South), a high level of voltage-unbalance could occur at Ingleburn substation.

To ensure compliance with Clause S5.1a.7 of the NER, lines 76 and 77 were transposed to mitigate the voltage unbalance at Ingleburn substation when line 78 is open.

This project was completed in September 2014.

Remediation works for 97G 132 kV transmission line
The 97G Murray – Guthega 132 kV line was originally constructed by the Snowy Mountains Hydro Electricity Authority in the 1960s and supplies Guthega power station and Jindabyne pumping station. The line also supplies Munyang during outages of the 132 kV line between Cooma and Munyang. The remediation work restored the line to its original capacity by raising the conductors.

The work was completed in March 2015.

5.2.2 Minor works

TABLE 5.1 – Completed line switchbays for customer requirements

Location	Installation	Completion	Comments
Wagga North substation	One 132 kV switchbay	April 2015	Supply to Temora. Essential Energy is constructing a second 132 kV transmission line between Wagga North and Temora to ensure supply reliability.
Broken Hill 220/22 kV substation	Two 22 kV line switchbays	November 2014	To facilitate connection of a 53 MW solar farm
Marulan substation	One 132 kV switchbay	August 2014	To facilitate the connection of Taralga wind farm

TABLE 5.2 – Completed transformer and reactor replacements and upgrades

Location	Installation	Completion	Comments
Newcastle 330/132 kV substation	Condition-based replacement of two of the three remaining banks of single-phase 330/132 kV transformers with new 375 MVA three-phase units	October 2014	The replaced assets were nearing the end of their service life. Due to lower demand in the area following closure of the Kurri Kurri aluminium smelter, one bank of single-phase units was retired but not replaced
Griffith 132/33 kV substation	Replacement of three 45 MVA 132/33 kV transformers with three new 60 MVA units	November 2014	Condition-based replacement
Yanco 132/33 kV substation	Replacement of two 45 MVA 132/33 kV transformers with two new 60 MVA units	August 2014	Condition-based replacement

TABLE 5.3 – Completed reactive plant installations

Location	Installation	Completion	Comments
Canberra 330/132 kV substation	Expansion of existing 80 MVAr bank to a 120 MVAr 132 kV capacitor bank	March 2015	To maintain adequate power transfer from the southern generators towards Sydney and the NSW South Coast
Canberra 330/132 kV substation	Additional 120 MVAr 132 kV capacitor	August 2014	To maintain adequate power transfer from the southern generators towards Sydney and the NSW South Coast
Yass 330/132 kV substation	New 80 MVAr 132 kV capacitor bank	September 2014	To maintain adequate power transfer from the southern generators towards Sydney and the NSW South Coast

TABLE 5.4 – Other completed works

Location	Installation	Completion	Comments
Various 330 kV substations	Install surge arrestors on various 330 kV line entries to substations	December 2014	To provide necessary surge protection for substation equipment. All sites are completed.
967 Koolkhan – Lismore 132 kV line	Pole replacement	April 2015	Condition-based replacement
Lines 14, 26 and 29 near Marsden Park	Relocation of structures	September 2014	To maintain supply reliability
94B Wellington – Beryl 132 kV transmission line	Replacement of wooden poles for 132 kV transmission	June 2015	Condition-based replacement
Broken Hill 220/22 kV substation	SVC control system replacement	March 2015	Condition-based replacement
Dapto 330/132 kV substation	Secondary systems replacement	June 2014	Condition-based replacement
Griffith 132/33 kV substation	Secondary systems replacement	November 2014	Condition-based replacement
97C Tamworth 330 kV – Tamworth 132 kV line	Line renewal (pole replacements to allow line to be returned to service, so it can be used in staging of Tamworth 132 kV substation rebuild)	June 2015	Condition-based replacement
97G Murray – Guthega 132 kV line	Replacement of disconnectors at Geehi switching station, to restore capability to sectionalise 97G	June 2015	Condition-based replacement
Marulan – Gullen Range – Yass 61 and 3J lines	Uprating to an operating temperature of 100°C	October 2014	To maintain supply reliability

5.3 Committed developments

5.3.1 Major works

Redevelopment of Orange 132/66 kV substation
Commissioned in 1954, the Orange 132/66 kV substation and the 66 kV equipment and secondary systems, are nearing the end of their serviceable lives. Following the completion of the Orange North 132 kV switching station, most of the 132 kV equipment at the Orange substation will be removed and the 66 kV equipment and secondary systems will be replaced. While removing and replacing the necessary parts at this substation, we will install an additional 66 kV capacitor required as part of our reliability commitment.

The work is expected to be completed in 2017.

Strategic land acquisition at Riley Street
Haymarket 330 kV substation plays a critical role in maintaining reliable supply in the Sydney inner city and CBD areas. It supplies fourteen 132 kV cables via three 400 MVA 330/132 kV transformers. The substation was commissioned in 2001 and, with a service life of approximately 40 years, it is expected that it will need to be replaced around 2041.

Rebuilding Haymarket substation on the existing site is not feasible, because of heavily restricted space, congestion of the existing cable routes and lack of suitable adjacent sites.

Ausgrid has recently offered for sale a parcel of land in Riley Street, Surry Hills. The size of the property is suitable for building a replacement substation for Haymarket. In addition, the property has immediate access to Ausgrid's inner city 132 kV cable tunnel ring, as it was used as an adit for the construction of the tunnels.

This site will be purchased to allow for the future replacement of the Haymarket substation.

Rehabilitation of the Upper Tumut switching station
Most of the rehabilitation work at the Upper Tumut switching station has been completed, including replacement of the high-voltage equipment.

Replacement of the secondary systems is scheduled to be completed progressively until December 2015.

Replacement of the Cooma substation
The Cooma 132/66/11 kV substation, which supplies the Cooma area, the NSW alpine region and the NSW far south coast, was commissioned in 1954.

The substation and its equipment are approaching the end of their serviceable lives and need to be replaced. Most of the high-voltage plant components and secondary systems are also approaching the end of their serviceable lives and are being replaced, to ensure supply reliability.

A new Cooma 132/66 kV substation will be established close to the existing substation. The existing Cooma substation will be transferred to Essential Energy and converted to a 66/11 kV substation.

The establishment of the new Cooma 132/66 kV substation is expected to be completed in November 2015. Essential Energy will then convert the existing Cooma substation to a 66/11 kV substation.

Refurbishment of the Yanco substation
The Yanco 132/33 kV substation was commissioned in 1969 and supplies Essential Energy's Narrandera zone substation at 66 kV, and several local 33 kV feeders. The majority of the substation's equipment is nearing the end of its serviceable life and will be replaced to maintain reliability of supply.

The refurbishment of Yanco substation is expected to be completed in September 2015.

Dynamic line ratings
Our current line ratings consider the probabilistic nature of weather and line loading conditions. The weather information used for determining the line ratings, does not necessarily refer to the weather conditions on critical constraint spans of a transmission line, where conductor sagging is the constraining issue.

Real-time line ratings have the dual benefit of allowing maximum power transfer capability of the system (where thermal ratings are the determining factor) to be available and de-rating lines in order to protect the assets and the system during adverse conditions. Transmission lines have been identified where constraints were seen to impose future power flow, and dynamic line rating (DLR) will be implemented on these.

Installation on lines 01, 02, 03 and 07 is expected to be completed by December 2015. The overall program of installations is expected to be completed in mid-2016.

Quality of supply monitoring
Quality of Supply (QoS) monitors will be installed at 13 strategic customer connection points, so that we can measure, record and analyse aspects of the quality of supply at these customer connection points.

The installations are expected to be completed by December 2016.

Point-on-wave switching control
Our transmission system contains about 110 shunt capacitor banks, each of which is connected to, or disconnected from, the network by closing or opening its capacitor circuit breaker. Unless the capacitor circuit breaker has special features, energising a shunt capacitor bank can produce high levels of transient distortion. These distorted voltage waveforms are applied to customer loads and can cause the customer equipment to malfunction or fail.

Since 2005, new capacitor banks have included capacitor circuit breakers fitted with point-on-wave (POW) closing controls. Replacement capacitor circuit breakers also have included POW closing controls.

There are still some shunt capacitor banks remaining where the circuit breakers need to be replaced with those fitted with POW closing controls. These replacements are expected to be completed by January 2018.

5.3.2 Minor works

TABLE 5.5 – Committed line switchbays to meet distributor requirements

Location	Installation	Completion	Comments
Beryl 132 kV substation	One 66 kV line switchbay	September 2015	Essential Energy plans to reinforce the network supplying Dunedoo and Coonabarabran
Molong 132 kV substation	One 66 kV switchbay	December 2015	Essential Energy has proposed installation of a second 66/11 kV transformer at Molong to be used as a back-up supply
Vineyard 330 kV substation	One 132 kV switchbay	December 2015	Endeavour Energy request for 132 kV line switchbay to connect new 132 kV line supplying the new Marsden Park zone substation

TABLE 5.6 – Committed substation fault rating upgrades

Location	Installation	Completion	Comments
Sydney West 330/132 kV substation	Equipment replacements to ensure the 132 kV fault rating is at least 38 kA	December 2015	To maintain supply reliability

TABLE 5.7 – Committed transformer and reactor replacements and upgrades

Location	Installation	Completion	Comments
Beaconsfield West 330 kV substation	No 1 and 2 transformer replacement with a single transformer	2018	Condition-based replacement of one transformer. The other will not be replaced
Buronga 220 kV switching station	Reactor X2 replacement	Summer 2015/16	Condition-based replacement
Broken Hill 220/22 kV substation	No 1 and 2 reactor replacement	Winter 2016	Condition-based replacement

TABLE 5.8 – Committed capacitor bank installations

Location	Installation	Completion	Comments
Orange 132/66 kV substation	Additional 66 kV capacitor bank	April 2017	To be provided as part of condition-based replacement. See Section 5.3.1

TABLE 5.9 – Other committed works

Location	Installation	Completion	Comments
Armidale 330/132 kV substation	Replacement of the SVC control system	Late 2015	Condition-based replacement
Tamworth 132/66 kV substation	Substation rebuild	March 2017	Condition-based replacement. The new substation is to be constructed on an adjacent site with two 120 MVA 132/66 kV transformers and with no 132 kV busbar initially
Kangaroo Valley 330 kV substation	Replacement of the secondary systems	February 2016	Condition-based replacement
Sydney West 330/132 kV substation	Replacement of the secondary systems	Late 2015	Condition-based replacement
Sydney North 330 kV substation	Replacement of the secondary systems	Late 2018	Condition-based replacement
Sydney South 330 kV substation	Replacement of the 415-VAC system and LV cables	November 2015	Condition-based replacement
Haymarket 330 kV substation	Removal of SICAM (control and monitoring system) from GIS	April 2017	Condition-based removal
Albury 132 kV substation	Replacement of the secondary systems	Late 2016	Condition-based replacement
970 Burrinjuck – Yass 132 kV line	Pole replacements (including installation of OPGW)	2016	Condition-based replacement

5.4 Planned developments

5.4.1 Major works

Condition of Vales Point 330/132 kV substation
Vales Point substation forms an integral part of the 330 kV transmission system on the Central Coast. It provides a connection for Vales Point power station and supplies Ausgrid's 132 kV network through two 200 MVA transformers. An assessment of the condition of Vales Point substation and its assets revealed that many components are reaching the end of their service life. The assessment also revealed a number of other problems that need to be addressed, including the condition of the steelwork and buildings.

The replacement of equipment at Vales Point is expected to be completed in 2018.

Development of southern supply to the ACT
TransGrid was granted a licence in early 2015 to provide electricity transmission services in the ACT. A condition of the licence was for TransGrid to provide two geographically separate 330 kV supplies to the ACT, the first of which is the existing Canberra 330/132 kV substation.

The recently commissioned Williamsdale 330/132 kV substation provides a second supply point to the ACT. However, Williamsdale substation is currently supplied from the Canberra 330 kV substation via line 3C and is therefore dependent on Canberra 330/132 kV substation being in service. Williamsdale is therefore not considered to be a geographically separate supply point.

There are no feasible non-network options as the obligation for reliability mandates a network solution. The only feasible option identified, and one that complies with the licence conditions, is the establishment of a switching station at a suitable site together with associated 330 kV line connections.

Initially, the preferred site was at Wallaroo. However, after review by the ACT Government, a site near Stockdill Drive is preferred.

Condition of Wagga 132/66 kV substation
Commissioned in 1955, the Wagga 132 kV substation supplies most of the load in Wagga and the surrounding area. The balance of the load is supplied from Wagga North and Morven substations.

An assessment of the condition of the Wagga 132 kV substation and its assets revealed that many components are reaching the end of their service life. The assessment also revealed some substation problems with the No 2 and No 3 132/66/11 kV transformers that need to be addressed.

Since publication of the TAPR 2014, the work to be done has been reviewed and the substation will now be re-built in situ, including:

> Replacement of the existing No 1 and 3 132/66 kV 60 MVA transformers with 132/66 kV 120 MVA transformers

> Removal of the existing No 2 transformer

> Installation of secondary systems buildings and associated cable trenches

> Replacement of equipment that is identified as nearing the end of its serviceable life

> New oil containment system.

This work is expected to be completed in 2018.

Supply to Beryl/Mudgee area
The Beryl 132/66 kV substation is supplied by two 132 kV transmission lines, the 53 kilometres line 94B from Wellington 330/132 kV substation, and the 125 kilometres line 94M from Mt Piper 330/132 kV substation. The 94M Mt Piper-to-Beryl 132 kV line also supplies 132 kV substations at Ilford and Mudgee via tee-connections.

In recent years, mines in the area have been developed or expanded, and further expansions are forecast.

An additional 66 kV capacitor will be installed at Beryl substation, to provide additional reactive support. The work is expected to be completed in summer 2016/17.

5.4.2 Minor works

There are no:

> New minor developments that have completed the regulatory process since the publication of TAPR 2014

> Substation fault rating upgrades in this category since the publication of TAPR 2014

> Transformer or reactor replacements in this category since the publication of TAPR 2014

> Projects for the provision of line switchbays to meet NSW Distributor's requirements in this category since the publications of TAPR 2014

> System reactive plant requirements in this category since TAPR 2014.

5.5 Replacement transmission network assets previously reported

Table 5.10 summarises replacement transmission network assets previously reported.

TABLE 5.10 – Replacement transmission network assets previously reported

Location	Installation	Completion	Comments
Taree 132 kV substation	Secondary systems replacement and 33 kV switchyard condition	September 2017	Condition-based replacement
Haymarket 330 kV substation	Secondary systems replacement	2018	Condition-based replacement. Work will be undertaken in two phases. Phase 1 involves implementing a mitigation measure on the busbar protection. Phase 2 is the replacement of the secondary systems in situ
97K Cooma – Munyang 132 kV line	Line rehabilitation	2018	Remediation of low spans
96H Coffs Harbour – Koolkhan 132 kV line	Pole replacement	2017	Condition-based replacement


6
Chapter

Constraint and possible network developments

- Possible projects in the next five years include load related development in the Gunnedah/Narrabri area as well as condition based works at Tamworth, Central Sydney, Munmorah/Doyalson, Canberra, Burrinjuck and the multiple contingency protection scheme
- Possible developments in the five to ten year period include Hunter Valley – Tamworth – Armidale line capacity, Northern NSW voltage control, Newcastle substation condition, Marulan – Avon, Marulan – Dapto, Kangaroo Valley – Dapto line capacity and Wallerawang – Orange line condition. With the exception of works at Newcastle substation and the Wallerawang – Orange line, these would be based on market benefits being achieved
- Some possible developments reported last year are now expected to arise further into the future because of moderating load forecasts. These include the Queensland – NSW Interconnector (QNI) upgrade and associated projects, development of supply to the Sydney inner metropolitan area and development of the Snowy to Sydney network capacity
- Some asset replacements, such as Sydney North and Albury secondary systems, Beaconsfield transformer and Buronga reactor replacements, have progressed and are now committed projects. Others have modified scopes and timeframes due to regular review, refer to Appendix 8.

6.1 Introduction

This chapter:

> Describes contraints for which the regulatory consultation process is underway (Section 6.1)

> Describes contraints expected to emerge within a five year planning horizon, where there is at present no firm proposal. One or more options for removing each constraint are described. Asset replacement projects in the same timeframe are also identified (Section 6.2)

> Summerises constraints expected to arise within the five to ten year planning horizon. One or more indicative developments to mitigate the constraints are given (Section 6.3)

> Outlines potential constraints beyond the TAPR ten year planning horizon (Section 6.4)

> Identifies those contraints expected to arise in one, three and five years in respect of which we intend to issue Requests for Proposals (RfPs) (Section 6.5).

During the past year, the RIT-T consultation process for the Queensland – NSW Interconnector (QNI) capacity upgrade was completed with the publication of the Project Assessment Conclusion Report (PACR). This project and the outcome of the consultation process, including links to the published documents, are described in Section 6.3.1. At the time of publication of this TAPR, no RIT-T consultations were being undertaken.

Information on transmission augmentation projects in the NTNDP is provided in Section 2.4.1.

6.2 Possible network developments within five years

6.2.1 Supply to the Gunnedah/Narrabri area

Background

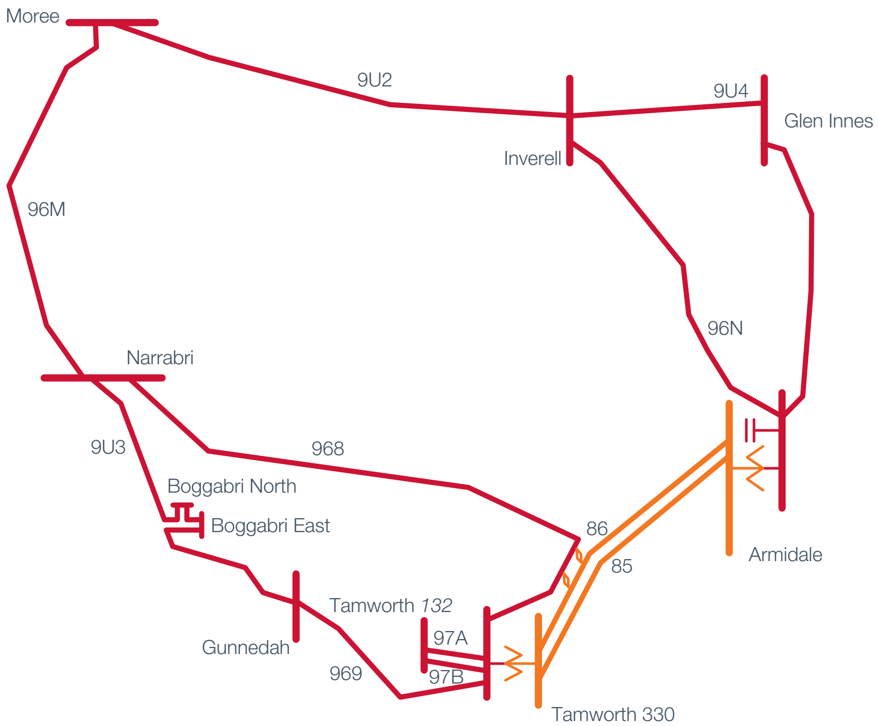
The transmission system supplying the Gunnedah, Narrabri and Moree areas, shown in the figure below, is about 300 kilometres long. An outage in the 968 Tamworth – Narrabri 132 kV line, at times of high summer load, would cause the 969 Tamworth – Gunnedah 132 kV line to reach its thermal capacity. The power flows on QNI and Directlink would also influence the thermal constraint. A northerly flow would exacerbate the constraint while a southerly flow would relieve the constraint.

Two new mines in the area have recently been connected to the network. This increase in load will exacerbate the thermal constraints.

To date, it has been possible to manage the thermal constraint through operational measures. The operating voltage of the 132 kV network has been increased and, in the event of a critical contingency, it is possible to open the 96M Narrabri – Moree 132 kV line when power is flowing northward.

The thermal constraint is expected to arise in the summer of 2015/16.

There is potential for additional mines in the area to be developed and for existing mines to be expanded. Should additional mining loads come to fruition, they would exacerbate the thermal limitation and, depending on their magnitude, introduce a second limitation. That second limitation is unacceptably low voltages at Gunnedah should the 969 Tamworth – Gunnedah 132 kV line be out of service at times of high summer load.



Transmission System Supplying Gunnedah and Narrabri.

Nature of the constraint	A thermal constraint on line 969 in the event of an outage on line 968. The shortfall in network capability is approximately 15 MW in summer.
Possible network options	Options being considered to alleviate the thermal constraint include: > Constructing a 132 kV line from Tamworth to Gunnedah, possibly on the route of the recently dismantled 875 Tamworth – Gunnedah 66 kV line ($34 to $42m in 2014) > Installing a phase shifting transformer in line 969 ($15m) > Relocating the phase shifting transformer which is presently connected to 965 line at Armidale ($5.8m) > Reconductoring line 969 and the 9U3 lines with higher capacity conductors ($15m).
Load reduction to delay constraint and non-network option requirements	**Feasibility:** We continue to work closely with our customers to plan, develop and manage the network to ensure it meets their service expectations now and into the future. In September 2014, we wrote to two major electricity consumers in the constrained area to gauge their interest in providing a non-network solution, and discussed the requirements for a non-network solution in person in February 2014. A non-network solution will not be progressed further until we have consulted publicly on the need via the RIT-T consultation process. **N–1:** 968 **Shortfall:** 15-16 MW summer and up to 8 MW winter from 2016 to 2024 **Location:** Gunnedah, Narrabri and Boggabri area **Deferral value:** $15m **Speed:** Any demand management would need to be dispatched within 5 – 10 minutes. This includes the notification process following the contingency.
Preferred network option	At this stage the preferred network option is the installation of a phase shifting transformer (connected into line 969).

6.2.2 Condition of Tamworth No 2 330/132 kV transformer

Background	The No 2 330/132 kV 150 MVA transformer at the Tamworth 330 kV substation is nearing the end of its serviceable life and needs to be retired. The signs of ageing include deteriorated paper insulation systems and poor oil quality.
Nature of the constraint	Tamworth No 2 330/132 kV transformer is reaching the end of its serviceable life. If the transformer is retired and not replaced, the capacity of the two remaining transformers would not be sufficient to supply all of the load, in the event that one of them is out of service at times of high load.
Expected date	2019
Possible network options	Options available to address these constraints include: > Replacing the Tamworth No 2 330/132 kV transformer with a unit of similar rating (and addition of 330 kV bus section breaker for system reliability) ($14m) > Replacing the Tamworth No 2 330/132 kV transformer with a 375 MVA unit (and associated transformer reconfigurations) ($11m).
Load reduction to delay constraint and non-network option requirements	**Feasibility:** Non-network solutions are technically feasible to address the constraint. **Scenario:** If the No 2 150 MVA transformer was not replaced, the constraint would arise in the summer following the transformer decommissioning, with the new mining loads. **N–1:** Outage of the Tamworth No 3 330/132 kV 200 MVA transformer **Shortfall:** 88 MVA depending on the location of the reduction and the power flows on QNI and Directlink. **Location:** 132 kV loads at Tamworth, Gunnedah, Narrabri, and Moree **Deferral Value:** $11m **Speed:** 5 – 10 minutes following the failure of a transformer, should that occur at a time of high load. Support may also be required on other days of high load, in the period during which the transformer which failed is being replaced. At this stage, it is expected that the response time would be a longer period in these circumstances.
Preferred network option	At this stage the preferred network option is the replacement of the Tamworth No 2 330/132 kV transformer with a 375 MVA unit in the No 1 position, and relocation of the existing No 1 transformer to the No 2 position at a cost of around $11m.

6.2.3 Capacity of cable 41, Sydney South – Beaconsfield

Background

Cable 41 is one of two major 330 kV cables that supply the Sydney inner metropolitan area and CBD. Both cables have series reactors to limit their loading. Recent investigations into the condition of cable 41 have found that the cable backfill has degraded, reducing the thermal performance of the cable (the cable rating).

In addition, field measurements have identified ground temperatures exceeding those assumed in the original cable design. This problem has resulted in an interim de-rating of the cable's continuous cyclic capacity from 663 MVA to 575 MVA.

The degraded condition of the backfill has caused the rating of cable 41 to be susceptible to variations in soil moisture levels. The interim 575 MVA rating is not assured. A prolonged period of dry weather could see the rating of the cable reduced to a level where it becomes inoperable (where the rating is so low that it can serve no useful purpose).

The capacity of cable 41 also affects the Powering Sydney's Future need. Refer to Section 6.3.5.

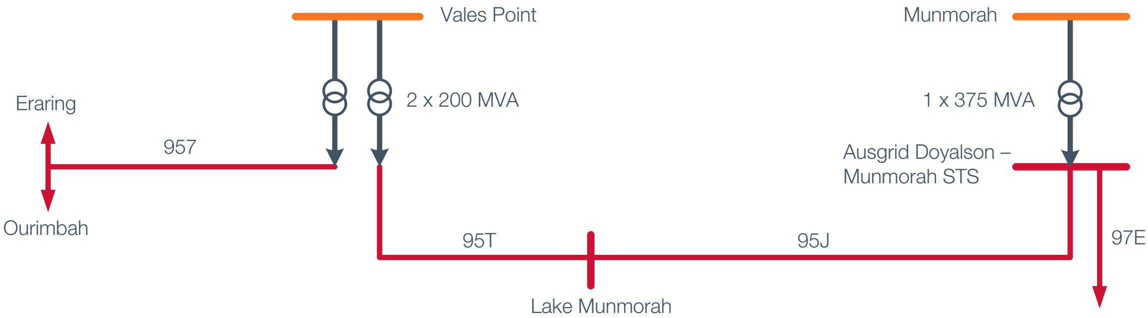
Nature of the constraint

If the moisture in the cable 41 bedding material is reduced sufficiently to render the cable inoperable, the result would be a substantial shortfall in the supply capacity to the Sydney inner metropolitan area and CBD.

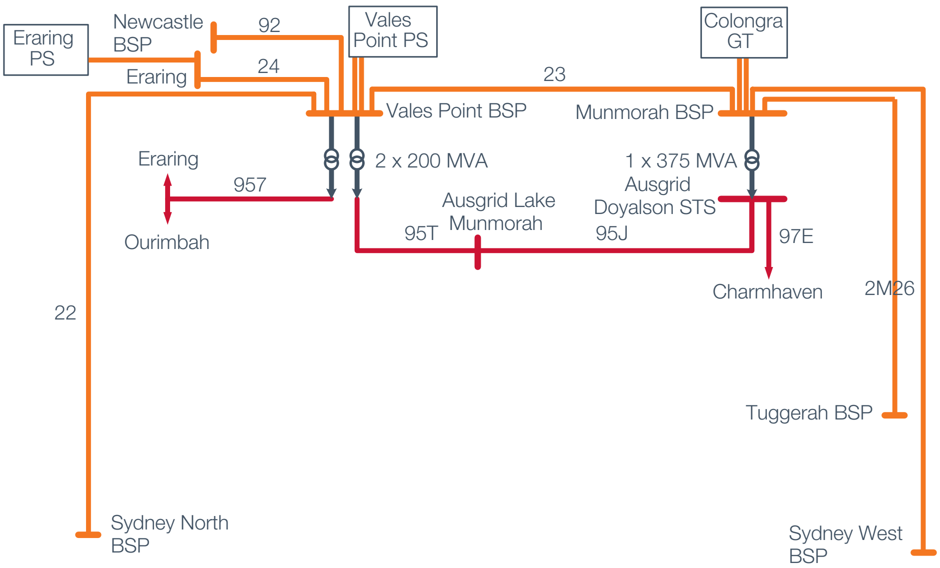
The following figure shows the inner metropolitan and CBD supply network loading and the network capacity over the coming years both for the interim 575 MVA rating and for when the cable 41 cable rating is reduced to below a useful level.

Possible network options	The following options have been identified: > Perform a detailed assessment of the cable installation by testing soil samples at a large number of points along the entire cable route, installing soil property and condition monitors. Results of the assessment would then be used to develop a calibrated thermal model of the cable to determine a firm cable rating and to develop a long term cable management strategy > Bringing forward the conversion of the Rookwood Road to Beaconsfield West 132 kV cables being considered as an option for Powering Sydney's Future, to 330 kV operation > Remediating the cable 41 backfill > Installing a new series reactor on cable 41 at Sydney South > Installing a phase shifting transformer on cable 41 at Sydney South.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** Demand management initiatives are considered as part of the overall strategy to maintain reliability of supply to the inner metropolitan area over the coming years as the expected retirement of 132 kV cables, identified as nearing the end of their serviceable life, occurs. However, the loss of cable 41 (through its rating being reduced to below a useful level) would result in a substantial shortfall in the adequacy of the network to supply the inner metropolitan load of around 800 MW in the mid 2020s. It is not expected that the required levels of demand management would be available to cover the loss of cable 41 capacity, particularly as this would be required in addition to demand management being sought to compensate for the expected 132 kV cable retirements.
Preferred network option	At this stage, the preferred option is to perform a detailed assessment of the cable installation by testing soil samples at a large number of points along the entire cable route, installing soil property and condition monitors. Results of the assessment will then be used to develop a calibrated thermal model of the cable to determine a firm cable rating and to develop a long term cable management strategy. The information provided by the operation of the monitoring system would be used in deciding any future actions necessary. Early indicative estimates of the costs for this option are around \$0.5 – 3m, depending on the number of spot condition monitoring devices installed. There are plans to commence preliminary design and preparatory work for the installation of two Rookwood Road to Beaconsfield West 330 kV cables, to minimise lead times in the event that the need for these cables is established.

6.2.4 Connection of Ausgrid's new sub-transmission substation in the Munmorah/Doyalson area

Background	Munmorah power station has been retired. However, the two 330/33 kV transformers which provide supply to Ausgrid have been retained. Those transformers are nearing the end of their serviceable lives and are to be retired in 2017. Joint planning with Ausgrid has identified that the most efficient option is for Ausgrid to establish a new 132/33 kV sub-transmission substation (STS) in the Doyalson/Munmorah area. This substation would also provide for any future 132 kV feeder connections. Neither Munmorah nor Vales Point substations have an established 132 kV busbar, nor is there space to establish a 132 kV busbar within the existing Munmorah substation. We need to provide for the connection of a 132 kV supply for Ausgrid's planned new STS. The final location of the STS is yet to be determined. 
Nature of the constraint	The need is to provide a safe and reliable supply to Munmorah/Doyalson when the present 33 kV supply from Munmorah power station is no longer available.
Possible network options	Options considered to provide for connection for the Doyalson area STS include: > Providing a connection at Munmorah substation, requiring the existing 132 kV lines into Munmorah substation to be rearranged into the new Ausgrid STS, as shown in the figure above > Providing a connection at Vales Point substation, requiring us to establish a 132 kV busbar at Vales Point, and Ausgrid to construct a new 132 kV line between Vales Point and the new Munmorah/Doyalson STS (although there is considerable doubt as to whether a suitable line route could be obtained).
Load reduction to delay constraint and non-network option requirements	**Feasibility:** This project is to maintain supply to Ausgrid's 33 kV network, following the planned retirement of the present 33 kV supplies from Munmorah power station. A non-network option covering the entire 33 kV load, of up to about 25 MW, all of the time is unlikely to be feasible.
Preferred network option	The preferred network option is for Ausgrid's new STS to be connected to the Munmorah substation. This option requires less line work, and it is expected that only minor work will be required by us.

6.2.5 Condition of Munmorah 330/132 kV substation

Background	Munmorah substation forms an integral part of the 330 kV transmission system on the Central Coast. It provides connection for the Colongra power station and supplies Ausgrid's 132 kV network through a single 375 MVA transformer.  Following the retirement of the Munmorah power station, its generator connections to Munmorah substation were removed in 2014. The station supply transformer switchbays within Munmorah substation are required until 2017 to supply Ausgrid's local 33 kV network, until a new supply point from Doyalson/Munmorah STS is established.
Nature of the constraint	An assessment of the condition of Munmorah substation and its assets found that numerous items of equipment are reaching the end of their serviceable life and that substation issues need to be addressed.
Possible network options	A number of options were considered to address the condition of the Munmorah substation, including: > Replacing the Munmorah substation either in-situ or in a piecemeal fashion > Consolidating Munmorah connections into Vales Point substation > Constructing a new large 330/132 kV substation to consolidate the 330 kV and 132 kV connections in the area.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** Munmorah forms an integral connection between Vales Point, Colongra, and Eraring power stations to the Central Coast and greater Sydney area. As non-network options cannot provide these connections, they are not feasible. Also, a reduction in load would not defer the retirement date of substation assets. The renewal of Munmorah substation is driven by the condition of the substation and its assets and steelwork. The substation is connected to significant gas generation (724 MW) and the existing 330/132 kV transformer will be retained. The number of connections in the renewed substation will be reduced by removing the old Munmorah Power Station connections, including those to the 330/33 kV transformers.
Preferred network option	The preferred network option is to rebuild the substation in a piecemeal fashion. This is expected to cost around $9m and to be completed in 2020.

6.2.6 Condition of Canberra substation

Background	The Canberra 330/132 kV substation was commissioned in 1967 and supplies Queanbeyan substation and the ActewAGL 132 kV sub-transmission network. The Canberra substation forms an integral part of the transmission interconnection between the Victorian region, Snowy Mountains generation and the rest of NSW.
Nature of the constraint	An assessment of the condition of Canberra substation and its assets, found that numerous items of equipment are reaching the end of their serviceable life and that substation issues need to be addressed.
Possible network options	A number of options were considered to address the Canberra substation condition, including: > Replacing the Canberra substation in-situ or in a piecemeal fashion > Rebuilding the Canberra substation across two interconnected sites, on an adjacent site, or at a location remote from the existing substation.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** The Canberra 330 kV busbar forms an important part of the 330 kV network in the southern part of NSW, including the ACT, a service which cannot be delivered by non-network options. Therefore, non-network options are not feasible. Also, a reduction in load would not defer the retirement date of substation assets. The retirement of Canberra substation is not a feasible option as the ACT government's requirement for two independent supply points would not be met. Similarly, non-network options cannot meet this requirement. The replacement of Canberra substation is driven by the condition of the substation and its assets, including two of the transformers. The number of line connections to the new substation will remain unchanged. One of the transformers is to be retired and the other replaced.
Preferred network option	The preferred option is to address the Canberra substation condition through a program of piecemeal replacements. The project is expected to cost around $30m and to be completed by 2019.

6.2.7 Condition of Burrinjuck substation

Background	The Burrinjuck 132 kV substation was commissioned in 1944 and connects Burrinjuck Dam hydro generation to the Yass – Tumut – Wagga 132 kV transmission system. The substation also supplies power to Burrinjuck village.
Nature of the constraint	An assessment of the condition of Burrinjuck substation and its assets found that numerous items of equipment are reaching the end of their serviceable life.
Possible network options	A number of options were considered to address the Burrinjuck substation condition, including: > Replacing the Burrinjuck substation in-situ in a piecemeal approach > Rebuilding the Burrinjuck substation across two interconnected sites, on an adjacent site, or at a location remote from the existing substation > Replacing the Burrinjuck substation in-situ using gas insulated switchgear > Eliminating the need for a 132 kV busbar by either forming a tee-connection to the 132/11 kV transformer or rebuilding the 970 Yass – Burrinjuck 132 kV line as a double circuit to provide a dedicated connection from Yass to Burrinjuck.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** Burrinjuck substation connects generation, a service which cannot be provided by non-network options. Therefore, non-network options are not feasible. Also a reduction in load would not defer the retirement date of substation assets. The replacement of Burrinjuck substation is driven by the condition of the substation and its assets. The substation is connected to hydro-generation (28 MW), and the transformer is not owned by TransGrid. The number of connections to the new substation will remain unchanged.
Preferred network option	The preferred option is to connect line 970, line 992 and the Burrinjuck power station in a tee-connection, and decommission the portion of the Burrinjuck substation owned by TransGrid. This work is expected to cost around $7m and would be completed in 2017.

6.2.8 Murraylink runback control scheme

Background	There are presently a number of runback schemes on Murraylink covering contingencies in the Victorian and South Australian transmission networks, including: > Murraylink automatic slow runback control (Victoria) > Murraylink very fast runback scheme (Victoria) > Automatic sever trip (South Australia) > Automatic runback scheme (South Australia). These schemes allow higher pre-contingency flows on Murraylink due to automatic post-contingency action returning the network to a secure state. A fast runback control scheme has been installed for some substations in the NSW network. However this scheme has not yet been placed into service due to the lack of communication link. Without the NSW runback scheme enabled, Murraylink transfers to SA may be limited to near zero under high demand conditions in NSW. The remaining communication works are to be completed by the owner of Murraylink.
Nature of the constraint	Completion of this project is being undertaken by Murraylink.
Target date	2015
Load reduction to delay constraint and non-network option requirements	As this constraint is being addressed by Murraylink, we have not identified or investigated any other options.
Preferred network option	Complete the communication link works and commission the NSW runback scheme. This project would be funded and implemented by the owner of Murraylink.

6.2.9 Multiple contingency protection scheme

Background	Together with AEMO and AEMC, we have identified the need for investment to prevent or minimise the effects of interruptions following a non-credible event. The studies we have undertaken, as well as those undertaken by AEMO, and us have identified specific multiple contingencies that present risks of cascading failures. Consequently, it is necessary to manage the stability of both frequency and voltage following these multiple contingencies by means of control, protection or other systems. Under existing and future load growth and generation scenarios, AEMO has identified several non-credible contingencies that may result in voltage or frequency collapse within the NSW transmission system. Significant stability constraints may arise under the following conditions: > Loss of the Tamworth – Muswellbrook and either the Armidale – Tamworth or Tamworth – Liddell 330 kV lines > Loss of both the Yass – Marulan and Yass – Bannaby 330 kV lines > Loss of the Murray – Lower Tumut and Murray – Upper Tumut 330 kV lines. We have similarly identified a number of major transmission lines that, if affected by multiple contingencies, could lead to cascading failures in the greater Sydney load area: > Lines 31 and 32, Bayswater – Sydney West/Regentville > Lines 76 and 77, Wallerawang – Sydney South/Ingleburn > Lines 5A1 and 5A2, Eraring – Kemps Creek > Line 25, Eraring – Vineyard and Line 26, Munmorah – Sydney West > Line 39, Bannaby – Sydney West > Line 21, Tuggerah – Sydney North and Line 22, Vales Point – Sydney North > Line 11, Dapto – Sydney South.
Nature of the constraint	This project is driven by regulatory obligations. It mitigates the effect of multiple contingencies that result in voltage instability.
Target date	2020/2021
Possible network options	The options to meet the identified need are: > Implementing a SCADA-based multiple contingency protection scheme > Implementing a protection-based multiple contingency protection scheme > Implementing an optimised combination of a SCADA and protection-based multiple contingency scheme.
Preferred network option	The preferred option is to implement a combination of SCADA and protection-based multiple contingency schemes. The project is estimated to cost approximately $9.3m.

6.2.10 Line switchbays for distributor requirements within five years

The following table summarises possible projects occurring within five years to provide line switchbays to meet NSW distributors' requirements.

TABLE 6.1 – Possible line switchbays for distributor requirements within five years

Location	Installation	Indicative date	Distributor
Williamsdale 330/132 kV substation	One 132 kV switchbay	2018	Essential Energy

6.2.11 Other possible network asset replacements within five years

The following table summarises other possible network asset replacements within five years.

TABLE 6.2 – Other possible network asset replacements within five years

Project	Location	Scope of works	Possible commissioning date	Indicative cost
21 Sydney North – Tuggerah 330 kV transmission line: tower life extension	Sydney North – Tuggerah 330 kV line 21, Sydney metropolitan area to Central Coast	Refurbishment of the Sydney North – Tuggerah 330 kV line 21 from Sydney North to Sterland	2017	$5m
959/92Z Sydney North – Sydney East 132 kV transmission line: tower life extension	Sydney metropolitan area	Refurbishment of the Sydney North – Sydney East 132 kV line 959/92Z	2019	$8.5m
Deniliquin 132/66 kV substation: secondary systems replacement	Deniliquin substation, Southern NSW	Secondary system buildings (SSB)	2019	$10m
ANM 132 kV substation: secondary systems replacement	Australian Newsprint Mills (ANM) substation, Southern NSW	Replacement of secondary systems	2019	$6m
1 and 2 Snowy – Yass/Canberra 330 kV transmission lines remediation	Upper Tumut – Canberra 330 kV line 1 and Upper Tumut – Yass 330 kV line 2 Southern NSW	Remediation of low spans	2019	$29m
Low spans northern tower lines	Central Coast, Hunter Valley, Northern NSW	Remediation of high priority low spans	2018	$4m[1]
Low spans northern pole lines	Central Coast, Hunter Valley, Northern NSW	Remediation of high priority low spans	2018	$8m[1]
Low spans central tower lines	NSW metropolitan area	Remediation of high priority low spans	2019	$2m[1]
Low spans central pole lines	Central West NSW	Remediation of high priority low spans	2019	$3.7m[1]
Low spans southern tower lines	Southern NSW	Remediation of high priority low spans	2019	$3m[1]

1 Indicative costs of works within the five year period 2014 to 2019.

Project	Location	Scope of works	Possible commissioning date	Indicative cost
Low spans southern pole lines	Southern NSW	Remediation of high priority low spans	2019	$5m[1]
22 Sydney North – Vales Point 330 kV transmission line and tower life extension	Central Coast NSW	Painting of all tension towers	2017	$9m
Murrumburrah 132 kV substation secondary systems replacement	Murrumburrah substation Southern NSW	Replacement of the secondary systems	2020	$5m
Hume 132 kV substation secondary systems replacement	Southern NSW	Replacement of the secondary systems	2019	$7m

6.3 Possible network developments within five to ten years

Since the publication of TAPR 2014, some possible developments that were expected to arise within five years, are now expected to arise later.

This year, the RIT-T process for development of QNI's transmission capacity (Section 6.3.1) was completed. Six credible options were analysed, but many have negative market benefits under a number of scenarios. At this time, QNI's capacity will be monitored together with developments in the NEM. Should there be a material change in circumstances, possible development options and their market benefits will be re-evaluated. At this stage, any development is expected to be beyond five years. A number of possible developments that were contingent on an upgrade to the QNI will also be reviewed at that time (Section 6.3.2 – 6.3.4).

The development of supply to the Sydney inner metropolitan area and CBD (the 'Powering Sydney's Future' project) has also moved further into the future. The constraints on the network in this area were expected to arise within five years, however, under more recent forecasts, they are now expected to arise later, within five to ten years. This is described in Section 6.3.5.

Since the publication of TAPR 2014, some possible developments that were expected to arise within five years are now expected to arise later.

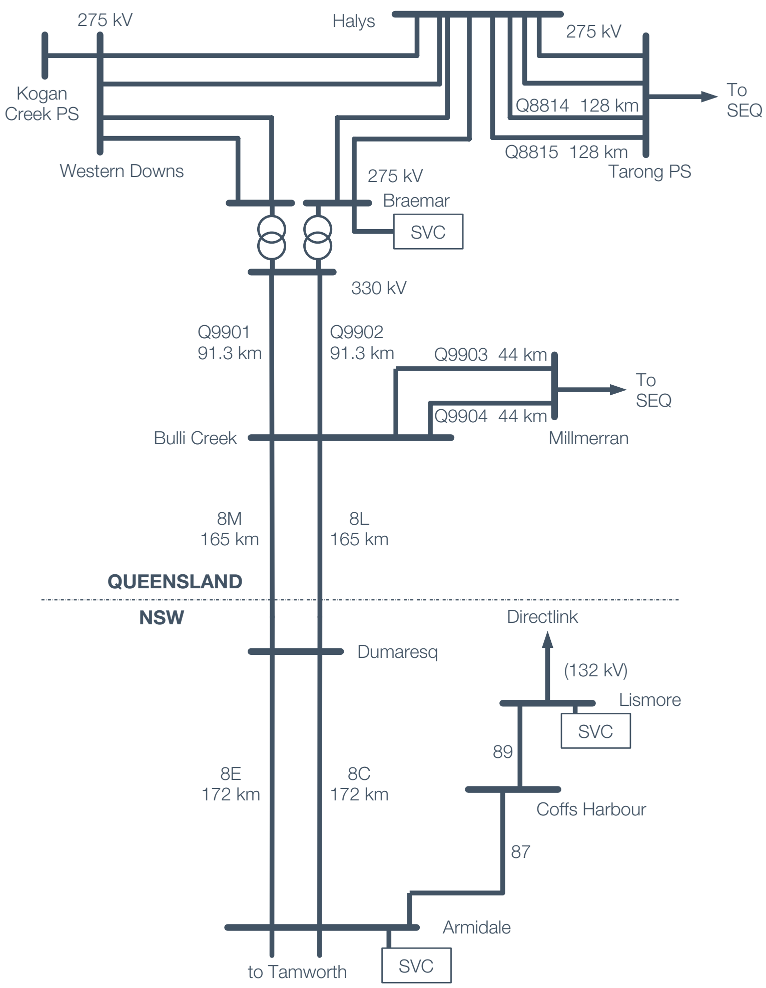
6.3.1 Queensland – NSW Interconnector (QNI) transmission capacity

Background

QNI connects the NSW and Queensland power systems. Its power transfer capability is governed by overall system-wide stability constraints and also by voltage control and line rating constraints in the supporting 330 kV systems. Directlink operates in parallel with QNI.

QNI can be heavily loaded depending on the dispatch of generation across the NEM. There is potential for upgrading of the interconnector capability.

In June 2012, together with Powerlink, we issued a Project Specification Consultation Report (PSCR). The two organisations published a Project Assessment Draft Report (PADR) in March 2014 and a Project Assessment Conclusion Report in November 2014. These documents are available on our websites[2].



2 http://www.transgrid.com.au/network/consultations/Pages/CurrentConsultations.aspx
http://www.powerlink.com.au/Network/Network_Planning_and_Development/QNI_upgrade_study.aspx

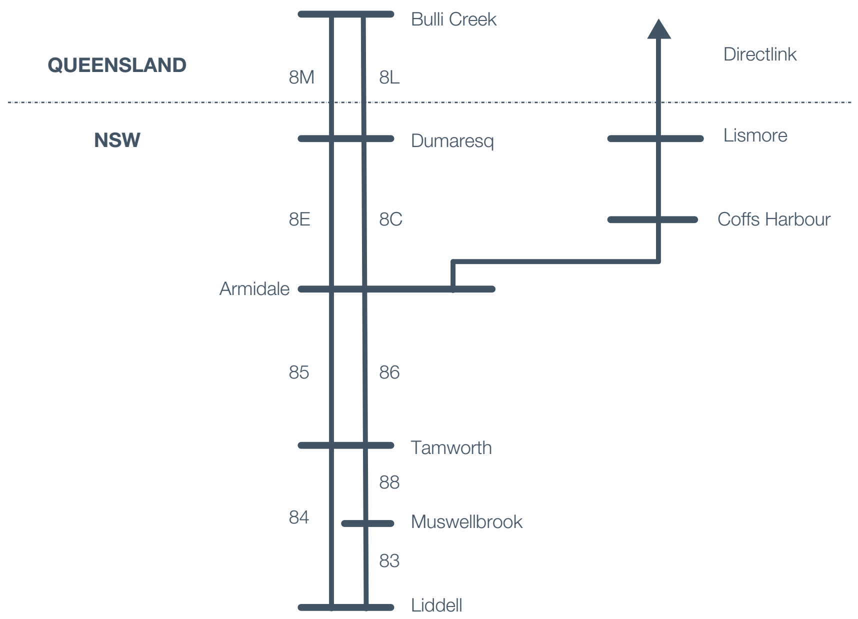
Nature of the constraint	The regulatory consultation considered net benefits to the market. The constraints are given in the regulatory consultation documents.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** With Powerlink, we have examined the possibility of a non-network option to increase the capability across QNI. Non-network options including demand-side response, would need to be considered on a case by case basis as discussed in the PADR.
Possible network options	The following options have been included as credible options in the RIT-T: > Uprating of the Northern NSW 330 kV transmission lines > Series compensation of the interconnecting 330 kV lines between Armidale, Dumaresq and Bulli Creek > New SVCs at Armidale, Dumaresq and Tamworth, and switched shunt capacitors at Dumaresq, Armidale and Tamworth substations. The cost estimates for these options are given in the PADR document. Each of these options would have a material inter-network impact.
Preferred network option	The RIT-T assessment identified four important factors that influence the market benefit of credible options: > Future gas prices in Queensland > The possible retirement of Redbank power station > The development of wind farms in Northern NSW > Load growth. We also tested the robustness of the net market benefits and ranking of options against a number of other factors, including: > The exclusion of competition benefits > A reduction in QNI capacity provided by the option > An increase and decrease in the cost of the credible options > Differences in the discount rate used in the net present value (NPV) assessment. These analyses reveal that the ranking of credible options is inconsistent across the scenarios. Further, many credible options have negative net market benefits under a number of scenarios and, as such, rank below the 'do nothing' option. Therefore, with Powerlink, it is our view that there is too much uncertainty concerning these factors and that it is prudent to not recommend a preferred option. Instead, we will continue to monitor developments, with Powerlink, regarding these key input assumptions.

6.3.2 Tamworth and Armidale 330 kV switchyards

Background	The 330 kV switchyards at Tamworth and Armidale were originally constructed to service the relatively small loads in Northern NSW, when there was a limited 330 kV network development extending north of Liddell. The switchyards are configured with single busbars and bus section circuit breakers. The establishment of QNI and the connection of an SVC at Armidale changed the utilisation of the substations. Instead of serving local loads, they became critical switching stations and, in the case of Armidale, voltage support points for high transfers on QNI. In the future, it is expected that there may be new wind farms and gas-fired generation developments in the area, and higher power transfers between NSW and Queensland.
Nature of the constraint	Should any development proceed, it would be driven by benefit to the market and on QNI being upgraded.
Possible network options	A set of options and staging strategies that may be viable for the redevelopment of the Armidale and Tamworth substations are: > Expanding only the Tamworth substation by installing an additional bus-section circuit breaker on the existing single busbar > Rebuilding both Armidale and Tamworth substations now in a breaker-and-a-half configuration to improve reliability to the desired level > Rebuilding both Armidale and Tamworth substations in a breaker-and-a-half configuration in the future, when the existing assets reach the end of their serviceable life > At both Armidale and Tamworth substations, undertaking the staged development of a second switchyard in a breaker-and-a-half configuration adjacent to the existing switchyard. Should any development be warranted, the preferred option is to develop a new 330 kV switchyard with a breaker-and-a-half arrangement to make these switchyards compatible with other major main-system switchyards. Consideration is being given to the feasibility of reconstructing the switchyards within the existing site boundaries. We are also identifying potential sites for the new switchyards in the event that an in-situ development is not feasible.

6.3.3 Hunter Valley – Tamworth – Armidale 330 kV system capacity

Background	Capacity constraints may arise in the Northern NSW supply system due to the increased power flows to and from Queensland. The constraints may also arise due to increased generation developments from gas, solar and wind power in Northern NSW. Recent de-rating of lines 83 and 84 have imposed further thermal constraints on the capability of NSW export to Queensland at times of high load in the Northern NSW system. The Northern NSW supply system, shown in the following figure, comprises four 330 kV lines: > Liddell – Tamworth line 84 > Liddell – Tamworth via Muswellbrook lines 83 and 88 > Tamworth – Armidale line 85 > Tamworth – Armidale line 86. The 330 kV system extends north from Liddell to Armidale via Muswellbrook and Tamworth. The 330 kV lines are conventional steel tower design, except for the Tamworth – Armidale line 86, which is a wooden pole line with relatively small conductors.



Nature of the constraint	Should any development proceed, it would be contingent on QNI being upgraded and new generation being connected in Northern NSW.
Network options	Should load development in the northern area and upgrading of the power transfer levels with Queensland occur, augmentation of the transmission system using one or a combination of the following options may be cost-effective: > Uprating the lines 83, 84, 85 and 88 from an operating temperature of 85°C to 120°C > Installing a new single circuit 330 kV line from Liddell to Tamworth > Installing a new double circuit 330 kV line on a new route from Liddell to Tamworth.

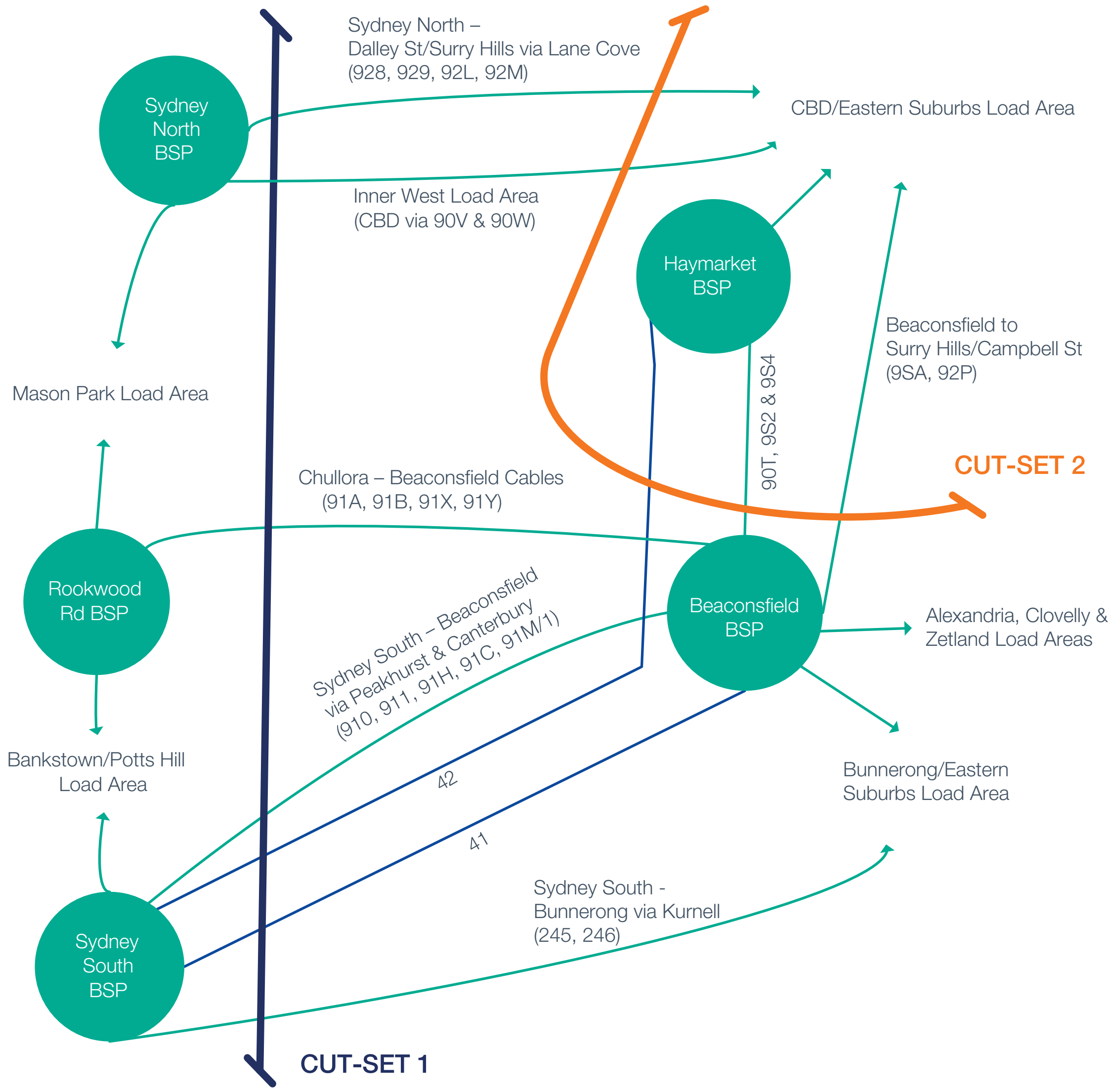
6.3.4 Voltage control in Northern NSW

Background	The 330 kV system extends north beyond Armidale to Dumaresq and forms part of the interconnection with Queensland over QNI. The power transfer capability north from Liddell, to supply the Northern NSW loads and to export power to Queensland, is partly governed by line thermal ratings, the ability to maintain adequate voltage levels and transient stability constraints. The power transfer capability of the system is dependent on load levels and the dispatch of generators across the National Electricity Market. The ability to maintain adequate voltage levels is currently the main constraint on the NSW export capability to Queensland under a wide range of operating conditions. In particular, the ability to maintain adequate voltage levels at Tamworth, Armidale and Dumaresq is critical.
Nature of the constraint	Should this development proceed, it would be driven by net benefits to the market. It is contingent on QNI being upgraded and new generation being connected in Northern NSW.
Network options	Subject to the amount of new generation in Northern NSW and the magnitude of the increase in QNI capacity, the most cost effective way of managing the voltage stability constraints would be to install additional capacitors or an SVC in the area.

6.3.5 'Powering Sydney's Future' supply to the Sydney inner metropolitan area

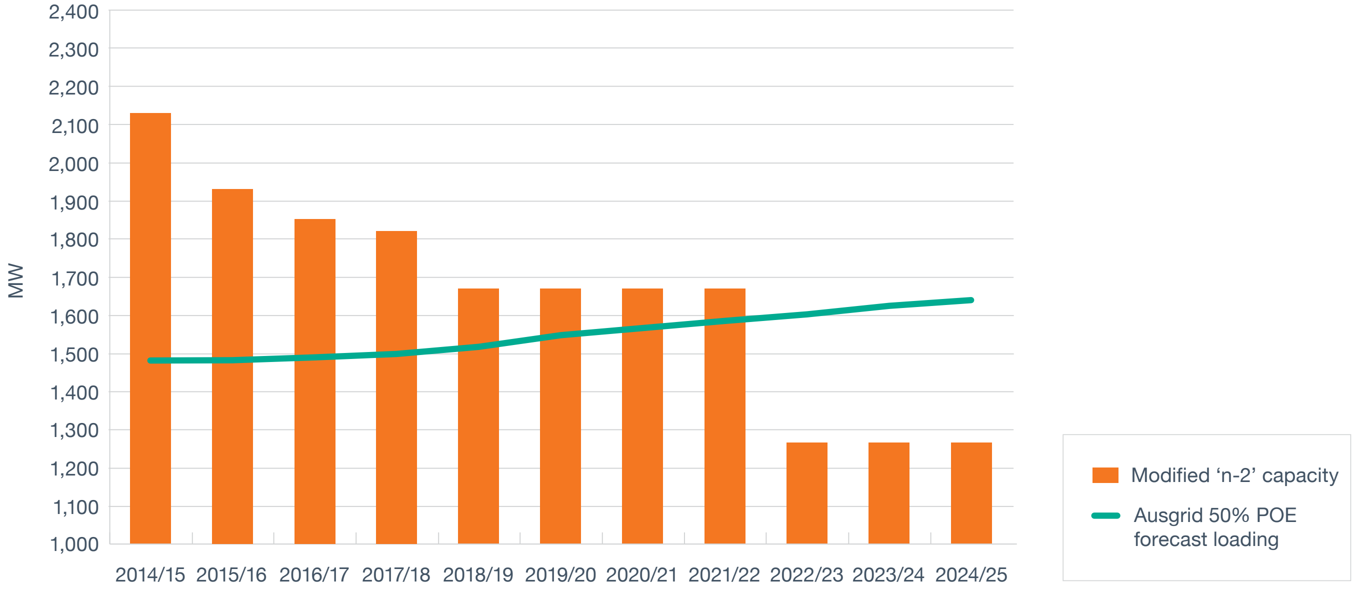
Background	The Sydney inner metropolitan area and CBD are supplied by an integrated network consisting of two 330 kV cables and a large number of 132 kV cables. Over the coming years, the supply capacity of this network is forecast to decrease as cables nearing the end of their serviceable lives are retired, based on their condition. In addition, cable de-ratings resulting from the degraded condition of the backfill of numerous cables has contributed to the decrease in the capacity of the inner metropolitan supply network.
Nature of the constraint	A shortfall in the adequacy of the network to supply the inner metropolitan load at the required level of reliability is forecast. This shortfall is due to the planned cable retirements in conjunction with a modest forecast load growth in the area. Constraints are expected to arise in two parts of the network, shown as cut-set 1 and cut-set 2 in the figure below. The first is a constraint between the bulk supply points located on the perimeter of the metropolitan area and the inner metropolitan area. The second is a constraint within the inner metropolitan area between the Beaconsfield bulk supply point and the inner city area. As mentioned in Section 6.2.3, there is uncertainty about the rating of cable 41. Should its rating reduce, the shortfall in network capacity would be greater and the onset of capacity limitations would most probably be earlier than described here.

Nature of the constraint

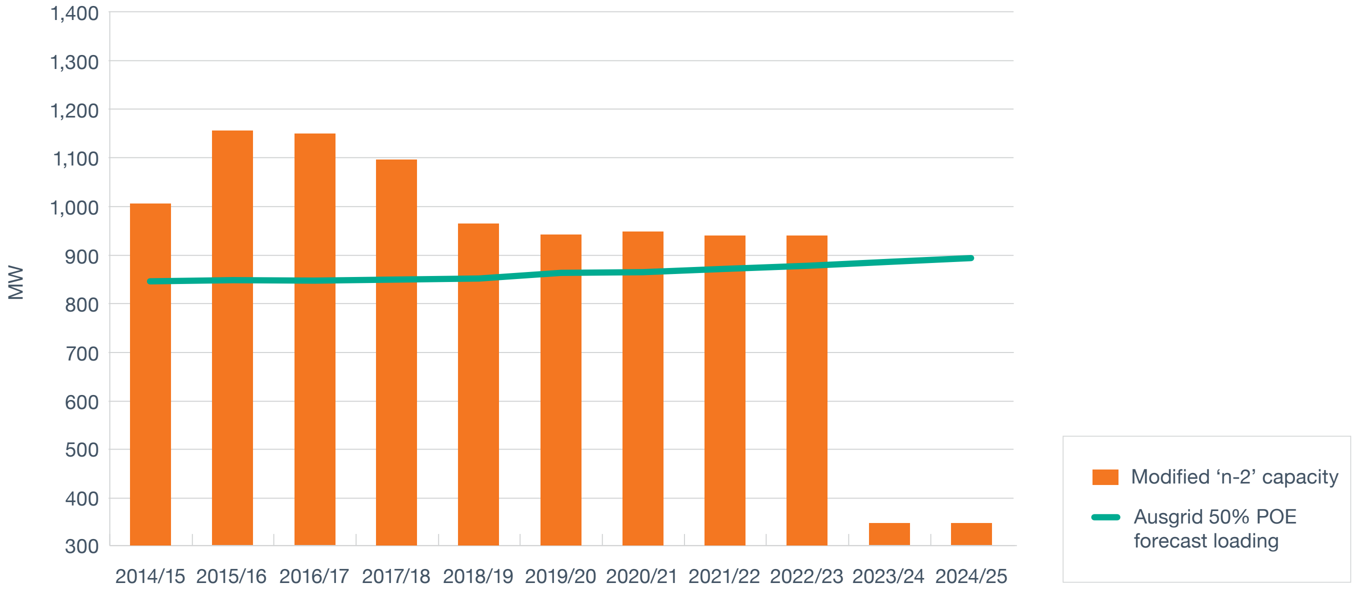


Sydney inner metropolitan supply network constraint cut-sets 1 & 2
The following figures show the progressive reduction in network capacity that occur year-to-year, with the expected cable retirements for each of the identified constraint cut-sets, against the forecast load across those cut-sets. The reduction in network capability is due to the expected retirement of Ausgrid 132 kV cables. The retirement of cables is regularly reviewed as part of joint planning with Ausgrid.

Cut-set 1 network capacity and forecast load



Cut-set 2 network capacity and forecast load



Possible network options	The following options have been identified: > Establishing a new 330 kV cable between Rookwood Road and Beaconsfield West and a new 330 kV cable between Beaconsfield and Haymarket. Part of the latter cable is presently in service at 132 kV. This would require the installation of additional 330 kV GIS switchbays at each of these substations > Establishing two new 330 kV cables connected and operated at 132 kV between Rookwood Road and Beaconsfield West substations, and replacing the 132 kV cables supplying the Surry Hills area > Establishing two high-capacity 132 kV cables from Lane Cove to Pyrmont, and replacing the 132 kV cable supplying the Surry Hills area > Non-network options to defer or avoid network investment to address the need.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** The capacity shortfall that would result from the planned retirement of existing cables is expected to exceed the level of demand management that would currently be available. However, we will continue to monitor the level of demand growth and likely levels of demand management available from time to time, with the intent to implement any economic deferral of capital expenditure with non-network options where practicable. **Scenario:** A shortfall in capacity is expected to occur in the mid 2020s. This is dependent on the retirement of Ausgrid 132 kV cables. **N–2 (modified):** Cable 42 and one of many 132 kV Ausgrid feeders **Shortfall:** 338 MW in 2023 summer, 359 MW in 2024 summer **Location:** The Sydney inner metropolitan area including the CBD, the Eastern suburbs, and parts of the Inner East and Inner West. **Deferral Value:** $409m **Speed:** 5-10 minutes
Preferred option	At this stage, our preferred option is to establish two new 330 kV cables between Rookwood Road and Beaconsfield West connected and operated at 132 kV, in conjunction with Ausgrid's replacement of the 132 kV cables supplying the Surry Hills area. The use of non-network options, such as demand management to defer or, if possible, avoid one or both of these cables would be implemented if practical and cost-effective.

6.3.6 Condition of the Newcastle substation

Background	The Newcastle substation is a focal point for 330 kV connections to generators (Liddell, Eraring and Vales Point power stations), and the major bulk supply points at Waratah West and Tomago. It also provides significant supply capacity to Ausgrid's 132 kV network through the 330/132 kV transformers. Significant parts of the Newcastle substation, which was commissioned in 1969, are in poor condition as the original equipment is approaching the end of their serviceable lives. The original transformers were previously identified as being in poor condition and have been replaced under a separate project. Refer to Section 5.2.2.
Nature of the constraint	The condition of Newcastle substation is expected to need to be addressed by 2024. The substation is required to meet the present and future demand in the area, and provide a focal point for seven 330 kV connections.
Possible network options	Options available to address the constraints include: > Rebuilding the Newcastle substation within the existing site in a piecemeal fashion > Rebuilding the Newcastle substation adjacent to the existing site > Rebuilding the Newcastle substation across the existing site and an adjacent site. The piecemeal reconstruction is the least-cost option. It addresses the identified targeted asset replacements and substation condition issues over six years at a cost of around $51m. The transformers have been replaced under a separate project, and will be retained under the reconstruction.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** The renewal of Newcastle substation is driven by the condition of the substation and its assets. The substation is a 330 kV focal point connecting large thermal generators to the greater Newcastle area, including the Mid North Coast (via Tomago). As non-network options cannot provide these connections, they are not feasible. Also, a reduction in load would not defer the retirement date of substation assets. The number of connections in the new substation will remain unchanged, and the transformers are not being replaced.
Preferred network option	The preferred network option is to rebuild Newcastle substation in a piecemeal fashion. The 132 kV network in the future may change depending on industrial load developments. However, given the number of existing connections, Newcastle is likely to remain the focal point for 330 kV circuits in the area.

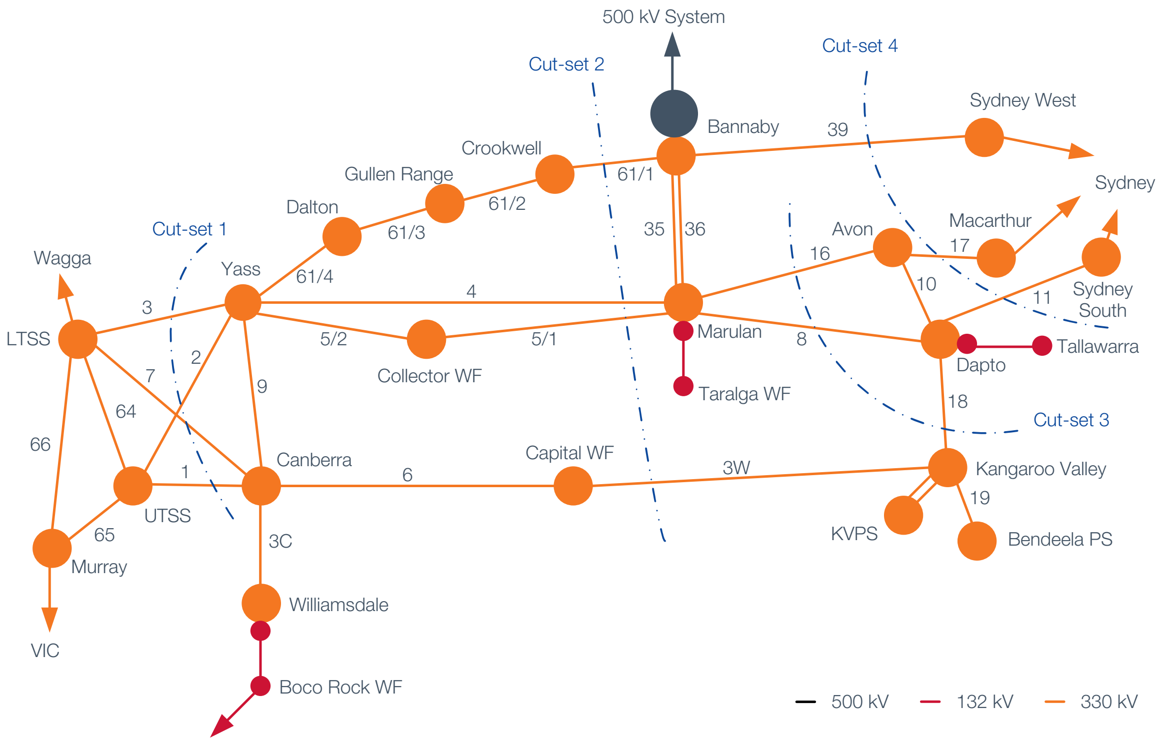
6.3.7 Capacity of the Snowy to Sydney network

Background

The loading of the Snowy to Sydney network depends on the distribution of load and generation within the NSW region. Preliminary market modelling of scenarios involving retirement of some of the existing coal fired generating units, indicates that there may be net market benefits if parts of the network between Snowy to Sydney were to be up-rated.

The balance of this item considers three parts of the network between Snowy to Sydney, namely cut-sets 1, 2 and 4 in the figure below. The remaining section (cut-set 3) is addressed in Section 6.3.8.

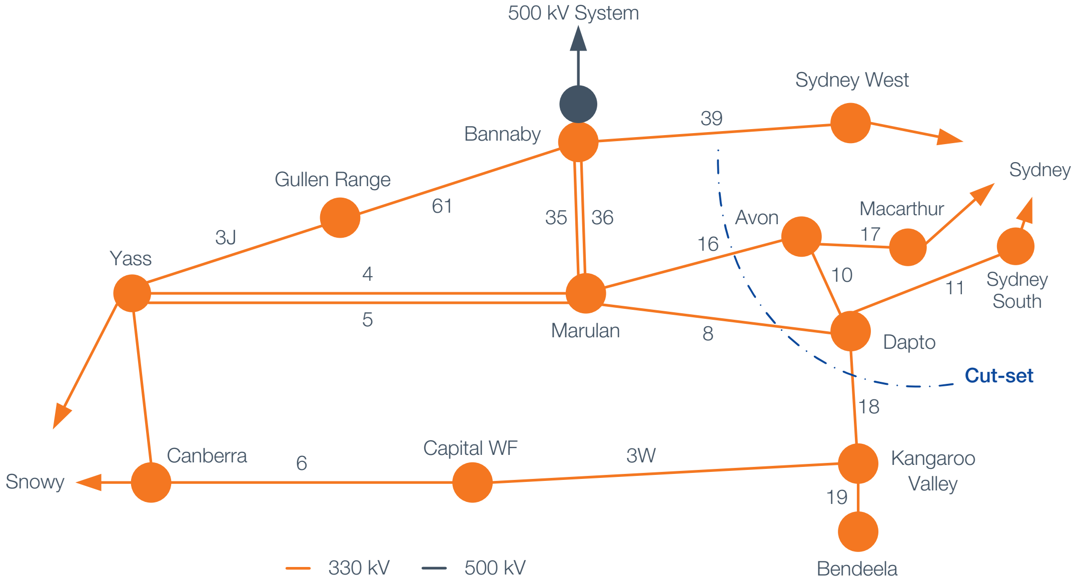
The figure below shows existing network connections between Snowy to Sydney as well as existing and possible future generation in the area.



Background (continued)	**1. Capacity of Snowy to Yass/Canberra (cut-set 1)** The No. 01 and 02 330 kV lines were designed to operate at a maximum temperature of 85°C. Recent aerial laser surveys show that remedial work is required on both lines to ensure that they can operate at this temperature. Should there be a need to transfer higher levels of power across the Snowy to Yass/Canberra lines, up-rating the lines may be cost-effective. The increased power transfer may arise from: > Increased Snowy generation > Increased import from South Australia and Victoria at times of high NSW and Queensland load > Load growth in Queensland and NSW > Decommissioning or reduction of coal fired generation in NSW. **2. Capacity of Yass/Canberra to Bannaby/Marulan (cut-set 2)** System studies have identified that the existing Yass/Canberra to Bannaby/Marulan network could be constrained under certain operating conditions if: > The Snowy – Yass/Canberra network is upgraded and generation from Victoria and Snowy is transferred to NSW to the maximum capacity allowed by those works > The present and future wind farms connected to the southern network generate power at, or near, their rated capacities. **3. Capacity of Bannaby/Avon/Dapto – Sydney (cut-set 4)** System studies have identified that the capacity of the Bannaby – Sydney West line 39 could be exceeded if the recently commissioned Gullen Range and Boco Rock wind farms and the Taralga wind farm which is presently being commissioned, operate at their maximum capacity, even without any increase in the Snowy to Yass/Canberra capacity. Constraints in this part of the network would increase if other proposed generation comes to fruition.
Nature of the constraint	Any network development would be driven by net benefits to the market. It is expected to be contingent on new generation development in Southern NSW. Given the uncertainties surrounding generation developments, decommissioning, mothballing and re-powering, the time at which there may be net market benefits from any option is difficult to predict.
Target date	The target date would be determined by detailed market modelling. Should any line upgrades be warranted, it may be possible to undertake them in conjunction with the planned transmission line remediation work in the area.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** Non-network options are considered alongside network options where feasible and cost-effective to do so. The preliminary market modelling is not sufficiently detailed to allow the performance requirements for non-network options to be determined. Consequently, they are not available at this stage.

Possible network options	A range of options are being investigated, including: **1. Capacity of Snowy to Yass/Canberra (cut-set 1):** > Implementing a system protection scheme and procuring a network support contract with a suitable load and generator > Upgrading the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV lines. This requires work in the sensitive national park areas of the Snowy > Installing a power flow control plant, such as series capacitors or phase-shifting transformers (PSTs) to improve the sharing of power flows in the four lines under contingency conditions. **2. Capacity of Yass/Canberra to Bannaby/Marulan (cut-set 2):** > Upgrading lines 4 and 5 to an operating temperature of 100°C > Upgrading lines 4 and 5 to an operating temperature of 100°C and installing a PST on line 61 at Bannaby > Upgrading lines 4 and 5 to an operating temperature of 100°C and installing PSTs on line 61 at Bannaby and on line 5 at Marulan. **3. Capacity of Bannaby/Avon/Dapto – Sydney (cut-set 4):** > Upgrading line 39 to an operating temperature of 100°C > Installing a PST on line 39 at Bannaby > Upgrading line 39 to an operating temperature of 100°C and installing a PST on line 39 at Bannaby.
Preferred network option	It is expected that cost-effective options to increase the capacity of the network between Snowy and Sydney (if any) would be identified by market modelling. At present, there is no preferred network option. However, should any network upgrading be appropriate, it is expected that it could entail one or more of the following: > Uprating line 01 to an operating temperature of 100°C > Uprating line 39 to an operating temperature of 100°C > Uprating lines 4 and 5 to an operating temperature of 100°C > Installing a PST at Bannaby on line 39 > Replacing terminal equipment on line 11 at Dapto and Sydney South.

6.3.8 Capacity of the Marulan – Avon, Marulan – Dapto and Kangaroo Valley – Dapto lines

Background	Lines 8, 16 and 18 form the cut-set supplying the Sydney/Wollongong area from the south of Sydney. The following figure shows the existing 330 kV connections between Marulan/Kangaroo Valley and Avon/Dapto.  In the longer term, if additional generators are connected to the southern network, lines 8, 16 and 18 may have thermal rating constraints.
Nature of the constraint	Any development, would be driven by net benefits to the market.
Target date	The target date depends on generation developments occurring and there being net market benefits in relieving the resulting constraints.
Possible network options	Various options are to be investigated, including: > Implementing a special protection scheme (SPS) – generation runback scheme > Upgrading line 18 to an operating temperature of 100°C > Upgrading of lines 8 and 16 to an operating temperature of 100°C > Developing a new line from Kangaroo Valley to Dapto > Rebuilding line 18 as a double circuit.
Preferred network option	At this stage there is no preferred option. However, it is anticipated that the most appropriate development, should one be required, would be to upgrade line 18 to an operating temperature of 100°C.

6.3.9 Condition of 944 Wallerawang – Orange North 132 kV transmission line

Background	The 944 Wallerawang – Orange North wooden pole 132 kV line was constructed in 1956/57. A condition assessment has identified that the line is near the end of its serviceable life. There was an intention to rebuild the line. However, with the moderation of maximum demand forecasts in Central Western NSW, a lower cost option became viable. Subsequently, a short term solution of replacing some poles is being adopted.
Nature of the constraint	In the medium term, if line 944 is retired and not replaced, thermal rating and/or voltage control constraints are expected to arise on parts of the network supplying the area in the event of an outage on either the 94X Wallerawang – Panorama or 949 Mt Piper – Orange North 132 kV line.
Network options	Possible network options include: > Replacement of the 944 line with a new 132 kV line > Provision of a 330/132 kV substation in the Orange area > Substation works entailing the installation of series reactors to limit flows on critical lines together with the installation of shunt capacitors.
Load reduction to delay constraint and non-network option requirements	**Feasibility:** In the medium term, a non-network solution may be technically feasible to address this need. At this stage, the timing of any major work is not clear. Consequently, the performance required of non-network options cannot be defined.
Preferred network option	In the short term, some poles will be replaced. The condition of the line will be regularly reviewed. The outcomes of those reviews will inform future actions. Consequently, at this stage, there is no preferred option for the longer term.

6.3.10 Other possible network asset replacements within five to ten years

The following table summarises other possible network asset replacement projects within five to ten years.

TABLE 6.3 – Other possible network asset replacements within five to ten years

Project	Location	Scope of works	Possible commission date	Indicative cost
Beryl secondary systems replacement	Beryl substation Central Western NSW.	In-situ replacement of the existing control and protection panels within the existing control room	2020	$6m
Armidale 330/132 kV substation: secondary systems replacement	Armidale substation, Northern NSW	In-situ replacement of the existing control and protection panels within the existing control room, retaining the existing LV cabling.	2021	$1m
Forbes No 1 and No 2 132/66 kV transformer replacement	Central Western NSW	Replacement of the existing 60 MVA transformers	2021	$8m
99J Yanco – Griffith 132 kV transmission line rebuild	Yanco – Griffith 132 kV line 99J, Southern NSW	Replacement of the line	2022	$18m

6.4 Possible developments beyond ten years

6.4.1 Supply to the Forster/Tuncurry area

Background	In the longer term, the load in the Forster/Tuncurry area is expected to reach the capacity of Essential Energy's 66 kV network supplying the area from Taree. At this stage, the constraint is not expected to arise before the mid 2020s.
Network options	Together with Essential Energy, we are considering a number of options to relieve the constraint, including: > Local generation and/or demand management > Reinforcing the existing Essential Energy network by providing an additional line from Taree or uprating the existing lines > Constructing a 132/66 kV substation in the Hallidays Point area. The substation would be supplied from our existing 963 Tomago – Taree 132 kV line. New sections of 132 kV and 66 kV lines would form connections to the new substation.

6.4.2 Line switchbays for distributor requirements beyond ten years

The following table summarises possible line switchbays for distributor requirements beyond ten years.

TABLE 6.4 – Possible line switchbays for distributor requirements beyond ten years

Location	Installation	Indicative date	Distributor
Lismore	Two 132 kV switchbays	Beyond 2024	Essential Energy
Tamworth 132/66 kV substation	One 66 kV switchbay	Beyond 2024	Essential Energy
Tumut 132/66 kV substation	One 66 kV switchbay	Beyond 2024	Essential Energy

6.5 Reporting under NER Clause 5.12.2(c)

NER Clause 5.12.2(c)(4) concerns constraints expected to arise in one, three and five years and requires that we indicate our intent to issue a Request for Proposal (RfP) with respect to those constraints. The following two sections describe constraints that are expected to arise in one, three and five years, and include constraints that are expected to emerge in two and four years as well.

6.5.1 Forecast constraint information

The required forecast constraint information is provided in Table 6.5. The season in which the constraint is expected to arise is given, rather than the month and year.

TABLE 6.5 – Forecast constraint information

Anticipated constraint or constraint	Reason for constraint	Bulk supply point(s) at which MW reduction would apply	MW at time that constraint is reached
Queensland – NSW Interconnector capacity	Thermal overload, voltage control, system stability	South of the relevant cut-set. Refer to Section 6.3.1	Refer to Section 6.3.1
Supply to the Gunnedah/Narrabri area	Thermal overload	Gunnedah and/or Narrabri	Refer to Section 6.2.1
Supply to the Sydney inner metropolitan area	Thermal overload	Primarily Beaconsfield and Haymarket	Refer to Section 6.3.5
Sydney South – Beaconsfield cable capacity	Thermal overload	Primarily Beaconsfield and Haymarket	Refer to Section 6.2.3
Capacity of the Snowy to Sydney network	Thermal overload	North of the relevant cut-set. Refer to Section 6.3.7	Refer to Section 6.3.7

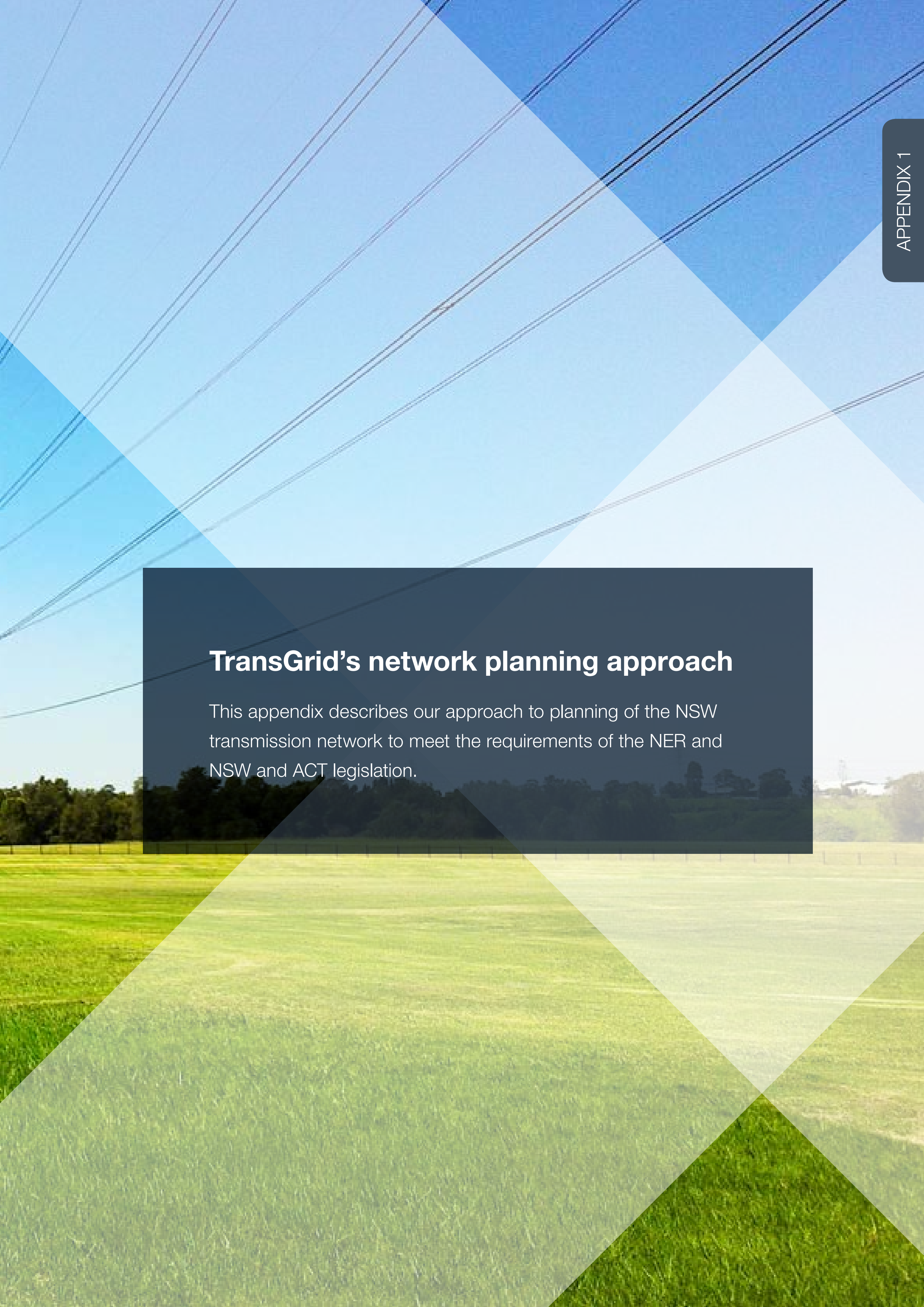
6.5.2 Intent to issue Request for Proposals

Table 6.6 indicates our intent to issue an RfP for non-network services.

TABLE 6.6 – Anticipated Issue of an RfP for non-network services

Anticipated constraint	Intend to issue RfP	Date
Queensland – NSW Interconnector capacity	To be assessed	
Supply to the Gunnedah/Narrabri area	To be assessed	Dependant on quantification of new load
Supply to the Sydney inner metropolitan area	To be assessed	
Sydney South – Beaconsfield cable capacity	To be assessed	
Capacity of the Snowy to Sydney network	To be assessed	


1
Appendix



TransGrid's network planning approach

This appendix describes our approach to planning of the NSW transmission network to meet the requirements of the NER and NSW and ACT legislation.

A1.1 General

Under NSW legislation TransGrid has responsibility to plan for future NSW transmission needs, including interconnection with other networks.

The NSW Government has specified the Transmission Network Design and Reliability Standard to be applied by TransGrid.

In addition, as a Transmission Network Service Provider (TNSP), TransGrid is obliged to meet the requirements of the National Electricity Rules (NER). In particular, TransGrid is obliged to meet the requirements of clause S 5.1.2.1:

'Network Service Providers must plan, design, maintain and operate their transmission networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called 'credible contingency events').'

The NER sets out the required processes for developing networks as well as minimum performance requirements of the network and connections to the network. It also requires TransGrid to consult with Registered Participants and interested parties and to apply the Australian Energy Regulator's (AER's) Regulatory Investment Test – Transmission (RIT-T) as appropriate to development proposals.

TransGrid's planning obligations are also interlinked with the reliability obligations placed on Distribution Network Service Providers (DNSP) in NSW. TransGrid must ensure that its system is adequately planned to enable these licence requirements to be met.

TransGrid also has obligations to meet community expectations in the supply of electricity, including ensuring that developments are undertaken in a socially and environmentally responsible manner. TransGrid plans the network to achieve supply at least cost to the community, without being constrained by state borders or ownership considerations.

TransGrid's approach to network planning includes consideration of non-network options, such as demand side response and demand management and/or embedded generation, as an integral part of the planning process. Joint planning with DNSPs, directly supplied industrial customers, generators and interstate TNSPs is carried out to ensure that the most economic options, whether network options or non-network options, consistent with customer and community requirements are identified and implemented.

A1.1.1 Jurisdictional planning requirements

In addition to meeting requirements imposed by the NER, environmental legislation and other statutory instruments, TransGrid is generally expected by the NSW jurisdiction to plan and develop its transmission network on an N–1[1] basis. That is, unless specifically agreed otherwise by TransGrid and the affected distribution network owner or major directly connected end-use customer, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following an outage of a single circuit (a line or a cable) or transformer, during periods of forecast high load.

In fulfilling this obligation, TransGrid must recognise specific customer requirements as well as the Australian Energy Market Operator's (AEMO) role as system operator for the National Electricity Market (NEM). To accommodate this, the standard N–1 approach can be modified in the following circumstances:

- Where agreed between TransGrid and a distribution network owner or major directly connected end-use customer, agreed levels of supply interruption can be accepted for particular single outages, before augmentation of the network is undertaken (for example the situation with radial supplies)
- Where requested by a distribution network owner or major directly connected end-use customer and agreed with TransGrid, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following events more onerous than N–1 such as concurrent outages of two network elements
- The main transmission network, which is operated by AEMO, should have sufficient capacity to accommodate AEMO's operating practices without inadvertent loss of load (other than load which is interruptible or dispatchable) or uneconomic constraints on the energy market. At present AEMO's operational practices include the re-dispatch of generation and ancillary services following a first contingency, such that within 30 minutes the system will again be 'secure' in anticipation of the next critical credible contingency.

The NSW Government requires TransGrid to provide a level of reliability in its network supplying NSW DNSPs to enable them to meet their reliability obligations.

1 N–1 reliability means the system is planned for no loss of load on the outage of a single element such as a line, cable or transformer

These jurisdictional requirements and other obligations require the following to be observed in planning:

> At all times when the system is either in its normal state with all elements in service or following a credible contingency:
    - Electrical and thermal ratings of equipment will not be exceeded
    - Stable control of the interconnected system will be maintained, with system voltages maintained within acceptable levels
> A quality of electricity supply at least to NER requirements is to be provided
> A standard of connection to individual customers as specified by Connection Agreements is to be provided
> As far as possible connection of a customer is to have no adverse effect on other connected customers
> Environmental and social objectives are to be satisfied
> Acceptable safety standards are to be maintained
> The power system in NSW is to be developed at the lowest cost possible whilst meeting the constraints imposed by the above factors.

Consistent with a responsible approach to the environment, it is also aimed to reduce system energy losses where economic.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with TransGrid's asset management strategies.

A1.1.2 National planning requirements

AEMO has the role of the national transmission planner and is required to produce a National Transmission Network Development Plan (NTNDP). The NTNDP has regard to jurisdictional planning and regulatory documents (such as Transission Annual Planning Reports (TAPRs)) and, in turn, the jurisdictional planning bodies need to have regard to the NTNDP in formulating their plans. The first NTNDP was published in 2010 with input from TransGrid. Through a close working relationship, TransGrid's future plans will be consistent with AEMO's.

A1.1.3 The network planning process

The network planning process is undertaken at three levels:

1. Connection planning
Connection planning is concerned with the local network directly related to the connection of loads and generators. Connection planning typically includes connection enquiries and the formulation of draft connection agreements leading to a preliminary review of the capability of connections. Further discussions are held with specific customers where there is a need for augmentation or for provision of new connection points.

2. Network planning within the NSW region
The main 500 kV, 330 kV and 220 kV transmission system is developed in response to the overall load growth and generation requirements and may be influenced by interstate interconnection power transfers. Any developments include negotiation with affected NSW and interstate parties.

The assessment of the adequacy of 132 kV systems requires joint planning with DNSPs. This ensures that development proposals are optimal with respect to both TransGrid and DNSP requirements leading to the lowest possible cost of transmission to the end customer. This is particularly important where the DNSP's network operates in parallel with the transmission network, forming a meshed system.

3. Inter-regional planning
The development of interconnectors between regions and of augmentations within regions that have a material effect on inter-regional power transfer capability are coordinated with network owners in other states in accordance with the NER. The inter-regional developments will be consistent with the NTNDP.

A1.1.4 Consideration of non-network alternatives

TransGrid's planning process includes consideration, and adoption where economic, of non-network alternatives which can address the emerging constraint(s) under consideration and may defer or cancel the need for network augmentations.

A1.1.5 Compliance with NER requirements

TransGrid's approach to the development of the network since the advent of the NEM is in accordance with the NER, other rules and guidelines promulgated by the AER and the Australian Energy Market Commission (AEMC).

A1.1.6 Planning horizons and reporting

Transmission planning is carried out over a short-term time frame of one to five years, and also over long-term time frames of five to 20 years or more. The short-term planning supports commitments to network developments with relatively short lead-times. The long-term planning considers options for future major developments and provides a framework for the orderly and economic development of the transmission network and the strategic acquisition of critical line and substation sites.

In this TAPR, the constraints that appear over long-term time frames are considered to be indicative. The timing and capital cost of possible network options to relieve them may change significantly as system conditions evolve. TransGrid has published outline plans for long-term developments.

A1.1.7 Identifying network constraints and assessing possible solutions

An emerging constraint is identified during various planning activities covering the planning horizon. It may be identified through:

> TransGrid's planning activities

> Joint planning with a DNSP

> The impact of prospective generation developments

> The occurrence of constraints affecting generation dispatch in the NEM

> The impact of network developments undertaken by other TNSPs

> As a result of a major load development.

During the initial planning phase, a number of options for addressing the constraint are developed. In accordance with NER requirements, consultation with interested parties is carried out to determine a range of options including network, demand management and local generation options and/or to refine existing options.

A cost effectiveness or cost-benefit analysis is carried out in which the costs and benefits of each option are compared in accordance with the AER's RIT–T. In applying the applicable test the cost and benefit factors may include:

> Avoiding unserved energy caused by either a generation shortfall or inadequate transmission capability or reliability

> Loss reductions

> Alleviating constraints affecting generation dispatch

> Avoiding the need for generation developments

> More efficient generation and fuel type alternatives

> Improvement in marginal loss factors

> Deferral of related transmission works

> Reduction in operation and maintenance costs.

Options with similar net present value would be assessed with respect to factors that may not be able to be quantified and/or included in the RIT–T, but nonetheless may be important from environmental or operational viewpoints. These factors include (but are not limited to):

> Reduction in greenhouse gas emissions or increased capability to apply greenhouse-friendly plant

> Improvement in quality of supply above minimum requirements

> Improvement in operational flexibility.

A1.1.8 Application of power system controls and technology

TransGrid seeks to take advantage of the latest proven technologies in network control systems and electrical plant where these are found to be economic. For example, the application of static var compensators[2] has had a considerable impact on the power transfer capabilities of parts of the main grid, and has deferred or removed the need for higher cost transmission line developments.

System protection schemes have been applied in several areas of the NSW system to reduce the impact of network limitations on the operation of the NEM, and to facilitate the removal of circuits for maintenance.

The broad approach to planning and consideration of these technologies, together with related issues of protection facilities, transmission line design, substation switching arrangements and power system control and communication, is set out in the following sections. This approach is in line with international practice and provides a cost effective means of maintaining a safe, reliable, secure and economic supply system consistent with maintaining a responsible approach to environmental and social impacts.

2 A static var compensator or SVC is an electrical device installed on the high voltage transmission system to provide fast acting voltage control to regulate and stabilise the system

A1.2 Planning criteria

The NER specifies the minimum and general technical requirements in a range of areas including:

> A definition of the minimum level of credible contingency events to be considered
> The power transfer capability during the most critical single element outage. This can range from zero in the case of a single element supply to a portion of the normal power transfer capability
> Frequency variations
> Magnitude of power frequency voltages
> Voltage fluctuations
> Voltage harmonics
> Voltage unbalance
> Voltage stability
> Synchronous stability
> Damping of power system oscillations
> Fault clearance times
> The need for two independent high speed protection systems
> Rating of transmission lines and equipment.

In addition to adherence to NER and regulatory requirements, TransGrid's transmission planning approach has been developed taking into account the historical performance of the components of the NSW system, the sensitivity of loads to supply interruption, and state-of-the-art asset maintenance procedures. It has also been recognised that there is a need for an orderly development of the system taking into account the long-term requirements of the system to meet future load and generation developments.

A set of criteria, detailed below, are applied as a point of first review, from which point a detailed assessment of each individual case is made.

A1.2.1 Main transmission network

The NSW main transmission system is the transmission system connecting the major power stations and load centres and providing the interconnections from NSW to Queensland and Victoria. It includes the majority of the transmission system operating at 500 kV, 330 kV and 220 kV.

This system comprises over 7,000 kilometres of transmission circuits supplying a peak load of approximately 13,000 MW throughout NSW.

Power flows on the main transmission network are subject to overall State load patterns and the dispatch of generation within the NEM, including interstate export and import of power. AEMO operates the interconnected power system and applies operational constraints on generator dispatch to maintain power flows within the capability of the NSW and other regional networks. These constraints are based on the ability of the networks to sustain credible contingency events that are defined in the NER. These events mainly cover forced outages of single generation or transmission elements, but also provide for multiple outages to be redefined as credible from time to time. Constraints are often based on short-duration loadings on network elements, on the basis that generation can be re-dispatched to relieve the line loading within 15 minutes.

The rationale for this approach is that, if operated beyond a defined power transfer level, credible contingency disturbances could potentially lead to system-wide loss of load with severe social and economic impact.

Following any transmission outage, for example during maintenance or following a forced line outage for which line reclosure[3] has not been possible, AEMO applies more severe constraints within a short adjustment period, in anticipation of the impact of a further contingency event. This may require:

> The re-dispatch of generation and dispatchable loads
> The re-distribution of ancillary services
> Where there is no other alternative, the shedding (interruption) of load.

AEMO may direct the shedding of customer load, rather than operate for a sustained period in a manner where overall security would be at risk for a further contingency. The risk is, however, accepted over a period of up to 30 minutes. TransGrid considers AEMO's imperative to operate the network in a secure manner.

TransGrid's planning for its main network concentrates on the security of supply to load connection points under sustained outage conditions, consistent with the overall principle that supply to load connection points must be satisfactory after any single contingency.

The main 500 kV, 330 kV and 220 kV transmission system is augmented in response to the overall load growth and generation requirements and may be influenced by interstate interconnection power transfers. Any developments include negotiation with affected NSW and interstate parties including AEMO to maintain power flows within the capability of the NSW and other regional networks.

3 TransGrid lines have automatic systems to return them to service (reclose them) following a fault.

The reliability of the main system components and the ability to withstand a disturbance to the system are critically important in maintaining the security of supply to NSW customers. A high level of reliability implies the need for a robust transmission system. The capital cost of this system is balanced by:

- > Avoiding the large cost to the community of widespread shortages of supply
- > Providing flexibility in the choice of economical generating patterns
- > Allowing reduced maintenance costs through easier access to equipment
- > Minimising electrical losses which also provides benefit to the environment.

The planning of the main system must take into account the risk of forced outages of a transmission element coinciding with adverse conditions of load and generation dispatch. Two levels of load forecast (summer and winter) are considered, as follows.

Loads at or exceeding a one in two year probability of occurrence (50% probability of exceedance)

The system will be able to withstand a single contingency under all reasonably probable patterns of generation dispatch or interconnection power flow. In this context, a single contingency is defined as the forced outage of a single transmission circuit, a single generating unit, a single transformer, a single item of reactive plant or a single busbar section.

Provision will be made for a prior outage (following failure) of a single item of reactive plant.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive shedding (interruption) of load, so as to withstand the impact of a second contingency.

Loads at or exceeding a one in ten year probability of occurrence (10% probability of exceedance)

The system will be able to withstand a single contingency under a limited set of patterns of generation dispatch or interconnection power flow.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive load shedding, so as to withstand the impact of a second contingency.

These criteria do not apply to radial sections of the main system.

The patterns of generation applied to the 50% probability of exceedence load level cover patterns that are expected to have a relatively high probability of occurrence, based on the historical performance of the NEM and modelling of the NEM generation sources into the future. The limited set of patterns of generation applied to the 10% probability of exceedance load level cover two major power flow characteristics that occur in NSW. The first power flow characteristic involves high output from base-load generation sources throughout NSW and high import to NSW from Queensland. The second power flow characteristic involves high import to NSW from Victoria and Southern NSW generation coupled with high output from the NSW base-load generators.

Under all conditions there is a need to achieve adequate voltage control capability. TransGrid has traditionally assumed that all on-line generators can provide reactive power support within their rated capability. However, in the future, TransGrid intends to align with other utilities in relying only on the reactive capability given by performance standards. Reactive support beyond the performance standards may need to be procured under network support arrangements.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with TransGrid's asset management strategies.

Overall supply in NSW is heavily dependent on base load coal fired generation in the Hunter Valley, Western area and Central Coast. These areas are interconnected with the load centres via numerous single and double circuit lines. In planning the NSW system, taking into account AEMO's operational approach to the system, there is a need to consider the risk and impact of overlapping outages of circuits under high probability patterns of load and generation.

The analysis of network adequacy must take into account the probable load patterns, typical dispatch of generators and loads, the availability characteristics of generators (as influenced by maintenance and forced outages), energy limitations and other factors relevant to each case.

Options to address an emerging inability to meet all connection point loads would be considered with allowance for the lead time for a network augmentation solution.

Before this time, consideration may be given to the costs involved in re-dispatch in the energy and ancillary services markets to manage single contingencies. In situations where these costs appear to exceed the costs of a network augmentation, this will be brought to the attention of network load customers for consideration. TransGrid may then initiate the development of a network or non-network solution through a consultation process.

A1.2.2 Relationship with inter-regional planning

TransGrid monitors the occurrence of constraints in the main transmission system that affect generator dispatch. TransGrid's planning therefore also considers the scope for network augmentations to reduce constraints that may satisfy the RIT-T.

Under the provisions of the NER, a Region may be created where constraints to generator dispatch are predicted to occur with reasonable frequency when the network is operated in the 'system normal' (all significant elements in service) condition. The creation of a Region does not consider the consequences to load connection points if there should be a network contingency.

The capacity of interconnectors that is applied in the market dispatch is the short-time capacity determined by the ability to maintain secure operation in the system normal state in anticipation of a single contingency. The operation of the interconnector at this capacity must be supported by appropriate ancillary services. However, AEMO does not operate on the basis that the contingency may be sustained but TransGrid must consider the impact of a prolonged plant outage.

As a consequence, it is probable that for parts of the network that are critical to the supply to loads, TransGrid would initiate augmentation to meet an N–1 criterion before the creation of a new Region.

The development of interconnectors between regions will be undertaken where the augmentation satisfies the RIT-T. The planning of interconnections will be undertaken in consultation with the jurisdictional planning bodies of the other states.

It is not planned to maintain the capability of an interconnector where relevant network developments would not satisfy the RIT-T.

A1.2.3 Networks supplied from the main transmission network

Some parts of TransGrid's network are primarily concerned with supply to local loads and are not significantly impacted by the dispatch of generation (although they may contain embedded generators). The loss of a transmission element within these networks does not have to be considered by AEMO in determining network constraints, although ancillary services may need to be provided to cover load rejection in the event of a single contingency.

A1.2.4 Supply to major load areas and sensitive loads

The NSW system contains six major load areas with indicative loads as follows:

Load area	Indicative peak load
The NSW North, supplied from the Hunter Valley, Newcastle and over QNI	1,000 MW
Newcastle area	2,400 MW (this includes aluminium smelters with a load of around 1,000 MW)
Greater Sydney	6,000 MW
Western Area	600 MW
South Coast	700 MW
South and South West	1,600 MW

Some of these load areas, including individual smelters, are supplied by a limited number of circuits, some of which may share double circuit line sections. It is strategically necessary to ensure that significant individual loads and load areas are not exposed to loss of supply in the event of multiple circuit failures. As a consequence, it is necessary to assess the impact of contingency levels that exceed N–1.

Outages of network elements for planned maintenance must also be considered. Generally this will require 75% of the peak load to be supplied during the outage. While every effort would be made to secure supplies in the event of a further outage, this may not be always possible. In this case attention would be directed to minimising the duration of the plant outage.

A1.2.5 Urban and suburban areas

Generally the urban and suburban networks are characterised by a high load density served by high capacity underground cables and relatively short transmission lines. The connection points to TransGrid's network are usually the low voltage (132 kV) busbars of 330 kV substations. There may be multiple connection points and significant capability on the part of the DNSP to transfer load between connection points, either permanently or to relieve short-time loadings on network elements after a contingency.

The focus of joint planning with the DNSP is the capability of the meshed 330/132 kV system and the capability of the existing connection points to meet expected peak loadings. Joint planning addresses the need for augmentation to the meshed 330/132 kV system and TransGrid's connection point capacity or to provide a new connection point where this is the most economic overall solution.

Consistent with good international practice, supply to high-density urban and central business districts is given special consideration. For example, the inner Sydney metropolitan network serves a large and important part of the State load. Supply to this area is largely via a 330 kV and 132 kV underground cable network. The two 330 kV cables are part of TransGrid's network and the 132 kV cable system is part of Ausgrid's network. The reliability standard for the area specified by the NSW Government in the Transmission Network Design and Reliability Standard is that the system will be capable of meeting the peak load under the following contingencies:

1. The simultaneous outage of a single 330 kV cable and any 132 kV feeder or 330/132 kV transformer; or

2. An outage of any section of 132 kV busbar.

The requirement for a reliability criterion for the overall network that is more onerous than N–1 reflects:

> The importance and sensitivity of the Sydney area load to supply interruptions
> The high cost of applying a strict N–2 criterion to the 330 kV cable network
> The large number of elements in the 132 kV network
> The past performance of the cable system
> The long time to repair cables should they fail.

The criterion applied to the inner Sydney area is consistent with that applied in the electricity supply to major cities throughout the world. Most countries use an N–2 criterion. Some countries apply an N–1 criterion with some selected N–2 contingencies that commonly include two cables sharing the one trench or a double circuit line.

The above criterion is applied in the following manner in planning analysis:

1. Under system normal conditions, all elements must be loaded within their 'recurrent cyclic' rating
2. System loadings under first contingency outages will remain within equipment recurrent cyclic ratings without corrective switching other than for automatic switching or 'auto-change-over'
3. Cyclic load shedding (in areas other than the Sydney CBD) may be required in the short term following a simultaneous outage of a single 330 kV cable, and any 132 kV transmission feeder or 330/132 kV transformer in the inner metropolitan area, until corrective switching is carried out on the 330 kV or 132 kV systems
4. The system should be designed to remove the impact of a bus section outage at existing transmission substations. New transmission substations should be designed to cater for bus section outages
5. The load forecast to be considered is based on '50% probability of exceedence'
6. Loading is regarded as unsatisfactory when 330/132 kV transformers and 330 kV or 132 kV cables are loaded beyond their recurrent cyclic rating
7. Fault interruption duty must be contained to within equipment ratings at all times.

Outages of network elements for planned maintenance must also be considered. Generally this will require 75% of the peak load to be supplied during an outage. While every effort would be made to secure supplies in the event of a further outage, this may not be always possible. In this case attention would be directed to minimising the duration of the outage.

A1.2.6 Non urban areas

Generally these areas are characterised by lower load densities and, generally, lower reliability requirements than urban systems. The areas are sometimes supplied by relatively long, often radial, transmission systems. Connection points are either on 132 kV lines or on the low voltage busbars of 132 kV substations. Although there may be multiple connection points to a DNSP, they are often far apart and there will be little capacity for power transfer between them. Frequently supply limitations will apply to the combined capacity of several supply points together.

The focus of joint planning with the DNSP will usually relate to:

> Augmentation of connection point capacity
> Duplication of radial supplies
> Extension of the 132 kV system to reinforce or replace existing lower voltage systems and to reduce losses
> Development of a higher voltage system to provide a major augmentation and to reduce network losses.

Supply to one or more connection points would be considered for augmentation when the forecast peak load at the end of the planning horizon exceeds the load firm N–1 capacity of TransGrid's network. However, consistent with the lower level of reliability that may be appropriate in a non-urban area, an agreed level of risk of loss of supply may be accepted. Thus augmentations may actually be undertaken:

> When the forecast load exceeds the firm capacity by an agreed amount

> Where the period that some load is at risk exceeds an agreed proportion of the time

> An agreed amount of energy (or proportion of annual energy supplied) is at risk.

As a result of the application of the criteria, some radial parts of the 330 kV and 220 kV network are not able to withstand the forced outage of a single circuit line at time of peak load, and in these cases provision has been made for under-voltage load shedding.

Provision is also required for the maintenance of the network. Additional redundancy in the network is required where maintenance cannot be scheduled without causing load restrictions or an unacceptable level of risk to the security of supply.

A1.2.7 Transformer augmentation

In considering the augmentation of transformers, appropriate allowance is made for the transformer cyclic rating [4] and the practicality of load transfers between connection points. The outage of a single transformer (or single-phase unit) or a transmission line that supports the load carried by the transformer is allowed for.

Provision is also required for the maintenance of transformers. This has become a critical issue at a number of sites in NSW where there are multiple transformers in service. To enable maintenance to be carried out, additional transformer capacity or a means of transferring load to other supply points via the underlying lower voltage network may be required.

A1.2.8 Consideration of low probability events

Although there is a low probability that loads will need to be shed (interrupted) as a result of system disturbances, no power system can be guaranteed to deliver a firm capability 100% of the time, particularly when subjected to disturbances that are severe or widespread. It is also possible that extreme loads, above the level allowed for in planning, can occur, usually under extreme weather conditions.

The NSW network contains numerous lines of double circuit construction and, whilst the probability of overlapping outages of both circuits of a line is very low, the consequences could be widespread supply disturbances.

Thus there is a potential for low probability events to cause localised or widespread disruption to the power system. These events can include:

> Loss of several transmission lines within a single corridor, as may occur during bushfires

> Loss of a number of cables sharing a common trench

> Loss of more than one section of busbar within a substation, possibly following a major plant failure

> Loss of a number of generating units

> Occurrence of three-phase faults [5], or faults with delayed clearing.

In TransGrid's network, appropriate facilities and mechanisms are put in place to minimise the probability of such events and to ameliorate their impact. The decision process considers the underlying economics of facilities or corrective actions, taking account of the low probability of the occurrence of extreme events.

TransGrid will take measures, where practicable, to minimise the impact of disturbances to the power system by implementing power system control systems at minimal cost in accordance with the NER.

A1.2.9 Planning criteria for the transmission supply to the ACT

TransGrid has been awarded a utility services licence to provide electricity transmission services within the ACT. This licence requires, inter alia, a second 330 kV supply point to the ACT. The provision of Stockdill 330 kV switching station is part of the solution to fulfil this requirement.

4 Transformer nominal ratings are based on them carrying a constant load. However, loads are often cyclic (they vary throughout the day). In these cases transformers may be able to carry more than their nominal rating for a short period around the time of the maximum load as they are loaded less heavily before and after that period. A cyclic loading takes this into account.

5 Alternating current power systems generally have three phases. Faults on those systems can involve one, two or all three of those phases. Faults involving three phases are generally the most onerous.

A1.3 Protection requirements

Basic protection requirements are included in the NER. The NER requires that protection systems be installed so that any fault can be detected by at least two fully independent protection systems. Backup protection is provided against circuit breaker failure. Provision is also made for detecting high resistance earth faults.

Required protection clearance times are specified by the NER and determined by stability considerations as well as the characteristics of modern power system equipment. Where special protection facilities or equipment are required for high-speed fault clearance, they are justified on either an NER compliance or a benefit/cost basis.

All modern distance protection systems on the main network include the facility for power swing blocking (PSB). PSB is utilised to control the impact of a disturbance that can cause synchronous instability. At the moment PSB is not enabled, except at locations where demonstrated advantages apply. This feature will become increasingly more important as the interconnected system is developed and extended.

A1.4 Transient stability

In accordance with the NER, transient stability is assessed on the basis of the angular swings following a solid fault on one circuit at the most critical location that is cleared by the faster of the two protections (with intertrips assumed in service where installed). At the main system level a two phase-to-ground fault is applied and on 132 kV systems which are to be augmented a three-phase fault is applied.

Recognition of the potential impact of a three-phase fault at the main system level is made by instituting maintenance and operating precautions to minimise the risk of such a fault.

The determination of the transient stability capability of the main grid is undertaken using software that has been calibrated against commercially available system dynamic analysis software.

Where transient stability is a factor in the development of the main network, preference is given to the application of advanced control of the power system or high-speed protection systems, before consideration is given to the installation of high capital cost plant.

A1.5 Steady state stability

The requirements for the control of steady state stability are included in the NER. For planning purposes, steady state stability (or system damping) is considered adequate under any given operating condition if, after the most critical credible contingency, simulations indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

The determination of the steady state stability performance of the system is undertaken using software that has been calibrated against commercially available software and from data derived from the monitoring of system behaviour.

In planning the network, maximum use is made of existing plant, through the optimum adjustment of plant control system settings, before consideration is given to the installation of high capital cost plant.

Under NSW legislation, TransGrid has the responsibility to plan for future NSW transmission needs, including interconnection with other networks.

A1.6 Line and equipment thermal ratings

Line thermal ratings have often traditionally been based on a fixed continuous rating and a fixed short-time rating. TransGrid applies probabilistic-based line ratings, which are dependent on the likelihood of coincident adverse weather conditions and unfavourable loading levels. This approach has been applied to selected lines whose design temperature is about 100°C or less. For these lines, a contingency rating and a short-time emergency rating have been developed. Typically, the short-time rating is based on a load duration of 15 minutes, although the duration can be adjusted to suit the particular load pattern to which the line is expected to be exposed. The duration and level of loading must take into account any requirements for re-dispatch of generation or load control.

TransGrid is presently installing ambient condition monitors on critical transmission lines to enable the application of real-time line conductor ratings in the generation dispatch systems.

Transformers are rated according to their specification. Provision is also made for use of the short-time capability of the transformers during the outage of a parallel transformer or transmission line.

TransGrid owns two 330 kV cables and these are rated according to the manufacturer's recommendations that have been checked against an appropriate thermal model of the cable.

The rating of line terminal equipment is based on the manufacturers' advice.

A1.7 Reactive support and voltage stability

It is necessary to maintain voltage stability, with voltages within acceptable levels, following the loss of a single element in the power system at times of peak system loading. The single element includes a generator, a single transmission circuit, a cable and single items of reactive support plant.

To cover fluctuations in system operating conditions, uncertainties of load levels, measurement errors and errors in the setting of control operating points, it is necessary to maintain a margin from operating points that may result in a loss of voltage control. A reactive power margin is maintained over the point of voltage instability or alternatively a margin is maintained with respect to the power transfer compared to the maximum feasible power transfer.

The system voltage profile is set to standard levels during generator dispatch to minimise the need for post-contingency reactive power support.

Reactive power plant generally has a low cost relative to major transmission lines, and the incremental cost of providing additional capacity in a shunt capacitor bank can be very low. Such plant can also have a very high benefit/cost ratio and therefore the timing of reactive plant installations is generally less sensitive to changes in load growth, than the timing of other network augmentations. Even so, TransGrid aims to make maximum use of existing reactive sources before new installations are considered.

TransGrid has traditionally assumed that all on-line generators can provide reactive power support within their rated capability, but in the future intends to align with other utilities in relying only on the reactive capability given by performance standards. Reactive support beyond the performance standards may need to be procured under network support arrangements.

Reactive power plant is installed to support planned power flows up to the capability defined by limit equations, and is often the critical factor determining network capability. On the main network, allowance is made for the unavailability of a single major source of reactive power support in the critical area affected at times of high load, but not at the maximum load level.

It is also necessary to maintain control of the supply voltage to the connected loads under minimum load conditions.

The factors that determine the need for reactive plant installations are:

> In general it has proven prudent and economic to limit the voltage change between the pre- and post-contingency operating conditions

> It has also proven prudent, in general, and economic to ensure that the post-contingency operating voltage at major 330 kV busbars lies above a lower limit

> The reactive margin from the point of voltage collapse is maintained to be greater than a minimum acceptable level

> A margin between the power transmitted and the maximum feasible power transmission is maintained

> At times of light system load, it is essential to ensure that voltages can be maintained within the system highest voltage limits of equipment.

Following forced outages, relatively large voltage changes are accepted at some locations on the main network, and agreed with customers, providing voltage stability is not placed at risk. These voltage changes can approach, and in certain cases, exceed 10% at peak load.

On some sections of the network, the possibility of loss of load due to depressed voltages following a contingency is also accepted. However, there is a preference to install load shedding initiated by under-voltage so that the disconnection of load occurs in a controlled manner.

When determining the allowable rating of switched reactive plant, the requirements of the NER are observed.

A1.8 Transmission line voltage and conductor sizes determined by economic considerations

Consideration is given to the selection of line design voltages within the standard nominal 132 kV, 220 kV, 275 kV, 330 kV and 500 kV range, taking due account of transformation costs.

Minimum conductor sizes are governed by losses, radio interference and field strength considerations.

TransGrid strives to reduce the overall cost of energy and network services by the economic selection of line conductor size. The actual losses that occur are governed by generation dispatch in the market.

For a line whose design is governed by economic loading limits, the conductor size is determined by a rigorous consideration of capital cost versus loss costs. Hence the impact of the development on generator and load marginal loss factors in the market is considered. For other lines, the rating requirements will determine the conductor requirements.

Double circuit lines are built in place of two single circuit lines where this is considered to be both economic and to provide adequate reliability. Consideration would be given to the impact of a double circuit line failure, both over relatively short terms and for extended durations. This means that supply to a relatively large load may require single rather than double circuit transmission line construction where environmentally acceptable.

In areas prone to bushfire, any parallel single circuit lines would preferably be routed well apart.

A1.9 Short-circuit rating requirements

Substation high voltage equipment is designed to withstand the maximum expected short circuit duty[6] in accordance with the applicable Australian Standard.

Operating constraints are enforced to ensure equipment is not exposed to fault duties beyond the plant rating.

In general, the short circuit capability of all of the plant at a site would be designed to match or exceed the maximum short circuit duty at the relevant busbar. In order to achieve cost efficiencies when augmenting an existing substation, the maximum possible short circuit duty on individual substation components may be calculated and applied in order to establish the adequacy of the equipment.

Short circuit duty calculations are based on the following assumptions:

> All main network generators that are capable of operating, as set out in connection agreements, are assumed to be in service

> All generating units that are embedded in distribution networks are assumed to be in service

> The maximum fault contribution from interstate interconnections is assumed

> The worst-case pre-fault power flow conditions are assumed

> Normally open connections are treated as open

> Networks are modeled in full

> Motor load contributions are not modeled at load substations

> Generators are modelled as a constant voltage behind sub-transient reactance.

At power station switchyards, allowance is made for the contribution of the motor component of loads. TransGrid is further analysing the impact of the motor component of loads and is assessing the need to include such contributions when assessing the adequacy of the rating of load substation equipment.

A1.10 Substation configurations

Substation configurations are adopted that provide acceptable reliability at minimum cost, consistent with the overall reliability of the transmission network. In determining a switching arrangement, consideration is also given to:

> Site constraints

> Reliability expectations with respect to connected loads and generators

> The physical location of 'incoming' and 'outgoing' circuits

> Maintenance requirements

> Operating requirements

> Transformer arrangements.

TransGrid has applied the following configurations in the past:

> Single busbar

> Double busbar

> Multiple element mesh

> Breaker-and-a-half.

In general, at main system locations, a mesh or breaker-and-a-half arrangement is now usually adopted.

Where necessary, the expected reliability performance of potential substation configurations can be compared using equipment reliability parameters derived from local and international data.

The forced outage of a single busbar zone is generally provided for. Under this condition, the main network is planned to have adequate capability although loss of load may eventuate. In general, the forced outage of a single busbar zone should not result in the outage of any base-load generating unit.

Where appropriate a 330 kV bus section breaker would ordinarily be provided, to segregate 'incoming' lines, when a second 'incoming' 330 kV line is connected to the substation.

A 132 kV bus section circuit breaker would generally be considered necessary when the peak load supplied via that busbar exceeds 120 MW. A bus section breaker is generally provided on the low voltage busbar of 132 kV substations when supply to a particular location or area is taken over more than two low voltage feeders.

6 The maximum fault current that the equipment may be subjected to.

A1.11 Autoreclosure

As most line faults are of a transient nature, all of TransGrid's overhead transmission lines are equipped with autoreclose facilities.

Slow speed three-pole reclosure is applied to most overhead circuits. On the remaining overhead circuits, under special circumstances, high-speed single-pole autoreclosing may be applied.

For public safety reasons, reclosure is not applied to underground cables.

Autoreclose is inhibited following the operation of breaker-fail protection.

A1.12 Power system control and communication

In the design of the network and its operation to designed power transfer levels, reliance is generally placed on the provision of some of the following control facilities:

> Automatic excitation control on generators

> Power system stabilisers on generators and static var compensators

> Load drop compensation on generators and transformers

> Supervisory control over main network circuit breakers

> Under-frequency load shedding

> Under-voltage load shedding

> Under and over-voltage initiation of reactive plant switching

> High speed transformer tap changing

> Network connection control

> Check and voltage block synchronisation

> Control of reactive output from SVCs

> System Protection Schemes (SPS).

The following communication, monitoring and indication facilities are also provided where appropriate:

> Network wide SCADA and Energy Management System (EMS)

> Telecommunications and data links

> Mobile radio

> Fault locators and disturbance monitors

> Protection signalling

> Load monitors.

Protection signalling and communication is provided over a range of media including pilot wire, power line carrier, microwave links and, increasingly, optical fibres in overhead earthwires.

A1.13 Scenario planning

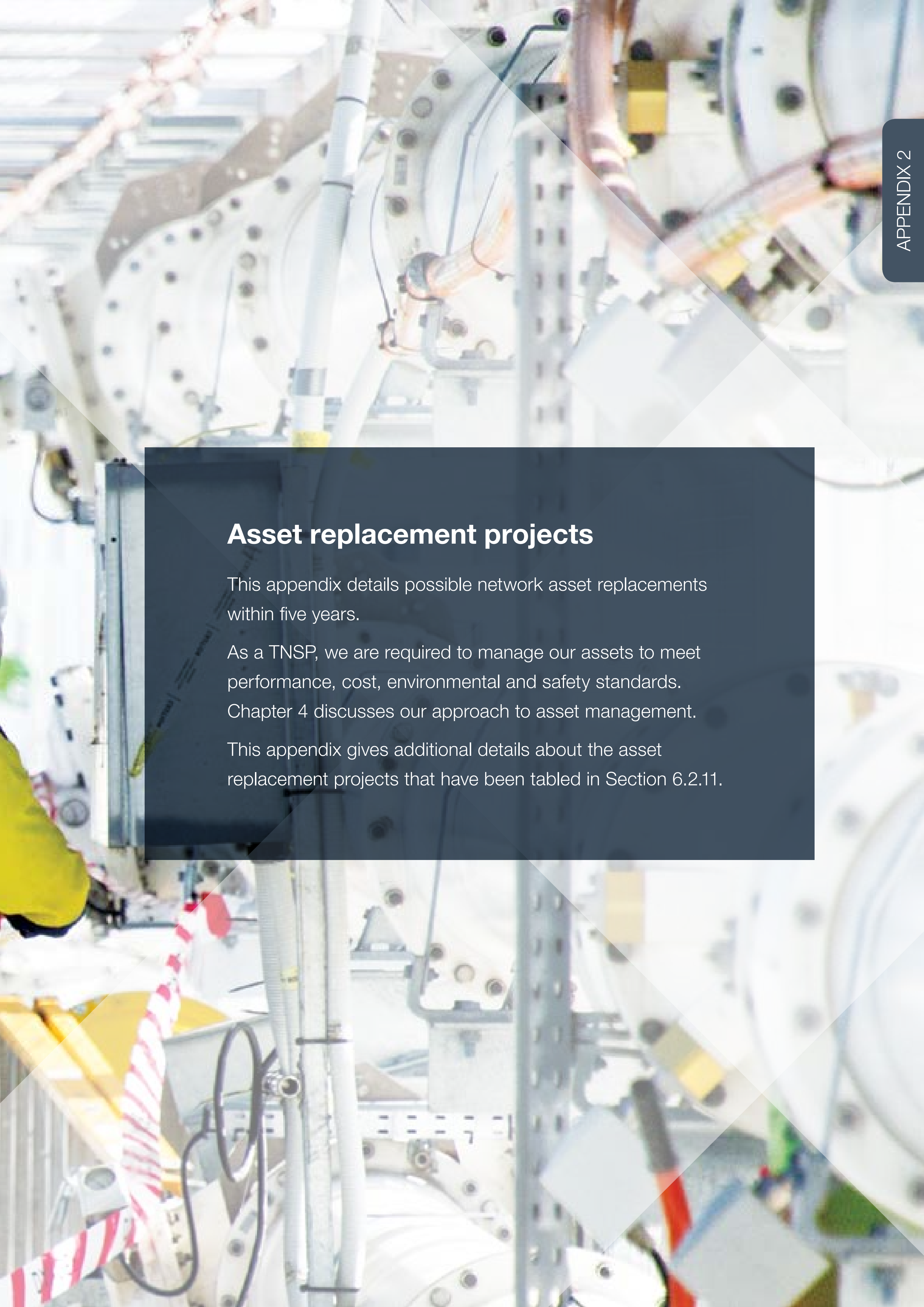
Scenario planning assesses network capacity, based on the factors described above, for a number of NEM load and generation scenarios. The process entails:

1. Identification of possible future load growth scenarios. These are developed based on AEMO's forecasts to be used in the next NTNDP. TransGrid uses the key data for each scenario to prepare load forecasts for NSW. These are published in the TAPR and by AEMO in the forthcoming National Electricity Forecasting Report. The forecast can also incorporate specific possible local developments such as the establishment of new loads or the expansion or closure of existing industrial loads.
2. Development of a number of generation scenarios for each load growth scenario. These generation scenarios relate to the development of new generators and utilisation (including retirement) of existing generators. This is generally undertaken by a specialist electricity market modelling consultant, using their knowledge of relevant factors, including:
   - Generation costs
   - Impacts of government policies
   - Impacts of energy related developments such as gas pipeline projects.
3. Modelling of the NEM for load and generation scenarios to quantify factors which affect network performance, including:
   - Generation from individual power stations
   - Interconnector flows.
4. Modelling of network performance for the load and generation scenarios utilising the data from the market modelling.

The resulting set of scenarios is then assessed over the planning horizon to establish the adequacy of the system and to assess network and non-network augmentation options.

The future planning scenarios developed by TransGrid will take into account AEMO's future scenarios from the NTNDP.

2 Appendix



Asset replacement projects

This appendix details possible network asset replacements within five years.

As a TNSP, we are required to manage our assets to meet performance, cost, environmental and safety standards. Chapter 4 discusses our approach to asset management.

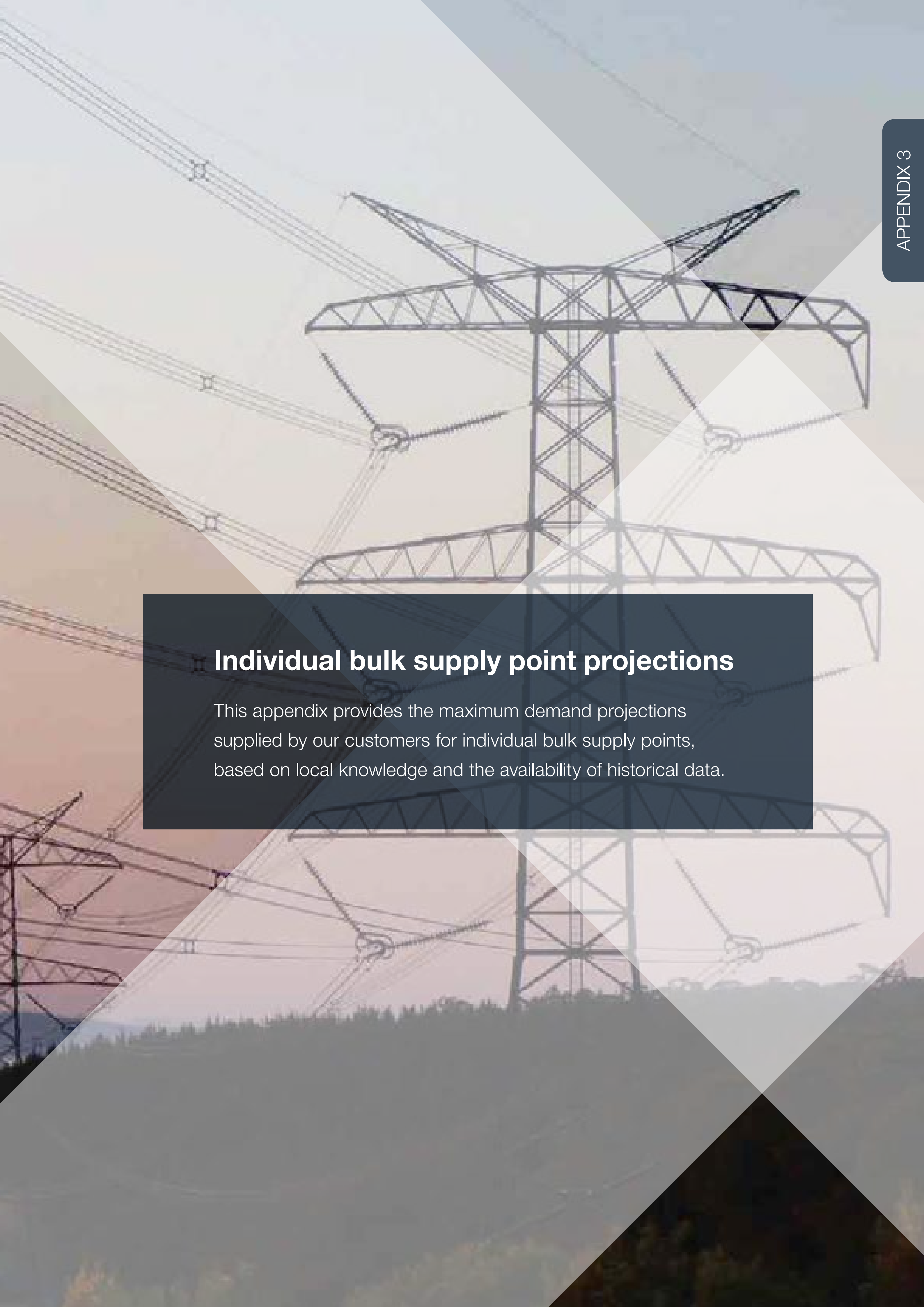
This appendix gives additional details about the asset replacement projects that have been tabled in Section 6.2.11.

Project description	Location	Scope of works	Non-network solution viability[1]	Network options considered
21 Sydney North – Tuggerah 330 kV transmission line: tower life extension	Sydney North – Tuggerah 330 kV line 21 Sydney metropolitan area to Central Coast	Replacement of corroded nuts and bolts and painting of tension towers on line 21, from Sydney North to Sterland	**Feasibility:** Non-network options are unsuitable for alleviating the corrosion issues on the towers due to coastal weathering. The circuit supported by these structures is connected to high levels of generation. Subject to generation developments, it is likely that these circuits (possibly in a reconfigured form) will continue to be required into the future to supply Sydney North, Sydney East and Tuggerah.	1. Base case (do nothing) 2. Paint all towers 3. Replace suspension structures with concrete pole structures at end of life 4. Paint tension towers
959/92Z Sydney North – Sydney East 132 kV transmission line: tower life extension	Sydney metropolitan area	Replacement of corroded nuts and bolts and painting of tension towers on lines 959/92Z	**Feasibility:** Non-network options are unsuitable for alleviating the corrosion issues on the towers due to coastal weathering. The circuit supported by these structures is connected to high levels of generation. Subject to generation developments, it is likely that these circuits (possibly in a reconfigured form) will continue to be required into the future to supply Sydney North, Sydney East and Tuggerah.	1. Base case (do nothing) 2. Paint all towers 3. Replace suspension structures with concrete pole structures at end of life 4. Paint tension towers
Deniliquin 132/66 kV substation: secondary systems replacement	Deniliquin substation Southern NSW	Secondary System Buildings (SSB)	**Feasibility:** No non-network options that can completely or partially meet the need have been identified.	1. Base case (do nothing) 2. SSB 3. In-situ – retain LV cables
ANM 132 kV substation: secondary systems replacement	Australian Newsprint Mills (ANM) substation Southern NSW	Replacing secondary systems	**Feasibility:** No non-network options that can completely or partially meet the need have been identified.	1. Base case (do nothing) 2. SSB 3. In-situ
1 and 2 Snowy – Yass/ Canberra 330 kV transmission lines: remediation	Upper Tumut – Canberra 330 kV line 1 Upper Tumut – Yass 330 kV line 2 Southern NSW	Remediation of low span through changing insulator arrangement, structure replacement or raising structures	**Feasibility:** Non-network options are unsuitable for alleviating this issue. The circuit supported by these structures is connected to high levels of generation hydro-generation from Snowy. Subject to generation developments, it is likely that these circuits (possibly in a reconfigured form) will continue to be required.	1. Base case 2. Upgrading of the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV lines 3. New line development – Lower Tumut – Yass single circuit 330 kV line 4. Installation of power flow control plant to improve the sharing of power flows in the four lines under contingency
Low spans northern tower lines	Central Coast, Hunter Valley, Northern NSW	Remediating low spans on Northern Region tower lines	**Feasibility:** Non-network options will be considered on a line-by-line basis in this region.	1. Base case 2. Remediate high priority low spans on Northern Region tower lines 3. Remediate all low spans on Northern Region tower lines
Low spans northern pole lines	Central Coast, Hunter Valley, Northern NSW	Remediating low spans on Northern Region pole lines	**Feasibility:** Non-network options will be considered on a line-by-line basis in this region.	1. Base case 2. Remediate high priority low spans on Northern Region pole lines 3. Remediate all low spans on Northern Region pole lines

Project description	Location	Scope of works	Non-network solution viability[1]	Network options considered
Low spans central tower lines	NSW metropolitan area	Remediating low spans on Central Region tower lines	**Feasibility:** Non-network options will be considered on a line-by-line basis in this region.	1. Base case 2. Remediate high priority low spans on Central Region tower lines 3. Remediate all low spans on Southern Region tower lines
Low spans central pole lines	Central west NSW	Remediating low spans on Central Region pole lines	**Feasibility:** Non-network options will be considered on a line-by-line basis in this region.	1. Base case 2. Remediate high priority low spans on Central Region pole lines 3. Remediate all low spans on Central Region pole lines
Low spans southern tower lines	Southern NSW	Remediating low spans on Southern Region tower lines	**Feasibility:** Non-network options will be considered on a line by line basis in this region.	1. Base case 2. Remediate high priority low spans on Southern Region pole lines 3. Remediate all low spans on Southern Region pole lines
Low spans southern pole lines	Southern NSW	Remediating low spans on Southern Region pole lines	**Feasibility:** Non-network options will be considered on a line-by-line basis in this region.	1. Base case 2. Remediate high priority low spans on Southern Region pole lines 3. Remediate all low spans on Southern Region pole lines
22 Sydney North to Vales Point 330 kV transmission line: tower life extension	Central Coast NSW	Replacement of corroded nuts and bolts and painting of tension towers	**Feasibility:** Non-network options are unsuitable for alleviating the corrosion issues on the towers due to coastal weathering. The circuit supported by these structures is connected to high levels of generation. Subject to generation developments, it is likely that these circuits (possibly in a reconfigured form) will continue to be required into the future to supply Sydney North, Sydney East.	1. Base case (do nothing) 2. Paint all towers 3. Replace all suspension towers 4. Paint tension towers 5. Replace all suspension towers and paint tension towers
Murrumburrah 132 kV substation: secondary systems replacement	Murrumburrah substation Southern NSW	Replacement of the existing secondary systems	**Feasibility:** No non-network options that can completely or partially meet the need have been identified.	1. Base case (do nothing) 2. Replacement of the secondary systems and cabling 3. In-situ replacement of the secondary systems and retaining the existing LV cabling
Hume 132 kV substation: secondary systems replacement	Hume substation Southern NSW	Replacement of the secondary systems	**Feasibility:** No non-network options that can completely or partially meet the need have been identified.	1. Base case (do nothing) 2. SSB 3. In-situ replacement

1 In relation to the replacements of secondary systems, as those systems are essential for the substation to be able to operate in a safe and orderly manner, non-network options would need to be able to supply all of the load all of the time. As this is unlikely to be achievable non-network options are generally not feasible alternatives to replacements of secondary systems. Similarly, in relation to refurbishment of transmission lines, non-network options would need to be able to substitute for the capacity and 'connectivity' that those lines provide to the network. Generally, this is not possible. Consequently non-network options are generally not feasible.

3 Appendix



Individual bulk supply point projections

This appendix provides the maximum demand projections supplied by our customers for individual bulk supply points, based on local knowledge and the availability of historical data.

A3 Individual bulk supply point projections

Our customers have provided maximum demand projections, in terms of both Megawatts (MW) and megavolt ampere reactive (MVAr), for individual bulk supply points between the NSW transmission network and the relevant customer's network. These projections are produced using methodologies that are likely to have been tailored to the circumstances relating to the load(s) at particular bulk supply point(s) such as the degree of local knowledge and the availability of historical data. The projections are given in the tables below.

Some large and relatively stable industrial loads that we isolate for modelling purposes have been removed from the bulk supply point projections and aggregated. The removal of this data affects the projections shown for Broken Hill. Other industrial loads are included in bulk supply point forecasts provided by distributors. Aggregate projections for all identified major industrial loads (excluding those that are also in the bulk supply point forecasts) are given in Tables A3.11 and A3.12.

Tables A3.1 to A3.12 represent projections of maximum demand occurring during a particular season at a particular bulk supply point (or group of bulk supply points) on the NSW transmission network. They do not represent projections of demand contributions at these bulk supply points to the overall NSW region maximum demand.

Essential Energy and Endeavour Energy provided forecasts for potential spot loads within their networks which are well advanced, but not yet committed. Those forecasts have not been included here.

Load profile information for critical bulk supply points is provided in Appendix 4.

Information on forecast diversity factors for each bulk supply point with respect to the network (NER Schedule 5.7) have not been provided as:

> The NER definition of 'network' is very broad, making it unclear what combination of other load or loads are to be assumed when calculating the diversities. The absence of this information could lead to an impossibly large number of diversity combinations[1], many of which are unlikely to be of use

> In an interconnected network, the loading on a particular substation can reflect the configuration of the underlying network as well as generation patterns within the national electricity market. Consequently, there can be considerable variation in diversity factors at a particular location from year to year[2].

In relation to the near-term major load-related network limitations in TransGrid's network:

> Diversity between the Gunnedah and Narrabri summer maximum demands has varied between 0% and 3% over the past five summers[3], making it difficult to determine a typical value.

When undertaking the comparison between the AEMO NSW region forecasts and the aggregated distribution network service provider forecasts, TransGrid uses diversity factors of 4% in both summer and winter[4].

Information on particular diversity factors is available from TransGrid, notwithstanding the above difficulties. Contact details are provided on the inside of the back cover of this document.

1 For example, in a ten-node network, there are over 500 diversity figures for each node, covering the ways in which its diversity can be calculated with respect to the various combinations of one or more of the other nine nodes. For larger networks such as the TransGrid network, the number of possible diversity figures is immense.

2 For example, over the past five summers, the diversity of the Sydney South load (a major load in the TransGrid network) with respect to that of the NSW region has varied between 0% and 3%. Over the same period, that for the Lismore load (a reasonably large load on the periphery of the TransGrid network) has varied between 6% and 32%. It is likely that some of the variation in diversity factors at Lismore is due to the extent to which adverse weather conditions that affect the Newcastle / Sydney / Wollongong area (where the bulk of the NSW load is located) also affect the NSW far north coast. Longer-term weather events can be very difficult to forecast.

3 Some of this variation may be due to variations in pumping loads, which vary from year to year depending on weather conditions (which affect the need for irrigation) and the availability of water (which can be affected by El Niño and La Niña events). Longer-term weather conditions are very difficult to forecast.

4 These diversity factors apply at the NSW region level. They represent the difference between the undiversified regional maximum demand (the summated maximum demands of the individual bulk supply points) and the diversified regional maximum demand (the maximum of the summated bulk supply point loads). This regional approach was adopted as it is not possible to estimate a typical diversity factor for individual bulk supply point loads with respect to the NSW regional load due to the year to year variability of those individual diversity factors.

TABLE A3.1 – Ausgrid bulk supply point summer maximum demand [5]

	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Beaconsfield West 132 kV	311	4	336	34	328	50	353	78	356	86	363	88	363	97	375	110	374	116	378	123
Rookwood Rd 132 kV	256	2	282	25	273	36	299	41	301	46	289	46	289	50	286	56	288	58	289	61
Haymarket 132 kV	382	5	414	42	405	63	436	83	444	91	452	95	452	104	465	116	475	121	482	132
Liddell 33 kV	30	24	31	25	31	25	31	25	31	25	31	25	31	25	31	25	31	25	31	25
Munmorah 132 kV & 33 kV	119	24	114	24	113	29	113	31	119	35	127	40	127	40	141	46	142	46	144	46
Muswellbrook 132 kV	215	120	223	124	222	124	223	124	223	124	223	124	224	125	225	125	225	126	226	126
Newcastle 132 kV	446	122	441	118	438	115	438	114	440	115	444	117	448	120	451	122	454	124	456	126
Sydney East 132 kV	645	81	637	87	634	102	687	128	690	133	697	142	697	153	714	167	723	172	730	180
Sydney North 132 kV	917	5	855	76	849	116	716	171	720	202	727	220	727	229	749	261	760	267	769	275
Sydney South 132 kV	930	16	973	101	995	157	1027	193	1033	211	1054	221	1054	240	1086	272	1102	284	1111	299
Tomago 132 kV	221	60	219	58	218	57	218	57	219	57	221	58	224	60	226	61	228	62	231	64
Tuggerah 132 kV	181	85	183	88	181	91	182	94	186	99	190	100	190	101	200	111	202	112	204	116
Vales Point 132 kV	85	11	85	12	84	3	84	3	85	2	86	4	86	3	88	3	89	4	90	4
Waratah West 132 kV	150	41	148	40	148	39	147	38	148	39	149	39	149	40	150	41	151	41	152	42

TABLE A3.2 – Ausgrid bulk supply point winter maximum demand [5]

	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Beaconsfield West 132 kV	294	14	292	15	318	31	314	36	332	44	345	39	345	54	348	39	357	43	358	48
Rookwood Rd 132 kV	245	7	240	8	263	21	260	23	280	23	286	20	290	31	289	23	267	24	272	24
Haymarket 132 kV	357	17	356	19	383	38	383	44	413	48	418	43	425	61	430	44	440	49	451	53
Liddell 33 kV	30	24	30	24	31	25	31	25	31	25	31	25	31	25	31	25	31	26	31	26
Munmorah 132 kV & 33 kV	120	18	119	26	114	27	114	32	116	35	124	43	131	41	139	46	147	50	149	54
Muswellbrook 132 kV	190	91	193	93	200	101	200	101	200	101	202	102	203	102	203	103	204	104	205	104
Newcastle 132 kV	377	61	375	59	375	59	377	60	382	62	388	65	395	69	400	72	406	75	412	78
Sydney East 132 kV	692	-2	688	17	696	21	698	37	754	67	764	118	773	81	782	94	791	91	801	96
Sydney North 132 kV	772	38	783	28	761	62	738	70	611	152	620	172	630	198	641	201	649	268	659	293
Sydney South 132 kV	922	50	913	53	974	99	1002	116	1034	120	1050	104	1067	149	1073	109	1107	121	1114	133
Tomago 132 kV	186	30	185	29	186	29	187	30	190	31	194	33	198	34	201	36	205	38	209	40
Tuggerah 132 kV	191	64	188	51	193	64	193	59	197	60	202	63	210	73	215	75	219	75	224	76
Vales Point 132 kV	85	3	84	8	86	6	86	8	86	11	88	11	89	8	91	10	92	9	93	10
Waratah West 132 kV	139	22	138	22	138	22	138	22	139	22	141	24	142	25	144	26	145	27	146	28

5 Zone substation projections aggregated to TransGrid bulk supply points using agreed load flow models.

TABLE A3.3 – Endeavour Energy bulk supply point summer maximum demand[6]

	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Dapto 132 kV	614	53	630	54	633	54	637	54	639	55	642	55	645	55	647	55	652	56	656	56
Holroyd 132 kV	390	98	396	99	397	99	397	99	397	99	397	99	397	99	397	99	397	99	397	99
Ingleburn 66 kV	132	30	133	30	134	30	134	30	135	30	136	30	137	31	137	31	137	31	138	31
Liverpool 132 kV	369	79	380	81	388	83	394	85	400	86	405	87	410	88	415	89	419	90	423	91
Macarthur 132 kV & 66 kV	287	81	305	86	312	88	317	89	325	92	333	94	343	97	355	100	367	104	379	107
Marulan 132 kV	75	34	75	34	76	35	77	35	77	35	78	36	79	36	80	36	80	37	81	37
Mount Piper 66 kV	38	19	39	19	39	19	39	19	39	19	39	19	39	19	39	19	39	19	39	19
Regentville 132 kV	274	72	278	73	281	74	282	74	283	75	283	75	283	75	283	75	283	75	283	75
Sydney North 132 kV	41	4	41	4	41	4	41	4	41	4	41	4	41	4	41	4	41	4	41	4
Sydney West 132 kV	1253	155	1257	155	1254	155	1275	157	1278	158	1285	159	1293	160	1301	161	1307	161	1313	162
Vineyard 132 kV	477	139	486	142	499	146	530	155	535	156	550	160	567	165	585	171	602	176	620	181
Wallerawang 132 kV & 66 kV	64	24	64	24	64	24	64	24	64	24	64	24	64	24	64	24	64	24	64	24

TABLE A3.4 – Endeavour Energy bulk supply point winter maximum demand[7]

	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Dapto 132 kV	674	65	683	66	690	67	691	67	691	67	691	67	692	67	692	67	692	67	693	67
Holroyd 132 kV	314	78	316	78	317	79	317	79	317	79	317	79	318	79	318	79	317	79	317	79
Ingleburn 66 kV	115	16	116	16	116	16	117	16	118	16	118	17	119	17	119	17	120	17	120	17
Liverpool 132 kV	276	24	282	25	288	25	293	26	298	26	302	27	307	27	312	28	316	28	320	28
Macarthur 132 kV & 66 kV	263	60	269	61	275	63	283	65	293	67	303	69	313	71	322	73	331	76	340	78
Marulan 132 kV	86	28	86	28	87	28	87	28	88	29	88	29	88	29	88	29	88	29	88	29
Mount Piper 66 kV	36	15	39	16	39	16	39	16	39	16	39	16	39	16	39	16	39	16	39	16
Regentville 132 kV	192	41	195	41	197	42	199	42	200	43	201	43	201	43	201	43	201	43	201	43
Sydney North 132 kV	31	3	31	3	31	3	31	3	31	3	31	3	31	3	31	3	31	3	31	3
Sydney West 132 kV	922	35	931	36	930	36	934	36	939	36	942	36	949	36	957	37	964	37	972	37
Vineyard 132 kV	312	68	312	68	318	69	329	71	338	73	342	74	352	77	363	79	373	81	384	83
Wallerawang 132 kV & 66 kV	77	25	77	25	77	25	77	25	77	25	77	25	77	25	77	25	77	25	77	25

6 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Endeavour Energy component. Diversity factors of 3% in summer should be applied to obtain the forecast total summer load at Marulan.

7 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Endeavour Energy component. Diversity factors of 2% in winter should be applied to obtain the forecast total winter load at Marulan.

TABLE A3.5 – Essential Energy (North) bulk supply point summer maximum demand

	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Armidale 66 kV	25	7	26	7	26	7	26	7	26	7	26	7	26	7	26	7	26	7	26	7
Boambee South 132 kV	21	4	21	4	21	4	21	4	21	4	22	4	22	4	22	4	22	4	22	4
Casino 132 kV	27	5	27	5	27	5	27	5	27	5	27	5	27	5	27	5	27	5	27	5
Coffs Harbour 66 kV	53	9	54	9	54	9	54	9	54	10	55	10	55	10	55	10	55	10	56	10
Dorrigo 132kV	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Dunoon 132kV	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1
Glen Innes 66 kV	9	-2	9	-2	9	-2	9	-2	9	-2	9	-2	9	-2	9	-2	9	-2	9	-2
Gunnedah 66 kV	26	2	26	2	26	2	26	2	26	2	26	2	26	2	26	2	26	2	26	2
Hawks Nest 132 kV	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1
Herons Ck 132 kV	9	3	9	3	9	3	9	3	9	3	9	3	9	3	10	3	10	3	10	3
Inverell 66 kV	36	3	36	3	36	3	36	3	36	3	36	3	37	3	37	3	37	3	37	3
Kempsey 33 kV	25	5	25	5	26	5	26	5	26	5	26	5	26	5	26	5	26	5	26	5
Kempsey 66 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Koolkhan 66 kV	49	4	49	4	49	4	49	4	49	4	50	4	50	4	50	4	50	4	50	4
Lismore 132 kV	73	-10	73	-10	74	-11	74	-11	74	-11	75	-11	75	-11	75	-11	75	-11	76	-11
Macksville 132 kV	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2
Moree 66 kV	27	2	27	2	27	2	27	2	27	2	27	2	27	2	27	2	27	2	27	2
Mullumbimby 132 kV	43	-5	43	-5	44	-5	44	-5	44	-5	44	-5	45	-5	45	-5	45	-5	45	-5
Hallidays Point 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nambucca 66 kV	6	1	6	1	6	1	6	1	6	1	7	1	7	1	7	1	7	1	7	1
Narrabri 66 kV	49	6	49	6	49	6	49	6	49	6	50	6	50	6	50	6	50	6	50	6
Port Macquarie 33 kV	59	10	60	10	60	10	60	10	61	10	61	10	62	10	62	10	62	10	63	10
Raleigh 132 kV	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2
Stroud 132 kV	30	-1	30	-1	30	-1	30	-1	30	-1	30	-1	30	-1	30	-1	31	-1	31	-1
Tamworth 66 kV	115	20	116	20	116	20	117	21	118	21	119	21	120	21	121	21	121	21	122	21
Taree 33 kV	23	6	23	6	23	6	23	6	24	6	24	6	24	6	24	6	24	6	24	6
Taree 66 kV	48	12	48	12	49	12	49	12	49	12	49	12	50	12	50	13	50	13	50	13
Tenterfield 22 kV	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1
Terranora 110 kV	78	-6	79	-6	79	-6	80	-6	80	-6	81	-6	82	-6	82	-6	83	-6	83	-6

TABLE A3.6 – Essential Energy (North) bulk supply point winter maximum demand

	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Armidale 66 kV	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6
Boambee South 132 kV	20	3	21	3	21	3	21	3	21	3	21	3	21	3	21	3	21	3	21	3
Casino 132 kV	22	4	22	4	22	4	22	4	22	4	22	4	22	4	22	4	23	4	23	4
Coffs Harbour 66 kV	51	6	51	6	51	6	51	6	51	6	52	6	52	6	52	6	52	6	52	6
Dorrigo 132 kV	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Dunoon 132 kV	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1
Glen Innes 66 kV	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2
Gunnedah 66 kV	22	2	22	2	22	2	22	2	22	2	22	2	22	2	22	2	22	2	22	2
Hawks Nest 132 kV	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1	8	1
Herons Ck 132 kV	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2
Inverell 66 kV	30	-2	34	-2	34	-2	34	-2	34	-2	34	-2	34	-2	34	-2	34	-2	34	-2
Kempsey 33 kV	27	5	27	5	27	5	27	5	28	5	28	5	28	5	28	5	28	5	28	5
Kempsey 66 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Koolkhan 66 kV	47	2	47	2	47	2	47	2	47	2	47	2	47	2	47	2	47	2	47	2
Lismore 132 kV	75	-8	75	-8	75	-8	76	-8	76	-8	76	-8	76	-8	76	-8	76	-8	77	-8
Macksville 132 kV	9	2	9	2	9	2	9	2	9	2	9	2	9	2	9	2	9	2	9	2
Moree 66 kV	39	4	39	4	39	4	39	4	39	4	39	4	39	4	39	4	40	4	40	4
Mullumbimby 132 kV	50	4	50	4	50	4	50	4	50	4	51	4	51	4	51	4	51	4	51	4
Hallidays Point 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nambucca 66 kV	9	1	9	1	9	1	9	1	9	1	9	1	9	1	9	1	9	1	9	1
Narrabri 66 kV	50	8	50	8	50	8	50	8	50	8	51	8	51	8	51	8	51	8	51	8
Port Macquarie 33 kV	66	8	66	8	67	8	67	8	67	8	68	8	68	8	68	8	69	8	69	8
Raleigh 132 kV	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2
Stroud 132 kV	27	-5	27	-5	27	-5	27	-5	27	-5	27	-5	27	-5	28	-5	28	-5	28	-5
Tamworth 66 kV	93	15	94	15	94	15	95	15	95	16	96	16	96	16	97	16	98	16	98	16
Taree 33 kV	23	4	23	4	23	4	23	4	23	4	23	4	24	4	24	4	24	4	24	4
Taree 66 kV	49	7	49	7	49	7	50	7	50	7	50	7	50	7	50	7	51	7	51	7
Tenterfield 22 kV	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1
Terranora 110 kV	80	-6	80	-6	81	-6	81	-6	82	-6	82	-6	83	-6	83	-6	84	-7	84	-7

TABLE A3.7 – Essential Energy (Central) bulk supply point summer maximum demand

	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Beryl 66 kV	62	23	65	23	70	23	70	24	70	24	70	24	70	24	70	24	70	24	70	25
Cowra 66 kV	30	5	30	5	30	5	30	5	30	5	30	5	30	5	30	5	30	5	30	5
Forbes 66 kV	33	2	33	2	33	2	33	2	33	2	33	2	33	2	33	2	33	2	33	2
Manildra 132 kV	10	4	10	4	10	4	10	4	10	4	10	4	10	4	10	4	10	4	10	4
Molong 66 kV	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0	5	0
Mudgee 132 kV	22	3	22	3	22	3	22	3	22	3	22	3	22	3	22	3	23	3	23	3
Orange 66 kV	51	20	51	20	51	20	51	20	51	20	51	20	51	20	51	20	51	20	51	20
Orange 132 kV	147	32	147	32	147	32	147	32	147	32	148	32	156	32	156	32	156	32	156	32
Panorama 66 kV	68	23	68	23	68	23	68	23	68	23	68	23	68	23	68	23	68	23	68	23
Parkes 66 kV	25	5	25	5	25	5	25	5	25	5	25	5	25	5	25	5	25	5	25	5
Parkes 132 kV	30	12	30	12	30	12	30	12	30	12	30	12	30	12	30	12	30	12	30	12
Wallerawang 66 kV	4	2	4	2	4	2	4	2	4	2	4	2	4	2	4	2	4	2	4	2
Wallerawang 132 kV	21	13	21	13	21	13	21	13	21	13	21	13	21	13	21	13	21	13	21	13
Wellington 66 kV	10	0	10	0	10	0	11	0	11	0	11	0	11	0	11	0	11	0	11	0
Wellington 132 kV	173	18	173	18	174	18	174	18	175	18	175	18	176	18	176	18	177	18	177	18

TABLE A3.8 – Essential Energy (Central) bulk supply point winter maximum demand

	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Beryl 66 kV	63	17	63	17	71	17	71	18	71	18	71	18	71	18	71	18	71	18	72	19
Cowra 66 kV	23	0	23	0	23	0	23	0	23	0	23	0	23	0	23	0	23	0	23	0
Forbes 66 kV	24	-5	24	-5	24	-5	24	-5	24	-5	24	-5	24	-5	24	-5	24	-5	24	-5
Manildra 132 kV	10	3	10	3	10	3	10	3	10	3	10	3	10	3	10	3	10	3	10	3
Molong 66 kV	5	-1	5	-1	5	-1	5	-1	5	-1	5	-1	5	-1	5	-1	5	-1	5	-1
Mudgee 132 kV	20	1	20	1	20	1	20	1	20	1	20	1	20	1	20	1	20	1	20	1
Orange 66 kV	60	16	60	16	60	16	60	16	60	16	60	16	60	16	60	16	60	16	60	16
Orange 132 kV	144	38	148	38	148	38	148	38	149	38	149	38	150	38	158	38	158	38	158	38
Panorama 66 kV	72	18	72	18	72	18	72	18	72	18	72	18	72	18	72	18	72	18	72	18
Parkes 66 kV	20	0	20	0	20	0	20	0	20	0	20	0	20	0	20	0	20	0	20	0
Parkes 132 kV	30	13	30	13	30	13	30	13	30	13	30	13	30	13	30	13	30	13	30	13
Wallerawang 66 kV	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1	6	1
Wallerawang 132 kV	21	12	21	12	21	12	21	12	21	12	21	12	21	12	21	12	21	12	21	12
Wellington 66 kV	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0
Wellington 132 kV	149	2	150	2	150	2	150	2	150	2	150	2	151	2	151	2	151	2	151	2

TABLE A3.9 – Essential Energy (South and Far West) and ActewAGL bulk supply point summer maximum demand [8]

	2015/16		2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Albury 132 kV	121	20	121	20	121	20	121	20	122	20	122	20	122	20	122	20	122	20	122	20
Balranald 22 kV	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0
Broken Hill 22 kV	36	12	36	12	36	12	37	12	37	12	37	12	37	12	37	12	37	12	37	12
Canberra 132 kV	382	211	387	213	391	216	396	219	401	221	405	224	410	226	415	229	420	232	425	235
Coleambally 33 kV	11	6	11	6	11	6	11	6	11	6	11	6	11	6	11	6	11	6	11	6
Cooma 11 kV	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2	10	2
Cooma 66 kV	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1
Cooma 132 kV	44	5	44	5	44	5	44	5	44	5	44	5	44	5	44	5	44	5	44	5
Darlington Pt 132 kV	18	4	19	5	19	5	19	5	19	5	19	5	20	5	20	5	20	5	20	5
Deniliquin 66 kV	46	14	46	14	46	14	47	14	47	14	47	14	47	14	47	14	47	14	47	14
Finley 66 kV	19	5	19	5	19	5	19	5	19	5	19	5	19	5	19	5	19	5	19	5
Griffith 66 kV	85	21	86	21	87	21	87	21	88	21	89	21	89	21	90	21	90	21	90	21
Marulan 132 kV	47	11	47	11	47	11	47	11	47	11	47	11	47	11	47	11	47	11	47	11
Morven 132 kV	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2	8	2
Munyang 33 kV	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Murrumbateman 132 kV	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1
Murrumburrah 66 kV	38	12	38	12	38	12	38	12	38	12	38	12	38	12	38	12	38	12	38	12
Queanbeyan 66 kV	65	21	65	21	66	21	66	21	66	21	67	21	67	21	67	22	68	22	68	22
Queanbeyan 132 kV	7	3	8	3	9	3	10	3	13	5	14	5	15	4	17	5	18	5	20	6
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tumut 66 kV	35	14	35	14	35	14	35	14	35	14	35	14	35	14	35	14	35	14	35	14
Wagga 66 kV	90	33	90	33	90	33	90	33	90	33	90	33	90	33	90	33	90	33	90	33
Wagga North 132 kV	60	5	60	4	60	4	60	4	60	4	60	4	60	4	60	4	60	4	60	4
Wagga North 66 kV	24	9	25	9	25	9	25	9	25	9	25	9	25	9	25	9	26	9	26	9
Williamsdale 132 kV	163	90	164	91	165	91	166	92	167	92	168	93	170	94	171	94	172	95	173	95
Yanco 33 kV	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6	38	6
Yass 66 kV	13	0	13	0	13	0	13	0	13	0	13	0	13	0	13	0	13	0	13	0

8 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Essential Energy component. Diversity factors of 3% in summer should be applied to obtain the forecast total summer load at Marulan.

TABLE A3.10 – Essential Energy (South and Far West) and ActewAGL bulk supply point winter maximum demand[9]

	2015		2016		2017		2018		2019		2020		2021		2022		2023		2024	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Albury 132 kV	87	10	87	10	87	10	87	10	87	10	87	10	87	10	87	10	87	10	87	10
Balranald 22 kV	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0
Broken Hill 22 kV	34	6	34	6	34	6	35	6	35	6	35	6	35	6	35	6	35	6	35	6
Canberra 132 kV	460	129	460	129	460	129	460	129	460	129	460	129	460	129	460	129	460	129	460	129
Coleambally 33 kV	8	4	8	4	8	4	8	4	8	4	8	4	8	4	8	4	8	4	8	4
Cooma 11 kV	13	2	13	2	13	2	13	2	13	2	13	2	13	2	13	2	13	2	13	2
Cooma 66 kV	21	2	21	2	21	2	21	2	21	2	21	2	21	2	21	2	21	2	21	2
Cooma 132 kV	50	-1	50	-1	50	-1	50	-1	50	-1	50	-1	50	-1	50	-1	50	-1	50	-1
Darlington Pt 132 kV	14	2	14	2	14	2	14	2	14	2	14	2	14	2	14	2	14	2	14	2
Deniliquin 66 kV	35	7	35	7	35	7	35	7	35	7	35	7	35	7	35	7	35	7	35	7
Finley 66 kV	17	3	17	3	17	3	17	3	17	3	17	3	17	3	17	3	17	3	17	3
Griffith 66 kV	53	14	58	14	58	14	60	14	61	14	61	14	62	14	62	14	62	14	63	14
Marulan 132 kV	50	7	50	7	50	7	50	7	50	7	50	7	50	7	50	7	50	7	50	7
Morven 132 kV	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1	7	1
Munyang 33 kV	29	26	29	25	29	25	29	25	29	25	29	25	29	25	29	25	29	25	29	25
Murrumbateman 132 kV	6	0	6	0	6	0	6	0	6	0	6	0	6	0	6	0	6	0	6	0
Murrumburrah 66 kV	30	7	30	7	30	7	30	7	30	7	30	7	30	7	30	7	30	7	30	7
Queanbeyan 66 kV	68	11	61	10	61	10	61	10	61	10	61	10	61	10	61	10	61	10	61	10
Queanbeyan 132 kV	0	0	8	3	9	3	10	3	11	3	14	5	15	5	17	5	19	5	21	5
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tumut 66 kV	33	8	33	8	33	8	33	8	33	8	33	8	33	8	33	8	33	8	33	8
Wagga 66 kV	64	13	64	13	64	13	64	13	64	13	64	13	64	13	64	13	64	13	64	13
Wagga North 132 kV	48	-4	55	-2	55	-2	55	-2	55	-2	55	-2	55	-2	55	-2	55	-2	55	-2
Wagga North 66 kV	26	6	19	5	19	5	19	5	19	5	20	5	20	5	20	5	20	5	20	5
Williamsdale 132 kV	145	41	145	41	145	41	145	41	145	41	145	41	145	41	145	41	145	41	145	41
Yanco 33 kV	32	1	32	0	32	0	32	0	32	0	33	0	33	0	33	0	33	0	33	0
Yass 66 kV	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2	12	-2

TABLE A3.11 – Major industrial customers – Sum of individual summer maximum demands

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	982	982	982	982	982	982	982	982	982	982

TABLE A3.12 – Major industrial customers – Sum of individual winter maximum demands

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	995	995	995	995	995	995	995	995	995	995

9 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Essential Energy component. Diversity factors of 2% in winter should be applied to obtain the forecast total winter load at Marulan.

4 Appendix

Load profiles and load at risk

This appendix provides information for potential providers of network support about a possible network constraint in the Gunnedah/Narrabri area.

The possible constraint is one that may be able to be addressed via a non-network solution. The information provided includes forecasts of loads, the magnitude of load at risk for the critical seasons, typical load profiles for the day of maximum demand, and general information about the possible variations in the periods over which network support may be required.

This information is provided for the benefit of potential providers of network support.

A4 Load profiles and load at risk

Supply to the Gunnedah/Narrabri area

The nature of the constraints in the network supplying the Gunnedah/Narrabri area is described in Section 6.2.1. The forecast summer loads in the area together with the expected amount of load at risk are given in Table A4.1. Table A4.2 shows the winter quantities.

TABLE A4.1 – Gunnedah/Narrabri area summer load forecast and expected load at risk (MW)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Gunnedah	26	26	26	26	26	26	26	26	26	26
Narrabri	49	49	49	49	49	50	50	50	50	50
Boggabri area mines	15	15	15	15	15	15	15	15	15	15
Total	90	90	90	90	90	91	91	91	91	91
Expected load at risk	15	15	15	15	15	15	15	15	16	16

TABLE A4.2 – Gunnedah/Narrabri area winter load forecast and expected load at risk (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gunnedah	22	22	22	22	22	22	22	22	22	22
Narrabri	50	50	50	50	50	51	51	51	51	51
Boggabri area mines	8	15	15	15	15	15	15	15	15	15
Total	80	87	87	87	87	88	88	88	88	88
Expected load at risk	0	8	7	7	5	6	7	7	6	6

In recent years, there have been minor variations in the load profiles on the day of summer and winter maximum demands. Figure A4.1 shows the envelope that fits the profiles for the past five years. Figure A4.2 shows the winter envelope. As the effect of the expected additional mining loads is not known, this is the current best estimate of future load profiles.

FIGURE A4.1 – Gunnedah and Narrabri load profile on day of summer maximum demand

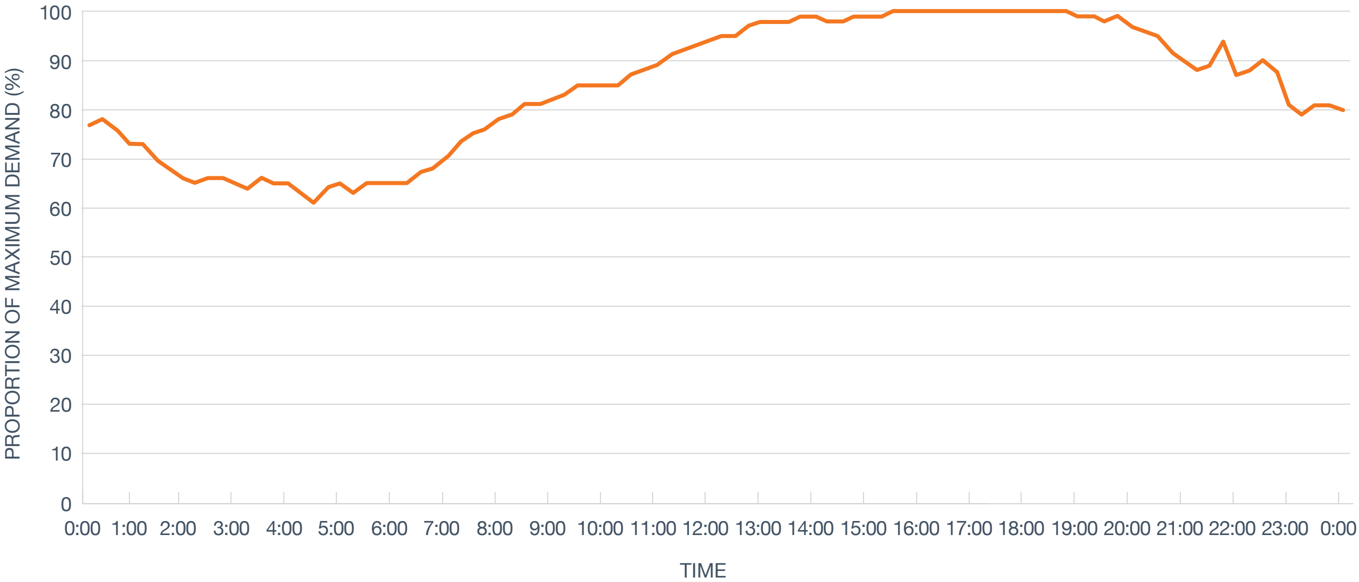
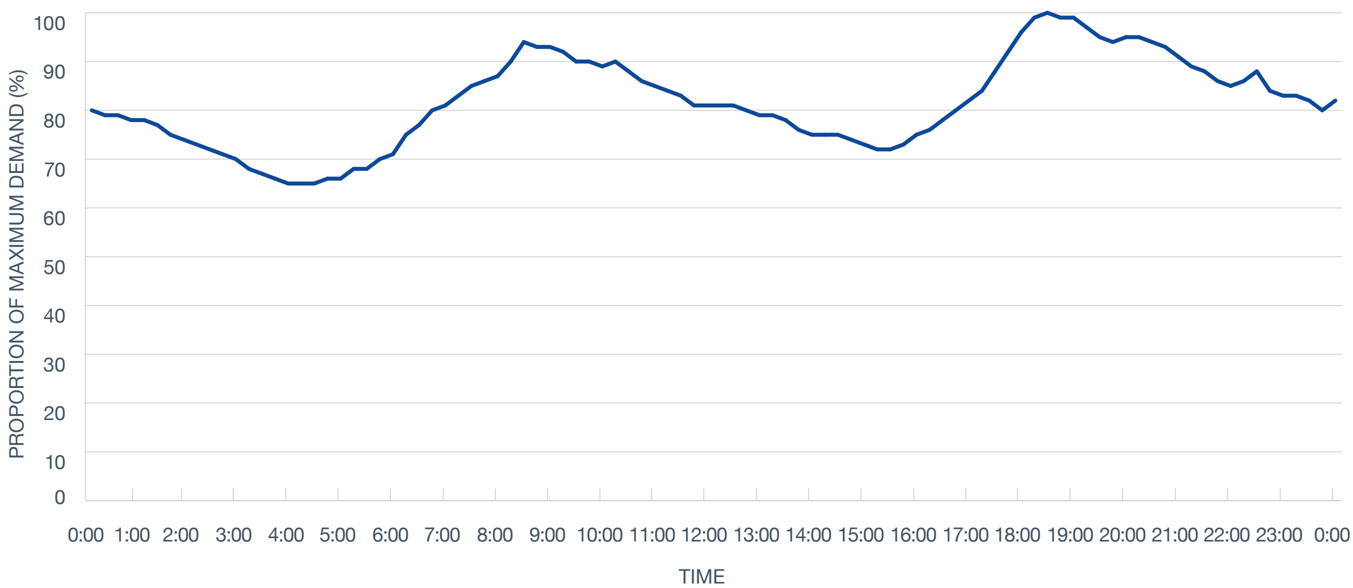


FIGURE A4.2 – Gunnedah and Narrabri load profile on day of winter maximum demand



Variability in the periods over which network support may be required

There can be considerable variation in weather conditions over seasons, and this can affect the number and duration of periods of high loads during which network support may be required. For example, the weather is generally hotter and drier than usual under El Niño conditions and cooler and wetter under La Niña conditions[1].

Appendix 4 of TAPR 2014 contained an analysis that showed that the periods over which network support may be required, was quite variable from year to year. That analysis was based on Wagga Wagga temperature data and considered adverse weather events as a proxy for days on which high demands could occur. Wagga Wagga was selected due to the amount of data available (over 70 years) and the quality of the data (all from the same location, Wagga Wagga airport, with relatively few days of missing data).

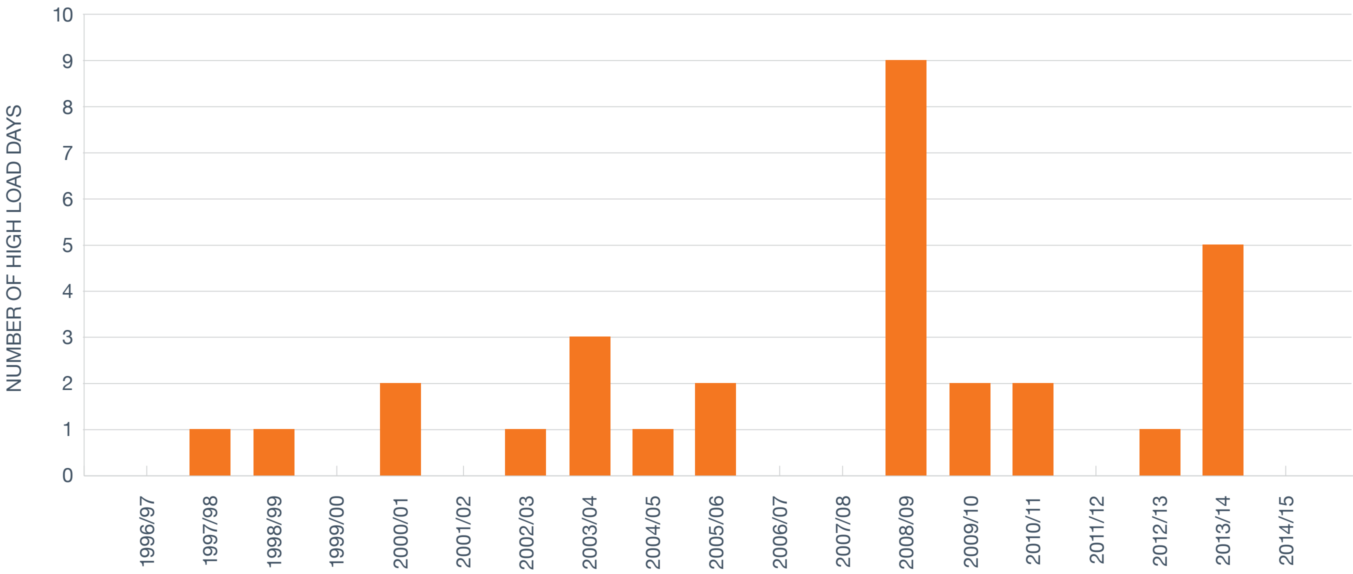
Since TAPR 2014 was published, summer weather and day-type correction models[2] for the load supplied by TransGrid's network at 66 kilovolts in the Wagga Wagga area have been developed. This has enabled a similar analysis utilising actual summer maximum demands to be undertaken. In this case, high demand days have been taken to be those on which the maximum demand exceeded the 50% probability of exceedance (POE) corrected maximum demand for that particular summer.

For each of the past 19 summers, the following quantities were determined:

- the number of high-load days
- the number of groups of consecutive high-load days[3]
- the maximum number of consecutive high load days.

These quantities are shown in Figure A4.3, Figure A4.4 and Figure A4.5, respectively.

FIGURE A4.3 – Number of high load days



1 The Bureau of Meteorology provides extensive information on Australia's climate at www.bom.gov.au/climate. Information on El Niño Southern Oscillation events is available at www.bom.gov.au/enso

2 These are ordinary least-squares regression models. They regress daily maximum demands against a measure of temperature and day-type variables. The two day-type variables used were weekends plus public holidays and the Christmas/New Year period. The temperature measure used was 'cooling degrees,' which is based on a two-day weighted average temperature, relative to a threshold above which discretionary cooling loads could be expected to occur. Where the weighted average temperature exceeds the threshold, the 'cooling degrees' are the extent to which it does so, otherwise it is zero.
The temperature weightings and threshold were adjusted to give the best (most powerful) model for each summer. As a broad indication, for summer 2014/15, the weighted average temperature for each day was based on 85% of the maximum temperature versus 15% of the minimum temperature and 85% of the present day versus 15% of the previous day. The weighted average temperature threshold was 23°C.

3 For this analysis, a single isolated high-load day has been taken to be a group consisting of a of one-day duration.

FIGURE A4.4 – Number of groups of high load days

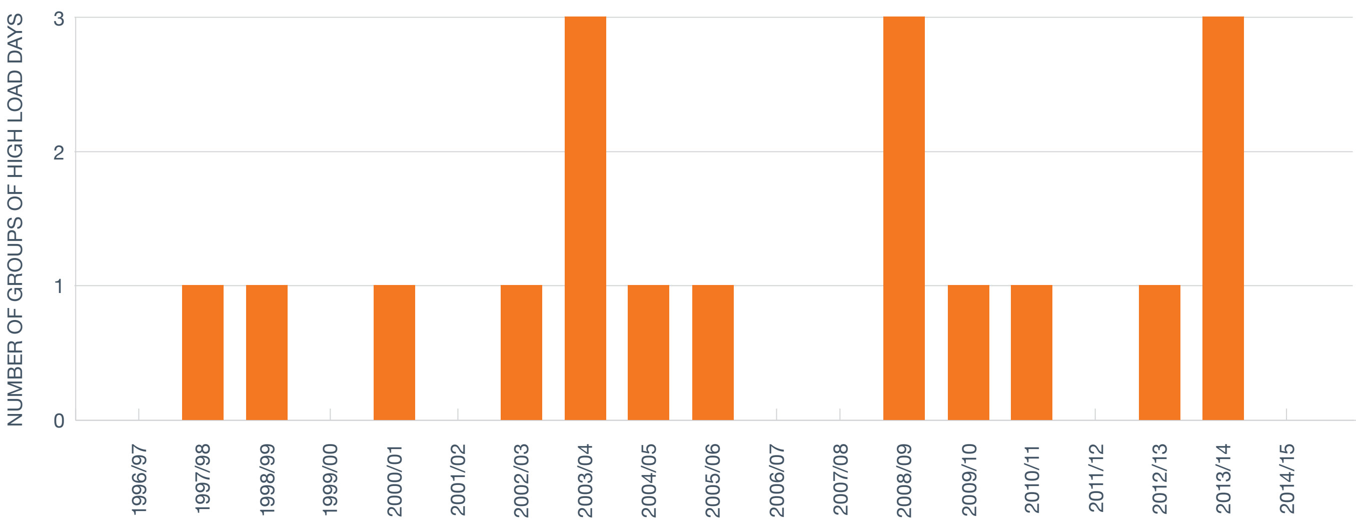
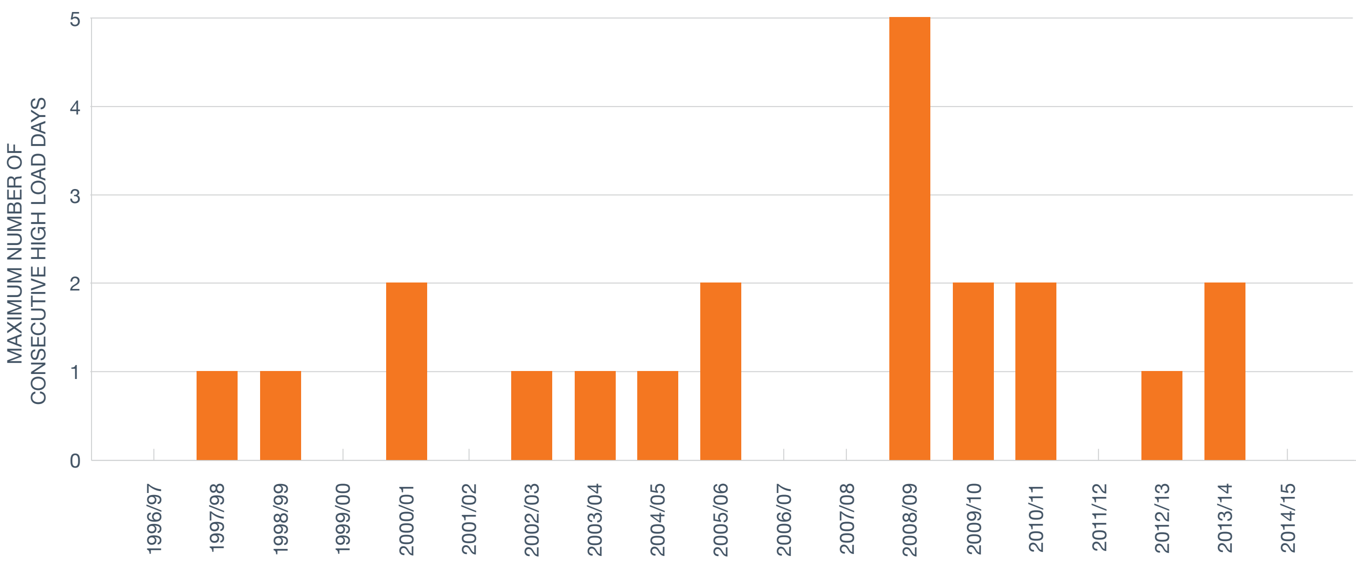


FIGURE A4.5 – Maximum number of consecutive high load days



The development of the summer weather and day-type correction models has provided some insights into the changing nature of loads. In the case of the Wagga Wagga area, the 50% PoE corrected maximum demand has been exceeded in 12 of the past 19 summers, which is more often than would normally be expected. It's possible that this is due to the Wagga Wagga area load becoming:

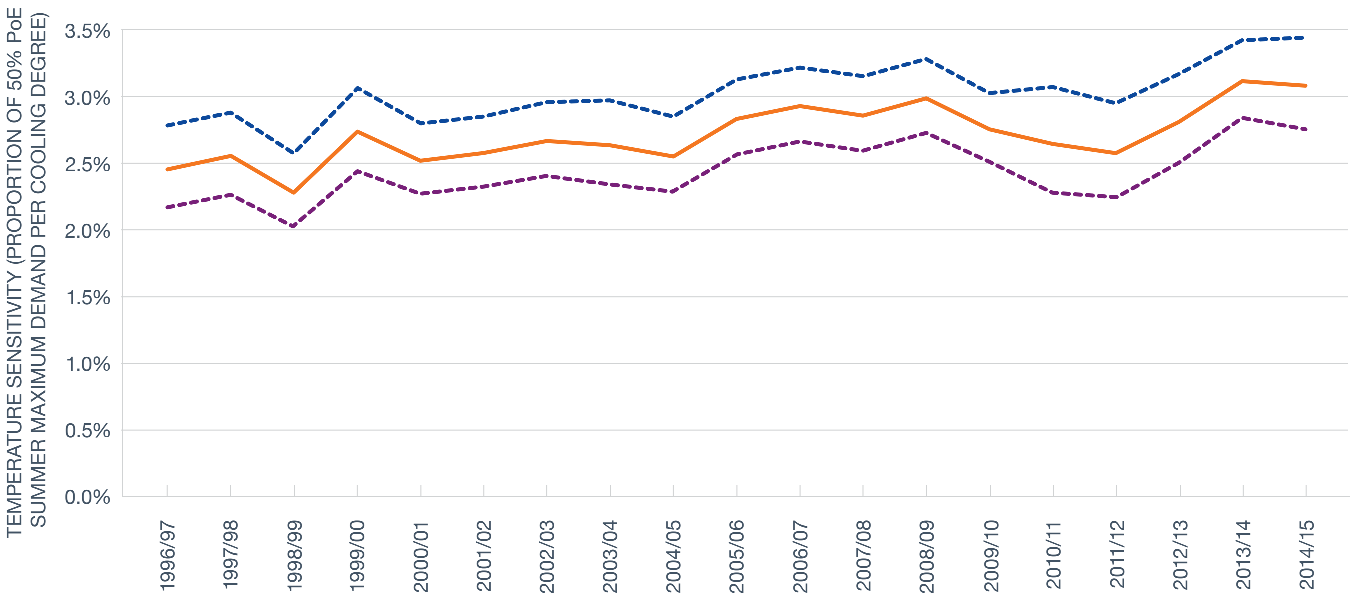
> more sensitive to temperature

> less sensitive to weekends and public holidays in more recent summers. That is, maximum demands on weekends and public holidays are becoming closer to those on working weekdays (having similar temperature conditions).

These factors are likely to have led to the Wagga Wagga area load progressively having larger responses to variations in temperature and an increase in the number of days on which high demands are possible.

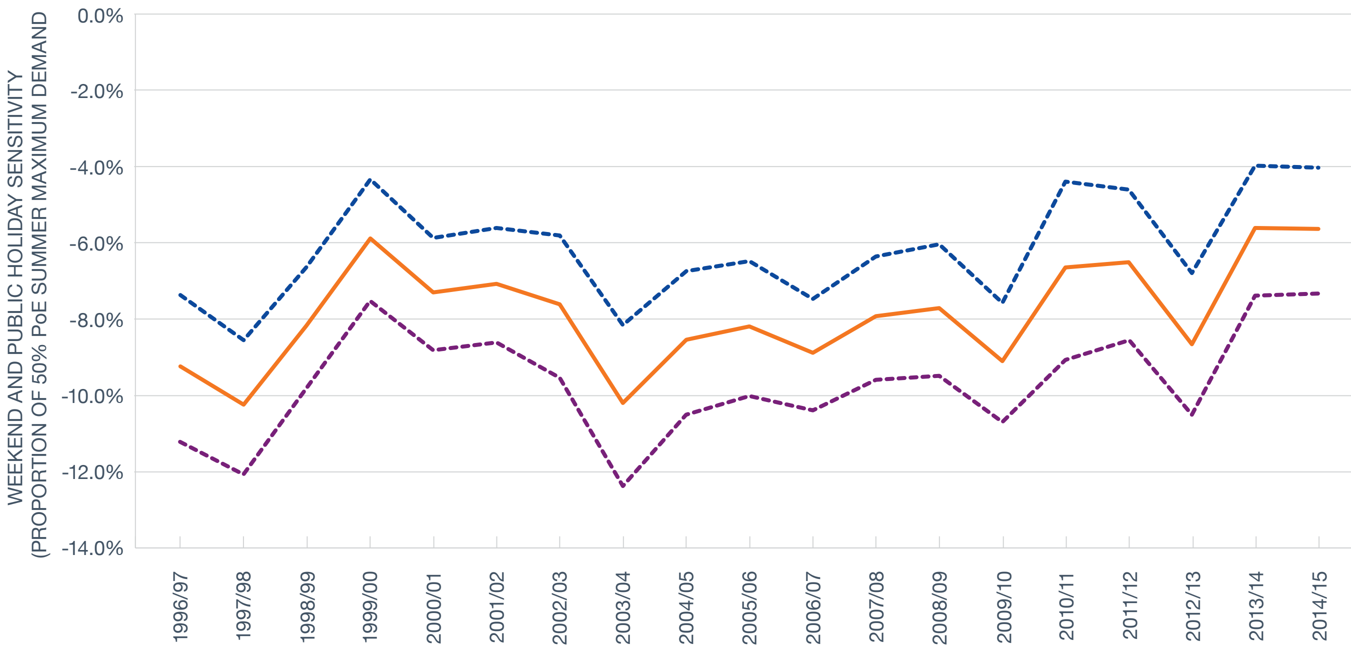
Figure A4.6 shows the historical temperature sensitivity [5] of the Wagga Wagga area load. Figure A4.6 shows the sensitivity to weekends and public holidays. As the correction models are not perfect (they have an error term), the 95% confidence interval for the particular sensitivity (the range within which there is 95% confidence that the particular sensitivity lies) was also calculated. Each figure shows the 'most likely' sensitivity (the solid line) and the 95% confidence interval (the two dashed lines).

FIGURE A4.6 – Temperature sensitivity of Wagga Wagga area load



5 To enable year on year comparisons to be made, a consistent definition of 'cooling degrees' was used in each correction model and the temperature sensitivities were 'normalised' (expressed as a proportion of the 50% PoE corrected maximum demand for that summer).

FIGURE A4.7 – Sensitivity of Wagga Wagga area load to weekends and public holidays



As with the analysis in TAPR 2014, this analysis is intended to give a broad indication, rather than a precise indication, of how the number of high-load events can vary from season to season. For example, the results for other locations could be expected to depend on:

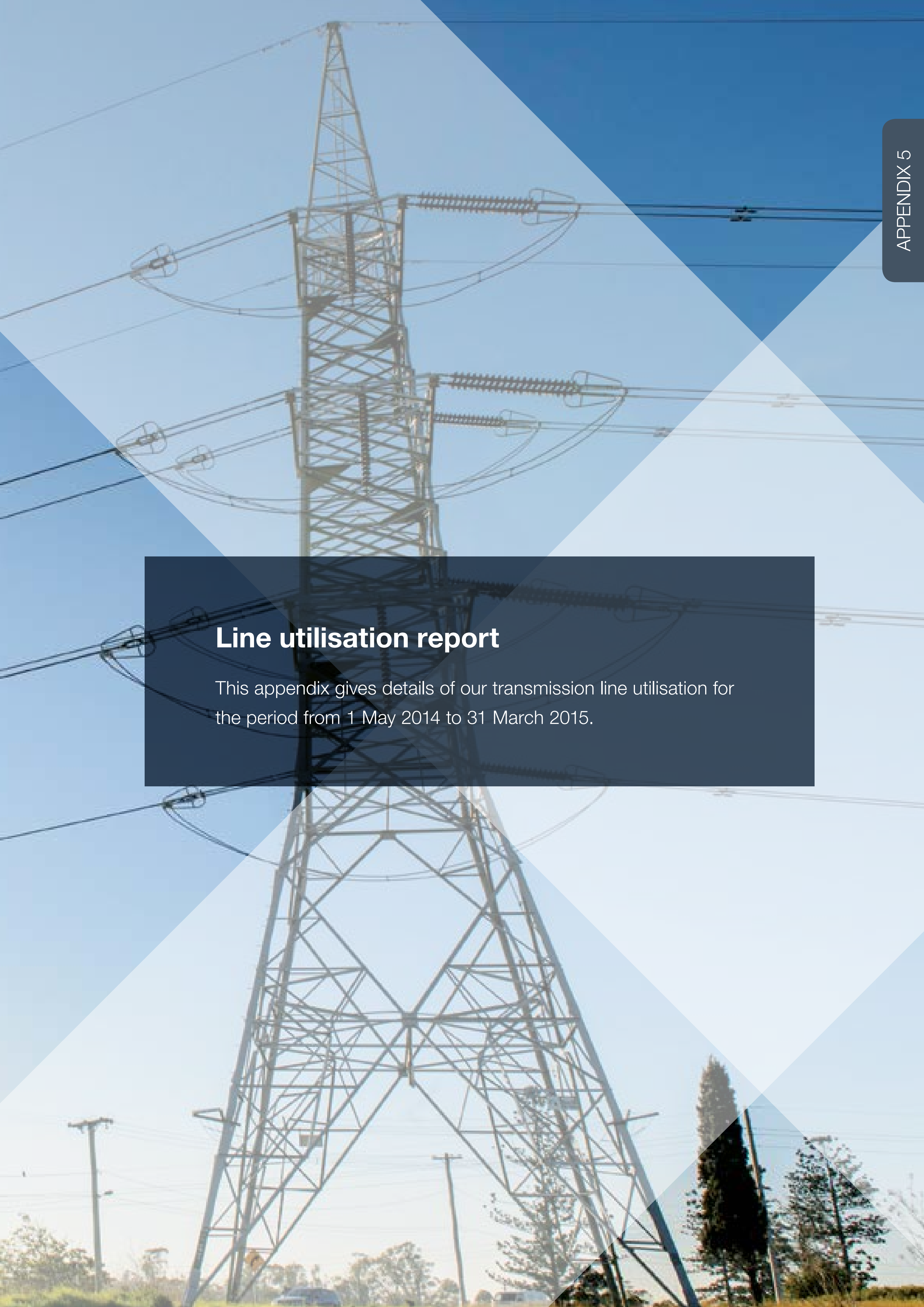
> The nature of the load in that area, particularly how temperature sensitive it is and the extent to which it varies with different day-types

> Whether there are trends, such as increasing or decreasing sensitivities, which mean that past behaviour of the particular load may not be a good indicator of its future behaviour

> Changes in external factors. For example, climate change may result in more frequent or more severe weather conditions in the future.

Given the potential variability in the number and duration of high-load events and considering that it is not possible to forecast weather more than a few days in advance, we welcome any feedback on additional information which may be of use to potential providers of network support. Contact details are provided on the inside of the back cover.

5 Appendix



Line utilisation report

This appendix gives details of our transmission line utilisation for the period from 1 May 2014 to 31 March 2015.

A5 Line utilisation report

The line loading information over the analysis period was obtained from AEMO's Operation Planning and Data Management System (OPDMS). This system produces half hourly system load flow models (snapshots) of the NEM.

For each half hour period, the utilisation (loading) of each line was calculated as a proportion of the relevant rating. The highest values of these proportions are reported here.

The utilisation of each line was calculated based on two conditions:

> With all network elements in service, referred to as the 'N utilisation'. These utilisation figures are based on normal line ratings

> With the most critical credible contingency (usually an outage of another line in the area), referred to as the 'N–1 utilisation'. These utilisation figures are based on the line emergency ratings.

The N utilisation and N–1 utilisation of the transmission lines in the NSW transmission network are shown in Figures A5.2 to A5.10.

For each line, the utilisations are shown in the white box placed adjacent to the line. The box shows:

A. The transmission line number

B. The maximum N utilisation of the transmission line

C. The maximum N–1 utilisation of the transmission line

D. The number of the line that creates the critical contingency in the event of an outage.

The utilisation is shown in Figure A5.1

FIGURE A5.1 – Key to interpreting the information shown in Figures A5.2 to A5.10

A – Line number: B – Maximum N Utilisation %
C – Maximum N–1 Utilisation % [D – Line number out for N–1]

In some situations, the N–1 utilisation has been estimated to be more than 100%. These situations could be because of:

> A higher level of line loading being allowed, considering the operational line overloading control schemes and run-back schemes available for managing the line loadings

> The predicted dispatch conditions that change over the five-minute dispatch period, causing the line loadings to increase above the predicted values.

FIGURE A5.2 – TransGrid N and N–1 line utilisations – Map 1

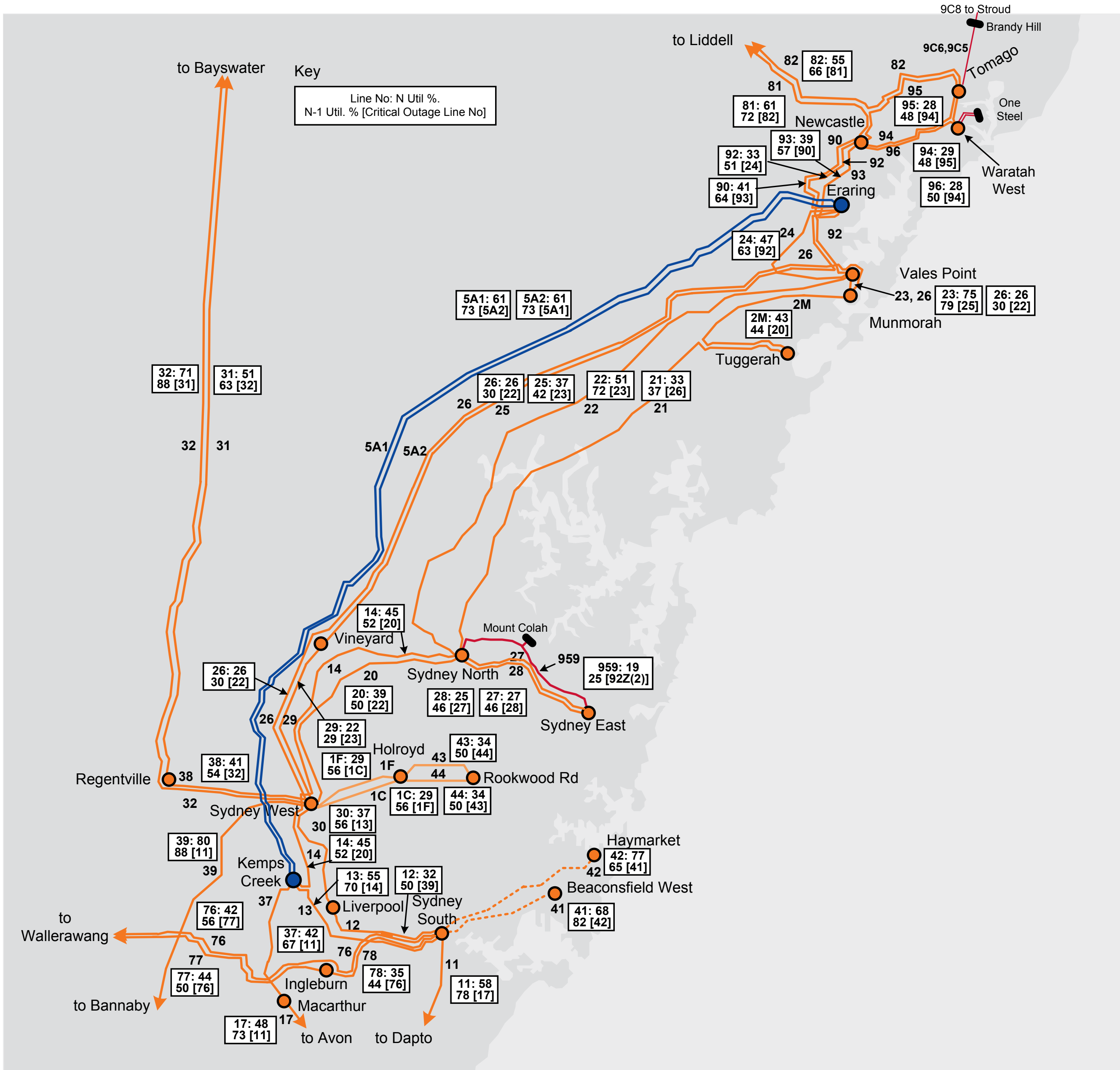


FIGURE A5.3 – TransGrid N and N–1 line utilisations – Map 2 – North East NSW

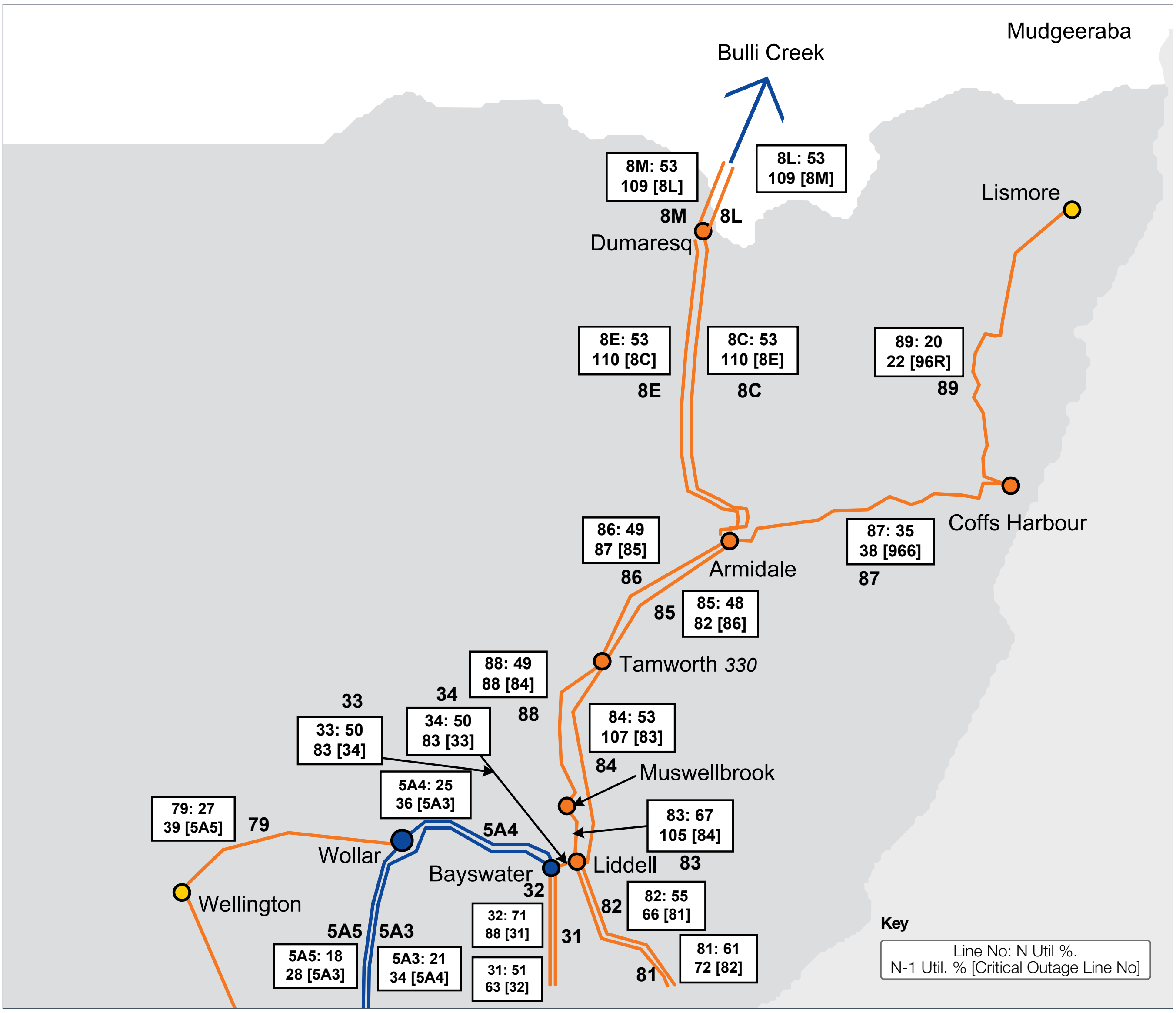


FIGURE A5.4 – TransGrid N and N–1 line utilisations – Map 3 – Hunter Valley

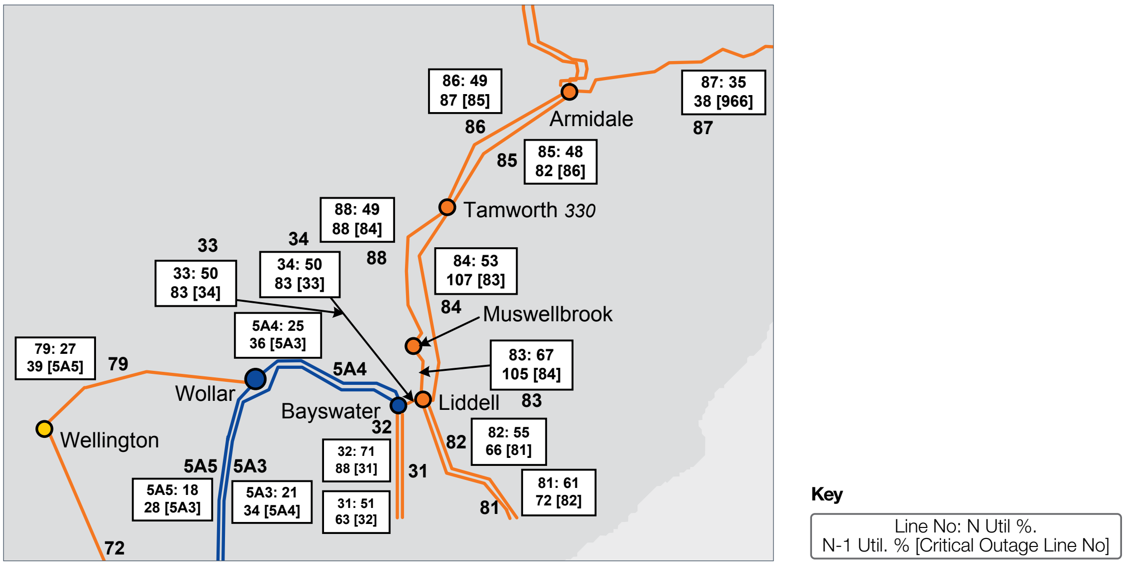


FIGURE A5.5 – TransGrid N and N–1 line utilisations – Map 4 – South and South East

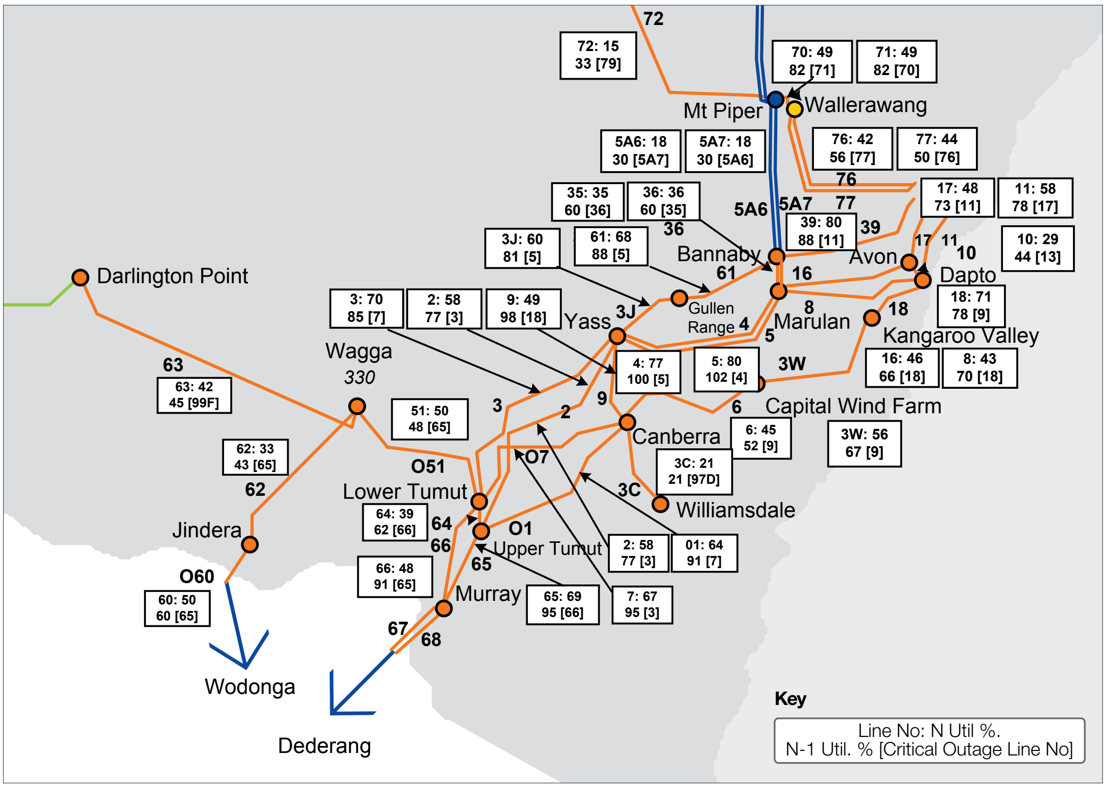


FIGURE A5.6 – TransGrid N and N–1 line utilisations – Map 5 – Far West

FIGURE A5.7 – TransGrid N and N–1 line utilisations – Map 6 – North Coast and North West 132 kV System

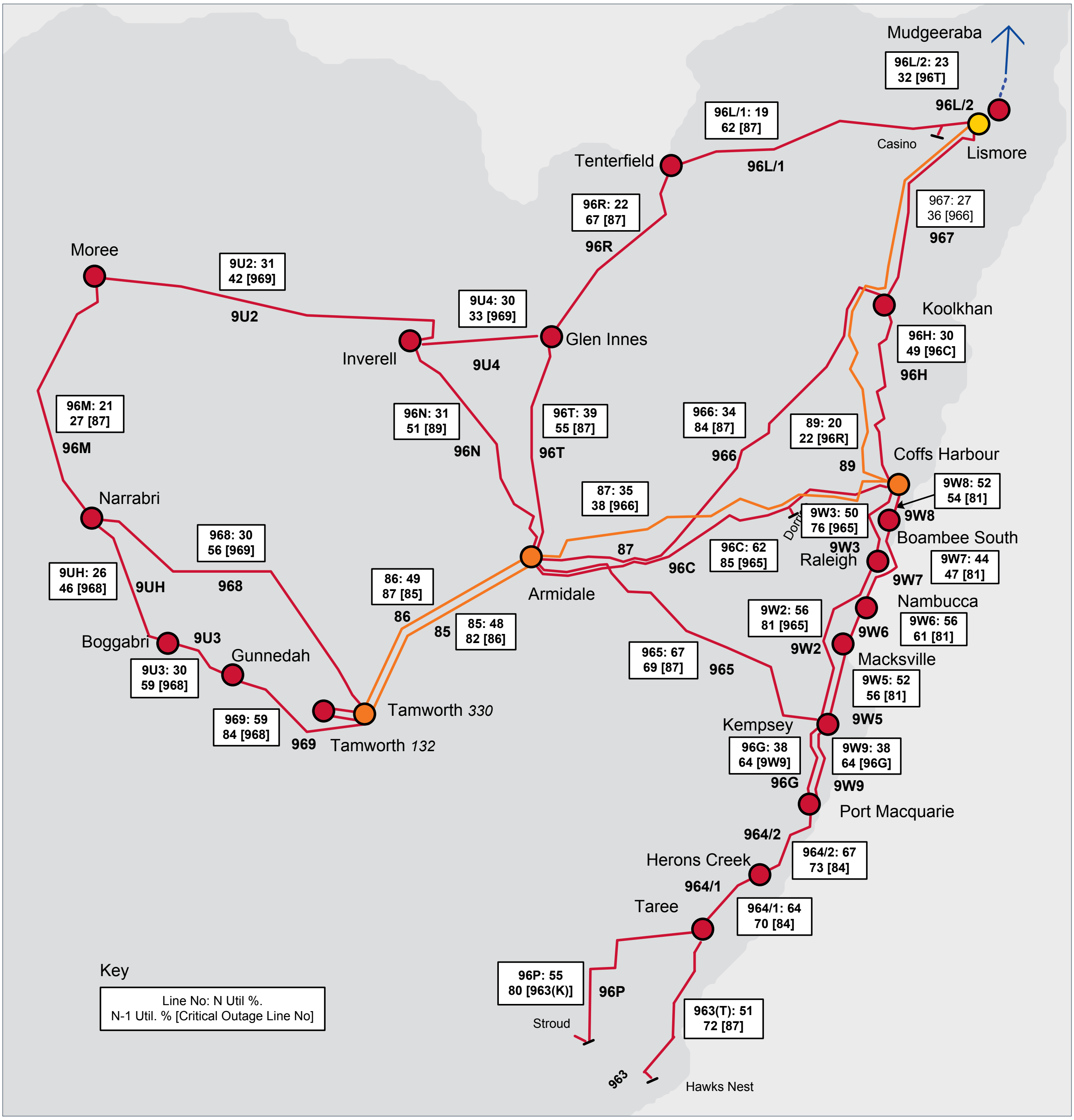


FIGURE A5.8 – TransGrid N and N–1 line utilisations – Map 7 – Central West

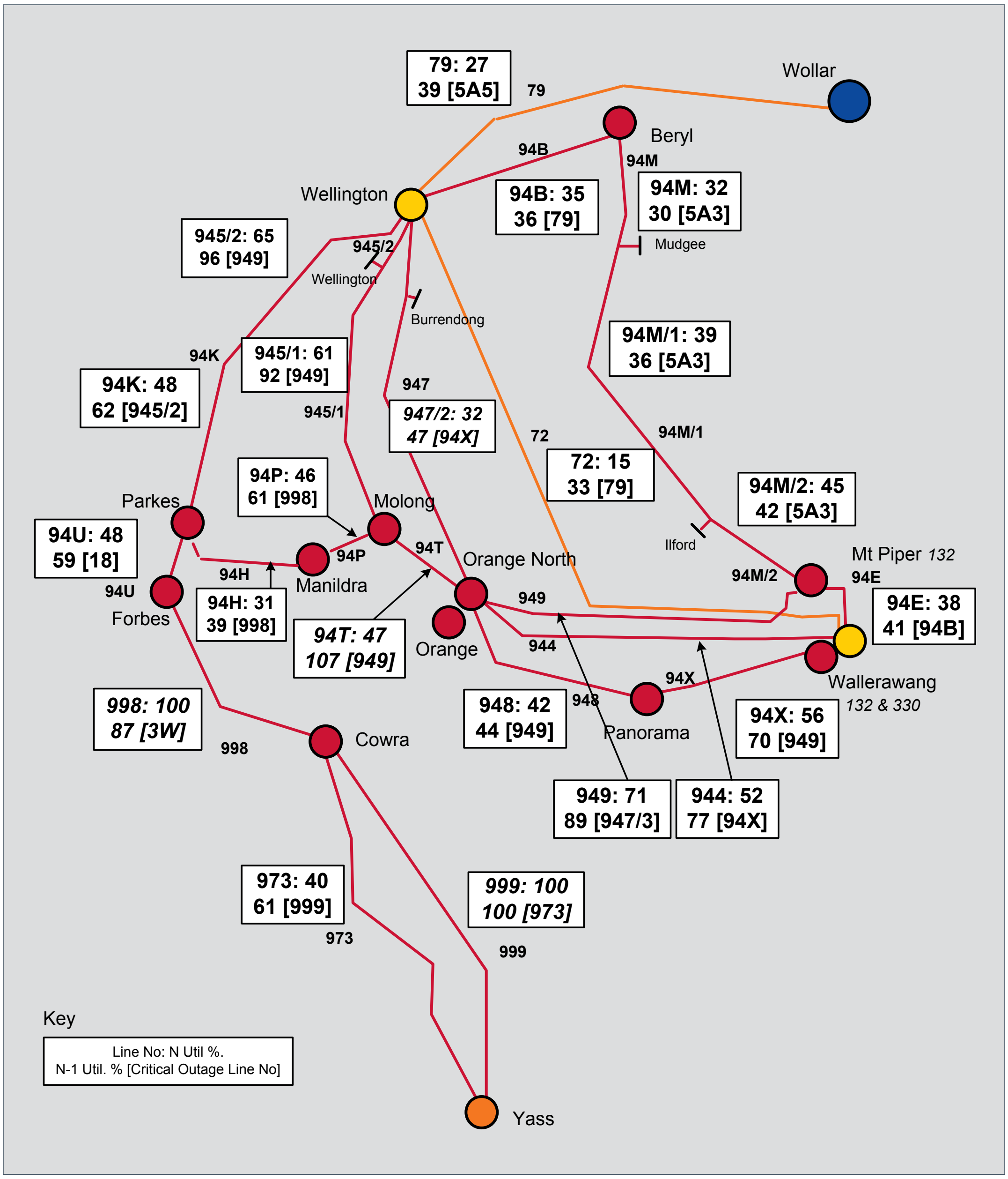


FIGURE A5.9 – TransGrid N and N–1 line utilisations – Map 8 – South and Snowy

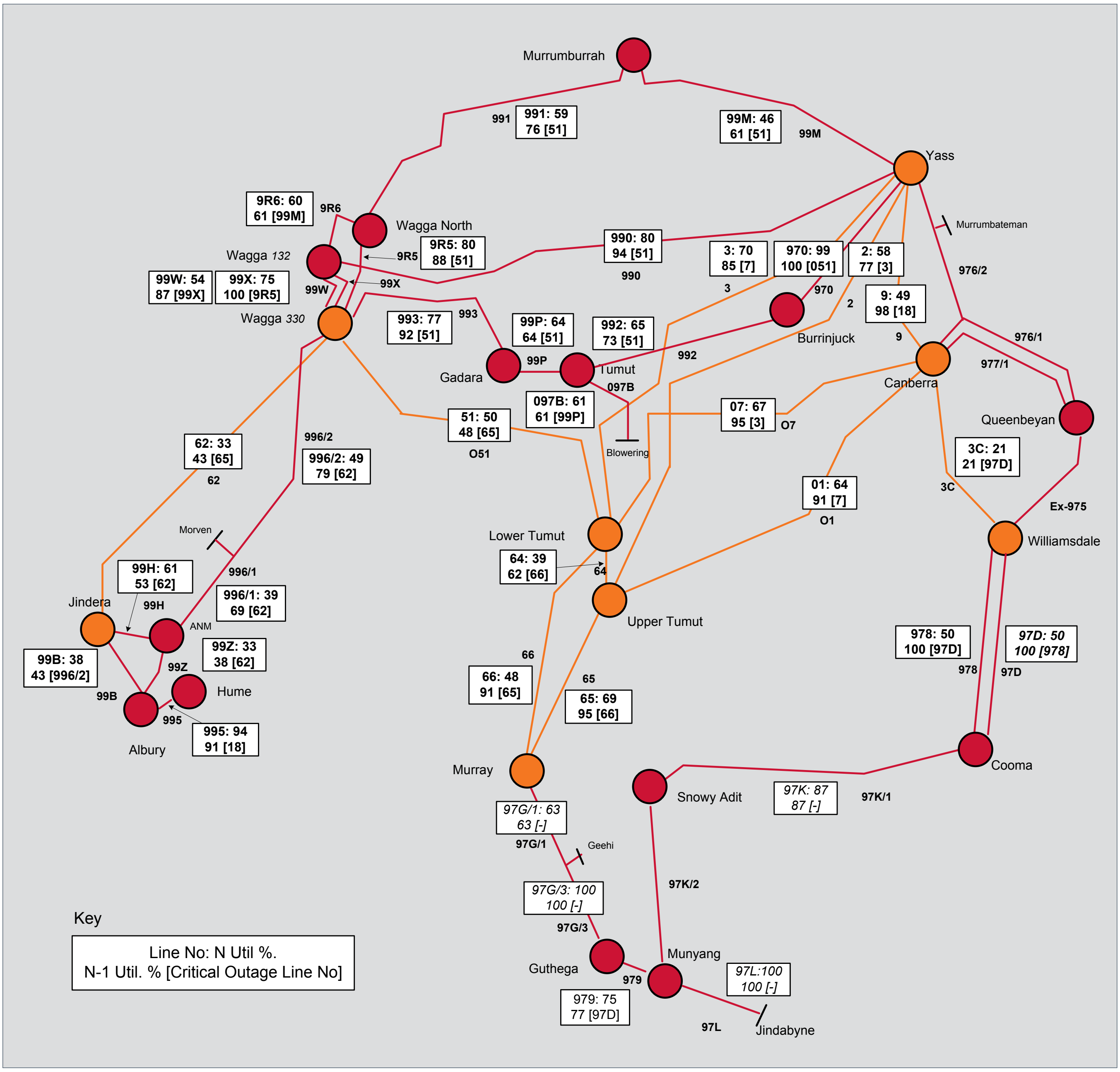
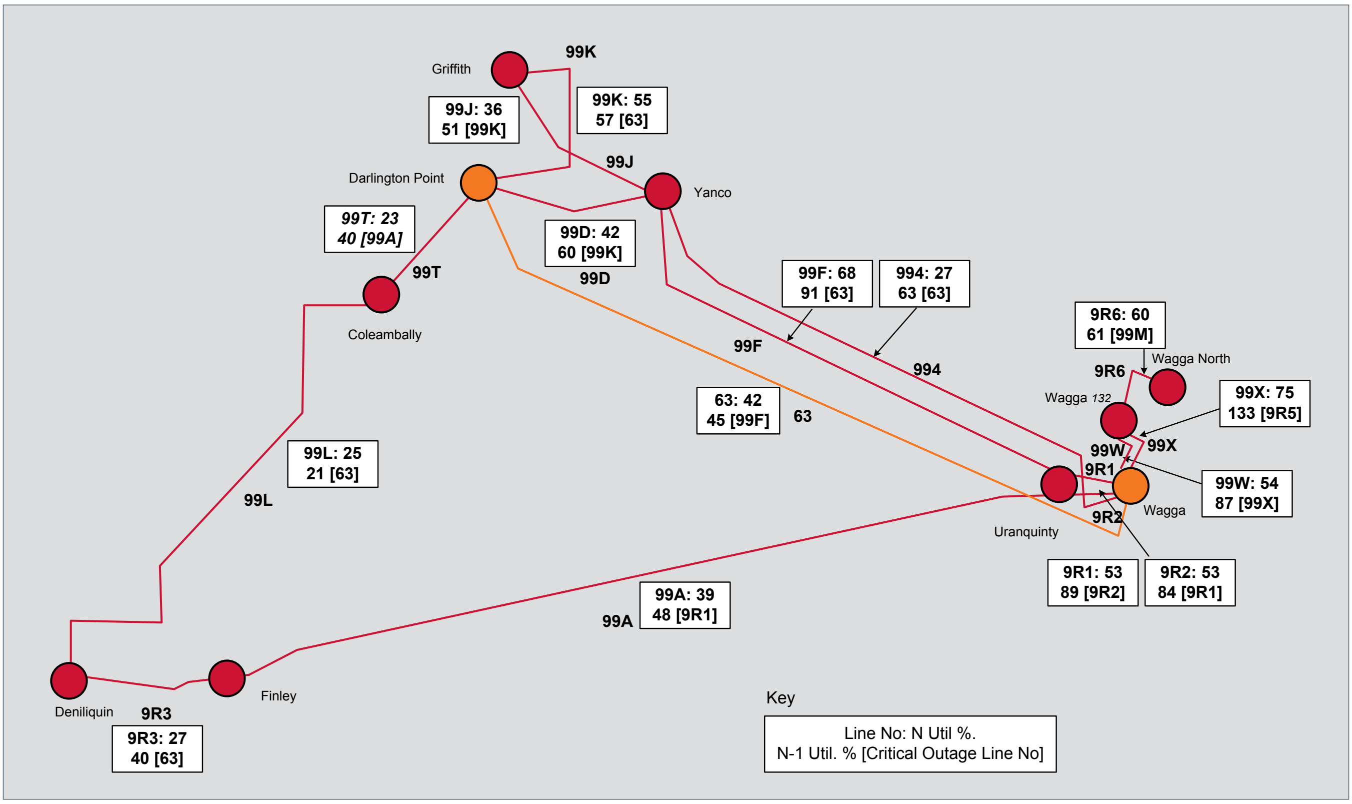


FIGURE A5.10 – TransGrid N and N–1 line utilisations – Map 9 – South West



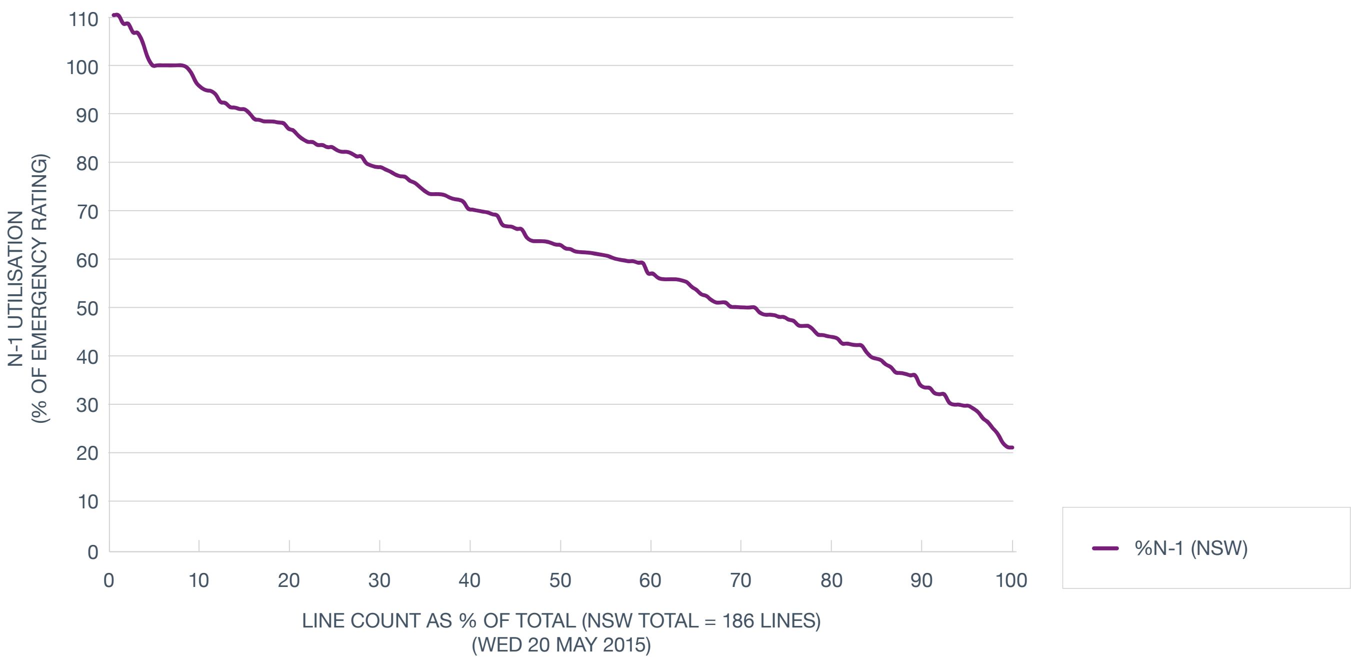
Summary of the N–1 utilisation of the transmission lines in the TransGrid's network

The distribution of the utilisation of the transmission lines across our network is shown in Figure A5.11.

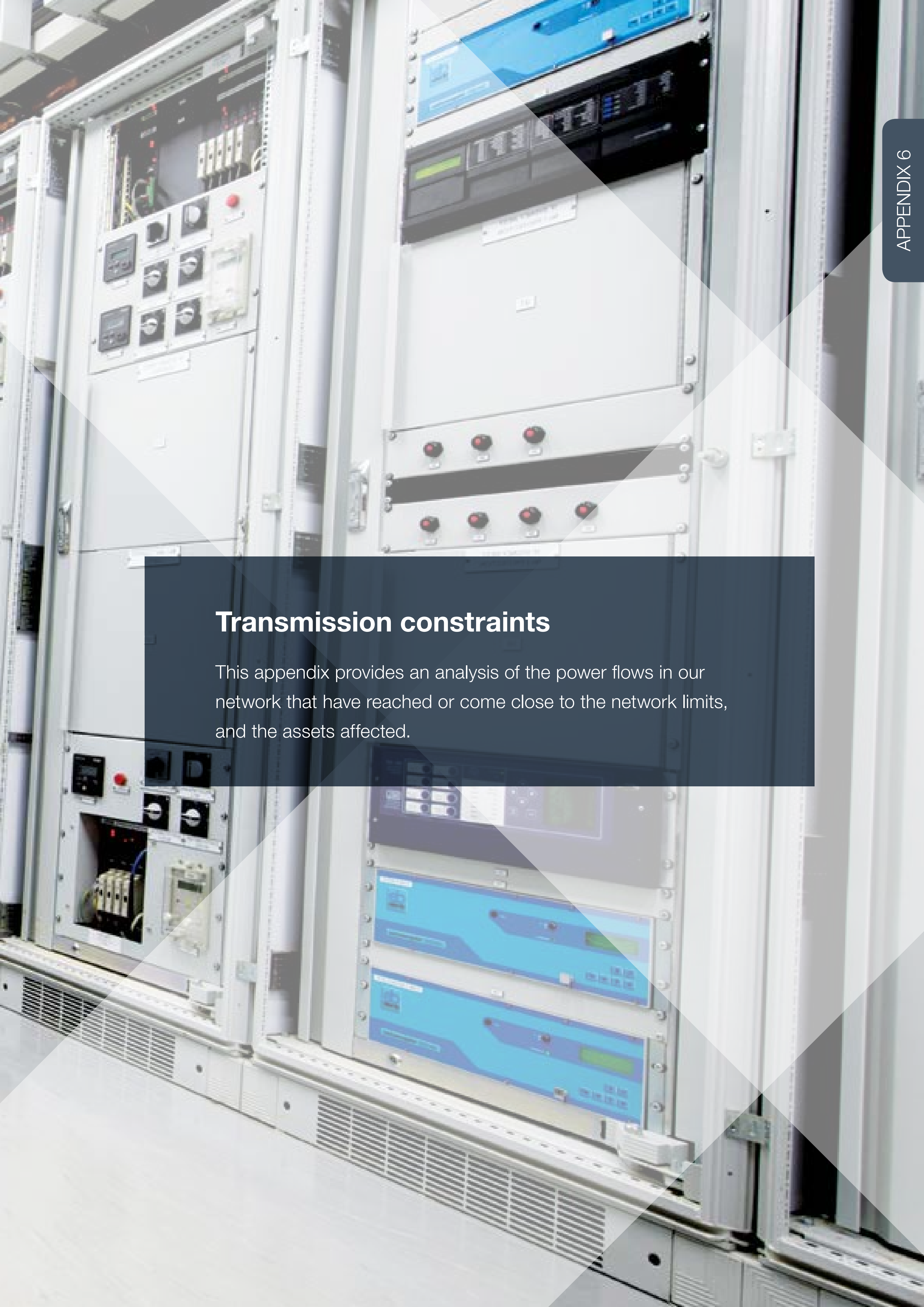
The distribution shows that approximately 8% of the transmission lines in the network are utilised up to their installed maximum capacity. TransGrid's plans for the most economical approach for managing the loadings on these lines are given in Chapters 5 and 6. Approximately 28% of the lines utilise more than 80% of their installed capacity. On the other hand, approximately 24% of the transmission lines are presently only utilised between 30% and 50% of their installed capacity, representing the 'step' increments in the transmission capacity, as the network is augmented by building new transmission lines. The new augmentations are built with the expectation of providing adequate capacity over their asset lives of approximately 40 to 50 years.

The distribution of the N–1 line utilisations reflects at least 40 years of planning history of the transmission network. It is considered to be typical of a well-planned network where various parts of the network are well-established, while other parts have had recent step augmentations that will be further utilised in future years.

FIGURE A5.11 – Distribution of TransGrid line N–1 utilisations (01/05/2014-31/03/2015)



6 Appendix



Transmission constraints

This appendix provides an analysis of the power flows in our network that have reached or come close to the network limits, and the assets affected.

A6.1 Introduction

This section describes an analysis of how close the flows in TransGrid's network are, to its capacity limits. It identifies the transmission elements where flows have been at, or close to, the limits.

Capacity could be limited due to the power flows reaching:

> The maximum rating of a single transmission element such as a transmission line or a transformer

> The combined capacity of a group of transmission elements such as several parallel transmission lines constituting inter regional links

> The limits set by system wide considerations such as voltage, transient or oscillatory stability limits.

TransGrid provides the capability of its transmission network to AEMO. AEMO manages the power flows in the transmission network to be within the capability of the declared limits of the individual assets or the capability of the transmission system. AEMO do so by automatically adjusting the quantity of generation dispatched, so that the transmission flows will be maintained under the prevailing operating conditions, including the flows to be expected under credible unplanned outages. The optimal generation dispatch, the dispatch which minimises total cost while ensuring the capability limits of the transmission system are not violated, is determined using the analytical tool: National Electricity Market Dispatch Engine (NEMDE). The capability limits are included within NEMDE as mathematical equations, which are known as the 'Constraint Equations' (refer to Sections A6.4 and A6.5). Each constraint equation is identified by a unique identifier, and contains information including the capability limit and the factors which describe or determine the limiting power flows, such as power flow in a transmission line or generator power outputs, which contribute to the limiting power flow.

The capability limitations of the transmission system are normally termed as 'constraints' reflecting that each limitation is represented by a constraint equation in NEMDE.

The constraints reported in this section cover the transmission system capability limitation experienced during the period from 1 December 2013 to 30 November 2014. The same information is also used to predict the potential future constraints.

A6.2 Historical transmission system performance

The following table summarises the constraints, where higher cost generation may have to be dispatched because some transmission elements or parts of the transmission network have reached their maximum capability. The table shows the constraint identifier, its description, type of limitation addressed by the constraint equation, and length of the time period where the transmission element, or the part of the transmission system, was operated at its maximum capability.

Constraint name	Constraint description	Type of limitation	Total duration (dd:hh:mm)
Q:N_NIL_ AR_2L-G	Constrain the southerly flow on QNI to avoid transient instability for a two phase to ground fault at Armidale.	Transient Stability	31:02:10
N^^V_NIL_1	Constrain the southerly flow on the New South Wales to Victoria interconnector, the flow from Victoria to South Australia on Murraylink and various generators to avoid voltage collapse in Southern NSW if the largest Victorian generator, or Basslink trips.	Voltage Stability	08:12:55
N^^Q_NIL_B1	Constrain the northerly flow on QNI and Terranora interconnector to avoid voltage collapse on loss of Kogan Creek generator.	Voltage Stability	04:15:25
V::N_NIL_V4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (VIC accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	04:15:25
V::N_NIL_V3	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (VIC accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	01:12:30
V::N_NIL_Q4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (QLD accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	01:05:40
N^Q_NIL_A	Constrain the northerly flow on QNI and the Terranora interconnector to avoid voltage collapse if 83 Liddell to Muswellbrook 330kV transmission line trips.	Voltage Stability	00:06:10
V>>N-NIL_HA	Constrain the northerly flow on the Victoria to New South Wales interconnector, the flow from Victoria to South Australia on Murraylink and various generators to avoid Murray to Upper Tumut (65) line overload on Murray to Lower Tumut (66) line trip.	Thermal	00:04:05
Q:N_NIL_BI_POT	Constrain the southerly flow on QNI to avoid transient instability on trip of a Boyne Island potline.	Transient Stability	00:03:25
V::N_NIL_Q3	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (QLD accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	00:03:15
N^^Q_NIL_B4	Constrain the northerly flow on QNI and Terranora interconnector to avoid voltage collapse on loss of Tarong North generator.	Voltage Stability	00:02:35
V::N_NIL_V1	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (VIC accelerates and Basslink flow from Tasmania to Victoria).	Transient Stability	00:02:25
N>>V-NIL_O	Constrain the southerly flow on the New South Wales to Victoria interconnector and NSW generators to avoid Murray to Upper Tumut (65) line overload on trip of Lower Tumut to Wagga (051) line with subsequent opening of Yass to Wagga 132 kV parallel (lines 970,990,99M).	Thermal	00:02:10

Constraint name	Constraint description	Type of limitation	Total duration (dd:hh:mm)
V::N_NIL_S4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (SA accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	00:01:35
N>>N-NIL__3_ OPENED	Constrain northerly flow on QNI and the Terranora interconnector to avoid the overload of Liddell to Muswellbrook (83) line if Liddell to Tamworth (84) line trips.	Thermal	00:01:25
Q:N_NIL_OSC	Constrain the southerly flow on QNI to avoid oscillatory instability.	Transient Stability	00:01:05
V::N_NIL_S3	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (SA accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability	00:00:40
N>N-NIL__4_15M	Constrain northerly flow on QNI and the Terranora interconnector to avoid the overload of Muswellbrook to Tamworth (88) line if Liddell to Tamworth (84) line trips.	Thermal	00:00:30
N>>N-NIL__2_ OPENED	Constrain northerly flow on QNI and the Terranora interconnector to avoid the overload of Liddell to Tamworth (84) line if Liddell to Muswellbrook (83) line trips.	Thermal	00:00:30
N>N-NIL_LSDU	Constrain northerly flow on the Terranora interconnector to avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6).	Transient Stability	00:00:25
V::N_NIL_V2	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (VIC accelerates and Basslink flow from Tasmania to Victoria).	Transient Stability	00:00:25
N>>N-NIL_DPTX	Constrain the southerly flow on the New South Wales to Victoria interconnector, the flow from Victoria to South Australia on Murraylink and various generators to avoid overloading a Darlington Point transformer on trip of the other transformer.	Thermal	00:00:15
N>N-NIL_8C_8E	Constrain northerly flow on the QNI interconnector to avoid overloading Dumaresq to Armidale (8C) line on trip of Dumaresq to Armidale (8E) line.	Thermal	00:00:05

A6.3 Possible future transmission system performance

Based on the performance[1] of the transmission system over the period 1 December 2013 to 30 November 2014, it is expected that the following transmission elements or parts of the transmission system may be operated approaching their maximum limits as described in the following table.

The constraints listed in the tables above are being reviewed by TransGrid to fully understand their nature, and to provide possible solutions to reduce the market impact of the transmission constraints.

TransGrid intends to continue with its analysis of network constraints. It is expected that this will involve:

> Analysing additional data as it becomes available

> Investigation of the distribution(s) of marginality values and, if possible, refinement of likelihood estimates

> Identification and analysis of trends (which may be a leading indicator of the onset of constraints).

Constraint name	Constraint description	Type of limitation
N^^V_NIL_1	Constrain the southerly flow on the New South Wales to Victoria interconnector, the flow from Victoria to South Australia on Murraylink and various generators to avoid voltage collapse in Southern NSW if the largest Victorian generator, or Basslink trips.	Voltage Stability
N>N-NIL_8C_8E	Constrain northerly flow on the QNI interconnector to avoid overloading Dumaresq to Armidale (8C) line on trip of Dumaresq to Armidale (8E) line.	Thermal
N>N-NIL_DC	Constrain northerly flow on QNI and the Terranora interconnector to avoid the overload of Armidale to Tamworth (86) line if Armidale to Tamworth (85) line trips.	Thermal
Q:N_NIL_AR_2L-G	Constrain the southerly flow on QNI to avoid transient instability for a 2 phase to ground fault at Armidale.	Transient Stability
Q:N_NIL_BI_POT	Constrain the southerly flow on QNI to avoid transient instability on trip of a Boyne Island potline.	Transient Stability
Q:N_NIL_BWRG	Constrain the southerly flow on QNI interconnector to avoid transient instability if Bayswater to Regentville 31 line trips.	Transient Stability
Q:N_NIL_LDNC	Constrain the southerly flow on QNI interconnector to avoid transient instability if Liddell to Newcastle 81 line trips.	Transient Stability
Q:N_NIL_OSC	Constrain the southerly flow on QNI to avoid oscillatory instability.	Transient Stability
Q>N-NIL_8L_8M	Constrain southerly flow on the QNI interconnector to avoid overloading Bulli Creek to Dumaresq (8L) line on trip of Bulli Creek to Dumaresq (8M) line.	Thermal
V::N_NIL_Q3	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (QLD accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability
V::N_NIL_Q4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (QLD accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability
V::N_NIL_S4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (SA accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability
V::N_NIL_V3	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 220 kV (VIC accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability
V::N_NIL_V4	Constrain the northerly flow on the Victoria to New South Wales interconnector (and other Victorian interconnectors and generators) to prevent transient instability if one of the Hazelwood to South Morang 500 kV transmission lines trips when Yallourn W Unit 1 is on 500 kV (VIC accelerates and Basslink flow from Victoria to Tasmania).	Transient Stability

1 These constraints had average value for the period from 1 December 2013 to 30 November 2014 that was the closest to binding in terms of direct value, or number of standard deviations.

A6.4 Background to constraint equations

This appendix describes an analysis of how close constraints relating to TransGrid's network have come to binding. It identifies the most onerous constraints using three different criteria and provides the historical outcomes as well as broad estimates of future constraints.

TransGrid provides the capability of its transmission network to AEMO, which AEMO then translates into constraint equations. AEMO use the constraint equations in the NEMDE, to control the transmission network to be within its physical capability.

The NEMDE uses linear programming (LP) methods to dispatch the NEM, and the constraint equations use the jargon of LP, which gives special meaning to the left and right hand sides of the equations.

The Left Hand Side (LHS) of the equations contain variables that are controllable by the NEMDE, and contains terms like the MW generated at a power station. The Right Hand Side (RHS) of the equation generally contains the variables that are not controlled by dispatch such as line ratings and the size of loads at various locations. A simple example of a constraint equation follows:

LHS	≤	RHS
a^1 x Generation at power station 1		$+b^1$ x Network Limit1
$+a^2$ x Generation at power station 2	≤	$+b^2$ x Network Limit2
$+a^3$ x generation at power station 3		$+b^3$ x Load1

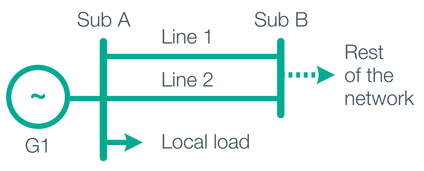
Subtracting the RHS from the LHS (LHS – RHS) of the equation gives an indication of 'how close' the constraint is to binding. If both sides of the equation are equal, then (LHS – RHS) equals zero, the constraint is binding, and the transmission network is operating at its limit.

The (LHS – RHS) value is referred to as the marginality of the constraint.

A6.5 Indicative example of a constraint equation

Figure A6.1 illustrates a network which consists of a generator (G1) and a 'Local load' connected to 'Sub A'. Two transmission lines ('Line 1' and 'Line 2') are connected from 'Sub A' to 'Sub B', which in turn is connected to the rest of the network. The limit of generation from G1 will be the local load plus the power that can be securely transferred from 'Sub A' to 'Sub B' to the rest of the network via 'Line 1' and 'Line 2'. In this example, that will be the minimum Contingency Rating of the two lines. For example, if 'Line 1' has a Contingency Rating of 100 MVA and 'Line 2' has an Contingency Rating of 90 MVA, then the maximum power that can be transferred securely will be 90 MVA. We assume the generation cannot be reduced sufficiently quickly on the loss of one of the lines. If 'Line 1' trips, then 'Line 2' will be at its limit, if 90 MVA is being transferred.

FIGURE A6.1 – A Two Transmission Line example of a Transfer Limit



The constraint equation for the network illustrated in Figure 1 would be:

LHS	≤	RHS
Generation at power station (G1)	≤	Local load + Rating of ‘Line 2’

If the local load is 10 MVA, and the lowest rating of the lines is 90 MVA, then:

> If the generation output is 100 MVA then the marginality of the equation is zero, the constraint is binding, that is, the system is operating at its very limit of power transfer. The constraint equation would be:

LHS	≤	RHS
100	≤	10 + 90

> If we consider the same load and rating, but reduce the generation to 90 MVA, then the marginality is -10, hence, the maximum additional power transfer capacity is 10 MVA. The constraint equation would be:

LHS	≤	RHS
90	≤	10 + 90

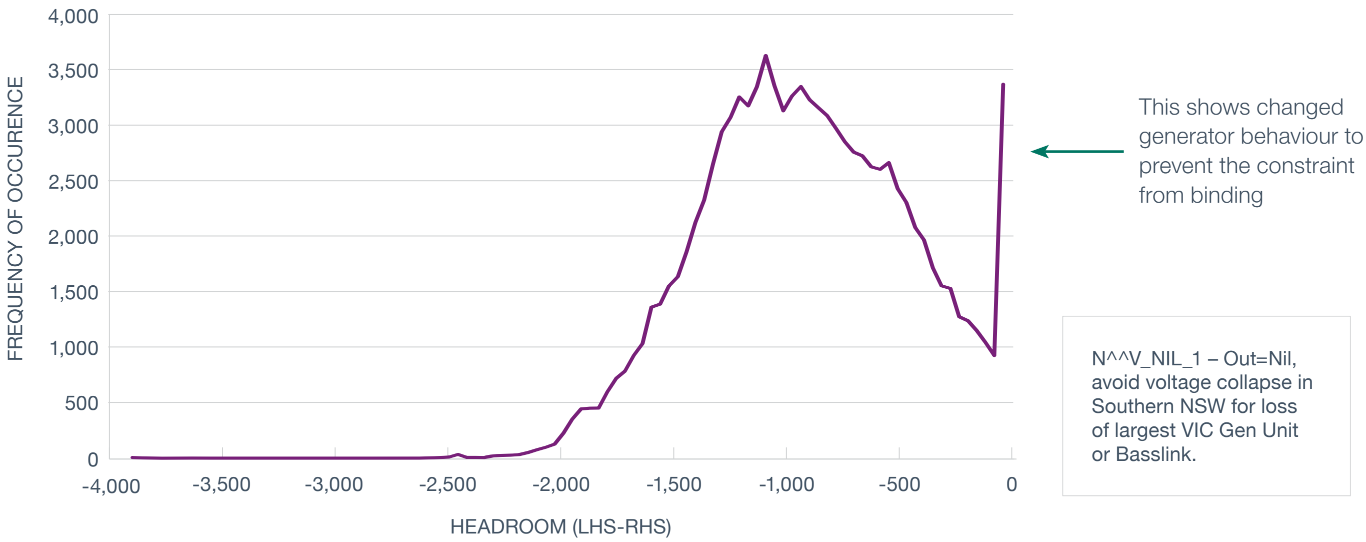
> If the generation is increased to 110 MVA, the marginality would be +10. In addition, in the event of a contingency trip of ‘Line 1’, ‘Line 2’ would be overloaded. The constraint equation would be:

LHS	≤	RHS
110	≤	10 + 90

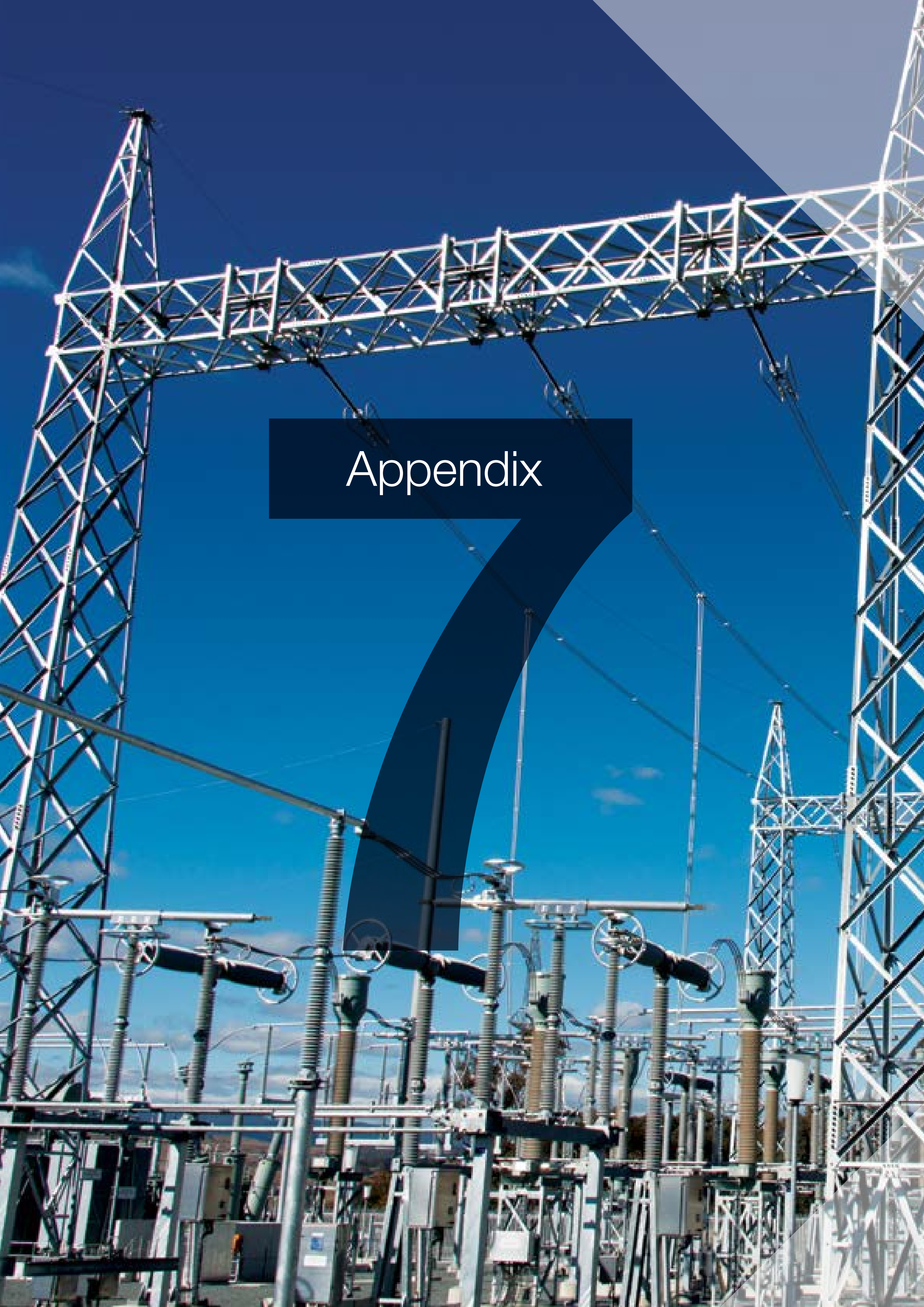
If the marginality is greater than zero the network is operating in an insecure state, and the constraint has been violated.

The following Figure A6.2 shows an example of how close one constraint has come to binding. It also shows the impact of generators changing their behaviour to prevent the constraint from binding.

FIGURE A6.2 – Generator behaviour to prevent constraint from binding



Appendix 7



Planning proposals for future connection points

This appendix describes planning proposals for future connection points for the next five years that have been initiated by generators or customers, or that have arisen as the result of joint planning with a distributor.

These planning proposals cover provision of new bulk supply points, provision of additional switchbays for new connections at existing bulk supply points, and developments that may increase the capability of a bulk supply point, such as installation of new transformers or capacitors.

A7 Planning proposals for future connection points

The NER requires that the TAPR set out planning proposals for future connection points. The proposals can be initiated by generators or customers, or arise as the result of joint planning with a distributor.

As the NER does not define the term, planning proposal, we have taken a broad interpretation in previous TAPRs, covering developments up to five years into the future that relate to:

- Provision of new bulk supply points
- Provision of additional switchbays for new connections at existing bulk supply points
- Developments that may increase the capability of a bulk supply point, such as installation of new transformers or capacitors.

For consistency, we have maintained this approach in TAPR 2015, even though it includes developments that are not considered to be proposed under TransGrid's network investment process, that do not relate to connection points as defined in the NER, and that involve existing bulk supply points.

The following table covers developments that meet our broad interpretation.

TABLE A7.1 – Connection point

Bulk supply point	Development	Proposed service date	TAPR 2015 section
Orange 132/66 kV substation	Replacement of 66 kV substation equipment and additional 66 kV capacitor	2017	5.3.1
Cooma 132/66/11 kV substation	Condition based substation replacement	November 2015	5.3.1
Yanco 132/33 kV substation	Condition based substation replacement	September 2015	5.3.1
Orange 132/66 kV substation	Additional capacitor	April 2017	5.3.2
Tamworth 132/66 kV substation	Condition based substation replacement	March 2017	5.3.2
Williamsdale 330/132 kV substation	New 132 kV switchbay connection	2018	6.2.10
Tamworth 330/132 kV substation	Condition based transformer replacement	2019	6.2.2
Beryl 132/66 kV substation	Additional or expanded capacitor	2016/17	5.4.1
Munmorah 330/132 kV substation	Condition based substation replacement	2019	6.2.5
Vales Point 330/132 kV substation	Condition based substation replacement	2018	5.4.1
Beryl 132/66 kV substation	New 66 kV switchbay	September 2015	5.3.2
Molong 132/66 kV substation	New 66 kV switchbay	December 2015	5.3.2
Vineyard 330/132 kV substation	New 132 kV switchbay	December 2015	5.3.2
Canberra 330/132 kV substation	Condition based equipment replacement	2019	6.2.6
Burrinjuck 132 kV substation	Line reconfigurations to allow retirement of the 132 kV switchyard	2017	6.2.7
Taree 132/66/33 kV substation	Condition based secondary systems and 33 kV switchyard replacement	September 2017	5.5
Forbes 132/66 kV substation	Condition based transformer replacements	2021	6.3.10
Beaconsfield 330/132 kV substation	Condition based transformer replacement	2018	5.3.2
Wagga 132/66 kV substation	Condition based substation replacement	2018	5.4.1

The following connection point works were completed in 2014/15:

Bulk supply point	Development	Proposed service date	TAPR 2015 section
Boggabri East 132 kV switching station	New 132 kV connection points	September 2014	5.2.1
Boggabri North 132 kV switching station	New 132 kV connection points	April 2015	5.2.1
Rookwood Road 330/132 kV substation	New 132 kV connection points	September 2014	5.2.1
Marulan 330/132 kV substation	New 132 kV switchbay connection	August 2014	5.2.2
Wagga North 132/66 kV substation	New 132 kV switchbay connection	April 2015	5.2.2
Broken Hill 220/22 kV substation	New 22 kV connections	November 2014	5.2.2
Yanco 132/33 kV substation	Condition based transformer replacement	November 2014	5.2.2
Griffith 132/33 kV substation	Condition based transformer replacement	November 2014	5.2.2
Newcastle 330/132 kV substation	Condition based transformer replacement	October 2014	5.2.2
Canberra 330/132 kV substation	Additional capacitor bank Expansion of a capacitor bank	August 2014 March 2015	5.2.2
Yass 330/132/66 kV substation	Additional capacitor bank	September 2014	5.2.2

8 Appendix

Progress of developments reported in TAPR 2014

A8 Progress of developments reported in TAPR 2014

The following table lists the developments reported in TransGrid's TAPR 2014 and where they have been reported in this TAPR, along with a brief comment to indicate the current status of each development.

Development	TAPR 2014 section	TAPR 2015 section	Comment
Redevelopment of Orange 132/66 kV substation	6.2.1.1	5.3.1	Committed, with expected completion 2017
Western Sydney Supply Project	6.2.1.2	5.2.1	Completed Sept 2014
Disconnection of Munmorah power station	6.2.1.3	5.2.1	Completed Aug 2014
Upper Tumut switching station rehabilitation	6.2.2.1	5.3.1	Committed, with expected completion Dec 2015
97G 132 kV transmission line remediation works	6.2.2.2	5.2.1	Completed Mar 2015
Cooma substation replacement	6.2.2.3	5.3.1	Committed, with expected completion Nov 2015
Yanco substation refurbishment	6.2.2.4	5.3.1	Committed, with expected completion Sept 2015
Uprating of lines 61 and 3J	6.2.2.5	5.2.2	Completed Oct 2014
Wagga North 132/66 kV substation: one 132 kV switchbay	6.2.3	5.2.2	Completed Apr 2015
Newcastle 330/132 kV substation: replacement of two banks of single phase 330/132 kV transformers with new 375 MVA three phase units	6.2.5	5.2.2	Completed Oct 2014
Griffith 132/33 kV substation: replacement of three 45 MVA 132/33 kV transformers by three new 60 MVA units	6.2.5	5.2.2	Completed Nov 2014
Yanco 132/33 kV substation: replacement of two 45 MVA 132/33 kV units with new 60 MVA units	6.2.5	5.2.2	Completed Aug 2014
Canberra 330/132 kV substation: expansion of existing 80 MVAr bank to a 120 MVAr 132 kV capacitor bank	6.2.6	5.2.2	Completed Mar 2015
Yass 330/132 kV substation: new 80 MVAr 132 kV capacitor bank	6.2.6	5.2.2	Completed Sept 2014
Orange 132/66 kV substation: additional 66 kV capacitor bank	6.2.6	5.3.2	Part of the redevelopment of Orange 132 kV substation. Committed, with expected completion Apr 2017
Canberra 330/132 kV substation: additional 120 MVAr 132 kV capacitor	6.2.6	5.2.2	Completed Aug 2014
Various 330 kV substations: install surge arrestors on 330 kV line entries to substations	6.2.7	5.2.2	Completed Dec 2014
Armidale 330/132 kV substation: SVC control system replacement	6.2.7	5.3.2	Committed, with expected completion late 2015
Tamworth 132/66 kV substation: substation rebuild	6.2.7	5.3.2	Committed, with expected completion Mar 2017
Sydney West 330/132 kV substation: secondary systems replacement	6.2.7	5.3.2	Committed, with expected completion late 2015

Development	TAPR 2014 section	TAPR 2015 section	Comment
Vineyard/Cattai area: acquisition of a site to enable a future 500/330 kV substation to be developed.	6.2.7	Not reported	This project has been withdrawn from our revenue within 2014-2018. It is strategic acquisition and the need date is beyond 10 years
94B Wellington – Beryl 132 kV transmission line: wooden pole replacement	6.2.7	5.2.2	Completed Jun 2015
Broken Hill 220/22 kV substation: SVC control system replacement	6.2.7	5.2.2	Completed March 2015
Dapto 330/132 kV substation: secondary systems replacement	6.2.7	5.2.2	Completed Jun 2014
Griffith 132/33 kV substation: secondary systems replacement	6.2.7	5.2.2	Completed Nov 2014
Transposition works on the 76/77 Wallerawang – Sydney South/Ingleburn double circuit 330 kV lines	6.3.1.1	5.2.1	Completed Sept 2014
Development of southern supply to the ACT	6.3.2.1	5.4.1	Required by 2020. Preferred site is now near Stockdill Drive
Dynamic line ratings	6.3.3.1	5.3.1	Committed, with first installations expected Dec 2015, remaining installations expected mid 2016
Multiple contingency protection scheme	6.3.3.2	6.2.9	Expected 2020/2021
Quality of supply monitoring	6.3.3.3	5.3.1	Committed, with expected completion Dec 2016
Point on wave switching control	6.3.3.4	5.3.1	Committed, with expected completion Jan 2018
Sydney West: 330/132 kV substation: two 132 kV line switchbays	6.3.8	Not reported	Need is not expected to arise within ten years
Newcastle 330 kV substation: one 132 kV line switchbay	6.3.8	Not reported	Need is not expected to arise within ten years
Buronga 220 kV switching station: x2 shunt reactor replacement	6.3.9	5.3.2	Committed, with expected completion summer 2015/16
NSW to Queensland transmission capacity	7.1.1	6.3.1	Regulatory consultation completed. Limitation will be reviewed in five to ten years
Supply to the Gunnedah/Narrabri area	7.2.1.1	6.2.1	Refer to Section 6.2.1 and Appendix 4
Condition of Tamworth No 2 330/132 kV transformer	7.2.1.2	6.2.2	Indicative date: 2019
'Powering Sydney's Future' Supply to the Sydney Inner Metropolitan Area	7.2.2.1	6.3.5	Due to moderating demand, limitation is not expected to arise for five to ten years
41 Cable Sydney South – Beaconsfield capacity	7.2.2.2	6.2.3	Anticipated within five years
Strategic land acquistion at Riley Street	7.2.2.3	5.3.1	Project is now committed
Supply to the Beryl/Mudgee area	7.2.2.4	5.4.1	Indicative date: summer 2016/17

Development	TAPR 2014 section	TAPR 2015 section	Comment
Connection of Ausgrid's new subtransmission substation in the Munmorah/Doyalson area	7.2.2.5	6.2.4	Indicative date: 2017
Condition of Munmorah 330 kV substation	7.2.2.6	6.2.5	Indicative date: 2020
Condition of Vales Point 330/132 kV substation	7.2.2.7	5.4.1	Expected completion: 2018
Condition of 944 Wallerawang – Orange North 132 kV transmission line	7.2.2.8	6.3.9	In the short term, some poles will be replaced. There is presently no preferred option for the longer term
Provision of a 66 kV line switchbay at Beryl 132/66 kV substation	7.2.2.9	5.3.2	Committed, with expected completion Sept 2015
Provision of a 66 kV transformer switchbay at Molong 132/66 kV substation	7.2.2.10	5.3.2	Committed, with expected completion Dec 2015
Provision of a new 132 kV line switchbay at Vineyard 330/132 kV switchyard	7.2.2.11	5.3.2	Committed, with expected completion Dec 2015
Sydney West 330 kV substation: 132 kV fault rating	7.2.2.12	5.3.2	Committed, with expected completion Dec 2015
Snowy to Sydney network capacity	7.2.3.1	6.3.7	Due to moderating load growth, this constraint is now expected to arise later (between five and ten years)
Murraylink runback control scheme	7.2.3.2	6.2.8	Indicative date: 2015
Condition of Canberra 330/132 kV substation	7.2.3.3	6.2.6	Indicative date: 2019
Condition of Burrinjuck 132 kV substation	7.2.3.4	6.2.7	Indicative date: 2017
Condition of Wagga 132/66 kV substation	7.2.3.5	5.4.1	Expected completion: Nov 2018
Provision of a new 132 kV line switchbay at Williamsdale 330/132 kV substation	7.2.3.6	6.2.10	Indicative date: 2018
Sydney North 330/132 kV substation: secondary systems replacement	7.2.5	5.3.2	Committed, with expected completion late 2018
Armidale 330/132 kV substation: secondary systems replacement	7.2.5	6.3.10	Deferred to 2021 with reduced scope
21 Sydney North – Tuggerah 330 kV transmission line: tower life extension	7.2.5	6.2.11	Indicative date: 2017
959/92Z Sydney North – Sydney East 132 kV transmission line: tower life extension	7.2.5	6.2.11	Indicative date: 2019
Deniliquin 132/66 kV substation: secondary systems replacement	7.2.5	6.2.11	Indicative date: 2019
99F Uranquinty – Yanco 132 kV transmission line: pole replacements	7.2.5	Not reported	Project has been reviewed and poles will be replaced as defects arise

Development	TAPR 2014 section	TAPR 2015 section	Comment
Albury 132/22 kV substation: secondary systems replacement	7.2.5	5.3.2	Committed, with expected completion late 2016
ANM 132 kV substation: secondary systems replacement	7.2.5	6.2.11	Indicative date: 2019
8 Dapto – Marulan 330 kV transmission line: tower life extension	7.2.5	Not reported	Project scope and cost reduced
11 Sydney South – Dapto 330 kV transmission line condition	7.2.5	Not reported	Project scope and cost reduced
Kangaroo Valley 330 kV substation: secondary systems replacement	7.2.5	5.3.2	Committed, with expected completion Feb 2016
2M Munmorah – Tuggerah 330 kV transmission line: tower life extension	7.2.5	Not reported	Project scope and cost reduced
97K Cooma – Munyang 132 kV transmission line rehabilitation	7.2.5	5.5	Indicative date: 2018
99J Yanco – Griffith 132 kV transmission line rebuild	7.2.5	6.3.10	Indicative date: 2022
96H Coffs Harbour – Koolkhan 132 kV transmission line: pole replacements	7.2.5	5.5	Indicative date: 2017
Taree 132/66/33 kV substation: secondary systems condition	7.2.5	5.5	Expected completion: Sept 2017
Taree substation 33 kV switchyard condition	7.2.5	5.5	Project to be run jointly with the secondary systems replacement, with expected completion Sept 2017
01 and 2 Canberra – Upper Tumut and Upper Tumut – Yass 330 kV transmission lines remediation	7.2.3.1 and 7.2.5	6.2.11	Indicative date: 2019
Low spans northern tower lines	7.2.5	6.2.11	Indicative date: 2018
Low spans northern pole lines	7.2.5	6.2.11	Indicative date: 2018
Low spans central tower lines	7.2.5	6.2.11	Indicative date: 2019
Low spans central pole lines	7.2.5	6.2.11	Indicative date: 2019
Low spans southern tower lines	7.2.5	6.2.11	Indicative date: 2019
Low spans southern pole lines	7.2.5	6.2.11	Indicative date: 2019
Broken Hill 220/22 kV substation: No 1 and No 2 shunt reactor replacement	7.2.5	5.3.2	Committed, with expected completion winter 2016
Forbes 132/66 kV substation: No 1 and No 2 132/66 kV transformer replacement	7.2.5	6.3.10	Indicative date: 2021
Beaconsfield West 330/132 kV substation: No 1 and 2 transformer replacement	7.2.5	5.3.2	Committed, with expected completion 2018

Development	TAPR 2014 section	TAPR 2015 section	Comment
970 Burrinjuck – Yass 132 kV transmission line: pole replacements	7.2.5	5.3.2	Committed, with expected completion 2016
22 Sydney North – Vales Point 330 kV transmission line: tower life extension	7.2.5	6.2.11	Indicative date: 2017
Sydney South 330 kV substation: replacement of 415 V AC aux supply systems	7.2.5	5.3.2	Committed, with expected completion Nov 2015
Haymarket 330/132 kV substation: secondary systems replacement	7.2.5	5.5	Expected completion: 2018
Murrumburrah 132/66 kV substation: secondary systems replacement	7.2.5	6.2.11	Indicative date: 2020
Tamworth and Armidale 330 kV switchyards	7.3.1.1	6.3.2	Anticipated between five and ten years
Hunter Valley – Tamworth – Armidale 330 kV system	7.3.1.2	6.3.3	Anticipated between five and ten years
Reinforcement of voltage control in Northern NSW	7.3.1.3	6.3.4	Anticipated between five and ten years
Supply to the Forster/Tuncurry Area	7.3.1.4	6.4.1	Limitation not expected to arise within ten years
Newcastle substation condition	7.3.2.1	6.3.6	Anticipated between five and ten years
Capacity of the Marulan – Avon, Marulan – Dapto and Kangaroo Valley – Dapto 330 kV lines	7.3.3.1	6.3.8	Anticipated between five and ten years
Lismore 330/132 kV substation: two 132 kV switchbays	7.3.4	Not reported	Need is now not expected to arise within ten years
Tamworth 132/66 kV substation: one 66 kV line switchbay	7.3.4	Not reported	Need is now not expected to arise within ten years
Tumut 132/66 kV substation: one 66 kV switchbay	7.3.4	Not reported	Need is now not expected to arise within ten years
Beryl 132/66 kV substation: secondary systems replacement	7.3.5	6.3.10	Indicative date: 2020
Supply to far north NSW	7.4.1.1	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to Sydney East	7.4.2.1	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to Southern Sydney	7.4.2.2	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Loading on the Wallerawang – Sydney South/Ingleburn 330 kV lines	7.4.2.3	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Kemps Creek 500/330 kV transformers	7.4.2.4	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Further development of supply to the Newcastle/Sydney/ Wollongong area	7.4.2.5	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years

Development	TAPR 2014 section	TAPR 2015 section	Comment
999 Yass to Cowra 132 kV transmission line: line rating restoration	7.4.2.6	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to Mudgee	7.4.2.7	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to the Tomerong/Nowra area	7.4.2.8	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to the Darlington Point area	7.4.3.1	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
NSW – South Australia interconnection	7.4.3.2	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
NSW – Victoria interconnection	7.4.3.3	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to the Albury area	7.4.3.4	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years
Supply to Tumut/Gadara	7.4.3.5	Not reported	Not reported in 2015 as the limitation is not expected to arise within ten years

Appendix 9

Results of December 2014 survey

The main outcomes of our most recent survey of TAPR stakeholders following the TAPR 2014 Forum are described in this appendix.

A9 Results of December 2014 survey

The main details and outcomes of the survey are summarised below:

> 339 stakeholders were invited to participate

> The survey was open for more than two weeks and extended for a further two weeks

> 44 responses were received, 13% of those invited

> 57% of the respondents were NSPs or service providers to the industry

> Others were generators, government, large users, university or consultants

> All those who responded to the question rated all chapters to be fairly useful or better, with all chapters receiving average ratings above 8 out of 10 and two chapters above 9 with 10 being extremely useful

> Overall usefulness of the report to the person and the company received an average response of 8.9 out of 10

> On occasions a comment may have balanced out another; 'too much information' balanced out by 'appreciate as much detail as possible'

> Many positive comments were received such as:

- 'The document is very useful providing indications of emerging system limitations'
- 'Load information supplied is extremely useful to assess TransGrid expectations'
- 'This is becoming a very comprehensive and useful document, it is better every year'
- 'This is a highly useful report, congratulations'
- 'Excellent report – well organised and presented'

> 45% of respondents refer to the report at least once per month

> 58% of respondents preferred the present format of constraints in chronological order by region

> 66% of respondents used the forecast information in the report

> The several comments made on the forecast information, clearly indicate a very significant use and need for this information

> 6 of 19 (32%) respondents indicated that other types of load forecast information such as 10% PoE would be useful

> 56% of respondents said such additional information should be available in the TAPR, with the remainder saying by request and on the website

> 42% support for existing arrangements of hard copy with PDF download as the report medium

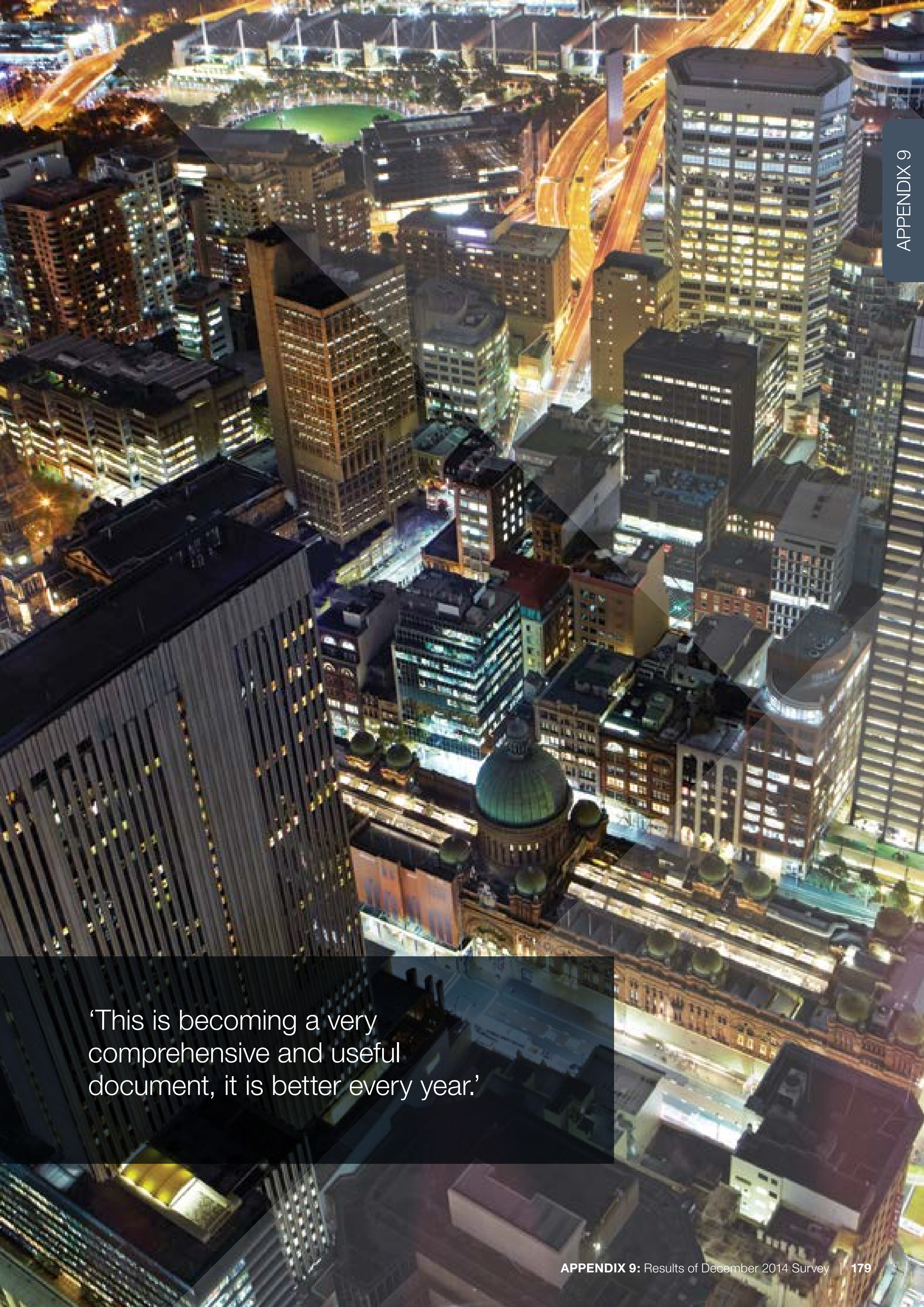
> Six or 16% of respondents indicated interactive online as a preferred medium

> There was support for browse and read online (average usefulness 7.5) by chapters and download of data (average usefulness 9.0)

> Medium level of awareness of the following stakeholder engagement programs; Powering Sydney's Future, 'Have Your Say TransGrid' and the Demand Management Forum (all above 43%)

> Our recent engagement on network planning rated quite highly with average 8.1 out of 10 with 10 being excellent and 6 out of 10 for TransGrid's engagement level overall

> Most (8.5 out of 10) felt their opinions were captured by this survey.



‘This is becoming a very comprehensive and useful document, it is better every year.’

10 Appendix

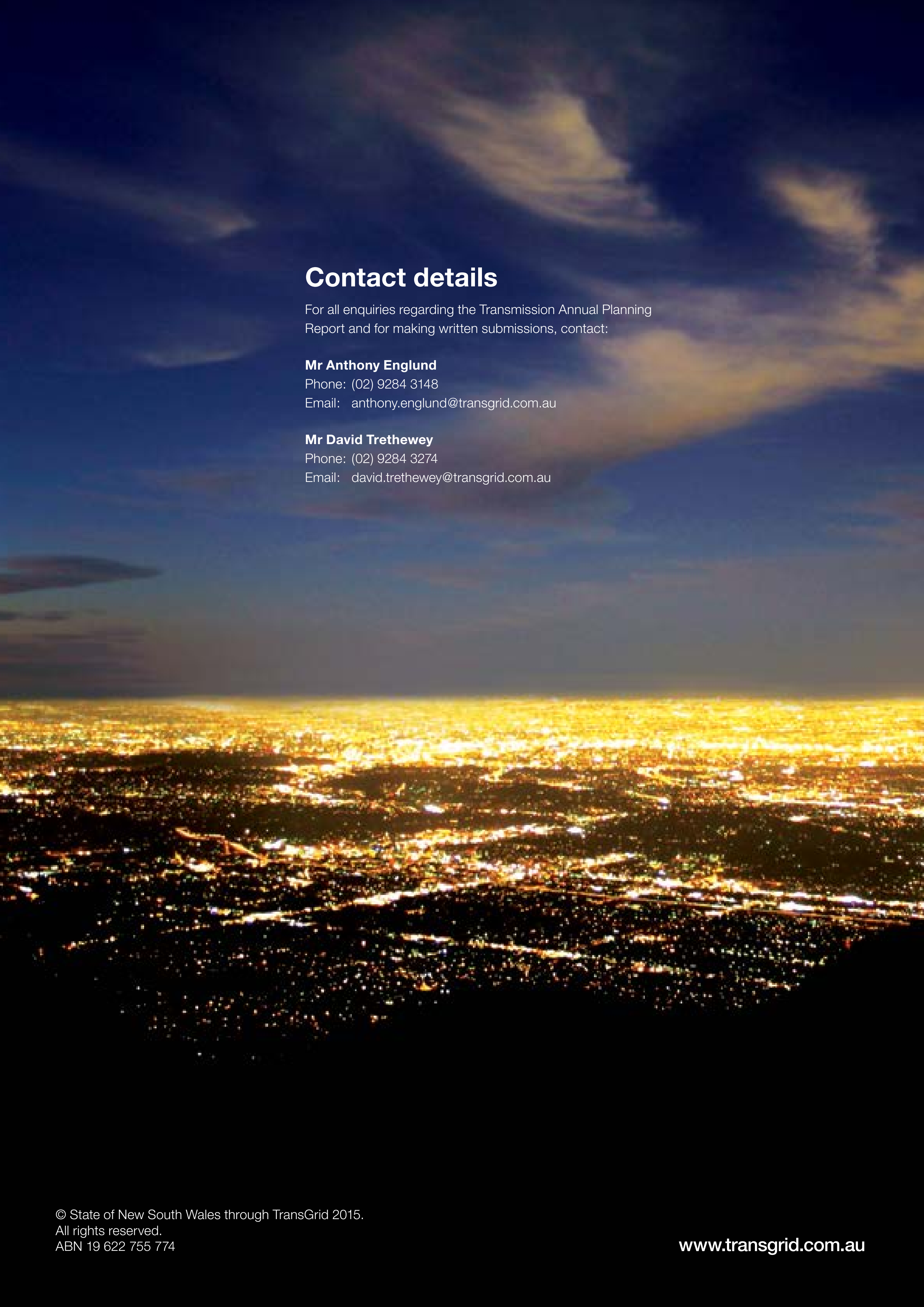
Glossary

A 10 Glossary

Term	Explanation/Comments
ACT	Australian Capital Territory
AEMC	The Australian Energy Market Commission
AEMO	The Australian Energy Market Operator. Responsible for management of the NEM and has the role of Victorian JPB
AER ('the regulator')	The Australian Energy Regulator
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
Annual Planning Review	The annual planning process covering transmission networks in NSW
Annual Planning Report (APR)	Please see Transmission Annual Planning Report
Assets	TransGrid's 'poles and wires', all the substations and electricity transmission lines that make up the network
Augmentation expenditure, or Augex	Expenditure required to enlarge the transmission system or to increase its capacity to transmit electricity
Bulk supply point (BSP)	A point of supply of electricity from a transmission system to a distribution system
Capital expenditure, or Capex	When a business spends money either to buy fixed assets or add to the value of existing assets. Expenditure to acquire or upgrade physical assets such as buildings and machinery
CBD	Central Business District
Connection point	The agreed point of supply established between the network service provider and another registered participant or customer
Constraint	An inability of a transmission system or distribution system to supply a required amount of electricity to a required standard. Also referred to as 'limitation'
Consumers	Any end user of electricity, for example large users, such as paper mills, or small users, such as households
Demand	The total amount of electrical power that is drawn from the network by consumers. This is talked about in terms of 'maximum demand' (the maximum amount of power drawn throughout a given period) and 'total energy consumed' (the total amount of energy drawn across a period)
Demand management (DM)	A set of initiatives that are put in place at the point of end-use to reduce the total and/or maximum consumption of electricity
Demand Management Innovation Allowance, DMIA	An allowance given to TransGrid by the AER as part of its 2009 – 2014 revenue allowance, to develop the demand management market
Direct customers	TransGrid's customers are those directly connected to our network. They are either Distribution Network Service Providers, directly connected generators, large industrial customers, customers connected through inter-regional connections or potential new customers
Distribution Network Service Provider, DNSP (Distributor)	An organisation that owns, controls or operates a distribution system in the National Electricity Market. Distribution systems operate at a lower voltage than transmission systems and deliver power from the transmission network to households and businesses
Easement	A designated area in which TransGrid has the right to construct, access and maintain our assets, while ownership of the property remains with the original land owner
Electricity Statement of Opportunities (ESOO) or Statement of Opportunities (SOO)	A document produced by AEMO that focuses on electricity supply demand balance in the NEM
Embedded generation	A generating unit connected to the distribution network, or connected to a distribution network customer. (Not a transmission connected generator)

Term	Explanation/Comments
Generator	An organisation that produces electricity. Power can be generated from various sources, e.g. coal fired power plants, gas-fired power plants, wind farms
GW	Gigawatt This is a unit for measuring power, or the rate of using energy. One Gigawatt is equal to a thousand Megawatts
GWh	Gigawatt hour This is a unit for measuring the amount of energy consumed in one hour. A Gigawatt-hour is equal to one thousand Megawatts consumed in one hour
Interconnection	The points on an electricity transmission network that cross jurisdictional/state boundaries
IPART	Independent Pricing and Regulatory Tribunal of NSW
Jurisdictional Planning Body (JPB)	The organisation nominated by a relevant minister as having transmission system planning responsibility in a jurisdiction of the NEM
kV	kilovolt The operating voltage of transmission equipment is generally expressed in kilovolts (kV), where one kilovolt is equal to one thousand volts
kW	kilowatt This is a unit for measuring power, or the rate of using energy. One kilowatt is equal to one thousand watts
kWh	kilowatt hour This is a unit for measuring the amount of energy consumed in one hour. A kilowatt-hour is equal to one thousand watts consumed in one hour
Limitation	See ‘Constraint’
Load	The amount of electrical power that is drawn from the network
Local generation	A generation or cogeneration facility that is located on the load side of a transmission constraint
LRET	Large Scale Renewable Energy Target
Market benefits	Cost benefits expected to flow to electricity consumers as a result of activity in the competitive electricity generation market
MV	megavolt A megavolt is equal to one thousand kilovolts (kV)
MVA	megavolt-ampere A unit for measuring the maximum power that a transformer can deliver
MVAr	megavolt-ampere reactive This is a unit of reactive power. One mega-VAr is equal to 1,000,000 VAr
MW	Megawatt A unit for measuring power, or rate of using energy. One megawatt is equal to one million watts
MWh	Megawatt hour This is a unit for measuring the amount of energy consumed in one hour. A Megawatt hour is equal to one million watts consumed in one hour
‘N – 1’ reliability	The system is planned for no loss of load on the outage of a single element such as a line, cable or transformer

Term	Explanation/Comments
National Electricity Law	Common laws across the states which comprise the NEM, which make the NER enforceable
National Electricity Market (NEM)	The National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania
National Electricity Rules (NER or 'the Rules')	The rules that govern the NEM. The NER supersedes the National Electricity Code (NEC or 'the Code') and is administered by the AEMC
Native energy (demand)	Energy (demand) that is inclusive of Scheduled, Semi-Scheduled and Non-Scheduled generation
The network	The systems and assets which allows electricity to be transported to consumers
Network augmentation	An expansion of the existing electricity transmission network
Non-network options	Alternatives to network augmentation which address a potential shortage in electricity supply in a region, e.g. demand response or local generation
NSCAS	Network Support and Ancillary Services
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
Operational expenditure, or Opex	Expenditure TransGrid incurs to operate on an ongoing, day to day basis in order to plan, maintain and operate the transmission network
Outage	An outage is when part of the network is switched off. This can be either planned (i.e. when work needs to be done on the line) or unplanned
PoE	Probability of Exceedence This is the probability a forecast would be met or exceeded, e.g. a 50% POE demand implies there is a 50% probability of the forecast being met or exceeded
Power	The rate of energy transfer in a system. In electricity we talk about power as watts (joules transferred per second)
PV	Photovoltaic
Reliability	Reliability is a measure of a power system's capacity to continue to supply sufficient power to satisfy customer demand, allowing for the loss of generation capacity
Registered Participant	A person registered with AEMO as an NER participant
RET	Renewable Energy Target
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
Secondary system	Equipment used to control, automate and monitor the network
Substation	A set of electrical equipment used to step high voltage electricity down to a lower voltage. Lower voltages are used to deliver power safely to small businesses and residential consumers
SVC	Static VAr Compensator. An electrical device installed on the high voltage transmission system to provide fast acting voltage control to regulate and stabilise the system
the Minister	The NSW Minister for Industry, Resources and Energy
Transmission Annual Planning Report (TAPR [YEAR])	A document that sets out issues and provides information to the market that is relevant to transmission planning in NSW. This document is the NSW TAPR 2015
Transmission line	A high voltage power line running at 500 kV, 330 kV, 220 kV or 132 kV. The high voltage allows delivery of bulk power over long distances with minimal power loss
Transmission Network Service Provider, TNSP	A body that owns controls and operates a transmission system in the NEM



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