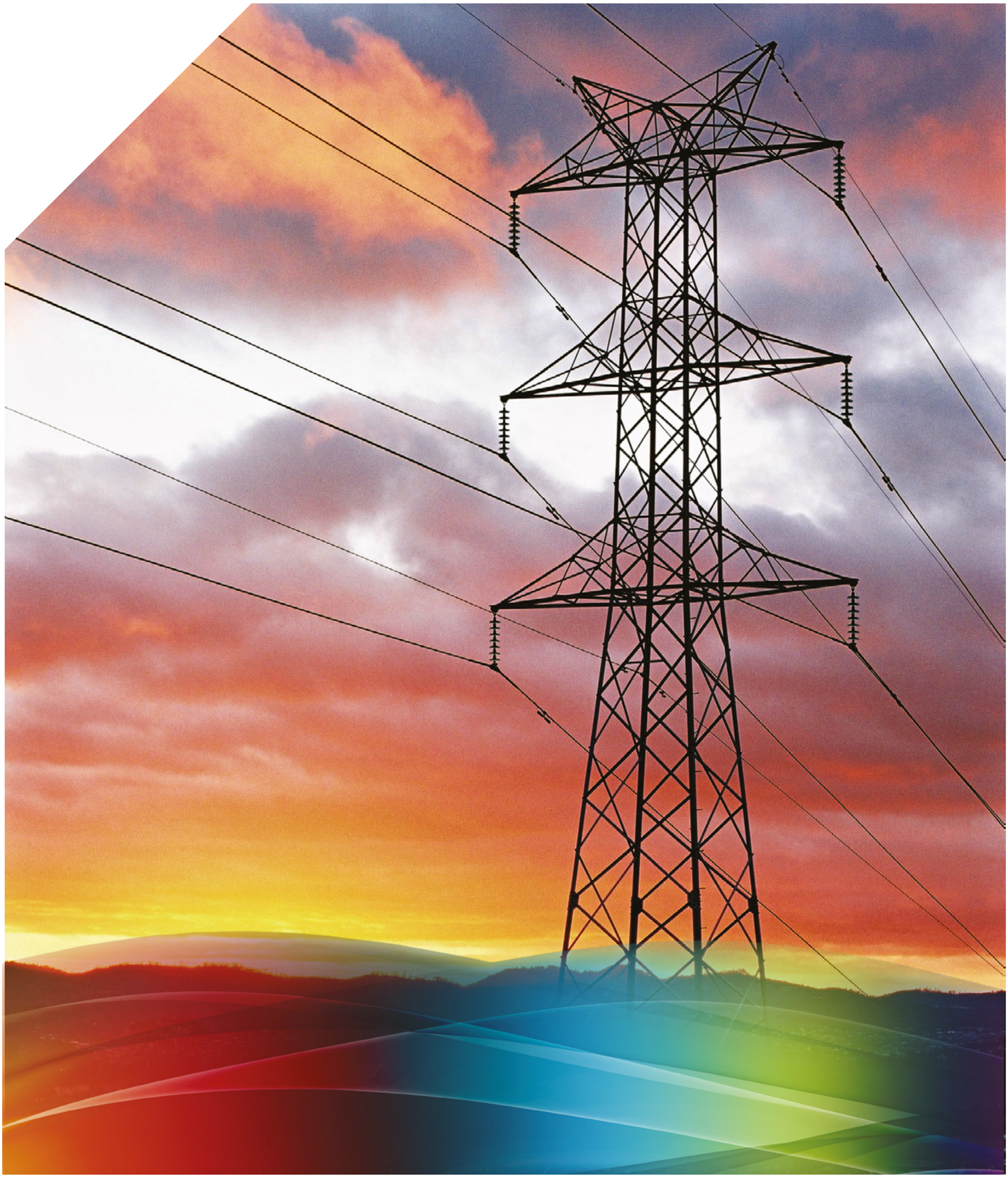
# Annual Planning Report

2017



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The APR sets out network planning proposals, scenarios and forecasts as at the date of publication, which may change at any time or not eventuate. It has been prepared in good faith, including information and assumptions provided by third parties without further verification. It may not contain all information on the subject matter. Nothing in this APR should be taken as a recommendation in respect of any possible investment. Anyone considering using the information contained in this document should independently verify the currency, reliability, accuracy and completeness of the information.

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# Contents

# Executive summary

TasNetworks owns, operates and maintains the electricity transmission and distribution networks on mainland Tasmania and Bruny Island. We supply power from generation sources to homes and businesses through a network of transmission towers, substations and powerlines. We also operate a telecommunications business that serves customers in the electricity industry and other industries.

An important part of our function is to plan for the future operation of the electricity network and ensure it is adequate to support future needs. This Annual Planning Report **(APR)** presents the outcomes of our planning activities in the past year. It meets our requirements in publishing transmission and distribution APRs, and our Tasmanian Annual Planning Statement.

There has been keen focus on energy security in Tasmania following the challenges experienced in the first half of 2016. This period saw the unavailability of the Basslink Interconnector, which connects the Tasmanian and mainland electricity networks, coupled with record low rainfall and inflows into hydro generation storages. As part of our requirements under the Tasmanian Annual Planning Statement, and included in our APR, we perform analysis of the adequacy of generation capacity and electrical energy availability over the next 10 years. We also analyse the likely impact of extended failure of a generation source, as occurred in 2016. There has been a significant recovery in hydro storages and our analysis indicates that there is sufficient generation capacity and energy availability to meet forecast demand over the next 10 years. We also expect there would be no unserved energy for an extended failure of a generation source, including Basslink, under the scenarios considered.

The role of electricity network is changing, and will continue to change over the next 10 years and beyond. Some of these changes include the growth of distributed generation, of non-traditional generation sources, and the use of energy storage, coupled with and contributing to reduced growth in demand. These changes are being led by customers. We have prepared a network transition plan to capture what we will do over this period to transition the network to its new role, while not adversely affecting existing customers and ensuring any additional costs are appropriately allocated.

We forecast demand for electricity in Tasmania will grow over the next 10 years, although at a subdued rate and remaining within historical maximums at the transmission network level. This is reflected in our network augmentation plans, with minimal demand-driven projects identified over the next 10 years. This APR, and our 2018 APR, will support our forthcoming revenue submission for the 2019–24 regulatory period in January 2018.

For further information on our 2017 Annual Planning Report, including submissions to any proposed investments or identified limitations, or to provide feedback, please contact:

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# 1 Introduction



## Overview

TasNetworks publishes an Annual Planning Report to provide information about the Tasmanian power system, any current or emerging network limitations and planned investments, and opportunities for new load or generation customers to connect to the network.
This chapter explains the background to the Annual Planning Report. It also provides a summary of the material changes that have occurred since publishing the 2016 Annual Planning Report.

## 1.1 About TasNetworks

Tasmanian Networks Pty Ltd (TasNetworks) delivers electricity and telecommunication network services in Tasmania, creating value for our customers, our owners and the community. TasNetworks is wholly owned by the Tasmanian Government.

TasNetworks is the sole licensee for regulated transmission and distribution network services on mainland Tasmania. We are registered with the Australian Energy Market Operator (AEMO) as both a Transmission and Distribution Network Service Provider and operate in the National Electricity Market (NEM).

As a monopoly provider of transmission and distribution network services, our revenue for these services is regulated. We prepare submissions to the Australian Energy Regulator (AER) which determine our revenue and the maximum amount we can recover from customers, generally for periods of five years.

## 1.2 What we do

TasNetworks owns, operates and maintains the transmission and distribution electricity networks on mainland Tasmania and Bruny Island.[1] We deliver electricity generated by our generation customers at hydro, wind and gas-fired power stations to approximately 280,000 demand customers throughout the state. Our demand customers range from domestic and commercial customers to major energy users connected directly to the transmission network. Our network also allows electricity generated from embedded generating units to be transported to other customers. The widespread adoption of rooftop photovoltaic (PV) systems has dramatically increased the use of the network for this purpose in recent years.

We also facilitate the transfer of electricity to and from mainland Australia, via the Basslink Interconnector (Basslink). Basslink is a privately-owned under-sea cable between George Town in Tasmania and Loy Yang in Victoria. Basslink can transfer electricity in either direction.

TasNetworks also owns and operates a high-reliability telecommunications network. This network supports the operation of the electricity network, and also provides communications services to other customers.

## 1.3 Purpose of this document

We produce the Annual Planning Report (APR) to provide information on the planning activities we have undertaken in the past year. We conduct an annual planning review to analyse the existing network and consider its future requirements to accommodate changes to load and generation, and whether there are any limitations in meeting the required performance standards. We then look for opportunities for innovative solutions to address any emerging limitations. We do this in consultation with our customers and in accordance with our relevant legal obligations.

This APR presents the outcomes of these planning studies, in accordance with our obligations under clauses 5.12.2 and 5.13.2 of the National Electricity Rules (the Rules) for the publication of Transmission and Distribution Annual Planning Reports. This APR also incorporates the requirements of our Tasmanian Annual Planning Statement, required under clause 15 of our transmission licence issued under the *Electricity Supply Industry Act 1995* and as set by the Office of the Tasmanian Economic Regulator (OTTER). We are required to publish the APR by 30 June each year, in accordance with clause 5.12.2(a) and 5.13.2(a)(1) of the Rules and in conjunction with clause 8.3.2 of the Tasmanian Electricity Code (the Code).

In addition to these requirements, we present further information to better inform customers and other stakeholders about the limitations and opportunities in our network. We provide information on:

- the capability of our network to transfer electrical energy;
- how the network may affect their operations;
- the locations that would benefit from supply capability improvements or network support initiatives; and
- locations where new loads or generation could be readily connected.

We actively investigate alternate options to traditional network augmentation or straight like-for-like equipment replacements to address limitations. Our intent is that this APR provides existing and potential new customers and non-network solution providers with preliminary information to prompt discussion on opportunities for solutions to address limitations.

## 1.4 Audience

This APR is primarily written for stakeholders and those with an interest in the Tasmanian electricity industry. It specifically provides information which will be useful to:

- existing transmission-connected customers and larger customers connected to the distribution network;
- potential new generation and load customers;
- non-network solution providers;
- AEMO and the AER; and
- other interested parties.

We also aim to enable those without a direct interest in the electricity industry to gain an appreciation of the operation of the electricity network, network planning and the drivers for network investment.

1 *Hydro Tasmania is responsible for the electricity networks on King and Flinders islands.*

## 1.5 Planning horizon

This APR covers a 10-year planning period from winter 2017 to winter 2027. However, some aspects are based on shorter planning periods. Distribution line overload determinations are based on a 2-year planning horizon.

## 1.6 Strategic focus areas

Aside from what is included in this APR, there are a number of wider strategic focus areas we are working on. These include wider power system and energy security requirements and the changing nature of the network, amongst others. This section provides overview of some of our key strategic focus areas that are not normally included in an APR.

### 1.6.1 Energy security

The Tasmanian Government established the Tasmanian Energy Security Taskforce to identify ways to help future proof Tasmania's energy security. The taskforce was established following the energy security situation in Tasmania in 2016 resulting from historically low inflows to hydro water storages and the outage of the Basslink interconnector. We are engaging with and supporting the taskforce in its assessment process. In the interim report, released in December 2016, the taskforce identified TasNetworks as a potential resource in its recommendations for meeting the identified priority actions. The taskforce's final report is due to be provided to the Government by mid-2017. More information is available from the Department of State Growth.[2]

### 1.6.2 Second Bass Strait interconnector

The feasibility of a second Bass Strait interconnector is currently being assessed. A second Bass Strait interconnector, along with the existing Basslink interconnector, would allow for increased renewable energy development within Tasmania and maximising current hydro generation. It would also add to Tasmania's energy security.

Early feasibility studies and cost-benefit assessments for a second Bass Strait interconnector are being performed by The Tasmanian and Australian governments and AEMO, and are being considered by the Tasmanian Energy Security Taskforce and other bodies. We are engaging with these bodies as a key stakeholder in the development of a second interconnector. As well as the opportunities a second interconnector would bring, a key focus for us is understanding the impact it would have on the electricity network and existing customers in Tasmania. Network augmentations and protection schemes will be required to facilitate a second interconnector, with a large portion of the costs potentially flowing through to existing customers.

2 http://www.stategrowth.tas.gov.au/tasmanian_energy_security_taskforce

### 1.6.3 Tariff reform

We are currently reviewing our network tariffs to understand how they could provide better price signals for our customers. As part of this review we have proposed moving tariffs towards demand-based pricing rather than consumption-based pricing. We are considering a distinction between demand use at peak and off-peak periods in a way that encourages practical changes in customer behaviour. This pricing approach will also encourage greater usage at times where there is spare network capacity. By using existing capacity better, we can deliver more electricity without investing to build new network capacity.

We are conducting a trial to better understand how and when our customers use electricity. The trial will involve 600 residential customers selected from the Bridgewater, Brighton, Lower Midlands and surrounding areas. The first and second phases of recruitment and meter installation have been completed. More information is available on our website.[3]

3 http://www.tasnetworks.com.au/customer-engagement/tariff-reform/

### 1.6.4 Network transformation

The role of the electricity network is changing. Historically, power flow was one-way from large scale generation, via the transmission and distribution networks, to customers. While the majority of people rely on the network for electricity supply, its role is changing. Within the last 10 years, small-scale distributed generation – predominately roof-top photovoltaic – has grown to become common place, and energy storage via batteries is close to becoming an economic proposition to average households. These, along with other factors, are combining to reduce demand on the network and also providing for power transfer back into the network.

To capture the role of the changing network into the future, CSIRO and Energy Networks Australia **(ENA)** have partnered to develop an Electricity Network Transformation Roadmap.[4] The purpose of the roadmap states "the Electricity Transformation Roadmap project will help guide the transformation of Australia's electricity networks over the 2017–27 decade toward a customer-oriented future." Successful implementation of the roadmap activities over the next decade "can achieve a positive energy future for Australian energy customers enabling choice, lower costs, high security and reliability and a clean electricity system to 2050." We are participating with the CSIRO and ENA in this process.

We are in turn developing our own roadmap to 2025 to ensure we adapt to the changing operating environment and continue to provide the most cost effective services to our customers. We are engaging our customers on the details of our roadmap in the first half of 2017. The initiatives included in the roadmap will inform our revenue proposal for the 2019–24 regulatory period.

We have taken this further to develop a network transition plan for our network and Tasmania. We provide an overview of this plan in Section 2.3.2 of this APR.

4 http://www.energynetworks.com.au/electricity-network-transformation-roadmap

## 1.7 What has changed since 2016

This section summarises what has changed since publication of our last APR. It includes changes to our load forecast, planned investments and forecast limitations, and any other material changes to the information provided in our 2016 APR.

### 1.7.1 Changes in load forecasts

The load forecast used in the 2017 APR is similar to that used in 2016. At a state level, the forecast growth rate of 1.1 per cent per annum is unchanged, however starts at a lower point this year due to the low maximum demand experienced in 2016. This is detailed further in Chapter 5.

### 1.7.2 Operation of Tamar Valley Power Station

Tamar Valley Power Station comprises a 208 MW combined cycle gas turbine (CCGT) and 178 MW of open cycle gas turbines. The operation of the CCGT has varied in recent years following it being transferred to Hydro Tasmania in 2013 and the low rainfall periods and Basslink outage in 2015–16. The CCGT is currently identified as withdrawn from service; however it has the ability to be recalled to service in less than three months.[5,6] As such, it is not considered available for service for the intra-regional generation projections (Section 5.5), and capacity balance (Section 5.6.1) and energy balance (Section 5.6.2) components of the supply-demand balance analysis in this APR. It is considered available for the extended failure of generation source scenarios (Section 5.6.3) due to its ability to be recalled if required for this purpose.

The previously advised withdrawal of Bell Bay Three Power Station, part of the open cycle gas turbines at Tamar Valley Power Station, from January 2018 will no longer occur. This has been re-included in our supply-demand balance assessment.

5 *Table 5, Electricity statement of opportunities for the National Electricity Market, Australian Energy Market Operator, August 2016.* http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

6 *Despite its identified withdrawal, the CCGT has been operating in early 2017 to support storages and maintain it in optimal condition summer* https://www.hydro.com.au/about-us/news/2017-01/routine-ccgt-operation

## 1.7.3 Changes in planned investments and forecast limitations

Material differences in planned investments and forecast limitations from the 2016 APR are summarised in Table 1-1 and Table 1-2; inconsequential changes to investment timing etc are not included in these tables.

Table 1-1 presents the changes in planned investments from our 2016 APR. We have deferred one planned investment and introduced one new one. Further details of these and our other planned investments are provided in section 6.3.

**Table 1-1: Differences in planned investments since 2016**

| Location | Summary of change | Reference |
|---|---|---|
| Queenstown–Newton 110 kV transmission line | The 2016 APR proposed a project to decommission the Queenstown–Newton 110 kV transmission line due to its poor condition, and provide an alternate supply to Newton Substation. This project is now committed. | 6.2.1.1 |
| George Town | New planned investment included in the 2017 APR. We plan to install capacitor bank reactive power compensation at George Town Substation to relieve voltage and reactive margin limitations. | 6.3.2.1 |
| Various substations | The proposed project to undertake a power transformer dynamic rating program on network transformers at a number of substations has been deferred. Further analysis identified that the benefit was currently not sufficient to justify the investment requirement. | 6.3.4.1 |

Table 1-2 presents the changes in forecast limitations (constraints and inability to meet network performance requirements) from our 2016 APR.

**Table 1-2: Differences in forecast constraints and inability to meet network performance requirements since 2016**

| Location | Summary of change | Reference |
|---|---|---|
| Meadowbank | New identified limitation included in the 2017 APR. A supply transformer contingency at Meadowbank Substation will interrupt more than 300 MWh, exceeding the maximum unserved energy allowed under our jurisdictional network planning requirements. | 6.4.1.1 |
| Rosebery | New identified limitation included in the 2017 APR. The firm capacity of Rosebery Substation was exceeded in 2016. Demand is forecast to remain below, although close to, the firm rating within the planning period. Notwithstanding, as it primarily supplies mining customers, demand at Rosebery Substation can be variable and there is a risk the firm rating may be exceeded again. | 6.4.1.2 |
| Richmond | The 2016 APR identified the maximum demand at Richmond Rural Zone Substation exceeded the substation firm rating. Due to augmentation work within the distribution network, additional fast and remote load transfers are available such that this is no longer a limitation. | 6.4.4.1 |
| Various substations | New identified limitations included in the 2017 APR. The 2016 load forecast identified the forecast demand at various connection point and zone substations will exceed their firm ratings within the planning period. These are: | |
| | • zone substations: Derwent Park (2023); and | 6.4.3.2 |
| | • connection points: Railton (2022), North Hobart (2025) and Burnie (2026). | 6.4.1 |

## 1.7.4 Other material changes

### 1.7.4.1 Reporting of planned investments

Chapter 6 presents our planned investments over the planning period. This year, we have stopped reporting on projects that are outside the scope for inclusion in an APR as defined in the Rules. These include asset replacement projects where the estimated cost is below $5 million for transmission or $2 million for distribution and procurement of large assets as strategic spares.

The planned investments from the 2016 APR no longer reported on are:

- Triabunna Spur transmission line Kay pole replacement program;
- Gretna and New Norfolk zone substations supply transformer replacements; and
- transportable substation procurement.

Going forward, we intend to continue reporting only planned investments within the scope of the Rules requirements.

## 1.8 Overview of this document

| | |
|---|---|
| Chapter 1: | introduces TasNetworks, the purpose of the Annual Planning Report, and summarises the information that has changed since the 2016 APR. |
| Chapter 2: | provides information on the environment TasNetworks operates in and considerations in planning the electricity network. |
| Chapter 3: | introduces the Tasmanian electricity network, the transmission and distribution networks, and where TasNetworks fits in the Tasmanian electricity supply industry. |
| Chapter 4: | details the performance of the electricity network. It details our performance against transmission and distribution reliability targets, transmission network constraints, and factors that materially affect network performance. |
| Chapter 5: | describes the forecast electricity demand over the next ten years, the factors that influence that demand, and provides an assessment of whether the generation supply is sufficient to meet the forecast demand. |
| Chapter 6: | details our planned investments and forecast limitations over the planning period. It also summarises how our proposals align with national transmission planning performed by AEMO, and those subject to the regulatory investment test. |
| Chapter 7: | provides a summary of information which may be useful for owners of generators or large loads that are connected to, or are considering connecting to, the transmission network. |
| Appendices: | provide additional and supporting data, notably a glossary and abbreviations in Appendix A. Bulk data is available as downloadable supplementary information, and is not included in this report. |

## 1.9 Feedback and enquiries

We welcome feedback on our 2017 Annual Planning Report. We are particularly interested in discussing opportunities for interested parties to participate in demand side management or other innovative solutions to manage network limitations.

We also welcome feedback on the content of this report, to allow us to improve it in future years.

Please address enquiries to:

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PO Box 606
Moonah, TAS 7009

or email: planning.enquiries@tasnetworks.com.au

We invite potential demand management solution providers to register with us via our demand side engagement register: https://www.tasnetworks.com.au/our-network/planning-and-development/demand-management-engagement-strategy/

# 2
# Planning considerations



## Overview

This chapter discusses relevant aspects of the legal framework which governs network planning and expansion activities in Tasmania, and informs key aspects of the strategies that support our network planning process. This chapter also discusses our customer engagement and how customers can be involved in the planning process.

## 2.1 The regulatory framework

TasNetworks operates under both state and national regulatory regimes. As a registered participant in the NEM, we are required to develop, operate and maintain the electricity supply system in accordance with the Rules. In addition, there are local requirements that we must comply with under the terms of our licences issued by the OTTER under the *Tasmanian Electricity Supply Industry (ESI) Act 1995*. We are also subject to a number of other Acts and industry-specific Regulations in planning the network. These include:

- the technical requirements of Schedule 5.1 of the National Electricity Rules[7];
- the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007*[8];
- the Tasmanian Electricity Code[9];
- the regulatory investment test[10]; and
- a number of environmental, cultural, land use planning and other acts.

7 http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules

8 http://www.thelaw.tas.gov.au/tocview/index.w3p;cond=;doc_id=%2B114%2B2007%2BAT%40EN%2B20161221090000;histon=;pdfauthverid=;prompt=;rec=;rtfauthverid=;term=;webauthverid=

9 http://www.energyregulator.tas.gov.au/domino/otter.nsf/8f46477f11c891c7ca256c4b001b41f2/b9ea21012c6e8199ca2572e500207c2a?OpenDocument#The%20Tasmanian%20Electricity%20Code%20ha_0

10 Clause 5.16 (transmission) and 5.17 (distribution) of the National Electricity Rules.

### 2.1.1 National Electricity Rules Schedule 5.1

Schedule 5.1 of the Rules describes the planning, design and operating criteria that must be applied by Network Service Providers to the networks which they own, operate or control. These criteria are quantitative, and relate to electrical characteristics such as voltage limits, voltage unbalance, short term voltage fluctuations, harmonic voltage limits, protection operation times, and power system stability.

### 2.1.2 Electricity Supply Industry (Network Planning Requirements) Regulations 2007

The *Electricity Supply Industry (Network Planning Requirements) Regulations 2007* (the regulations) are Tasmanian regulations which specify reliability standards that we must aim to meet when planning the transmission network. The regulations define the maximum extent of power interruptions following contingency events. These regulations only apply to the transmission network, not the distribution network. These regulations are our jurisdictional network performance requirements, and are referred to as this in the remainder of this APR.

These regulations allow for exemptions from the performance requirements, based on consultation with our customers. If all transmission customers, whose supply reliability would be affected by a proposed network augmentation, consider that it would not be sufficiently beneficial, then we must report this in our Annual Planning Report. We are exempt from undertaking that augmentation for five years, and we are also exempt, for five years, from meeting the network performance requirement which was the basis for the proposed augmentation. The exemption may cease early if the circumstances surrounding the exemption change, or if one of the affected transmission customers no longer wishes the exemption to remain.

### 2.1.3 Tasmanian Electricity Code

The Tasmanian Electricity Code (the Code) is published and maintained by the OTTER. It contains arrangements for the regulation of the Tasmanian electricity supply industry additional to those in the Rules. The Code largely relates to operation of the distribution network. The Code contains the technical standards for power quality, standards of service for embedded generators, and distribution network reliability standards.

### 2.1.4 The regulatory investment test

The regulatory investment test (for transmission and distribution) is a procedure published by the AER under clause 5.16 and clause 5.17 of the Rules. As a transmission and distribution network service provider, we are required to apply the regulatory investment test for all transmission and distribution projects where certain thresholds are met.

The regulatory investment test defines the economic analysis and public consultation process that a network service provider must undertake in selecting an option to address a need in the power system.

There are some cases in which a network service provider is not obliged to undertake a regulatory investment test. These are described in clause 5.16.3(a) and clause 5.17.3(a) of the Rules and include proposals not intended to augment the network or that are in response to a connection application.

## 2.2 Revenue determination

The revenue we earn from providing regulated transmission and distribution services is set by the AER. This is currently done separately for transmission and distribution services. We therefore operate under two separate revenue determinations, for transmission and distribution. We are currently within our 2014–19 transmission regulatory period and our 2012–17 distribution regulatory period.

The AER released its preliminary decision for our 2017–19 distribution regulatory period. In it, the AER accepted our proposed capital and operating forecasts. This acceptance recognises that we are operating our business efficiently and reducing costs while delivering a safe and reliable electricity supply to our customers. The AER will make its final decision in April 2017, with it coming into effect from 1 July 2017.

We have only prepared a two year distribution regulatory proposal as from 2019 we will align our transmission and distribution regulatory periods. The intended outcomes of merging the determination processes are to reduce costs through combined planning, contribute to our strategic objective of 'one business' and allow us to engage meaningfully with our customers on the full service suite offered. We are undertaking a range of community engagement workshops and forums, which has included our regional and large transmission-connected communities and customers, which will inform our revenue proposal. We are continuing our engagement with these communities as we prepare for our submission to the AER in January 2018.

### 2.2.1 Service target performance incentive scheme

Included in the revenue determination is a set of regulatory incentive schemes. Incentive schemes are used by the AER to provide incentives for network businesses to sustainably reduce costs whilst also maintaining or improving service levels. The service target performance incentive scheme (STPIS) is one such incentive scheme that we use to measure our performance. The STPIS is based on a number of parameters and the intent of the scheme is to reward network businesses for improvements in performance, and penalise them where performance has decreased.

The STPIS for transmission comprises three components; the service component, the market impact component, and the network capability component. The STPIS for distribution is intended to focus a network operator's attention on the service that it provides to its customers. It has two components; reliability of supply and customer service. There is also a guaranteed service level scheme (GSL scheme) whereby our customers are compensated for prolonged and/or excessive interruptions to their supply.

## 2.3 TasNetworks integrated planning

As the transmission and distribution network service provider in Tasmania, we have a responsibility to ensure that the infrastructure to supply Tasmanians with electricity evolves to meet customer and network requirements, in an economically optimal and sustainable way. We achieve this through our network planning process, to ensure the most economically-optimal technically-acceptable solution is pursued.

To support this, integrated into our planning processes are the following business strategies:

- network transition plan – ensure what we do in the next 10 to 15 years facilitates an efficient and orderly transition of the network to its new roles in a changing energy sector;
- network reliability strategy – at least maintaining current overall network reliability whilst reducing the total outage costs;
- asset management strategy – replacement of transmission and distribution assets is considered based on asset condition and risk, rather than age; and
- network innovation strategy – maximise benefits of the existing networks to our customers through technology and non-network solutions.

Our network planning process and the integrated business strategies are described in this section.

## 2.3.1 Overview of the network planning process

We consider transmission and distribution planning as one integrated function, planning for one electricity network. Our network planning process aims to identify what changes to the electricity network will be needed in future years. The need for network changes can arise from a number of factors:

- Electricity demand can change. For example, the existing network may not have sufficient capacity to supply additional electricity to a rapidly expanding suburban area. Or there may be a general overall increase, or decrease, in the amount of electricity consumed per household. A new specific large load, such as a new shopping centre, or closure of large load, such as a mine, will also cause changes in electricity demand that need to be considered.
- As network equipment ages, it becomes more likely to fail. We investigate whether it is best to continue maintenance of the existing equipment, replace the equipment entirely, or whether it may be possible to decommission equipment and use alternative parts of the network, or non-network solutions, to supply electricity.
- New power stations, including embedded generators, may be constructed, or old ones removed from service. These changes influence where electricity flows in a network.
- Technological changes impact on the network. Historically end-use customers only consumed electricity. Now with PV and battery storage technology, customers are producing and storing electricity. These technological developments affect the way we plan and operate the network.

We perform an annual planning review to identify and report on existing and future limitations in the electricity network taking account of transmission and distribution network requirements as required by our regulatory obligations and in consultation with our customers and other stakeholders. From these detailed studies on the Tasmanian power system, we create 15-year area strategies. These strategies consider the contributing factors outlined above and result in the network needs identified in this Annual Planning Report, for a 10-year timeframe. Because the detailed annual planning looks ahead 15 years, we can revise our plans if forecast load or generation changes do not eventuate.

We also identify the changes in the network that may be required in the long term (ie beyond 15 years), from different load and generation scenarios. From this, we ensure that our future development plans can accommodate a range of possible futures for the network and consumers in Tasmania.

### 2.3.1.1 Annual planning review

We perform an annual planning review to identify and report on existing and future limitations in the electricity network. A summary of the outcomes arising from our annual planning review forms the basis for the Annual Planning Report. It presents the foreseeable network needs, the potential options to resolve them, and – where a particular option looks favourable – the likely cost and timing of that option. It is a summary of how things appear now, in 2017. Because network planning is a cyclic process, we may find the expected needs change from one year to the next. If demand changes at a different rate than is currently forecast, some proposed network changes may not be required. Others may be required sooner.

The planning process followed by the annual review is illustrated in Figure 2-1 and outlined in the following sections.

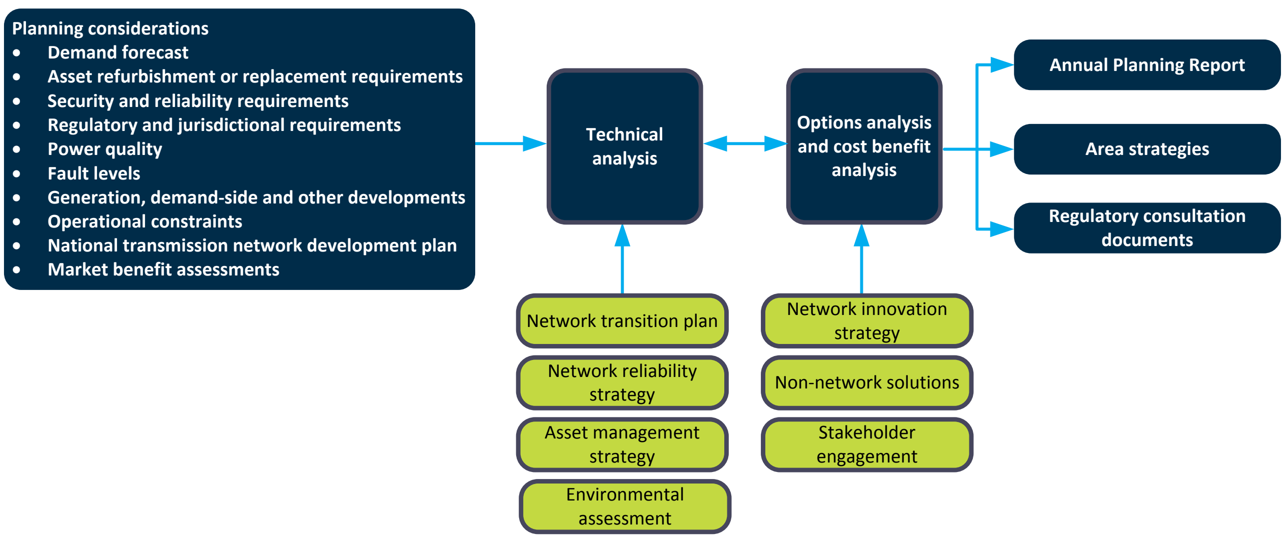



Figure 2-1: Overview of the network planning process

#### 2.3.1.2 Demand forecast and technical analysis

A key input to the planning process is the electricity demand forecast. We have developed an overall energy and demand forecast from forecasts provided by:

- National Institute of Economic and Industrial Research (NIEIR). NIEIR provides an overall forecast based on current economic trends;
- directly connected transmission customers – who forecast their demand based on their business outlook; and
- our forecast of demand at transmission-distribution connection points based on the NIEIR retail forecast.

Our state-level and transmission-distribution connection point forecasts differ in inputs, scenarios and model to AEMO's forecasts. At a state-level, AEMO's forecast has virtually zero growth over next 10 years whereas we forecast maximum demand to grow at 1.1 per cent per annum. Despite this growth, we forecast maximum demand to remain within the state-level historic peak in 2008. As such, under either forecast there is only very small augmentation programs forecast.

After finalising our demand forecast, we undertake computer simulations of the power system to determine whether the network is capable of meeting the forecast demand without exceeding technical limits. These limits relate not only to the design capacity of equipment, but also to other regulations that dictate how the network must perform in the event of a fault.

We also consider possible future generation connections, and our network reliability and asset management requirements. We investigate the advances in technology where these can be used to manage demand.

Where a future network limitation is identified, we conduct a sensitivity analysis on it. This is to determine the impact a change in the demand forecast or other assumptions may have on the timing of the limitation occurring, or its severity. We consult with customers on the risk (probability and impact) associated with the limitation. The sensitivity analysis and consultation are key inputs into our decision of what solution, if any, is required and the optimal timing to implement it.

#### 2.3.1.3 Options and cost-benefit analysis

Where we find that network changes are likely to be needed, we identify the possible options that would solve the problem. Options could include expansion of the network, or working with customers to reduce their energy or demand to eliminate the problem, or some other alternative. Only options that meet the needs of our customers and communities now and into the future are considered. We determine the advantages and disadvantages of each option, and investigate each one in detail to confirm its feasibility. For those options that are feasible, we estimate the cost of each option and the potential economic benefits it would bring (for example, averting or reducing the loss of supply to an area has an economic benefit).

Upon identification of a preferred solution we consult with affected customers, when they are materially affected, to confirm if there is sufficient benefit in proceeding with the proposal.

#### 2.3.1.4 Regulatory consultation

When it becomes clear that significant network investment will be needed and the cost of any credible option to address the identified need is in excess of the applicable cost threshold, we undertake a regulatory investment test. This is the final – and public – option selection and consultation process. Once the final option has been selected via this process, we can then commence the implementation of that option.

### 2.3.2 Network transition plan

We have prepared a network transition plan to capture and articulate the changing role of the electricity network over the coming 10 to 15 years. Complementing CSIRO and Energy Networks Australia's Electricity Network Transformation Roadmap and focussing on our network and Tasmania, it captures what we will do over that period to facilitate an efficient and orderly transition of the network into its new role in a changing energy sector. The aspiration is to manage an orderly and efficient transition of the network so that existing connected parties are not adversely impacted, and that any additional costs associated with that transition are appropriately allocated.

Key influences in the changing role of the network are:

- Tasmania – we have the smallest, oldest and fastest ageing population in Australia and a low level of economic diversity compared to the national average. Economic growth in Tasmania is required to drive job creation and increase population. The Tasmanian power system is also unique with low demand, generally dispersed generation sites and high concentration of demand with four major industrial customers consuming more than 50 per cent of state electrical energy.

- minimal load growth –previously continuing growth in electricity demand now cannot be relied on. Electrical energy sales have declined since 2009–10 and the Tasmanian maximum demand peaked in 2008. Although beginning to recover, growth in maximum demand is no longer a key driver for network augmentation.
- price sensitivity of customers – the prices paid for electricity by Australian households increased on average 72 per cent, in real terms, between 2003 and 2013. In Hobart, prices increased by 20 per cent between 2007 and 2012. Due to high winter consumption and the low availability and take-up of gas, Tasmanian households have the highest average consumption and weekly spend on electricity in Australia. In Tasmania, network charges contribute approximately half the domestic power bill.
- growth of embedded generation – the number of small-scale embedded generators in Tasmania has increased dramatically since 2008, from virtually zero to approximately 96 MW of installed capacity at over 27,000 locations. This growth is forecast to continue. The impact of this is the traditional load profiles and one-way flow of electricity is changing.
- increase in non-synchronous generation – most new small-scale and large generation connecting to the network is non-synchronous, eg roof-top photovoltaic and wind. Traditional generation, such as hydro and thermal rotating plant, is synchronous. There are significant differences in how synchronous and non-synchronous generation operate following a fault on the network, with synchronous generation generally supporting operation of the network. New solutions are required to ensure increasing non-synchronous generation connecting to the network does not negatively impact network security.
- growth in energy storage – the technology supporting domestic energy storage is on the cusp of becoming an economic proposition to average households. Once this occurs, it will add to embedded generation in further changing network load profiles and the flow of electricity.

Our role under the transition plan is to ensure we continue to listen to, and be influenced by, our customers, ensuring lowest sustainable prices, protecting existing customers, and maximising the capability of the network to host new generation sources.

## 2.3.3 Network reliability strategy

Transmission network reliability is measured in terms of the number and duration of loss of supply (LOS) events that occur during a calendar year. We have an obligation to monitor and report against service measures and objectives to national (AER) and state (OTTER) regulatory bodies.

In meeting these requirements we actively undertake:

- performance monitoring;
- performance benchmarking;
- incident investigations; and
- implementation of service improvement initiatives.

Distribution network reliability is a measure of performance with regard to frequency (number of events) and duration of unplanned interruptions to our customers.

We have an obligation under the Code to manage the reliability performance of our network, and to mitigate any reliability impacts on our customers and the broader Tasmanian community.

Our reliability management strategy is to:

- at least maintain current overall network reliability performance in accordance with the principles of the economic incentive scheme whilst providing lowest sustainable prices and maximising value to our customers;
- ensure compliance with regulation, codes and legislative requirements;
- manage our risk profile to maintain a safe and reliable network, now and into the future with respect to cost effectiveness and reliability; and
- reduce total outage costs for the network.

The strategy does not preclude enhancing network reliability where community or individual distribution line performance is inadequate or where asset risk is unacceptably high. It is proposed that all reliability activities will be managed within the cost allowance approved for reliability maintenance or improvement in the remaining 2012–17 and forthcoming 2017–19 distribution regulatory periods.

Our network reliability strategy has been a key part of our recent customer engagement activities. Customers in the majority are satisfied with network reliability and want reliability levels maintained at the same cost. This was a common theme across all customer segments. This expectation aligns with our strategy.

Section 4.2.2 presents how we manage our distribution supply reliability for both the supply reliability communities and the categories. Appendix C provides our historic distribution network reliability performance results and measures.

## 2.3.4 Asset management strategy

Our asset management strategy aims to meet required service levels in the most cost-efficient manner. The strategy focuses on ensuring that the replacement of assets is determined by asset condition and risk rather than age alone. Our Strategic Asset Management Plan outlines the systems and strategies developed to effectively and efficiently manage the delivery of electricity and telecommunication network services to customers and to provide information to stakeholders regarding the environment in which we operate. Key themes supporting our asset management approach and associated levels of investment are:

- caring for our assets to ensure safety of our people and the community is not compromised;
- maintaining reliability of the network;
- where we can safely do so, running our network harder rather than building more;
- taking a whole of life (life-cycle) approach to optimise cost and service outcomes for our customers; and
- working hard to ensure we deliver the lowest sustainable prices.

Our approach centres on asset life-cycle management extending over five phases, as presented in Figure 2-2. Each phase of the life-cycle has a corresponding life-cycle strategy detailing our objectives and approach to the particular activities undertaken in that phase to ensure performance to required levels.

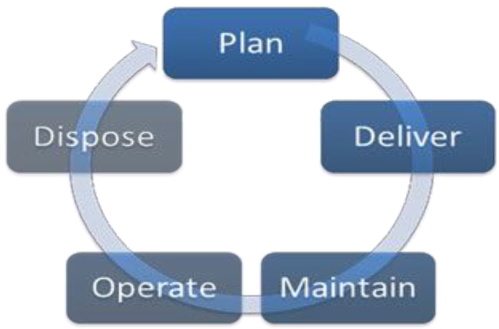



**Figure 2-2: Asset management life cycle**

Most of our asset management activities are managed at an asset category (or asset fleet) level. The strategies for each asset category are known as Asset Management Plans (AMPs). Our AMPs identify the performance and risks presented by each asset type within the category and define specific actions that must be undertaken to sustain asset and system performance. The actions include:

- run to failure;
- subject matter expert advice;
- time based replacement;
- reliability centred maintenance; and
- condition based risk management.

Our Strategic Asset Management Plan is available on our website.[11]

### 2.3.4.1 Network losses

Schedule 5.8(k)(1A) of the Rules requires us to explain how we take account of the cost of distribution losses when developing and implementing asset management and investment strategies. Losses are considered when balancing current on distribution lines, power factor correction, and managing fault levels. Losses are also considered in calculating benefit associated with loss reductions in the economic justification of projects at both transmission and distribution level.

## 2.3.5 Network innovation strategy

The electricity industry is undergoing significant change, much of which is being driven by disruptive technologies. With this disruption to the status quo, our network innovation strategy aims to ensure that TasNetworks continues to maximise the benefits of the existing networks to Tasmanian customers. The principal objectives driving the strategy being to:

1. facilitate customer choice;
2. facilitate customer interaction; and
3. increase network efficiency.

We recognise that customers want more choice. While some simply want a low cost and reliable connection, others are seeking a greater range of supply and service offerings. We are committed to facilitating our customers' ambitions in this regard.

Industries such as insurance, banking, airlines, and couriers have all sought to maximise their interactions with customers through digital interaction. We also recognise the value that can be derived from facilitating such customer interaction. For customers, these benefits would include up to date information on outages, updates on emerging limitations, and practical advice on technology choices. TasNetworks benefits through building greater engagement and trust with our customers and helping customers make more informed decisions.

A cost effective and efficient network is essential to ensure the sustainability of the network. Many new and innovative technologies are available to address existing and emerging limitations. Areas of focus include:

- fault and emergency costs;
- localised peak demand and voltage limitations;
- risk of asset stranding from uncertain load growth;
- expensive edge-of-grid assets; and
- accurate and timely data for decision making – especially in the distribution network.

11 http://www.tasnetworks.com.au/TasNetworks/WebParts/TasNetworks/EWP/DownloadDD17.ashx?d=10743&m=v

We have selected initiatives to achieve the innovation objectives, detailed in Section 6.5 of this APR. Each initiative has alignment with one or more of the innovation objectives. These initiatives are described in further detail in our network innovation strategy which is available upon request.

### 2.3.6 Joint planning

The Rules require Transmission and Distribution Network Service Providers to perform joint planning where a transmission network connects to a distribution network, and a distribution network connects to other distribution networks. As our network does not connect to any other distribution networks, we do not need to undertake joint planning as defined in the Rules.

To support providing efficient network services, our network planning team is structured as a single team which plans the transmission and distribution networks as a single network. Therefore joint planning between our transmission and distribution networks is inherent in our planning process, as detailed in this Section 2.3. All planned investments identified in Section 6.3 of this APR have been identified through this process.

## 2.4 Customer connections

We are currently developing a process of choice in the design and construction of some aspects of customer-initiated work in the distribution network. We have recently implemented choice in the design and construction for underground residential developments and are expanding this to other types of customer-initiated work. Connection services generally involve five stages:

- assessing applications;
- designing connections;
- preparing offers and terms to present to customers;
- constructing connection infrastructure; and
- providing final connection services.

We have a regulated pricing framework for these connection services being in accordance with our Customer Capital Contributions Policy and revenue decision.[12] We receive approximately 10,000 enquiries or applications to connect to our network every year.

12 http://www.tasnetworks.com.au/customer-engagement/connections-pricing

## 2.5 Customer engagement

We provide a variety of electricity network services for the transmission and distribution of electricity in Tasmania. We have established our business to achieve different outcomes, principally to deliver lowest sustainable prices to customers, safely and reliably. We also want our business to provide a better future for all of our customers and the community.

We value our customers and the relationships we have with them. This customer focus has helped shape our vision to be "Trusted by our customers to deliver today and create a better tomorrow". Our customers are one of the three key pillars fundamental to the achievement of our business strategy.

We have developed a Voice of the Customer Program that drives the focus on how we deliver quality service outcomes for our customers, which is closely aligned to our customer charter.

Although we have a diverse range of customer segments, we have a holistic approach to customer service. We are committed to engaging with our customers about our activities and plans for the future. The Voice of the Customer Program includes an engagement framework that assists us to drive a culture of 'Customer First'.

Further customer engagement information is available on our website.[13]

13 http://www.tasnetworks.com.au/customer-engagement

# 3 The Tasmanian network



## Overview

This chapter provides an overview of a number of aspects of the Tasmanian electricity supply system. It discusses the entities in the supply chain and their responsibilities. It points out those aspects of the Tasmanian electricity system that are distinctly different from the electricity networks in mainland Australian states. It also discusses the main components of the Tasmanian electricity network and details the geographical planning areas.

## 3.1 Overview of the Tasmanian power system

The key participants in the Tasmanian electricity supply chain comprise:

- power stations and wind farms that generate large-scale electricity;
- an extra-high voltage transmission network that transmits electricity from generators to the distribution network and large industrial and mining customers, and facilitates electricity exchange with mainland Australia via Basslink;
- a distribution network that supplies industrial, commercial, irrigation and residential electricity customers;
- embedded generation, which is small-scale generation connected within the distribution network;
- retailers that provide energy services to customers; and
- end use consumers of electricity.

We own and are responsible for the transmission and distribution networks on mainland Tasmania and Bruny Island. The Tasmanian power system is shown pictorially in Figure 3-1.

The Tasmanian power system forms a part of the eastern Australian power system, which extends from north Queensland to South Australia. Tasmania is connected to the mainland network via Basslink, a privately owned undersea cable. Basslink has the capability to transfer electricity in either direction.

There are currently five generating companies which have power stations connected to the Tasmanian transmission network:

- AETV Pty Ltd[14];
- Hydro Electric Corporation (Hydro Tasmania);
- Musselroe Wind Farm Pty Ltd;
- Woolnorth Bluff Point Wind Farm Pty Ltd; and
- Woolnorth Studland Bay Wind Farm Pty Ltd.

Mainland generators also supply energy to the Tasmanian transmission network via Basslink. A number of other small generators that are connected within the distribution network, termed embedded generation, are also licensed to operate in Tasmania. Very small embedded generation, such as roof-top photovoltaic systems, do not require a generating licence but must still have a connection agreement with TasNetworks.

All large generators sell electricity to a central market, the NEM. AEMO is responsible for electricity consumption and flow in the NEM and coordinates the dispatch of generators so that the power supplied into the network, at any instant, matches the total being consumed. The interconnected nature of the NEM allows electricity to flow across state borders, which means electricity can be sourced from whichever generators can supply it at the lowest price. AEMO is also responsible for power system security in the NEM.

TasNetworks is responsible for the transmission and distribution networks in the Tasmanian power system. The transmission network provides bulk power transfer from generators, often in remote areas, to transmission-distribution connection points (substations) near load centres throughout Tasmania, and to large customers directly connected to the transmission network. The distribution network distributes the electricity to smaller industrial and commercial, irrigation and residential customers.

Electricity is sold to end-use consumers, including those directly connected to the transmission network, by retailers, who purchase electricity in bulk quantities from the NEM and sell it to the businesses and residences that use it. The price of electricity for distribution customers includes a component for the use of the transmission and distribution networks in delivery.

*14 AETV Pty Ltd owns Tamar Valley Power Station and is a wholly-owned subsidiary of Hydro Tasmania.*

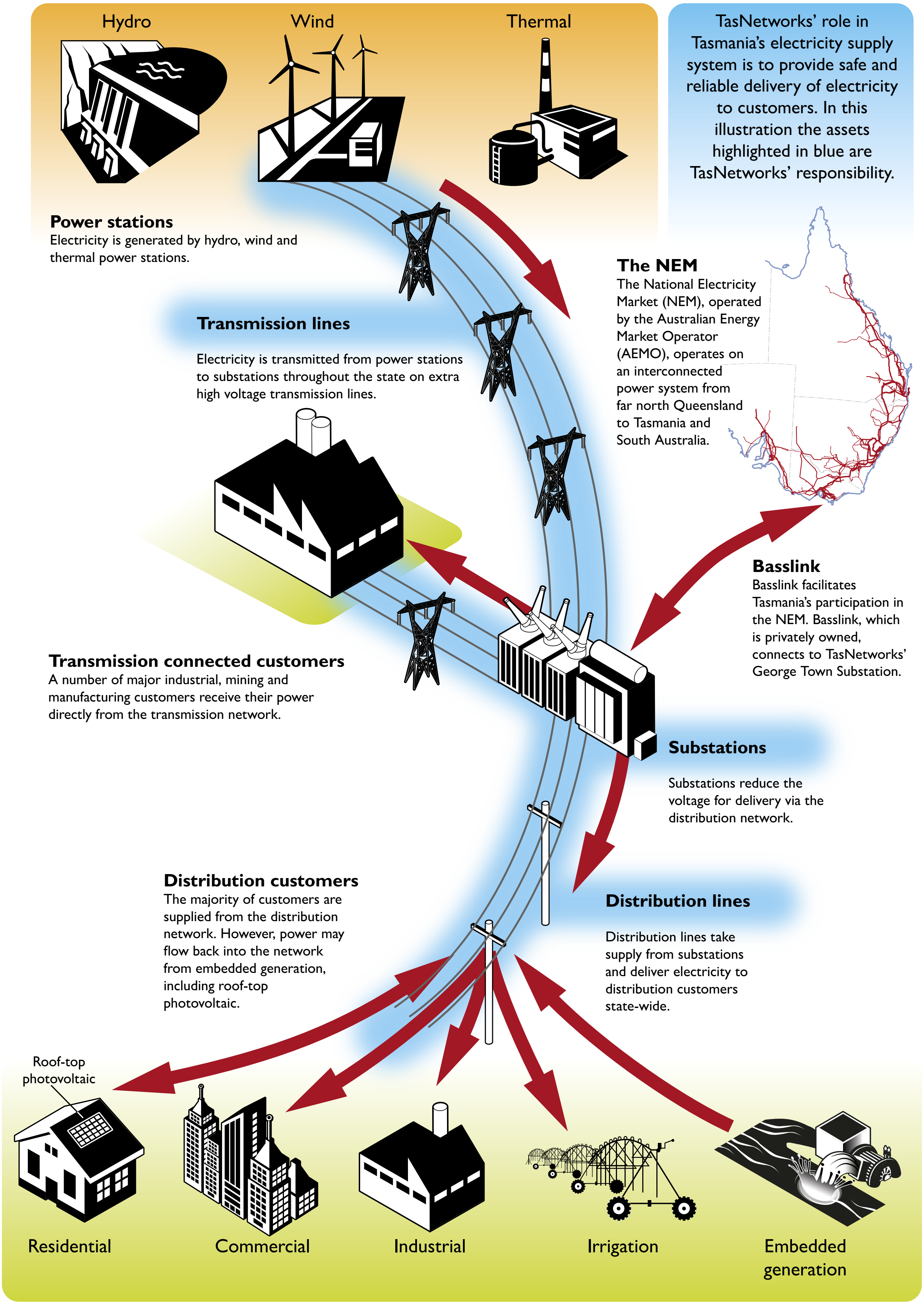



**Figure 3-1: Tasmania's electricity supply industry**

## 3.1.1 Unique features of the Tasmanian electricity system

The Tasmanian electricity system has a number of features which make it unique in the NEM.

### 3.1.1.1 Small load

The transmission network median demand during 2015–16 was approximately 1,150 MW, and spends approximately 50 per cent of the time between 1,100 and 1,300 MW. The practical minimum demand is approximately 850 MW, and forecast to reduce over coming years as increasing PV generation reduces summer day demand.

The largest generating system in Tasmania which connects via a single transmission circuit is rated at 168 MW, and there are four more generating units rated at 144 MW each. These generators each have the capacity to supply a much larger portion of the state's load compared with the largest generating units in other NEM states. This gives rise to larger frequency deviations in Tasmania than occur in mainland NEM regions. Consequently, Tasmania's Frequency Operating Standards differ from those of the mainland. The technical implications of this are discussed further in Section 7.3.

### 3.1.1.2 Customer load base

The majority of the electrical energy consumed in Tasmania is supplied to the large customers directly connected to the transmission network. We have ten load customers who are directly connected to the transmission network.[15] Collectively they consumed approximately 58 per cent of the electrical energy in Tasmania and contributed to approximately 43 per cent of the state-level peak demand in 2015–16. Energy consumption from transmission-connected customers is dominated by four major industrial customers consuming over 50 per cent of the total energy consumed. Figure 3-2 presents the relative energy consumption in 2015–16 supplied from the transmission network.

As major industrial and other transmission connected customers consume a significant portion of energy transferred through the transmission network, their operation can have a significant impact upon the power system. Changes to the transmission-connected customer base, such as a permanent reduction in load, would alter the normal operation of the power system and impact on such things as power flow and utilisation of the transmission network. We continue to engage with our customers and be cognisant of their operations in our planning activities.

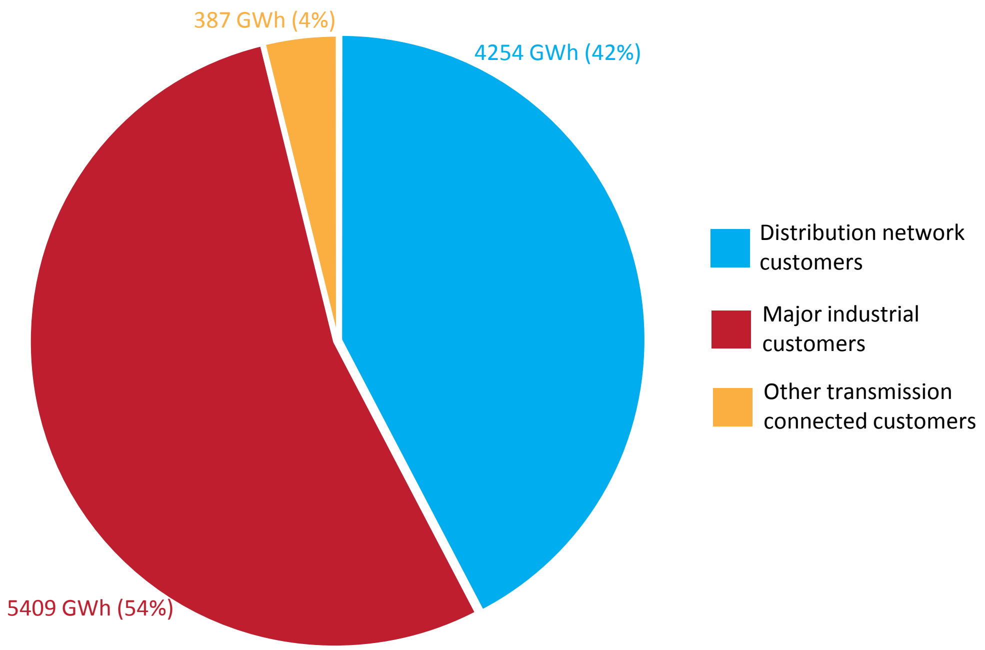



**Figure 3-2: Relative energy consumption supplied from the transmission network in 2015–16**

*15 This follows one small transmission network customer transitioning to become a distribution network customer on 1 July 2016.*

### 3.1.1.3 Hydro generation dominated

Figure 3-3 shows the relative composition of the generators located in Tasmania. Power generation is dominated by hydro generating units, which are dispersed throughout Tasmania. The dominance and geographic diversity of hydro generation has the following impacts:

- hydro generating units are much slower to respond to frequency deviations than steam generating units, the dominant source of generation in the NEM. This compounds the frequency deviation impacts caused by the high generator size to system load ratio. Providing sufficient frequency control ancillary services can be problematic in Tasmania;
- the geographic dispersion of a large number of smaller sized generating units means that relatively more transmission infrastructure, per MW generated, is required compared with other states; and
- Tasmania's electricity network has traditionally been energy constrained not capacity constrained. That is, there is always sufficient generation plant capacity available to meet short term load peaks, but sustained low rainfall can give rise to difficulties in meeting the state's long-term electric energy needs.

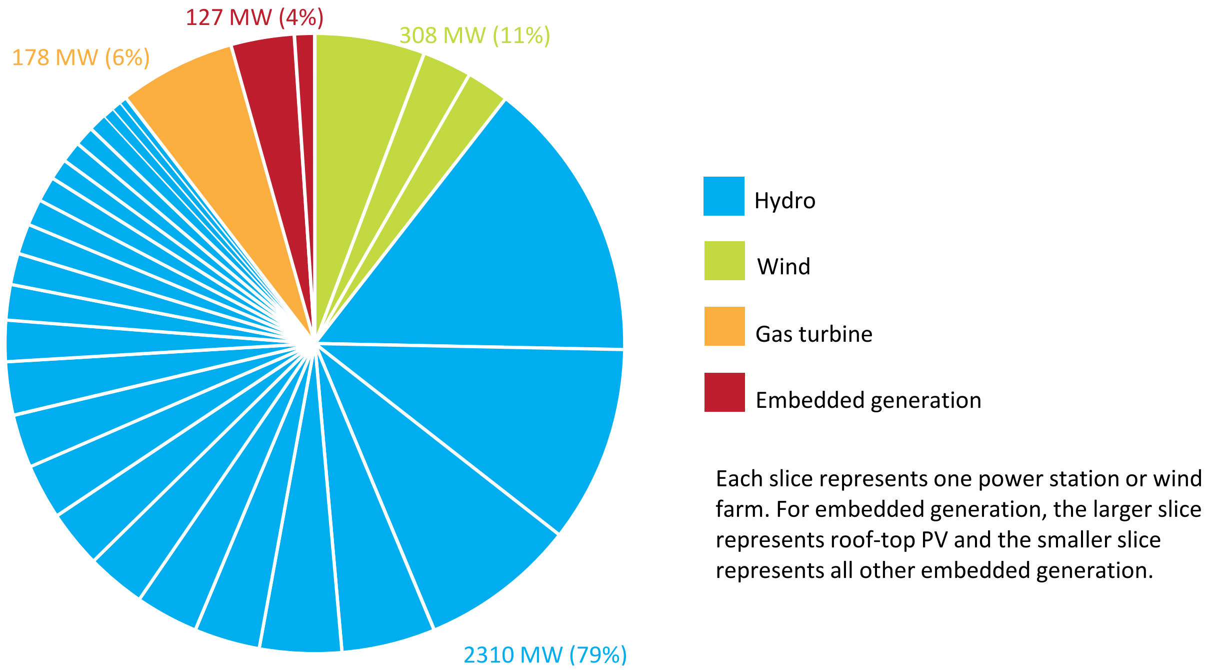



**Figure 3-3: Generation capacity by type**

### 3.1.1.4 Windy location

Tasmania is an inherently windy state, being located in the Roaring Forties latitudes. There is sufficient wind resource to suggest an expansion of wind generation in the state is possible. This needs to be balanced however against the technical difficulties associated with integrating wind generators into a small power system with the characteristics described above. Section 7.5 discusses the technical issues associated with connecting new generation technologies (notably wind generation) into the Tasmanian network.

### 3.1.1.5 Single non-regulated interconnector to other NEM regions

Tasmania's only connection to the remainder of the NEM is via Basslink, a privately owned HVDC market network service provider. This contrasts with mainland NEM regions, which are all interconnected via regulated interconnectors. Further details of Basslink are provided in Section 3.4.

## 3.2 Transmission network overview

Figure 3-4 presents a geographical overview of the Tasmanian transmission network, which comprises:

- a 220 kV, and some parallel 110 kV, bulk transmission network that provides corridors for transferring power from several major generation centres to major load centres and Basslink;
- a peripheral 110 kV transmission network that connects smaller load centres and generators to the bulk transmission network; and
- substations at which the lower voltage distribution network, and large industrial loads, are connected to the 110 kV or 220 kV transmission network.

Most loads are concentrated in the north and south-east of the state. Bulk 220 kV supply points are located at Burnie and Sheffield (supplying the north-west coast), George Town and Hadspen (supplying Launceston and the north-east), and Chapel Street and Lindisfarne (supplying Hobart and the south-east) substations. Smaller load centres are supplied via the 110 kV peripheral transmission network.

A high-level summary of the composition of our transmission network infrastructure is presented in Table 3-1.

**Table 3-1: Transmission network infrastructure**

| Asset | Quantity |
|---|---|
| Substations | 49 |
| Switching stations | 6 |
| Circuit kilometres of transmission lines | 3,540 |
| Route kilometres of transmission lines | 2,342 |
| Circuit kilometres of transmission cable | 24 |
| Transmission line support structures (towers and poles) | 7,726 |
| Easement area (Ha) | 11,183 |

### 3.2.1 Substations

Substations in the Tasmanian transmission network transform between transmission voltages, between transmission and distribution voltages, or both. Our substations also connect generators to the transmission network, provide network switching, and provide supply to those customers connected directly to the transmission network.

Substations supplying the distribution network, known as transmission-distribution connection points, are provided at 44 substations at 44, 33, 22, 11 and 6.6 kV voltages. Three substations are connection points solely for transmission-connected industrial and other customers. Two substations, providing transformation between transmission voltages only, do not provide direct supply to customers.

### 3.2.2 Switching stations

Switching stations provide network switching capabilities, allowing the transfer of power throughout the transmission network. Some switching stations also connect generation to the network.

### 3.2.3 Transmission lines and circuits

Transmission lines connect generators to substations, and substations to each other, providing the mesh arrangement of the interconnected network. A transmission line may either carry one or two transmission circuits. A transmission circuit is the conductors that provide the physical delivery of electricity. A transmission line is the physical asset that includes the circuit(s), towers and other equipment that support the circuit(s), and the route that these take between two points.

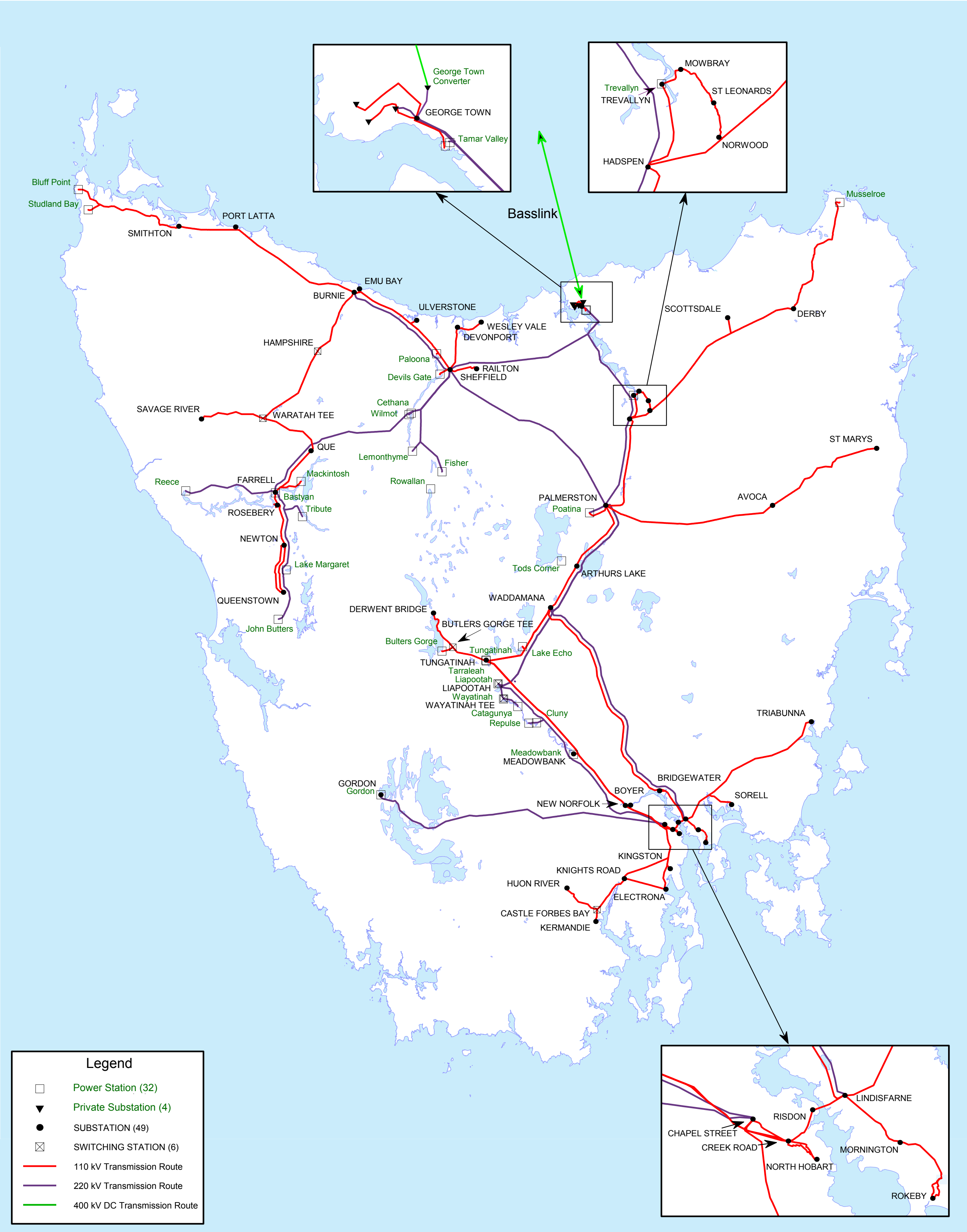



**Figure 3-4: Tasmania's electricity transmission network[16]**

16 The transmission lines between Smithton Substation and Bluff Point and Studland Bay wind farms, between Derby Substation and Musselroe Wind Farm, and between George Town Substation and George Town Converter Station are owned by third parties.


## 3.3 Distribution network overview

TasNetworks is responsible for the distribution of electricity to homes and businesses on mainland Tasmania and Bruny Island.[17]

The Tasmanian distribution network provides supply to over 280,000 customers and comprises:

- a sub-transmission network in greater Hobart, including Kingston, and one sub-transmission line on the west coast of Tasmania that provide supply to the the high voltage network in addition to transmission-distribution connection points;
- a high voltage network of distribution lines that distribute electricity from transmission-distribution connection points and zone substations to the low voltage network and a small number of customers connected directly to the high voltage network; and
- distribution substations and low voltage circuits providing supply to the majority of customers in Tasmania.

Figure 3-5 presents a geographical overview of the high-voltage distribution network by voltage. Distribution lines are classified as supplying rural and urban areas, and these tend to have different characteristics. In Figure 3-5, urban areas are shown as shaded areas in Greater Hobart, Launceston and the north-west coast; all other areas are classified as rural.

Rural areas generally have low load, low customer connection density, and smaller rural population centres that are remote from supply points. Distribution lines supplying rural areas tend to cover wide geographic areas and can have a total route length between 50 km and 500 km. The significant route length creates a high exposure to external influences such as storm damage, vegetation (trees and branches), and lightning strikes. Additionally, rural lines are generally radial in nature, with limited ability to interconnect with adjacent lines. These two characteristics tend to result in more frequent and longer duration interruptions to supply.

The majority of lines supplying rural areas are operated at 22 kV. Rural areas supplied at 11 kV are generally those on the outer areas surrounding greater Hobart, Kingston, Kermandie, Huonville, New Norfolk and Richmond. Limitations experienced on distribution lines supplying rural areas are characterised by managing poor reliability performance due to vegetation, voltage and power quality limitations due to line length, and disturbing loads such as pumping load.

Urban areas have higher load and customer connection density. Distribution lines supplying urban areas are generally much shorter than rural lines. They tend to have more underground distribution, and more interconnections with other urban lines. Consequently, restoration following interruptions to supply is usually quicker than in rural areas.

Lines supplying urban areas of greater Hobart, Kingston and a pocket of the Burnie commercial area, are operated at 11 kV. Those in Launceston, Devonport and Burnie are operated at 22 kV. Limitations experienced on lines supplying urban areas are generally capacity limitations and high fault level.

*17 The provision of electricity supplies on the Bass Strait Islands is managed by Hydro Tasmania.*

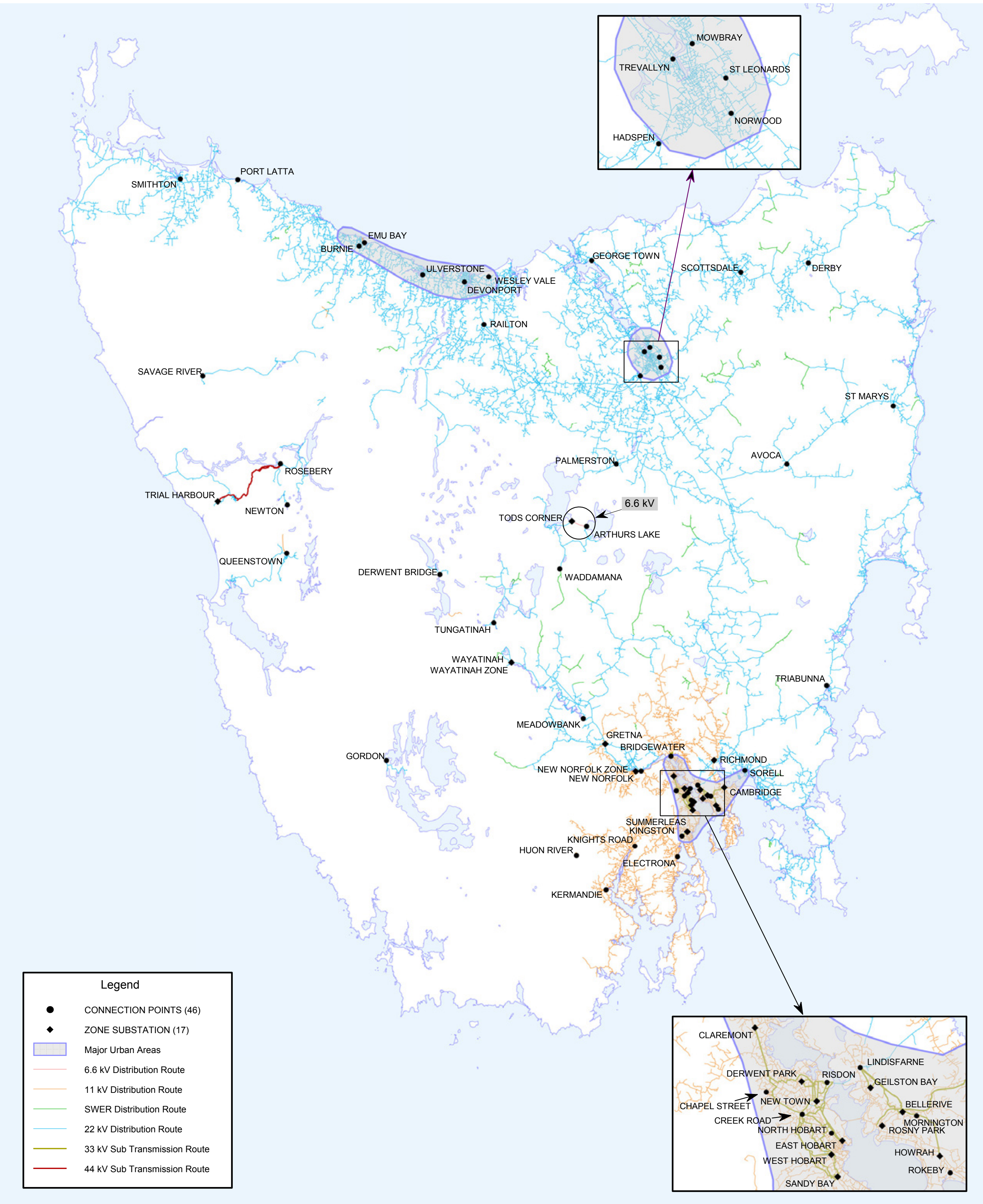



Figure 3-5: Tasmanian distribution voltage areas

A high-level summary of the composition of our distribution network infrastructure is presented in Table 3-2.

**Table 3-2: Distribution network infrastructure[18]**

| Infrastructure | Nominal voltage (kV) | Quantity |
|---|---|---|
| **Connection points** | | |
| Sites | 44, 33, 22, 11 and 6.6 | 46 |
| Sub-transmission lines | 44, 33 and 22 | 27 |
| Rural zone substation source lines[19] | 22 and 11 | 6 |
| Distribution lines | 22, 11 and 6.6 | 273 |
| **Zone substations** | | |
| Major zone substations | 44, 33 and 22 | 14 |
| Major zone distribution lines | 22 and 11 | 135 |
| Rural zone substations | 22 and 11 | 3 |
| Rural zone distribution lines | 22 and 11 | 8 |
| **Distribution substations** | | |
| Overhead | | 30,214 |
| Ground-mounted | | 2,300 |
| **Route data[20]** | | |
| High voltage overhead | 6.6 to 44 | 15,234 km |
| High voltage underground | | 1,237 km |
| Low voltage overhead[21] | 0.4 | 4,945 km |
| Low voltage underground[21] | | 1,265 km |
| Poles | All voltages | 229,996 |

## 3.3.1 Connection points

The distribution network is supplied from connection points at 46 connection sites. 44 of these are supplied from the transmission network, and the remaining two directly from Hydro Tasmania generating sites at Gordon and Wayatinah power stations. These generally supply the high-voltage distribution lines at 22 and 11 kV, with a single 6.6 kV line from Arthurs Lake Substation. Connections sites also supply the 33 kV sub-transmission network in greater Hobart and Kingston, and 44 kV (from Rosebery Substation) and 22 kV (from New Norfolk Substation) sub-transmission lines.

## 3.3.2 Zone substations

Zone substations provide supply points for high-voltage distribution lines in addition to the connection points detailed above. We have two classifications of zone substations: major zone substations are those supplied from sub-transmission lines and rural zone substations are those supplied from within the distribution network. We have 14 major zone substations: 12 in greater Hobart and Kingston which reduce the voltage from 33 to 11 kV, and one in each of Trial Harbour (44 to 22 kV) and New Norfolk (22 to 11 kV). We have three rural zone substations, two of which transform voltage from 22 to 11 kV and one from 11 to 22 kV.

## 3.3.3 Sub-transmission lines

Sub-transmission lines directly supply major zone substations from transmission-distribution connection points and generally have no direct customers connected. There are 27 sub-transmission lines in the distribution network: 25 operate at 33 kV and one each at 44 kV and 22 kV, supplying the zone substations detailed above.

*18 At 1 July 2016, with the exception of new Rosny Park Zone Substation and associated sub-transmission line commissioned October 2016*

*19 Includes rural zone alternate-supply lines*

*20 Includes TasNetworks owned assets only*

*21 Excludes customer service lines*

### 3.3.4 Rural zone substation source lines

Rural zone substation source lines are high voltage distribution lines that also provide supply to rural zone substations. These generally supply multiple distribution substations as well as rural zone substations.

### 3.3.5 High voltage distribution lines

High voltage distribution lines (also referred to as feeders) distribute electricity from connection points and zone substations. A small number of customers take supply directly from high voltage distribution lines; however the majority of supply is to distribution substations for supply to the low voltage network.

### 3.3.6 Distribution substations and low voltage circuits

The low voltage network is operated at 230 Volts (single phase) and 400 Volts (three-phase). The majority of residential and business customers take a single-phase supply. Low voltage circuits are short (generally less than 300 m long) and are supplied through more than 32,000 distribution substations. Distribution substations have various arrangements (pole or ground-mounted, enclosed, or within a building) and sizes. Pole-mounted substations range in size from 25 kVA to 500 kVA and ground mounted substations from 100 kVA to 3,000 kVA. The majority of load customers are supplied from the low voltage network.

## 3.4 Basslink

Basslink Pty Ltd is a Market Network Service Provider in the NEM. Basslink Pty Ltd owns, operates and maintains the Basslink interconnector, a High Voltage Direct Current (HVDC) electrical interconnector between Victoria and Tasmania.

Basslink has a continuous sending end capacity of 500 MW and a short term sending end capacity of 630 MW when exporting electricity from Tasmania to Victoria. Power flow into Tasmania is limited to 478 MW. These figures are maximum limits. Basslink has a non-operational zone between 50 MW export and 50 MW import at all times.

Basslink is also normally able to transfer frequency control ancillary services (FCAS) between the mainland and Tasmania. Currently, FCAS must be sourced within Tasmania due to constraints on Basslink, detailed in Section 4.1.3.

## 3.5 Telecommunications network

TasNetworks owns, operates, and maintains a telecommunications network within Tasmania. The telecommunications network supports operation of the electricity network interfacing protection, control and data, telephone handsets and mobile radio transceivers. It also serves customers in the electricity supply industry, and is utilised by other parties under commercial agreements. The telecommunications assets comprise communications rooms and associated ancillary equipment within substations and administrative buildings, optical fibre on transmission and distribution lines, digital microwave radios and associated repeater stations, and some power line carrier equipment.

In support of our telecommunications network, a number of telecommunications circuits are provided via a third-party network. This is generally outside our network's coverage area and includes all interstate services.

## 3.6 Planning areas

TasNetworks' annual planning review is performed based on geographical planning areas. For planning purposes, we divide Tasmania into seven areas and produce an area strategy for each of these, as well as a core-grid strategy for the transmission backbone and inter-area limitations. The planning areas are designated based on the transmission network supplied through bulk supply points and the geographical coverage of the distribution network. Figure 3-6 and the notes below show the seven planning areas in Tasmania with a brief description.

Chapter 6 of this APR presents the results of our annual planning review which includes the existing and forecast network limitations and planned investments. Appendix E summarises this information on network diagrams by planning area. Information on where spare capacity is available that may allow simple connection of new loads to the network is provided in Section 7.1.

**West Coast** The west coast area of Tasmania, covering the area supplied from Farrell Substation

**North West** The north-west area of Tasmania from Deloraine and Port Sorell to Smithton and the far north-west. This area is supplied through major supply points at Burnie and Sheffield substations.

**Northern** The greater Launceston area, George Town and the far north-east. This area is supplied through major supply points at Hadspen, George Town and Palmerston (near Poatina) substations.

**Central** The Central Highlands and Derwent Valley areas of Tasmania. This area also includes the supply at Strathgordon. There is no major supply point in this area, with the area generally supplied from the 110 kV network between New Norfolk, Tungatinah (near Tarraleah) and Waddamana substations.

**Eastern** The east coast of Tasmania from the Tasman Peninsula to St Helens and extending inland to Campbell Town, Oatlands and Richmond. The area is supplied through the peripheral 110 kV network, supplied from bulk supply points at Lindisfarne and Palmerston substations.

**Greater Hobart** Generally the areas covered by Hobart, Glenorchy, Brighton and Clarence council areas. High concentration of load within the Hobart CBD and eastern and western shore areas, however the area extends from Sandy Bay and South Arm to Brighton and Kempton. This area is supplied through major supply points at Chapel Street (in Glenorchy) and Lindisfarne substations.

**Kingston-South** The Kingborough and Huon Valley area of Tasmania, including Bruny Island. The area is supplied through Chapel Street Substation.


Figure 3-6: Geographical planning areas

# 4 Network performance



## Overview

This chapter focuses on the performance of the network in recent years. Firstly we present information about constraints which resulted in the power flow through the transmission network being altered to ensure the power system remained in a secure operating condition. We then present information about the reliability of the transmission and distribution networks, and our performance against our target standards. We provide a summary of our demand management activities and, finally, include discussion on embedded generation and factors that have a material impact on the network.

## 4.1 Transmission network constraints

A network constraint is a situation where the power flow through part of the transmission network must be restricted in order to avoid exceeding a known technical limit. In some instances, it is possible to restrict the power flow by adjusting the output of generators and/or Basslink. Constraint equations define how generators' or Basslink's dispatch targets should be reduced to avoid exceeding these technical limits. Constraint equations are developed by AEMO and are based on advice provided by TasNetworks.

We undertake periodic reviews of all binding and violating constraints and provide AEMO with revised limit advice to modify, remove or add new constraints, as required. This is to ensure that power system security is maintained and the available transmission capacity is maximised. The Market Impact Component of the AER's Service Target Performance Incentive Scheme (STPIS) creates a financial incentive for us to minimise the impact of transmission constraints.

Figure 4-1 illustrates the occurrence of binding (if the power flow must be constrained) and violating (if the technical limit is exceeded) constraints on the major Tasmanian transmission elements in 2015–16. It shows the number of NEM dispatch intervals[22] that constraints occurred in various parts of the network. "Thermal limit – no outage" indicates that the constraint bound or violated without any outage. "Thermal limit – with outage" means the constraint was caused by one or more transmission elements being out of service.

### 4.1.1 Existing constraints on major transmission network elements

In 2015–16, Tasmania recorded net electricity import via Basslink for four continuous months between September and December 2015. This is similar to the 2014–15 financial year. The primary reason for the increased or decreased instances of binding and violating constraints in 2015–16 compared to 2014–15 was due to Basslink being out of service for almost six months between December 2015 and June 2016, with the associated supplementary diesel generation.

Table 4-1 presents the number of dispatch intervals for major binding constraints (where the total bound or violated period exceeds 150 dispatch intervals, ie 12.5 hours) in 2015–16 or significant changes from major binding constraints in 2014–15. Detailed information of these constraints is provided in Appendix G. It contains the constraint identifiers (ID), detail of the constraints and the marginal cost of the constraint binding for 2014–15 and 2015–16.

**Table 4-1: Major binding constraints and significant changes in 2015–16**

| Constraint | Period constraint bound or violated | | | |
|---|---|---|---|---|
| | 2014–15 | | 2015–16 | |
| | Dispatch intervals | Hours | Dispatch intervals | Hours |
| **Constraints with increased incidence of binding in 2015–16** | | | | |
| Scottsdale Tee–Derby 110 kV thermal limit no outage | 1150 | 96 | 1504 | 125 |
| Farrell–Sheffield 220 kV thermal limit with no outage | 344 | 29 | 921 | 77 |
| **Constraints with decreased incidence of binding in 2015–16** | | | | |
| George Town 220 kV bus voltage limits | 526 | 44 | 244 | 20 |
| Farrell–Sheffield 220 kV transient stability | 268 | 22 | 84 | 7 |
| Waddamana–Palmerston 110 kV thermal limit with no outage | 111 | 9 | 74 | 6 |
| Sheffield–George Town 220 kV thermal limit with no outage | 192 | 16 | 62 | 5 |
| Palmerston–Sheffield 220 kV transient stability | 508 | 42 | 61 | 5 |
| Palmerston–Hadspen 220 kV thermal limit with no outage | 164 | 14 | 35 | 3 |

*22 Dispatch intervals are 5-minutes*

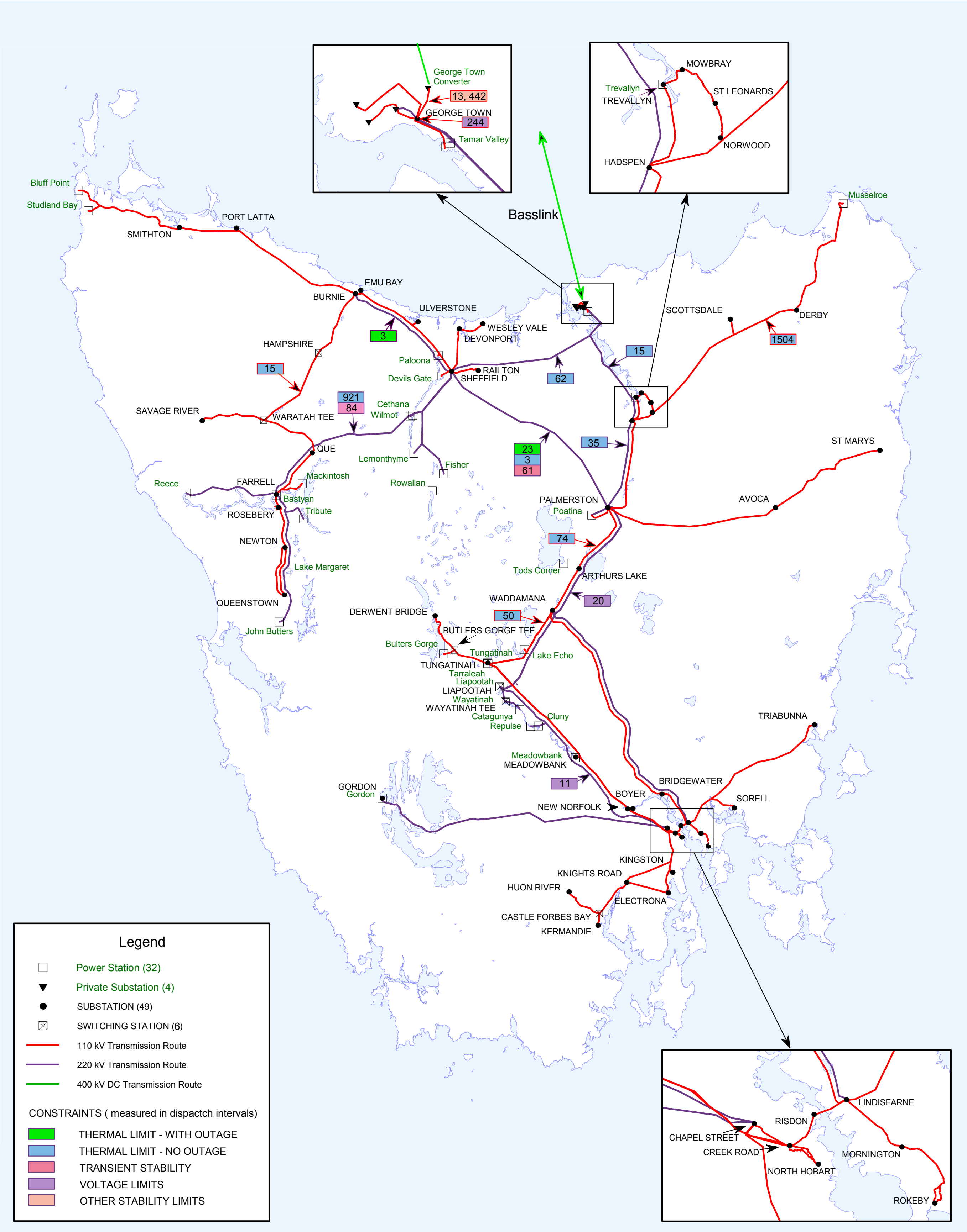



**Figure 4-1: Recorded transmission constraints during 2015–16**

**Table 4-2: Network constraint equations affecting Basslink flows in 2015–16**

| Constraint | Period constraint bound or violated | | | |
|---|---|---|---|---|
| | 2014–15 | | 2015–16 | |
| | Dispatch intervals | Hours | Dispatch intervals | Hours |
| **Constraints with increased incidence of binding in 2015–16** | | | | |
| Basslink discretionary limit | 165 | 14 | 8476 | 706 |
| Farrell–Sheffield 220 kV transmission line rating constraint with NCSPS operation | 155 | 13 | 168 | 14 |
| **Constraints with decreased incidence of binding in 2015–16** | | | | |
| Basslink energy and FCAS related constraint (ie Basslink no go zone) | 4975 | 415 | 3615 | 301 |
| Basslink import limited due to load unavailability for FCSPS operation | 9123 | 760 | 1201 | 100 |
| George Town 220 kV bus voltage limits | 526 | 44 | 244 | 20 |
| Basslink rate-of-change limit | 328 | 27 | 121 | 10 |
| Farrell–Sheffield 220 kV transient stability | 268 | 22 | 84 | 7 |
| Sheffield–George Town 220 kV transmission line constraint with NCSPS operation | 157 | 13 | 62 | 5 |
| Palmerston–Sheffield 220 kV transient stability | 508 | 42 | 61 | 5 |
| Basslink inverter commutation instability limit | 200 | 17 | 29 | 2 |

### 4.1.2 Constraint equations affecting Basslink dispatch

Table 4-2 presents the number of dispatch intervals constraint equations bound or violated which affected Basslink flows during 2015–16. Similar to major binding constraints, the predominant reason for the increased or decreased incidence of binding was due to Basslink being out of service for almost six months, with the associated supplementary diesel generation. More details on these binding or violated constraints are provided in the Appendix G.

### 4.1.3 Basslink performance and impact on the Tasmanian system

On 20 December 2015 a fault occurred on the subsea section of Basslink Interconnector's HVDC cable, resulting in a long-term outage of the Interconnector. Basslink was returned to service on 13 June 2016. Despite the long-term outage, Basslink remained a net energy importer in 2015–16, but with reduced energy flows of 1070 GWh imported from the mainland and 509 GWh exported.

Generation dispatch patterns changed dramatically in 2015–16 due to the Basslink outage, extremely low levels of Tasmanian water storage until May 2016 and spill conditions on Hydro Tasmania's small storage capacity power stations after May 2016.

Due to the extreme energy situation in Tasmania between December 2015 and May 2016, measures were taken to increase local generation capabilities, maximise the efficiency of the hydro generation fleet and reduce the energy taken by loads as follows:

- Hydro Tasmania returned to service the combined cycle gas turbines at Tamar Valley Power Station;
- the open cycle gas turbines at Tamar Valley Power Station, which are normally used only for peak demand, were in regular operation;
- we worked with Hydro Tasmania and other stakeholders to facilitate the connection of 220 MW of temporary containerised diesel generation to the network;
- with Hydro Tasmania we developed algorithms to reduce the (higher) level of spinning reserves required in Tasmania without Basslink, allowing Hydro Tasmania to dispatch generation more efficiently (in terms of water usage);
- major industrial loads made significant reductions to their energy consumption; and
- we raised the voltage profile of the network.

Since December 2014, the loss of Basslink concurrent with the loss of a major Tasmanian transmission line has remained a credible contingency event during Basslink import into Tasmania. Therefore all "raise" FCAS requirements must be sourced within Tasmania (from local generation and contracted load) since Basslink cannot always transfer FCAS from mainland Australia. Information on the events that led to this requirement is available from AEMO.[23]

23 *Trip of Basslink and transmission lines in Tasmania, Power system incident reports 2014, publication date 13 May 2015, AEMO* *http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports*

**Table 4-3: Transmission network reliability performance**

| Performance measure | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|
| Number of LOS events >0.1 system minute | 11 | 11 | 7 | 5 | 0 |
| Number of LOS events >1.0 system minute | 3 | 3 | 0 | 0 | 0 |

### 4.1.4 Performance of system protection schemes

The potential impact of Basslink's high transfer capabilities on the Tasmanian power system requires system protection schemes (SPS). Without these schemes, significant investment and augmentation to the transmission network would be required to allow the present Basslink transfer capability. The SPS encompasses two separate schemes which mitigate limitations which would otherwise occur following loss of Basslink: the Frequency Control System Protection Scheme (FCSPS) to ensure frequency remains within bounds, and the Network Control System Protection Scheme (NCSPS) to prevent transmission line overloads when Basslink is exporting.

During 2015–16, the FCSPS was required to operate on two occasions: one event during Basslink import due to a DC cable fault and one event during Basslink export due to a fault in surge diverter tank at Loy Yang. The FCSPS operated correctly on both occasions and the Tasmanian frequency complied with the frequency operating standards. There were no NCSPS events during 2015–16, however it operated correctly twice in July 2016.

## 4.2 Tasmanian supply reliability

Reliability of supply is a key indicator in measuring network performance and is an indicator of the impact of supply interruptions to customers. We measure the duration, frequency and impact of supply interruptions, using different measures for the transmission and distribution networks. We continually analyse the performance of our electricity network and regularly report to OTTER and the AER against our measures. Our performance against the reliability targets set by the AER is a key component of our service target performance incentive scheme (STPIS).

The following sections provide information on network reliability targets and historical performance. More information on our network reliability performance is detailed in Appendix C.

### 4.2.1 Transmission network reliability

Transmission network reliability is monitored and reported to the AER and OTTER in terms of the number of loss of supply (LOS) events that occurred during the year.[24] There are no targets associated with loss of supply events reporting to OTTER. The AER does set targets, along with additional reliability measures. Loss of supply is measured in 'system minutes' and is calculated by dividing the total energy (MWh) not supplied to customers during an event by the energy supplied during one minute at the time of historical Tasmanian maximum demand.[25] Table 4-3 presents the loss of supply performance of the transmission network as reported to OTTER over the last five years.

We have continually improved our reliability performance in recent years such that we now have a high reliability performance of the transmission network. This has resulted from a focus on continual service improvement with many initiatives included in operational and capital programs. This includes: improving our incident investigation and remediation process; targeting improved performance to access incentive schemes; improved maintenance practices; and targeted replacement of unreliable assets.

We have had one loss of supply event greater than 1.0 system minute in 2016–17 to February 2017. We will report on this event in the 2018 APR.

#### 4.2.1.1 Significant network incidents

A significant network incident is defined as a loss of supply event exceeding 1.0 system minute. We did not incur any significant network incidents in 2015–16.

### 4.2.2 Distribution network reliability

Reliability in the distribution network is measured in frequency and duration, and is reported as averages termed SAIFI and SAIDI totalled over a 12-month period. SAIFI is the System Average Interruption Frequency Index (measured in number of interruptions), and SAIDI is the equivalent measure for duration (measured in minutes). The measures represent the average frequency and duration of interruptions each customer in a system (reliability community or category) experiences in a 12-month period. In Tasmania, distribution network reliability is reported to OTTER and the AER.

*24 Transmission reliability is reported to the AER and OTTER by calendar and financial year, respectively.*

*25 In Tasmania, an event of one system minute equates to approximately 31.2 MWh of unserved energy.*

**Table 4-4: Code supply reliability category standards and performance**

| Supply reliability category | Annual number of supply interruptions (on average) (SAIFI) | | Annual duration of supply interruptions (on average) (SAIDI) | |
|---|---|---|---|---|
| | Standard | 2015–16 performance | Standard | 2015–16 performance |
| Critical infrastructure | 0.2 | 0.25 | 30 | 34 |
| High density commercial | 1 | 0.26 | 60 | 23 |
| Urban and regional centres | 2 | 1.26 | 120 | 141 |
| High density rural | 4 | 3.12 | 480 | 521 |
| Low density rural | 6 | 6.86 | 600 | 725 |

**Table 4-5: Code supply reliability community standards and performance**

| Supply reliability category (number of communities) | Annual number of supply interruptions (on average) (SAIFI) | | Annual duration of supply interruptions (on average) (SAIDI) | |
|---|---|---|---|---|
| | Standard | No. of poor performing communities in 2015–16 | Standard | No. of poor performing communities in 2015–16 |
| Critical infrastructure (1) | 0.2 | 1 | 30 | 1 |
| High density commercial (8) | 2 | 0 | 120 | 1 |
| Urban and regional centres (32) | 4 | 4 | 240 | 10 |
| High density rural (33) | 6 | 2 | 600 | 5 |
| Low density rural (27) | 8 | 1 | 720 | 8 |
| Total (101) | | 8 | | 25 |

In this section we present an overview of our distribution network reliability measures, standards and 2015–16 performance. Our network reliability past performance and forecast data is detailed in Appendix C.

#### 4.2.2.1 Measures

The Tasmanian Electricity Code **(the Code)**, enforced by OTTER, specifies the reliability performance standards for both supply reliability communities and categories. Under the Code, Tasmania has been divided into 101 supply reliability communities. The five supply reliability categories are made up of those communities as follows:

- critical infrastructure (1 community);
- high density commercial (8);
- urban and regional centres (32);
- high density rural (33); and
- low density rural (27).

Community standards set the reliability standards of each individual community and category standards set the reliability of all communities together within that category. The standards set out in the Code exclude outages caused by third-party faults, customer plant, and the transmission network.

We are required to use reasonable endeavours to ensure that each supply reliability community and category meets the respective standards. We report distribution reliability to OTTER on a quarterly and financial year basis.

In addition, the AER sets targets for supply reliability categories each regulatory period for our distribution service target performance incentive scheme. These targets are calculated from our average performance in the preceding five years. We are subject to financial penalties if we perform worse than target levels and financial rewards if we perform better than target levels. We have a strategic objective of maintaining network service performance, and not incurring a net STPIS penalty. We report distribution reliability to the AER on a financial year basis.

#### 4.2.2.2 Code standards and performance

The Code specifies the reliability standard for each supply reliability category, and for the supply reliability communities within each category. Category standards are more onerous than individual community standards.[26] The standards set out in the Code exclude outages caused by third-party faults, customer plant, and the transmission network.

The Code standards and 2015–16 performance is presented in Table 4-4 at category level, and Table 4-5, at community level. Historic performance against Code standards is presented in Appendix C.1.

Our performance in SAIFI, the frequency measure, has generally been good with all categories, apart from low density rural and critical infrastructure, performing better than their respective standard. Our performance in SAIDI has been poor, with all categories, apart from high density commercial, performing worse than their

*26 Critical infrastructure category has only one community and therefore the standard is the same.*


**Table 4-6: AER supply reliability category targets and performance**

| Supply reliability category | Annual number of supply interruptions (on average) (SAIFI) | | Annual duration of supply interruptions (on average) (SAIDI) | |
|---|---|---|---|---|
| | Target | 2015–16 performance | Target | 2015–16 performance |
| Critical infrastructure | 0.22 | 0.16 | 20.79 | 14.57 |
| High density commercial | 0.49 | 0.19 | 38.34 | 11.37 |
| Urban and regional centres | 1.04 | 0.97 | 82.75 | 78.06 |
| High density rural | 2.79 | 2.61 | 259.48 | 254.26 |
| Low density rural | 3.20 | 3.22 | 333.16 | 370.53 |

respective standard. Poor performance in SAIDI at the category level can be largely attributed to the number and magnitude of extreme weather conditions in this year. In 2015–16 we experienced six major event days, the most in at least the last 10 years.

At community level, supply reliability was worse than standard in 26 of the 101 communities in 2015–16. 25 communities did not meet their respective SAIDI standards and eight communities did not meet their respective SAIFI standards.

### 4.2.2.3 AER targets and performance

Reliability targets set by the AER exclude planned outages to the network, major event days[27], transmission network outages, customer installation faults, and bushfire and total fire ban day related outages. AER targets and 2015–16 performance is presented in Table 4-6. Historic performance against AER targets is presented in Appendix C.2.

We have met our SAIFI and SAIDI targets for all reliability categories except for low density rural. Our SAIDI performance against AER targets is better than our SAIDI performance against Code requirements. As the performance standards in the Code are generally more onerous than the AER performance targets, it suggests that events excluded from AER reporting are having an impact on our reliability performance under the Code. These are predominantly major event days, in which a large number of network areas experience concurrent outages resulting in long restoration times.

### 4.2.2.4 Compliance process

As detailed in Section 2.3.2, our reliability strategy includes maintaining overall network reliability performance while ensuring compliance with our relevant requirements. The strategy does not preclude enhancing network reliability where performance is inadequate and below target or where asset risk is unacceptably high.

We have recently created a service performance improvement framework and an asset management plan for service performance to enable us to deliver on our reliability strategy. The service performance improvement framework was created to improve our processes in managing service performance and improve service performance outcomes. The management plan describes our service performance management strategy over the planning period and influencing factors.

*27 A major event day is defined as a day when the number of system minutes caused by outages exceeds an annually calculated threshold. These are predominately a result of large storms across wide areas of the state.*

Table 4-7: Planned reliability corrective action

| Program | Benefit | Volume |
|---|---|---|
| Distribution line trunk strategy (protection reviews, targeted and aggressive vegetation management, and asset renewal/relocation) | Reducing probability of unplanned outage occurring | 35 distribution lines |
| Remote switching reinforcement (loop automation and multiple switches) | Reducing supply restoration time following unplanned outage | 10 projects |
| Distribution line extensions (including new lines) | Reducing customer exposure to unplanned outages | 10 projects |
| Stand-by generation | Reducing supply restoration time following unplanned outage | 1-2 projects |

#### 4.2.2.5 Corrective action

Our corrective action to improve reliability in the distribution network is progressing under three streams: targeted investigations into our worst performing distribution lines, network reinforcement and ongoing asset management activities.

We are currently investigating the causes of poor reliability on our seven worst performing distribution lines, which between them affect 15 reliability communities. The outcome of this will drive targeted reliability improvement programs to bring reliability in these areas up to standard.

Our proposed network reinforcement work to improve reliability is presented in Table 4-7. It details the program of corrective action planned for the five year period to 2021, the benefit it provides and the size of the program.

We also implement a number of asset management initiatives to ensure reliability is managed appropriately:

- implementation of a service performance improvement framework;
- vegetation management (trimmed or removed) to prevent contact with distribution lines resulting in supply interruptions;
- prioritised defect rectification programs to ensure assets posing a risk to reliability are repaired to reduce the likelihood of supply interruptions;
- protection settings are reviewed to ensure the fewest customers as possible lose supply following fault;
- targeted and specialised inspections programs, such as aerial and thermographic surveys, that focus on high risk assets or specific asset failure modes; and
- provision of new technologies, such as line fault indicators, to assist field crews in finding failed assets or restoring distribution line sections more quickly, minimising duration of supply interruptions and assisting in root cause analysis and reducing recurrences.

These network augmentations and asset management initiatives will assist us in maintaining an appropriate level of reliability and improving the resilience of the network against extreme weather events, including major event days and high bushfire-risk events.

## 4.3 Service target performance incentive scheme submission

As part of our Regulatory Information Notices (RINs) submissions, a range of information was provided to the AER with regards to the service target performance incentive scheme for 2015–16 year. The full detail is available on the AER website[28], with a summary provided as follows:

**Reliability**

- System Average Interruption Duration Index (SAIDI);
- System Average Interruption Frequency Index (SAIFI);
- Momentary System Average Interruption Frequency Index (MAIFI);
- Start, end and average financial year connected kVA; and
- Start, end and average financial year customer numbers.

A summary of the information provided is presented in Table 4-8.

**Customer service**

Under the customer service category, we have reported on telephone answering. Table 4-9 presents the STPIS data reported on telephone answering.

**Daily performance**

Daily performance for supply reliability category, with and without excluded events for SAIDI, SAIFI and MAIFI, is too detailed to summarise here and is available on the AER website.

**Guaranteed Service Level**

The AER did not impose its guaranteed service level scheme during the regulatory year. Instead, it relied upon the scheme already established by OTTER as part of the Code.

28 *TasNetworks (distribution) 2015–16 – Annual Reporting RIN – non-financial templates:* *https://www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses*

**Table 4-8: STPIS reliability**

| Reliability measure | Measure | Critical infrastructure | High density commercial | Urban | High density rural | Low density rural | Whole network |
|---|---|---|---|---|---|---|---|
| SAIDI | Total | 19.27 | 20.90 | 118.76 | 515.91 | 733.82 | 344.75 |
| | Removing exclusions[29] | 14.57 | 11.37 | 78.06 | 254.26 | 370.53 | 181.77 |
| SAIFI | Total | 0.19 | 0.35 | 1.21 | 3.27 | 0.00 | 2.25 |
| | Removing exclusions[29] | 0.16 | 0.19 | 0.97 | 2.61 | 3.22 | 1.81 |
| MAIFI | Total | 0.62 | 1.09 | 2.65 | 6.60 | 8.89 | 4.88 |
| | Removing exclusions[29] | 0.62 | 1.05 | 2.10 | 4.97 | 6.97 | 3.80 |
| Average customer numbers ('000s) | | 1.88 | 4.70 | 191.44 | 43.29 | 44.02 | 285.32 |
| Average customer numbers (in '000s of kVA) | | 124.03 | 135.43 | 1,882.90 | 781.60 | 966.37 | 3,890.28 |

**Table 4-9: STPIS customer service**

| Telephone answering | Total – removing exclusions[29] | Total |
|---|---|---|
| Number of calls | 44,455 | 55,628 |
| Number of calls answered in 30 seconds | 32,314 | 34,895 |
| Percentage of calls answered within 30 seconds | 72.69 | 63.73 |

## 4.4 Demand management activities

This section provides information on the demand management activities and non-network options we have undertaken in the past year to address network limitations.

### 4.4.1 Non-network options considered

In the past year we have considered the following non-network options as part of our demand management activities:

- continue to utilise Bruny Island peak-shaving generator to manage the loading on the cables supplying Bruny Island;
- Bruny Island distributed energy storage trial project, which uses customer owned energy storage to reduce cable load or diesel use on Bruny Island; and
- establishing an embedded generation network support trial project, which will use customer-owned generation to manage loading on a distribution line from Palmerston Substation.

### 4.4.2 Promotion and plans of non-network options

The following actions were taken to promote non-network options:

- facilitating the connection of embedded generation to the network through the management of technical limitations;
- discussions with the Bruny Island community on Bruny Island Battery Trial project;
- publication on our website of our updated Demand Side Engagement Strategy[30];
- promotion of Demand Side Engagement Strategy with stakeholder groups;
- analysing further sites suitable for remote area power supply systems;
- analysis of suitable locations of mobile and embedded generator units;
- discussions with energy storage aggregators leading to Bruny Island project; and
- discussions on grid connect controls at an embedded generation site.

Over the forward planning period we intend to continue with our initiatives and to consider other demand management options, where economical to manage network limitations. Further information on our promotion of non-network options (our network innovation and trial projects) is provided in Section 6.5.

*29 Excluded events and major event days*

*30 http://www.tasnetworks.com.au/our-network/planning-and-development/demand-side-engagement-strategy*

## 4.5 Embedded generation

There has been a continued increase in the number of customers wishing to generate electricity on their own premises – termed embedded generation. Generally embedded generators fit into two broad categories: the larger systems tend to use rotating machines whereas low power generators are dominated by small-scale photovoltaic (PV) asynchronous installations (roof-top solar). To facilitate the connection of small embedded generators, exemption from full compliance with the Rules is granted by AEMO for small generators (less than 5 MW)[31] – although they must still have a connection agreement with TasNetworks. Micro embedded generators (including PV) connecting to the network must meet our connection guidelines.

In 2015–16, we received 2,651 applications to connect embedded generation to the network. This was predominantly applications for roof-top photovoltaic. The average time taken to connect was 47 days.

The recent proliferation of embedded generators has caused some technical challenges to us. The key issues arising from applications to connect embedded generating units received in the past year include:

- ensuring safe disconnection of embedded generation during faults that may lead to "island" conditions – especially for synchronous machines;
- ensuring that embedded synchronous generators are not exposed to auto-reclose events; and
- maintaining stable voltages at weak connection points.

These points are discussed further below.

### 4.5.1 Rotating machines

Synchronous generators (rotating machines) can pose risks to other network users (and the synchronous generator) during islanding type faults. An "island" is a situation in which part of the network, which contains a generator, becomes disconnected from the remainder of the network. Should that generator continue to operate, the islanded part of the network will still be live, with possibly minimal control over the voltage and frequency. This would pose a danger to customers, electrical equipment still connected and to service crews. It is therefore necessary to ensure embedded generators are equipped with anti-islanding protection devices.[32] TasNetworks must approve the anti-islanding protection device of the synchronous generator before network connection.

No significant embedded synchronous generators have been connected into the distribution network in the past year. We are, however, processing some connection applications.

31 http://www.aemo.com.au/Electricity/Network-Connections

32 *An anti-islanding protection device will cause the generator to shut down should its part of the network become disconnected from the remainder of the network. All grid-connected PV inverters inherently contain anti-islanding protection.*

### 4.5.2 Photovoltaic

#### 4.5.2.1 Photovoltaic unit penetration

Historically PV uptake in Tasmania lagged behind that of the mainland states, although tariff incentives contributed to some minor surges in uptake. However, since 2012 there has been dramatic growth in installed capacity, primarily driven by falls in equipment cost. At the end of 2015–16, Tasmania had 96.4 MW of registered PV at over 27,400 locations.[33]

In Tasmania, PV contributes very little to reducing the maximum demand on the network. Maximum PV output usually occurs in the middle of the day in summer, when solar radiation is highest. Maximum demand in Tasmania occurs during early mornings or evenings in winter, when there is virtually zero contribution from PV.

#### 4.5.2.2 Challenges with photovoltaic

There are both network-wide and local issues associated with PV installations. From a network-wide perspective it is important that PV installations remain connected to the network following frequency disturbances. This is a major issue for Tasmania because:

- being a small power system, frequency disturbances are relatively common; and
- our operational frequency bands are significantly wider than mainland Australia (summarised in Section 7.3).

Disconnection of a high proportion of PV installations during a low-frequency disturbance would magnify the frequency excursion, which could lead to unanticipated load tripping. In the worst case, this could occur even in response to single contingency events, which would be unacceptable for customers and contravene the Rules.

Local issues mainly relate to voltage regulation in the distribution network. Historically the low voltage distribution circuits were optimised to supply customer load. The design ensured that standard voltages could be maintained above the allowable minimum voltage (during maximum winter load) and below the allowable maximum voltage (during minimum summer load). Essentially, PV penetration further depresses the summer minimum load and a number of low voltage circuits are becoming net generators. When operating at unity power factor, PV inverters must generate at higher voltages than supplied by the grid, which can lead to very high voltages being generated by the PV inverters.

Two consequences of inaction in the face of increased PV penetration are:

- "saturation" of many distribution circuits at relatively low penetration levels making the connection of further PV installations unfeasible;

33 *This includes PV systems registered under the Small-scale Renewable Energy Scheme (SRES) only (systems size no more than 100 kW and annual output less than 250 MWh).* http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

- major infrastructure upgrades to facilitate further PV connections.

To avoid these consequences, we have established connection guidelines that new connecting micro generating systems (including PV) must meet.[34] The guidelines specify modern inverter technology that will contribute to voltage regulation. This approach allows the network to accommodate higher amounts of PV, increasing the point at which saturation occurs.

## 4.6 Factors affecting the network

### 4.6.1 Fault levels

The network fault level can be defined in terms of apparent power (MVA fault level) or current, typically expressed in kilo-amperes (kA). The short-circuit fault current, defined at a given point in the network, is the current that would flow should a solid fault occur at that particular point. Determining the maximum fault currents within the network is important for the appropriate selection of equipment such as circuit breakers, switchgear, cables and busbars. This equipment should be designed to withstand the thermal and mechanical stresses that would be experienced due to the high currents that occur under short circuit conditions.

We require that all new connecting circuit breakers to the network meet a minimum access standard. For all voltage levels, circuit breakers require a minimum symmetrical three phase fault current withstand capability of 25 kA for connection to the transmission network, and 16 kA for connection to the high voltage side of the distribution network.

Within our network, the maximum allowable fault current contribution at transmission-distribution connection points has historically been 13 kA. This was determined on the assumption that the distribution network design fault current is 16 kA, with a 3 kA margin for embedded generation. We have a number of connection points where the maximum fault level exceeds 13 kA, as listed in Table 4-10, however we are currently reviewing this threshold. Our operational procedures in place to manage the fault level at these connection points below 13 kA are as follows:

- at five sites we operate the bus coupler circuit breaker normally open. Except for Electrona Substation, an auto-close scheme will immediately close the bus coupler to restore supply to the other busbar following a contingency on the connecting supply transformer.
- at three sites we remove a supply transformer from service to reduce fault level. It is operated normally-open at Wesley Vale Substation, however is only opened at Creek Road and Trevallyn substations when fault current exceeds 13 kA.

Fault level limitations exist at two additional connection points due to limitations within the distribution network. At Scottsdale Substation, some fuses within the distribution network have low fault rating. At Smithton Substation, a distribution earthing issue has required fault level to be reduced until corrective action can be implemented. As detailed in Table 4-10, the bus coupler at both substations is operated normally-open to reduce the fault level.

MVA fault levels are used to define the strength of the power system during normal operation. Minimum fault levels may be used to determine the appropriateness of a connection point to accommodate a new load or for planned switching in regards to voltage power quality. Connection points with higher fault levels experience lower levels of voltage flicker for load switching compared to those with low fault levels.

**Table 4-10: Transmission-distribution connection points with high fault current**

| Connection point substation (connection voltage [kV]) | Management strategy |
|---|---|
| Bridgewater (11) | Bus coupler operated normally-open, with auto-close scheme |
| Chapel Street (11) | Bus coupler operated normally-open, with auto-close scheme |
| Creek Road (33) | Supply transformer incoming circuit breaker opened when fault current exceeds 13 kA, with auto-close scheme |
| Electrona (11) | Bus coupler operated normally-open |
| Kingston (11) | Bus coupler operated normally-open, with auto-close scheme |
| Rokeby (11) | Bus coupler operated normally-open, with auto-close scheme |
| Scottsdale (22) | Bus coupler operated normally-open |
| Smithton (22) | Bus coupler operated normally-open |
| Trevallyn (22) | Supply transformer incoming circuit breaker opened when fault current exceeds 13 kA, with auto-close scheme |
| Wesley Vale (11) | Supply transformer incoming circuit breaker operated normally-open |

34 *Guidelines for connecting Micro Generating Systems (AS4777 compliant)* https://www.tasnetworks.com.au/our-network/new-connections-and-alterations/connecting-micro-embedded-generators-information-p/

Wind farm connections also require a certain fault level at their connection point to enable them to connect to the network. The existing wind farms in Tasmania have already absorbed much of the available MVA fault level in their locality. This means the future wind farms may connect to an effectively weaker power system in certain locations.

Appendix B provides a technical description of fault level quantities and our calculation methodology. Fault level data is provided in a Microsoft Excel file on our website, via the 2017 Annual Planning Report page. The file is available at http://apr.tasnetworks.com.au. The spreadsheet contains the existing maximum and minimum three-phase and single phase fault levels, and positive, negative and zero sequence impedances, at all transmission substation busbars.

### 4.6.2 Voltage management

Maintaining voltages within target ranges is important for ensuring the safety of people and equipment, the efficient and secure operation the power system, and quality of supply to customers.

Exceeding the upper voltage limit may result in insulation breakdown and subsequent equipment damage. Operating below the lower limit impacts on power quality, and could cause fuses to blow or equipment to trip. We have a number of constraint equations to ensure transmission voltages are maintained within target ranges. More detail on constraints and the voltage constraint equations that bound during 2015–16 is provided in Section 4.1.

The ranges of acceptable voltage limits are specified in the Rules and Australian Standards (AS), specifically:

- the Rules S5.1a.4 power frequency voltage (specifying maximum and minimum voltages in normal operation and following contingency);
- the Rules S5.3.5 power factor requirements (specifying permissible power factor range); and
- AS 60038-2012 Standard voltages (specifying maximum and minimum household supply and other voltages).

Voltage management also forms a critical component of power quality, impacting all our customers. Voltage management in the distribution network is considered part of power quality. The network-wide and localised voltage limitations from PV installations are detailed in Section 4.5.2, with other voltage-related power quality limitations detailed in the Section 4.6.5.

### 4.6.3 Power system security

Power system security is the safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in section 4.2.6 of the Rules. A key factor that may impact power system security is the ongoing installation of embedded generation, especially PV installations and decrease in fault levels. These issues are discussed in Section 4.5.2 and Section 4.6.1 respectively. Other factors that impact power system security are the load forecast and customer connections. In chapter 6 we discuss the impact of these on the network and present solutions to manage them.

### 4.6.4 Ageing and potentially unreliable assets

There are many ageing assets within the network and we carry out routine maintenance on all our assets to reduce the probability of plant failure. Factors that may impact on ageing and potentially unreliable assets are:

- asset location – whether the assets are located indoors or outdoors;
- operating factors – load utilisation, frequency of use and load profiles; and
- condition of the equipment.

Ageing and potentially unreliable assets are managed as part of our overall asset management strategy and is discussed in Section 2.3.4 with planned investments to address asset management requirements identified in Section 6.3.3.

### 4.6.5 Power quality

Power quality refers to the technical characteristics of the electricity supply received by customers that ensure that the consumer can utilise electric energy from the network successfully, without interference to or mal-operation of electrical equipment. Power quality encompasses the following key areas:

- supply voltage;
- frequency departures;
- voltage disturbances;
- voltage dips; and
- distortion disturbances, including transients, waveform and harmonic distortion, and voltage/current differences between neutral and earth.

Generally, the quality of voltage is most important, because customers generally notice voltage deviations more than other power quality limitations. The main categories of deviation are: temporary voltage variations, repeated voltage fluctuations (flicker), harmonic voltage distortions and voltage unbalance.

Schedules 5.1a, 5.1 and 5.3 of the Rules describe the planning, design and operating criteria that must be applied to transmission and distribution networks for power quality. This section details our recent performance in power quality. More information, including performance criteria and planning levels, is included in Section 7.2 and Appendix A.

#### 4.6.5.1 Performance monitoring (transmission)

The increasing participation of power electronic sources of energy over the past decade has resulted in the power system being operated closer to the boundaries for longer periods of time. This "weaker" state of the power system generally leads to more adverse conditions for power quality. The monitoring of power quality performance is a crucial stage in the process of planning the network and managing any emerging limitations.

We use an automated data management system to report against transmission network power quality performance. This system evaluates various characteristics against defined planning criteria.

Power quality monitoring meters are installed at George Town (220 kV and 110 kV), New Norfolk (110 kV), Derby (110 kV and 22 kV), Risdon (110 kV) and Smithton (110 kV) substations. We also have two portable monitoring units, for temporary installation at locations where power quality limitations require investigation. In addition, we have a portable optical current transformer at George Town Substation for high bandwidth harmonic current measurements.

We may expand the monitoring program for wider network coverage as new connection proposals are made. This will enable us to identify sources which inject additional flicker, harmonics or voltage unbalance into the power system. The following points summarise our currently-known power quality limitations. The power quality planning standards referenced here are detailed in Appendix A.

**(a) Temporary over voltage performance**

Some remote parts of the 110 kV network are at risk of single phase temporary over voltage (TOV) during unbalanced line-ground faults. In particular, the transmission lines near Derby, Smithton, and St Marys substations could reach TOV levels of about 1.4 per unit during faults. Since these over-voltages are asymmetrical, with high zero phase sequence voltages, they do not penetrate into the distribution or customer voltage systems. However, we advise future connection applicants who may wish to connect to the 110 kV network, to liaise with us to ensure that suitable transformers are specified to block zero phase sequence voltages.

**(b) Voltage unbalance performance**

Voltage unbalance is within planning levels for at least 95 per cent of the time (annual probability) at all monitored busbars except Smithton 110 kV. For less than 5 per cent of the time, the 10 minute average values vary typically between 0.5 per cent and 1.4 per cent of nominal voltage, outside of the specified level of 1 per cent.

The most prominent voltage unbalance occurs on the 110 kV busbars at George Town, Derby and Smithton substations. We require corrective action at Smithton Substation, which we anticipate will be transmission line conductor transpositioning. We have already transpositioned transmission line conductors into George Town Substation, and are investigating installation of a STATCOM to improve performance there. This installation would have a run-on effect and also improve voltage unbalance performance at Derby Substation.

Voltage unbalance has not caused operational limitations for either the transmission network or customer plant. We are continuing to monitor voltage unbalance at multiple locations to ensure that the transmission network continues to operate within system standards and rules. In doing so, we are ensuring that sufficient data is available to respond to any potential power quality concerns that may be identified in the future.

We also support an industry initiative considering proposing a rule change in relation to the voltage unbalance system standards. This change would result in a softening of the present requirement. We consider that this would make the Rules more realistic and better aligned with the relevant international standards and rules.

**(c) Voltage flicker performance**

The short term voltage flicker indices are within the limits for at least 99 per cent of the time (annual probability) with some excursions above the planning levels noted for less than 1 per cent of the time.

The long term flicker indices are compliant for over 95 per cent of the time but have exceeded the planning levels when 99 per cent annual probability is considered.

**(d) Harmonic performance**

Voltage harmonics are within limits for all measured harmonic frequencies for at least 95 per cent of the time (annual probability) at all monitored substations.

The 5th harmonic is of particular interest for the Tasmanian transmission network. To keep the harmonic voltages in southern Tasmania within the planning levels, the 2 x 40 MVAr 110 kV capacitor banks at Risdon Substation are tuned to 240 Hz. Since the installation of these capacitors, the 5th harmonic voltage level has been significantly below the specified limit and is expected to remain within the planning limits at least within the forward planning period.

The 110 kV capacitor banks at Chapel Street (tuned to 204 Hz) and Burnie (225 Hz) substations are two other capacitor banks in the transmission network that have been de-tuned for harmonic mitigation purposes. These optimisations have resulted in the transmission network being generally compliant with specified harmonic planning levels for the majority of the time, with only occasional excursions beyond the limits.

The harmonic performance of the network is influenced by the connected equipment of our customers. As customers' equipment changes over time, the harmonic performance of the network is likely to change also, which makes prediction of limitations into the long term future somewhat difficult. Our power quality monitoring program allows us to actively keep abreast of any harmonic performance limitations which may evolve.

#### 4.6.5.2 Performance monitoring (distribution)

We have minimal permanent power quality measuring devices in the distribution network, and therefore performance monitoring and the identification of limitations are largely reactive. Where identified, we study these limitations and apply corrective action, if appropriate. Power quality limitations are generally identified through the following methods:

- **Customer feedback**
  We receive feedback from domestic, commercial and industrial customers in relation to quality of supply, generally relating to over or under voltages. The trend of customer feedback received in relation to over and under voltages is presented in Table 4-11.
- **Operational network limitations**
  As part of operating the network, we study alternative supply arrangements to maintain supply to customers during planned outages. This can identify power quality limitations in the network, which limit our operational flexibility.
- **Load or voltage studies arising from new connections or limitations**
  New and existing power quality limitations may be identified when performing studies to analyse new load connections or loading limitations in the network.

The increasing number of over-voltage limitations was almost exclusively as a result of the coincident increasing penetration of roof-top PV. These were predominately identified as part of compliance testing on PV installations. The subsequent reduction in customer over-voltages is attributed to the introduction of specifications for the performance of the inverters installed as part of PV installations.

We have identified that a number of customer energy meters within the network have the ability to transmit voltage information. We are investigating activating this function and collating the information to provide measured power quality information. This will provide the capability to identify and improve power quality in the distribution network.

#### 4.6.5.3 Compliance process (distribution)

We continually investigate identified power quality limitations. Limitations are generally addressed in two ways:

1. **Confirmed major non-compliance**
   We investigate and assess major non-compliances to identify likelihood of impact. Where we consider the level of risk (ie customer service, voltage, power factor etc.) in continuing with the existing arrangement unacceptable, we undertake corrective action; and
2. **Confirmed minor non-compliance**
   We monitor minor non-compliances for 12 months following confirmation. We apply corrective action where the level of exceedance increases.

#### 4.6.5.4 Corrective action (distribution)

We continually undertake corrective action programs to address power quality limitations. Projects are generally undertaken in the low voltage network to address specific power quality limitations. Examples of projects we commonly undertake in the low voltage network are:

- transformer re-tapping;
- circuit phase rebalancing or load shifting;
- transformer upgrade;
- circuit split through the introduction of a new transformer; and
- conductor upgrades.

Work may extend into the medium voltage network to address multiple limitations through a single upstream solution. The most commonly selected solutions in these cases are:

- regulating transformer installation or repositioning; and
- conductor upgrades.

In addition to our continuing corrective action programs, we propose two trial projects to more economically address power quality limitations than traditional corrective measures. These are detailed in Section 6.5.9.

**Table 4-11: Customer feedback on over and under voltage limitations**

| Category | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|
| Over-voltage | 82 | 100 | 146 | 129 | 98 |
| Under-voltage | 49 | 32 | 36 | 25 | 19 |
| Total | 131 | 132 | 182 | 154 | 117 |

# 5
# Energy and demand forecast, and the supply-demand balance



## Overview

This chapter presents the electricity demand forecasts and the anticipated supply-demand balance of the Tasmanian power system. We present an overview of our forecasting methodology and the 10-year energy and demand forecasts for Tasmania, with comparison to the previous year's forecast. This chapter also includes the state-level generation capacity forecast, including possible new generation developments, and presents the generation capacity and energy adequacy over the forthcoming 10 years.

## 5.1 Demand forecasts and the planning process

Each year we produce forecasts of the future use of our network. We prepare forecasts for the energy consumption and maximum demand at a state-level, and for maximum demand at each of our transmission-distribution connection points, zone substations and distribution lines.

The demand forecast is a key component of the network planning process. We use the demand forecast to identify the timing of the occurrence of capacity and other technical limitations in the network. This helps to understand the future challenges of the network and the areas which are of particular interest; however it is not the only factor that drives network investment. As detailed in Section 2.3.1, we analyse potential network limitations and consult with customers to ensure that a limitation presents sufficient risk and the proposed solution provides sufficient benefit prior to investing in augmenting the network, or pursuing other non-network options. As part of this process, we conduct sensitivity analysis to determine the impact a change in the demand forecast may have on the timing of a limitation, its severity, or the preferred solution for addressing it.

Electricity consumption and demand peaked in Tasmania in 2008. The subsequent reduction coincided with the global financial crisis and low economic growth in Tasmania, with gross state product growing at less than 1 per cent per annum. Demand decreased on both the distribution network and from transmission-connected customers. It has begun to recover in recent years, with demand from transmission-connected customers now at its highest ever level. Energy consumption and maximum demand was down in 2016 due to major industrial customers reducing their demand to assist with energy storage levels during the period of low rainfall and concurrent Basslink outage. We forecast a modest increase in electricity consumption over the next 10 years, aligned with forecast continued economic growth in Tasmania. There is minimal augmentation investment associated with this increase, though, as demand is generally recovering only and not forecast to again reach 2008 levels until the end of the 10 year planning period.

The results of the demand and energy forecasts are available to download from our website http://apr.tasnetworks.com.au. A summary of this information provided is available in Appendix I.1.

## 5.2 Forecasting methodology

Each year we produce demand and energy forecasts at state-level and connection point level. Our forecasts are based upon economic scenarios and inputs developed by the National Institute of Economic and Industry Research (NIEIR). These economic scenarios model a high, medium and low performing Tasmanian economy and the resulting impact on electricity consumption in the state. The medium economic scenario is considered the most likely to occur. The state level forecasts produced by NIEIR are reconciled with connection point forecasts developed by TasNetworks.

Each economic scenario has three temperature variation scenarios. In total, nine forecast scenarios are produced. The three sub-scenarios are presented as a probability of exceedance (POE) and reflect the one in ten, five in ten, and nine in ten year temperature events (10 per cent POE, 50 per cent POE and 90 per cent POE respectively). We plan the network to 50 per cent POE forecasts.[35] At the state level, there is approximately a one year difference in winter maximum demand between the 10 per cent and 50 per cent POE forecasts.

More detailed information on our forecasting process, at both state and connection point level, is presented in Appendix I.

## 5.2.1 Factors affecting forecast

This section presents the economic indicators and other factors that influence the energy and demand forecasts. There are four key economic indicators to the forecasts, with gross state product providing the biggest influence. The other factors influencing the forecasts are changes in electricity prices, changes in usage from large customers (including new developments), and the impact of photovoltaic and other embedded generation. These are the factors prepared by NIEIR in its preparation of the load forecast.

*35 Previous APRs stated the distribution network was planned to 50 per cent POE and the transmission network to 10 per cent POE. We have consolidated our planning approach such that the whole network is now planned to 50 per cent POE.*

### 5.2.1.1 Gross state product

Tasmanian gross state product (GSP) is one of the key inputs to the forecast. NIEIR's forecast model has a good correlation between GSP and electricity usage at the economic sector level. The GSP forecast includes three scenarios: base, high and low. The base scenario is considered most likely and drives the medium forecasts.

Figure 5-1 presents the historic and forecast Tasmanian overall GSP growth rate from 2009–10 to 2025–26. There has been slight growth in the economy in Tasmania in recent years. Since 2009–10, the GSP growth has averaged only 0.2 per cent per annum. By comparison, in the ten years to 2009–10 Tasmanian GSP growth was 2.0 per cent per annum. The main factors that contributed to the weakness in the Tasmanian economy in recent years have been:

- weak and stagnant growth in private business investment;
- reductions in public sector capital expenditures and weak growth in government consumption expenditures; and
- slow growth in private consumption expenditures.

Tasmanian GSP growth is forecast to recover somewhat to average 1.2 per cent per annum to 2025–26. This is similar to the economic growth experienced in 2013–14 and 2014–15. Tasmanian GSP growth to 2025–26 for high and low economic growth scenarios is forecast to average 1.7 and 0.8 per cent per annum, respectively.

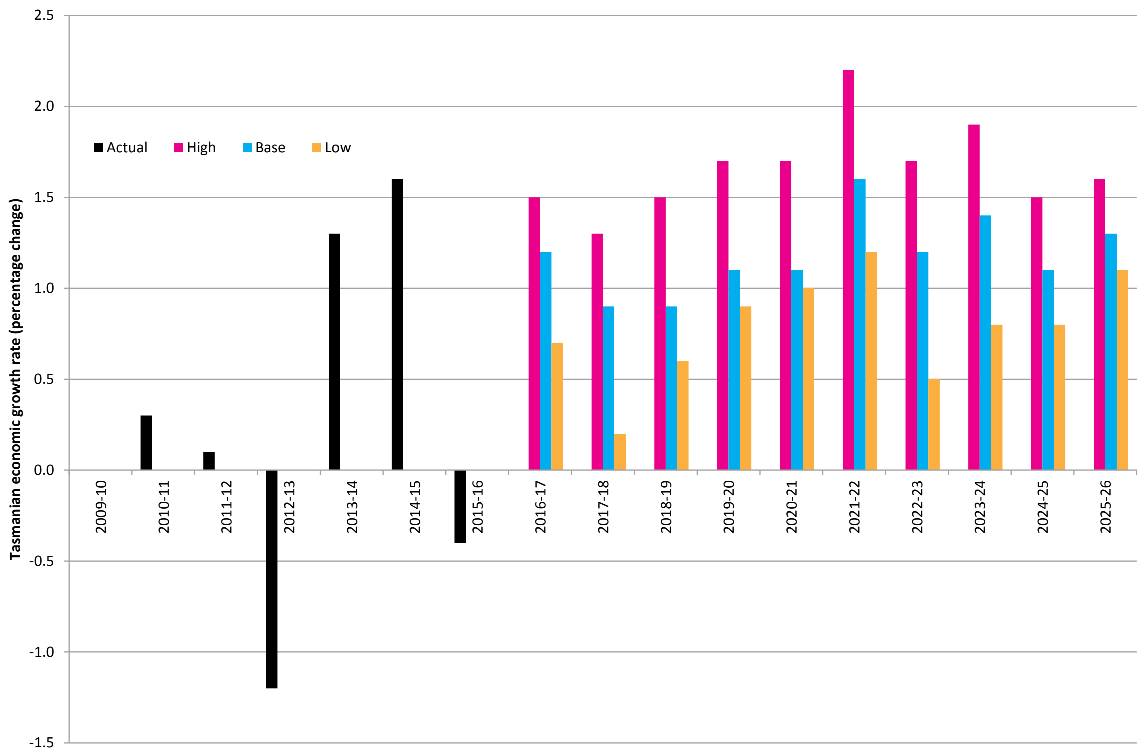



**Figure 5-1: Tasmanian GSP growth**

**Table 5-1: Percentage growth of other economic indicators to load forecast**

| Economic indicator | 2014–15 | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2016–22 average |
|---|---|---|---|---|---|---|---|---|---|
| Household consumption expenditure | 1.5 | 1.5 | 1.1 | 1.3 | 1.3 | 1.4 | 1.4 | 1.5 | 1.3 |
| Private dwelling investment | 3.9 | 3.8 | 2.9 | -3.2 | 2.6 | 2.6 | 1.8 | 1.9 | 1.5 |
| Population | 0.3 | 0.3 | 0.5 | 0.4 | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 |

#### 5.2.1.2 Other economic indicators

Less significant than GSP, there are three other material economic indicators to the load forecast: household consumption expenditure, private dwelling investment and population. Additional economic indicators to these have minimal influence on the load forecast.

Table 5-1 presents the three other material economic indicators to the forecast and their forecast growth rates to 2021–22. The growth rates presented are for the base (medium) scenario. The growth of both household consumption expenditure and private dwelling investment is expected to be slow over the next six years, and remain below the growth rates of the last two years. Slow private dwelling investment is due to household debt saturation and high, by recent historical standards, public sector deficits. The rate of population growth is expected to improve, however remain subdued at 0.5 per cent per annum.

#### 5.2.1.3 Electricity prices and price elasticity

Electricity prices impact electricity consumption. As electricity prices increase, less electricity is consumed with the reverse also holding true. The forecasting model includes price elasticity by class. The long run price elasticity implies effects of consumption response due to price changes over 15 to 20 years. In practice, most of the effect has occurred by year four or five. Price elasticity applies to residential, commercial and industrial loads. Transmission-connected customers are treated on a customer-by-customer basis and do not include price effects.

The long-run own price elasticity[36] of demand, measured as percentage change in electricity sales per percentage increase in price, for each class is as follows:

- residential: -0.25;
- commercial: -0.20; and
- industrial: -0.30.

For clarity, the -0.25 for residential implies that a 10 per cent increase in residential prices will reduce residential sales by 2.5 per cent.

NIEIR forecasts the electricity price to increase by an average of 0.2 (residential) and 1.8 (business) per cent per annum to 2025–26. Prices may increase from a future carbon policy, however competition between gas and electricity may not be significant to electricity price changes as gas prices will also rise. The impact is currently indeterminate as the introduction of any future carbon price is unknown.

#### 5.2.1.4 Impact of gas supply on electricity sales

The uptake of natural gas by Tasmanian households has been relatively slow, with growth predominantly expected from new, rather than existing, dwellings. Greater uptake is forecast in the commercial and industrial sectors, typically in boilers, kilns and cooking as well as co-generation. The substitution of natural gas for electricity is forecast to have a small, but gradual, impact on residential electricity sales and will dampen growth in commercial sales.

#### 5.2.1.5 Major industrial and other transmission-connected customers

Three of the four major industrial loads can be highly variable and may be well below their individual maximum demands at the time of the distribution network maximum demand. As major industrials are a high proportion of overall load, it can create large year-on-year variations on state-level maximum demand. As it can be difficult to forecast these variations, the maximum demand forecast forecasts the major industrial load contribution to be near its maximum output.

Under the medium growth scenario, growth in major industrial load and other transmission-connected customers is forecast to come from existing customers. The high growth scenario forecasts higher growth from existing customers and the addition of a new major industry. The low growth scenario forecasts the loss of approximately 100 MW of major industrial load and the reduction in demand from some other transmission-connected customers.

#### 5.2.1.6 Roof-top photovoltaic generation

Roof-top photovoltaic (PV) are behind-the-meter generation systems offsetting energy consumption, predominantly in the residential and business sectors. Tasmanian winter and summer maximum demand days occur during cold weather conditions when the output from PV systems is low; hence PV penetration has more of an impact on reducing energy consumption than on reducing the maximum demand.

NIEIR developed a growth forecast for PV penetration, which is included in the energy forecasting model. There is currently in excess of 27,400 PV systems installed in

*36 The own price elasticity is the price elasticity of each class.*

Tasmania, with an installed total capacity of 96.4 MW.[37] NIEIR forecast this to rise to 167.4 MW installed capacity and 40,000 installations by 2025.

#### 5.2.1.7 Government policy

The forecast incorporates the impact of national and state government policy on electricity consumption in Tasmania, through its impact to electricity prices presented in Section 5.2.1.3. The policies relate to both large industrial and domestic energy users, and include matters relating to:

- climate change, being the Emissions Reduction Fund and State Renewable Energy Strategy;
- renewable energy, including the Renewable Energy Target, support for renewable energy projects, and roof-top PV feed-in tariffs; and
- energy efficiency and demand management, including appliance standards, building requirements, energy productivity, and electric vehicles.

*37 Installed capacity at the end of 2015–16. This includes PV systems registered under the Small-scale Renewable Energy Scheme (SRES) only (systems size no more than 100 kW and annual output less than 250 MWh). http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations*

### 5.2.2 Forecast model verification

To validate the econometric model used for maximum demand forecasting, a back cast (a backward looking forecast) of winter maximum demand has been conducted and compared with actual figures. The back cast is based on daily reference temperatures and actual economic conditions. Variations in transmission-connected customer loads between what is modelled and their actual contribution to maximum demand can contribute up to 40 MW back casting error, although more typically it is around 30 MW. The model verification, showing the comparison of actual and back casted values for the past 10 years, is presented in Figure 5-2.

The back casting indicates the model has produced forecasts that are representative of likely maximum demands with known economic conditions. The model is optimised annually to ensure it captures the changing drivers of maximum demand as technology, behaviour and policy changes.

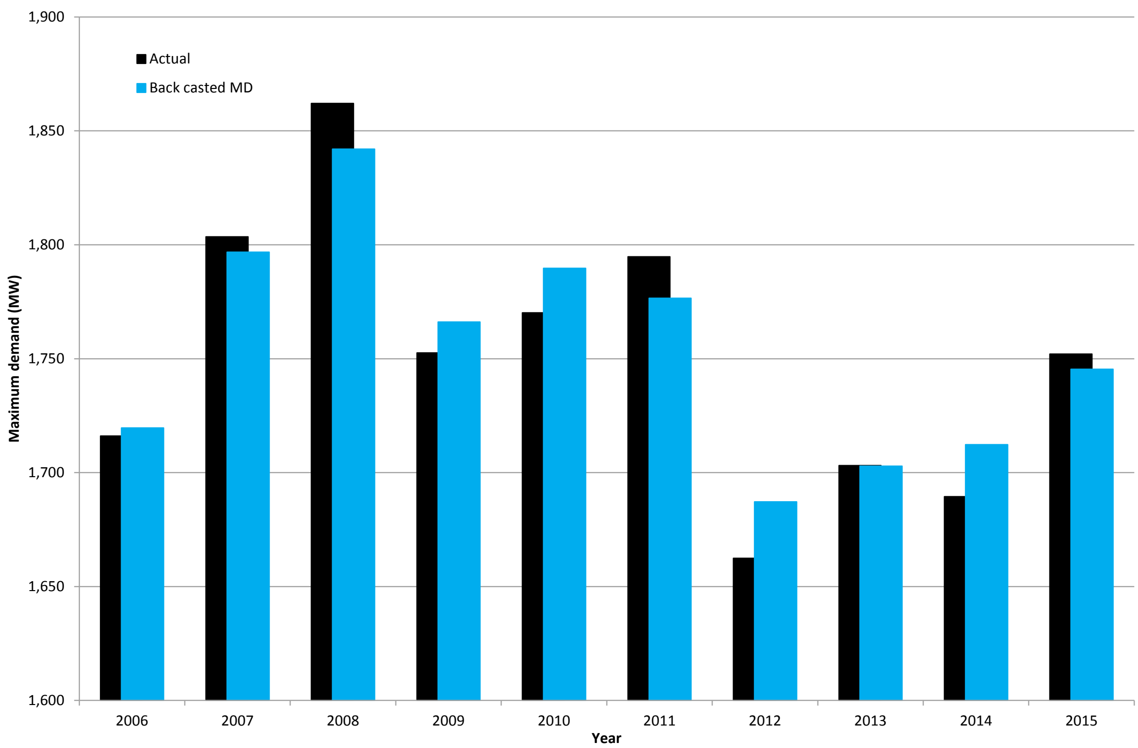



**Figure 5-2: Back cast of Tasmania winter maximum demand**

## 5.3 Tasmanian forecast energy and maximum demand

### 5.3.1 Tasmanian forecast energy

Figure 5-3 presents actual and forecast electrical energy generation required to meet consumption demand in Tasmania to 2026 for the medium, high and low growth scenarios. This is the electrical energy generated at power stations and wind farms connected to the transmission network, and includes losses incurred in the delivery to customers.

Energy generation to meet Tasmanian demand has reduced by six per cent since its peak in 2007–08. This is primarily attributed to a reduction in industrial and commercial production, as well as increased penetration of roof-top photovoltaic and other embedded generation and increased energy efficiency in homes and businesses. Contributing to low energy generation in 2015–16 was load reductions by transmission-connected customers to assist with maintaining energy storage levels, as outlined in Section 4.1.3.

We forecast a recovery in energy generation at 0.8 per cent per annum to 2026 in the medium growth forecast with forecast economic growth, as outlined in Section 5.2.1.

The forecast average annual growth for the low scenario is 0.2 per cent – excluding the step-change from the assumed reduction in major industrial load between 2021 and 2023 assumed in this scenario. The forecast average annual growth for the high scenario is 1.8 per cent. This is based on more favourable economic conditions with an increase in major industrial load, including a new large customer connecting to the transmission network.

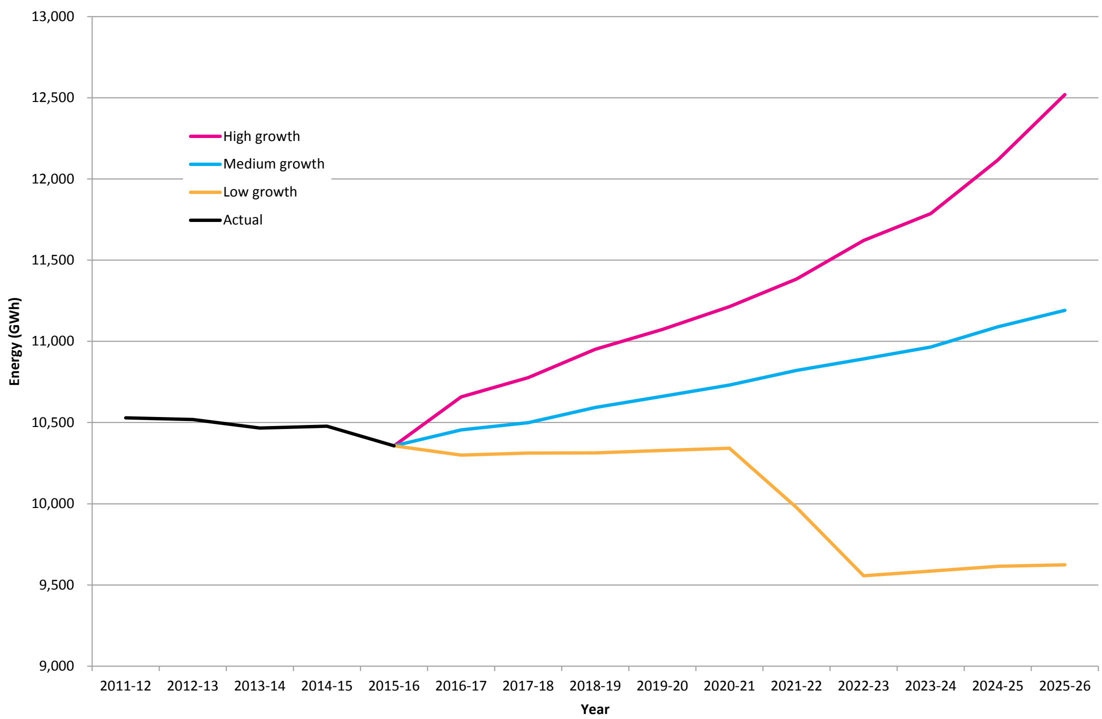



**Figure 5-3: Forecast of total Tasmanian electrical energy sales**

### 5.3.2 Tasmanian forecast maximum demand

The maximum demand forecast represents the demand on generation (and Basslink import) to meet the maximum Tasmanian load (ie the load on the transmission network). This includes losses in the electricity network.

It is important to note that the differences between the high, medium and low growth scenarios reflect both different underlying economic growth and different load assumptions for industrial customers as detailed in Section 5.2.

Figure 5-4 and Figure 5-5 present winter and summer maximum demand respectively for each scenario. The figures present the actual recorded maximum demand for the last five years, the actual values temperature-corrected[38], each of the medium, high and low growth scenarios, and for comparison purposes the growth forecast used in our 2016 APR.

*38 The actual maximum demands recorded are temperature corrected to allow like-for-like comparison with the forecasts, which are prepared to 50 per cent POE.*

**Temperature correction and maximum demand**

Temperature is a key factor contributing to daily demand. In Tasmania, demand for electricity generally increases as reference temperature decreases. The reference temperature is a combination of that day's minimum temperature and the previous day's maximum temperature. The maximum demand does not necessarily occur on the day of the lowest reference temperature however, as there are many factors which contribute to demand.

Temperature correction, defined in probability of exceedance (POE) terms, is used to answer the question 'what would the maximum demand have been if it occurred on the day of a nominated probability of exceedance?'. We plan for 50 per cent POE. Probability of exceedance refers to the probability that the reference temperature will be higher than the reference temperature for the nominated POE, not what probability the actual maximum demand has of exceeding the temperature corrected maximum demand.

This means we plan for what the maximum demand would be if it occurred on the day of the reference temperature being at the 50th percentile. Our temperature correction process is detailed in Appendix I.2.1.

#### 5.3.2.1 Winter maximum demand forecast

The Tasmanian maximum demand forecast is presented in Figure 5-4. The winter maximum demand had been moderately increasing in recent years, until a sharp reduction in 2016 brought it back to the approximate maximum demand experienced in 2012. This reduction was predominantly a result of customer response to the Basslink outage and associated energy storage levels in the first six months of 2016. For each of the previous five years, the actual maximum demand has increased when temperature correction is applied. The text box on this page explains the relationship between temperature correction and maximum demand.

The maximum demand is made up of contributions from the distribution network and transmission-connected customers (dominated by large industrial customers), and usually occurs at or near the distribution network maximum demand. This did not happen in 2016 because, at the time of distribution network maximum demand, demand from some transmission-connected customers was down to assist with maintaining energy storage levels. When transmission-connected customer demand returned to normal levels following Basslink return to service, the demand on the distribution network had reduced.

Despite this year's low Tasmanian maximum demand, the maximum demand on the distribution network has increased since 2014 and the maximum demand from transmission-connected customers is at its all-time highest level. As such, we forecast the maximum demand to recover and continue to moderately increase in line with the economic conditions outlined in Section 5.2.1. The forecast average growth rate in winter maximum demand is 1.1 per cent per annum for the medium scenario. The forecast average growth rate for the distribution network maximum demand itself is 1.7 per cent per annum.

The forecast average winter growth rate for the low growth scenario is 0.4 per cent per annum. This is the growth rate excluding the step-change reduction in demand. This scenario predicts a drop in maximum demand from 2020 to 2022 due to a reduction in existing transmission-connected load, including the assumed loss of around 100 MW of major industrial load.

The forecast average winter growth rate for the high growth scenario is 2.2 per cent per annum. The better economic conditions are forecast to create an environment where a hypothetical new transmission-connected customer connects in 2023, and existing transmission-connected customers increase their demand.

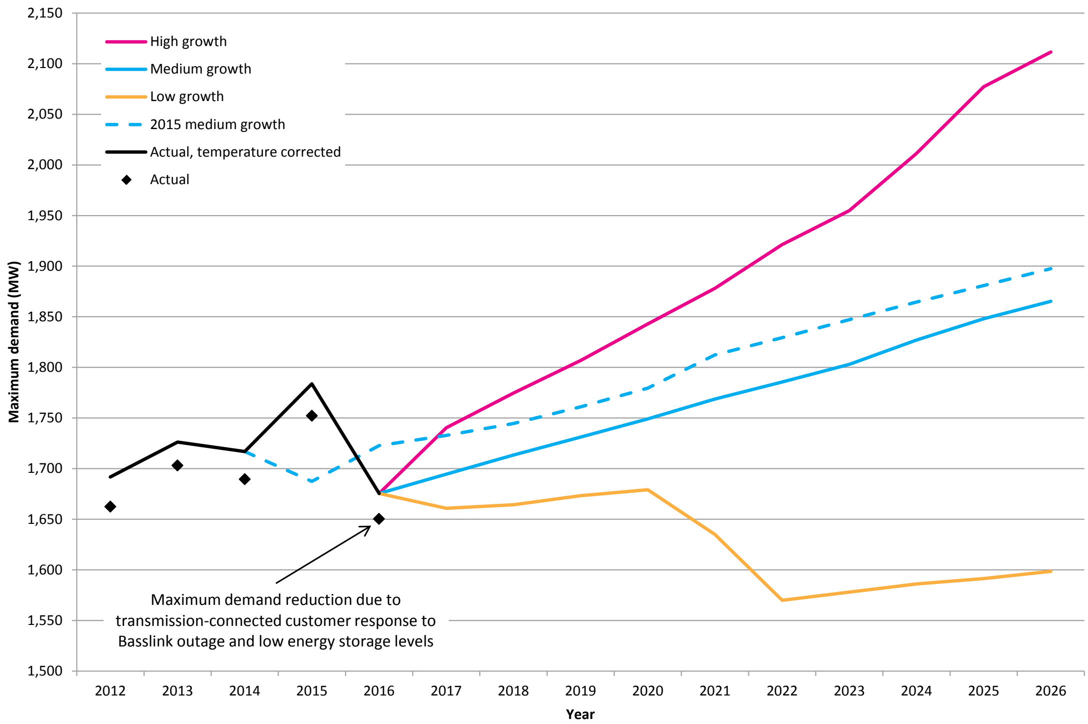



**Figure 5-4: Forecast of total Tasmanian winter maximum demand**

**TasNetworks vs AEMO forecast**

AEMO prepares state-level energy and maximum demand forecasts and transmission-distribution connection point forecasts for each region in the NEM. Our forecasts differ in inputs, scenarios and model to AEMO's forecasts. At a state-level, AEMO forecasts growth in 2017, reduce through to 2021 (to 2014 levels), then growth again at an average 0.4 per cent per annum. Our forecast average maximum demand growth is 1.1 per cent per annum. Despite our maximum demand forecast being higher than AEMO's, it is forecast to remain within the state-level historic peak in 2008. As such, under either forecast there is only very small augmentation programs forecast as demand remains within historic levels.

### 5.3.2.2 Summer maximum demand forecast

The summer maximum demand forecast is presented in Figure 5-5. The summer maximum demand occurs when temperatures are low, not during high temperatures, which is what drives network maximum demands in most other Australian jurisdictions. Historically it occurs in either early December or late February. It is forecast to grow at an average rate of 1.2 per cent per annum under the medium growth scenario, equivalent to the summer maximum demand forecast provided in the forecast in our 2016 APR.

The summer low growth rate is 0.4 per cent per annum, excluding the step-change assumed loss of major industrial load, detailed previously. The average growth rate for the summer high growth scenario is 2.2 per cent per annum.

## 5.4 Demand profile

Figure 5-6 presents the Tasmanian demand profiles on the maximum demand day in winter and summer for the past two years. The maximum demand day curve illustrates the load profiles and the greater demand variability for electrical energy in winter compared with summer.

The 2016 winter maximum demand was lower than that in 2015. The peak was again an evening peak; however the corresponding morning peak did not occur because the winter maximum demand day in 2016 occurred on a Saturday – the first recorded weekend maximum demand day. This occurred because the Tasmanian maximum demand did not occur at or near the time of distribution network maximum demand, as it normally would, due to reduced major industrial load as detailed in Section 5.3.2.1. We expect that this is a 'one-off' occurrence and there will be typical maximum demand profile again from 2017.

The summer maximum demand profile in 2015–16 was similar to that experienced in 2014–15. There was a slight increase in both the morning and evening peaks.

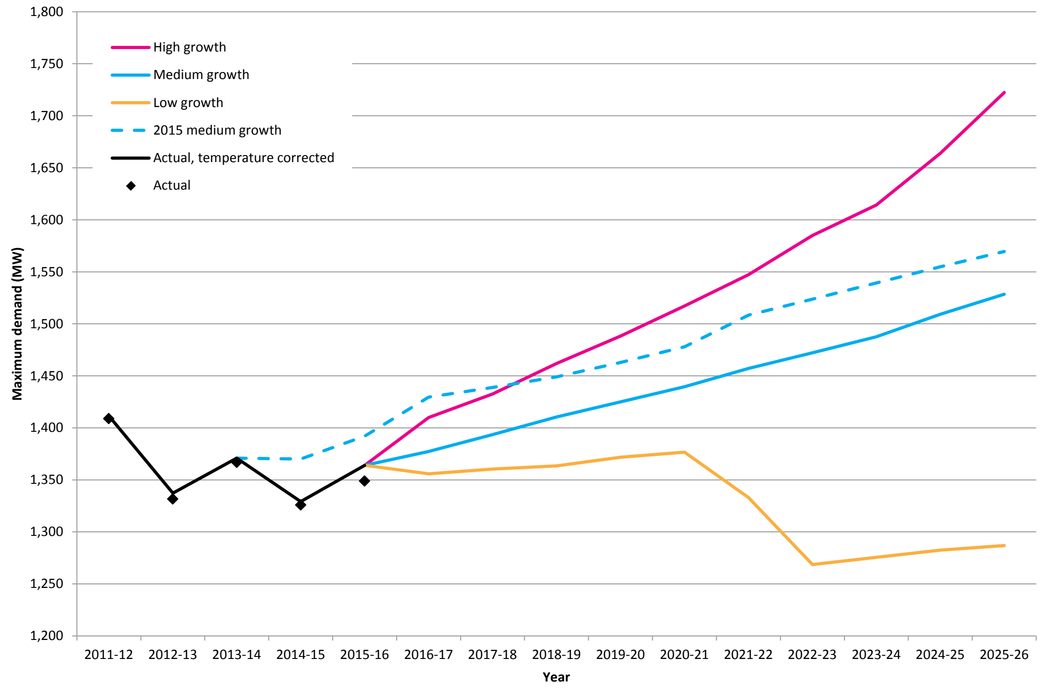



Figure 5-5: Forecast total Tasmanian summer maximum demand

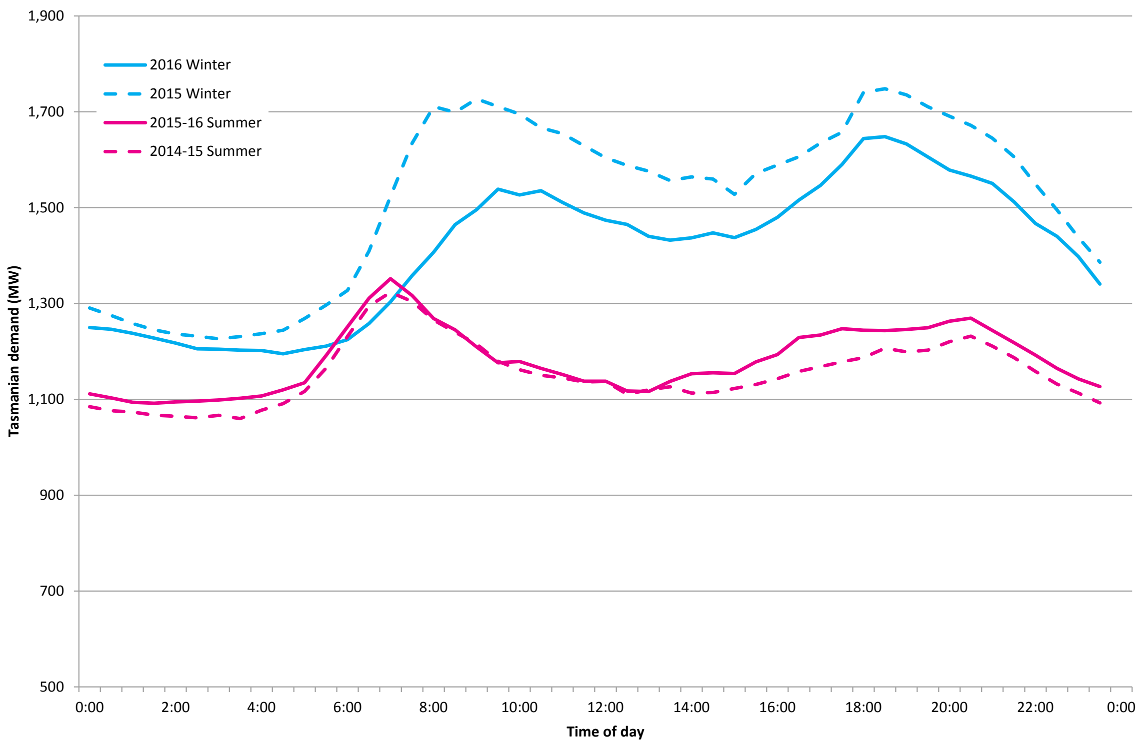



Figure 5-6: Winter and summer maximum demand curves

## 5.5 Intra-regional generation projections

This section presents a summary of our intra-regional (within Tasmania) generation projects. It includes our current generation capacity, type of generators and any forthcoming generation developments.

### 5.5.1 Generation capacity

Table 5-2 presents the total existing generation capacity, including Basslink import, connected to the transmission network now and at the end of the planning period. This excludes embedded generation in the distribution network, which is not directly modelled in transmission planning studies, but its impact is reflected as a reduction in connection point demand. The details of individual transmission-connected and embedded generation sites are listed in Appendix F.

There have been changes to the operation and plans for Tamar Valley Power Station – the only transmission-connected gas-fired power station in Tasmania – since the 2016 APR. Tamar Valley Power Station consists of a 208 MW combined cycle gas turbine (CCGT) and 178 MW of open cycle gas turbines. The operation of the CCGT has varied in recent years following it being transferred to Hydro Tasmania in 2013 and the low rainfall periods and Basslink outage in 2015–16. The CCGT is currently identified as withdrawn from service; however it has the ability to be recalled to service in less than three months.[39,40] As such, it has not been included in the modelling for the capacity balance (Section 5.6.1) and energy balance (Section 5.6.2) components of the supply-demand balance analysis. It is included in the extended failure of generation source scenarios (Section 5.6.3) due to its availability to be recalled within a short timeframe for energy security purposes, if required. The previously advised withdrawal of Bell Bay Three Power Station, part of the open cycle gas turbines at Tamar Valley Power Station, from January 2018 will no longer occur.[41] This has been re-included in our supply-demand balance assessment for the 2017 APR.

Generation sites are periodically removed from service for planned maintenance and other activities. These short-term reductions in generation capacity have not been accounted for here because these reductions are generally out of peak demand periods and are scheduled cognisant of general capacity availability. These short-term reductions are included in AEMO's capacity balance assessment.[41]

**Table 5-2: Generation capacity**

| Generation type | Number of sites | Total name-plate rating (MW) |
|---|---|---|
| Hydro | 25 | 2,310 |
| Gas | 1 | 178 |
| Wind | 3 | 308 |
| Basslink imports | 1 | 478 |
| Total | 30 | 3,274 |

### 5.5.2 Prospective generation developments

We are aware of three current publically announced generation development proposals. Table 5-3 presents their project names, proponent, capacity, type, status and their websites. As these prospective developments are not yet committed, they have not been included in the supply-demand balance assessment in the following section.

39 *Table 5, Electricity statement of opportunities for the National Electricity Market, Australian Energy Market Operator, August 2016. http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities*

40 *Despite its identified withdrawal, the CCGT has been operating during summer 2017 to support storages and maintain it in optimal condition summer https://www.hydro.com.au/about-us/news/2017-01/routine-ccgt-operation*

41 *AEMO generation information, TAS 2016 November 18: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information*

**Table 5-3: Generation developments in Tasmania**

| Name | Proponent | Capacity (MW) | Type | Status | Website |
|---|---|---|---|---|---|
| Granville Harbour Wind Farm | West Coast Wind Pty Ltd | 99 | Wind | Publicly announced | http://www.westcoastwind.com.au/ |
| Low Head Wind Farm | Low Head Wind Farm Pty Ltd | 30 | Wind | Publicly announced | http://www.lowheadwindfarm.com.au/ |
| Wild Cattle Hill Wind Farm | Wild Cattle Hill Wind Farm Pty Ltd | 200 | Wind | Publicly announced | AEMO generation information[41] |

# 5.6 Supply-demand balance assessment

The supply-demand balance is an important consideration in assessing the future adequacy of the Tasmanian power system. It assesses the adequacy of existing generation in meeting the forecast demand and energy requirements. A lack of adequacy provides an indication that additional generation may be required within the region.

Tasmania's hydro-dominated generation system is more exposed to energy constraints than demand constraints. This is mainly due to hydro inflow variation during the year and most of the capacity is available even under very dry conditions and low storage levels for short periods. Notwithstanding, hydro generation availability is affected by the availability of water and maintenance needs of generators and water ways. Even with overall water storage at reasonable levels it is possible that some hydro generating plants associated with small and medium storages may not be available due to planned or unplanned outages.

This section considers:

- the capacity of the existing and future generation assets to meet the forecast maximum demand over the next 10 years;
- the electrical energy generation adequacy compared with forecast energy consumption over the next 10 years; and
- the impact to Tasmania's energy security in the event of an extended outage to each of Tasmania's three major energy sources.

The analysis presented in this section is part of our obligation to produce a Tasmanian Annual Planning Statement (TAPS). We acknowledge that the current Tasmanian Energy Security Taskforce review into energy security in Tasmania may lead to different or additional requirements in performing the supply-demand balance assessment in the future, and that the responsibility for energy security in Tasmania may change.

The methodology and assumptions detailed in this section are our normal planning assumptions and may differ to some extent to how the power system is managed operationally.

## 5.6.1 Capacity balance

Generation capacity is the sum of the name-plate ratings of all available generators. The capacity balance determines the ability of the generating system to meet the network maximum demand now and in future years.


### 5.6.1.1 Methodology and assumptions

As detailed in Section 5.5.1, there is currently 3,274 MW of transmission-connected generation capacity, including Basslink import. The use of Basslink is dependent on market conditions and the availability of generation elsewhere in the NEM.

Due to the intermittent nature of wind generation, we do not consider its full capacity in the capacity balance assessment. The contribution from wind generation at the time of maximum demand is assumed to be five per cent of its peak capacity. This is the 90 per cent confidence level of wind during the top 10 per cent of demand since 2014. Accordingly, the total existing capacity assumed for capacity balance studies is 2,981 MW. There are currently no committed future generation developments in Tasmania.

This available capacity is compared against medium, low and high demand growth scenarios. Furthermore, the available excess capacity is tested for the following three outages:

- Basslink (478 MW);
- a major hydro scheme (ie Gordon Power Station, 432 MW); and
- the gas supply network (ie Tamar Valley Power Station, 178 MW).

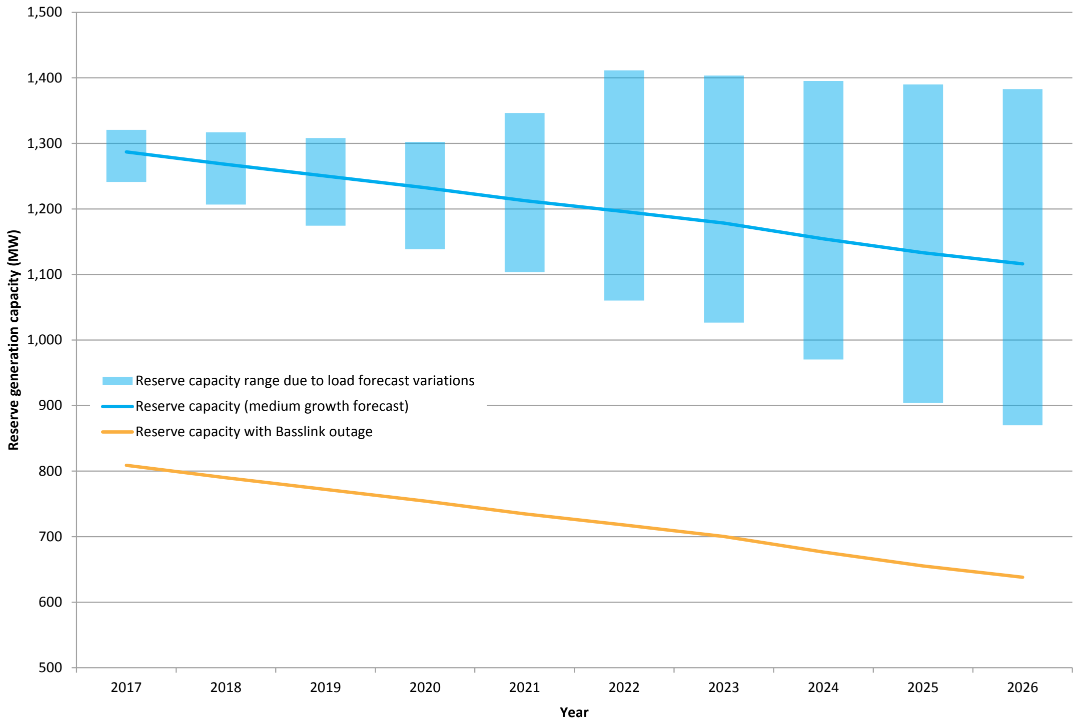



**Figure 5-7: Reserve capacity variation due to load variations and severe outage**

#### 5.6.1.2 Results summary

The analysis shows that there is sufficient generation capacity to meet peak demand until at least 2026 for all three scenarios. Of the three scenarios, the highest capacity impact is from a Basslink outage. The expected excess generation capacity under a Basslink outage against medium growth forecast is shown in Figure 5-7. Furthermore Figure 5-7 shows the possible excess generation capacity range as per the medium, low and high growth scenarios. Excess generation capacity remains almost 900 MW under high growth scenario, and almost 1,400 MW under the low growth scenario to 2026. Under a Basslink outage, reserve capacity remains over 600 MW by 2026, under the medium growth forecast.

## 5.6.2 Energy balance

The energy balance considers the ability of Tasmania's generation sources, including Basslink, to meet future Tasmanian electrical energy needs for a range of generation and energy growth scenarios. As the main source of electrical energy in Tasmania is from hydro generation, the energy balance takes into account three rainfall scenarios (wet, medium and dry) which impacts the amount of water available in hydro storages.

#### 5.6.2.1 Methodology

We use a market simulation model to determine long-term forecasts of energy availability from all energy sources. It models the Tasmanian generation system (hydro, wind and thermal) and Basslink. It simulates market behaviour within the Tasmanian region by optimising the dispatch of generation (ie dispatching lowest cost generation while maintaining network security constraints) to meet the Tasmanian demand, maintain a reasonable storage position, and to trade across Basslink.

Our approach is to model hydro generation as a limited resource without assigning any price, and allow the model to dispatch hydro generation based on Victorian prices and the cost of thermal generation. With this approach, the model optimises hydro energy utilisation by replacing highest cost thermal generation with hydro generation.

Historical inputs include initial water volume, daily inflow and half hourly demand. Thermal fuel costs and hourly wind generation data are also included in the model. The model uses forecast Victorian energy prices based on 2015–16 half hourly regional reference prices to represent supply in Victoria. It considers periods where there is a supply shortfall as high prices and excess supply as low prices.

Generator company business imperatives and financial parameters have not been modelled explicitly. However, financial parameters have been included in an indirect manner with assumptions on fuel price and variable operation costs of thermal generators in Tasmania.

In addition to the generation system, the Tasmanian transmission network is represented by 28 nodes. Some of the network constraints, which affect energy dispatch, are also included in the model formulation. All hydro schemes are represented in the model.

#### 5.6.2.2 Assumptions

The following assumptions have been used in the simulation:

- three independent inflow scenarios were included:
  - wet (based on 10 per cent POE rainfall condition) – 10,535 GWh total inflows each year;
  - medium (based on 50 per cent POE rainfall conditions) – 8,740 GWh total inflows per year;
  - dry (based on 90 per cent POE rainfall conditions) – 7,181 GWh total inflows per year.
- the future energy demand was developed based on the historic load profile and 50 per cent POE maximum demand forecast of each transmission-distribution connection point;
- generation capacity is as outlined in Section 5.5.1, and does not include the availability of the combined cycle gas turbine at Tamar Valley Power Station;
- the wind profile for each wind farm was based on their respective historical operating patterns;
- variable operation and maintenance costs and fuel prices for Tamar Valley Power Station gas turbines were sourced from publicly available information;[42]
- the initial water storage levels modelled for each sequence were the actual levels as at the beginning of 2017;[43]
- outages to generation plant have not been included, as these have minimal impact on long term energy supply;
- system Frequency Control Ancillary Services (FCAS) demand has been included in the model as constant demand; and
- medium and high energy growth scenarios have been assessed to determine the impact of energy growth rate variations.

The findings regarding the energy supply–demand balance assessment are dependent on the assumptions made about the demand, the forecast Victorian pool price and the heuristic controls in the simulation tool. Any changes to these assumptions will affect the results.

*42 Model developed for the NEM by AEMO*

*43 Sourced from Hydro Tasmania web site http://www.hydro.com.au/system/files/water-storage/storage_summary-4.xls and extrapolated for the year end.*

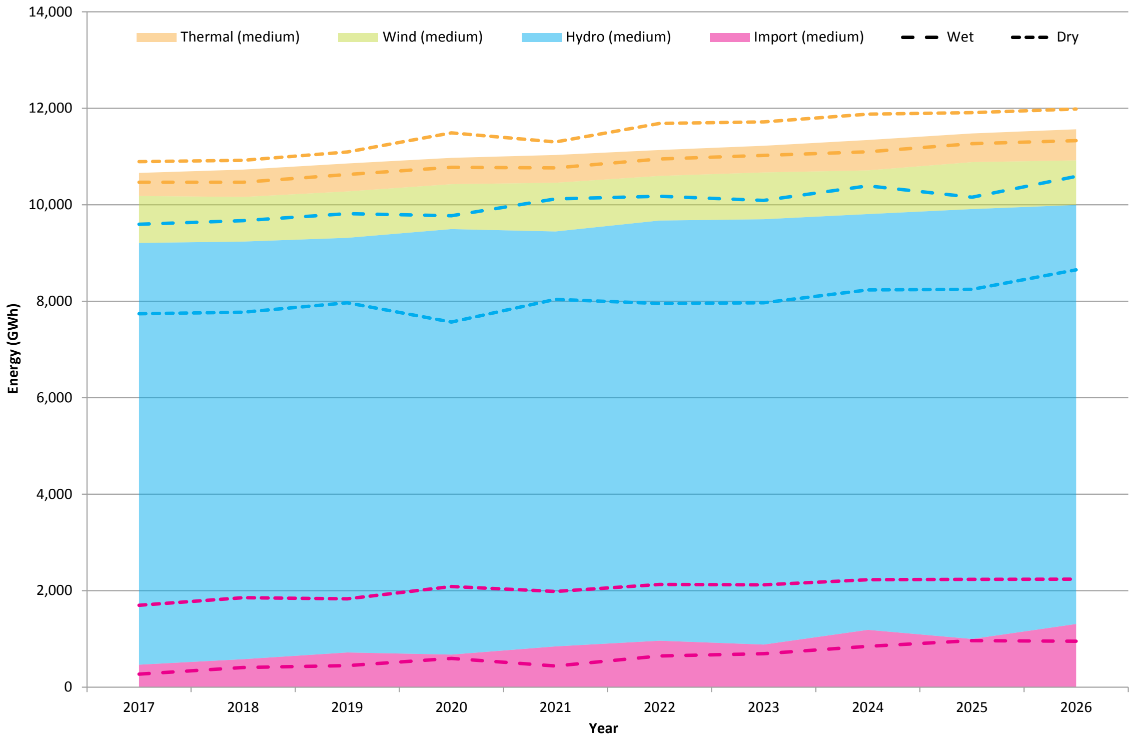



**Figure 5-8: Supply balance to meet the energy demand under medium energy growth**

### 5.6.2.3 Medium energy growth

The base scenario estimates the future energy balance with respect to the 2016 medium energy growth forecast and the variation of hydro inflows. Figure 5-8 shows the variations in expected supply share from the available generation sources to meet the future energy demand for each of the three hydro storage projections.

Figure 5-8 and Figure 5-9 present the medium rainfall scenario as the shaded areas, with the dashed lines representing the low and high rainfall variances. For the medium rainfall scenario the figure shows the contribution from each of the four generation types to meet the forecast energy demand. The short and long-dashed lines represent the variances of each generation type from the medium rainfall scenario under the dry (low rainfall) and wet (heavy rainfall) scenarios respectively.

Under the wet scenario there is additional hydro generation, resulting in less thermal generation and Basslink imports. Under the dry scenario, less hydro generation means a greater energy requirement from thermal generation and Basslink imports. Wind generation does not vary under the rainfall scenarios.

Figure 5-8 presents the following observations:

- there are no significant changes in the energy supply pattern as no new generation or retirements are expected during the study period; and
- increased imports from Victoria and thermal generation from open cycle gas turbines at Tamar Valley Power Station are the main contributor to meeting the future additional energy demand. Increased hydro output also makes a small contribution to supplying the future energy demand.

No unserved energy is expected during the 10-year planning horizon for the three inflow scenarios, based on the assumptions presented in Section 5.6.2.2 and all generation sources being available.

### 5.6.2.4 High energy growth

This scenario uses the same hydro assumptions as the base scenario, but considers the requirements under the high energy growth scenario. It is assumed that the economic factors favouring a high growth in energy demand would also favour growth in industrial demand. Figure 5-9 shows the expected supply share to meet a high energy growth forecast.

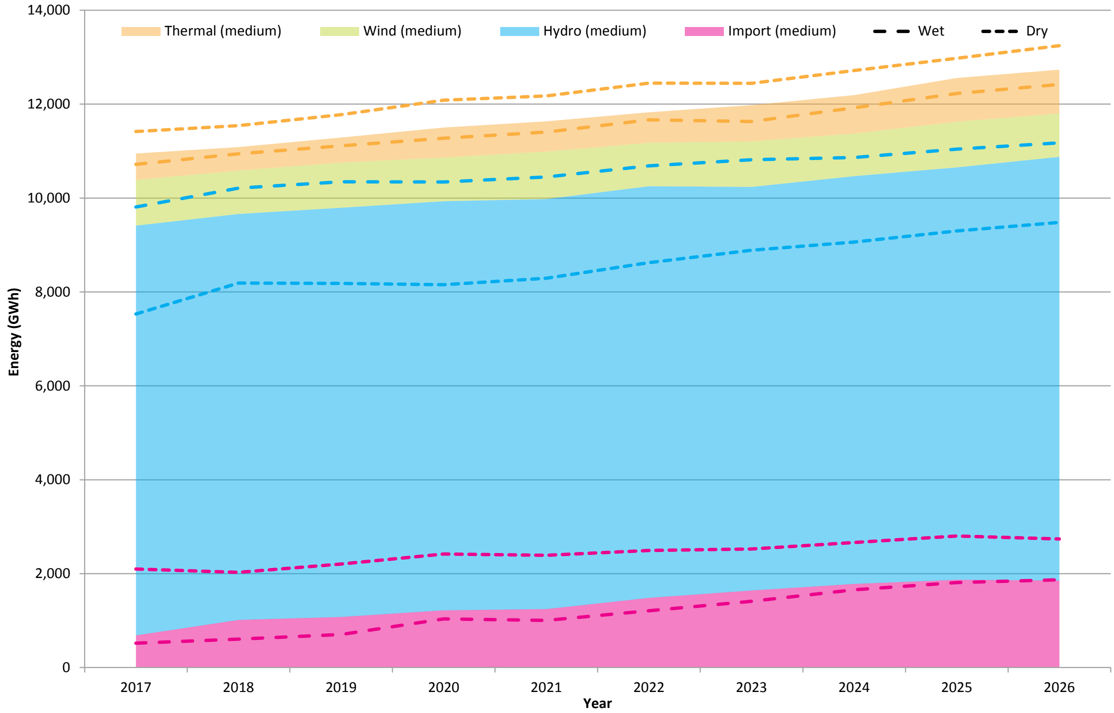



**Figure 5-9: Supply balance to meet the energy demand under high energy growth**

The contribution from all generation sources, including Basslink imports from Victoria, is significant in meeting the future demand under a high energy growth scenario. The additional contribution to meet the energy requirement, compared to the medium energy growth scenario, is from Basslink imports and thermal generation from the open cycle units at Tamar Valley Power Station. However, there is no unserved energy expected during the 10-year planning horizon under this scenario for the three inflow scenarios, based on the assumptions presented in Section 5.6.2.2 and all generation sources being available.

## 5.6.3 Extended failure of generation source

This scenario assesses the risks to the security of Tasmania's energy supply following the extended failure of a major generation source. That is, the near-term impact to hydro storages during an extended outage and the period of recovery following the generation source's return to service.

### 5.6.3.1 Methodology and assumptions

The assessment considers the extended failure of the following major generation sources:

- Basslink (478 MW);
- a major hydro scheme (ie Gordon Power Station, 432 MW); and
- the gas supply network (ie Tamar Valley Power Station, 383 MW).

The assessment has been performed using the same market simulation model, methodology and assumptions as used in the energy balance in Section 5.6.2. The following additional assumptions are used in this scenario:

- a dry year (low inflows) is modelled;
- the combined cycle gas turbine at Tamar Valley Power Station is available to support energy security requirements, as discussed in Section 5.5.1;
- the extended failure is assumed as a six-month failure for each outage; and
- the scenarios are analysed over 12 months, the six month outage followed by a six month period to return the storage levels to their initial levels.

As detailed in Section 5.6.2.3, Basslink is a net importer of generation in the energy balance base scenario. The analysis with all generation elements in service indicates that the storage levels fall in the first months of the calendar year and recover in later months. Therefore, the outages were considered from January to June for the analysis, because these would have a greater adverse impact on water storages.

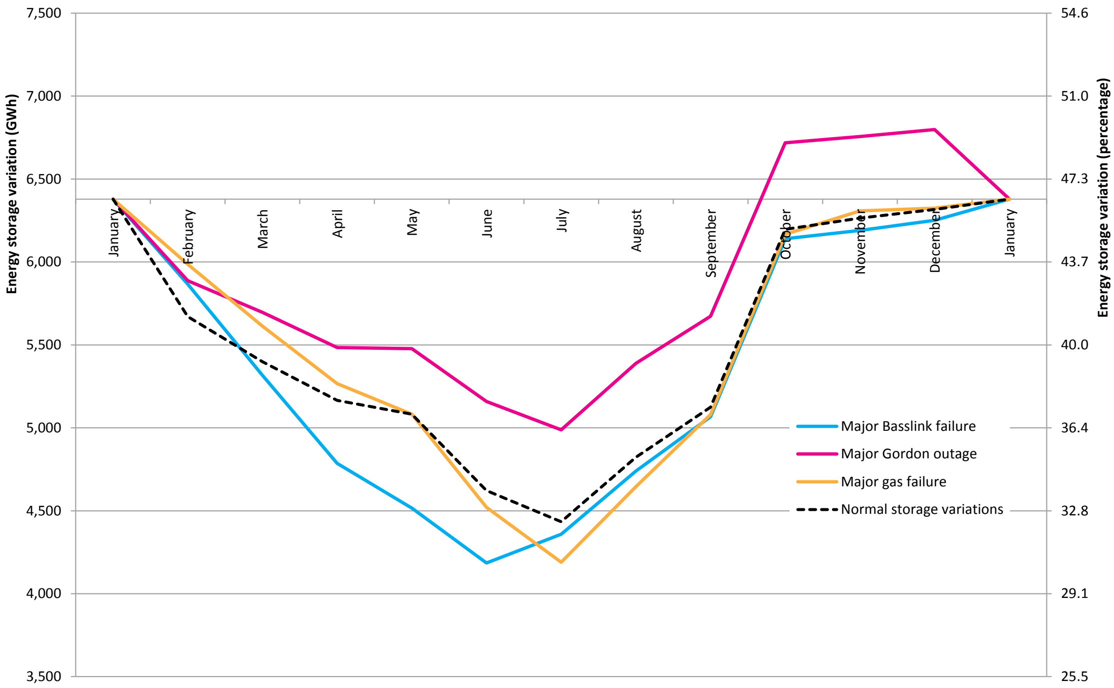



**Figure 5-10: Monthly hydro storage variation due to selected outages**

### 5.6.3.2 Results summary

Figure 5-10 presents the monthly energy storage variations under the three different system outages, against normal storage variations. The storage variation is shown with respect to the storage level at the beginning of January 2017.

As hydro inflows are low in initial months of the year, storage levels go down in that period and then start to recover in the later part of the year. Basslink flows are dependent on Tasmania and Victoria price differentials, with the Tasmanian price driven by hydro inflows amongst other things. In normal operation (ie without any major outages), the analysis indicates that Tasmania is a net importer of energy in most months, excluding January, May and June.

A Basslink outage would result in the lowest hydro storage level at the beginning of June during the outage. A Basslink outage reduces the reduction in storage level, compared to normal storage variations, in the net export months of the base case and the storage level falls further in other months. The expected reduction in energy storage due to a major Basslink outage is around two per cent of the total energy storage volume more than under normal storage variations.

A gas supply failure would bring the hydro storages to minimal level by the end of June. The loss of supply due to gas failure is compensated by extra import through Basslink and extra hydro generation during the outage period. A Gordon Power Station outage would result in an improvement in hydro storage levels due to the subsequent reduction in Basslink export. Note that Figure 5-10 shows healthy storage levels in this scenario, because it includes the supply for the out of service Gordon Power Station; however storages in the remainder of the system are enough that there is no risk to supply.

The assessment concludes that, if a major six-month outage was to occur to Basslink, a major hydro scheme (Gordon Power Station) or the gas supply network (Tamar Valley Power Station), the Tasmanian power system has sufficient energy capacity to allow hydro storage levels to return to the pre-outage levels, with all energy requirements able to be supplied during that period. This analysis is based on methodology and assumptions presented in Section 5.6.3.1.

# 6

# Planned investments and forecast constraints



## Overview

This chapter discusses our proposed investments and forecast limitations and limitations within the next 10 years, identified through our annual planning review. We present projects which are committed or have been completed since our last APR. We then present our planned investments for the planning period; including the need, timing and cost of the investment and the alternate options considered. The section on forecast limitations presents the location and timing of limitations, requirements to defer the limitation by one or five years where relevant, and potential solutions to alleviate them.

This chapter also presents our current network innovation and trial projects, and summarises any regulatory investment tests and AEMO's national transmission network development plan and how it relates to the Tasmanian network.


## 6.1 Annual planning review

Each year, we undertake a planning review of our network. The purpose of the annual planning review is to assess the adequacy of the electricity network over an appropriate planning period. We prepare our plans on a minimum 10 year planning period. The outcomes of the annual planning review are published in this APR – specifically this chapter 6.

In undertaking the annual planning review, we take into account the information presented in earlier chapters of this APR. Namely, national and jurisdictional planning considerations (chapter 2), the operation of the existing network (chapter 3), the performance of the existing network (chapter 4), and the expected future demand on the network (chapter 5). We also take into account the national transmission network development plan, existing and known future customer plans and requirements, and the requirement for asset refurbishment or replacement.

Where we identify the network is not adequate to meet future operation requirements, we investigate and analyse potential solutions. These solutions may include network augmentation, replacement and rationalisation, and non-network alternatives, including embedded generation. We also investigate augmentations that are likely to provide a net economic benefit to those who participate in the national electricity market.

We welcome feedback on any item presented in this chapter. We are particularly interested in opportunities to defer network limitations or credible alternate solutions to proposed investments.

## 6.2 Committed and completed works

This section describes the material network projects that are committed (construction has begun or a firm date has been set) or that have been completed since publication of our 2016 APR. We will report on the progress of our committed projects in future APRs.

### 6.2.1 Committed works

#### 6.2.1.1 Queenstown–Newton 110 kV transmission line decommissioning

The single-circuit radial 110 kV transmission line between Queenstown and Newton substations, commissioned in 1936, is in poor condition and would have required extensive refurbishment to extend its service life. The tower members, bolts and foundations are all in poor condition and present a risk of failure, particularly in severe weather conditions. The project comprises the decommissioning of the Queenstown–Newton 110 kV transmission line and providing a connection to the existing Farrell–Rosebery–Queenstown 110 kV transmission circuit to create a Farrell–Rosebery–Newton–Queenstown 110 kV transmission circuit.

The estimated cost of the project is $2.4 million and it is proposed to be operational by May 2018.

### 6.2.2 Completed works

#### 6.2.2.1 Transmission lines – dead end assembly rating upgrade program stage 2 (George Town–Comalco 220 kV transmission line)

This project comprised the upgrade of dead end assemblies on the George Town–Comalco 220 kV transmission line to remove a capacity limitation. This project was included as a NCIPAP project in our 2014–19 transmission regulatory period.

This project was completed in August 2016.

#### 6.2.2.2 Rosny Park Zone Substation

The project to establish the Rosny Park Zone Substation was the final stage of our current strategy to strengthen the network on Hobart's eastern shore. Rosny Park Zone Substation has been established as a single-transformer substation, supplied via a single 33 kV sub-transmission line from Mornington Substation. It was built to de-load Bellerive and Geilston Bay zone substations (both supplied via sub-transmission lines from Lindisfarne Substation), ensuring these substations operate within their firm ratings.

The project was completed in December 2016.

#### 6.2.2.3 Sheffield Substation 220 kV 'K' and 'L' bay upgrades

This project comprised the replacement of selected assets within the 'K' and 'L' bays at Sheffield Substation. This removed a capacity limitation on the Sheffield–George Town 220 kV transmission circuits, allowing more power to be transferred through this corridor. This project was included as a NCIPAP project in our 2014–19 transmission regulatory period.

This project was completed in December 2016.

## 6.3 Planned investments

This section details the planned investments within the network during the next 10 years. These projects have been identified as our preferred solutions through technical and economic analysis. Our planned investments are listed in Table 6-1 and shown in the geographic planning area diagrams in Appendix E.

Planned investments identified in this APR include forecasts of future transmission-distribution connection points, proposed augmentations, and replacement network assets. We do not have any planned investments for future zone substations or sub-transmission lines. There were no investments to address urgent or unforeseen network issues in the past year.

Replacement network assets are included only where the cost is greater than $5 million in the transmission network and greater than $2 million in the distribution network. Needs for replacement network assets have been identified through our asset management process, outlined in Section 2.3.4 of this APR.

We welcome feedback from interested parties at any time regarding opportunities to defer expenditure or provide more cost-effective solutions to our planned investments presented in this section.

### 6.3.1 Forecast of future connection points

This section details our forecast of future transmission-distribution connection points. We propose one connection point project, which is a conversion of the supply voltage to the distribution network at Wesley Vale Substation.

#### 6.3.1.1 Wesley Vale Substation conversion

**Identified need**

The Port Sorell, Cradle Coast and Latrobe communities experience poor reliability. They are supplied via long and heavily loaded 22 kV distribution lines from Devonport and Railton substations. There is limited transfer capability between these substations.

Wesley Vale Substation comprises two 25 MVA supply transformers and was established at 11 kV to supply a large paper manufacturer. Since the closure of the site in 2010, Wesley Vale Substation has only supplied a single distribution line and customer. The substation is unable to provide load transfer capability to the surrounding 22 kV network due to the different operating voltage.

**Proposed solution**

We propose to convert the connection point supply voltage at Wesley Vale Substation from 11 kV to 22 kV to increase supply diversity to these communities.

**Table 6-1: Summary of planned investments**

| Location | Proposal | Estimated cost ($m) | Forecast completion | Reference |
|---|---|---|---|---|
| **Future connection points** | | | | |
| Wesley Vale Substation | Convert supply voltage from 11 kV to 22 kV | 1.9 | March 2018 | 6.3.1.1 |
| **Proposed augmentations** | | | | |
| Liapootah–Chapel Street 220 kV and Hadspen–Norwood 110 kV transmission lines | Upgrade transmission line dead end assemblies | 0.4 | May 2017 | 6.3.2.2 |
| George Town Substation | Install a new 40 MVAr 110 kV capacitor bank | 3.6 | March 2018 | 6.3.2.1 |
| Chapel Street Substation | Install second 110 kV bus coupler circuit breaker | 0.5 | January 2019 | 6.3.2.2 |
| **Replacement network assets** | | | | |
| Waddamana–Bridgewater 110 kV transmission line | Decommission line and provide alternate second supply to Bridgewater Substation | 6.6 | July 2018 | 6.3.3.1 |
| Lindisfarne Substation | Replace supply transformers | 6.4 | November 2018 | 6.3.3.2 |
| North Hobart Substation | Replace 11 kV switchgear | 5.1 | April 2019 | 6.3.3.3 |
| Palmerston Substation | Replace selected disconnectors and earth switches | 5.8 | June 2019 | 6.3.3.4 |
| Various zone substations | Replace supply transformers | Refer Table 63 | | 6.3.3.5 |

The existing supply transformers and switchboard at Wesley Vale Substation were designed to operate at either 11 kV or 22 kV, to allow the connection point supply to be converted to 22 kV with only minor modification work. Providing 22 kV supply from Wesley Vale Substation will allow the remote ends of selected distribution lines emanating from Devonport and Railton substations to be supplied from Wesley Vale Substation. This will shorten the lines supplying the affected communities, improving their supply reliability. This proposal also has the benefits of reducing the maximum demand at Devonport and Railton substations, which operate close to their firm capacity, and increase the utilisation and operational flexibility of the distribution network. This conversion was first proposed in the 2014 APR.

The initial loading level of Wesley Vale Substation following the conversion is expected to be approximately 6 MW, transferred from Devonport Substation. This will increase in future years as we continue to optimise the supply between Devonport, Railton and Wesley Vale substations.

The estimated cost of this project is $1.9 million and it is planned to be operational in March 2018.

## 6.3.2 Proposed augmentations

This section details our proposed augmentations to the network in the forward planning period. We have one proposed augmentation, in addition to those as part of our network capability incentive parameter action plan.

### 6.3.2.1 George Town Substation reactive power compensation

**Identified need**

The amount of power that can be exported across Basslink is restricted for periods due to voltage control limitations at George Town Substation. The restrictions occur under certain generation scenarios and if Basslink's own reactive compensation is unavailable. Basslink's export capability is restricted to ensure we maintain a reactive margin of one per cent of maximum fault level at George Town Substation, as required by the Rules.

The amount of time Basslink is restricted is expected to increase in coming years due to identified load increases at George Town Substation and growth in solar PV and wind generation. PV and wind generation are non-synchronous, displacing existing hydro generation which contributes to voltage limitations at George Town Substation.

**Proposed solution**

We propose to install a new 40 MVAr 110 kV capacitor bank at George Town Substation. This augmentation will allow the reactive margin at George Town Substation to be maintained, ensuring compliance with the Rules and maintaining the export capability of Basslink. It will also allow 20-30 MW increased power transfer through the transmission network and reduce our dependence on third party reactive plant. This is the first APR in which we have included this proposal.

The estimated cost of this project is $3.6 million and it is planned to be operational in March 2018.

**Table 6-2: Proposed NCIPAP augmentation investments**

| Project | Location | Solution to limitation | Cost ($000) | Operational completion |
|---|---|---|---|---|
| Transmission lines – dead end assembly rating upgrade program stage 2 | Liapootah–Chapel Street 220 kV and Hadspen–Norwood 110 kV transmission lines | Upgrade assemblies that constrain transmission line ratings | 388 | May 2017 |
| Chapel Street Substation 110 kV security augmentation | Chapel Street Substation | Install second 110 kV bus coupler circuit breaker to minimise impact of bus coupler circuit breaker fault | 450 | January 2019 |

### 6.3.2.2 Network capability incentive parameter action plan augmentations

As part of our network capability incentive parameter action plan (NCIPAP), we propose two augmentations within the remainder of our current transmission regulatory period, to June 2019. These are listed in Table 6-2. There are a number of other non-augmentation projects, not listed here, included in our NCIPAP program.

The projects will not have a material inter-network impact. Additionally, no other reasonable options were identified to address the limitations.

## 6.3.3 Proposed replacement network assets

This section details our proposed replacement network assets in the forward planning period. As well as like-for-like replacements, it includes proposals for decommissioning and the associated supply rearrangements driven by asset management requirements.

### 6.3.3.1 Waddamana–Bridgewater 110 kV transmission line decommissioning and network reconfiguration

**Identified need**

The Waddamana–Bridgewater Junction 110 kV transmission line was constructed in 1943. It is in poor condition and would require significant refurbishment if it is to be sustained in a safe and reliable condition.

In addition to this line, we have identified significant maintenance and refurbishment requirements on all 110 kV transmission lines in the Upper Derwent area. These lines were progressively commissioned from the mid-1930s to the mid-1950s, with some upgrades undertaken between 1999 and 2003. The refurbishment is required over coming decades; however the Waddamana–Bridgewater Junction transmission line condition is most pressing. This need was first identified in the 2013 APR.

**Proposed solution**

We propose to decommission the Waddamana–Bridgewater Junction 110 kV transmission line and reconfigure the network supplying Bridgewater Substation. A currently unused 110 kV circuit between Lindisfarne and Bridgewater substations will be used to provide the second supply to Bridgewater Substation. As there will be one less circuit from Waddamana Substation, control schemes will be required to manage post-contingent loading on these remaining circuits. The existing and proposed supply arrangements are shown in Figure 6-1.

The estimated cost to decommission this line and reconfigure the supply to Bridgewater Substation is $6.6 million and it is proposed to be operational by July 2018.

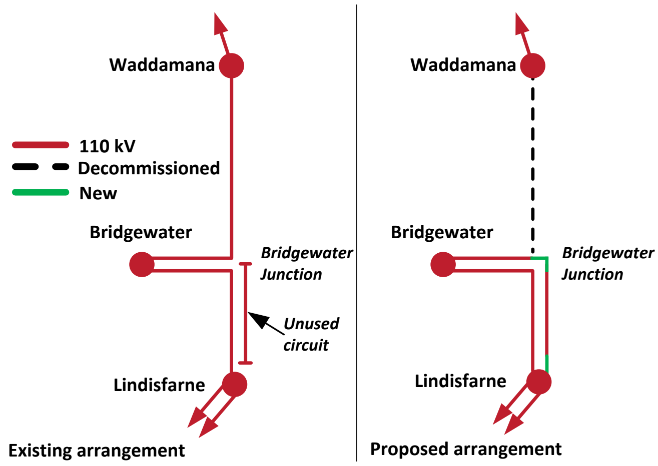



**Figure 6-1: Waddamana–Bridgewater–Lindisfarne existing (left) and proposed (right) network configuration**

Decommissioning the Waddamana–Bridgewater Junction 110 kV transmission line was identified as the first stage of a strategy to rationalise the Upper Derwent 110 kV network over coming years. It provides the most economic path to manage the network against the strategies assessed, including maintaining the existing network. Our preferred strategy is shown in Figure 6-2, with the intent to provide at least the existing network capacity to load and generation customers.

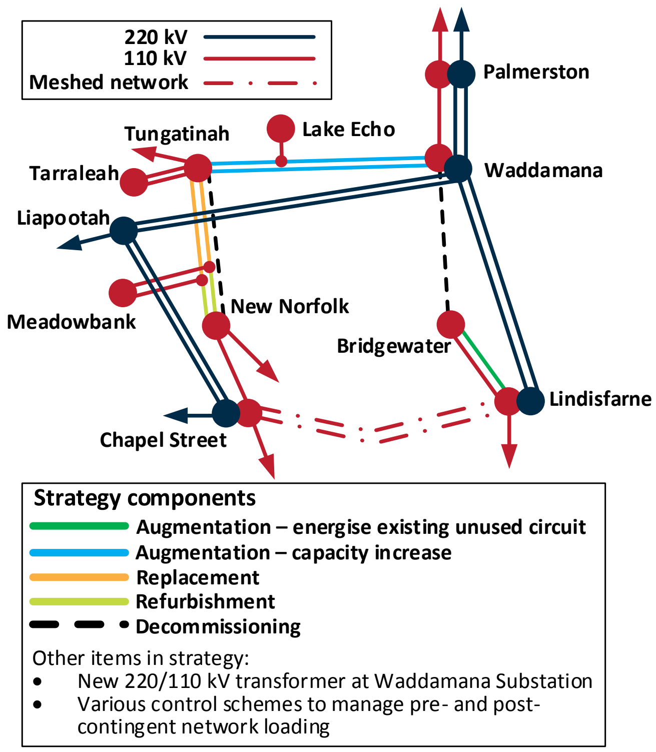



**Figure 6-2: Southern transmission network rationalisation strategy**

### 6.3.3.2 Lindisfarne Substation supply transformer replacements

**Identified need**

Lindisfarne Substation has two 110/33 kV 45 MVA supply transformers, which were manufactured in 1964. Condition assessment indicates their condition is deteriorating and they are approaching the end of their service life.

**Proposed solution**

We propose to replace these transformers with two new standard 110/33 kV 60 MVA units. This replacement project was first proposed in the 2013 APR.

We assessed refurbishing the transformers and deferring replacement past 2019. However there is little benefit in refurbishing these units due to their poor condition and it is more economical to replace them.

The estimated cost of the project is $6.4 million and it is planned to be operational by November 2018.

### 6.3.3.3 North Hobart Substation 11 kV switchgear replacement

**Identified need**

The two 11 kV switchboards at North Hobart Substation were manufactured in 1976 and are no longer supported by the manufacturer. We do not have this type of switchgear installed at any other site. The switchboards are not designed for arc containment and are not explosion proof. The circuit breakers also require manual spring charging after each operation, resulting in delays in restoring supply.

In addition, the switchboards comprise six distribution line circuit breakers each and provide connection to 22 distribution lines plus two local service station transformers. That is, 12 circuit breakers provide connection to 24 x 11 kV circuits. This arrangement reduces the reliability of supply to the Hobart CBD area, as a single distribution line fault will trip its associated circuit breaker resulting in the loss of supply to both the faulty line and the healthy line connected to that circuit breaker.

**Proposed solution**

We have assessed three arrangements to address the identified needs. These arrangements were to replace the switchboard with:

- 24 kV air-insulated equipment (operated at 11 kV) to match our standard equipment;
- 12 kV air insulated equipment (operated at 11 kV) to fit in the existing station footprint, although non-standard within our network; and
- 24 kV gas-insulated equipment (operated at 11 kV) to fit in the existing station footprint, although non-standard within our network.

We propose to replace the 11 kV switchboards at North Hobart Substation with new 12 kV air-insulated switchboards (operated at 11 kV) that have sufficient circuit breakers to enable one distribution line to be connected per circuit breaker. The new switchgear will align with current standards and include arc containment facilities, be explosion proof, and be fully remote controllable. This replacement was first proposed in the 2012 APR.

The estimated cost of the project is $5.1 million and it is planned to be operational by April 2019.

### 6.3.3.4 Palmerston Substation disconnector and earth switch replacements

**Identified need**

We have identified that our population of Stanger type DR2 disconnectors are unreliable and are approaching the end of their service lives, with spare parts no longer available.

**Proposed solution**

As part of our replacement programs for these assets, we propose a project at Palmerston Substation to replace the 23 type DR2 disconnectors and associated earth switches. This will reduce the risk of failure of equipment due to poor condition, and increase transmission circuit availability. This program was first proposed in our 2015 APR.

We assessed whether to replace the assets within the next five years or defer replacement past this time. The most economic option to address the need is to replace the disconnectors and earth switches.

The estimated cost of this project is $5.8 million and it is planned to be operational by June 2019.

**Table 6-3: Planned zone and rural zone substation transformer replacements**

| Zone substation | Existing transformers (MVA) | Year of manufacture | Forecast end of life | Replacement transformers (MVA) | Estimated cost ($m) | Estimated completion date | APR where first identified |
|---|---|---|---|---|---|---|---|
| Claremont | 2 x 22.5 | 1969 | Within 5 years | 2 x 25 | 3.0 | June 2019 | 2015 |
| Richmond rural | 2 x 2.5 | 1960 | Within 5 years | 2 x 5 | 2.8 | June 2019 | 2013 |
| Derwent Park | 2 x 22.5 | 1969 | Within 10 years | 2 x 25 | 3.0 | June 2023 | 2015 |
| Geilston Bay | 2 x 22.5 | 1964 | Within 10 years | 2 x 25 | 4.2 | June 2024 | 2015 |
| Bellerive | 2 x 22.5 | 1971 | Within 10 years | 2 x 25 | 4.0 | June 2026 | 2015 |

#### 6.3.3.5 Zone and rural zone substation transformer replacements

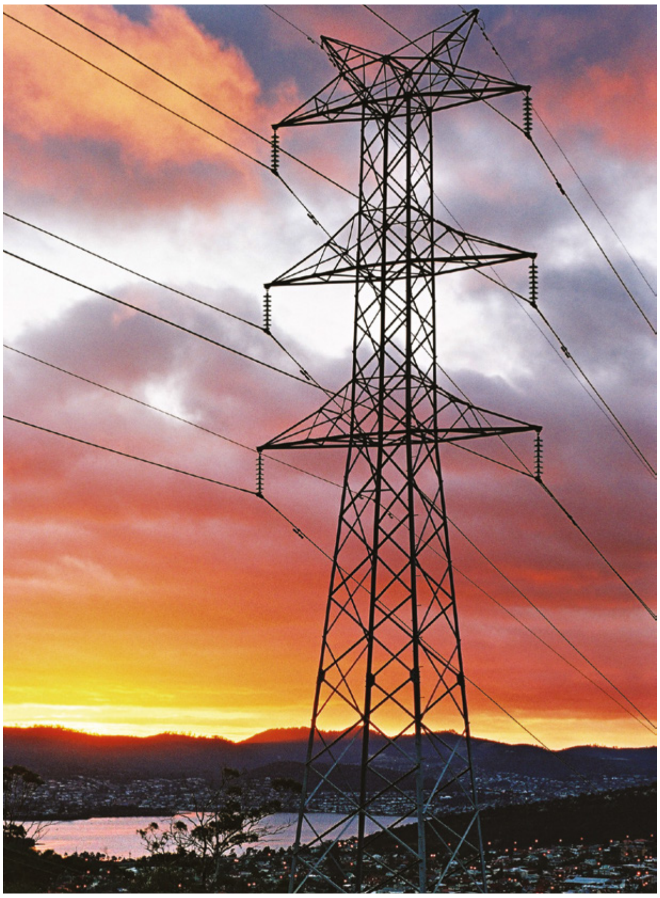
Table 6-3 presents the planned supply transformer replacements at our zone and rural zone substations. The transformers need to be replaced due to their condition, and we plan to install units of standard sizes.

### 6.3.4 Deferred or averted investments

This section details proposed investments from our 2016 APR that have been deferred or averted for various reasons.

#### 6.3.4.1 Power transformer dynamic rating program

In our 2016 APR, we proposed undertaking a power transformer dynamic rating program. The aim of this program was to provide dynamic rating of network transformers, to increase load transfer capability, at Farrell, Hadspen, Palmerston and Sheffield substations. This program formed part of our NCIPAP projects and was included in Section 6.3.2.1 of the 2016 APR.
We subsequently identified that additional capacity to the network transformers is not currently required. This program has been removed from our proposed NCIPAP investment plan for the 2014–19 regulatory period.



## 6.4 Forecast constraints and inability to meet network performance requirements

This section presents the forecast limitations, not addressed by a planned investment in Section 6.3, within the network during the next 10 years. These limitations identify the points in the network that are currently inadequate to cater for the future demand on the network, due to capacity, a network performance requirement, or other technical limit. These forecast constraints and inability to meet network performance requirements are shown in our planning area diagrams in Appendix E.

We do not have any identified limitations for primary distribution line overloads within the next two years. In addition, none of the limitations applying to sub-transmission lines or zone substations impact on the capacity at the respective transmission-distribution connection points.

The project specification consultation report stage of the regulatory investment test, where required, will constitute our formal request for proposals for limitations identified in this section. However, we welcome feedback from interested parties at any time regarding feasible options that may provide cost-effective solutions, including deferral, to the network limitations presented in this APR.

Table 6-4: Summary of forecast constraints and inability to meet network performance requirements

| Area of limitation | Limitation | Forecast year | Reference |
|---|---|---|---|
| **Within one year (2017)** | | | |
| Risdon–New Town sub-transmission lines | Sub-transmission lines non-firm | Current (summer and winter) | 6.4.2 |
| Risdon–Derwent Park sub-transmission lines | Sub-transmission lines non-firm | Current (summer) (winter 2017) | 6.4.2 |
| Meadowbank Substation | Above 300 MWh unserved energy network performance requirement | Current (summer) | 6.4.1.1 |
| New Town Zone Substation | Substation non-firm (11 kV switchboard limitation) | Current (winter) | 6.4.3.1 |
| Rosebery Substation | Supply-transformers non-firm | Current (winter) | 6.4.1.2 |
| St Marys Substation | Supply transformers non-firm | Current (winter) | 6.4.1.3 |
| **Within one to three years (2018 and 2019)** | | | |
| Farrell–Que–Savage River–Hampshire 110 kV transmission circuit | Above 300 MWh unserved energy network performance requirement (limitation exists now, but at customer request we have an exemption until 2018) | June 2018 | 6.4.4.2 |
| Creek Road–West Hobart sub-transmission lines | Sub-transmission lines non-firm | Summer 2019 (winter 2024) | 6.4.2 |
| Risdon–East Hobart sub-transmission lines | Sub-transmission lines non-firm | Summer 2019 | 6.4.2 |
| **Within three to five years (2020 and 2021)** | | | |
| Creek Road–Claremont sub-transmission lines | Sub-transmission lines non-firm | Summer 2021 (winter 2024) | 6.4.2 |
| **Within five to ten years (2022 to 2026)** | | | |
| Railton Substation | Substation non-firm (22 kV cable limitation) | Summer 2022 | 6.4.1.4 |
| Derwent Park Zone Substation | Substation non-firm (11 kV switchboard limitation) | Winter 2023 | 6.4.3.2 |
| Hadspen Substation | Supply transformers non-firm | Winter 2025 | 6.4.1.5 |
| North Hobart Substation | Supply transformers non-firm | Winter 2025 | 6.4.1.6 |
| Burnie Substation | Supply transformers non-firm | Winter 2026 | 6.4.1.7 |

## 6.4.1 Transmission network limitations

### 6.4.1.1 Meadowbank Substation transformer reliability

#### Limitation overview

Meadowbank Substation comprises a single 10 MVA supply transformer, the loss of this transformer would result in supply interruption to all customers supplied from this connection point. Currently, in summer, the unserved energy from the loss of this transformer would exceed 300 MWh, the maximum unserved energy amount allowed under our jurisdictional network planning requirements. The unserved energy amount is for an eight-day period to replace the transformer, and allows for the existing backup available from other substations.

#### Limitation deferral

Table 6-5 presents the requirements to defer the identified limitation at Meadowbank Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2018) or five (to 2022) years. The reduction would maintain the unserved energy below 300 MWh, the maximum amount allowed under our jurisdictional network planning requirements.

Table 6-5: Meadowbank Substation limitation deferral

| Deferral period | Maximum demand (2016) (MW) | Generation support or reduction in forecasted load (MW) |
|---|---|---|
| One year | 6.8 | 3.8 |
| Five years | | 4.4 |

Load transfer of 3.4 MVA is available from Meadowbank Substation to New Norfolk Substation for short periods, under certain network conditions.

#### Potential solution

Potential solutions to manage this limitation include:

- use proposed transportable substation to restore customer supply;
- strengthening the distribution network to provide either increased post-contingent or permanent load transfers away from Meadowbank Substation;
- demand management activities, including embedded generation or contracted load shedding;
- reduce the transformer outage duration; and
- seek exemption from network planning requirements if costs of potential solutions outweigh the benefits to customers.

#### 6.4.1.2 Rosebery Substation transformer capacity

**Limitation overview**

Rosebery Substation comprises two 36 MVA transformers, with no additional short-term rating.[44] The substation maximum demand in 2016 exceeded 36 MVA, the firm rating of the substation. This is the first APR in which this limitation has been identified.The firm rating exceedance in 2016 was not identified in the maximum demand forecast. Maximum demand had previously been below, although close to, firm capacity and was forecast to remain flat over the short to medium term. The increased coincident maximum demand in 2016 is attributed to a number of mining customers performing de-watering operations following heavy rains.

**Limitation deferral**

As maximum demand is forecast to remain within, although close to, the firm rating, there is no identified limitation deferral amount. There is no load transfer available away from Rosebery Substation.

**Potential solution**

We have implemented operational solutions at Rosebery Substation to manage the possibility of non-firm operation and we do not propose any immediate corrective action to address this possible limitation. Notwithstanding, potential solutions further to this include:

- demand management activities, likely being contracted load shedding; and
- installation of a third supply transformer.

Rosebery Substation predominantly supplies mining customers, and existing or new mining customers may require additional demand with minimal lead time. As such we continue to closely monitor loading at Rosebery Substation and engage with existing and potential future customers.

#### 6.4.1.3 St Marys Substation transformer capacity

**Limitation overview**

St Marys Substation comprises two 10 MVA transformers, with a short-term rating of 12 MVA. The substation maximum demand in 2016 was 14.4 MVA, currently exceeding the short-term firm rating of the substation. This limitation has been identified in APRs for the past decade; however we have been able to avoid the need to install larger transformers due to the substation load growth remaining virtually flat during that time.

To prevent overloading the remaining in-service transformer in the event of a fault on the alternate unit, we utilise a load-shedding scheme. Following the loss of one transformer, the scheme will open distribution line circuit breakers until the load is within the rating of the remaining in-service transformer. This results in interruption to customer supply until supply can be restored either by transferring the interrupted distribution lines to adjacent substations or waiting until demand reduces and the interrupted line can be brought back into service. The amount of unserved energy from this action is less than 300 MWh, the maximum allowed under our jurisdictional network performance requirements.

**Limitation deferral**

Table 6-6 presents the requirements to defer the identified limitation at St Marys Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2018) or five (to 2022) years. The reduction would maintain the load below 12 MVA, the short-term firm capacity.

**Table 6-6: St Marys Substation limitation deferral**

| Deferral period | Maximum demand (2016) (MVA) | Generation support or reduction in forecasted load (MVA) |
|---|---|---|
| One year | 14.4 | 2.9 |
| Five years | | 4.0 |

Load transfer of 11.3 MVA is available from St Marys Substation to Avoca, Triabunna and Derby substations for short periods, under certain network conditions.

**Potential solution**

We do not propose any investment to address this limitation because it is not economical to do so, however will maintain operation of the load shedding scheme. Potential solutions further to this include:

- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from St Marys Substation;
- real-time (dynamic) rating of the transformers;
- replacement of the transformers with larger units; and
- establishment of a new connection point.

#### 6.4.1.4 Railton Substation capacity

**Limitation overview**

Railton Substation comprises two 50 MVA transformers, with a short-term rating of 60 MVA constrained to 57 MVA by the rating of the transformer cables. The maximum demand at Railton Substation was 47.3 MVA in 2016. We forecast the maximum demand will exceed the constrained short-term firm rating from summer 2022. This is the first APR in which this limitation has been identified.

*44 These transformers were previously 30 MVA capacity with a short-term rating of 36 MVA. We installed additional cooling to increase the normal rating to 36 MVA, however no increase in the short-term rating was available.*

#### Limitation deferral

Table 6-7 presents the requirements to defer the identified limitation at Railton Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2023) or five (to 2027) years. The reduction would maintain the load below 57 MVA, the capacity of the transformer cables.

**Table 6-7: Railton Substation limitation deferral**

| Deferral period | Maximum demand (2022) (MVA) | Generation support or reduction in forecasted load (MVA) |
|---|---|---|
| One year | 58.2 | 2.4 |
| Five years | | 7.5 |

Load transfer of 13.1 MVA is available away from Railton Substation to Devonport and Ulverstone substations for short periods, under certain network conditions.

#### Potential solutions

Potential solutions to manage the forecast limitation at Railton Substation include:

- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers; and
- short-term or real-time (dynamic) rating of the transformers and transformer cables.

Solutions to enlarge the network such as transformer replacement with larger units or the establishment of a new connection point are not justified in the current planning period.

The likely solution for this limitation is to provide permanent load transfers away from Railton Substation to Wesley Vale Substation. As detailed in Section 6.3.1.1, we propose to convert Wesley Vale Substation to 22 kV supply voltage to manage loading between it, Devonport and Railton substations.

### 6.4.1.5 Hadspen Substation transformer capacity

#### Limitation overview

Hadspen Substation comprises two 50 MVA transformers, each with a short-term rating of 60 MVA. The maximum demand at Hadspen Substation was 50.4 MVA in winter 2016. We forecast the maximum demand will exceed the short-term firm rating from winter 2025. This limitation was first identified in our 2015 APR.

#### Limitation deferral

Table 6-8 presents the requirements to defer the identified limitation at Hadspen Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2026) or five (to 2030) years. The reduction would maintain the load below 60 MVA, the short-term firm capacity.

**Table 6-8: Hadspen Substation limitation deferral**

| Deferral period | Maximum demand (2025) (MVA) | Generation support or reduction in forecasted load (MVA) |
|---|---|---|
| One year | 60.5 | 1.4 |
| Five years | | 6.1 |

Load transfer of 50.7 MVA is available away from Hadspen Substation to Norwood, Palmerston, Trevallyn and Railton substations for short periods, under certain network conditions. Primarily this is to Norwood and Trevallyn substations via the heavy distribution interconnection.

#### Potential solutions

Potential solutions to manage the forecast limitation at Hadspen Substation include:

- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from Hadspen Substation; and
- real-time (dynamic) rating of the transformers.

Solutions to enlarge the network such as transformer replacement with larger units or the establishment of a new connection point are not justified in the current planning period based on the current load forecast.

### 6.4.1.6 North Hobart Substation transformer capacity

#### Limitation overview

North Hobart Substation has two 45 MVA supply transformers, each with a short-term rating of 50 MVA. The substation maximum demand was 39.2 MVA in winter 2016, and is forecast to exceed the short-term firm rating from 2025. This limitation was first identified in the 2007 APR.

#### Limitation deferral

Table 6-9 presents the requirements to defer the identified limitation at North Hobart Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2026) or five (to 2030) years. The reduction would maintain the load below 50 MVA, the short-term firm capacity.

**Table 6-9: North Hobart Substation limitation deferral**

| Deferral period | Maximum demand (2025) (MVA) | Generation support or reduction in forecasted load (MVA) |
|---|---|---|
| One year | 50.2 | 1.0 |
| Five years | | 4.9 |

Load transfer of 48.8 MVA is available from North Hobart Substation to Chapel Street, East Hobart Zone, New Town Zone and West Hobart Zone substations for short periods, under certain network conditions.

**Potential solutions**

The distribution network within Hobart is heavily interconnected; this means large portions of load can be transferred between substations for short periods. As such, for these substations we consider the "group firm" rating, and develop strategies to manage load across a number of substations, rather than as individual sites.

We will continue to manage loading in this manner, however future potential solutions to manage specific loading limitations at North Hobart Substation include:

- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from North Hobart Substation;
- real-time (dynamic) rating of the transformers;
- replacement of the transformers with larger units; and
- establishment of a new connection point.

#### 6.4.1.7 Burnie Substation transformer capacity

**Limitation overview**

Burnie Substation comprises two 60 MVA transformers, each with a short-term rating of 72 MVA. The maximum demand at Burnie Substation was 58.3 MVA in 2016. We forecast the maximum demand will exceed the short-term firm rating from winter 2026. This is the first APR in which this limitation has been presented.

**Limitation deferral**

Table 6-10 presents the requirements to defer the identified limitation at Burnie Substation. The table presents the reduction in the forecasted load, or amount of generation support, required to defer the limitation by either one (to 2027) or five (to 2031) years. The reduction would maintain the load below 72 MVA, the short-term firm capacity.

**Table 6-10: Burnie Substation limitation deferral**

| Deferral period | Maximum demand (2026) (MVA) | Generation support or reduction in forecasted load (MVA) |
|---|---|---|
| One year | 72.4 | 1.5 |
| Five years | | 7.6 |

Load transfer of 17.6 MVA is available away from Burnie Substation to Port Latta and Ulverstone substations for short periods, under certain network conditions.

**Potential solutions**

Potential solutions to manage the forecast limitation at Burnie Substation include:

- demand management activities, including embedded generation or contracted load shedding;
- real-time (dynamic) rating of the transformers;
- conversion of Emu Bay Substation from 11 kV to 22 kV and transfer load from Burnie Substation; and
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from Burnie Substation.

Solutions to augment the network such as transformer replacement with larger units or the establishment of a new connection point are not justified in the current planning period.

### 6.4.2 Sub-transmission line limitations

We have identified limitations on a number of sub-transmission lines. In all of these limitations, the load on the sub-transmission lines is forecast to exceed their firm ratings. The limitations generally first occur during summer, however they will also occur in winter during the planning period on most lines. These limitations are identified in Table 6-11 and were first identified in our 2016 APR.

Table 6-11 identifies the affected sub-transmission lines, the forecast year of non-firm for summer and winter periods, the load transfer capability away from the zone substations supplied from these lines, and the load reduction required to defer the limitations. The load transfer capability presented is the capability during winter, when peak loading occurs. As these limitations are appearing during summer first, we will investigate

**Table 6-11: Forecast sub-transmission line limitations**

| Sub-transmission lines | Forecast year non-firm | | Load transfer capability (MVA) (winter) | Load reduction required to defer limitation (MVA) (for season limitation first appears) | |
|---|---|---|---|---|---|
| | Summer | Winter | | 1 year | 5 years |
| Risdon–New Town | Current | Current | 20.3 | 3.5 | 5.2 |
| Risdon–Derwent Park | Current | 2019 | 23.3 | 2.2 | 3.5 |
| Creek Road–West Hobart | 2019 | 2024 | 23.4 | 0.9 | 3.3 |
| Risdon–East Hobart | 2019 | Past 2026 | 25.5 | 1.8 | 4.3 |
| Creek Road–Claremont | 2021 | 2024 | 10.9 | 0.6 | 1.8 |

whether load transfers during this period present a viable option for deferring the limitations.

Power factor improvement is not a viable option to defer the limitations because the MW load is in excess of the MVA firm rating. This means only load reduction or generation support will have the capability to defer these limitations.

We propose a rating upgrade strategy to address these limitations. The strategy has three components, depending on the limiting component of the sub-transmission line. The strategy is as follows:

1. replace limiting copper sections of overhead line with larger capacity conductor. We already plan to replace these copper sections and others due to asset condition, and therefore plan to fund these replacements under that program;
2. increase the operating temperature of limiting sections of overhead line through re-tensioning conductor, installing additional poles, or re-locating line sections where required; and
3. re-rate or apply short-term ratings to limiting underground cable sections.

In addition to this strategy, we may also be able to apply dynamic (real-time) ratings to the sub-transmission lines.

## 6.4.3 Zone substation limitations

### 6.4.3.1 New Town Zone Substation capacity

**Limitation overview**

New Town Zone Substation has two 22.5 MVA supply transformers, with a short-term firm rating of 30 MVA constrained to 22.9 MVA by the rating of the 11 kV switchboard. The substation maximum demand in 2016 was 23.6 MVA, which would exceed the rating of the 11 kV switchboard when one transformer is out of service. This limitation was first identified in the 2014 APR.

**Limitation deferral**

Table 6-12 presents the requirements to defer the identified limitation at New Town Zone Substation. The table presents the reduction in the forecasted load or amount of generation support required to defer the limitation by either one (to 2018) or five (to 2022) years. The reduction or improvement would maintain the load below 22.9 MVA, the short-term firm rating.

Power factor improvement is not a viable option to defer this limitation. The MW load is in excess of the MVA rating of the transformers, meaning it can only be deferred by load reduction or generation support.

Load transfer of 20.3 MVA is available away from New Town Zone Substation to Chapel Street, Derwent Park Zone, East Hobart Zone and North Hobart substations for short periods, under certain network conditions.

**Potential solutions**

Potential solutions to manage the forecast limitation at New Town Zone Substation include:

- apply a short-term rating to the 11 kV switchboard;
- introducing a load shedding scheme;
- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from New Town Zone Substation; and
- replacement of the 11 kV switchboard.

### 6.4.3.2 Derwent Park Zone Substation capacity

**Limitation overview**

Derwent Park Zone Substation has two 22.5 MVA supply transformers, with a short-term firm rating of 30 MVA limited to 22.9 MVA by the rating of the 11 kV switchboard. The substation maximum demand in 2016 was 19.7 MVA. We forecast the maximum demand will exceed the rating of the 11 kV switchboard from winter 2023 when one transformer is out of service. This is the first APR in which this limitation has been identified.

**Limitation deferral**

Table 6-13 presents the requirements to defer the identified limitation at Derwent Park Zone Substation. The table presents the reduction in the forecasted load

**Table 6-12: New Town Zone Substation limitation deferral**

| Deferral period | 2016 values | | Generation support or reduction in forecasted load (MVA) |
|---|---|---|---|
| | Maximum demand (MVA) | Power factor | |
| One year | 23.6 | 0.987 | 2.3 |
| Five years | | | 4.2 |

**Table 6-13: Derwent Park Zone Substation limitation deferral**

| Deferral period | Forecast for 2023 | | Generation support or reduction in forecasted load (MVA) | Improved power factor |
|---|---|---|---|---|
| | Maximum demand (MVA) | Power factor | | |
| One year | 23.0 | 0.967 | 0.5 | 0.988 |
| Five years | | | 2.1 | -- |

or amount of generation support, or improvement in power factor, required to defer the limitation by either one (to 2024) or five (to 2028) years. The reduction or improvement would maintain the load below 22.9 MVA, the short-term firm rating.

Power factor improvement is not a viable option to defer this limitation by five years. By then, the MW load will be in excess of the MVA rating of the transformers, meaning it can only be deferred by load reduction or generation support.

Load transfer of 23.0 MVA is available away from Derwent Park Zone Substation to Chapel Street and New Town Zone substations for short periods, under certain network conditions.

**Potential solutions**

Due to the poor condition of the transformers, we propose to replace them as presented in Section 6.3.3.5. We will replace the transformers with standard 25 MVA units, however the 22.9 MVA limitation will remain due to the 11 kV switchboard. Potential solutions to manage the forecast limitation at Derwent Park Zone Substation include:

- introducing a load shedding scheme;
- demand management activities, including embedded generation or contracted load shedding;
- strengthening the distribution network to provide either post-contingent (automated) or permanent load transfers away from Derwent Park Zone Substation; and
- replacement of the 11 kV switchboard.

## 6.4.4 Deferred or averted limitations

### 6.4.4.1 Richmond Rural Zone Substation capacity

Previous APRs have identified the maximum demand at Richmond Rural Zone Substation is forecast to exceed the substation firm rating, currently forecast from summer 2019. We have recently augmented the distribution network to allow additional load transfers away from Richmond Rural Zone Substation. These transfers are able to be completed quickly and remotely, and will be able to maintain the load at Richmond Rural Zone Substation to within the firm rating following the loss of one transformer. This solution addresses the limitation until the supply transformers are replaced (Section 6.3.3.5), providing sufficient firm capacity.


### 6.4.4.2 Savage River Substation transmission network performance requirement

The Farrell–Que–Savage River–Hampshire 110 kV transmission circuit supplies a distribution load at Savage River Substation and transmission-connected customers at both Savage River and Que substations.

A contingency event occurring on this circuit between the Waratah Tee and Savage River Substation could result in more than 300 MWh of unserved energy at Savage River Substation, the maximum amount allowed under our jurisdictional network performance requirements. This situation applies now, and is not dependent on load growth.

We have an agreement under the network performance requirements with the transmission customers supplied from Savage River Substation that there is insufficient benefit to undertake a network augmentation solution to address this limitation. We are thus exempt under clause 8(4) of the jurisdictional network performance requirements, for the period 1 June 2013 until 30 June 2018, from planning the network to meet this requirement.

The exemption will cease from the date of expiry (June 2018), or when an affected customer considers remedial action has sufficient benefit, or circumstances have materially changed. We do not consider circumstances to have materially changed since the exemption period commenced, however we continue to consult with the affected customers.

## 6.5 Network innovation and trial projects

We have investigated and implemented a number of projects that are potential alternatives to traditional investment in poles and wires. Such projects are termed "non-network" projects. This section details a selection of the non-network solutions we have investigated or implemented, and trial projects either underway or recently completed.

Aside from our own process of developing non-network solutions, we welcome feedback and invite proposals on approaches to managing our network limitations. We welcome feedback at any time, and also invite potential demand management solution providers to register with us via our demand side engagement register: https://www.tasnetworks.com.au/our-network/planning-and-development/demand-management-engagement-strategy/.

### 6.5.1 Mesh radio

Much of our communication with field devices, such as reclosers and voltage regulators, utilise the commercially available mobile network. These communications arrangements do not have the reliability and expansion capability that is required for critical electricity infrastructure. We are currently trialling a mesh radio system, which would provide appropriate reliability levels. A successful mesh radio system would:

- reduce cost of communications to field devices;
- be less vulnerable to bad weather or congestion; and
- allow more economic communications with more field devices.

We are nearing completion of our trial in the Bridgewater/Brighton area. The trial has presented some challenges which need to be addressed before we consider expansion of the mesh radio system.

### 6.5.2 Advanced distribution automation system

Currently, many switching elements in the distribution network are remotely controlled. This will increase as more devices become capable of remote control. These devices are still manually controlled by control room operators in most cases.[45] An advanced distribution automation system would place an automation layer over the top of the remote control. This allows faster fault finding and faster load restoration.

We have started implementing a trial of the advanced distribution automation system at Strahan. Strahan's power is supplied from Queenstown, via a single 30 km 22 kV distribution line. A fault on this line will result in a blackout of Strahan. We have installed two backup diesel generators at Strahan, which can provide power to the town if the line is faulty. However, the process of starting these generators following a distribution line fault currently requires operator intervention. The advanced distribution automation system will automate the generator start-up and supply restoration following a line fault, which will reduce the time which Strahan is without power. This trial is due for completion in early 2017.

### 6.5.3 Remote area power supplies

Some parts of the distribution network are underutilised because there are long sections of distribution lines supplying very small loads. These sections of the network are expensive to maintain. Some of these loads can be supplied more economically using a remote area power supply (RAPS). We commissioned a hybrid diesel/battery RAPS at Crotty Dam in March 2014, allowing a long line section to be decommissioned.

The second RAPS site identified is at Mt Tim Shea radio communications site, a communications site used by multiple customers. The driver for this project is to minimise the costs of maintaining the existing local network. The system to be installed will likely be a hybrid solar/battery /diesel and may also include a small wind turbine. We are currently developing this proposal.

We have identified several other candidate sites in Tasmania for RAPS installations. The experience we gain from these initial RAPS solutions will guide our future deployment of RAPS at other locations.

### 6.5.4 Tariff trial

We are working to improve the way we price network services. The intent is to transition to more cost-reflective pricing over time so that customers are more fairly charged for their impact on the network, ie demand-based tariffs. It will also allow customers to be provided with information to make informed choices about how they can use electricity to suit their lifestyle.

We are implementing a trial with 600 residential customers in the Brighton/Bridgewater supply area. The first phase of the trial involves a 12 month period of data capture. During this phase we will also provide participants with tools to increase understanding of their own electricity usage patterns. In the second phase of the trial we will test cost reflective tariff structures, including the new demand-based time-of-use tariff.

*45 Excluding 'loop automation' sites. This style of automation can only be implemented in specific circumstances.*

As the tariff trial is being conducted off-market, customers participating in the trial will continue to pay electricity accounts based on their consumption as is currently the case. However, they will be provided a financial incentive if they reduce their bill under the demand-base tariff phase of the trial.

The project aims to inform our future tariff strategy and provide us with information to support our customers through the journey towards more cost reflective pricing.

### 6.5.5 Network intelligence project

The network intelligence project, an extension of the previous virtual network monitoring project, will use consumption and power quality data from the 600 residential meters that are participating in our tariff trial. Additional network data including phasing information, low voltage network connectivity and telemetered data from reclosers and voltage regulators will be used to develop a detailed network model of the distribution network in the Brighton/Bridgewater area. The purpose of gathering this data is to improve our understanding of the power quality limitations that affect the low voltage network and the extent to which the upstream medium voltage network impacts the low voltage network.

The data collected will be used to test and validate a suite of mathematical models that include virtual network model and state estimation. Both of these methods use mathematical techniques to estimate the load in parts of the distribution network where no monitoring exists.

### 6.5.6 Residential battery technology

We are undertaking a residential battery trial on Bruny Island. In this trial we are subsidising Bruny Island residents to install battery and solar systems on their houses. We expect to install 34 systems. We will use the batteries during peak times to reduce the amount of diesel generation required to manage loading on the cable which supplies the island, reducing both operating costs and emissions. The batteries will also help to stabilise network voltages within acceptable levels, and enable households to make optimal use of their solar power generation. Customers will be paid for providing network support.

As part of the trial, we are seeking to validate residential energy storage as a solution that we can use elsewhere in the network. With the information gathered in this trial we will understand when and how to use this technology. If successful, we will be able to pass on benefits to all customers through lower cost alternatives to network augmentation.

We are working in partnership with the Australian National University, University of Sydney, University of Tasmania, and Reposit Power to deliver this project.

It is a three year research project. In this project we are investigating:

- an innovative new control algorithm that makes batteries an active part of the electricity network;
- what is the most fair way of paying participants for the services they provide while encouraging participants to respond in the right way; and
- how participants feel about the battery technology and about helping to managing the network.

This leading edge research puts TasNetworks at the forefront of the world in implementing these technologies. This project is an exciting look to the future where customers can help us manage network limitations. It takes us closer to our strategic direction of making customers central to all we do.

This project received funding from the Australian Renewable Energy Agency as part of its Research and Development Program. More information can be found on the trial website http://brunybatterytrial.org/.

### 6.5.7 Commercial and industrial demand management

We have been evaluating the viability of a program to reduce peak demand by engaging commercial and industrial distribution customers to reduce load during times of high demand. A customer's participation in such a scheme would be voluntary and under commercial terms acceptable to the customer. Only commercial and industrial customers in areas where demand reductions would be beneficial would be approached to participate in the program.

We have undertaken a state-wide commercial and industrial distribution-connected load survey to identify the characteristics of the principal customers (and customer groups) across Tasmania, and the demand management potential that may be realised by such customers. The conclusion from this survey was that sufficient load reduction and customer participation is likely to be available for demand management, and further detailed investigation is warranted.

We are currently evaluating the next step in the trial, however customers may register with us if they are interested in providing demand side management solutions in the future. Our website provides our demand side engagement strategy and register: https://www.tasnetworks.com.au/our-network/planning-and-development/demand-management-engagement-strategy/

### 6.5.8 Electric vehicles

Although electric vehicle use in Australia is still in its infancy, we expect that, eventually, electric vehicles will be commonplace. This expectation is supported by developments since our last Annual Planning Report, such as the overseas release of family-affordable electric vehicles with 300 km travelling range.

We expect electric vehicles to change the way electricity is used in Tasmania, similar to how PV has caused patterns of electricity use to change. Our aim is to ensure, as far as practicable, that electric vehicle charging can be accommodated by the existing electricity network, and any need to increase the network capacity is minimised.

We are in the process of undertaking detailed studies into the impact of electric vehicles on the electricity network. We have incorporated electric vehicles and the required charging infrastructure into our own vehicle fleet, and made an electric vehicle available to a not-for-profit organisation, in order to gain first-hand experience of fleet use of such vehicles. We are currently working with the Tasmanian government and other organisations that have an interest in electric vehicle uptake in Tasmania, with a view to sharing knowledge about this emerging technology.

### 6.5.9 Power quality corrective actions

We propose two trials to assist in addressing power quality limitations. The first is at Bruny Island to address island-wide limitations, and the second trial is to address limitations in the low voltage network. The trials are not expected to be implemented in the short term.

The first project is to purchase and trial a portable medium voltage (11 kV) STATCOM. The aim of this project is to address power quality limitations which occur on Bruny Island during peak periods, and to improve the poor power factor of the main 11 kV distribution line supplying the island which occurs for approximately 50 per cent of the year. Traditionally a voltage regulator would be installed, however the STATCOM may provide a more cost-effective solution and be able to be re-deployed to other locations when not required during peak periods. This trial is expected to be implemented by 2020.

The second project is to trial low voltage regulation technology as opposed to traditional transformer and low voltage circuit upgrades. This cost of this technology is estimated to be approximately 20 per cent lower than traditional solutions. The trial is required to prove the technology and provide understanding of optimum equipment, capacity, and connection locations. This trial is expected be implemented by 2021.

### 6.5.10 Ceased network innovation and trial projects

#### 6.5.10.1 FuseSavers

We conducted a trial of FuseSavers, which are devices which protect an expulsion drop-out (EDO) fuse. These devices were intended to protect EDO fuses from blowing for transient faults, reducing the need for operator attendance to replace the blown fuse. We undertook a trial at 29 sites.

FuseSavers use normal line current to maintain charge on their batteries. The trial took place at rural sites, where the reduced operator attendance would provide the most benefit, however normal line current at these locations was generally not sufficient to maintain battery charge. As a consequence, the FuseSavers could not act to protect fuses. Therefore we will not be proceeding past the trial and are removing the FuseSavers from the network.

## 6.6 Regulatory investment tests

As detailed in Sections 5.16.3(a)(2) and 5.17.3(a)(2) of the Rules, we are required to undertake a regulatory investment test for all capital works projects where the augmentation component is estimated to be in excess of the applicable cost threshold. The regulatory investment test requires us to consult with AEMO and all interested parties; however we continue to consult with additional stakeholders as part of our normal planning process. Our requirements under the regulatory investment test are detailed in Section 2.1.4 of this document.

We did not complete any regulatory investment tests in the past year, nor do we have any in progress. In addition, we do not propose any projects in this APR that will likely be subject to the regulatory investment test.

## 6.7 National transmission planning

As the national transmission network planner, AEMO produces an annual National Transmission Network Development Plan (NTNDP). AEMO states that the NTNDP is an independent, strategic assessment of, and appropriate course for, efficient transmission grid development in the National Electricity Market over the next 20 years.

The NTNDP's analysis focuses on the adequacy of the main transmission network and national transmission flow paths over a 20-year study period (to 2036). In Tasmania, the main transmission network is the 220 kV bulk transmission network and the portion of 110 kV transmission network that operates in parallel to and supports the 220 kV network. National transmission flow paths support major power transfers between zones of generation and demand centres in the NEM. Tasmania is considered a single zone and therefore there are no national transmission flow paths in Tasmania, however Basslink is a national transmission flow path linking the Tasmania and Latrobe Valley (in Victoria) zones.

The NTNDP also reports on AEMO's assessment of the needs for Network Support and Control Ancillary Services (NSCAS) in a five-year period. NSCAS relate to the capability to control active and reactive power flow into or out of the transmission network.

This section details the manner in which our proposed augmentations to the transmission network relate to the NTNDP and the development strategies for national transmission flow paths specified in the NTNDP. The most recent NTNDP was published in December 2016.[46]

46 *Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan*

### 6.7.1 Relationship of our proposed augmentations to the NTNDP

We propose to install reactive compensation, in the form of a new 40 MVAr 110 kV capacitor bank, at George Town Substation in 2017, as detailed in Section 6.3.2.1 of this APR. This will go some way to addressing the voltage limitations at George Town Substation, identified in the 2016 NTNDP.[47] Network security is currently maintained through network constraints, however this creates a market cost. As identified in the NTNDP, further potential solutions may require dynamic reactive support at George Town Substation.

Our other proposed augmentations in this APR form part of our NCIPAP program. These are not within the scope of the 2016 NTNDP.

### 6.7.2 Other limitations identified in the NTNDP

The 2016 NTNDP did not identify any reliability limitations or any NSCAS gaps for maintaining power system security in Tasmania. However it did identify a number of projected economic dispatch limitations under differing scenarios.[47] These limitations are summarised in Table 6-14 and also consider the establishment or not of a second Bass Strait interconnector.

We are familiar with these projected limitations and will continue to engage with AEMO and other parties on them. Any augmentation to address these will be identified in future APRs and, where required, undergo a regulatory investment test.

### 6.7.3 Development strategies for national transmission flow paths

There are no national transmission flow paths in Tasmania. However Basslink is a national transmission flow path, connecting the Tasmania and Latrobe Valley (in Victoria) zones. The 2016 NTNDP includes analysis of potential interconnector developments, including an additional flow path between Tasmania and Victoria. It suggests positive net benefits for a second Bass Strait interconnector under its 'Neutral' scenario.

The primary benefits of a second Bass Strait interconnector were identified as deferring the need for peaking generation capacity investments in the mainland NEM, and reductions in overall fuel and operating-and-maintenance costs due to increased production from hydro and wind generation in Tasmania displacing gas generation in the mainland NEM.

The benefits are marginal under this high level analysis, and are sensitive to assumptions on future grid demand, climate change policy and the uptake of large-scale battery storage. We continue to engage with AEMO and other parties on the possible development of a second Bass Strait interconnector, noting further joint analysis by the Australian and Tasmanian governments is expected to be released soon.

47 *AEMO 2016 NTNDP, Table 9.*

**Table 6-14: Summary of 2016 NTNDP projected economic limitations in Tasmania**

| Limitation | Dispatch condition |
|---|---|
| Palmerston–Sheffield 220 kV transmission corridors | New, high wind generation in North West Tasmania or high import from Victoria through a second Bass Strait interconnector (connected in the North West) |
| Sheffield–George Town 220 kV transmission corridors | New, high wind generation in North West and West Coast Tasmania and high Basslink export to Victoria, without a second Bass Strait interconnector |
| Voltage control at George Town Substation | No gas generation at George Town and reduced hydro generation in northern Tasmania at times of high Basslink export to Victoria (current limitation managed through constraints, projected to continue) |
| Basslink inverter commutation instability due to low fault level at George Town Substation | No gas generation at George Town and reduced hydro generation in northern Tasmania at times of high Basslink import from Victoria (current limitation managed through constraints, projected to continue) |
| High rate of change of frequency | New high wind generation in Tasmania and/or increased import from Victoria and reduced hydro generation, or the unavailability of existing frequency control ancillary services with retirement of major industrial customers under a low demand scenario |

# 7
# Information for new transmission network connections



## Overview

This chapter presents information which would be of interest to owners of generating units or large loads that are connected to, or are considering connecting to, our transmission network. The Tasmanian power system has some characteristics which make it unique in the NEM. These characteristics can have an impact on the connection of generating systems or large loads.

## 7.1 Availability to connect to the network

We have a number of load connection points with sufficient capacity such that new loads could connect with minimal or no upgrade work required at the connection point substation to accommodate it. Note that although capacity at the substation may be available, the new load may result in other upgrade works required for capacity increases deeper in the network or for network security or reliability reasons.

Figure 7-1 shows the available firm capacity at each connection point substation where redundancy is available, and the non-firm capacity at single transformer substations (shown in blue). We will work with proponents of any new load proposals to develop the optimal technical and cost-efficient solution.

## 7.2 Power quality

Power quality refers to the technical characteristics of the electricity supply received, such as voltage levels, fluctuations and disturbances that ensure that the consumer can utilise electric energy from the transmission or distribution systems successfully, without interference or mal-operation of electrical equipment.

Generally, the voltage magnitude is most important, because customers generally notice voltage deviations more than other power quality limitations. The main categories of deviation are: temporary voltage variations, repeated voltage fluctuations (flicker), harmonic voltage distortions and voltage unbalance.

### 7.2.1 Objectives

Our transmission network power quality objectives are to:

- comply with regulatory obligations as stipulated in Schedule 5.1 of the Rules;
- apply appropriate planning criteria to minimise the risk of non-compliance with power quality standards following the connection of new participants to the network;
- work in a collaborative manner with affected parties, continue to develop knowledge and understanding of power quality limitations and assist with identifying mitigating measures, where appropriate; and
- monitor power system performance and assess compliance in accordance with defined planning criteria.

### 7.2.2 Performance criteria (transmission)

The power system standards stipulated in Schedule 5.1a of the Rules include separate technical performance criteria, which we address collectively under the broader heading of power quality. These are:

- S5.1a.4 power frequency voltage (which deals with over & under voltage);
- S5.1a.5 voltage fluctuations (which deals with flicker);
- S5.1a.6 voltage waveform distortion (which deals with harmonics); and
- S5.1a.7 voltage unbalance.

In line with our stated objectives outlined above, we address the power system performance criteria by continuously monitoring power quality at key substations.

### 7.2.3 Performance criteria (distribution)

The power quality standards relevant to the distribution network are detailed in AS 61000 Electromagnetic capability and chapter 8 of the Tasmanian Electricity Code. The specific standards for each element of power quality are:

**Voltage**

- SA/SNZ TS IEC 61000.3.5:2013 Electromagnetic capability (EMC) –Limits – Limitation of voltage fluctuations and flicker in low-voltage power supply systems for equipment with rated current greater than 75 A;
- AS/NZS 61000.3.6:2001 Electromagnetic capability (EMC) – Limits – Assessment of emission limits for distorting loads in MV and HV power systems (IEC 61000-3-6:1996);
- AS 61000.3.100-2011 Electromagnetic capability (EMC) – Limits – Steady state voltage limits in public electricity systems; and
- Section 8.6.4 of Tasmanian Electricity Code.

**Harmonics**

- AS/NZS 61000.2.2:2003 (R2013) Electromagnetic compatibility (EMC) – Environment – Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems;
- AS/NZS 61000.2.4:2009 Electromagnetic compatibility (EMC) – Environment – Compatibility levels in industrial plants for low-frequency conducted disturbances;
- AS/NZS 61000.2.12:2003 (R2013) Electromagnetic compatibility (EMC) – Environment – Compatibility levels for low-frequency conducted disturbances and signalling in public medium-voltage power supply systems; and
- TR IEC 61000.3.7:2012 Electromagnetic compatibility (EMC) – Limits – Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

**Power factor**

- Section 8.6.3 of Tasmanian Electricity Code.

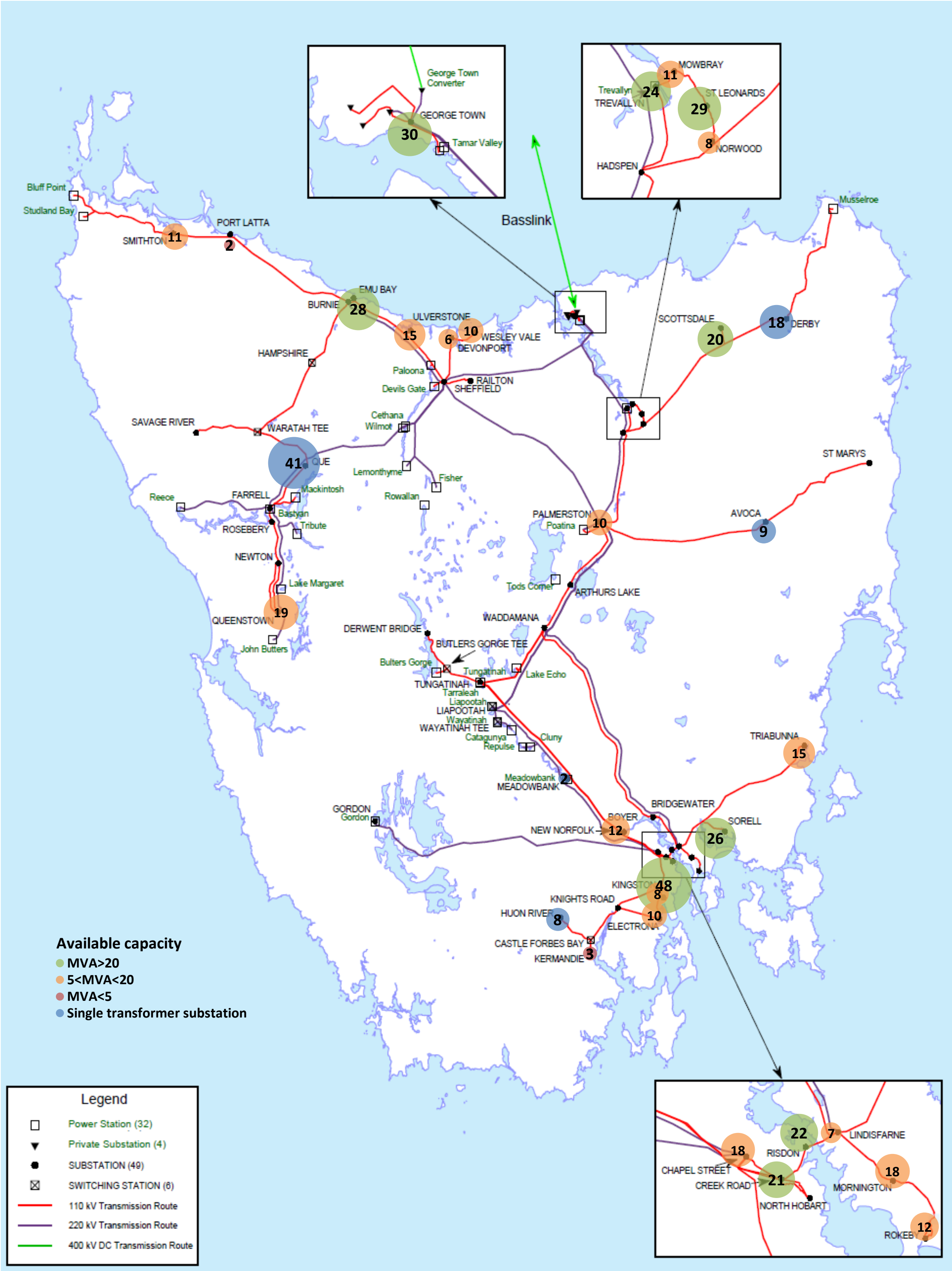



Figure 7-1: Load connection point available capacity

## 7.2.4 Planning levels and strategies (transmission)

### 7.2.4.1 Voltage fluctuations and voltage waveform distortion

Schedules 5.1.5 and 5.1.6 of the Rules require a Network Service Provider to determine 'planning levels' for connection points in its network. We have calculated these planning levels, which are presented in Appendix H.

When processing a new connection application, we will allocate a proportion of these planning levels to each connection applicant to define their maximum emission limits. The allocated limits will be a function of the applicant's maximum agreed demand and the connection point's firm MVA capability.

Our planning studies take into account the typical increased levels of harmonic voltages resulting from load growth, and we implement mitigation measures as required to keep the harmonic content within the specified limits. The planning process does not take into account high levels of harmonic injection from single connection points. We would require the causer to implement mitigation measures in such situations.

### 7.2.4.2 Under voltage performance

The Rules do not contain a system standard for under-voltage recovery. We have therefore developed an under-voltage recovery guideline, which we use as the basis for assessing whether the voltage recovery performance of equipment is acceptable. This guideline is included in Appendix H.

Whilst not strictly enforceable under either the Rules or Tasmanian regulations, this guideline does provide connecting parties with an indication of the post-fault voltage recovery profile which we are endeavouring to meet in our transmission network.

## 7.3 Frequency control ancillary services

For any power system to operate stably there must be a continuous and close balance between the power generated and the power consumed. FCAS is the mechanism by which this balance is maintained. The power system needs sufficient power reserves to offset the continually fluctuating loads with supply side adjustments. The supply side adjustments are usually provided by generators. There must also be sufficient reserves to cope with contingencies that cause major loss of generation or load.

The provision of FCAS in Tasmania is not the responsibility of the transmission network service provider; it is a service supplied by the market and thus AEMO is responsible for ensuring that sufficient FCAS is dispatched. During each dispatch interval, AEMO must enable sufficient FCAS to meet system requirements.

There are eight different categories of FCAS. In Tasmania, it is generally the provision of the Fast Raise and Fast Lower services (formerly known as 6-second raise and lower) that are the most challenging to provide. This is because of the inherent response characteristics of hydro generators. The provision of FCAS in the longer time frames of 60 seconds and 5 minutes is easier to achieve, as hydro generators are generally unhindered by temperature and fuel supply issues that tend to constrain the ramping capability of thermal generators.

To limit the requirement for Fast Raise FCAS, the Tasmanian Frequency Operating Standards[48] limit the maximum credible generator contingency size to 144 MW. Generating units operating above this output must implement suitable measures to effectively limit

48 *The Tasmanian Frequency Operating Standards: http://www.aemc.gov.au/Media/docs/Final%20Report-83b9ab86-e33f-463a-bc29-f3d62a74b0fb-0.pdf*

the maximum generator contingency to 144 MW. This may be accomplished via a tripping scheme to quickly disconnect an appropriately sized load in response to the generator's own trip event, resulting in a net generation loss of 144 MW or less. The commercial negotiations with a suitable network load owner are the responsibility of the generator. TasNetworks is able to provide and maintain the tripping scheme as a non-regulated service.

The tripping of Basslink is the largest single contingency risk in Tasmania. It is mitigated by the FCSPS. The FCSPS acts to limit frequency deviations in Tasmania by rapidly disconnecting appropriate generators if Basslink trips while exporting; it will disconnect loads if Basslink trips while importing. Participation of new loads or generators in the FCSPS is not mandatory, and is commercially negotiated through a Participation Agreement. TasNetworks owns and maintains the FCSPS hardware, and we are able to extend the scheme to include new participants following agreement by all parties.

The ability of Basslink and the other non-synchronous generators (mainly windfarms) to supply an increasing proportion of Tasmanian load increases the chances of the power system having too little inertia. We have mitigated this risk by implementing the NEM's first Rate of Change of Frequency (RoCoF) constraint equation. The constraint equation will limit non-synchronous generation and/or Basslink import, to contain the rate of change of frequency following a credible contingency event. This will achieve two outcomes:

1. Ensure generating systems that are sensitive to RoCoF are not disconnected from the power system due to operation of their protection systems following credible contingency events.
2. Ensure that RoCoF elements forming part of the existing design of the Tasmanian Under Frequency Loading Shedding Scheme do not operate for credible contingency events.

## 7.4 Tasmanian developments that could impact on Basslink energy transfer

Basslink is Tasmania's only interconnection to the remainder of the NEM. New developments that affect the energy transfer across Basslink could therefore have a material impact on the economic efficiency of the NEM, as well as constraining the energy production from Tasmanian based generators.

Basslink requires a certain level of support from the power system in order to maintain its energy transfer. To date, this has been provided by synchronous generation. The design and performance characteristics of many new forms of renewable generation (most notably wind and solar photovoltaic) are such that they are not equivalent and cannot be directly substituted in place of synchronous machines. Two characteristics which are relevant to the operation of Basslink, and the Tasmanian power system more broadly, are the limited contribution of inertia and fault level coming from solar photovoltaic and wind generation technologies. Other network performance aspects, including voltage and frequency control capability, can also indirectly affect Basslink's ability to operate unconstrained.

The capacity of wind generation in Tasmania now exceeds 300 MW. This has provided the first insight to the types of new operational constraints that can result from the connection of non-synchronous generation en masse. Modifications to FCAS calculations, and the implementation of the first rate-of-change-of-frequency constraint in the NEM, are two notable examples.

There is potential for further operating constraints to be imposed, which could limit the dispatch targets of Basslink and/or Tasmanian wind farms, if mechanisms are not identified to ensure the dispatch of sufficient inertia and fault level. There are three key aspects to this issue, which we are pursuing as part of ongoing investigations linked to the integration of large scale renewables:

- determining the minimum level of synchronous machine support required to support various combinations of Basslink power transfer (import and export), wind generation and Tasmanian load demand;
- determining the appropriate form of constraints to maintain the security of the power system if sufficient synchronous machine support is not available through normal market processes; and
- identifying alternative mechanisms that may reduce or eliminate constraints through the use of commercial instruments (e.g. network support agreements with generators) or other engineering solutions (e.g. installation of equipment such as synchronous condensers).

We are committed to understanding the issues outlined above. We are actively working with AEMO and network users to develop credible and practical solutions that maximise the capability of existing and potential new assets, without compromising power system security and reliability standards.

## 7.5 Connection and integration of additional wind generation

The issues Tasmania faces in connecting additional wind generation can be classified into two broad categories: connection issues and integration issues.

Connection issues can be considered the local issues that a wind farm may face when connecting to a specific location in the network, whereas integration issues are the system wide issues associated with accommodating higher levels of wind generation. Integration issues apply more broadly to any type of non-synchronous generation.

## 7.5.1 Connection issues

### 7.5.1.1 Short circuit ratio

Most wind farms require a certain level of power system support at their connection point to enable them to connect to the network in a stable and reliable manner. Larger wind farms require stronger power systems, and the accepted way of defining this relative strength is by defining the short circuit ratio at the connection point. The short circuit ratio is calculated by dividing the MVA fault level at the connection point by the MW rating of the wind farm. Many of Tasmania's best wind resource areas are often remote from the main network and have inherently low short circuit ratios. Existing wind farms may have already absorbed much of the available MVA fault level in their locality, meaning that future wind farms will connect to an effectively weaker power system.

### 7.5.1.2 Reactive power requirements

The reactive power capability (ie its size and response characteristics) that a wind farm requires to meet network access standards is heavily influenced by the network location at which the wind farm is to be connected.

## 7.5.2 Integration issues

### 7.5.2.1 Displacement of synchronous generators

At a higher level, consideration must be given to the impact that wind generation will have on the overall power system and in particular the displacement of traditional synchronous generators that could occur. Since synchronous generators supply the power system with the bulk of its FCAS and the bulk of its inertia, their displacement makes these services scarcer. Further displacement of synchronous generation by non-synchronous generation could ultimately place constraints upon the level of wind and other non-synchronous generation that could be securely dispatched. In Tasmania this is exacerbated by the presence of Basslink which, like wind farms, can cause large energy deficits (and hence frequency dips) when recovering from system faults.

Voltage control at George Town Substation can be challenging at times. Displacement of synchronous generators by non-synchronous generation will reduce the fault level at George Town Substation, making the voltage at George Town Substation more difficult to control.

### 7.5.2.2 Isolated operation

If the wind farm is located where it, along with other loads or generators, could become isolated from the main network, the wind farm must incorporate an anti-islanding protection scheme. We require this, as part of the Rules, to ensure power quality on the network and to customers is not compromised.


## 7.5.3 Connection requirements

To address these issues, we have developed connection requirements for existing and new connecting wind and other asynchronous generation to the Tasmanian power system. The purpose of the requirements is to provide generators clear guidance on what are acceptable access standards for the connection and operation of generating plant in the Tasmania.

Providing these requirements ensures the principles of the National Electricity Objective (NEO) are upheld and the capability of the future network is appropriately managed. The NEO will be upheld by not accepting equipment performance that does not compare favourably with contemporary industry standards and does not address the predictable system performance issues that will accompany ongoing development of renewable energies in Tasmania.

The information is contained in a document "Connection requirements for asynchronous generation in Tasmania", and is available to all existing and intending generators.

# Appendices

# Appendix A Glossary and abbreviations

## A.1 Glossary

The definitions provided here are common electricity industry definitions, provided to assist readers who may be unfamiliar with particular industry terminology.

Terms marked [R] are also formally defined in chapter 10 of the Rules. The definitions given below may be different from the Rules definitions. For the purposes of interpreting the requirements of the Rules, the formally defined terms within the Rules should be used.

| | |
|---|---|
| Basslink | a privately owned undersea cable connecting the Tasmanian electricity network to that of mainland Australia. Basslink is described in Section 3.4. |
| bay | the suite of electrical infrastructure installed within a substation to connect a transmission line, distribution line, transformer or generator to substation busbars. |
| circuit kilometre | the physical length of a transmission circuit that transports power between two points on the transmission system. A transmission line containing two circuits will traverse two circuit kilometres for every one route kilometre. See also: route kilometre. |
| Code | refers to the Tasmanian Electricity Code. The Code addresses Tasmanian jurisdictional interests which are not dealt with by the Rules. |
| coincident maximum demand | the highest amount of electricity delivered, or forecast to be delivered, simultaneously at a set of connection points. |
| committed project | a project which has received board commitment, funding approval, has satisfied the regulatory investment test (where relevant) and a firm date has been set for commencement. |
| constraint | a technical limitation in a part of the power system which makes it necessary to restrict the power flowing through that part of the system. [R] |
| constraint equation | a mathematical representation of a constraint, which is then programmed into AEMO's generation dispatch system. The use of constraint equations allows generators' outputs to be automatically adjusted so that constraints are not exceeded. |
| contingency event | an unplanned fault or other event affecting the power system. Typical contingency events include: lightning strikes, a generator or load or transmission circuit tripping, objects (such as bark, fallen trees, or possums) coming into contact with conductors, bushfire smoke causing a short circuit. [R] |
| dispatch interval | a five minute period during which the process of generator scheduling is undertaken. See also: trading interval. [R] |
| diversity | the ratio of demand of the particular load at the time of maximum demand of the group of loads considered to the maximum demand of the particular load. |
| embedded generator | a generating unit that is directly connected to the distribution network as opposed to the transmission network. [R] |
| energy generated | the total amount of electrical energy injected into the transmission network to meet the Tasmanian energy sales. It comprises the energy sent out from Tasmania's power stations, plus the energy imported via Basslink, minus energy exported to Basslink. It includes network losses but excludes power station auxiliary loads. |
| energy sales | the total amount of electrical energy consumed in Tasmania for a particular period. |
| fault level | the amount of current that would flow if a short circuit occurred at a specified location of the network. From a power system planning and operation perspective, fault level is also an indicator of the resilience of the network: a portion of the network with high fault levels is less likely to be affected by faults elsewhere in the network. |
| firm | indicates that the network, or a portion of the network, has the capacity to maintain supply to customers following a contingent event. See also: non-firm. |
| guaranteed service level scheme | a payment scheme where our distribution customers are compensated for prolonged and excessive interruptions to their supply. |
| inertia | the rotating mass inside a generator. The more inertia a power system contains, the more slowly its frequency will deviate from 50 Hertz following a contingency event. Only generators that are running (and therefore spinning) contribute inertia to a power system. |

| | |
|---|---|
| island | a part of the network, which has become disconnected from the remainder of the network, and contains at least one generator. An island can potentially remain live and stable provided the generation and load within the island are nearly equal. |
| Jurisdictional network performance requirements | reference to the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007*, described in Section 2.1.2. |
| kilo-Volt | one kilo-Volt equals 1,000 Volts. See also: voltage. |
| limitation | network constraint or inability to meet a network performance requirement. See also: constraint. |
| load factor | the ratio of average demand to maximum demand over the same period. |
| market network service provider | a network service provider whose network links two connection points located in different NEM regions, the power transfer between which can be independently controlled and dispatched via the central dispatch process. The network must not be the subject of a revenue determination by the Australian Energy Regulator. Basslink is the only MNSP in the NEM. [R] |
| network | the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers. See also: distribution network; transmission network. [R] |
| non-firm | indicates that a contingent event on the network, or portion of the network, may result in the loss of supply to customers. See also: firm. |
| non-network solution | a solution to a network limitation that does not require the construction of a network augmentation. Examples include electronic control schemes and demand side management. |
| non-synchronous generator | for the purposes of this APR, non-synchronous generators include Basslink, solar photovoltaic (PV) panels, wind farms, and some mini-hydro or micro-hydro generators. See also: synchronous generator. |
| power factor | the ratio of real power to the apparent power at a metering point. [R] |
| probability of exceedance (POE) | probability of dropping the temperature below the reference temperature used in estimating/forecasting the relevant demand. As temperature is inversely proportionate to demand in Tasmania, the probability is implied as probability to exceed the estimated/forecasted demand with respect to changes in temperatures. |
| protection | equipment which rapidly detects electrical faults in the network, and then disconnects that part of the network in order to prevent damage. |
| route kilometre | the physical length of transmission infrastructure required to transport power between two points on the transmission system. See also: circuit kilometre |
| Rules | the National Electricity Rules |
| substation | an installation of electrical infrastructure at a strategic location on the network to provide the functions of voltage transformation, switching and voltage conversion. [R] |
| switching station | an installation of electrical infrastructure at a strategic location on the network to provide the function switching at a single voltage level. |
| synchronous generator | for the purposes of this APR, synchronous generators refer to generators driven by hydro, gas, or steam (ie coal-fired) turbines. NB: There are no coal-fired power stations in Tasmania. See also: non-synchronous generator. [R] |
| trading interval | a 30 minute period ending on the hour or on the half hour and, where identified by a time, means the 30 minute period ending at that time. Financial settlement in the NEM takes place by trading interval. See also: dispatch interval. [R] |
| transmission network | the suite of electrical infrastructure required to transmit power from the generating stations to the distribution network and directly connected industrial consumers. In Tasmania, the transmission network comprises the network elements that operate at voltages of either 220 kV or 110 kV, plus the equipment required to control or support those elements. [R] |
| trip | the sudden disconnection of a generator, load or transmission or distribution circuit from the remainder of the network. |
| voltage | the force which causes electrical current to flow. [R] |

## A.2 Abbreviations

| | |
|---|---|
| AC | Alternating Current |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| APR | Annual Planning Report |
| AS | Australian Standards |
| CBD | Central Business District |
| DC | Direct Current |
| EHV | Extra High Voltage |
| ESI | Electricity Supply Industry |
| FCAS | Frequency Control Ancillary Services |
| FCSPS | Frequency Control System Protection Scheme |
| GSP | Gross State Product |
| GWh | Gigawatt-hour |
| Ha | Hectare |
| HV | High Voltage |
| HVDC | High Voltage Direct Current |
| Hz | Hertz |
| IEC | International Electrotechnical Commission |
| kA | Kiloamps |
| kV | Kilovolts |
| LOS | Loss of Supply |
| MAIFI | Momentary System Average Interruption Frequency Index |
| MD | Maximum Demand |
| MNSP | Market Network Service Provider |
| MV | Medium Voltage |
| MVA | Megavolt-amperes |
| MVAr | Megavolt-amperes reactive |
| MW | Megawatts |
| MWh | Megawatt-hour |
| NBN | National Broadband Network |
| NCIPAP | Network Capability Incentive Parameter Action Plan |
| NCSPS | Network Control System Protection Scheme |
| NEM | National Electricity Market |
| NEMDE | National Electricity Market Dispatch Engine |
| NIEIR | National Institute of Economic and Industry Research |
| NSCAS | Network Support and Control Ancillary Services |
| NTNDP | National Transmission Network Development Plan |
| NZS | New Zealand Standards |
| OTTER | Office of the Tasmanian Economic Regulator |
| POE | Probability of Exceedance |
| PU | per unit |
| PV | photovoltaic [solar generation system] |
| RIT | Regulatory Investment Test |
| RoCoF | Rate of Change of Frequency |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Supervisory Control and Data Acquisition |
| SPS | System Protection Scheme |
| STPIS | Service Target Performance Incentive Scheme |
| TOV | Temporary Over Voltage |
| TR | Technical Report |
| TS | Technical Specification |

# Appendix B Fault level and sequence impedances

We calculate fault currents at transmission network substations in accordance with the recommendations of Australian Standard AS 3851-1991. The calculation of short-circuit currents in three-phase AC systems. From this, the maximum fault currents calculated at 1.1 pu voltage and the minimum at 0.9 pu voltage. The Thevenin impedance is defined as the source impedance back to the generators, and large motors where considered. This method thus defines the extreme envelope for all fault currents and is appropriate to be used for future planning. We recognise that at particular network locations the actual envelope could be smaller but this would need confirmation with detailed local studies.

Figure B–1 illustrates the AC and DC components that make up fault currents. The size and rate of decay of the DC component is a function of the ratio between the reactance (X) and the resistance (R) of the impedance between the faulted point of the system and the generation feeding the fault. This ratio is defined as the X/R ratio of the system, with the DC component decaying with time constant X/2pfR.

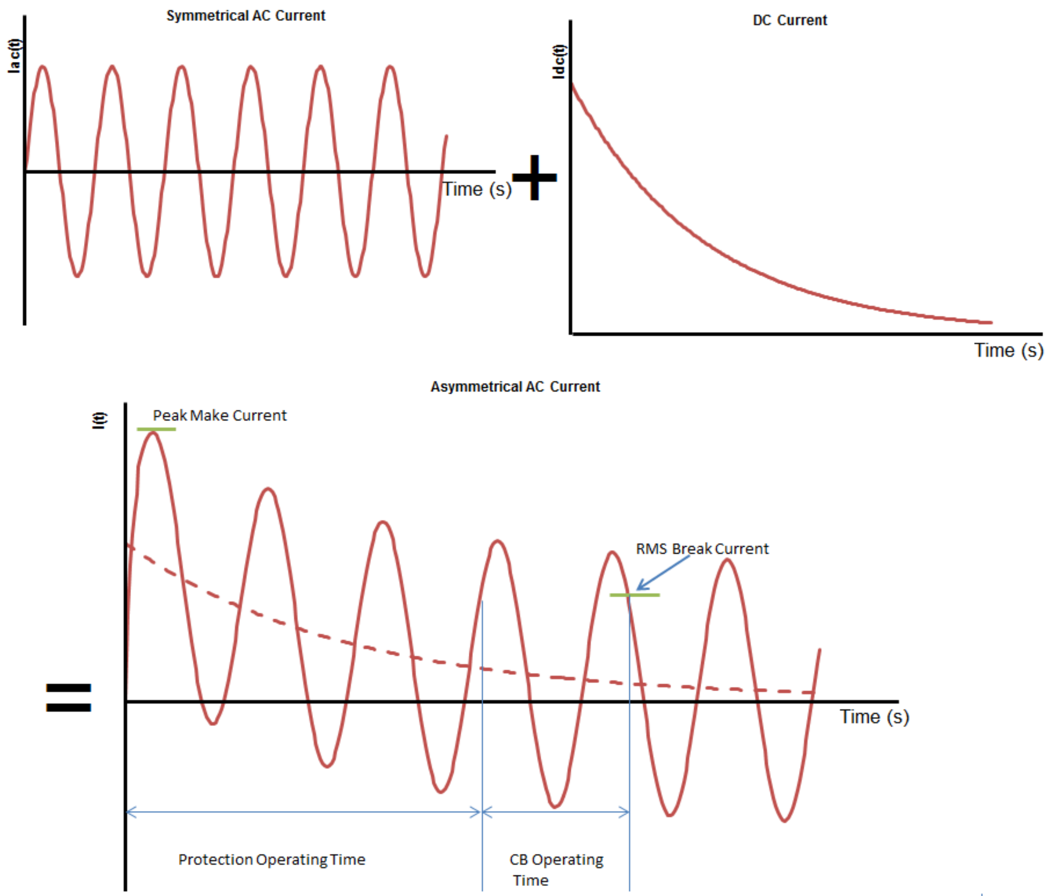



**Figure B–1: Components of AC fault current**

The maximum current that a circuit breaker will be exposed to is defined as the Peak Make Current. During fault conditions, the current a circuit breaker is expected to break is known as the RMS Break Current. This is defined as the RMS of the symmetrical AC component of the fault current plus the offset by the DC component at that point.

# Appendix C Distribution network reliability performance measures and results

Historical distribution reliability performance is presented in this section. This is supporting information for the discussion in Section 4.2.2 of this APR. The information presented here is our performance against the standards set out in the Tasmanian Electricity Code (the Code) and by the AER over the last five years. Our network reliability strategy is presented in Section 2.3.2.

## C.1 Performance against the Code standards

### C.1.1 Supply reliability categories

Table C–1 and Table C–2 present our performance for reliability categories for SAIFI and SAIDI, respectively, against the standards specified in the Code. The performance presented here is what we provide to OTTER as part of our normal reporting process. The standards exclude outages caused by third-party faults and customer plant, and the transmission network.

**Table C–1: SAIFI supply reliability category performance (the Code)**

| Supply reliability category | Standard (interruptions) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|---|
| Critical infrastructure | 0.2 | 0.22 | 0.27 | 0.21 | 0.34 | 0.25 |
| High density commercial | 1 | 0.27 | 0.43 | 0.47 | 0.33 | 0.26 |
| Urban and regional centres | 2 | 1.03 | 0.92 | 0.85 | 1.25 | 1.24 |
| High density rural | 4 | 2.29 | 2.36 | 2.18 | 2.94 | 3.12 |
| Low density rural | 6 | 3.72 | 3.49 | 3.11 | 4.04 | 3.86 |

**Table C–2: SAIDI supply reliability category performance (the Code)**

| Supply reliability category | Standard (minutes) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|---|
| Critical infrastructure | 30 | 25 | 30 | 16 | 57 | 34 |
| High density commercial | 60 | 32 | 77 | 43 | 27 | 23 |
| Urban and regional centres | 120 | 85 | 94 | 164 | 169 | 141 |
| High density rural | 480 | 259 | 269 | 521 | 582 | 521 |
| Low density rural | 600 | 498 | 547 | 740 | 931 | 725 |

### C.1.2 Supply reliability communities

In addition to performance requirements for supply reliability categories presented in Section C.1.1, the Code also sets performance standards for the supply reliability communities within the categories. Table C–3 and Table C–4 present our performance for the 101 supply reliability communities against the SAIFI and SAIDI standards, respectively.
The table presents the standards specified in the Code for each community across the five categories, and the number of communities in each category that is not meeting the standard.

**Table C–3: Number of poor performing communities (SAIFI)**

| Supply reliability category (number of communities) | Standard (interruptions) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|---|
| Critical infrastructure (1) | 0.2 | 1 | 1 | 0 | 1 | 1 |
| High density commercial (8) | 2 | 0 | 0 | 0 | 0 | 0 |
| Urban and regional centres (32) | 4 | 1 | 2 | 3 | 3 | 4 |
| High density rural (33) | 6 | 3 | 2 | 6 | 4 | 2 |
| Low density rural (27) | 8 | 2 | 1 | 2 | 0 | 1 |
| Total (101) | | 7 | 6 | 11 | 8 | 8 |

**Table C–4: Number of poor performing communities (SAIDI)**

| Supply reliability category (number of communities) | Standard (minutes) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 |
|---|---|---|---|---|---|---|
| Critical infrastructure (1) | 30 | 0 | 1 | 0 | 1 | 1 |
| High density commercial (8) | 120 | 1 | 3 | 0 | 0 | 1 |
| Urban and regional centres (32) | 240 | 5 | 5 | 12 | 13 | 10 |
| High density rural (33) | 600 | 3 | 4 | 11 | 13 | 5 |
| Low density rural (27) | 720 | 6 | 6 | 14 | 12 | 8 |
| Total (101) | | 15 | 19 | 37 | 39 | 25 |

# C.2 Performance against AER standards

At the commencement of each distribution regulatory period, the AER, as part of our revenue determination, sets standards for distribution network reliability. These standards form part of our service target performance incentive scheme (STPIS) and are calculated on our actual performance for the preceding five years. The standards set by the AER exclude planned outages to the network, major event days, outages caused by customer plant and certain third-party faults.

Table C–5 and Table C–6 present our performance for reliability categories for SAIFI and SAIDI, respectively, against the standards specified by the AER. These standards have been set for our 2012–17 distribution regulatory period.

The tables show our forecast reliability performance for the remainder of the regulatory period. In forecasting our performance, we use the method the AER uses to calculate our reliability standards. That is, we calculate performance targets from a five year historical average. We forecast reliability performance to generally align with our current STPIS standards. The low density rural supply reliability category is the only category forecast to perform worse than the current standard, in both measures. This is as a result of a particularly poor year experienced in 2013–14. It also reflects the continued challenges in maintaining reliability in the communities in this category, due to the large geographical areas covered by the high voltage distribution lines and limited alternate supply options.

In AER reporting, we currently measure reliability by 'connected kVA'. From July 2017, we will be measuring by customer numbers.

**Table C–5: SAIFI supply reliability category performance (AER)**

| Supply reliability category | Standard (2012–17) (interruptions) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 | Forecast to 2016–17 |
|---|---|---|---|---|---|---|---|
| Critical infrastructure | 0.22 | 0.26 | 0.17 | 0.13 | 0.19 | 0.16 | 0.18 |
| High density commercial | 0.49 | 0.21 | 0.30 | 0.32 | 0.27 | 0.19 | 0.26 |
| Urban and regional centres | 1.04 | 1.01 | 0.82 | 1.21 | 0.85 | 0.97 | 0.97 |
| High density rural | 2.79 | 2.20 | 2.21 | 3.00 | 2.10 | 2.61 | 2.42 |
| Low density rural | 3.20 | 3.36 | 3.00 | 4.65 | 2.77 | 3.22 | 3.40 |

**Table C–6: SAIDI supply reliability category performance (AER)**

| Supply reliability category | Standard (2012–17) (minutes) | 2011–12 | 2012–13 | 2013–14 | 2014–15 | 2015–16 | Forecast to 2016–17 |
|---|---|---|---|---|---|---|---|
| Critical infrastructure | 20.79 | 16.90 | 4.65 | 6.83 | 23.29 | 14.57 | 13.25 |
| High density commercial | 38.34 | 13.57 | 33.61 | 27.66 | 23.22 | 11.37 | 21.89 |
| Urban and regional centres | 82.75 | 67.55 | 64.19 | 101.89 | 76.88 | 78.06 | 77.71 |
| High density rural | 259.48 | 206.15 | 203.25 | 289.29 | 239.17 | 254.26 | 238.42 |
| Low density rural | 333.16 | 383.44 | 358.41 | 533.00 | 360.34 | 370.53 | 401.14 |

# Appendix D Metering and information technology systems

## D.1 Metering programs

An electricity meter is a device that records the amount of electrical energy consumed at a customer installation. The energy consumption data is in turn used to invoice customers for the amount of energy they use. Meters can record and display data as either cumulative total energy used or as energy consumed over shorter periods of time (known as intervals). Meters that record cumulative data are typically read manually on site by a meter reader whereas meters that record interval data are remotely read via a communications link.

Capital investment in metering is driven by new installations and meter replacement. Table D–1 presents our 2015–16 and forecast regulated investment in metering programs. From December 2017, new and replacement metering services will become contestable and unregulated and our expenditure no longer subject to regulation by the AER.

**Table D–1: Regulated investment in metering programs**

| Year | Investment ($m) | |
|---|---|---|
| | New installations | Meter replacements |
| 2015–16 (actual) | 3.20 | 0.68 |
| 2016–17 | 1.60 | 1.70 |
| 2017–18 | 0.80 | Nil |

### D.1.1 New installations

The installation program is driven by customer requirements. In accordance with our metering management plans, all new meters installed will be electronic meters.

Investment in new installations is based on historical volumes and is forecast to cease in December 2017 when the Rules changes for contestability in metering comes into effect. Investment in new meter installations in 2015–16 was above typical annual investment.

### D.1.2 Meter replacement

There are two key drivers for meter replacement:

- meters found to be non-compliant from testing regimes must be replaced to ensure compliance with Chapter 7 of the Rules; and
- planned replacement to address specific business needs such as access, obsolete technologies, obsolete network tariffs and safety issues.

Responsibility for meter replacement will be removed from network service providers in December 2017 when the Rules changes for contestability in metering come into effect. Meter replacements are forecast to cease in July 2017 in preparation for the changes. Meter families that fail compliance testing will be identified and we will advise the Metering Coordinator of the failed status so that arrangements can be made to replace them.

## D.2 Information systems programs

Information systems programs are critical in enabling us to increase our performance, efficiencies and effectiveness in asset management. Elements of focus for successful information systems programs are people, processes and technology. The objectives of the programs are:

- reduction in business risk;
- enhanced network system performance;
- enhanced standards compliance;
- effective knowledge management;
- effective resource utilisation; and
- optimum infrastructure investment.

This section details our investments in information systems programs in the distribution network.

## D.2.1 Investment in 2015–16

Our regulated investments in information systems programs in 2015–16 is summarised in Table D–2.

**Table D–2: Regulated investment in information systems in 2015–16**

| Project | Description | Investment ($000) |
|---|---|---|
| G-Tech upgrade | Upgrade to the latest version of the geographic information system (GIS) Technology software | 291 |
| Program of work management tool | Redevelopment and upgrade to the existing tool to track transmission and distribution network Program of Work forward estimates and expenditure | 69 |
| SCADA uplift | Meet ongoing business requirements for increased performance and dynamic and real-time visibility of assets | 893 |
| Substation data upgrade | Improve the capture and data quality of ground mounted substation asset information and single line diagrams | 117 |
| Unified drawing management | To support implementation of our Connection Choice project | 186 |

## D.2.2 Investment in forward planning period

Our planned investments in information systems programs in the forward planning period is summarised in Table D–3.

**Table D–3: Information systems expected investment forward planning period**

| Project | Description | Year of completion | Investment ($000) |
|---|---|---|---|
| Asset information management standards | Deliver a suite of integrated standards to support our asset management information system | 2016–17 | 644 |
| Asset register | Analyse and investigate current state of asset registers and investigate improvements | 2017–18 | 2,000 |
| Geo-Visualisation Tool | Upgrade to the latest version of WebMap application | 2017–18 | 710 |
| Vegetation management system | Improving and consolidating current data, processes and tools to support the capture and reporting of vegetation data | 2017–18 | 2,500 |
| Asset knowledge management | Improving and consolidating asset knowledge. This includes technical, asset financial, asset geospatial, and asset operational information | 2017–18 | 1,350 |
| Network performance | Improving and consolidating network performance management capability. This includes network performance targets and measures, and performance reporting | 2017–18 | 750 |
| Asset condition monitoring | Improving and consolidating asset condition monitoring and reporting capability. This includes asset inspection and condition, asset defects and incidents | 2019–20 | 2,100 |
| Asset planning | Improving and consolidating asset planning capability. This includes asset repair/refurbish/replace decision making, asset and system modelling, asset annual review, long-term and life-cycle planning | 2019–20 | 860 |
| Asset risk management | Improving and consolidating asset risk management capability. This includes asset failure probability, asset criticality assessment and asset risk evaluation | 2019–20 | 1,500 |
| Supporting asset management processes | Improving and consolidating network performance management capability. This includes data and information analytics, data quality, asset documentation, external systems integration and sustainable business processes | 2019–20 | 3,000 |

# Appendix E Planning area diagrams

This appendix presents geographical and one-line diagrams for each of our seven planning areas. A description of the planning areas is provided in Section 3.6 of this APR. The geographical diagrams present the transmission and sub-transmission networks of each planning area and the supply area of individual connection points to the distribution network. The one-line diagrams present a simplified network arrangement of the areas and identify the planned investments and forecast limitations of each area, as detailed in Chapter 6 of this APR.

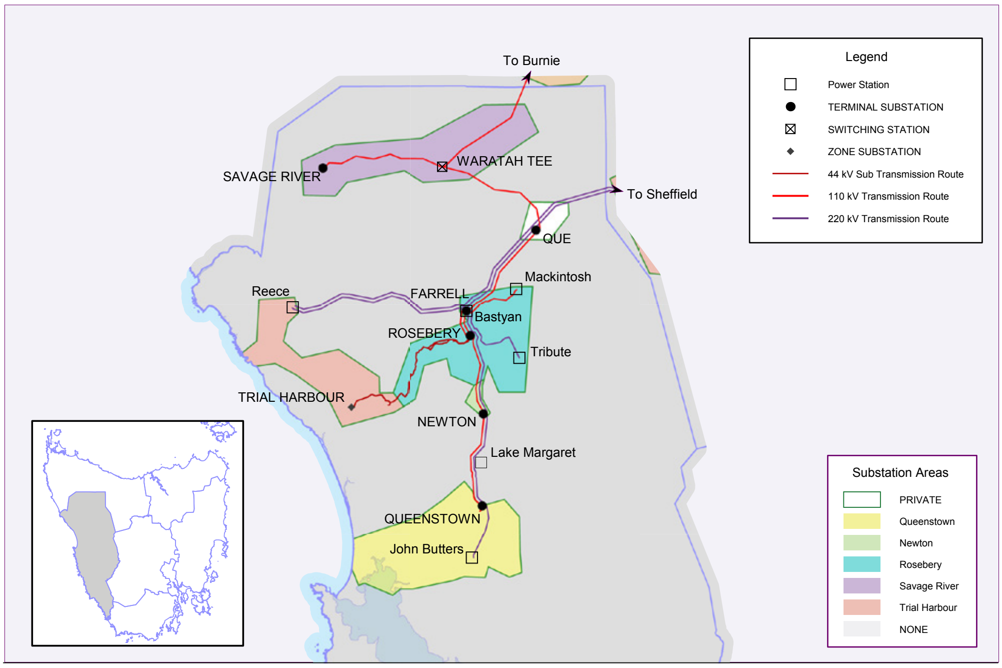



Figure E–1: West Coast planning area network

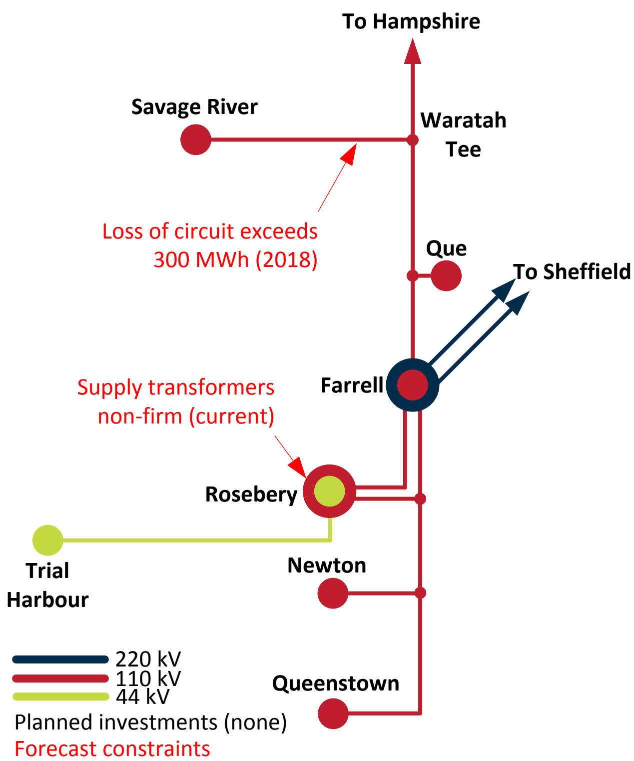



Figure E–2: Planned investments and forecast limitations in West Coast area

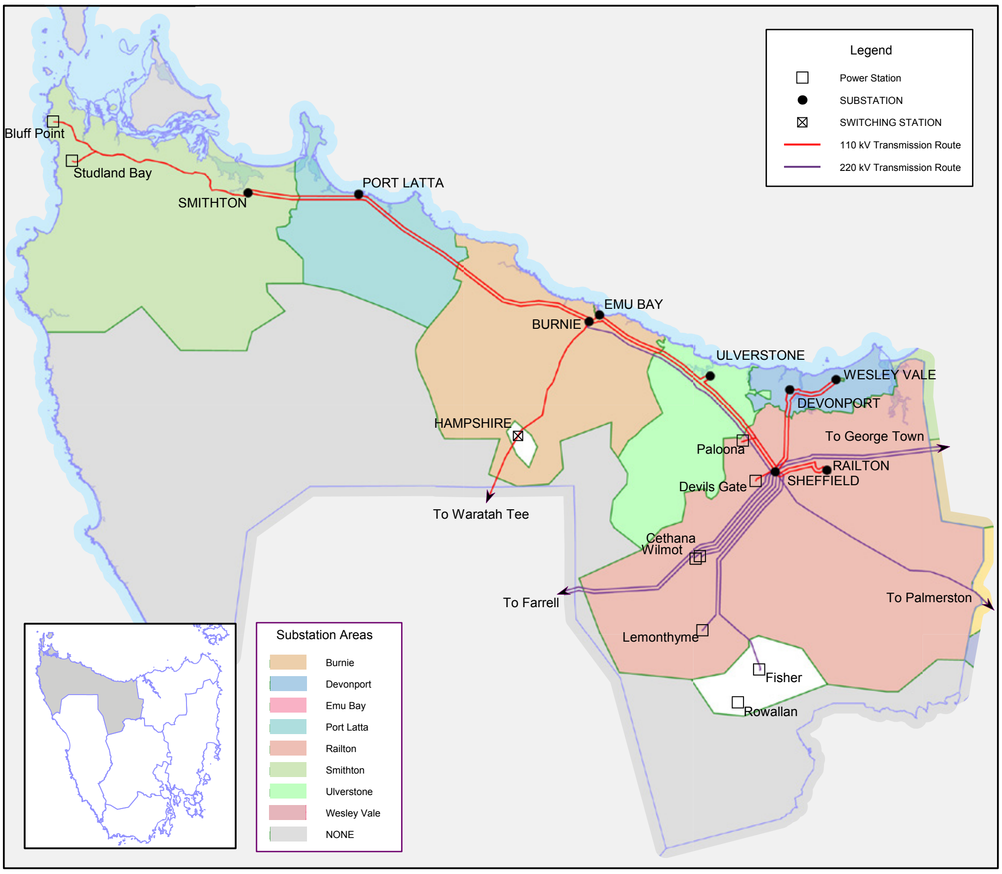



Figure E–3: North West planning area network

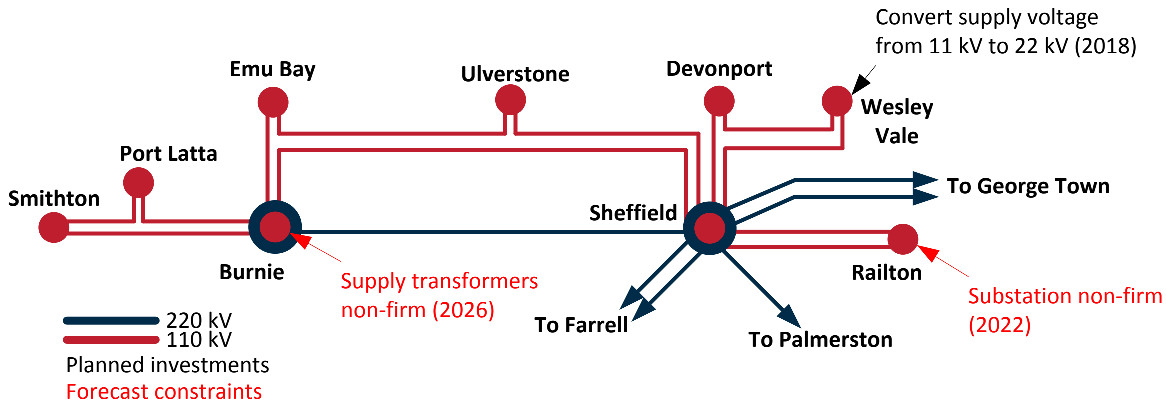



Figure E–4: Planned investments and forecast limitations in North West area

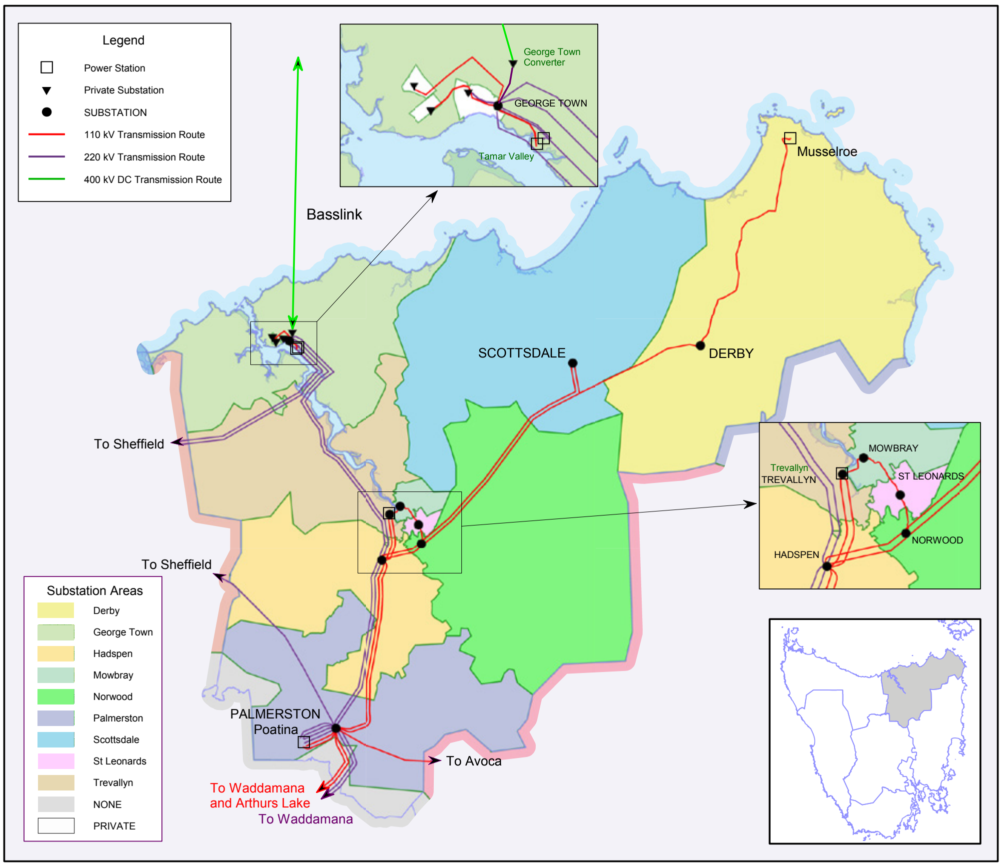



Figure E-5: Northern planning area network

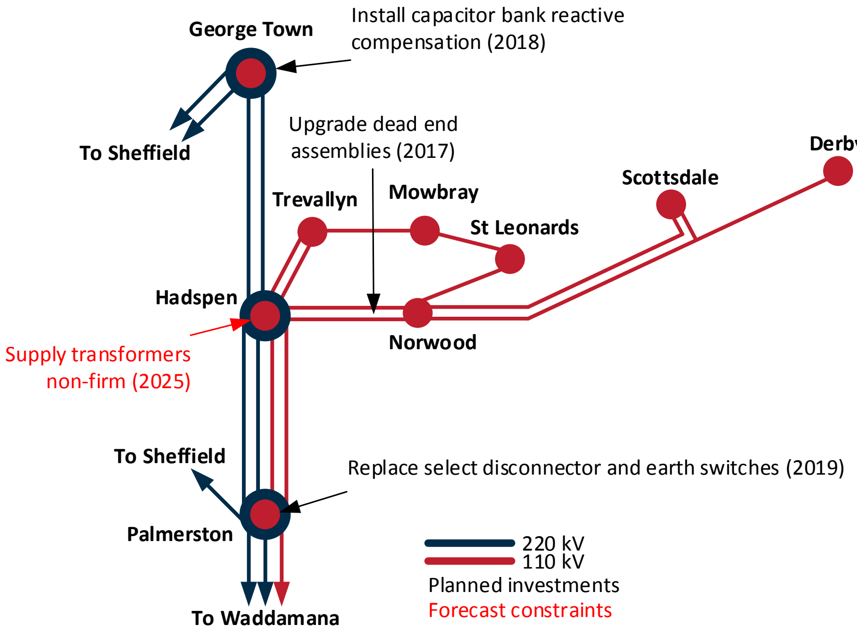



Figure E–6: Planned investments and forecast limitations in Northern area

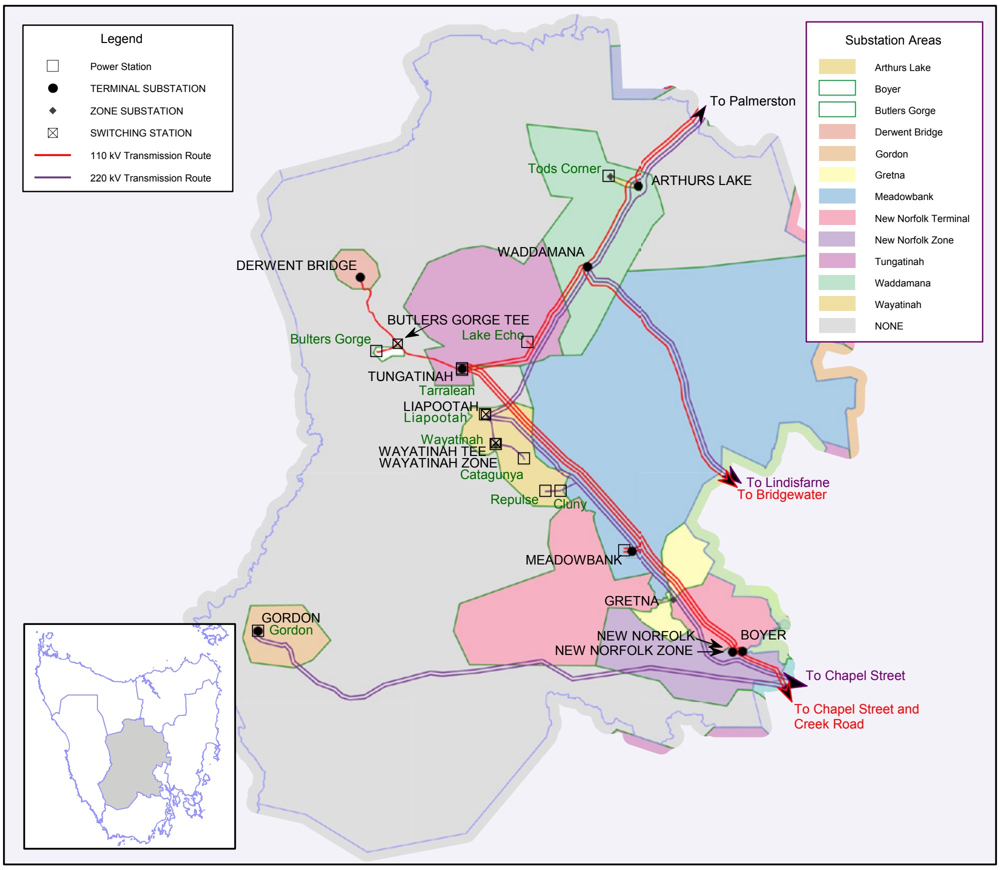



Figure E–7: Central planning area network

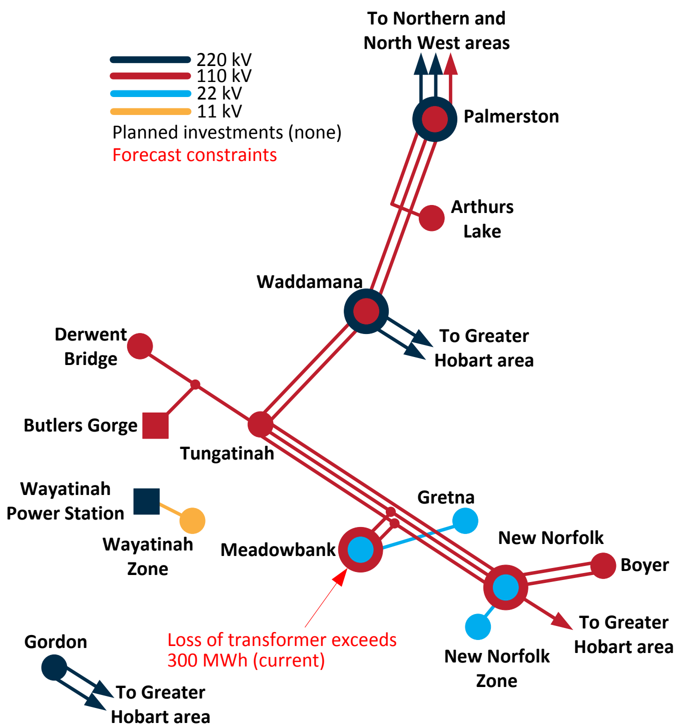



Figure E–8: Planned investments and forecast limitations in Central area

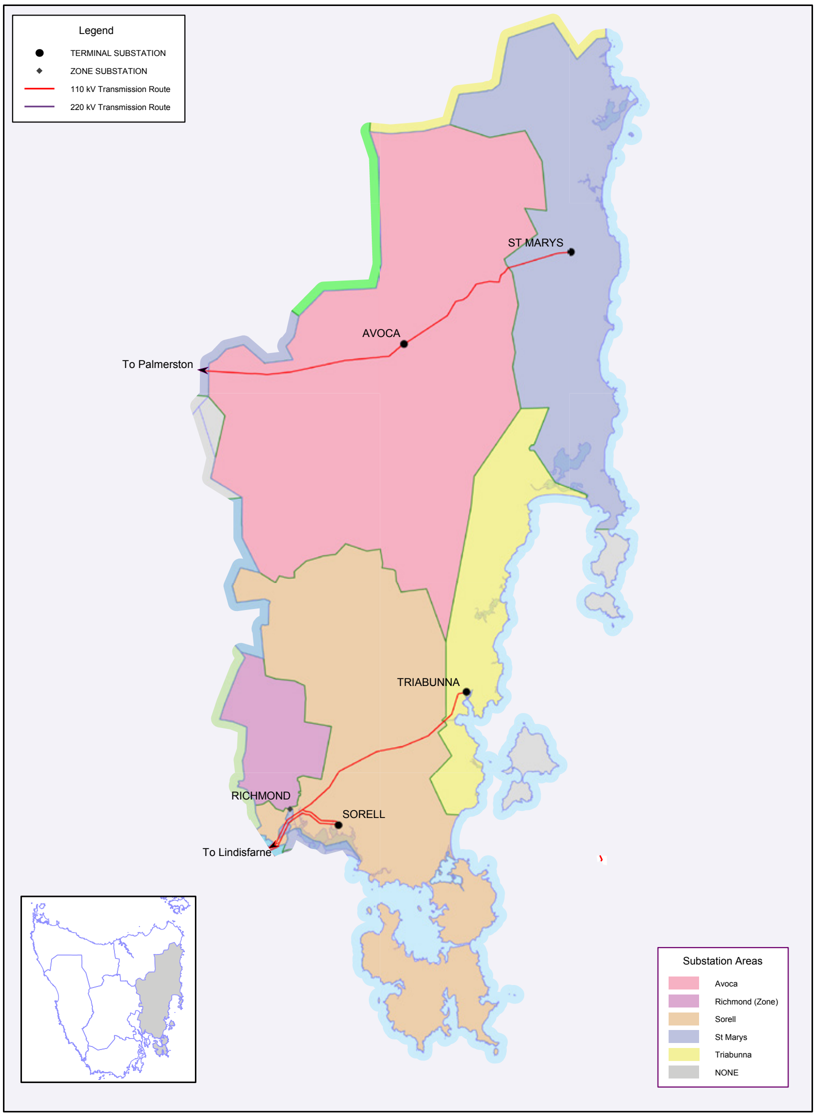



Figure E–9: Eastern planning area network

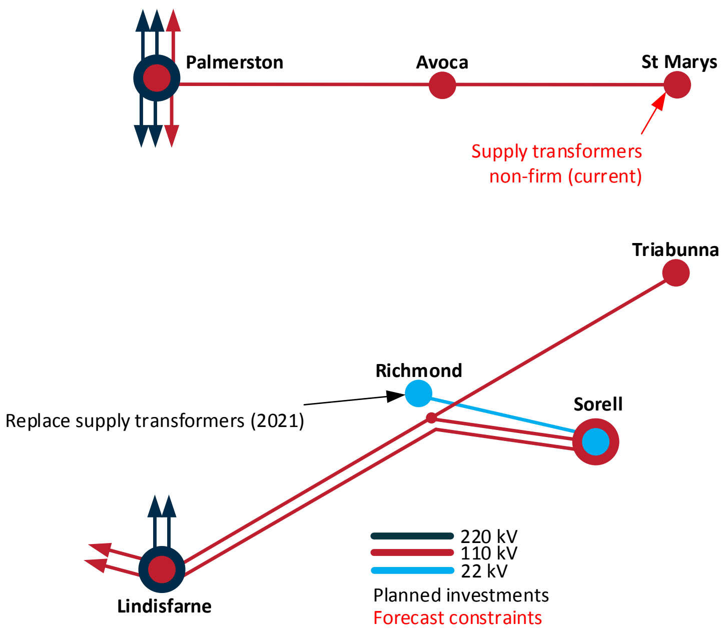



Figure E–10: Planned investments and forecast limitations in Eastern area

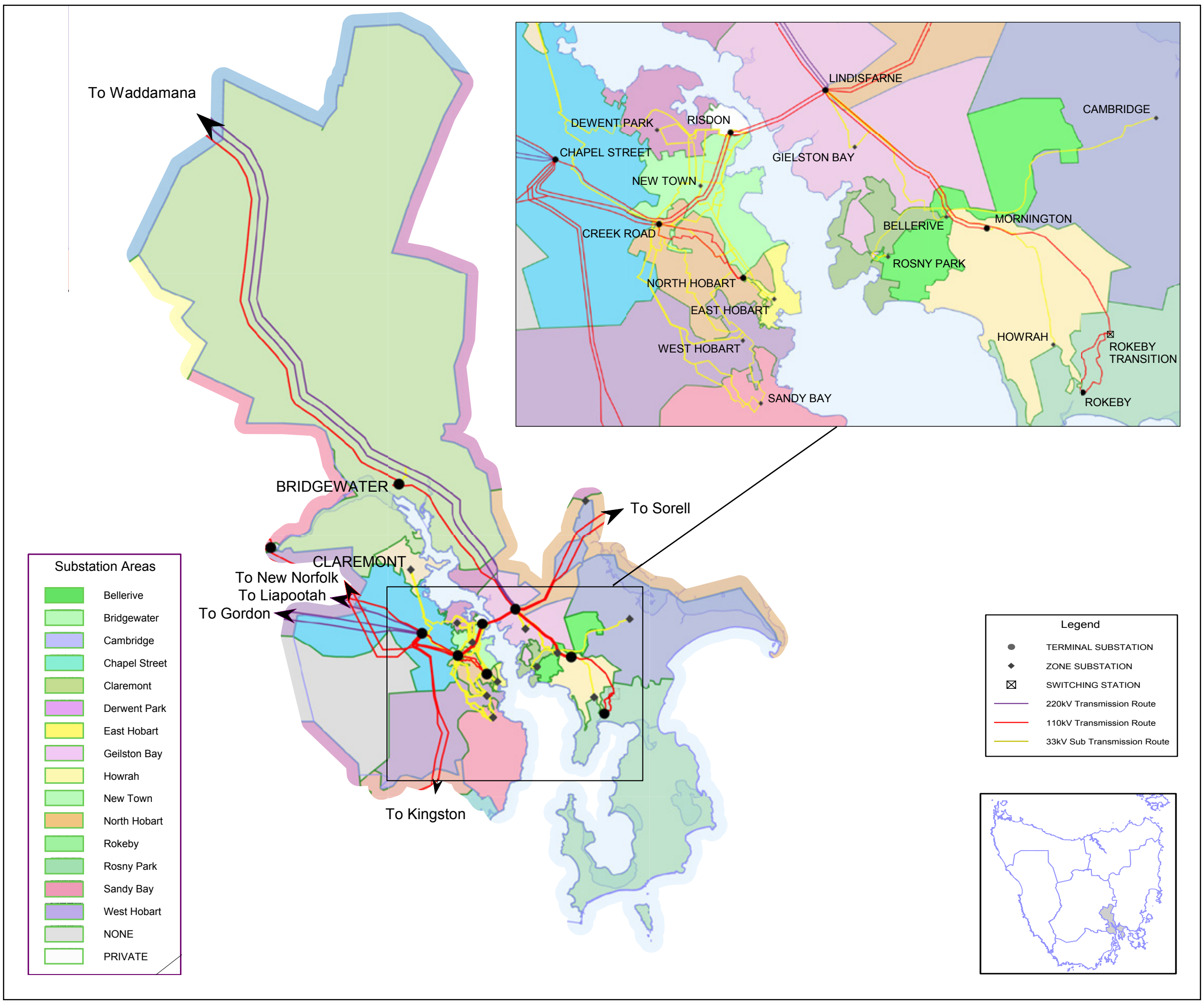



**Figure E–11: Greater Hobart planning area network**

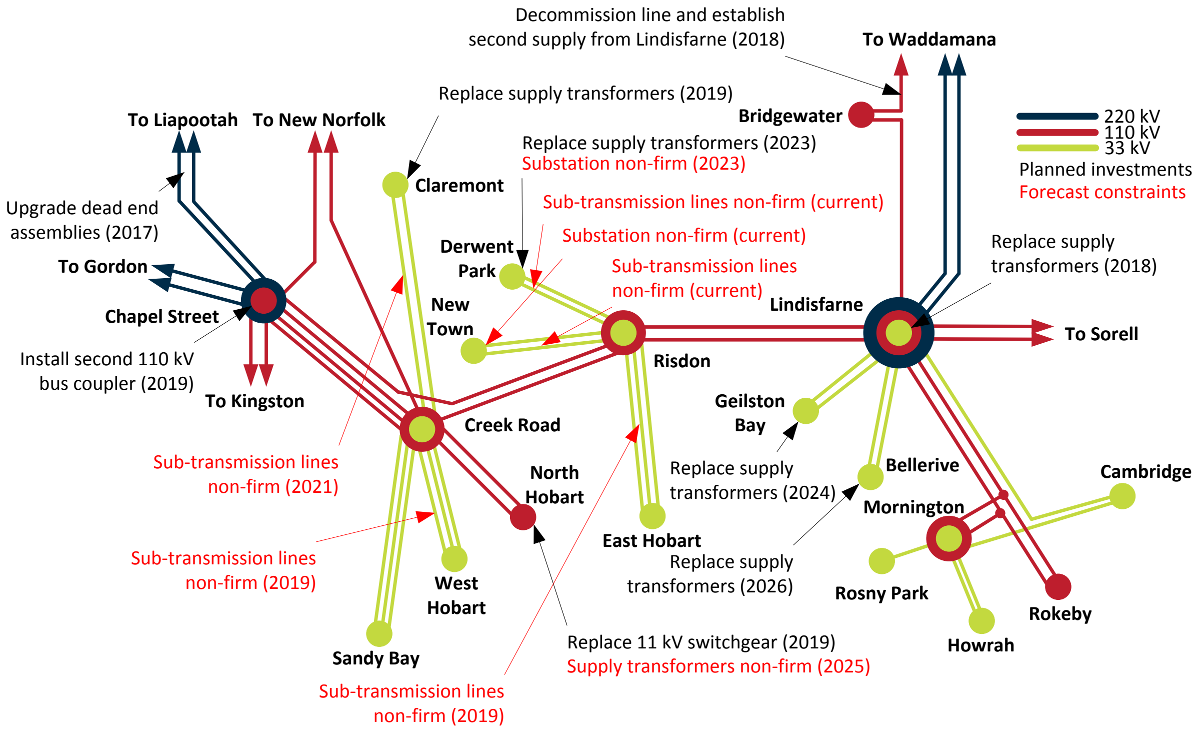



**Figure E–12: Planned investments and forecast limitations in Greater Hobart area**

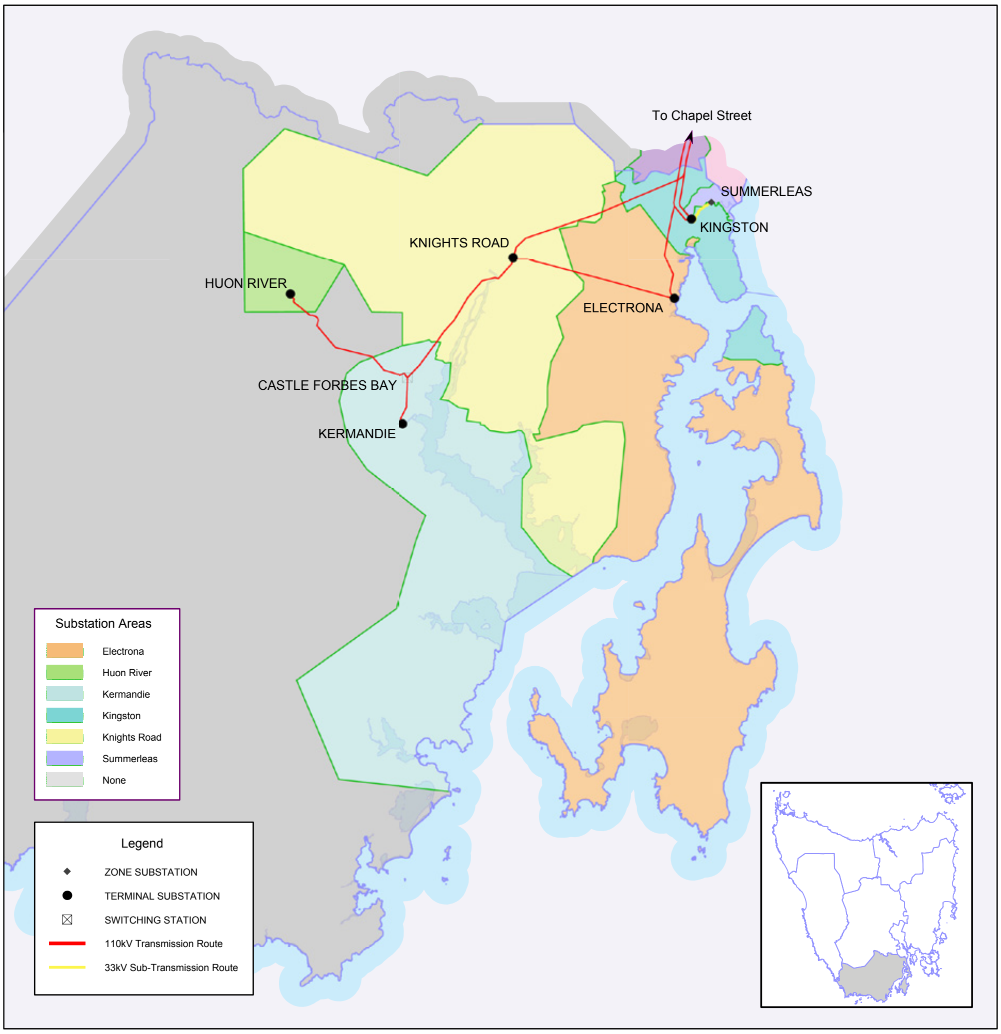



Figure E–13: Kingston-South planning area network

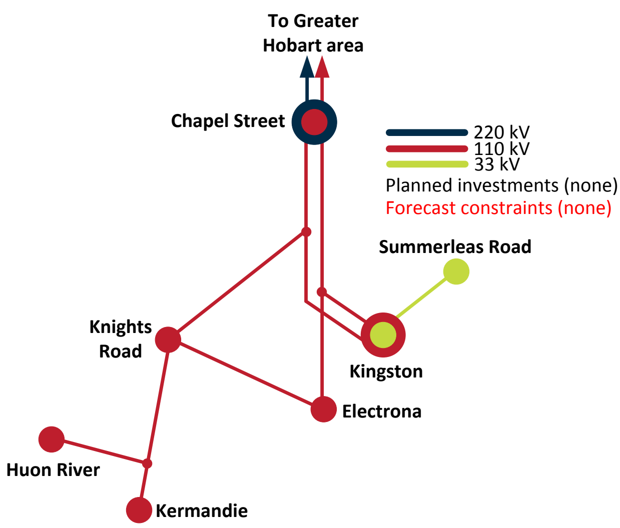



Figure E–14: Planned investments and forecast limitations in Kingston-South area

# Appendix F Generator information

Table F–1 lists the Tasmanian power stations connected to the transmission network.

**Table F–1: Transmission-connected generation**

| Generator | Capacity (MW) | TasNetworks planning area | Connecting substation or transmission line |
|---|---|---|---|
| **Gas** | | | |
| Tamar Valley | 178 | Northern | George Town |
| **Hydro** | | | |
| Bastyan | 81 | West Coast | Farrell |
| Butlers Gorge and Nieterana[49] | 14.4 | Central | Tungatinah |
| Catagunya | 48 | Central | Liapootah |
| Cethana | 100 | North West | Sheffield |
| Cluny | 17 | Central | Liapootah–Chapel Street 220 kV |
| Devils Gate | 63 | North West | Sheffield |
| Fisher | 46 | North West | Sheffield |
| Gordon | 432 | Central | Chapel Street |
| John Butters | 143 | West Coast | Farrell |
| Lake Echo | 32 | Central | Tungatinah–Waddamana 110 kV |
| Lemonthyme | 54 | North West | Sheffield |
| Liapootah | 87.3 | Central | Liapootah |
| Mackintosh | 81 | West Coast | Farrell |
| Meadowbank | 40 | Central | Meadowbank |
| Paloona | 30 | North West | Sheffield–Ulverstone 110 kV |
| Poatina | 300 | Northern | Palmerston |
| Reece | 238 | West Coast | Farrell |
| Repulse | 28 | Central | Liapootah–Chapel Street 220 kV |
| Rowallan | 10.5 | North West | Sheffield |
| Tarraleah | 90 | Central | Tungatinah |
| Trevallyn | 95.8 | Northern | Trevallyn |
| Tribute | 84 | West Coast | Farrell |
| Tungatinah | 125 | Central | Tungatinah |
| Wayatinah | 38.3 | Central | Liapootah |
| Wilmot | 32 | North West | Sheffield |
| **Wind** | | | |
| Bluff Point | 65 | North West | Smithton |
| Musselroe | 168 | Northern | Derby |
| Studland Bay | 75 | North West | Smithton |

49 *Nieterana is a mini-hydro power station, which is connected to Butlers Gorge Power Station. The total power generated by Butlers Gorge (capacity 12.2 MW) and Nieterana (2.2 MW) flows through this connection point to the network*

Table F–2 lists the embedded generation sites within the distribution network. Hydro Tasmania also operates two power stations, Upper Lake Margaret Power Station (8.4 MW) and Lower Lake Margaret mini hydro (3.2 MW) that are connected to the switchboard at Mt Lyell copper mine. These are not classified as embedded generation as they are not connected within the distribution network, however may export to the transmission network.

**Table F–2: Embedded generation over 0.5 MW**

| Location | Source | Capacity (MW) | Export (MW) | TasNetworks planning area | Connecting distribution line |
|---|---|---|---|---|---|
| Parangana Lake | Hydro | 0.75 | 0.75 | North West | Railton 85001 |
| Glenorchy | Biomass | 1.7 | 1.5 | Greater Hobart | Chapel Street 20551 |
| South Hobart | Biomass | 1.1 | 1.1 | Greater Hobart | West Hobart 13045 |
| Mowbray | Biomass | 2.2 | 1.1 | Northern | Mowbray 62006 |
| Meander | Hydro | 2.1 | 1.9 | North West | Railton 85006 |
| Launceston | Natural gas | 2.0 | 2.0 | Northern | Trevallyn 61026 |
| Ulverstone | Natural gas | 7.9 | 2.0 | North West | Ulverstone 82006 |
| Tods Corner | Hydro | 1.7 | 1.7 | Central | Arthurs Lake 49101 |
| Tunbridge | Hydro | 6.0 | 4.9 | Eastern | Avoca 56004 |
| Derby | Hydro | 1.12 | 1.12 | Northern | Derby 55001 |
| Wynyard | Natural gas | 2.0 | 0 | North West | Burnie 91004 |
| Nietta | Hydro | 1.0 | 1.0 | North West | Ulverstone 82004 |
| Herrick | Hydro | 0.9 | 0.9 | Northern | Derby 55002 |
| Maydena | Hydro | 0.55 | 0.55 | Central | New Norfolk 39571 |

# Appendix G Transmission network constraints supplementary material

This appendix provides more information on the binding transmission network constraints summarised in Section 4.1. The tables presented here detail the constraint ID(s) that are included under the general constraint, the reason for and impact of these constraints, the cumulative duration the constraints bound for, the summated marginal cost of the constraint, and an explanation of the reason for increase or decrease in the amount the constraint bound and/or actions to reduce this number.

The marginal cost of binding constraint is calculated by AEMO for every dispatch interval during which a binding constraint occurs. It is the change in market cost that would occur if the constraint could be relieved by one MW. This is not the same as the cost difference that would occur if the constraint could be removed completely. Full market simulations would be required to understand the potential market benefit of completely eliminating a constraint. Comparing the marginal cost of constraints does, however, give some indication of the relative impact that constraints are having on the market.

As detailed in Section 4.1, the primary reasons for the increase or decrease instances of binding constraints in 2015–16 was due to Basslink out of service for almost six months, with the associated supplementary diesel generation.

Table G–1: Comparison of binding constraints on major 220 kV and significant 110 kV transmission lines from 2014–15 to 2015–16

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| **Constraints with increased incidence of binding in 2014–15 financial year** | | | | | | | | |
| Farrell–Sheffield 220 kV thermal limit with no outage | T>>T_NIL_BL_EXP_7C<br>T>T_NIL_BL_IMP_7CC | Avoid overloading a Farrell–Sheffield 220 kV line for trip of the parallel line | Constrain generation in West Coast area and Basslink flows | 344 | 921 | 15,442 | 72,030 | The constraint mainly bound May to June 2016, with increase due maximising West Coast generation to meet energy demand |
| Derby–Scottsdale Tee 110 kV thermal limit no outage | T>T_NIL_110_1 | Avoid pre-contingent overload of the Derby–Scottsdale Tee 110 kV line section | Constrain Musselroe Wind Farm generation | 1150 | 1504 | 1,186,164 | 1,690,369 | Increase in 2015–16 due to strong wind coupled with lower dynamic line rating, during the period November 2015 to March 2016. Line rating to be addressed with new weather station in agreement with customer. |
| Lake Echo Tee–Waddamana No. 1 110 kV thermal limit no outage | T>T_NIL_BL_110_18_1 | Avoid overload of the Lake Echo-Waddamana No. 1 110 kV line for trip of the parallel line | Constrain Lower Derwent and Lake Echo generation | 1 | 50 | 0 | 1,345 | Increase due to lower transmission line dynamic rating during summer (17, 19 and 28 December 2015) |
| Liapootah–Chapel Street 220 kV voltage stability limit | T^T_LI_CL_CS_5_DS | Avoid voltage instability or violations for loss of remaining Liapootah–Chapel Street 220 kV line | Constrain southern Tasmanian generation | 0 | 10 | 0 | 823 | Increase due to Liapootah–Chapel Street or Liapootah–Cluny Tee–Chapel Street 220 kV line out of service and restrict generation from Gordon, Repulse and Cluny on 10 May 2016. This outage did not happen in 2014–15 |
| | T^T_NIL_LICS_N-2_DS | Avoid voltage instability or violations for loss of both Liapootah–Chapel Street 220 kV lines | | | | | | |
| Liapootah–Cluny Tee–Chapel Street 220 kV voltage stability limit | T^T_NIL_BL_5_DS | Avoid voltage instability or violations for loss of a Liapootah–Cluny Tee–Chapel Street 220 kV line | Constrain southern Tasmanian generation | 0 | 1 | 0 | 0 | This constraint was only marginally bound for 1 dispatch interval |
| Palmerston–Sheffield 220 kV thermal limit outage | T>T_GTSH_IMP_4K | Avoid overloading Palmerston–Sheffield 220 kV line for trip of remaining Sheffield–George Town 220 kV line | Constrain West Coast and Mersey Forth generation during Basslink import | 1 | 23 | 48 | 715 | Increase due to a Sheffield–George Town 220 kV line out of service and medium to high West Coast generation dispatch during the outage 11 May 2016 |

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| **Constraints with decreased incidence of binding in 2015–16 financial year** | | | | | | | | |
| George Town 220 kV bus voltage limits | T^V_NIL_10 | Prevent low voltages at George Town 220 kV bus following trip of Basslink filter bank with high Basslink flow TAS to VIC | Limit power flow on Basslink | 526 | 244 | 4,847 | 20,981 | Reduction by more than half of the binding constraint mainly due to Basslink out of service for almost six months |
| | T^V_NIL_11 | Avoid voltage collapse at George Town 220 kV bus for trip of Basslink HF7 98 MVAr harmonic filter | | | | | | |
| | T^V_NIL_8 | Avoid voltage collapse at George Town 220 kV following trip of Sheffield–George Town 220 kV line. NCSPS action on ID 81 and 82, and GTRSPS action on ID 500 and 501 considered | | | | | | |
| | T^V_NIL_9 | Ensure sufficient reactive margin is maintained at George Town 220 kV under conditions of low fault level | | | | | | |
| | T^V_NIL_BL_6 | Avoid transient over-voltage (TOV) for loss of Basslink | | | | | | |
| Sheffield–George Town 220 kV thermal limit with no outage | T>>T_NIL_BL_EXP_6E<br>T>T_NIL_BL_IMP_6EE<br>T>T_NIL_BL_IMP_6E | Avoid overloading a Sheffield–George Town 220 kV line for trip of the parallel line | Constrain West Coast and Mersey Forth generation during Basslink export | 192 | 62 | 2,972 | 9,714 | Reduction of two thirds of the binding constraint mainly due to Basslink out of service for almost six months. However, the marginal cost of constraint to the market was increased in 2015–16 due to higher bidding price from West Coast and Mersey Forth generators 20-30 June 2016.<br>This constraint is expected to be relieved following the project to increase transmission line rating as per Section 6.2.2.3 |
| Farrell–Sheffield 220 kV transient stability | T::T_NIL_2<br>T::T_GTSH_2 | Avoid transient instability for fault and trip of a Farrell–Sheffield 220 kV line | Limit West Coast generation and power flow on Basslink | 268 | 84 | 1,925 | 963 | Reduction of two thirds of the binding constraint mainly due to Basslink out of service for almost six months |

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| Hadspen–George Town 220 kV thermal limit with no outage | T>T_NIL_BL_5C T>>T_NIL_BL_EXP_5F T>T_NIL_BL_IMP_5FF T>T_NIL_BL_IMP_5F | Avoid overload of a Hadspen–George Town 220 kV line for trip of the parallel line considering NCSPS action, ensure sufficient NCSPS generation dispatched | Constrain power flow from south of Palmerston and the north east including Trevallyn and Musselroe generation | 45 | 15 | 408 | 231 | Reduction of two thirds of the binding constraint mainly due to Basslink out of service for almost six months |
| Liapootah–Waddamana–Palmerston 220 kV voltage stability limit | T^T_NIL_BL_6_DS | Avoid voltage instability or violations for loss of a Liapootah–Waddamana–Palmerston 220 kV line | | 22 | 20 | 1,184 | 2,379 | This constraint only marginally reduced, by 2 dispatch intervals |
| Palmerston–Sheffield 220 kV thermal limit with no outage | T>T_NIL_BL_220_6B | Avoid overloading the Palmerston–Sheffield 220kV line (flow to south) for loss of a Sheffield–George Town 220 kV line | Limit the generation from the West Coast and Mersey Forth. | 4 | 3 | 26 | 117 | This constraint only marginally reduced, by 1 dispatch interval |
| Palmerston–Sheffield 220 kV transient stability | T::T_HA_GT_PM_4 T::T_NIL_4 | Prevent poorly damped TAS North-South oscillations following fault and trip of Palmerston–Sheffield 220 kV line | Limit generation from West Coast and Mersey Forth during Basslink import | 508 | 61 | 1,853 | 553 | Reduction by almost 90% of the binding constraint mainly due to Basslink out of service for almost six months |
| Waddamana–Palmerston 110 kV thermal limit with no outage | T>T_NIL_LIPM_N-2_2A T>T_NIL_LIPM_N-2_2B | Avoid overloading the Waddamana–Palmerston 110 kV line for loss of both Liapootah–Waddamana (tee)–Palmerston 220 kV lines | Limit generation from Gordon and Derwent | 111 | 74 | 202,518 | 9,051 | Reduction mainly due to fewer occurrences of the loss of both Liapootah–Waddamana–Palmerston 220 kV lines being declared a credible contingency during 2015–16 |
| Waratah Tee–Hampshire–Burnie 110 kV thermal limit no outage | T>T_FASH_1_N-2 | Avoid overloading the Waratah Tee–Hampshire–Burnie 110 kV line for loss of both Farrell–Sheffield 220 kV lines | Limit Mackintosh, Catagunya and Tribute generation | 29 | 15 | 1,515 | 350 | Reduced mainly due to fewer occurrences where the loss of both Farrell–Sheffield lines being declared credible during 2015–16. There was one binding interval on 19 May 2016 at 10:25 AM with suspicious marginal cost of constraint of $409,216. Suspicious marginal cost of constraint has been excluded from calculation of summated marginal cost of constraint |
| Palmerston–Hadspen 220 kV thermal limit with no outage | T>T_NIL_BL_3C | Avoid overloading of a Hadspen–Palmerston 220 kV line for trip of the parallel line considering NCSPS action, ensure sufficient NCSPS generation dispatched | Constrain power flow from the south of Palmerston | 164 | 35 | 991 | 435 | Reduction due to Basslink mainly import September–December 2015 and after that Basslink was out of service for almost the last six months |

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| **Constraints with equal incidence of binding in 2015–16 financial year** | | | | | | | | |
| Burnie–Sheffield 220 kV or Burnie No. 2 transformer thermal limit outage | T>T_SH_TX | Avoid overloading the Burnie–Sheffield 220 kV line or Burnie No. 2 220/110 kV transformer for loss of the remaining Sheffield 220/110 kV transformer | Constrain Devils Gate generation | 3 | 3 | 159 | 224 | Constraint invoked when Sheffield 220/110 kV transformer out of service, the West Coast 110/220 kV parallel open. It appears similar scheduled maintenance around February-March caused these binding intervals |

## Table G–2: Network constraint equations affecting Basslink flows

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| **Constraints with increased incidence of binding in 2015–16 financial year** | | | | | | | | |
| Basslink discretionary limit | TV_300<br>TV_500<br>TV_ZERO<br><br>VT_ZERO<br>VT_000<br>VT_200<br>VT_350 | Upper limit on Tas to Vic on Basslink flow<br><br>Upper limit on Vic to Tas on Basslink flow | Limiting power flow on Basslink | 165 | 8476 | 325,125 | 1,159,623 | Increase of Basslink discretionary constraint type mainly due to the constraint VT_ZERO (7511 dispatch intervals) and TV_ZERO ( 932 dispatch intervals) which happened between December 2015 and June 2016. This is the period when the Basslink was out of service |
| Farrell–Sheffield 220 kV transmission line rating constraint with NCSPS operation | T>>T_NIL_BL_EXP_7C | Avoid overloading one of the Farrell–Sheffield 220 kV lines for the loss of the other line considering NCSPS action. Ensures that Basslink can fully compensate NCSPS action. | Limit generation from West Coast area and force higher Basslink export | 155 | 168 | 13,004 | 21,373 | Constraint bound mainly during 20-30 June 2016 once Basslink was returned to service and on export |
| **Constraints with decreased incidence of binding in 2015–16 financial year** | | | | | | | | |
| Basslink Energy and FCAS related constraint (ie Basslink no go zone) | T_V_NIL_BL1<br>V_T_NIL_BL1 | Ensure Basslink operates within its normal limits that guarantee the amount of FCAS that can be transferred across Basslink | Limit Basslink flow | 4975 | 3615 | 164,422 | 110,315 | A reduction of nearly one third in 2015–16 due to Basslink being out of service for almost six months |
| Basslink import limited due to load unavailability for FCSPS operation | V_T_NIL_FCSPS | To protect the Tasmanian system frequency following FCSPS action during Basslink import by ensuring sufficient availability of FCSPS load for tripping | Limit power flow on Basslink import from Victoria to Tasmania | 9123 | 1201 | 212,900 | 29,289 | Large decrease due to Basslink being out of service for almost six months |
| Basslink inverter commutation instability limit | V:T_HAPM_BL_1<br>V:T_NIL_BL_1<br>V:T_SH-GT_BL_1 | Avoid inverter commutation instability at low Tasmanian fault level | Limit Basslink flow to Tasmania at low fault levels | 200 | 29 | 3,605 | 744 | Large decrease due to Basslink being out of service for almost six months |
| Basslink rate-of-change limit | TVBL_ROC<br>VTBL_ROC | Rate of Change constraint for Basslink | Limit rate of change of Basslink power flow less than 200 MW / 5 min | 328 | 121 | 11,238,025 | 10,491,350 | Reduction of nearly two thirds in 2015–16 due to Basslink was out of service for almost six months |

| Constraint | Constraint ID | Reason for constraint | Impact of constraint | Number of dispatch intervals (and tine period) bound or violated | | Summated marginal cost of constraint (binding only) ($) | | Explanation |
|---|---|---|---|---|---|---|---|---|
| | | | | 2014–15 | 2015–16 | 2014–15 | 2015–16 | |
| George Town 220 kV bus voltage limits | T^V_NIL_10 | Prevent low voltages at George Town 220 kV bus following trip of Basslink filter bank with high Basslink flow TAS to VIC | Limit power flow on Basslink | 526 | 244 | 4,847 | 20,981 | Binding intervals halved in 2015–16, mainly due to Basslink being out of service for almost six months |
| | T^V_NIL_11 | Avoid voltage collapse at George Town 220 kV bus for trip of Basslink HF7 98 MVAr harmonic filter | | | | | | |
| | T^V_NIL_8 | Avoid voltage collapse at George Town 220 kV following trip of Sheffield–George Town 220 kV line. NCSPS action on ID 81 and 82, and GTRSPS action on ID 500 and 501 considered | | | | | | |
| | T^V_NIL_9 | Ensure sufficient reactive margin is maintained at George Town 220 kV under conditions of low fault level | | | | | | |
| | T^V_NIL_BL_6 | Avoid transient over-voltage (TOV) for loss of Basslink | | | | | | |
| Sheffield–George Town 220 kV transmission line constraint with NCSPS operation | T>>T_NIL_BL_EXP_6E | Avoid overloading one Sheffield–George Town 220 kV lines (flow to George Town) for loss of other line. Ensures that Basslink can fully compensate NCSPS action | Force higher Basslink export level to ensure that Basslink can fully compensate NCSPS action | 157 | 62 | 2,393 | 9,714 | Binding intervals reduced by nearly two thirds in 2015–16 due to Basslink being out of service for almost 6 months. NCSPS was still in service but was disabled during Basslink outage. |
| Palmerston–Sheffield 220 kV transient stability | T::T_HA_GT_PM_4 T::T_NIL_4 | Prevent poorly damped TAS North-South oscillations following fault and trip of Palmerston–Sheffield 220 kV line | Limit generation from West Coast and Mersey Forth during Basslink import | 508 | 61 | 1,853 | 553 | Reduction of nearly 90% in 2015–16 due to low storage that restricted generation from West Coast and Mersey forth during Basslink import |
| Farrell–Sheffield 220 kV transient stability | T::T_NIL_2 T::T_GTSH_2 | Avoid transient instability for fault and trip of a Farrell–Sheffield 220 kV line | Limit West Coast generation and power flow on Basslink | 268 | 84 | 1,925 | 963 | Reduction of nearly two thirds in 2015–16 due to low storage that restricted generation from West Coast and Mersey forth during Basslink import |

# Appendix H Power quality planning levels

This appendix provides TasNetworks' planning levels for over/under voltage, voltage unbalance, harmonic voltage content and voltage fluctuation.

The actual emission level allocated to any particular connection will be less than the planning level given below. We will allocate emission levels for particular connections at the time of assessing a connection application.

## H.1 Planning levels for over and under voltages

The Rules illustrate the allowable Temporary Over Voltage (TOV) envelope in S5.1a.4 (the Rules Figure S5.1a.1), which is reproduced in Figure H–1 below.

The Rules do not specify a standard for transient voltage recovery following under voltage events. We have compiled the under-voltage characteristic in Figure H–2 largely from performance standards applicable to generating units. We consider this to be a reasonable guide to the required voltage recovery characteristics that would enable the power system to adequately recover, following a network event. We will use Figure H–2 for general assessment of under voltage performance, but we reserve the right to apply alternate performance metrics as required.

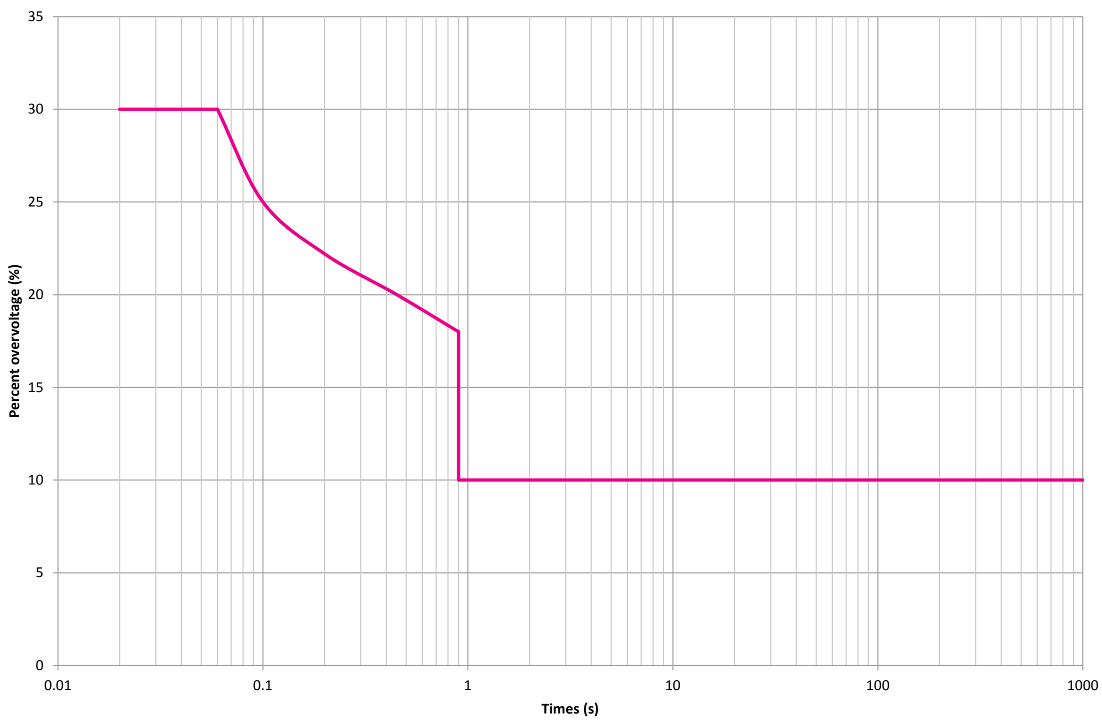



**Figure H–1: The Rules over-voltage requirements (reproduced from the Rules S5.1a.1)**

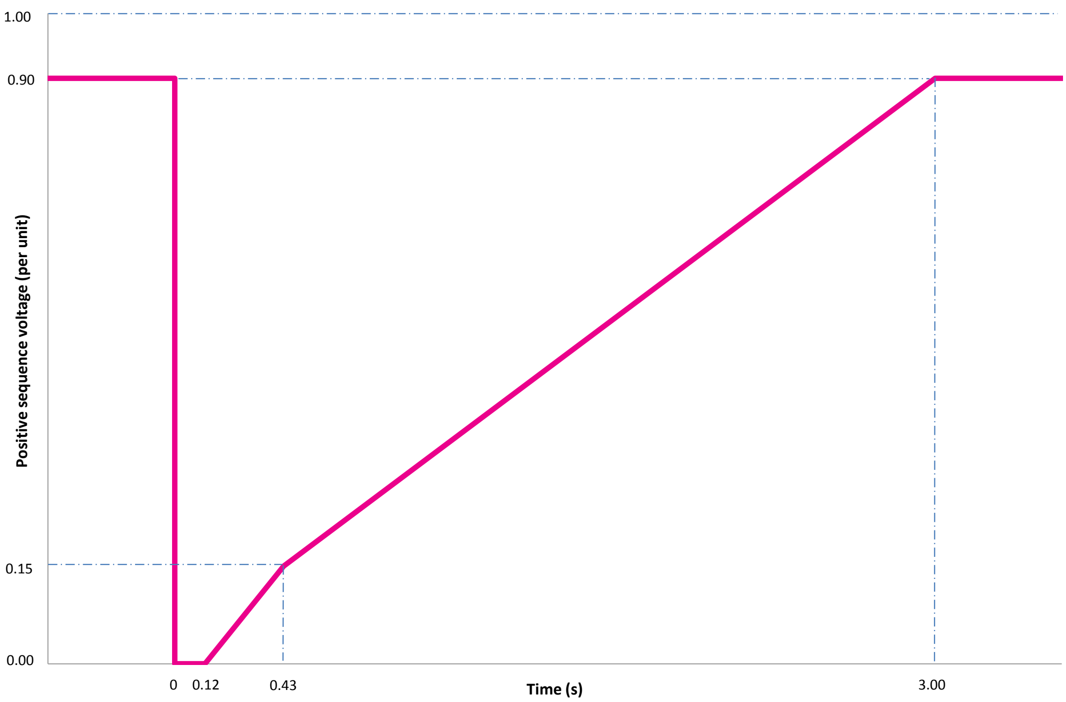



**Figure H–2: Voltage recovery requirements following network under voltage events**

## H.2 Planning levels for voltage fluctuation

Voltage fluctuations are defined as repetitive or random variations in the magnitude of the supply voltage. The magnitudes of these variations do not usually exceed 10 per cent of the nominal supply voltage. However, small magnitude changes occurring at particular frequencies can give rise to an effect called flicker.

There are two important parameters to voltage fluctuations: the frequency of fluctuation and the magnitude of fluctuation. Voltage fluctuations may cause spurious tripping of relays, interference with communications equipment, and may trip out electronic equipment.

With respect to planning levels for voltage fluctuations, Table H–1 has been derived and adopted for the Tasmanian transmission network. Note that TR IEC 61000.3.7:2012 should be referenced for further details.[50]

**Table H–1: Voltage fluctuation planning levels**

| Flicker level | Bus voltage | |
|---|---|---|
| | HV[51] | MV[52] |
| PST | 0.8 | 0.9 |
| PLT | 0.6 | 0.7 |

50 *The Rules S5.1a.5 refers to AS/NZS 61000.3.7:2001. This standard has been superseded by TR IEC 61000.3.7:2012*

51 *HV: 35 kV < Un ≤ 230 kV*

52 *MV: 1 kV < Un ≤ 35 kV*

**PST Short-term flicker level**

This is a measure of the change in relative voltage magnitude versus the frequency of the voltage changes, calculated on a 10-minute basis. An index level of less than 1.0 is considered acceptable.

**PLT Long-term flicker level**

This is an average of PST values evaluated over a period of two hours. An index level of less than 0.9 is considered acceptable.

## H.3 Planning levels for harmonic voltage

With respect to planning levels for harmonic voltages, Table H–2 has been derived and adopted for the Tasmanian transmission network. Note that TR IEC 61000.3.6:2012 should be referenced for further details.[53]

53 *The Rules S5.1a.6 refers to AS/NZS 61000.3.6:2001. This standard has been superseded by TR IEC 61000.3.6:2012*

**Table H–2: Harmonic planning levels for the Tasmanian network**

| Harmonic number | Permissible voltage level (% of the nominal voltage) | | | |
|---|---|---|---|---|
| | Transmission or sub-transmission busbars | | Load busbars | |
| | 220 kV / 110 kV | 44 kV / 33 kV | 33 kV / 22 kV / 11 kV | 6.6 kV |
| 2 | 1.14 | 1.37 | 1.84 | 1.87 |
| 3 | 2.00 | 2.75 | 4.27 | 4.39 |
| 4 | 0.60 | 0.72 | 0.96 | 0.98 |
| 5 | 2.00 | 3.01 | 5.12 | 5.31 |
| 6 | 0.27 | 0.32 | 0.43 | 0.44 |
| 7 | 2.00 | 2.69 | 4.19 | 4.34 |
| 8 | 0.27 | 0.32 | 0.43 | 0.44 |
| 9 | 0.81 | 0.95 | 1.27 | 1.31 |
| 10 | 0.29 | 0.34 | 0.46 | 0.47 |
| 11 | 1.50 | 1.94 | 2.97 | 3.11 |
| 12 | 0.27 | 0.31 | 0.41 | 0.43 |
| 13 | 1.50 | 1.80 | 2.53 | 2.64 |
| 14 | 0.25 | 0.29 | 0.38 | 0.40 |
| 15 | 0.21 | 0.24 | 0.32 | 0.34 |
| 16 | 0.23 | 0.27 | 0.36 | 0.38 |
| 17 | 1.11 | 1.27 | 1.69 | 1.77 |
| 18 | 0.22 | 0.25 | 0.34 | 0.36 |
| 19 | 0.98 | 1.11 | 1.48 | 1.56 |
| 20 | 0.22 | 0.24 | 0.33 | 0.34 |
| 21 | 0.15 | 0.17 | 0.23 | 0.24 |
| 22 | 0.21 | 0.23 | 0.31 | 0.33 |
| 23 | 0.78 | 0.87 | 1.17 | 1.24 |
| 24 | 0.20 | 0.23 | 0.30 | 0.32 |
| 25 | 0.71 | 0.79 | 1.05 | 1.12 |
| 26 | 0.20 | 0.22 | 0.29 | 0.31 |
| 27 | 0.12 | 0.13 | 0.18 | 0.19 |
| 28 | 0.19 | 0.21 | 0.28 | 0.30 |
| 29 | 0.59 | 0.65 | 0.86 | 0.93 |
| 30 | 0.19 | 0.21 | 0.28 | 0.30 |
| 31 | 0.55 | 0.59 | 0.79 | 0.85 |
| 32 | 0.19 | 0.20 | 0.27 | 0.29 |
| 33 | 0.12 | 0.13 | 0.17 | 0.19 |
| 34 | 0.19 | 0.20 | 0.26 | 0.29 |
| 35 | 0.47 | 0.50 | 0.66 | 0.72 |
| 36 | 0.18 | 0.19 | 0.26 | 0.28 |
| 37 | 0.43 | 0.46 | 0.61 | 0.67 |
| 38 | 0.18 | 0.19 | 0.25 | 0.28 |
| 39 | 0.12 | 0.13 | 0.17 | 0.18 |
| 40 | 0.18 | 0.19 | 0.25 | 0.27 |
| 41 | 0.38 | 0.39 | 0.53 | 0.58 |
| 42 | 0.18 | 0.18 | 0.24 | 0.27 |
| 43 | 0.35 | 0.36 | 0.49 | 0.54 |
| 44 | 0.18 | 0.18 | 0.24 | 0.27 |
| 45 | 0.12 | 0.12 | 0.16 | 0.18 |
| 46 | 0.17 | 0.18 | 0.24 | 0.26 |
| 47 | 0.31 | 0.32 | 0.42 | 0.47 |
| 48 | 0.17 | 0.17 | 0.23 | 0.26 |
| 49 | 0.29 | 0.29 | 0.39 | 0.44 |
| 50 | 0.17 | 0.17 | 0.23 | 0.26 |
| THD[54] | 3.00 | 4.36 | 6.61 | 6.93 |

Planning levels at generator busbars (terminal connection voltage) are to be taken as half of these values, recognising that there is a cost associated with specifying a higher level of required harmonic immunity for such plant.

*54 The Rules S5.1a.6 refers to AS/NZS 61000.3.6:2001. This standard has been superseded by TR IEC 61000.3.6:2012*

## H.4 Planning levels for voltage unbalance

The planning levels for voltage unbalance are summarised in Table S5.1a.1 of the Rules, being part of Schedule 5.1a (System Standards). This table is replicated in Table H–3.

**Table H–3: Planning levels for voltage unbalance (from the Rules Table S5.1a.1)**

| Nominal supply voltage (kV) | Maximum negative sequence voltage (% of nominal voltage) | | | |
|---|---|---|---|---|
| Column 1 | Column 2 | Column 3 | Column 4 | Column 5 |
| | No contingency event | Credible contingency event | General | Once per hour |
| | 30 minute average | 30 minute average | 10 minute average | 1 minute average |
| More than 100 | 0.5 | 0.7 | 1.0 | 2.0 |
| More than 10 but not more than 100 | 1.3 | 1.3 | 2.0 | 2.5 |
| 10 or less | 2.0 | 2.0 | 2.5 | 3.0 |

# **Appendix I** Chapter 5 supplementary material

## I.1 Results of demand and energy forecasts

Load forecast data is provided in two Microsoft Excel files on our website via the Annual Planning Report page, available at http://apr.tasnetworks.com.au. Load and energy forecasts, and other associated forecasts, are provided for a 10-year period, connection point load profiles are provided for a 5-year period. The files and information is provided is as follows:

**Load and energy forecasts**

- *Tasmanian energy*: the Tasmanian electrical energy demand forecast, including losses, for low, medium and high economic growth scenarios;
- *Tasmanian maximum demand*: the Tasmanian summer and winter maximum demand forecasts, for low, medium and high economic growth forecasts and 10, 50 and 90 per cent POE;
- *Tx-Dx connection points*: for transmission-distribution connection points, the current and forecast:
  - substation total and firm delivery capacity;
  - peak load (MW) with coincident MVAr and power factor for peak season (summer or winter);
  - peak load (MW) with coincident MVAr for non-peak season;
  - hours load exceeds 95 per cent of peak load and firm capacity (for substations of more than one transformer);
  - regional diversity factor, for summer and winter;
  - load transfer capacity; and
  - embedded generation capacity.
- *Zone subs & sub-trans lines*: for zone substations and sub-transmission lines, the current and forecast:
  - substation total and firm delivery capacity;
  - sub-transmission line total and firm delivery capacity, for summer and winter;
  - peak load (MVA) with coincident power factor, for summer and winter;
  - hours load exceeds 95 per cent of peak load;
  - load transfer capacity; and
  - embedded generation capacity.
- *Distribution line summer MD, Distribution line winter MD*: distribution line maximum demand forecast (in Amperes) for summer and winter.

**Connection point load profiles**

- *Day of connection point MD*: the forecast daily MW and MVAr load profiles for each connection point on the days its respective summer and winter maximum demands;
- *Day of network MD*: the forecast daily MW and MVAr load profiles for each connection point on the day of summer and winter network maximum demands;
- *Day of network minD*: the forecast daily MW and MVAr load profiles for each connection point on the day of network minimum demand (which occurs in summer);
- *Forecast average profiles*: the forecast daily MW and MVAr load profiles for each July, October, January and April under average conditions for weekdays, Saturdays and Sundays/public holidays.

## I.2 State forecasting methodology

TasNetworks state forecast is based on three economic scenarios (medium, high and low). These scenarios are built on key energy market policies and economic conditions known at the time. For each of these scenarios our forecaster, NIEIR, prepares a forecast of economic variables and regional energy and demand forecasts for Tasmania. We engage NIEIR to develop state energy and maximum demand forecasts because NIEIR is recognised as an independent expert in this field.

The medium growth load forecast represents an estimate of how the future energy and demand may develop with known and anticipated economic changes considered most likely. The high and the low growth forecasts are based on alternative economic growth scenarios.

NIEIR develops an econometric model for Tasmanian energy and maximum demand forecasts. The following factors are incorporated for the forecasting model:

- gross state product and real incomes;
- weather conditions;
- electricity prices;
- average consumption per dwelling; and
- major new industrial, mining and commercial developments.

Energy sales forecasts are based on econometric models. In modelling, Tasmanian energy sales by industry are linked to real output growth by industry, electricity prices, and weather conditions. Business energy sales in Tasmania are linked directly to business prices. Business sales by industry are also linked to real output growth by industry for Tasmania. Residential sales are determined from a model including average consumption per dwelling, weather, real income, and electricity prices. The schematic of the forecasting model is presented in Figure I–1.

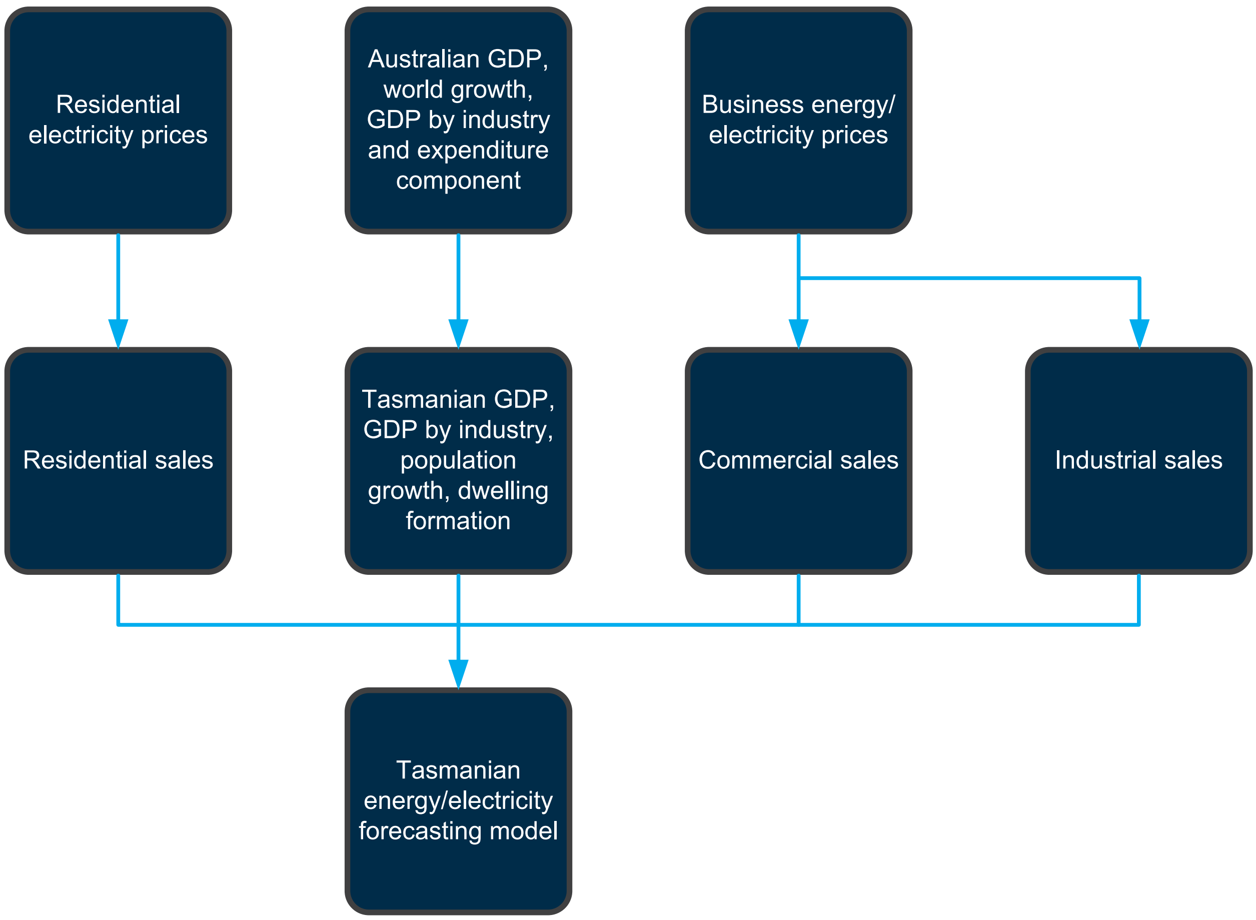



**Figure I-1: Schematic of energy/electrical forecasting model**

Forecasts of summer and winter maximum demands for Tasmania were developed using econometric regression equations based on historic data. These winter and summer maximum demand equations are estimated as a load factor equation. The load factor equation effectively means the forecast maximum demands for Tasmania indirectly reflects the impact of GSP and real electricity price changes. These maximum demand equations include Tasmanian GSP as an independent explanatory variable. A price variable is difficult to justify in any maximum demand forecast equation until customers are interval metered and/or face peak power pricing/ tariff structures. Price is excluded from the maximum demand model but included in the energy models as discussed above. Furthermore, these equations were derived excluding the impact of the top four transmission connected major industrial customers which are assumed to be weather/temperature insensitive and added to maximum demand outside the model.

As temperature variations are incorporated into the forecasting process, the maximum demand forecasts are prepared on a probability of exceedance (POE) basis relating to temperature for each high, medium, and low growth scenarios. Three conditions have been developed for Tasmania at 10, 50 and 90 per cent POE, which indicate the probability of the temperature dropping below the reference temperature – as maximum demand variation is inversely proportionate to temperature, the changes of the maximum demand exceeding the forecast.[55]

Transmission-connected customers provide their own demand forecasts. Transmission-connected customer demand forecasts are reconciled with NIEIR's forecast and combined with connection point projected demand forecast to produce a consolidated connection point and regional demand forecast for Tasmania.

55 *10 per cent POE represents a 10 per cent chance the actual temperature on the day dropping below the reference temperature in a given year.*

### I.2.1 Weather conditions

Daily electricity maximum demand in winter and summer depends on:

- the ambient minimum temperature during the day; and
- the ambient maximum temperature on the previous day.

The approach developed by NIEIR was to calculate the probabilities associated with different average daily temperatures. The average temperature was defined as the weighted average of the overnight minimum and the previous daily maximum. The daily minimum was assigned a weight of 0.8, while the previous day's maximum a weight of 0.2 in this calculation.

Based on historic data, the following temperature percentiles were derived for maximum demand forecasts:

- 10th percentile: temperature met once in every ten years;
- 50th percentile: temperature met once in every two years; and
- 90th percentile: temperature met nine out of ten years.

Temperature exercises the most important influence on peak demands. Other weather variables, such as humidity, rainfall and wind, were not considered in the POE calculations for Tasmania.

**Table I–1: Tasmanian reference temperatures at associated POE**

| POE (%) | Winter (°C at Hobart) | Summer (°C at Hobart) |
|---|---|---|
| 10 | 0.9 | 7.0 |
| 50 | 2.1 | 8.7 |
| 90 | 3.2 | 9.8 |

As per the historic data analysis, sensitivity of maximum demand in winter and summer are around 25 to 30 MW per degree and 12 to 15 MW per degree respectively. These sensitivities are dependent upon how cool each season actually is.

## I.3 Connection site forecasting methodology

The underlying approach is to project load for each connection site at a rate that is consistent with recent history, using weather corrected data. The sources of input information for the approach are as follows:

- state maximum demand forecast produce by NIEIR;
- temperature data retrieved from the Bureau of Meteorology website;
- connection point active and reactive power data from metering data;
- zone substation and distribution line data from TasNetworks SCADA system; and
- load adjustments information received from internal process associated with new or augmented customer connections. Only committed connections over 500 kW are used.

Historic data at each connection site is to be corrected for the temperature (weather correction, which is described in Appendix I.2.1). Temperature of the connection site is obtained from the nearest weather station of Bureau of Meteorology. Weather corrected data are then adjusted for large block loads and permanent transfers.

The basic approach is to extrapolate from recent history using linear time trends (over varying time frames) or applying growth rates based on historical behaviour to the most recent temperature corrected observation. This is applied to non-coincident peak demands for each connection site.

Similarly, our directly transmitted connected customer forecasts (provided by each customer) are reconciled with NIEIR produced directly transmitted connected customer forecasts.

The spatial forecasts for each connection site (ie distribution and directly transmitted connected customers) are aggregated together, using diversity factors, to a system level forecast (bottom-up). This is then compared to, and reconciled with the system level forecast produced by NIEIR (top-down).

Connection site maximum demand forecasts are prepared for both summer (December-February) and winter (June-August) periods.

The connection site forecast is used to derive a reactive power forecast for each site by using actual power factor values from the preceding year.

### I.3.1 Weather correction

TasNetworks weather corrects the data to the 10, 50 and 90 per cent POE load levels.

The random nature of weather means that any comparison of historical electricity loads over time requires these loads to be adjusted to standardised weather conditions.

Long term trending data are generated from temperature data retrieved from the Bureau of Meteorology web site. Accordingly, respective temperatures for each POE levels are generated for each weather station for each season based on annual minimum effective temperatures for the period from 1970 to date.

Load sensitivity for the temperature is calculated by generating a liner relationship between daily maximum demand and the daily effective temperature for each season for each connection point. In this regard, weekends and public holidays are excluded.

### I.3.2 Adjusting for significant block loads, permanent transfers and other factors

Before applying any form of analysis or growth factor to historical weather corrected peak demands, these are adjusted for transfers between connection point substations as well as significant block loads that comprise a large proportion of the loads at the specific connection site. The effects of transfers and large block loads are removed from the historical data series before any trends are fitted or growth rates are determined. These are later added back to the forecasts.

Forecasts are also adjusted for predicted transfers and large block loads that are expected to arise during the forecast period.

### I.3.3 Embedded generation

Embedded generation units are not specifically allocated load within the zone substation and distribution line load forecast.

Generation units connected to the distribution network are not required to be scheduled, in accordance with the Rules, however there are two registered generation units in the distribution network; a 6 MW mini-hydro generating unit (non-market, non-scheduled) and 2.2 MW natural gas unit (market, non-scheduled) embedded within the distribution networks supplied from Avoca and Mowbray substations, respectively. As a result, the load data used assumes that the generating units were displaying their normal operating pattern. The methodology does not take into account abnormal patterns of usage either generating or not generating during the load forecast periods.

Based on the nature of the input data the forecast of generation load is unavailable and is not provided. Therefore, the historic net load of distribution lines was taken for analysis and forecasting as embedded generation acts as a 'negative load' when seen from the network. Table F-2 provides the details of embedded generators connected within the distribution network.

## I.4 Zone substation and distribution line forecasts

Maximum demand forecasts of zone substations are determined based on the historic maximum demand of each zone substation and its contribution to the maximum demand of the relevant transmission-distribution connection point. The forecasts are then adjusted for any confirmed switching arrangements in the near future and/or the confirmed establishment of new distribution lines that would take load from the existing lines.

Maximum demand for summer and winter for each distribution line is extracted from 'PI' Historian (information technology storage system for transformer and cable loads and voltages) and the data is processed to remove spikes and erroneous data points. The maximum demand data is manually examined to ensure that switching of any distribution line has been correctly accounted for. Actual maximum demand for each distribution line is determined and that figure is extrapolated on an annual basis using the output of its station maximum demand forecasts.

Tasmanian Networks Pty Ltd

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