TasNetworks
Delivering your power

ANNUAL PLANNING REPORT 2018

Disclaimer

CONTENTS

FEEDBACK AND ENQUIRIES

We welcome feedback and enquiries on our 2018 APR; particularly from those interested in discussing opportunities for demand side management or other innovative solutions to manage network limitations.

Please send feedback and enquiries to:

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Potential demand management solution providers can also register with us via our demand side engagement register on our website at www.tasnetworks.com.au/demand-management-engagement-register

A NOTE ON THE TEXT
Our industry uses lots of abbreviations and industry-specific terms. We've placed all explanations of abbreviations and terms in our Glossary (page 107) and Abbreviations index (page 110).

1 OUR OPERATING ENVIRONMENT

1.1 Purpose

Annually we undertake planning reviews that analyse the existing distribution and transmission networks and consider their 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 relevant regulatory obligations.

From our reviews we produce by 30 June each year our APR in accordance with our obligations under clauses 5.12.2 and 5.13.2 of the Rules for the publication of transmission and distribution annual planning reports.[1] Our APR also incorporates the requirements of our Tasmanian Annual Planning Statement.[2]

The APR provides information on our planning activities covering a 10-year planning period from winter 2018 to winter 2028. However, some aspects are based on shorter planning periods; in particular, distribution line overload determinations are based on a two-year planning horizon.

To better inform our community, our customers and our stakeholders about the limitations and opportunities in our network, we also present further information on:

- the capability of our network to transfer electricity;
- 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 our APR provides existing and potential new customers and non-network solution providers with information to prompt discussion on opportunities for solutions to address limitations.

1.2 What we do

We own, operate and maintain the transmission and distribution electricity network that delivers electricity to more than 285,000 connected Tasmanian customers. In delivering our services, we seek to create value for our customers, our owners and our community. Our 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 PV systems (and domestic battery energy storage systems more recently) has dramatically increased the use of the network for this purpose in recent years.

We are the sole holder of licences issued by OTTER for the provision of regulated transmission and distribution network services in mainland Tasmania. We are registered with AEMO as both a transmission and distribution network service provider and operate in the NEM.

We also facilitate the transfer of electricity to and from mainland Australia via Basslink, a privately owned undersea cable between George Town in Tasmania and Loy Yang in Victoria that can transfer electricity in either direction.

We also own and operate a high-reliability telecommunications network. This network supports the operation of our electricity network, and also provides telecommunications services to other customers.

1.3 Regulatory framework

We operate 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 we comply with under the terms of our licences issued by OTTER.[3] We are also subject to a number of other acts and industry-specific regulations in planning our network. These include:

- the technical requirements of Schedule 5.1 of the Rules;
- the ESI (Network Planning Requirements) Regulations 2018[4];
- the Code; and
- a number of environmental, cultural, land use planning and other acts.

1 *In accordance with Clause 5.12.2(a) and Clause 5.13.2(a)(1) of the Rules and in conjunction with Clause 8.3.2 of the Code*

2 *Required under Clause 15 of our transmission licence issued under the Electricity Supply Industry Act 1995 and as set by OTTER*

3 *Under the Tasmanian Electricity Supply Industry Act 1995*

4 *www.legislation.tas.gov.au/view/html/inforce/current/sr-2018-002*

As the sole provider of prescribed transmission and distribution network services in Tasmania, our revenue for these services is regulated and set by the AER. We prepare submissions to the AER which determines our revenue and the maximum amount we can recover from our customers, generally for periods of five years. Previously, these revenue determinations were separate for transmission and distribution services and we presently operate under two revenue determinations. We are currently within our 2014-19 transmission regulatory period and our 2017-19 distribution regulatory period. From 1 July 2019 our transmission and distribution regulatory periods will align and their revenues will be set by the AER for five years.

In January 2018 we submitted our first combined transmission and distribution revenue proposals to the AER setting out our plans for 2019-24. Our proposal was prepared during a period of unprecedented change and uncertainty in the NEM. The transformation is being driven by customers as they embrace new technologies, take control of their energy use and support action on climate change, as well as changes to the Rules and the regulatory framework more generally.

The AER will release its preliminary decision in September 2018 and we will respond in late November 2018, before the AER makes its final decision in April 2019. Details of the regulatory determination process and our submission can be viewed on our website.[5] An outline of our associated STPIS is in Appendix A.

1.3.1 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.

1.3.2 Electricity Supply Industry (Network Planning Requirements) Regulations 2018

These regulations specify the reliability standards we must use when planning the transmission network. The regulations define the maximum extent of power interruptions following contingency events. They only apply to our transmission network; not our distribution network. They are referred to as "applicable regulatory instruments" under the Rules[6] being our jurisdictional transmission network performance requirements (and are referred to as this in the remainder of our 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 it would not be beneficial, then we must report this in our APR. We are exempt from undertaking that augmentation for five years, and we are also exempt (for five years) from meeting the network performance requirement that was the basis for the proposed augmentation. The exemption may end early if the circumstances surrounding the exemption change or if one of the affected transmission customers no longer wishes the exemption to remain.

1.3.3 Tasmanian Electricity Code

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

5 *www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals*

6 *The Rules, Section 5.10*

1.4 Integrated planning

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

To support this, integrated into our planning processes are:

- network transformation roadmap – ensure that 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 while 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.

1.4.1 The network planning process

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

- electricity demand can change. For example, our 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 used per household. A new large load, such as a new shopping centre, or closure of large load, such as a mine, will also cause changes in electricity demand;
- as network equipment ages and its condition deteriorates, it becomes more likely to fail. We investigate whether it is best to continue maintenance, replace, or if it may be possible to decommission and use alternative parts of the network, or implement non-network solutions;
- new power stations, including embedded generators, may be constructed, or old ones removed from service. These changes influence where electricity flows in a network; and
- technological changes impact on the network. Historically, residential customers only used electricity. Now with PV and battery storage technology, our customers are producing and storing electricity. This affects the way we plan and operate our network.

We perform an annual planning review to identify and report on existing and future limitations in our network, taking account of transmission and distribution network requirements and in consultation with our customers and our stakeholders. The network planning process is ongoing and while the APR is a view at a particular point in time, the planning environment is dynamic and plans can adjust with changing circumstances.

From these detailed studies of the Tasmanian power system, we create 15-year area strategies that results in the network needs identified in our APR for a 10-year timeframe. Because our 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 (beyond 15 years), from different load and generation scenarios. From this, we ensure our future development plans can accommodate a range of possible futures for our network and our customers in Tasmania.

1.4.1.1 Annual planning review

We perform an annual planning review to identify and report on existing and future limitations in our network. A summary of the outcomes from our annual planning review forms the basis of our APR. 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 2018. Because network planning is a recurring process, we may find the expected needs change from one year to the next. If demand changes at a different rate than is forecast, some proposed network changes may not be required. Others may be required sooner.

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

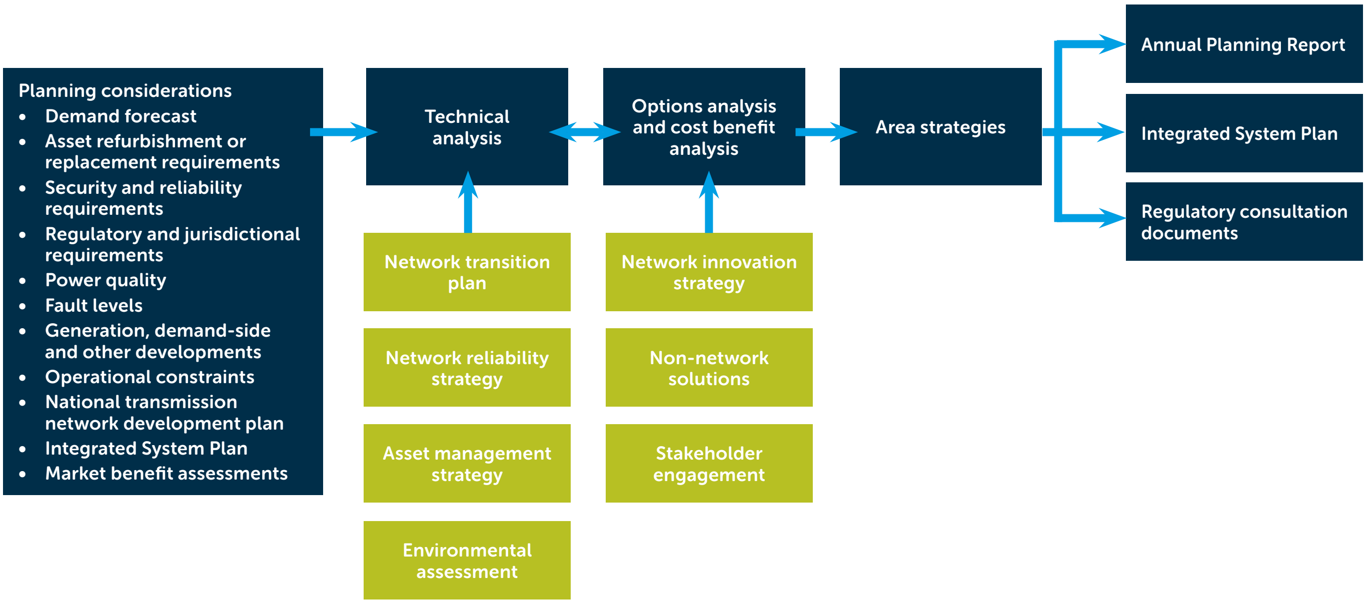

Figure 1-1: The network planning process

1.4.1.2 Demand forecast and technical analysis

A key input to the planning process is the electricity demand forecasts. In previous years we developed demand forecasts and an overall energy forecast based on:

- overall forecasts provided by NIEIR 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.

For national consistency, from 2018 we chose to change from NIEIR forecasts to AEMO's forecasts for the energy use and maximum demand at a state-level, and maximum demand at each transmission-distribution connection point.

Based on AEMO's forecasts we prepare forecasts for maximum demand for zone substations and distribution lines.

After finalising our demand forecast, we undertake computer simulations of the power system to determine whether our 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 our 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.

1.4.1.3 Accounting for network losses

Network losses are electrical energy (active energy) losses incurred in transporting electricity over transmission and distribution networks.

Electrical energy losses associated with a distribution system can be classified as:

- Technical losses comprising:
    1. series losses associated with the flow of electricity and the resistance of the electricity circuits; and
    2. shunt losses ("leakage" of electrical energy) associated with "charging up" or "excitation" of the network and occur regardless of the amount of electrical power flowing through the network.
- Non-technical losses due to metering data errors, un-metered supplies, unbilled customers, information system deficiencies, modelling assumptions and theft.

Each financial year we calculate DLFs[7] that describe the average electrical energy lost in transporting electricity from a transmission network connection point (or virtual transmission node) to a distribution customer connection. These loss factors account for both technical and non-technical losses. AEMO uses these DLFs in market settlements to calculate the electrical energy attributed to each retailer at each transmission network connection point.

Similarly, AEMO calculates forward-looking transmission loss factors to facilitate efficient scheduling and settlement processes in the NEM.[8]

As losses impact the price of electricity, they are an important consideration when developing and implementing asset management and investment strategies. Loss management is an optimisation between cost of infrastructure and loss reduction and the management of quality of supply and electricity flows across the network. Losses are a consideration in the RIT in calculating the costs and benefits associated with the economic justification of projects.

1.4.2 Asset management strategy

Management of our existing fleet of assets and the planning for future network requirements are fully coordinated processes ensuring they align to deliver the required service levels in the most cost-efficient manner. The asset management strategy focuses on ensuring the replacement of assets is determined by asset condition and risk, rather than age. 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 our customers and to provide information to our stakeholders regarding the environment in which we operate.

Key themes supporting our asset management approach and associated levels of investment are:

- managing our assets to ensure safety and the environment is not compromised;
- maintaining the reliability of our network;
- where we can safely do so, running our network harder rather than building more;
- responding to the changing nature of customer behaviours and requirements by participating in an industry-leading residential battery trial on Bruny Island;
- undertaking a feasibility analysis of a second interconnector with Victoria and working with Hydro Tasmania in its Battery of the Nation proposal;
- taking a whole-of-life (lifecycle) 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 lifecycle management extending over five phases, as presented in Figure 1-2.

Each phase of the lifecycle has a corresponding lifecycle strategy detailing our objectives and approach to the particular activities in that phase to ensure performance to required levels.

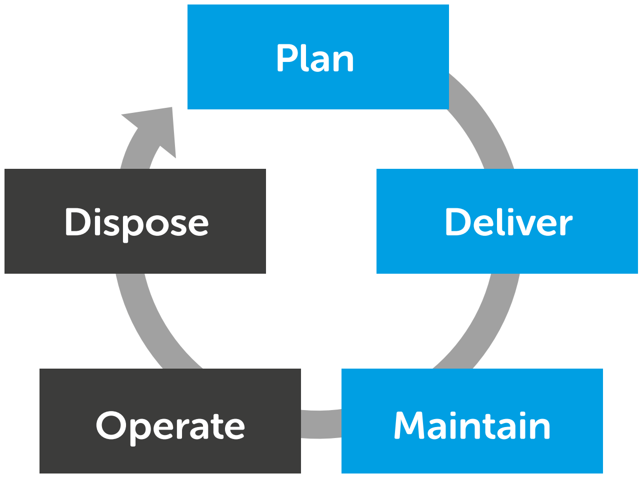

Figure 1-2: Asset lifecycle management

7 *www.tasnetworks.com.au/apr, Distribution loss factors*

8 *www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries*

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 AMPs. Our AMPs identify the performance and risks presented by each asset type within the category and define actions that must be undertaken to sustain asset and system performance. They include:

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

Our Strategic Asset Management Plan is available on our website along with our Asset Management Policy and a suite of individual asset category management plans.[9]

1.4.3 Demand management assessment

We consider demand management opportunities during the planning cycle when investigating solutions to network limitations, with particular focus on our distribution network. To that end, we have developed a Demand Management Engagement Strategy that explains how we will engage and consult with our customers and suppliers to deliver solutions for our distribution network. We encourage providers to register with us on our website.[10]

An early analysis of possible solutions is completed at a high level and includes desktop studies, site visits and discussions with our customers and providers. The assessment of solutions comprises four stages and involves analysis of the costs, benefits and risks of each option.

Stage 1: Investigation

We investigate the network issue and determine if a demand management option is a credible way to address the need. Economic analysis that estimates the savings derived by deferring or replacing the network upgrade project is then completed.

Stage 2: Development

If an option is deemed feasible, it is compared against network upgrade options and evaluated for cost, risk and potential benefits. During this stage, if a project is subject to the regulatory investment test for distribution, then we publish an options report on our website. The information enables proponents to assess their demand management options.

Stage 3: Assessment

We ask for proposals from our customers and providers to address an issue. These are evaluated against conventional project implementation criteria and costs and benefits.

Stage 4: Reporting

All enquiries and proposals receive a written response and interested parties are advised of the status of their assessment at regular intervals. We publish the initial results in a draft assessment report and allow our customers and providers to provide feedback. We consider feedback and then publish a final report that has the preferred solution and the reason for its selection.

1.4.4 Regulatory investment test

The RIT[11] defines the economic analysis and public consultation process a network service provider must undertake in selecting an option to address a need in the power system.

The RIT application guidelines are published by the AER[12] 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 RIT for all transmission and distribution projects where certain thresholds are met.

Under certain circumstances, network service providers are not obliged to undertake a RIT. 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 customer's connection application.

9 *www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals/regulatory-proposal-documents*

10 *www.tasnetworks.com.au/our-network/planning-and-development/demand-management-engagement-strategy*

11 *The Rules, Clause 5.16 (transmission) and 5.17 (distribution)*

12 *www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017*

1.4.4.1 Options and cost-benefit analysis

When we find network changes are required, we identify the possible options to solve the problem. Options could include expansion of the network; 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 our 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 feasible options, we estimate the cost and the potential economic benefits (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.

1.5 Customer engagement

As Tasmania's integrated electricity network services provider, we have a focus on caring for our customers and making their experience easier. We have made great progress to deliver safe, reliable and secure services to our customers while keeping prices as low as possible.

Our success is anchored to the prosperity of our customers and we are working hard to embed a culture of making customers central to all we do. To help us achieve this outcome, we remain committed to engaging with, informing and educating our customers about our activities and plans for the future. We are prioritising customer engagement in our activities, including through the following initiatives:

- delivering our voice of the customer program, ensuring we consider our customers' perspectives and "voice" in our activities and decisions;
- implementing a customer segmentation model and engagement framework;
- successful Customer Council and Pricing Reform Working Group with representation across our customer segments;
- adopting a dedicated Customer Service Strategy to assist us in sharpening our focus on delivering quality service outcomes for our customers; and
- undertaking monthly customer satisfaction surveys and Net Promoter Score surveys.

Further customer engagement information is available on our website.[14]

When significant network investment is required and the cost of any credible option to address the need is in excess of the cost threshold[15], we undertake a RIT inclusive of a public option selection and consultation process.[16]

1.6 What has changed since 2017

1.6.1 Load forecasts

Our forecasting approach has changed from 2017 as we previously engaged independent consultants from NIEIR to produce a state-level forecast from which we then developed forecasts for each transmission connect point. For 2018 we used state and transmission connection point forecasts published by AEMO[17] to develop zone substation and distribution feeder forecasts. These can be viewed on our website.[18]

At state level, the growth rate of energy use is forecast to reduce to 0.4% a year from the previously forecast average growth of 1.1% a year. Details of the forecast and method are in Chapter 5.

1.6.2 Reporting obligations

In July 2017 the AEMC made a rule[19] to increase the transparency of decisions to retire, de-rate and replace network assets. The rule makes a number of amendments creating requirements that apply equally to network replacement and augmentation investments.
In particular, the rule requires reporting on planned assets:

- retirements including the reasons for the retirements; and
- de-ratings that result in a system limitation or constraint on a network, including the reasons.

The rule also extends the distribution and transmission RITs to network replacement expenditure decisions.

1.6.3 Planned investments and forecast limitations

Material differences in planned investments and forecast limitations from those reported in our 2017 APR are summarised in Table 1-1. Inconsequential changes such as year-to-year changes in investment timing are not included. The reference provides to the section in Chapter 6 where these are identified in detail.

New planned investments and forecast limitations included in this APR as a result of the new reporting obligations presented in section 1.7.2 are not included in this table.

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14 www.tasnetworks.com.au/customer-engagement

15 The Rules, Clause 5.15.3, regulatory investment test thresholds

16 The Rules, Clause 5.16.4 and Clause 5.17.4, regulatory investment test procedures

17 www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Tasmania

18 www.tasnetworks.com.au/apr

19 www.aemc.gov.au/rule-changes/replacement-expenditure-planning-arrangements

Table 1-1: Differences in planned investments and forecast limitations reported from 2017

Area	Location	Summary of change	Ref
Backbone transmission network	George Town	A new project proposed for our 2018 APR is installation of dynamic reactive support at George Town Substation to reduce power transfer constraints on Basslink	6.2.1
	North-west Tasmania	New projects proposed for our 2018 APR are those as part of our north-west Tasmania transmission development plan to facilitate new large-scale wind connections[13]	6.2.2
	TAS-VIC	A new project proposed for our 2018 APR is the establishment of additional interconnection between Tasmania and Victoria through a second Bass Strait interconnector[13]	6.2.3
West	Rosebery	Our 2017 APR identified a limitation of the maximum demand at Rosebery Substation exceeding the firm rating of the supply transformers. We now propose a solution to install a third supply transformer, relocated from elsewhere in the network	6.4.3
North-west	Railton Burnie	The forecast limitation of the maximum demand exceeding the firm rating of the supply transformers at Burnie and Railton substations has been deferred past 2027 due to a reduction in the forecast load growth	6.5.4.1
	Wesley Vale	The proposed project to convert the supply voltage at Wesley Vale Substation from 11 kV to 22 kV, to match and rationalise the surrounding distribution network to improve local supply reliability, is now committed	6.5.1
Northern	Hadspen	The forecast limitation of the maximum demand exceeding the firm rating of the supply transformers at Hadspen Substation has been deferred past 2027 due to a reduction in the forecast load growth	6.6.4.1
	Hadspen-Norwood	The proposed project to upgrade the Hadspen-Norwood 110 kV transmission line dead-end assemblies, which were limiting the line capacity, is now complete	6.6.1
	George Town	The proposed project to install a 40 MVAr, 110 kV capacitor bank at George Town Substation, to relieve voltage and reactive margin limitations, is now complete	6.6.1
	Palmerston	The proposed project to replace disconnectors at Palmerston Substation has been incorporated into a wider disconnector replacement program	6.6.4.2
Central	Liapootah-Chapel Street	The proposed project to upgrade the Liapootah-Chapel Street 220 kV transmission line dead-end assemblies, which were limiting the line capacity, is now complete	6.7.1
	Meadowbank	Our 2017 APR identified a limitation of a supply transformer contingency at Meadowbank Substation exceeding the allowed unserved energy. We now propose a solution to establish a new distribution feeder from Waddamana Substation to reduce the unserved energy arising from the transformer contingency	6.7.2
Greater Hobart	Chapel Street	The proposed project to install a second 110 kV bus coupler circuit breaker at Chapel Street Substation, to minimise the impact of a fault of the existing bus coupler, has been removed from our NCIPAP investment plan for 2009-14 and deferred indefinitely due to an increase in the estimated project cost	6.9.4.1
	Derwent Park, New Town and North Hobart	The forecast limitation of the maximum demand exceeding the firm rating of the supply transformers at Derwent Park Zone, New Town Zone, and North Hobart substations has been deferred past 2027 due to a reduction in the forecast load growth	6.9.4.2
	Lindisfarne	The proposed project to replace the supply transformers at Lindisfarne Substation, due to their poor condition, is now committed	6.9.1
	Various sub-transmission lines	Our 2017 APR identified a limitation of various sub-transmission lines in the Greater Hobart planning area currently are forecast, or exceed, their firm ratings. We now propose a solution to upgrade the capacity of these lines through various means	6.9.2
	Waddamana-Bridgewater Junction	The proposed decommissioning the Waddamana-Bridgewater Junction 110 kV transmission line, due to its poor condition, is now committed	6.9.1

13 *Large projects as part of our north-west Tasmania transmission development plan and 50% funding of a second Bass Strait interconnector have been included as contingent projects in our revenue submission for 2019-24*


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2 NETWORK TRANSFORMATION

Customers are embracing new technologies, taking control of their energy use and supporting action on climate change. These shifts are dramatically changing our electricity system, and shape our economy and lifestyle. Electricity network businesses are working together to understand the many ways Australia's energy future may unfold.

Historically, power flow was one-way: from large scale generation, via transmission and distribution networks, to customers. Within the past 10 years, small-scale distributed generation – predominately rooftop PV – has grown to become commonplace. When the costs of energy storage via batteries further reduce they will likely become an economic proposition for commercial and domestic customers providing the opportunity for trading electricity at the distribution level.

Conversion of road transport from total reliance on fossil fuels to electricity will impact on both our network's use patterns and quantity of electricity supplied.

Government policy on low-emission energy futures has encouraged large-scale renewable developments and the consequent recognition of the need for transmission-connected systems to cater for the variability in their generation and to ensure continued stable and reliable operation of the integrated power system.

It is likely business and households will continue to rely on the network for their electricity supply. As a consequence of the transformation, the role of our network will continue to change with the need for new approaches to its design, operation and control.

A cost effective and technically efficient network is essential to ensure sustainable pricing. Many new and innovative technologies can address existing and emerging issues within the framework of network planning and operation, encompassing:

- adequacy to meet the demand within network element capacities, quality of supply limits and accessibility expectations; and
- reliability of the system to cope with incidents without the uncontrolled loss of load.

Successful transformation will need to ensure levels of reliability and security are at least maintained, requiring careful attention to three system design elements:

- susceptibility – ability to avoid incidents (prevent);
- vulnerability – ability to maintain supply (minimise); and
- recoverability – ability to restore supply (respond).

2.1 A national context

By 2050 Australia's electricity sector is likely to transition to net zero carbon emissions. If so, then 30% to 50% of Australia's electrical energy will be generated by customers who will choose to invest in customer-owned electricity generation such as PV and other DER, shown in Figure 2-1, and supported by energy storage technology like batteries.[20]

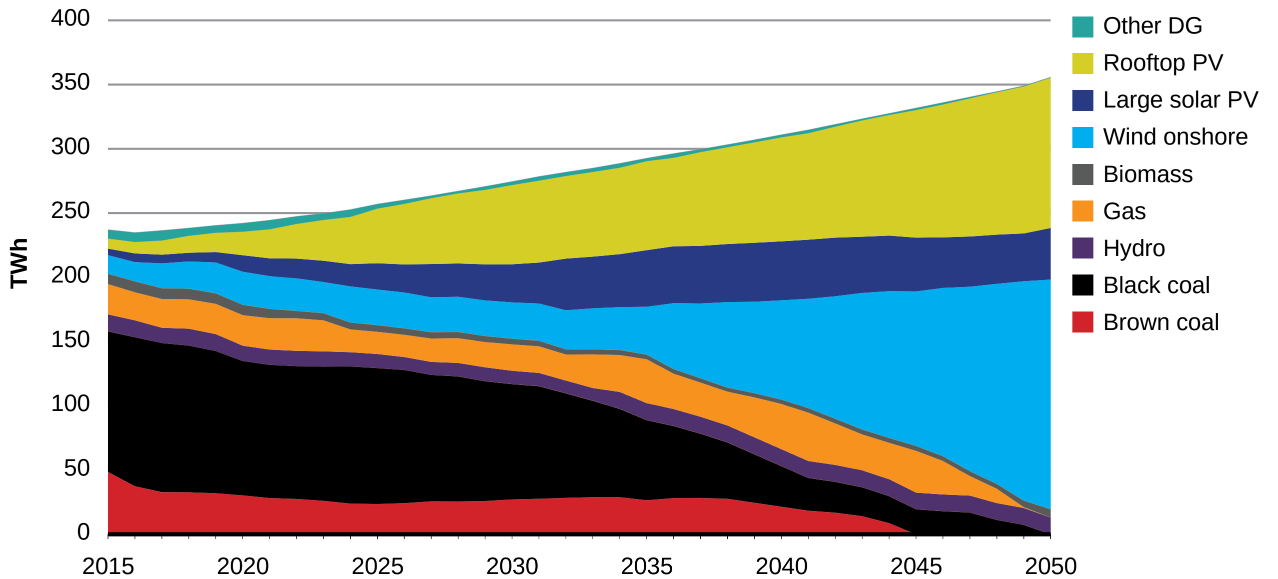

Figure 2-1: Projection of Australia's changing electricity generation mix to 2050

20 www.energynetworks.com.au/roadmap, DER is identified as DG (distributed generation) in this figure

In 2016, COAG energy ministers agreed to an independent review of the NEM to take stock of its current security and reliability and to provide advice to governments on a coordinated reform blueprint.[21] The review published its findings in June 2017. The *Blueprint for the Future Security of the National Electricity Market* delivers a plan to maintain security and reliability in the NEM in light of the significant transition underway, including due to rapid technological change. It sets out a vision for the future and focusses on four key outcomes:

1. increased security;
2. future reliability;
3. rewarding consumers; and
4. lower emissions.

These outcomes will be underpinned by the three pillars of:

1. an orderly transition;
2. better system planning; and
3. stronger governance.

To support the energy industry transformation, and as a result of the review's recommendations, AEMO has developed an ISP to facilitate the efficient development and connection of renewable energy zones across the NEM. Information on the contents of the ISP and how it relates to Tasmania is in section 6.2.5.1.

2.2 National roadmap

To capture the role of the changing network into the future, CSIRO and Energy Networks Australia partnered to develop an Electricity Network Transformation Roadmap.[22]

The purpose was to "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 participated with authors in this process.

Nationally, the outlook is that network businesses will:

- connect millions of customer-owned generators and energy storage systems to each other (known as DER);
- enable customers to trade excess energy;
- integrate large-scale renewable energy into the grid; and
- keep the electricity network secure.

In the future, by harnessing distributed energy resources and avoiding duplication of investments, it is predicted customers will benefit from significant savings in energy bills.

21 www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market

22 www.energynetworks.com.au/roadmap

2.3 Our own roadmap to 2025

In turn, we developed our own roadmap to 2025[23] to ensure we adapt to the changing operating environment and continue to provide the most cost-effective services to our customers. We engaged our customers on the details of our roadmap and the initiatives in it informed our revenue proposal for the 2019-24 regulatory period. Figure 2-2 shows a possible future for 2025 from our roadmap.

The aspiration is to manage an orderly and efficient transition of our network to an envisaged future illustrated below so that existing connected parties continue to receive safe, reliable and efficient services and can benefit from innovation and improvements in technology while any additional costs associated with that transition are appropriately allocated.

Electricity Network Transformation in Tasmania

There are a range of possible futures, this table shows what 2025 might look like:

CLEAN ENERGY TRANSITION	2016	2025
Conventional hydro power	Conventional hydro = 2,310MW	Conventional hydro = 2,400MW
Large scale wind farms	Wind = 308MW	Wind = 1,100MW
Solar systems	Solar (PV) = 96MW	Solar (PV) = 167MW
Pumped hydro (Battery of the Nation)	Pumped hydro = 0MW	Pumped hydro = approx 300MW
Customers with distributed energy resources	**27,000** customers or **(9.2%)**	**40,000** customers or **(12.5%)**
Batteries – installed capacity	Negligible installations and capacity	Low take-up but **increased** to 33MW **Equivalent** capacity to Hydro's Lake Echo Power Station
Electric vehicles	**200**	**Estimate 5,000 - 17,000**

Figure 2-2: Electricity network transformation in Tasmania

23 www.tasnetworks.com.au/about-us/corporate-profile/our-strategy

The key network issues facing us are:

- integration of new generation at both transmission and distribution levels;
- maintaining power system stability and reliability;
- network constraints on market operations;
- asset management, fault and emergency costs;
- availability of accurate and timely distribution; network data for decision making purposes;
- localised lower reliability performance; and
- maintaining edge-of-grid assets.

Our wind resources and complementary pumped hydro energy storage opportunities provide the potential for Tasmania to be a significant provider of dispatchable renewable energy for Australia. Further interconnection with Victoria, along with Hydro Tasmania's Battery of the Nation, will be needed to fully realise these opportunities. Tasmania has four renewable energy zones identified by AEMO[24] as some of Australia's key renewable energy zones.

The key ideas in our roadmap include improving our traditional services as we transition to potential new services. Our main role will be all about connecting, transferring and balancing energy. By doing these things, we will make sure we can continue to deliver power – whether customers are using it or selling it. As we approach 2025, our key challenge will be handling complex changes in the electricity industry to keep the system safe, stable and affordable. We will continue to listen to, and be influenced by, our customers, ensuring lowest sustainable prices and maximising the capability of the network to host new generation sources.

As part of our roadmap we developed seven programs focused on creating a better tomorrow:

1. Voice of the customer

We will keep investing in support systems that make it easy to do business with us and help us understand our customers' needs, so that either directly or through partnerships, we deliver services our customers' value

2. Network and operations productivity

We will improve how we deliver the field works program, continue to seek cost savings and use productivity targets to drive our business

3. Business productivity

We are transforming our business support systems to reduce costs and add value

4. Electricity and telecommunications network capability

To meet our customers' energy needs and ensure power system security, we will invest in the network to make sure it stays in good condition, even while the system grows more complex. For instance, we will need more sophisticated management, operating and protection schemes for intermittent power generation and to enable new technologies

5. Predictable and sustainable pricing

Because we want to deliver the lowest sustainable prices, we will transition our pricing to better reflect the way our customers produce and use electricity and provide our customers with greater choice and control over their energy use

6. Enabling and harnessing new technologies and services

By investing in technology and customer service, we will be better able to host the technologies our customers are embracing. We will aim to make the most of our customers' investments in DER for the benefit of all

7. Workforce of the future

Our people are integral to delivering power. We will keep developing knowledge and skills to continuously improve systems and processes, embrace new technologies and provide our customers with great service

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24 www.aemo.com.au/electricity/national-electricity-market-nem/planning-and-forecasting/integrated-system-plan

2.4 Energy security

The Tasmanian Government established the Tasmanian Energy Security Taskforce to identify ways to help future-proof Tasmania's energy security[25]. The taskforce was established in response to the 2015-16 energy supply security challenges resulting from historically low inflows to hydro water storages and the outage of Basslink. The taskforce advised the government on how it can better prepare for, and mitigate against, the risk of future energy security events. In its August 2017 final report, the taskforce noted the Tasmanian Government should:

- define energy security and responsibilities;
- strengthen independent energy security monitoring and assessment;
- establish a more rigorous and more widely understood framework for the management of water storages;
- retain the Tamar Valley Power Station as a backup power station for the present and provide clarity to the Tasmanian gas market;
- support new on-island generation and customer innovation;
- in relation to the fifth priority, the taskforce noted: new entrant developments should not face barriers to entry due to Tasmania's market structure and energy projects. Promoting new renewable energy development of between 700 GWh to 1000 GWh a year would improve Tasmania's energy security and reduce reliance on Basslink imports, thus mitigating against the risk of high priced imported energy from the rest of the NEM; and
- Tasmania's features make it desirable for private sector interests to partner with local businesses and researchers to trial new products and services, such as storage integration and electric vehicles. The piloting of fast moving customer-led technologies and other innovations would be positive for business sentiment.

The implications for us are:

- the need to retain technical and analytical capability to assist with a coordinated response across market participants to manage electricity supply risks when water storages are near or below an identified energy security reserve level; and
- to ensure our people and our network have the capability to respond to fast moving customer-led technologies and other innovations.

25 *www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce*

26 *The Rules, Clause 5.20B.4(h), inertia service provider*

2.5 System strength and inertia obligations

Two issues arising from non-synchronous generators connecting to our network and traditional synchronous generators operating less or being decommissioned are:

- system strength in some parts of the power system has been decreasing to a level that can mean it is insufficient to keep generating systems stable and remaining connected to the power system following a major contingency event; and
- reducing system inertia with the consequence of reduced ability to dampen rapid changes in frequency.

In response to these issues, AEMC made new rules that:

- established a transparent and efficient framework for the management of power system fault levels, also known as system strength; and
- placed an obligation on TNSPs to procure minimum levels of inertia or procure other services (such as frequency control services) that reduce the minimum level of inertia required to manage the rate of change of power system frequency.

The power system fault levels framework sets out clear allocation of roles and responsibilities for AEMO and NSPs in the management of system strength. It requires TNSPs to procure system strength services needed to provide the levels determined by AEMO.

It also required (from 17 November 2017) new connecting generators to "do no harm" to the security of the power system in relation to power system stability or on nearby generating systems. New connecting generation is required to fund the costs associated with the provision of any required system strength services to address the impact of its connection on system strength.

Historically, most generation in the NEM has been synchronous and, as such, the inertia provided by these generators has not been separately valued. As the generation mix shifts to smaller and more non-synchronous generation however, inertia is not provided as a matter of course giving rise to increasing challenges for AEMO in maintaining the power system in a secure operating state.

The AEMC established an obligation for TNSPs to meet the minimum inertia requirements determined by AEMO associated with maintaining a secure operating system. The TNSP can provide the inertia itself or procure inertia services from third parties (such as generators). In addition, the new rules[26] will require us to provide information in the Transmission Annual Planning Report about the activities undertaken to satisfy obligations to make inertia network services available; and inertia support activities undertaken.

The new obligations stemming from these rules begin on 1 July 2018.

Historically, we recognised these issues when connecting Basslink, wind generation and with the emergence of solar PV. To manage the system strength and inertia, we introduced mechanisms to manage the dispatch of generation and Basslink flows to ensure adequate system strength and minimise inertia related constraints. The new rules will provide AEMO and us with other mechanisms to operate the power system securely and to ensure a stable, resilient and strong system to deliver our customers' power. We are investigating new technology to implement at George Town Substation that will stabilise voltage and provide inertia-limiting services.

In addition, we have initiated a Tasmanian System Integration Study driven by the proposed development of significant on-island asynchronous generation in the next five years (mostly in the form of new wind projects), coupled with the potential for increased interconnection between Tasmania and mainland Australia. This work program is in recognition of the multitude of technical challenges that need to be properly analysed (and mitigated) if Tasmania is to successfully exploit its significant natural energy resources. It will map the technical envelope of Tasmania's power system in the presence of approximately 1100 MW of wind and solar generation and provide an understanding of what power system security criteria are most limiting.

The study will progress in parallel with the feasibility study and business case assessment of a second Bass Strait interconnector that we are coordinating (refer Section 2.8). In completing our study parallel to the second interconnector assessment project, we recognise we must prepare for the integration of significant new wind and solar generation with or without the realisation of a second interconnector.

2.6 Emergency frequency control schemes

AEMC made a rule to provide for emergency frequency control schemes being "last line of defence" mechanisms against non-credible contingency events and also introduced a new category of contingency event: the Protected Event[27].

The rule places an obligation on AEMO to undertake at least every two years, in collaboration with TNSPs, an integrated review of power system frequency risks associated with non-credible contingency events – the PSFR Review. The PSFR Review considers whether:

- there is a need to introduce, modify or adapt automatic emergency frequency control schemes (including existing under frequency load shedding) that are designed to limit the consequences of some non-credible contingency events; and/or
- if it would be economic for AEMO to operate the power system in a way that limits the consequences of certain high consequence non-credible contingency events, should they occur.

The outcomes on the PSFR Review may be a recommendation for new or improved emergency frequency control schemes and/or a proposal for the declaration of a Protected Event by the Reliability Panel. The TAPR must set out for proposed new or modified emergency frequency control schemes, the manner in which the project relates to the most recent PSFR Review.[28]

For a Protected Event, AEMO can use a mixture of ex-ante solutions, such as the purchase of FCAS or constraining generation dispatch, to maintain the power system in a configuration such that, if the event were to occur, there is a better chance that its consequences can be limited to an amount of controlled load shedding.

Where the management of a Protected Event includes a new or modified emergency frequency control scheme, the Reliability Panel sets a "protected event EFCS standard", which defines the target capabilities for the scheme. Under the framework, NSPs are:

- required to design, implement and monitor the scheme in accordance with the standard; and
- exempt from having to undertake the RIT-T (or the RIT-D) because the cost benefit assessment would have already been undertaken by the Reliability Panel.

AEMO published the first PSFR Review for Tasmania on 6 April 2018 and had the following insights:

- the current arrangements to protect against frequency risks are appropriate;
- there was not an immediate need to modify any emergency frequency control schemes; and
- the management of non-credible contingencies in Tasmania is appropriate.

27 www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen

28 The Rules, Clause 5.12.2(c)(6A)

2.7 System frequency reviews

New sources of electricity are changing the way Australia's power system works, which can have implications for power system security. One of these technical limits is frequency. Managing frequency involves balancing the supply of electricity against customer demand on an instantaneous basis. Large deviations in frequency can have significant impacts on the safety and reliability of the power system; thus controlling frequency is critically important. Analysis undertaken for AEMO also reflects that, in recent years, the frequency performance of the power system under normal operating conditions has deteriorated due to changes in the provision of frequency response capability.

In response, the AEMC self-initiated a frequency control frameworks review to assess whether the current market and regulatory arrangements to support effective control of system frequency are fit for purpose and what opportunities there are for new technologies to support power system security. The scope of the review may include (but is not limited to) primary frequency control, frequency control ancillary services and DER.

In addition, AEMC's Reliability Panel is undertaking a review of the Frequency Operating Standards that apply to Tasmania and mainland Australia. This review is in two stages. Stage one has been completed and primarily addressed technical issues and changes stemming from the emergency frequency control schemes rule that establishes an integrated, transparent framework for the consideration and management of power system frequency risks arising from non-credible contingency events.

Stage two will include a general consideration of the various components of the frequency operating standards, including the settings of the frequency bands and time requirements for maintenance and restoration of system frequency. Stage two will start when AEMC's frequency control frameworks review is further progressed.

2.8 A second Bass Strait interconnector

We are currently assessing the feasibility of a second Bass Strait interconnector. A second interconnector, along with Basslink, would allow for increased renewable energy development in Tasmania and maximise current hydro generation ability to support variable output from wind and solar sources in Victoria. It would also add to Tasmania's energy security.

In April 2016, the Commonwealth and Tasmanian governments established a study of the feasibility of a second Bass Strait interconnector between Tasmania and Victoria. The study was initiated in response to the energy supply challenges during 2015-16. The final report[29] concluded:

- The NEM is undergoing rapid transformation. The increasing penetration of non-synchronous forms of renewable generation is driving the need for resources that will maintain power system security. This presents opportunities for Tasmania to export balanced and dispatchable renewable energy, based on its hydro resources, to other NEM regions.
- The current energy market environment is subject to uncertainty. The uncertainty of the future investment environment for a second Bass Strait interconnector is further exacerbated by the length of its economic life of 40 years or more and the long lead times for planning and construction. While the modelling results suggest that under current anticipated market conditions a second Bass Strait interconnector may not be economically feasible, it has not been possible to fully reflect the implications of prevailing market uncertainty in those projections. Also, other relevant market benefits, such as power system security and reliability benefits, have not been fully captured by the modelling and may be given greater weight by electricity consumers and governments in current market conditions.

More recently, we announced plans with ARENA to explore a more detailed feasibility and business case assessment for a second Bass Strait interconnector.[30] We have established Project Marinus to undertake this assessment. Project Marinus builds upon the 2016 review and will be informed by the Battery of the Nation initiative and AEMO's Integrated System Plan. As well as the opportunities a second Bass Strait interconnector would bring, a key focus for Project Marinus will be to understand the impact it would have on our network and existing customers in Tasmania, and requirements for network augmentations and specialised protection schemes to facilitate it.

In assessing the case for a second Bass Strait interconnector, Project Marinus will consider:

- the optimum capacity;
- the preferred route;
- technical specifications and supply arrangements for the cable and grid interconnections;
- potential timing;
- detailed cost estimates;
- RIT; and
- financial and development models to implement it.

The possible investment required for a second Bass Strait interconnector, and its link with AEMO's Integrated System Plan is in Section 6.2.3

29 www.energy.gov.au/government-priorities/energy-supply/tasmanian-energy-taskforce

30 www.arena.gov.au/news/building-case-second-interconnector-bass-strait

2.9 Battery of the Nation

With the assistance of ARENA funding[31], Hydro Tasmania (with assistance from us on transmission infrastructure requirements and costs) is investigating future development opportunities for Tasmania to make a greater contribution to the NEM.[32]

Battery of the Nation is about setting up a blueprint for how Tasmania's renewable resources are developed over coming decades.

With further interconnection, favourable market settings and a sound development plan, Tasmania could produce significantly more renewable energy and realise the full value of Tasmania's hydropower system.

An energy system that increasingly relies on variable generation (such as wind and solar) will have extended periods of low energy production. It will need to be balanced with systems that can provide reliable energy in bulk and on demand for sustained periods. Pumped hydro energy storage has the greatest potential to complement wind and solar because it can store clean energy on a large scale to use during periods of low energy production. There are currently very few technologies that can cost-effectively provide large volumes of energy storage that will last for extended periods of time. A key focus will be understanding the impact of increased generation and large "tidal flows" associated with pumped hydro energy storage across our network and existing customers in Tasmania and associated requirements for network augmentations and specialised protection schemes.

2.10 Distributed energy resources

Customer-owned generators and energy storage systems, commonly referred to as DER (like rooftop PV, battery energy storage and electric vehicles) continue to be popular with our customers and we continue to connect them to our distribution network. While penetration of this technology is still low in Tasmania, we foresee the need to prepare our network for higher levels of technology, the disruptive applications of it and take advantage of the opportunities in assisting managing network constraints.

To further understand the opportunities, we – along with ARENA and other partner organisations – are trialling the use of behind-the-meter solar and battery storage for solving network constraints as part of the CONSORT Bruny Island Battery Trial.[33] We have successfully utilised the batteries for peak demand management and this has reduced the use of the peak shaving generator on the island.

The project goes further to explore the automatic and coordinated use of batteries to solve network issues while also exposing additional value streams to our customers. The Australian National University, the University of Tasmania, the University of Sydney and Reposit Power are using the trial to test network aware coordination, an algorithm that optimises the battery response to network constraints. By building this on top of the battery control platform, it also allows customers to access the possible value streams stemming from their storage, becoming one of the first tests of trans-active energy in Australia and

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31 www.arena.gov.au/blog/hydro-tasmania

32 www.hydro.com.au/clean-energy/battery-of-the-nation

33 brunybatterytrial.org

moves towards the distribution system operator concept.

We are planning the next steps to take the early learnings from the CONSORT Bruny Island Battery Trial and apply them to other areas of the state.

2.11 Electric vehicles

As reported in our 2017 Annual Planning Report, electric vehicle use in Tasmania remains in its infancy; however, we expect that eventually, electric vehicles will be commonplace. Electric vehicles, as well as being new loads on our network, are a form of energy storage and pose both challenges and opportunities for electricity networks:

- uncontrolled charging could exacerbate network demand issues; however
- electric vehicle use in general should improve the usage of the network.

Multiple domestic and international studies conclude electric vehicle charging impacts will firstly be experienced by low-voltage networks, finding that in most cases initially sufficient capacity for generation and transmission exists.

We are committed to finding innovative, least-cost strategies to manage our network in an environment where the number and size of electric vehicle charging and embedded generation installations is increasing and energy flows to meet customer requirements are also changing. We continue to investigate the potential consequences of electric vehicle charging for our low-voltage network and finding new strategies to manage increasing peak demands and impacts on voltage control, phase unbalance and harmonics.

We continue to trial the use of electric vehicles and partner with a not-for-profit organisation to understand the benefits to business, as well as gain experience with the impact of charging on the network. We have a broader leadership role in the development of policies to encourage greater uptake of electric vehicles. This includes public charging infrastructure development, provision of information about electric vehicle charging, and general promotion of electric vehicles. To this end, 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.

Other initiatives to encourage efficient uptake of electric vehicles include:

- introducing two new demand-based time-of-use tariffs to give residential and small business customers who invest in DER like solar generation, batteries and electric vehicles new opportunities to control their electricity costs;
- establishing new connection standards for two-way flows of electricity for micro-embedded generation, electric vehicles and batteries, and support two way flows on our distribution network; and
- offering a fast charger support scheme.

Electric vehicles are generally charged at home (although chargers are being found in public places such as tourism establishments and car parks). These chargers offer a top-up if staying for a short time. Several hours or an overnight stay is required to achieve full charge.

Alternatively, a fast charger can achieve a full recharge in between 30 and 90 minutes depending on the type of electric vehicle. Fast chargers can be expensive to install, therefore we have established an Electric Vehicle Fast Charger Support Scheme that provides assistance to potential fast charger operators.[34]

2.12 Distribution pricing reform

Technological and customer-driven changes in our industry mean the flat, consumption-based network tariffs that are used to recover the cost of building and operating our network are no longer fit for purpose. So, like other electricity networks across Australia, we are looking to improve the way we charge for the delivery of electricity.

Since our formation in 2014, we have embarked on tariff reform that has seen us move towards more cost-reflective pricing. This includes adjusting the prices of our existing network tariffs to unwind some longstanding cross-subsidies (both between tariffs and between different types of customers). We have also developed new tariffs that more accurately reflect the impact our customers' use has on the cost of running our network, including at different times of the day and at different days of the week. This pricing approach will also encourage greater use at times where there is spare network capacity. By using existing capacity better, we can deliver more electricity without building more network.

We are conducting our emPOWERing You Trial to better understand how and when our customers use electricity.[35] The trial involves about 600 residential customers selected from Bridgewater, Brighton, Lower Midlands and surrounding areas. The first phase of the trial, which involved 12 months of interval data collection, is now complete. The second phase involves providing participants with demand-based time-of-use pricing signals and gaining an understanding of their behaviour in response.

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34 www.tasnetworks.com.au/industry-and-development/electric-vehicle-fast-charger-scheme

35 www.tasnetworks.com.au/empoweringyou

3 THE TASMANIAN POWER SYSTEM

3.1 Overview

The key participants of Tasmania's electricity supply chain are (Figure 3-1):

- power stations and wind farms;
- a transmission network;
- a distribution network;
- small-scale generation connected within the distribution network;
- retailers;
- end-users of electricity; and
- DER.

Tasmania's power system forms 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 enabling Tasmanian generators to export to mainland Australia while mainland generators can supply energy to our transmission network.

Currently, five generation companies have power stations connected to our transmission network:

- AETV Pty Ltd[36]
- Hydro-Electric Corporation (Hydro Tasmania)
- Musselroe Wind Farm Pty Ltd
- Woolnorth Bluff Point Wind Farm Pty Ltd
- Woolnorth Studland Bay Wind Farm Pty Ltd

A number of other small generators that are connected within our distribution network, termed embedded generation, are also licensed to operate in Tasmania. Very small embedded generation, such as rooftop PV systems, do not require a generating licence but must have a connection agreement with us.

All large generators sell electricity to a central market: the NEM. AEMO is responsible for the security of the NEM and coordinates the dispatch of generators so 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 subject to power system constraints.

Our 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 our transmission network. Our distribution network distributes the electricity to smaller industrial and commercial, irrigation and residential customers.

Electricity is sold to end-users, including those directly connected to our 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 our transmission and distribution networks in delivery.

3.1.1 Unique features

3.1.1.1 Small load

Our transmission network median demand during 2016-17 was about 1160 MW, and spent about 50% of the time between 1100 MW and 1300 MW. The minimum demand occurs during summer nights and is about 850 MW. It is forecast to reduce over coming years as increasing embedded distribution PV generation reduces summer day demand below current summer night minimums.

The largest generating system in Tasmania that 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 in mainland Australia NEM regions. As a result, Tasmania's frequency operating standards differ from those of mainland Australia. The technical implications of this are discussed in Section 7.2.

3.1.1.2 Customer load base

Most of the energy used in Tasmania is supplied to large customers directly connected to our transmission network. We have 10 load customers directly connected to the transmission network. Collectively, they used about 58% of energy in Tasmania and contributed to about 43% of the state-level peak demand in 2016-17. Energy use of the 10 transmission-connected customers is dominated by four major industrial customers using 55% of the total energy. The relative energy use in 2016-17 supplied from our transmission network is presented in Figure 3-2.

As large customers use a significant portion of energy, their operation can have a significant impact upon our power system. Changes to our transmission-connected customer base, such as a permanent reduction in load, would alter the normal operation of our power system and impact on such things as power flow and utilisation of our transmission network. We continue to engage with our customers and incorporate of their needs in our planning activities.

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

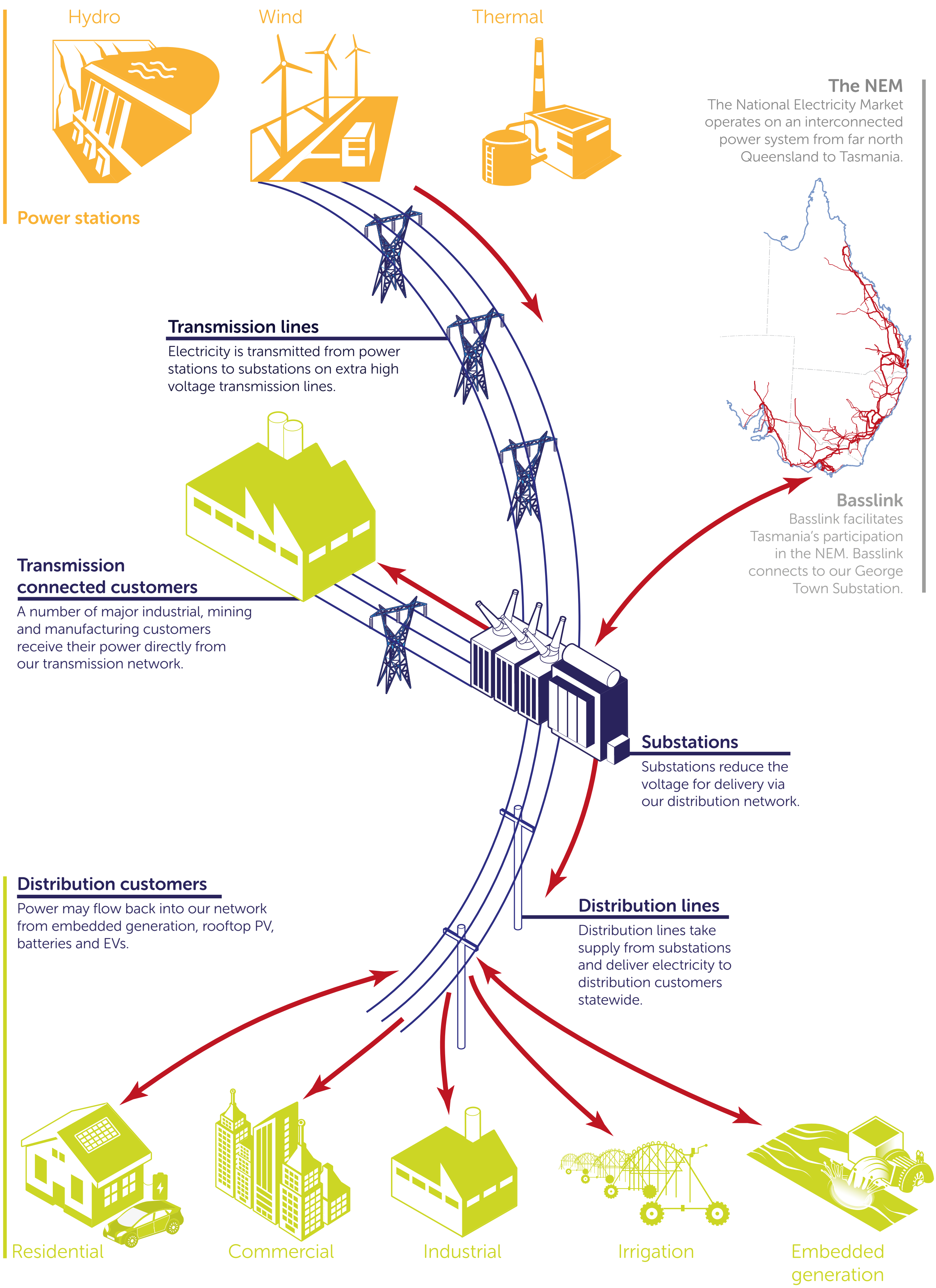

Figure 3-1: Tasmania's power system

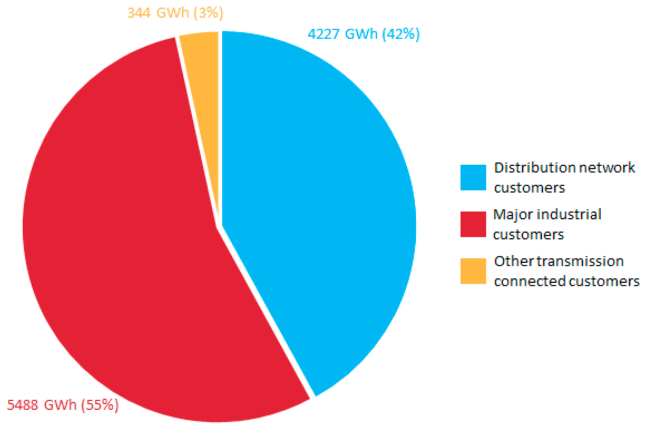

Figure 3-2: Relative transmission network use in 2016-17

3.1.1.3 Hydro generation dominated

The generation contribution by type to the network in 2016-17 is shown in Figure 3-3. Power generation is dominated by hydro, with the dominance and geographic diversity of hydro having 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 relatively more transmission infrastructure, per megawatt generated, is required compared with other states; and
- Tasmania's 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 energy needs.

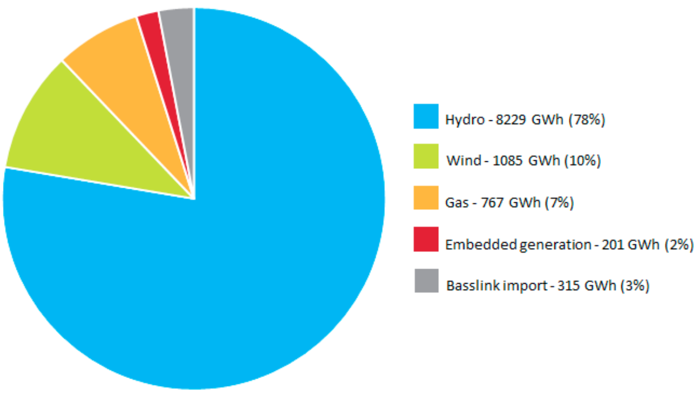

Figure 3-3: Generation contribution by type in 2016-17

3.1.1.4 Windy location

As an inherently windy state, there is sufficient wind resource to suggest an expansion of wind generation in Tasmania is possible. This needs to be balanced against the technical difficulties associated with integrating wind generators into a small power system. Section 7.4 discusses the technical challenges associated with connecting new generation technologies (notably wind generation) into our network.

3.1.1.5 Single non-regulated interconnector to other NEM regions

Tasmania's only connection to the rest of the NEM is via Basslink, a privately owned high voltage direct current market network service provider. This contrasts with mainland Australia NEM regions, which are all interconnected via regulated interconnectors.

Basslink is the only market network service provider in the NEM with a continuous sending end capacity of 500 MW and a non-operational zone between 50 MW export and 50 MW import.

Basslink is also able to transfer FCAS between mainland Australia and Tasmania. Currently, FCAS must be sourced within Tasmania due to constraints on Basslink.

3.2 Transmission network

Figure 3-4 presents a geographical overview of our transmission network, comprising:

- 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 that form interconnections within the 110 kV and 220 kV transmission network and provide transmission connection points for our distribution network and large industrial loads.

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), 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 our 110 kV fringe transmission network.

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

Table 3-1: Transmission infrastructure

Asset	Quantity
Substations	49
Switching stations	6
Circuit kilometres of transmission lines	3554
Route kilometres of transmission lines	2342
Circuit kilometres of transmission cable	24
Transmission line support structures (towers and poles)	7621
Easement area (Ha)	11,176

3.2.1 Substations

Substations in our transmission system transform between transmission voltages, between transmission and distribution voltages, or both. Our substations also connect generators to the transmission system, provide network switching, and provide supply to customers connected directly to the transmission network. There are 49 substations – many having dual roles.

The transmission substation sites are known as transmission-distribution connection points and supply the distribution network at voltages of 44 kV, 33 kV, 22 kV, 11 kV and 6.6 kV. Three substation sites have dedicated connection assets supplying individual industrial customers and one site has a small load point. There are four customers that take supply at either 110 kV or 220 kV transmission voltage (they also own the interfacing substation) and three customers are directly connected to transmission-distribution connection points. Two substations, Farrell and Sheffield, provide transformation between transmission voltages and are focus points for generation connection to our transmission network.

3.2.2 Switching stations

Switching stations provide network switching capabilities, allowing the transfer of power throughout our transmission system. 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 conductor that provides the physical delivery of electricity. A transmission line is the physical asset that includes the circuits, towers and other equipment that support the circuits, and the route these take between two points.

3.2.4 Network dynamic ratings

The rating of network infrastructure is determined by its maximum allowed operating temperature. Equipment temperature depends upon the balance between the amount of heating and cooling and is determined by the amount of electrical current flowing and external factors such as the ambient air temperature, cooling effects of the wind or fans, and the heating of the sun. Because these weather-related factors are continually changing, ratings are determined by making reasonable "worst case" assumptions about these conditions. The electrical current that can flow under these worst case conditions, without exceeding design temperature limits, is known as the "static rating".

The reasonable "worst case" weather conditions only occur a small fraction of the time. Typically, the weather conditions are more favourable, and the equipment will be at a lower temperature than it was designed for, even if it was carrying the full static rating current. Under these conditions (for example, if the air temperature is low), it may be possible to allow more current than the static rating to flow and still maintain the temperature within design limits.

Equipment ratings that are based on actual weather conditions are called dynamic ratings and can be used when actual information about the weather conditions is known. The use of dynamic ratings normally allows more current to flow than if the static rating was used, thereby releasing for use additional capacity.

We use dynamic ratings for the majority of our transmission lines where weather stations provide information about prevailing weather conditions along their length. In addition the installation of remote monitoring equipment on supply transformers at Boyer and Knights Road substations allows the transformers to be operated above their name-plate rating by monitoring the transformer temperature in real time.

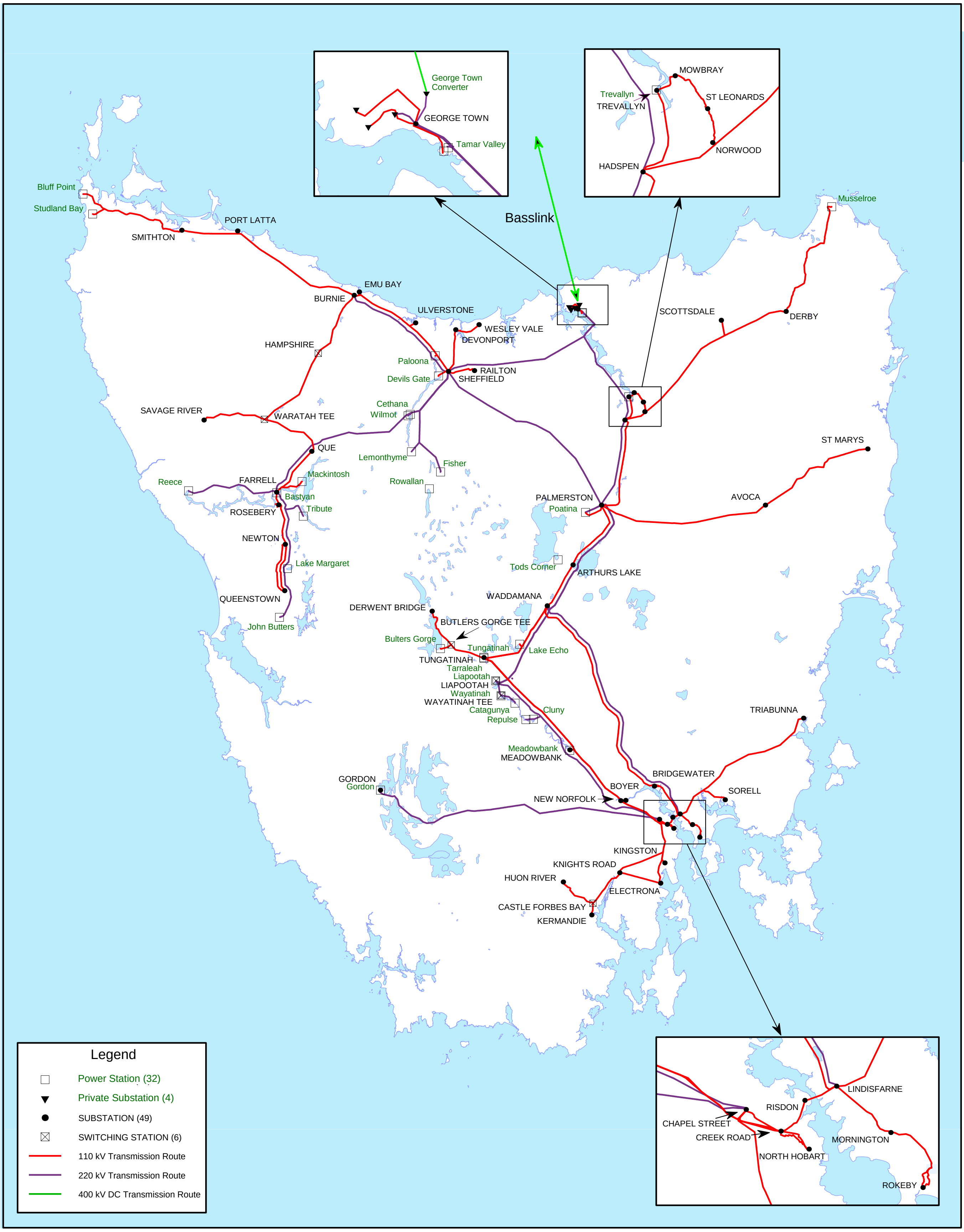

Figure 3-4: Tasmania's electricity transmission network[37]

37 *The transmission lines between Smithton Substation and Bluff Point and Studland Bay wind farms, and between Derby Substation and Musselroe Wind Farm are owned by third parties*

3.3 Distribution network

We are responsible for delivering electricity to homes and businesses on mainland Tasmania.[38]

Our distribution network provides power to over 280,000 customers and comprises:

- a sub-transmission network in the greater Hobart area, including Kingston, and one sub-transmission line on the west coast that, in addition to transmission-distribution connection points, provide supply to our high-voltage distribution network;
- a high-voltage network of distribution lines that distribute electricity from transmission-distribution connection points and zone substations to our 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 most customers.

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. Urban areas are shown as outlined areas in greater Hobart, Launceston and the north-west of Tasmania; all other areas are classified as rural.

Rural areas generally have low load, low customer connection density and smaller rural population centres 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. This significant route length creates a high exposure to external influences such as storm damage, trees and branches and lightning. Additionally, rural lines are generally radial in nature, with limited ability to interconnect with nearby lines. These characteristics tend to result in more frequent and longer duration interruptions.

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 trees and branches, 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. 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 operate at 22 kV. Limitations experienced on lines supplying urban areas are generally capacity limitations and high fault level.

38 *Electricity is delivered on the Bass Strait islands by Hydro Tasmania*

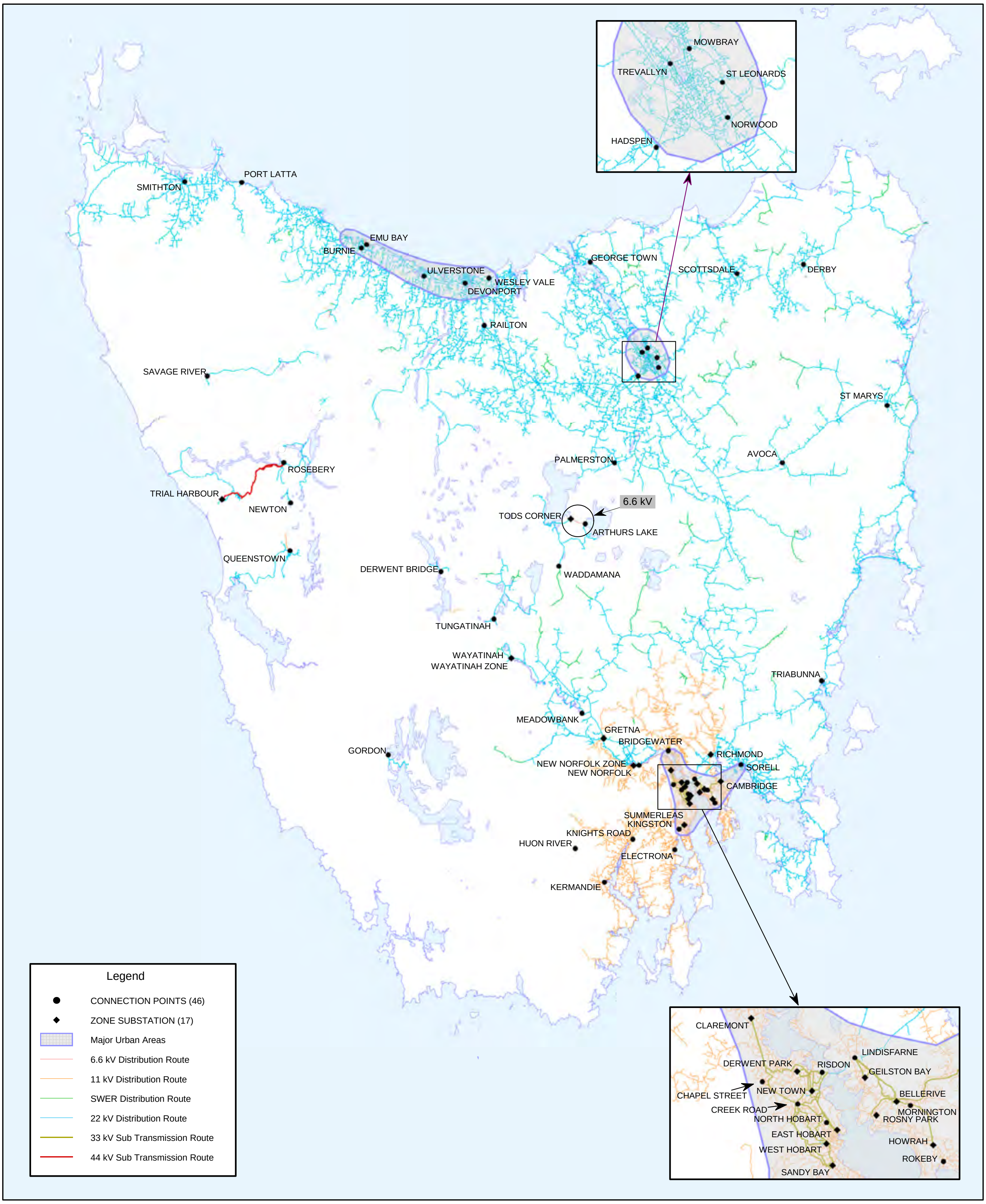

Figure 3-5: Tasmanian distribution voltage areas

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

Table 3-2: Distribution network infrastructure

Infrastructure	Nominal voltage (kV)	Quantity
Connection points		
Sites	44, 33, 22, 11 and 6.6	46
Sub-transmission lines	44, 33 and 22	27
Minor zone substation source lines[39]	22 and 11	6
Distribution lines	22, 11 and 6.6	243
Zone substations		
Major zone substations	44, 33 and 22	14
Major zone distribution lines	22 and 11	131
Minor zone substations[40]	22 and 11	3
Minor zone distribution lines	22 and 11	8
Distribution substations		
Overhead		30,478
Ground mounted		2313
Route data[41]		
High-voltage overhead	6.6 to 44	15,280km
High-voltage underground		1245km
Low-voltage overhead[42]	0.4	4920km
Low-voltage underground[42]		1279km
Poles	All voltages	232,634

3.3.1 Connection points

Our distribution network is supplied from connection points at 46 connection sites. Forty-four 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 kV and 11 kV, with a single 6.6 kV line from Arthurs Lake Substation. Connection 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. We have two classifications of zone substations: major zone substations are those supplied from 33 kV or 44 kV sub-transmission lines and minor zone substations are those supplied from within the distribution network. We have 14 major zone substations: 12 in greater Hobart and Kingston that reduce the voltage from 33 kV to 11 kV, and one in each at Trial Harbour (44 kV to 22 kV) and New Norfolk (22 kV to 11 kV). We have three minor zone substations, two that transform voltage from 22 kV to 11 kV (Gretna and Richmond) and one that transforms from 11 kV to 22 kV (Wayatinah).

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 our distribution network: 25 operate at 33 kV and one each at 44 kV and 22 kV, supplying the zone substations.

3.3.4 Minor zone substation source lines

Minor zone substation source lines are high-voltage distribution lines that also provide supply to minor zone substations. These generally supply multiple distribution substations as well as minor 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 these; however, the majority of supply is to distribution substations for supply to our low-voltage reticulation network.

39 Includes minor zone alternate-supply lines
40 Tods Corner 6.6 kV/22 kV interfacing transformation is excluded
41 Includes our assets only
42 Excludes customer service lines

3.3.6 Distribution substations and low-voltage circuits

Our low-voltage network is operated at 230 V (single phase) and 400 V (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 3000 kVA. The majority of load customers are supplied from our low-voltage network.

3.4 Factors affecting our network

3.4.1 Fault levels

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

We require new connecting circuit breakers meet a minimum fault clearance capability. For all voltage levels, circuit breakers require a minimum symmetrical three-phase fault current withstand capability of 25 kA for connection to our transmission network. For the high-voltage side of our distribution network, it is 16 kA.

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 our 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 in Table 3-3, 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:

- 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; and
- 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 have a low fault rating. At Smithton Substation, a distribution earthing issue has required the fault level to be reduced until corrective action can be implemented. There are also fault level limitations at Port Latta (to comply with a customer connection agreement). As in Table 3-3, the bus coupler at these substations is operated normally open to reduce the fault level.

Table 3-3: 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
Port Latta (22)	Bus coupler operated normally-open
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, with auto-close scheme
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

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.

Wind farm connections also require a certain fault level at their connection point to enable them to connect to our network. The existing wind farms in Tasmania have already absorbed much of the available MVA fault level in their locality. This means future wind farms may seek connection to an effectively weaker power system in certain locations requiring either the applicant to implement a system strength remediation scheme or the NSPs to undertake system strength connection works at the cost of the connection applicant. This is discussed further in Chapter 7.

Appendix B provides a technical description of fault level quantities and our methodology. Fault level data is provided on our website[43] and 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.

3.4.2 Voltage management

Maintaining voltages within target ranges ensures the safety of our people and equipment, the efficient and secure operation the power system and quality of supply to our 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 is in Section 4.1.

The ranges of acceptable voltage limits are specified in the Rules and Australian Standards, 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
- Australian Standard 60038-2012 standard voltages (specifying maximum and minimum household supply and other voltages).

Voltage management is a critical component of power quality, impacting all our customers. Voltage management in our distribution network is considered part of power quality. The network-wide and localised voltage limitations from PV installations are detailed in Section 4.9.2, with other voltage-related power quality limitations in Section 4.6.

3.4.3 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 clause 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 4.9.2. Other factors that impact power system security are the load forecast and customer connections. In Chapter 6 we describe the impact of these on our network and present solutions to manage them.

3.4.4 Ageing and potentially unreliable assets

There are many ageing assets within our network and undertake routine maintenance to reduce the probability of equipment failure. Factors that may impact on ageing and potentially unreliable assets are:

- location (whether the assets are located indoors or outdoors);
- operation (load utilisation, frequency of use and load profiles); and
- condition.

These are managed as part of our asset management strategy and discussed in Section 1.5.2 with planned investments to address asset management requirements identified as part of Chapter 6.

3.5 Telecommunications network

We also own, operate and maintain a telecommunications network. The telecommunications network supports operation of our 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 powerline 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.

43 www.tasnetworks.com.au/apr

4 NETWORK PERFORMANCE

4.1 Transmission network constraints

A network constraint is when the power flow through part of our transmission network must be restricted in order to avoid exceeding a known technical limit and to maintain the power system in a secure operating state. AEMO develops a set of constraint equations defining how the dispatch of generation and/or Basslink should be scheduled to avoid exceeding these technical limits. The equations are based on advice on limits within our transmission network provided by us.

While strictly not transmission network constraints, there are power system limitations required to maintain Tasmania's system frequency within operating standards and to ensure sufficient system strength to provide resilience under normal conditions and against contingency events.

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 power system security is maintained and the available transmission capacity is maximised. The market impact component of the AER's STPIS creates a financial incentive for us to minimise the impact of transmission constraints.

Figure 4-1 illustrates the occurrences during 2016-17 of binding constraints that resulted in impacts on generation dispatch or Basslink flows and violated constraints when a technical limit was exceeded. It shows the number of NEM dispatch intervals[44] that constraints occurred in various parts of the network. "Thermal limit – no outage" indicates 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.

There has been a significant increase in the instances of binding and violating constraints during 2016–17 compared with 2015-16. This is due to the return to service of Basslink on 13 June 2016 after a cable fault that occurred on 20 December 2015.

Generation dispatch patterns returned to normal in 2016-17, after the dramatic changes of 2015-16 caused by the Basslink outage and extremely low levels of Tasmanian water storage during that time.

4.1.1 Existing constraints on major transmission network elements

Table 4-1 presents the number of dispatch intervals for major binding constraints (where the total bound or violated period exceeds 150 dispatch intervals for the year – 12.5 hours) in 2016-17. Detailed information of these constraints is provided as supplementary material to this chapter and is available from our website.[45] It contains the constraint identifiers, detail of the constraints and the marginal cost of the constraint binding for 2014-15, 2015-16 and 2016-17.

44 Dispatch intervals are five minutes

45 www.tasnetworks.com.au/apr

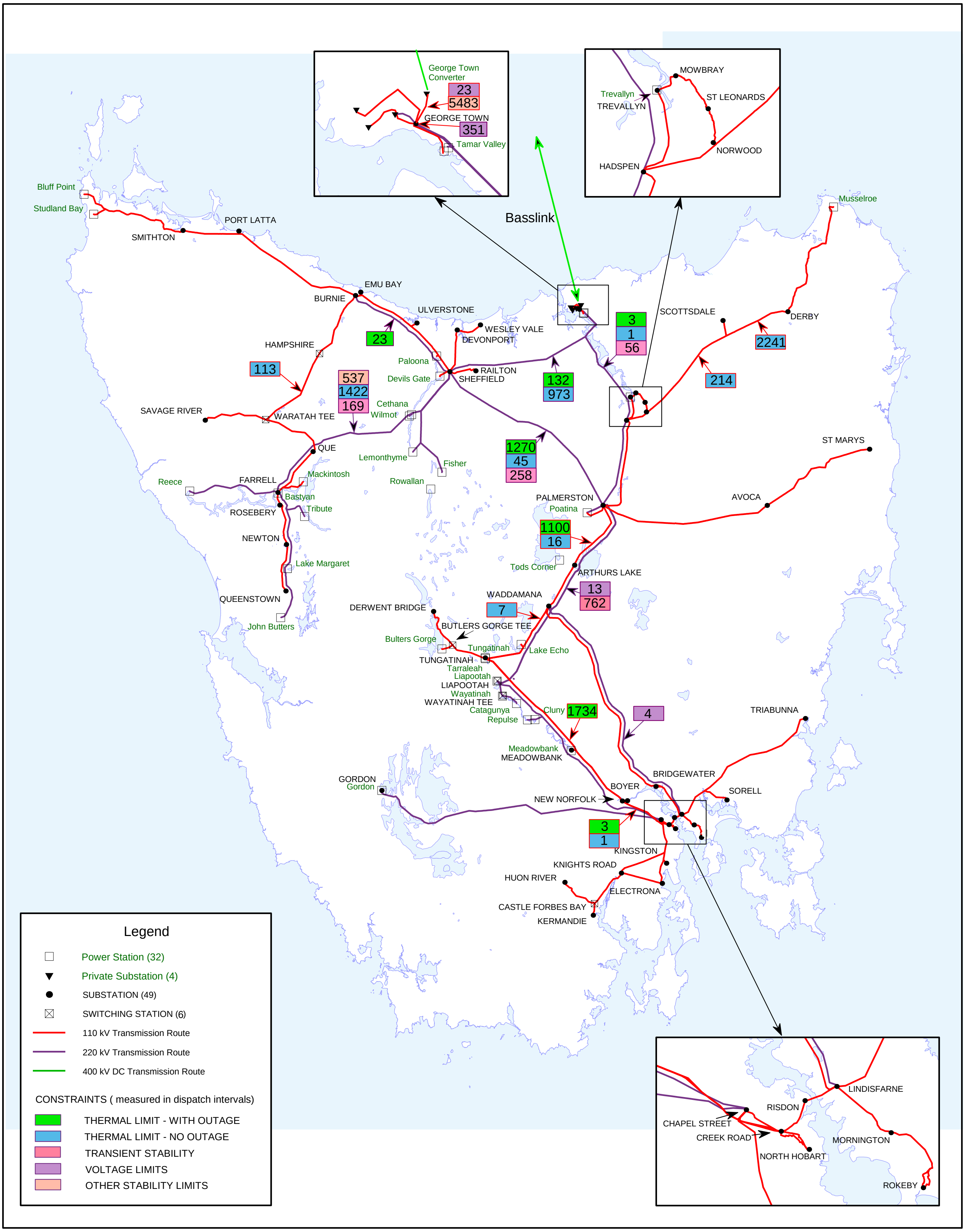

Figure 4-1: Transmission constraints during 2016-17

Table 4-1: Major binding constraints and significant changes in 2016-17

Constraint	Period constraint bound or violated			
	2015-16		2016-17	
	Dispatch intervals	Time (hours)	Dispatch intervals	Time (hours)
Constraints with increased incidence of binding in 2016–17				
Scottsdale Tee-Derby 110 kV thermal limit with no outage	1504	125	2241	187
Meadowbank Tee 2-New Norfolk 110 kV thermal limit with outage	0	0	1711	143
Farrell-Sheffield 220 kV thermal limit with no outage	921	77	1422	119
Palmerston-Sheffield 220 kV thermal limit with outage	23	2	1267	106
Waddamana-Palmerston 110 kV thermal limit with outage	0	0	1100	92
Sheffield-George Town 220 kV thermal limit with no outage	62	5	973	81
Liapootah-Palmerston 220 kV transient stability	0	0	762	64
Limit output of Tamar combine cycle gas turbine	11	1	668	56
Rate of change of Tasmanian frequency	0	0	574	48
Loss of double circuit declared credible	37	3	537	45
George Town 220 kV bus voltage limit	244	20	351	29
Palmerston-Sheffield 220 kV transient stability	61	5	258	22
Scottsdale Tee-Norwood 110 kV thermal limit no outage	0	0	214	18
Farrell-Sheffield 220 kV transient stability	84	7	169	14

4.1.2 Constraint equations affecting Basslink dispatch

Table 4-2 presents information on constraint equations that bound or violated to affect Basslink flows during 2016-17 more significantly than during 2015-16. More details on these binding or violated constraints are provided as supplementary material to this chapter and is available on our website.[46]

Table 4-2: Constraint equations with significant binding impact on Basslink flows in 2016-17

Constraint	Period constraint bound or violated			
	2015-16		2016-17	
	Dispatch intervals	Time (hours)	Dispatch intervals	Time (hours)
Constraints with increased incidence of binding in 2016-17				
Basslink import limited due to load unavailability for FCSPS operation	1201	100	2452	204
Farrell-Sheffield 220 kV transmission line rating constraint with NCSPS operation	168	14	1078	90
Sheffield-George Town 220 kV transmission line constraint with NCSPS operation	62	5	893	74
Rate of change of Tasmanian frequency	0	0	574	48
George Town 220 kV bus voltage limits	244	20	351	29
Palmerston-Sheffield 220 kV transient stability	61	5	258	22
Basslink rate-of-change limit	121	10	255	21
Farrell-Sheffield 220 kV transient stability	84	7	169	14
Constraints with decreased incidence of binding in 2016-17				
Basslink energy and FCAS related constraint (Basslink no-go zone)	3615	301	1797	150
Basslink discretionary limit	8476	706	253	21

46 www.tasnetworks.com.au/apr

4.2 System stability and emergency controls

Under both normal operation and following contingency events, including Protected Events[47], it is important to maintain stability of the power system and avoid consequences that lead to severe disruption.

This is achieved through combinations of controls on generation plant and transmission infrastructure and the implementation of emergency controls in consultation with AEMO.

In the Tasmanian context, many generation units are equipped with power system stabilisers that dampen power system oscillations and have sufficient reactive capability to satisfy voltage stability and reactive margin requirements.

However; in the NTNDP[48], AEMO, in conjunction with us, identified potential transmission limitations on high Basslink exports from Tasmania arising from reactive power deficiencies. Currently these are managed through constraints on dispatch but there is the option of installing dynamic reactive support at George Town Substation which is discussed further in Section 6.2.1.

We have had in place for some time emergency frequency control schemes that trigger either under frequency load shedding or over frequency generation shedding. In addition, there is a Tamar Valley Generator Contingency Scheme and, as discussed below, a Basslink Frequency Control System Protection Scheme.

In addition, we are working with Hydro Tasmania and ARENA to explore the use of super capacitors to stabilise system frequency within the state. The technology can allow increased large scale renewable energy penetration on the Tasmanian network. The super capacitor provides short term real power injection following the loss of other generation, stabilising the system frequency until other generation reserve comes online.

4.3 Basslink and system protection scheme performance

4.3.1 Basslink performance and impact on Tasmania's system

Tasmania remained a net energy importer during 2016-17, although reduced from 2015-16. Energy imported from the mainland increased from 1070 GWh to 1346 GWh with energy exported increasing from 509 GWh to 1039 GWh.

4.3.2 Performance of Basslink system protection schemes

The potential impact of Basslink's high transfer capabilities on Tasmania's power system requires SPS owned and operated by us. Without these schemes, significant investment and augmentation to our transmission network and increased dispatch of market ancillary services would be required to allow Basslink's transfer capability. The SPS encompasses two separate schemes that mitigate limitations which would otherwise occur:

- FCSPS to ensure frequency remains within bounds; and
- NCSPS to prevent transmission line overloads when Basslink is exporting.

During 2016-17, the FCSPS was required to operate on five occasions: four events during Basslink import and one event during Basslink export. The FCSPS operated correctly on all occasions and the Tasmanian frequency complied with the frequency operating standards.

During an event on 12 March 2017, a suspected cooling valve fault caused Basslink to reduce import from 450 MW to 220 MW over two minutes. The initial import reduction resulted in the Tasmanian frequency falling below 47.96 Hz, which resulted in under frequency load shedding. Following this (but unrelated to it), Basslink tripped and issued a "loss of link" signal that interrupted SPS load blocks as designed.

There were two NCSPS events during 2016-17; both for mid-span joint failures on the Sheffield-George Town 220 kV circuits. The NCSPS operated correctly on both occasions.

47 Protected Event means a non-credible contingency event the Reliability Panel has declared to be a Protected Event

48 AEMO 2016 NTNDP, Table 9

4.4 Service performance

In accordance with our Service Performance Asset Management Plan[49], we manage our network by balancing cost, risk and performance to deliver affordable levels of supply reliability and quality to our customers. Network service performance is a critical aspect of our customer service and must meet the requirements of our customers, our community and regulatory obligations.

Our objectives in relation to service performance are:

- safety is our top priority and we will ensure our safety performance continues to improve;
- service performance will be maintained at current overall network service levels, while service to poor-performing reliability areas will be improved to meet regulatory requirements;
- cost performance will be improved through prioritisation and efficiency improvements that enable us to provide predictable and lowest sustainable pricing to our customers;
- customer engagement will be improved to ensure our decision-making will maximise value to our customers;
- our program of work will be developed and delivered on time and within budget; and
- our asset management capability will be continually improved to support our cost and service performance, and efficiency improvements.

4.5 Tasmanian network and supply reliability

Network and supply reliability is measured by asset and supply outage occurrence frequency and outage duration being the two factors that are considered to have (and potentially have) the largest impact on our customers' experience.

Outage frequency reflects the effectiveness of our asset management strategies in the prevention of outages. It is measured using the number of LOS events and average circuit outage rate for our transmission network, and a SAIFI for our distribution network.

Outage durations reflect our effectiveness in responding to unplanned or forced outages. It is measured using average unplanned circuit outage and supply interruption duration for our transmission network, and a SAIDI for our distribution network.

We have a requirement to monitor and report supply reliability (among other measures) to the AER and OTTER. Relevant supply reliability performance metrics are used by the AER in each of our distribution and transmission STPIS. Additionally, we have an obligation under the Code to use reasonable endeavours to meet reliability targets.

This APR will be the last year where the STPIS distribution reliability is measured on a kilovolt-ampere basis. Performance in the 2019 APR for the 2017-18 financial year will be measured on a customer number basis to align with industry standards.

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

4.5.1 Transmission network reliability

Transmission network reliability is monitored and reported to the AER and OTTER in terms of the number of LOS events that occurred during the year,[50] the average LOS event duration and circuit outage rates (as a percentage of time) for lines, transformer and reactive plant. There are no targets associated with transmission network reliability measures reported to OTTER. Under the STPIS, the AER sets service component targets based on historical performance.

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.[51] LOS events are split into two categories: major events (measuring >1.0 system minute) and all events >0.1 system minutes (including major events).

Tables 4-3, 4-4 and 4-5 list the performance of our transmission network as reported to OTTER over the past five years.[52]

49 www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals/regulatory-proposal-documents, Asset Management Plans

50 Transmission reliability is reported to the AER and OTTER by calendar and financial years, respectively

51 In Tasmania, an event of one system minute equates to about 31.2 MWh of unserved energy

52 Performance reporting to the AER under STPIS can be viewed at www.aer.gov.au/networks-pipelines/compliance-reporting/tasnetworks-service-standards-compliance-report-2016

Table 4-3: Transmission network reliability performance

Performance measure	2012-13	2013-14	2014-15	2015-16	2016-17
Number of LOS events >0.1 system minute	11	7	5	0	2
Number of LOS events >1.0 system minute	3	0	0	0	1

Table 4-4: Transmission average circuit outage rate

Performance measure	2012-13	2013-14	2014-15	2015-16	2016-17
Transformer average circuit outage rate (%)	1.29	0.84	0.76	0.61	0.69
Transmission average circuit outage rate (%)	3.78	1.40	1.40	1.64	1.40
Capacitor average circuit outage rate (%)	1.39	0.69	2.08	0.00	1.39

Table 4-5: Transmission average circuit outage duration

Performance measure	2012-13	2013-14	2014-15	2015-16	2016-17
Average of LOS duration (minutes)	255	37	52	24	33

We have improved our transmission reliability performance in recent years as a result of a focus on continual service improvement through operational and capital programs including: improving our incident investigation and remediation process; targeting improved performance to access incentive schemes; improved maintenance practices; and targeted replacement of unreliable assets.

4.5.1.1 Significant network incidents

A significant network incident is defined as a loss of supply event exceeding 1.0 system minute. There was one significant network incident during the 2016-17 financial year.

On 20 December 2016, an error during routine telecommunications testing caused protection to operate and both circuits of the Sheffield-George Town 220 kV transmission line tripped. Load was shed from Nyrstar and Bell Bay Aluminium with 1.66 system minutes being lost. The loads were restored within 50 minutes. Protection settings and telecommunication procedures were reviewed and applied to prevent this event from reoccurring.

4.5.2 Distribution network reliability

We report distribution network reliability to the OTTER and AER on a geographic segmentation basis. In our geographic segmentation approach, we divide Tasmania into 101 communities and then to one of five reliability categories. The reliability category determination is based on energy use per unit area with boundaries defined by natural boundaries (like roads, rivers and land) and municipal boundaries.

The five reliability categories are:

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

The Code specifies performance standards for:

- each category, which represents the average level of service expected by communities of that category; and
- for each community, which represents the minimum level of service expected by the communities in each category.

We report SAIFI and SAIDI at the reliability category level to the AER each financial year. The AER sets targets for reliability categories in each regulatory period as a part of our distribution STPIS. These targets are calculated from our average performance in the preceding five years.

4.5.2.1 Code standards and performance

Distribution performance against the Code standards is measured excluding outages caused by third-party faults, customer plant and the transmission network. The Code standards and 2016-17 performance are in Table 4-6 at category level. Historic performance against the Code standards is in Appendix C.

Table 4-6: Code supply reliability category SAIFI and SAIDI standards and performance

Supply reliability category	Annual frequency of supply interruptions (on average) (SAIFI)		Annual duration of supply interruptions (on average) (SAIDI)	
	Standard	2016-17	Standard	2016-17
Critical infrastructure	0.2	0.36	30	27
High-density commercial	1	0.14	60	12
Urban and regional centres	2	1.14	120	140
High-density rural	4	3.01	480	530
Low-density rural	6	3.49	600	659

Our performance in SAIFI, the frequency measure, has generally been satisfactory. With the exception of critical infrastructure, all categories performed better than their respective standard. Below standard SAIFI performance at the critical infrastructure category level can be attributed to a single event caused by bird contact on a 33 kV sub-transmission feeder. This caused loss of supply for eight minutes to four 11 kV central business district feeders that come from the East Hobart Zone Substation. The feeder trip occurred at the time when the 11 kV bus coupler circuit breakers at the East Hobart Zone were open for planned switching.

Our performance in SAIDI, the duration measure, met targets in critical infrastructure and high-density commercial, and did not meet targets in the remaining three. Poor performance in the urban, high-density rural and low-density rural communities was a result of major event days due to widespread storm and flood events.

Table 4-7: Code supply reliability area 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	Number of poor-performing communities in 2016-17	Standard	Number of poor-performing communities in 2016-17
Critical infrastructure (1)	0.2	1	30	0
High-density commercial (8)	2	0	120	0
Urban and regional centres (32)	4	3	240	6
High-density rural (33)	6	4	600	7
Low-density rural (27)	8	1	720	11
Total (101)		9		24

As in Table 4-7, during 2016–17, of the 101 communities, 24 did not meet their SAIDI standards and nine did not meet their SAIFI standards. Of these communities, six met neither their SAIDI nor SAIFI standards.

As annual performances can vary significantly from year to year, trends over a five-year averaging period provide a perspective for planning purposes. In particular, we have identified the following 10 communities that warrant consideration of opportunities to improve supply reliability:

- Hobart critical extended — Critical infrastructure
- Strahan — Urban
- St Helens — Urban
- Westbury — Urban
- Zeehan — High-density rural
- Mid-Tamar (Exeter area) — High-density rural
- Wayatinah — High-density rural
- Highlands — Low-density rural
- Tasman Peninsula — Low-density rural
- West Coast — Low-density rural

4.5.2.2 Distribution STPIS reliability targets and performance

Service component parameters of the STPIS are proposed by us and confirmed by the AER as part of regulatory determinations. They are based on historic performance excluding planned outages, major event days,[55] transmission network outages, customer installation faults, and total fire ban day-related outages. The STPIS targets and our 2016-17 performance levels are in Table 4-8 and Table 4-9. A summary of historical performance against AER targets is in Appendix C with details available in the RIN.[54]

Table 4-8: STPIS supply reliability category SAIFI targets and performance

Supply reliability category	Annual number of supply interruptions (on average) (SAIFI)		
	Target	2016-17 performance	2018-19 forecast
Critical infrastructure	0.22	0.25	0.18
High-density commercial	0.49	0.1	0.24
Urban and regional centres	1.04	0.84	0.94
High-density rural	2.79	2.58	2.50
Low-density rural	3.20	2.89	3.31

Table 4-9: STPIS supply reliability category SAIDI targets and performance

Supply reliability category	Annual duration of supply interruptions (on average) (SAIDI)		
	Target	2016-17 performance	2018-19 forecast
Critical infrastructure	20.79	4.84	10.84
High-density commercial	38.34	4.97	20.17
Urban and regional centres	82.75	64.79	77.16
High-density rural	259.48	263.68	249.93
Low-density rural	333.16	356.79	395.81

4.5.2.3 Forecast distribution reliability performance

The above tables show our forecast reliability performance for the remainder of the regulatory period. In forecasting our performance, we calculate our reliability targets in alignment with the AER's methodology. That is, we calculate performance targets from a five-year historical average. The low-density rural supply category is the only category forecast to perform worse than the current target, in both measures. This is a result of a particularly poor year in 2013-14. It also reflects the continued challenges in maintaining reliability in the communities of this category, due to the geography covered by the high-voltage distribution lines and limited alternate supply options.

53 A major event day is 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

54 www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses

4.5.2.4 Distribution AER STPIS reporting

As part of our RIN submissions, we submit data used for our STPIS compliance requirements to the AER. Under the STPIS[55] the AER can apply three reliability parameters to each customer category: SAIDI, SAIFI and MAIFI.

Currently, the AER has not applied the MAIFI parameter to our STPIS; however, we include it in our performance reporting. The STPIS in relation to MAIFI is under review along with the establishment of a Distribution Reliability Measures Guideline. The effective date for the changes is 30 June 2018.[56]

In addition to these reliability parameters, the AER has also applied a customer service performance parameter in terms of phone answering.

The AER does not apply the GSL component of the STPIS to us as we are already subject to a jurisdictional GSL through OTTER as part of the Code.

A summary of our reported 2016-17 performance is in Table 4-10 and Table 4-11. In addition to the annual performance, daily performance for each supply reliability category is available on the AER's website.[57]

Reliability

Table 4-10: STPIS reliability parameter

Reliability measure	Measure	Critical infrastructure	High-density commercial	Urban	High-density rural	Low-density rural	Whole network
SAIDI	Unadjusted total	532	9.10	106	512	569	314
	Removing exclusions[58]	4.84	4.97	65	264	357	174
SAIFI	Unadjusted total	0.29	0.13	1.04	3.15	3.37	1.99
	Removing exclusions[58]	0.25	0.10	0.84	2.58	2.89	1.66
MAIFI	Unadjusted total	0.22	0.055	3.23	6.89	8.21	5.01
	Removing exclusions[58]	0.22	0.055	3.07	6.24	7.45	4.62
Average customer numbers and planned basis of future reporting ('000s)		1.88	4.68	193	43.7	44.3	288
Historic proxy for average customer numbers and basis of current reporting (installed distribution transformer capacity MVA)		127	136	1896	792	992	3943

55 www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-november-2009-amendment

56 www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-2017-amendment

57 www.aer.gov.au/networks-pipelines/network-performance/tasnetworks-aurora-energy-distribution-network-information-rin-responses

58 Excluded events and major event days

Phone answering

The phone answering parameter is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

Table 4-11: 2016-17 customer service performance

Phone answering	Total (removing exclusions)[58]	Total
Number of calls	40,944	48,889
Number of calls answered in 30 seconds	33,504	35,419
Percentage of calls answered within 30 seconds	81.83	72.45
STPIS Target (%)	78.7	

4.6 Quality of supply

Power quality refers to the technical characteristics of the electricity received by customers that ensure the customer can utilise energy from our network successfully, without interference to or incorrect use of electrical equipment. Power quality encompasses supply voltage:

- steady magnitude;
- fluctuations;
- distortion; and
- unbalance for multi-phase connections.

Steady magnitude relates to maintaining voltage within acceptable levels over the longer term.

Voltage fluctuation relates to short term swells and sags in voltage magnitude. If the fluctuations continue to occur then they are referred to as "flicker".

Voltage distortion relates to waveform deviations and includes recurrent harmonics and infrequent transients due to things such as network operational switching and lightning.

Other supply issues arise from deviations in system frequency that are a broader power system operational matter and circulating ground currents that can interfere with sensitive electronic equipment.

Generally, the voltage magnitude is most important because customers notice voltage magnitude deviations more than other power quality measures.

Schedules 5.1a, 5.1 and 5.3 of the Rules describe the planning, design and operating criteria applied to our distribution network for power quality. This section details our recent performance in power quality in our distribution network. Power quality performance in our transmission network is in Chapter 7.

4.6.1 Distribution quality of supply standards

The quality of supply standards relevant to our distribution network are detailed in AS 61000 Electromagnetic compatibility (EMC) and Chapter 8 of the Code. The standards for each element of quality of supply are:

- **Voltage**
  - SA/SNZ TS IEC 61000.3.5:2013 Electromagnetic compatibility (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 compatibility (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 compatibility (EMC) – Limits – Steady state voltage limits in public electricity systems; and
  - Section 8.6.4 of the 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 the Code.

4.6.2 Distribution quality of supply performance

Distribution quality of supply performance monitoring and issues identification is informed through customer feedback and largely relates to voltage magnitude issues. The trend of customer feedback received in relation to over and under voltages is in Table 4-12. Where identified, we study these limitations and apply corrective action (if appropriate).

Table 4-12: Customer feedback on over and under voltages

Category	2012-13	2013-14	2014-15	2015-16	2016-17
Over voltage	98	145	125	101	104
Under voltage	33	34	25	19	30
Total	131	179	150	120	134

The increasing number of over-voltage excursions was almost exclusively as a result of the coincident increasing penetration of rooftop 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.

Data obtained from smart meters installed as part of the emPOWERing You Trial indicated that there were issues associated with voltage levels at customer premises. Our actions taken as a result are discussed in Section 4.7.2.

4.7 Performance compliance process

We aim to comply with all relevant legislative and regulatory obligations. Accordingly, we have a compliance policy where we ensure there are processes of ongoing monitoring of compliance.

4.7.1 Network and supply reliability compliance

As detailed in our Strategic Asset Management Plan[59] our reliability strategy includes maintaining overall network reliability performance while ensuring compliance. It seeks to:

- maintain current overall network reliability performance in accordance with the principles of the economic incentive scheme while providing lowest sustainable prices and maximising value to our customers;
- ensure compliance with regulation, codes and legislation;
- 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 our network.

The reliability strategy does not preclude enhancing network reliability where performance is inadequate or where asset risk is unacceptably high. This resulted from a focus on continual service improvement with many initiatives included in operational and capital programs covering:

- improving our incident investigation and remediation process;
- incentive schemes to improve performance;
- improved maintenance practices; and
- targeted replacement of unreliable assets.

4.7.1.1 Reliability corrective action

We undertake corrective action to improve and maintain reliability in our distribution network under three streams: targeted investigations into our worst-performing distribution lines, network reinforcement and ongoing asset management activities.

We continue to investigate the causes of poor reliability on our worst-performing distribution lines and our poor-performing areas. The outcomes of these investigations will drive targeted reliability improvement programs to bring reliability in these areas up to standard. Our proposed network reliability improvement works and associated benefits are listed in Table 4-13.

59 *www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals/regulatory-proposal-documents, Key Strategies and Policies*

Table 4-13: Planned reliability corrective action

Program	Benefit
Distribution line trunk strategy (protection reviews, targeted and aggressive vegetation management, and asset renewal/relocation)	Reducing probability of unplanned outage occurring
Remote switching reinforcement (loop automation and multiple switches)	Reducing supply restoration time following unplanned outage
Distribution line extensions (including new lines)	Reducing customer exposure to unplanned outages
Standby generation	Reducing supply restoration time following unplanned outage

We also have a number of ongoing asset management initiatives that drive reliability outcomes:

- 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 faults;
- 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.

4.7.2 Quality of supply monitoring

Issues with distribution quality of supply are generally identified by:

- **Customer feedback**

  We receive feedback from residential, commercial and industrial customers in relation to quality of supply, generally relating to over or under voltages.
- **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, that 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.

As issues identification is informed by customer feedback corrective action is largely reactive. Supply impact studies and performance standards applied to customer installations are key preventative measures to maintain quality of supply across all of its dimensions.

We investigate identified power quality issues and address them in one of two ways:

(a) where we consider the level of risk to be unacceptable, we undertake corrective action; or

(b) alternatively, we monitor non-compliances over the next 12 months and after that time we undertake corrective action if required.

We identified that a number of customer energy meters within the network have the ability to transmit voltage information and we activated that function. We investigated the voltage readings from 2450 of these meters and found that 338 of these customers have experienced steady-state voltages larger than the limits mandated by the Code.

We are taking a systematic and proactive approach to rectify these 338 steady-state voltage issues. As a first priority, we are using this new visibility of our distribution network to lower the MV set point of some terminal and zone substations. Where this wide-area strategy is unable to resolve the issues identified, we will adjust the tap settings of individual distribution transformers. It is our expectation that lowering of the MV voltage set points will be complete by mid-2018. The reduction in MV set-point voltage will lower the number of overvoltages identified through customer feedback, presented in Section 4.6.2, in future years.

We have re-joined the National Long Term Power Quality Survey administered by the University of Wollongong. This survey targets total harmonic distortion and voltage flicker, sags and swells. On an ongoing basis we submit measurement data from distribution customer meters and we are currently awaiting analysis of the data by the university.

4.7.2.1 Quality of supply corrective action

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

- transformer re-tapping;
- circuit phase rebalancing or load shifting;
- transformer upgrades;
- 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, in our 2017 APR we proposed two trials aimed at addressing power quality limitations. The first project was to purchase and trial a portable medium-voltage (11 kV) STATCOM. The second project was to trial low-voltage regulation technology involving either pole mounted capacitor banks or STATCOMs (as opposed to traditional transformer and low-voltage circuit upgrades). Based on preliminary engineering studies we are not proceeding with these initiatives but we will continue to monitor these technologies.

4.8 Demand management activities

When the capacity of a network approaches its limit due to high electricity use, then either its capacity can be increased or steps taken to reduce present and forecast peak demand. Reducing peak demand is called demand management. Typically, this can be achieved by:

- shifting some of the peak appliances or loads from peak time to an off-peak time;
- shedding non-critical loads;
- change loads from electricity to another fuel source (like gas);
- reducing the electricity used by appliances for short periods (such as hot water load control);
- operating generators within a customer's electrical installation; and
- battery storage and using some of the battery capacity to address peak demand issues (like customer-owned batteries).[60]

Our objective is to work with our customers to identify cost-effective demand management solutions, which allow us to defer or avoid the need for network investment and reduce the long-term costs of our network. We are pursuing ways to address peak demand issues by offering financial incentives to those who can provide solutions.

To that end, we have developed a Demand Management Engagement Strategy that explains how we will engage and consult with our customers and suppliers to deliver solutions for our distribution network. We encourage providers to register with us on our website.[61]

Network support payments are available to our customers (or a third party contracted to provide services). This is subject to our network having an identified limitation and a formal agreement with the customer or provider.

4.8.1 Demand management options used

In the past year we have used these non-network options:

- Bruny Island peak-shaving diesel generator to manage the loading on the cables supplying the island;
- CONSORT Bruny Island Battery Trial, which uses customer-owned energy storage to reduce cable load or diesel use on the island;[62] and
- establishment of an embedded generation network support trial, which will use customer-owned generation to manage loading on a distribution line from Palmerston Substation.

Remote area power supplies

Some parts of our distribution network are underutilised because there are long sections of lines supplying very small loads. These sections are expensive to maintain. Some of these loads can be supplied more economically using a RAPS. We commissioned a hybrid diesel/battery RAPS at Crotty Dam in March 2014 and a second RAPS site has been identified at Tim Shea.

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

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. Participation in such a scheme would be voluntary and under commercial terms. Only commercial and industrial customers in areas where demand reductions would be beneficial will be approached to participate in the program.

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60 As Tasmania's demand is largely a winter peak, we do not usually consider rooftop PV to be a viable option

61 www.tasnetworks.com.au/our-network/planning-and-development/demand-side-engagement-strategy

62 The CONSORT Bruny Island Battery Trial is presented in more detail in Section 2.10

4.9 Embedded generation

There has been a continued increase in the number of our customers wishing to generate electricity on their own premises (called 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 rooftop PV. To facilitate their connection, exemption from full compliance with the Rules is granted by AEMO for small generators (less than 5 MW)[63] – although they must still have a connection agreement with us. Embedded generators (including PV) connecting to the network must meet our connection guidelines.[64]

The continued uptake of embedded generators causes some technical challenges to us as outlined below.

4.9.1 Synchronous generators

The key issues arising from applications to connect synchronous embedded generating units include:

- ensuring safe disconnection during faults that may lead to “island” conditions;
- ensuring they are not exposed to auto-reclose events; and
- maintaining stable voltages at weak connection points.

Synchronous generators (rotating machines) can pose risks to other network users (and the synchronous generator) during islanding-type faults. An “island” is a situation where part of a 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 our customers, electrical equipment and our people. It is therefore necessary to ensure embedded generators are equipped with anti-islanding protection devices.[65] We must approve the anti-islanding protection device of the synchronous generator before network connection.

Similarly, the nature of synchronous generation is that they cannot be re-connected to the network without firstly ensuring that conditions are suitable for them to do so. It is customary to have automatic reclose schemes on distribution feeders that can quickly restore supply. Before these schemes can restore supply all sources of generation must be disconnected from the network.

63 www.aemo.com.au/Electricity/Network-Connections

64 www.tasnetworks.com.au/our-network/new-connections-and-alterations/embedded-generation-and-information-packs

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

Sudden disconnection of distribution connected synchronous generation can lead to unacceptable reductions in local network voltage. In such circumstances, appropriate voltage control schemes approved by us will be required.

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

4.9.2 Photovoltaic

In 2016-17, we received 2538 applications to connect embedded generation. This was predominantly applications for rooftop PV. The average time taken to connect PVs was 47 days. At the end of December 2017, Tasmania had 116 MW of registered PV at over 31,000 locations.[66] In addition there were 119 PV installations with concurrent battery storage.

There are both network-wide and local issues associated with PV installations. From a network-wide perspective, and for maintenance of power system security, it is important PV installations remain connected following frequency disturbances. This is a major issue 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 7.2).

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 in response to even a single contingency event, which would be unacceptable for our customers and contravene the Rules.

High penetration of PV along with other inverter connected sources can result in reduction in system strength required to maintain a stable power system. As outlined in Chapter 2, a power system fault levels framework sets out clear allocation of roles and responsibilities for AEMO and network service providers in the management of system strength. It requires TNSPs to procure system strength services needed to provide the levels determined by AEMO.

Local issues mainly relate to voltage regulation in our distribution network. Unlike mainland jurisdictions, 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. Essentially, PV penetration further depresses the summer minimum load and a number of low-voltage circuits are becoming net generators with the result that voltages can rise to unacceptable levels.

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

1. saturation of many distribution circuits at relatively low penetration levels making the connection of further PV installations unfeasible; and
2. major infrastructure upgrades to facilitate further PV connections.

To avoid these consequences, we have established connection requirements new connecting micro-generating systems (including PV) must meet.[67] The requirements specify modern inverter technology that will contribute to voltage regulation. This approach allows our network to accommodate higher amounts of PV, increasing the point at which saturation occurs.

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

67 *www.tasnetworks.com.au/our-network/new-connections-and-alterations/connecting-micro-embedded-generators-information-p*

5 ENERGY AND DEMAND FORECAST, AND THE SUPPLY-DEMAND BALANCE

5.1 Demand forecasts and the planning process

Each year we produce forecasts of the future of our network. We use AEMO's forecasts for the energy use and summer and winter maximum demands at a state level, and maximum demands at each transmission-distribution connection point. The state-level energy and maximum demand forecasts are at the generation level but they exclude the impact of transfers across Basslink. The forecasts provide for the impacts of behind the meter generation; that is, increased rooftop PV generation reduces the forecasts. Based on AEMO's forecasts, we prepare forecasts for maximum demand for zone substations and distribution lines.

The demand forecast is a key component of our network planning process. We use the demand forecast to identify the timing of capacity and other technical limitations in the network. We plan our network to 50% POE forecasts. This helps to understand the future challenges of our network and the areas of particular interest; however, it is not the only factor that drives network investment. As detailed in Section 1.5.1, we analyse potential network limitations and consult with our customers to ensure a limitation presents sufficient risk and the proposed solution provides sufficient benefit before investing in network augmentation or pursuing 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.

AEMO forecast a modest increase in electricity use over the next 10 years, characterised by increased demand in the short term, followed by a period of constant or decreased demand. There is minimal proposed augmentation investment to meet this forecast modest increase in demand.

The demand and energy forecasts are provided as supplementary material to this chapter and are available on our website.[68]

5.2 Forecasting methodology

5.2.1 State-level forecast

In June 2017, AEMO published its National Electricity Forecasting Report (now the Electricity Forecasting Insights)[69] that included state-level forecasts of annual energy generation and maximum and minimum demands. These forecasts are used in this APR. AEMO has since published a March 2018 update forecasting lower growth, however we do not anticipate this reduction will have a material effect on the information presented in this APR.[70]

State-level energy and maximum demand forecasts are based upon scenarios of weak, neutral and strong economic growth. These scenarios were developed from the consideration of economic factors, environmental policies, consumer behaviour and technology improvements.[71] The neutral economic scenario is considered the most likely.

In turn, for each economic scenario, maximum demand forecasts are provided for three temperature likelihoods (probability of exceedance). Thus, in total, nine maximum demand forecasts are produced for each winter and summer season. The three sub-forecasts are presented as POE and reflect the one in ten, five in ten, and nine in ten-year events (10% POE, 50% POE and 90% POE respectively).

The forecast is developed from a bottom-up approach involving forward-looking economic and structural indicators. The forecasting methodology is available from AEMO's website.[72]

68 www.tasnetworks.com.au/apr

69 www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2017-Electricity-Forecasting-Insights.pdf

70 www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights

71 www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2017/Draft-2017-Planning-and-Forecasting-scenarios.pdf

72 www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Forecasting-Methodology-Information-Paper---2016-NEFR---Final.pdf

5.2.2 Transmission-distribution connection point, sub-transmission, and distribution feeder forecasts

In February 2017, AEMO published forecasts of active and reactive power demands at distribution connection points with the transmission network.[73] These are used in this APR although AEMO has since published a March 2018 update.

The connection point maximum demand forecast is based on the trend in historical maximum demand levels. The trend is projected into the future, as a baseline forecast, with post-model adjustments made to account for drivers influencing future demand. The forecasts are reconciled to a system-level forecast to incorporate effects of other drivers not already explicitly accounted for, such as forecast population growth, changes in electricity prices, the impact of energy efficiency in appliances and buildings, and the uptake of rooftop PV. The connection point forecasting methodology is available from AEMO's website.[74]

From the state-level and transmission connection point forecasts, we produce maximum demand forecasts for zone substations and distribution lines. These forecasts are for the neutral economic scenario and the 50% POE sub-forecast for both winter and summer seasons. We assume that the impacts of factors on the transmission-distribution connection point forecasts remain the same for the zone substation and distribution lines connected to those connection points. The latest historic maximum demand for transmission-distribution connection points, zone substations, and distribution lines data is considered as the basis for the forecasts.

The forecasts for zone substations and distribution lines are determined by multiplying the historic demand by the ratio of the forecast maximum demand and the historic maximum demand of the associated transmission-distribution connection point. Post model adjustments are made to these zone substation and distribution line maximum demands to reflect known changes in point loads.

5.3 Tasmanian forecast energy and maximum demand

5.3.1 Tasmanian forecast energy

Figure 5-1 presents the actual and forecast generation required to meet demand for electricity in Tasmania to 2027 for the neutral, strong and weak growth scenarios. It also presents the medium growth scenario from our 2017 APR for comparison. This forecast is the electrical energy generated at power stations and wind farms connected to our transmission network, and includes losses incurred in the delivery to customers.

Transmission-connected energy generation for Tasmania declined from its peak of about 11,000 GWh to 10,500 GWh between 2007-08 and 2011-12. Since 2011-12, transmission-connected energy generation has had a continued small decline of an average 0.3% a year. This decline has been from reduced energy use within our distribution network, with usage by transmission-connected load customers remaining relatively constant. A key factor in the decline in distribution network energy use is the increase in embedded generation. Embedded generation – from rooftop PV to larger biomass, gas, and mini-hydro generation – has increased from less than 100 GWh in 2012-13 to 201 GWh in 2016-17 – approaching 2% of total energy imported into our network. Other factors include increased energy efficiency and the level of economic activity with around 1% gross state product growth in Tasmania during this period.

Energy generation was forecast to increase in 2016-17 and 2017-18 across the three economic scenarios. This increase was forecast to occur with increased economic activity, however the forecast increase in 2016-17 did not occur.[75] We expect this to translate to a lower overall energy generation forecast in its next release.

The continued recovery in the underlying neutral scenario energy generation forecast is forecast at 0.4% a year to 2027. The underlying growth excludes the forecast reduction in the neutral (2021-22) and weak (2019-20) scenarios. We anticipate this is a reduction in transmission-connected customer demand.

The forecast growth rate from the 2017 APR medium scenario was 0.8% a year over the planning period. Despite the difference in the forecast in initial years, this year's forecast closely aligns with that from our 2017 APR from 2024 onwards.

73 *www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Tasmania*

74 *www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/TCPF/2016/AEMO-Transmission-Connection-Point-Forecasting-Methodology.pdf*

75 *AEMO published this forecast in June 2017*

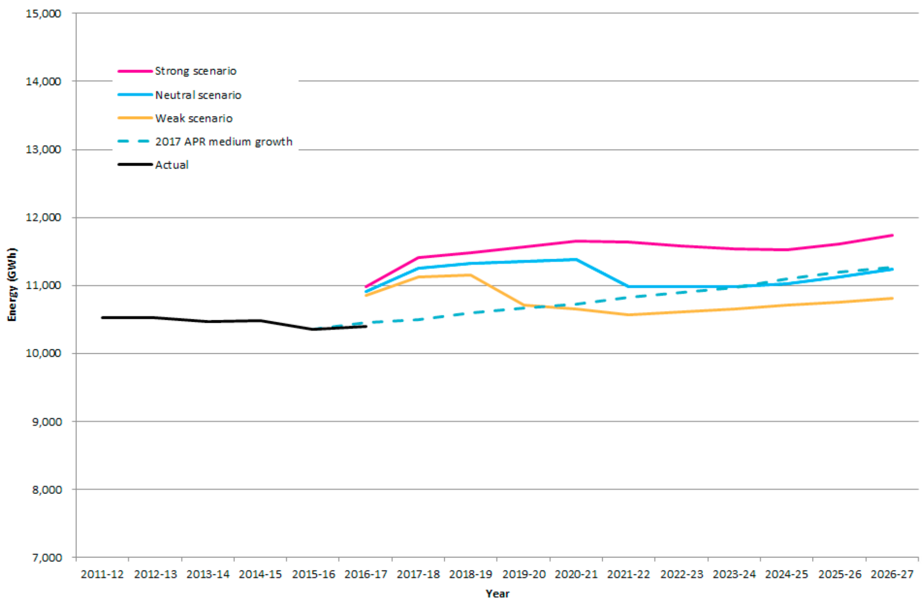

Figure 5-1: Forecast of transmission-connected Tasmanian electrical energy generation

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. This includes losses in our network in the supply to our customers. It is important to note the differences between the strong, neutral and weak growth scenarios reflect the different conditions as identified in Section 5.2.

Figure 5-2 presents the winter and summer maximum demand respectively for each scenario. It presents the actual recorded maximum demand since 2012, each of the neutral, strong and weak scenarios to 2027 with 50% POE temperature, and the medium growth forecast from our 2017 APR for comparison. Note in the summer forecast, the year is interpreted as (for example) 2012 being the 2011-12 summer.

5.3.2.1 Winter maximum demand forecast

The winter maximum demand recovered in 2017 from the drop in 2016[76] and continued the recovery since 2012.[77] The average increase in maximum demand since 2012 has been 0.9% a year. This is driven by continued recovery of maximum demand on the distribution network and continued increase of the maximum demand from transmission-connected customers.

There is continued recovery in maximum demand forecast across all three scenarios, continuing the trend since 2012. This continues over the planning period, aside from a reduction in both the neutral and weak scenarios in 2022 and 2020, respectively. We anticipate this is a reduction in transmission-connected customer demand, and is consistent with the energy usage forecase in Section 5.3.1.

The continued recovery in the underlying (i.e. excluding the 2022 reduction) neutral scenario maximum demand is forecast at 0.5% a year to 2027. The forecast growth rate from our 2017 APR was 1.0% a year over the forward planning period. Despite the differences in the forecast in initial years, this year's forecast closely aligns with that from our 2017 APR from 2024 onwards.

76 This was predominantly a result of some large customers reducing their demand in response to the Basslink outage and associated energy storage levels in the first six months of 2016

77 The maximum demand in 2012 was 1662 MW. This had declined from the historic peak of 1861 MW in 2008

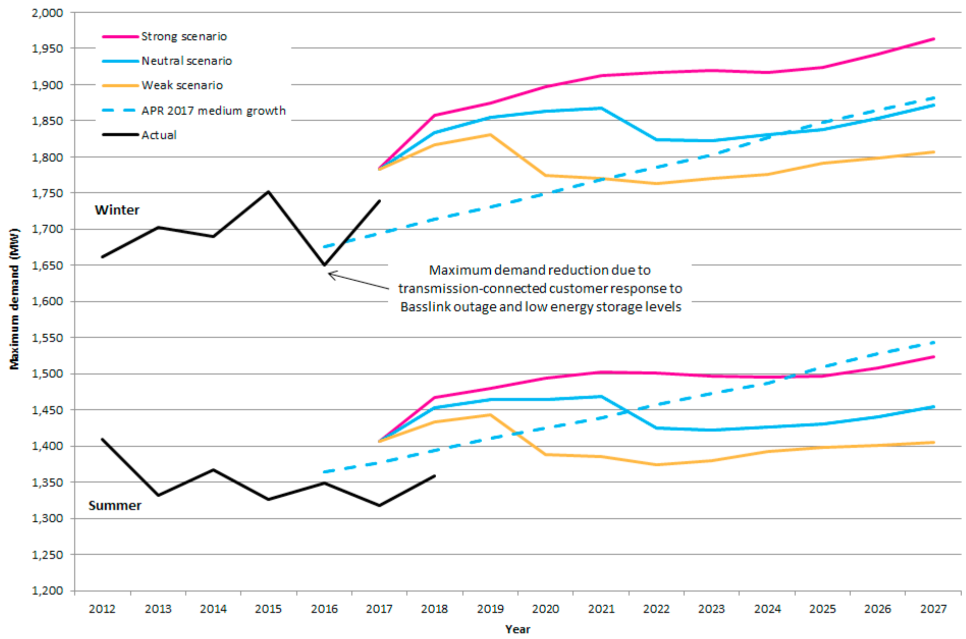

Figure 5-2: Forecast of total Tasmanian maximum demand for winter and summer

5.3.2.2 Summer maximum demand forecast

The summer maximum demand occurs when temperatures are low, not during high temperatures that drives network maximum demands in most other Australian jurisdictions. Historically, summer maximum demand occurs in either early December or late February.

The decline in maximum demand ceased following the 2012-13 summer, with a small overall increase since then. The forecast shows an increase in summer maximum demand to 2018-19, remaining constant until the decrease in 2021-22 neutral scenarios, followed by a continual gradual growth.

The neutral scenario summer maximum demand (excluding 2021-22 reduction) is forecast to grow at an average rate of 0.4% a year. The forecast growth rate from our 2017 APR was 1.2%. The summer forecast is an overall reduction to that from our 2017 APR, reflecting the continued slow growth in summer maximum demand since 2012-13.

5.4 Load profile

Figure 5-3 presents the Tasmanian load profiles on the maximum demand days in winter and summer for the past two years. The maximum demand day profiles illustrate the greater demand variability in winter compared with summer.

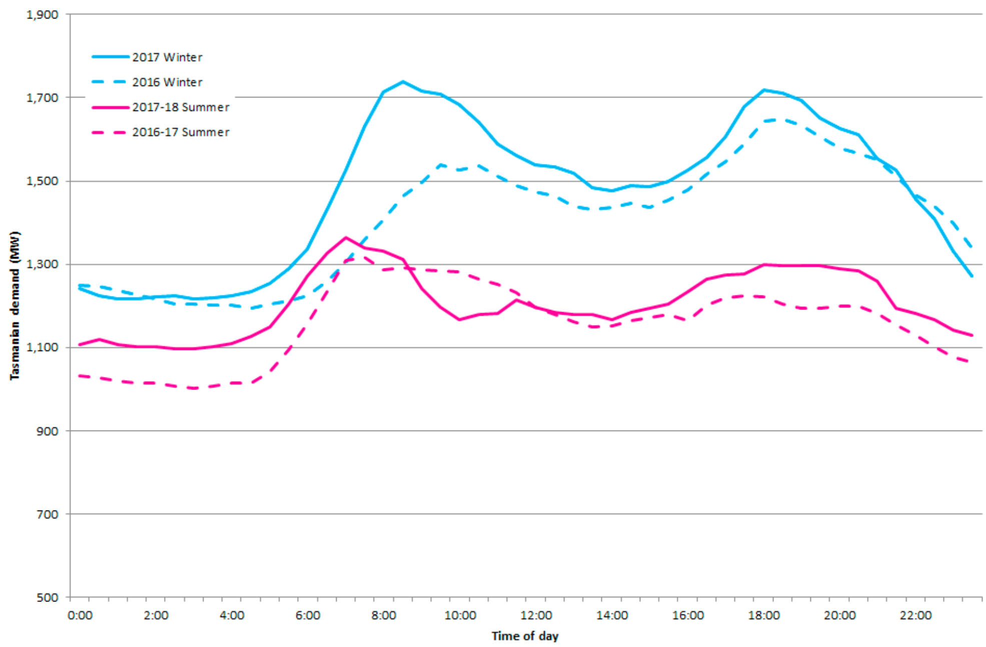

Figure 5-3: Winter and summer maximum demand day load profiles

The 2017 winter maximum demand curve is higher than that in 2016 except near midnight. The 2016 winter maximum demand occurred on a Saturday after the return to service of Basslink and transmission customers consequently increasing demand back to normal levels.

The 2016 distribution network maximum demand occurred before the Basslink return to service. If the transmission customer demand was at normal levels at that time, then that would have driven a higher maximum demand.

The load profile of the summer 2017-18 maximum demand day is generally higher than in 2016-17. The reduction in late morning may be partly due to increased output from PV embedded generation, though we cannot confirm this. Note that time of day in summer is Australian Eastern Standard Time – not Australian Eastern Daylight Time.

5.5 Intra-regional generation projections

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

5.5.1 Existing generation capacity

Table 5-1 presents the total existing generation capacity, including Basslink import, connected to the transmission network. 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 D.

Table 5-1: Existing generation capacity

Generation type	Number of sites	Total name-plate rating (MW)
Hydro	25	2310
Gas	1	178
Wind	3	308
Basslink import	1	478
Total	30	3274

The Tamar Valley Power Station CCGT was notified to AEMO as having been withdrawn from service; though available for operation with less than three months' notice.[78] Tamar Valley Power Station CCGT has however been in operation since September 2017, for commercial reasons.[79] Operation of the CCGT 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 relatively short timeframe if required. The peaking OCGTs at Tamar Valley Power Station continue to operate as normal.

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 because the 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 PASA.[80]

5.5.2 Prospective generation developments

There has been significant interest in new generation developments in Tasmania recently. There has been material progress on two existing wind farms identified in our 2017 APR – Cattle Hill and Granville Harbour – and at least 12 enquiries for other new wind and solar farms, some of which have progressed to the application stage. Table 5-2 presents these proposed generation developments, by connection application or enquiry. We have not disclosed information on prospective developments where the information has not been made public by the proponent.

We have executed connection agreements with Cattle Hill and Granville Harbour wind farms; however they have not yet commenced and so remain as connection applications. Cattle Hill Wind Farm is included in the capacity and energy balance assessments in Sections 5.6.1 and 5.6.2. Granville Harbour Wind Farm is not, as the connection agreement had not been executed at the time of the assessment. All other prospective developments have not been included in this assessment.

There may be significant future generation capability from pumped hydro energy storage in Tasmania. Hydro Tasmania is investigating the possibility of pumped hydro energy storage as part of its Battery of the Nation initiative.[81] Although this is additional prospective generation (and load) in Tasmania, they remain within feasibility study stage; hence we have not included it in our assessment of prospective generation developments.

78 *Table 11, Electricity statement of opportunities for the National Electricity Market, Australian Energy Market Operator, August 2017, www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities*

79 *Media release: Routine CCGT operation, 3 September 2017, www.hydro.com.au/news/media-releases/2017/09/14/routine-ccgt-operation*

80 *www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Projected-assessment-of-system-adequacy*

81 *www.hydro.com.au/clean-energy/battery-of-the-nation/pumped-hydro*

Table 5-2: Prospective Tasmanian generation developments

Development	Location and connection	Type	Capacity (MW)	Timing
Application				
Cattle Hill Wind Farm	Eastern shore of Lake Echo in central Tasmania and will connect to Waddamana Substation	Wind	144	2019
Granville Harbour Wind Farm	Granville Farm on the west coast of Tasmania and will connect to Farrell Substation via the existing Farrell–Reece transmission line	Wind	99	2019
Western Plains Wind Farm	North-west of Stanley and will connect to Port Latta Substation	Wind	40	2019
Port Latta Wind Farm	Near Port Latta and will connect to Port Latta Substation	Wind	25	2019
Wesley Vale Solar	North of Wesley Vale township and will connect to Wesley Vale Substation	Solar	12.5	2019
Jims Plain Wind Farm	In north-west Tasmania and will connect to Smithton Substation	Wind	50	2021
Robbins Island Wind Farm	In north-west Tasmania and will connect to Burnie Substation	Wind	400	2026
Enquiry				
George Town Solar	North of George Town and will connect to George Town Substation	Solar	5	
Low Head Wind Farm	On the coast at Low Head and will connect to George Town Substation	Wind	35	
Robbins Island renewable energy park	North-west of Smithton, just off the coast of mainland Tasmania, and will connect to Burnie Substation	Wind Solar Battery	1000[82]	
Jims Plain renewable energy park	In north-west Tasmania and will connect to Smithton Substation	Wind Solar Battery	160[81]	
Other wind farms	Various new wind farms around Tasmania	Wind	770	
Other solar farms	Various new solar farms around Tasmania	Solar	185	
Total new prospective generation			**2475.5**	

5.6 Supply-demand balance assessment

The supply-demand balance is an important consideration in assessing the future adequacy of Tasmania's power system. It assesses the adequacy of existing generation to meet forecast maximum demand and energy usage 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 and between years and most of the capacity is available even under very dry conditions and low storage levels for short periods. Notwithstanding, hydro generation capability is affected by the availability of water and maintenance needs of generators and water ways. Even with overall water storage at prudent levels, it is possible some hydro-generating plant associated with small and medium storages may not be available due to planned or unplanned outages.

This section consider the:

- capacity of the existing and future generation assets to meet the forecast maximum demand over the next 10 years;
- energy generation adequacy compared with forecast energy consumption over the next 10 years; and
- impact on Tasmania's energy security in the event of an extended outage of 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. The Tasmanian Government also produces an annual energy security review[83], and we have compared our analysis against this review in Section 5.6.4.

82 *This is inclusive of the amount included in the wind farm currently in application stage*

83 *www.economicregulator.tas.gov.au/about-us/energy-security-monitor-and-assessor/annual-energy-security-review*

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. Actual electricity generation operations are commercial decisions based on market factors.

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 3274 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 4% of its 452 MW capacity (existing 308 MW installed, with Cattle Hill Wind Farm 144 MW). This is the 90% confidence level of wind during the top 10% of demand since 2014. As detailed in Section 5.5.2, Cattle Hill Wind Farm is included in this analysis due to its near-commitment status. Table 5-3 presents the generation capacity used in the capacity balance analysis.

Table 5-3: Generation capacity for capacity balance assessment

Generation type	Assumed capacity (MW)	Assumption
Hydro	2310	Full capacity available
Gas	178	Full capacity available
Wind	20	4% of capacity available, including Cattle Hill Wind Farm from 2019
Basslink imports	478	Full capacity available
Total	2986	

This available capacity is compared against neutral, strong and weak economic growth scenarios. Furthermore, the available excess capacity is tested for the following three outages:

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

5.6.1.2 Results summary

The analysis shows there is sufficient generation capacity to meet peak demands until at least 2027 for all three scenarios. Of the three outages tested, the highest capacity impact is from a Basslink outage. The forecast reserve generation capacity under a Basslink outage against the neutral scenario is shown in Figure 5-4. Furthermore, Figure 5-4 shows the forecast reserve generation capacity range as per the neutral, strong and weak scenarios. The reserve generation capacity, and Basslink import capability, remains above 1000 MW under the strong scenario, and almost 1200 MW under the weak scenario to 2027. Reserve generation capacity under the neutral and strong scenarios is higher than assessed in 2017 due to the reduction in forecast demand. The reserve capacity under the weak scenario is lower than assessed in 2017 as this spread between the maximum demand forecasts in this year's scenarios are less.

With a Basslink outage, reserve capacity under the neutral growth scenario remains over 650 MW by 2027.

AEMO has assessed the adequacy of regional generation capacity to meet the demand as part of its Electricity Statement of Opportunities. No capacity issues were identified in its analysis.[84]

84 www.aemo.com.au/electricity/national-electricity-market-nem/planning-and-forecasting/nem-electricity-statement-of-opportunities

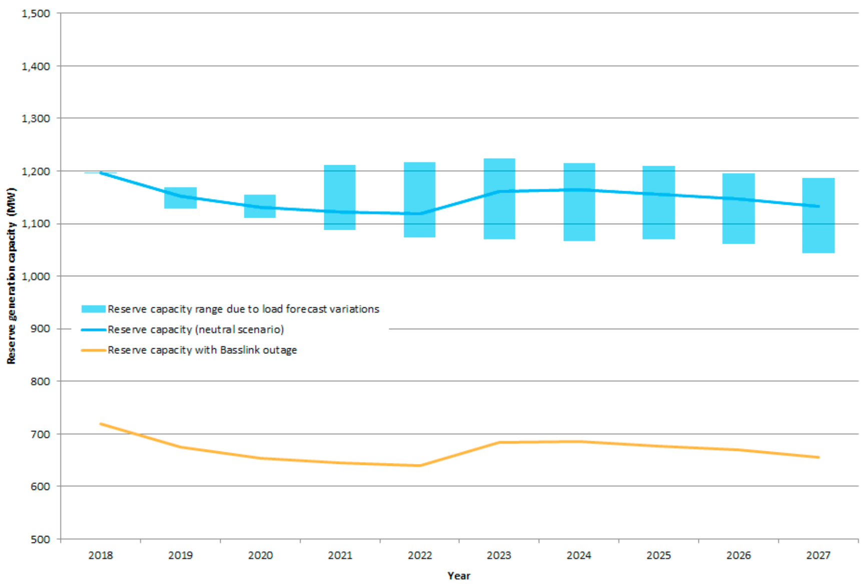

Figure 5-4: Reserve generation capacity variation due to load variations and severe outage

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, the energy balance considers three rainfall scenarios (wet, medium and dry) that determine 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 (i.e. dispatching lowest cost generation while maintaining network security constraints) to meet the Tasmanian demand, maintain a reasonable storage position, and to trade across Basslink.

Hydro generation is modelled as a limited resource without assigning any price and allowing the model to dispatch hydro generation based on Victorian prices and the cost of thermal generation. The model optimises hydro energy utilisation by replacing highest cost thermal generation with hydro generation and hydro generation by imports during extended low rainfall periods.

Historical inputs include initial water energy in storage, 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 2017 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 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, our transmission network is represented by 28 nodes. Some of the network constraints that 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% POE rainfall condition) – 10,912 GWh total inflows each year;
  - medium (based on 50% POE rainfall condition) – 8802 GWh total inflows per year; and
  - dry (based on 90% POE rainfall condition) – 7202 GWh total inflows per year.
- the future energy demand was developed based on the historic load profile, 50% POE maximum demand forecast of each transmission-distribution connection point, and the state energy forecast for the neutral and strong scenarios;
- generation capacity is as outlined in Section 5.5.1, which does not include the CCGT at Tamar Valley Power Station, and includes the proposed Cattle Hill Wind Farm from 2019;
- the wind profile for each wind farm was based on their respective historical operating patterns, with Cattle Hill Wind Farm based on the operating pattern of Musselroe Wind Farm;
- variable operation and maintenance costs and fuel prices for Tamar Valley Power Station OCGT were sourced from publicly available information;[85]
- the initial water storage levels modelled for each sequence were the actual levels as at the beginning of 2018;[86]
- outages of generation plant have not been included, as these have minimal impact on long-term energy supply;
- system FCAS demand has been included in the model as constant demand; and
- neutral and strong energy forecast scenarios have been assessed to determine the impact of energy growth rate variations.

Outcomes of the energy balance depend 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.

5.6.2.3 Result summary

The energy balance assesses the adequacy of generation to meet forecast energy consumption with respect to the 2017 scenarios for forecast energy generation and variation of hydro inflows. No unserved energy is expected during the 10-year planning horizon for the three hydro inflow scenarios, based on the assumptions presented in Section 5.6.2.2 and all generation sources being available.

Figure 5-5 presents the expected supply from each of the four generation types to meet the future energy demand for the neutral energy forecast and medium hydro inflow scenario.

85 *Model developed for Electricity Statement of Opportunities 2017 studies by AEMO*

86 *www.hydro.com.au/docs/default-source/energy-in-storage/storage-summary.xls*

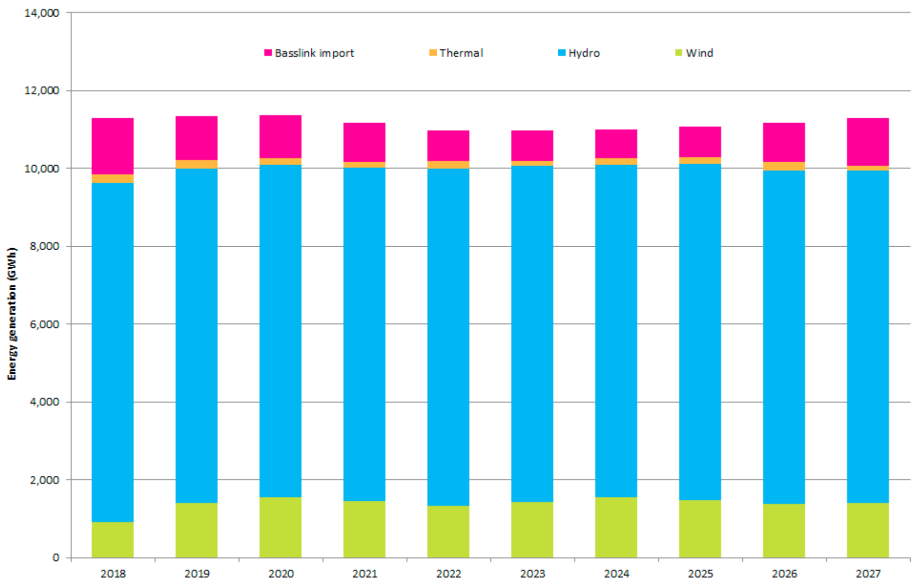

Figure 5-5: Energy balance under neutral energy growth and medium hydro inflows

Wind generation increases from 2019 with the commissioning of Cattle Hill Wind Farm. From there, variations in wind is due to the variations in historic wind data used for the forecast period. Hydro generation generally acts to counter the variation in wind energy, balancing storage levels, with thermal generation supply remaining relatively constant. The variation in forecast energy use over the planning period is predominantly met by changes in Basslink import amounts.

In addition to the neutral energy forecast and medium hydro inflow scenario presented in Figure 5-5, we also assessed the energy balance for combinations of the strong scenario for forecast energy generation, and wet and dry hydro inflows. Due to the nature of wind generation, its output does not change across the scenarios. There are expected changes in the contribution from hydro and thermal generation under differing scenarios, with the wet scenario leading to increased hydro generation and reduced thermal generation and the reverse holding true. The biggest effect of the scenarios is on the Basslink import amount required to balance Tasmania's energy requirements.

Figure 5-6 presents the contribution from Basslink import to Tasmania's energy requirements as it varies under the different scenarios. It presents Basslink import and export contribution under four scenarios: the three hydro inflow scenarios with neurtral energy growth, and the dry inflow – strong energy growth scenario – the worst case.

The base scenario (neutral forecast and medium inflows) shown in Figure 5-6 is the same scenario – and shows the same energy contribution – as in Figure 5-5. The other series show how Basslink import requirements vary from the base series under the different scenarios. Import requirements increase under the dry inflow-neutral energy (due to decreased contribution from hydro generation) and further under the dry inflow-strong energy (due to decreased contribution from hydro generation and increased energy usage). Under wet inflows, the Basslink import requirement is reduced.

For example, in 2018 under the base scenario, Basslink import is modelled to provide 1453 GWh of Tasmania's energy supply requirements. Under the wet inflow scenario, this decreases to 687 GWh and under the dry inflow scenario, Basslink import is required to provide 2185 GWh of Tasmania's energy supply requirements. Under the worst-case scenario of dry inflows and strong energy growth, Basslink import provided 2331 GWh of Tasmania's energy supply requirements in 2018.

Between 2022 and 2025 under the wet inflow-neutral energy scenario, there is sufficient energy availability for Basslink to be a net exporter in those years while maintaining a reasonable storage position. This is mainly due to the forecast decrease in energy demand across this period (refer Section 5.3.1).

These variations in Basslink import requirements are to maintain hydro storage levels, and there is no unserved energy forecast across any scenario.

Figure 5-6: Basslink import to meet the energy demand under different scenarios

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 on hydro storages during an extended outage and the period of recovery following the generation 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 (i.e. Gordon Power Station, 432 MW); and
- the gas supply network (i.e. 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 CCGT at Tamar Valley Power Station is available for the extended failure analysis (except under the gas supply network failure scenario);
- the proposed Cattle Hill Wind Farm is not included, as this assessment is for 2018 – prior to the wind farm commissioning;
- 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 due to seasonal variations in load and hydro inflow, 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.

5.6.3.2 Results summary

Figure 5-7 presents the monthly energy storage variations under the three different system outages, against normal storage variations expected with all sources available. The study is for the 2018 calendar year with storage variations shown with respect to the storage level at the beginning of January 2018.

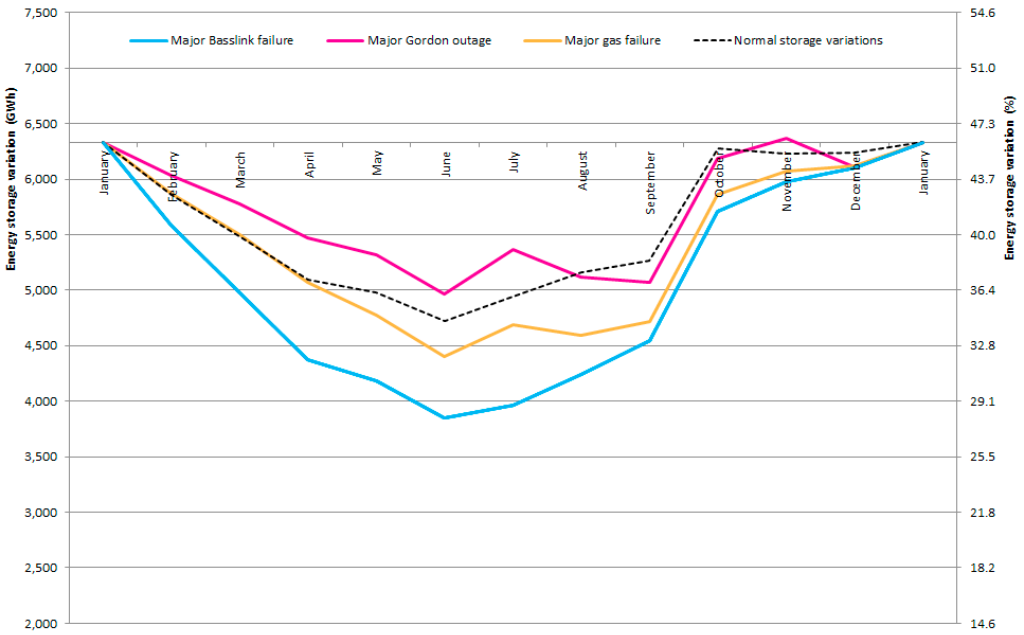

Figure 5-7: Monthly hydro storage variation due to selected outages

Hydro inflows are low early in the year and storage levels fall during that period before recovering in later months. Basslink flows are dependent on Tasmania and Victoria price differentials, with the Tasmanian price driven by hydro inflows among other things. In normal operation (i.e. without any major outages), the analysis indicates Tasmania is a net importer of energy throughout the year with the exception of June.

In normal operation and each extended failure, the lowest hydro storage levels are expected at the beginning of June. A Basslink outage is the most critical in reducing storage levels. Storages begin to decline immediately compared to normal storage variations and are predicted to fall to approximately 28% under this scenario. Storages reduce to approximately 34% under normal storage variations, with less hydro generation required and the ability to import energy with Basslink in service.

A gas supply failure would impact the hydro storages at the beginning of April. 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 overall hydro storage levels, only because the storage that supplies the power station builds; however, storages in the remainder of the system are enough that there is no risk of unserved energy.

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.

5.6.4 Tasmanian Government's Energy Security Framework

The Tasmanian Government established an Energy Security Taskforce to advise on how it could better prepare for, and mitigate against, risks to Tasmania's energy security. Among the Taskforce's August 2017 Final Report[87] recommendations was that the Tasmanian Government establish a Tasmanian energy security Monitor and Assessor, to provide independent oversight and regular transparent public reporting of the energy security situation in Tasmania. The Government formally assigned responsibility for the Monitor and Assessor role to OTTER in October 2017. Accordingly, the Regulator publishes:

- a monthly energy security dashboard; and
- an annual energy security review.

As part of the Energy Security Framework, the Regulator in its November 2017 Annual Energy Security Review[88] published two key energy-in-storage profiles across a rolling 12 month period, being:

- High reliability level – the threshold to which reserve water is held for energy security purposes where the reserve is sufficient to withstand a six-month Basslink outage coinciding with a very low inflow sequence and avoid extreme environmental risk in yingina/ Great Lake
- Prudent storage level – set to create a "storage buffer" from the high reliability level that is sufficiently conservative that the likelihood of storages falling below the high reliability level is low under normal operational conditions

Our conclusion from Section 5.6.3 supports the findings of the 2017 Annual Energy Security Review. Figure 5-8 shows the high reliability level and prudent storage level from the review and the normal storage variations from the analysis presented in Figure 5-7. It shows the normal storage variations in our analysis remain above the prudent storage level across the year, meaning there is no risk to Tasmania's energy security from the analysis presented in the review.

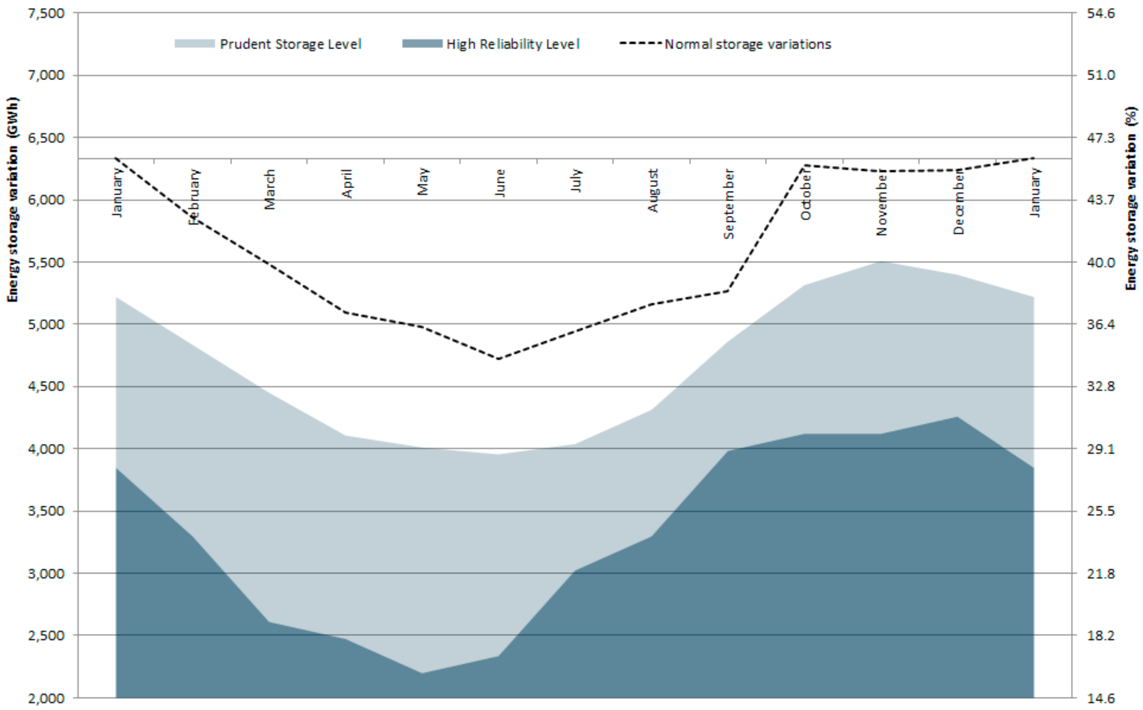

Figure 5-8: Normal storage variations against reliability levels

87 www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce/final_report

88 www.economicregulator.tas.gov.au/about-us/energy-security-monitor-and-assessor/annual-energy-security-review

6 PLANNED INVESTMENTS AND FORECAST LIMITATIONS

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 a minimum planning period. The outcomes of the annual planning review are presented in this chapter.

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 1), the operation of the existing network (Chapter 3), the performance of the existing network (Chapter 4), and the expected future generation and demand on the network (Chapter 5).[89] We also take into account the National Transmission Network Development Plan, and the Integrated System Plan, existing and known future customer plans and requirements, and forecast asset retirements. Our network planning process, including annual planning review process, is presented in Section 1.5.1.

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 NEM.

We present the outcomes of our annual planning review here in two sections:

- **Backbone transmission network:** Section 6.2 presents information on our proposed development of the backbone transmission network. It also includes information on how proposed developments in our APR align with national transmission planning performed by AEMO.
- **Area planning:** For local supply area issues, we perform our annual planning review on a geographical area basis. Section 6.3 presents our planning areas and information consistent to all planning areas and Sections 6.4 to 6.10 present the outcomes of our annual planning review for each area.

The project specification consultation report stage of the RIT, where required, will constitute our formal request for proposals to address limitations identified in this chapter. However, 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.

6.1.1 Planning considerations and assumptions

We plan our backbone transmission network against a market benefit analysis; however, there are also jurisdictional network planning reliability requirements. These ensure the network is planned to withstand certain non-credible contingencies.

When planning radial aspects of our transmission network – supply to transmission-distribution connection point substations and the substations themselves – we plan to the reliability standards of the jurisdictional network planning requirements. In summary, for a credible contingency we must ensure no more than 25 MW of load or more than 300 MWh of unserved energy is interrupted. In assessing these systems, we normally plan supply and network transformers to their four-hour short-term rating. These ratings depend on cyclic loads, so we cannot use these for energy-intensive and continuous loads. We plan our transmission circuits to their static ratings to identify limitations; however, our first check is then how the limitation is impacted when applying our dynamic ratings which are used in normal operation of the network.

In our sub-transmission and distribution network, our reliability planning requirements are our SAIFI and SAIDI targets under the Code. As part of our strategy to minimise outage impact on reliability, we plan our sub-transmission network and zone substations to firm (N-1) reliability. Switched firm – transferring interrupted load to an alternate supply in a short time – is generally acceptable.

In capacity planning of our distribution lines, we determine their capacity via simulation. We determine the capacity by identifying at what loading any element of the line trunk is at its limit for either thermal capacity or voltage compliance.

Our forecast asset retirements are identified from our suite of asset management plans. These strategies are underpinned by our Asset Management Strategy.

89 Load forecasts for transmission-distribution connection points, sub-transmission lines, zone substations and distribution feeders are available as an electronic attachment to this APR

6.1.2 Regulatory investment tests

As part of the Rules, we are required to undertake a RIT-T or a RIT-D for large network investments. RIT projects are essentially all network augmentation and replacement projects where the cost is estimated to be in excess of the applicable cost threshold, currently $6 million for transmission and $5 million for distribution. The RIT 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.

A number of proposed projects identified in this APR will likely be subject to a RIT. The proposed RITs are presented in Table 6-1 with their expected cost, proposed commencement date, and section reference within this APR where the projects are provided in more detail.

We do not have any RITs underway, and have not completed any since the 2017 APR.

Table 6-1: Proposed RITs

Project	Cost of preferred solution ($m)	Proposed commencement of RIT	APR reference
George Town Substation dynamic reactive support	15	Q2 2018	6.2.1
North-west Tasmania transmission development plan (staged)	275	TBA	6.2.2
Second Bass Strait interconnector	1100	January 2019	6.2.3
Rationalisation of Upper Derwent 110 kV network (stages 2 & 3)	118	TBA	6.2.4

6.2 Backbone transmission network

The backbone transmission network in Tasmania is made up of the 220 kV network and some parallel 110 kV network. Its role is the intra-regional transfer of electricity from generation to load centres and to mainland Australia via Basslink.

This section provides information on proposed and possible investments in the backbone transmission network. It includes both near-term investments and long-term strategies. In summary, they are:

- installation of dynamic reactive support at George Town Substation to reduce power transfer constraints on Basslink;
- development of the transmission network in north-west Tasmania to facilitate significant new wind generation;
- a second Bass Strait interconnector allowing Tasmania to play a greater role in the NEM; and
- rationalisation of our Upper Derwent 110 kV network due to forecast high refurbishment costs to maintain the existing network in service.

With the exception of the installation of dynamic reactive support at George Town Substation, each (or large portions) of these projects have been included as a contingent project in our revenue submission for the 2019-24 regulatory control period. Should they be approved by the AER as contingent projects in our revenue determination, the associated trigger point must be met, and the RIT-T completed, before these projects would be developed.

6.2.1 George Town Substation dynamic reactive support

George Town Substation forms a critical part of our transmission system. It provides supply to major industrial customers and is the connection point for Basslink and Tamar Valley Power Station.

As detailed in Section 5.5.1, the CCGT at Tamar Valley Power Station has been withdrawn from service.[90] When Tamar Valley Power Station is not generating and Basslink is exporting from Tasmania, the significant load at George Town Substation is supplied from remote generating units. This has presented a number of voltage control issues including low fault level, post-contingency temporary over-voltage, voltage instability and voltage unbalance.

To date, these issues have been addressed through constraining Basslink export capability or some generating units being operated in synchronous condenser mode, with the operational cost of this coming as a cost to the market. This issue is forecast to worsen in coming years with forecast load increases at George Town Substation and increasing non-synchronous generation (wind and other types) in the network. This new generation will displace generation closer to George Town Substation and synchronous generation generally. This will result in increased constraints on Basslink exports. As an initial step, we have installed a 40 MVAr 110 kV capacitor bank at George Town Substation as detailed in Section 6.6.1.

90 As noted in Section 5.5.1, the CCGT has been operated recently for commercial reasons

To address the issues, we also propose to install a ±50 MVAr 110 kV dynamic reactive support (STATCOM) at George Town Substation. A STATCOM was the only credible option identified to address voltage unbalance and instability issues, and the sizing was economically justified in reducing the amount of Basslink export constraint. The estimated cost of the project is $15.1 million and is planned to be operational by June 2022. This project will be subject to the RIT-T.

We are investigating an opportunity from this proposal to extend the solution to include frequency control services. These additional services will not be regulated, and this opportunity is being progressed with ARENA and generation customers.

6.2.2 North-west Tasmania transmission development plan

There is currently strong interest for the connection of new wind and solar generation in Tasmania, particularly new wind farms in north-west Tasmania. We have more than 2600 MW across Tasmania of new wind and solar generation between enquiry level and committed, with almost 1400 MW of that being proposed new wind farms by 2026 in north-west Tasmania. There is currently 140 MW of wind generation in north-west Tasmania at Bluff Point and Studland Bay wind farms.

Our transmission network in north-west Tasmania is sufficient to service the existing and forecast load, and wind farms, although a runback scheme was required to connect Bluff Point and Studland Bay wind farms to manage thermal loading of the Burnie-Smithton 110 kV transmission line. Depending on where it connects, further generation in this area may be heavily constrained if our existing network arrangement is maintained.

We have developed a long-term transmission development plan for north-west Tasmania to realise market benefits by alleviating the significant thermal constraints that would otherwise limit the dispatch of new generation. Table 6-2 presents the transmission development plan, with high level cost estimates, in line with the expected staging of the proposed new generation developments in north-west Tasmania. It consists of both small upgrades to release capacity from our existing network, as well as large capacity augmentations. Figure 6-1 presents a diagram of our transmission network in north-west Tasmania, showing the network with the development plan fully implemented.

Table 6-2: North-west Tasmania transmission development plan

Trigger	Development	Description	Cost ($m)
Small to moderate increase in generation in north-west Tasmania	Burnie-Smithton 110 kV transmission line capacity increase	Install a weather station at Smithton Substation to facilitate dynamic line ratings, expected 40 MW capacity increase	0.4
		Reconfigure supply arrangement to Port Latta Substation from existing loop in-loop out arrangement from the Burnie-Smithton 110 kV transmission line to a double tee, expected 20 MW capacity increase	2.0
		Commission the second (existing spare) 220 kV/110 kV network transformer at Burnie Substation	2.0
Moderate to large increase in generation in north-west Tasmania	North-west 110 kV network redevelopment	Construct a new double-circuit 110 kV Burnie-Smithton transmission line, initially operated with a single circuit only and capable for future operation at 220 kV	70.0
Moderate to large increase in generation in north-west Tasmania	Sheffield-Burnie 220 kV transmission line capacity increase	Augment the single-circuit Sheffield-Burnie 220 kV transmission line to increase operating temperature from 49C (138 MVA) to 75C (231 MVA)	1.0
Large increase in generation in north-west Tasmania	North-west 220 kV network redevelopment	Construct a second, new double-circuit Sheffield-Burnie 220 kV transmission line, initially operated with a single circuit only, with likely reconfiguration and rationalisation of Sheffield-Burnie 110 kV transmission line to accommodate the new 220 kV transmission line Convert new, second Burnie-Smithton 110 kV transmission line to 220 kV operation	80.0
	Sheffield to Palmerston 220 kV augmentation	Construct a second, new double-circuit Palmerston-Sheffield 220 kV transmission line, possibly initially operated with a single circuit only	120.0
Very large increase in generation in north-west Tasmania	Wind farm collector station at West Montagu	Construct a new wind farm collector station to efficiently connect multiple wind farms in north-west Tasmania String second side of new, second Sheffield-Burnie 220 kV transmission line	TBA

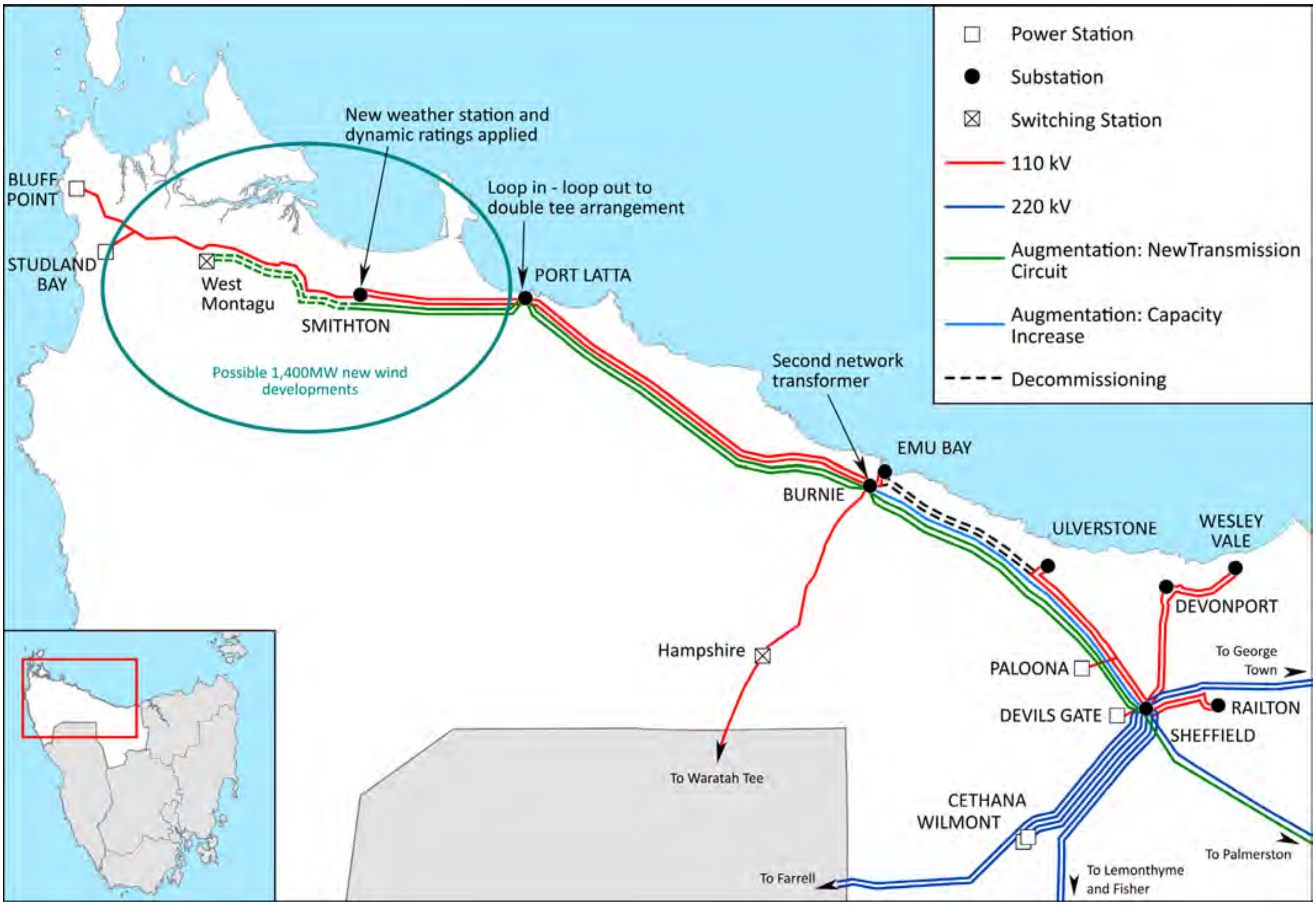

Figure 6-1: North-west Tasmania transmission development plan

This development plan presents the transmission infrastructure required, however the delineation between connection and shared assets will be negotiated with wind farm proponents. This plan currently does not consider system security requirements, which are yet to be assessed and may lead to additional investment requirements.

The north-west 110 kV network redevelopment, north-west 220 kV network redevelopment, and Sheffield to Palmerston 220 kV augmentation developments of the plan have been included as contingent projects in our revenue submission for the 2019-24 regulatory period. We will not develop these projects unless the relative triggers are met and approved by the AER. Components of this plan with costs exceeding thresholds will be subject to the RIT-T.

The timing of this development plan will be determined by the progress of the new generation developments. We will continue to develop the plan as the amount of new generation planned for the area becomes more certain, or changes.

6.2.3 Second Bass Strait interconnector

A second Bass Strait interconnector would allow Tasmania to expand the amount of dispatchable generation and ancillary services it could provide to mainland Australia, allowing Tasmania to play a greater role in the NEM. It would also enhance future security of supply to Tasmania.

A second interconnector is one of many transmission development options considered in AEMO's ISP. The ISP's assessments have a particular focus on the economic efficiency of projects and is due for publication in June 2018 (refer Section 6.2.5.1).

The most recent National Transmission Network Development Plan[91] assessed the economic justification of a second, 600 MW, Bass Strait interconnector. It identified that a second interconnector provided marginal net market benefits in some scenarios, with most benefit realised when combined with interconnector augmentations in other regions of the NEM. Subsequently, a feasibility study[92] for the Tasmanian Energy Taskforce identified a second interconnector would provide material market benefits, however those were only sufficient to outweigh costs under some scenarios. It estimated capital cost of a second interconnector in the range of $800m to $1100m, including network augmentation requirements in Tasmania and Victoria directly related to the second interconnector.

The funding for a second Bass Strait interconnector has been included as a contingent project in our revenue submission for the 2019-24 regulatory period. We included an allowance for $550 million, with Tasmania's network contribution assumed to be 50% of the total $1100 million estimate. A second Bass Strait interconnector will be subject to the RIT-T.

The Tasmanian Government, with support from the Commonwealth Government, has requested us to undertake a more detailed feasibility and business case assessment of a second Bass Strait interconnector. As provided in Section 2.8, we have established Project Marinus to undertake this assessment. We will invest $20 million in Project Marinus with ARENA contributing half of this funding. We will be undertaking this assessment over the next two years with an initial report delivered in December 2018 and the final report completed by December 2019.

Figure 6-2 shows possible route options for a second Bass Strait interconnector between Tasmania and Victoria. The preferred route will be identified from the detailed feasibility study being undertaken by Project Marinus.

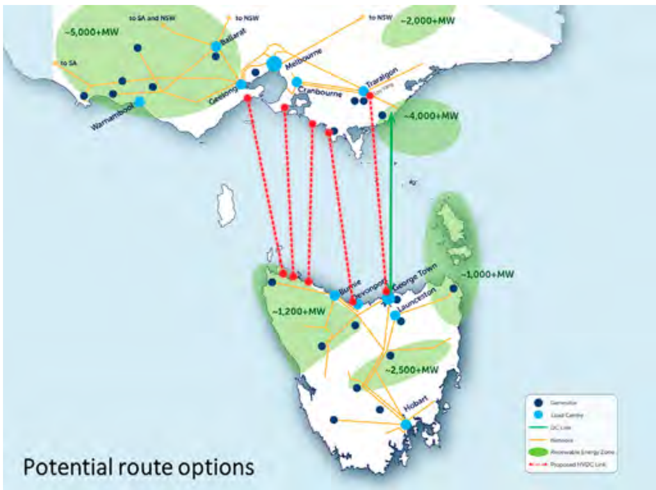

Figure 6-2: Possible route options of a second Bass Strait interconnector

The network augmentation requirements to facilitate a second Bass Strait interconnector (if in north-west Tasmani) are aligned with those in the transmission development plan for north-west Tasmania required for new generation (refer Section 6.2.2). The requirements to facilitate both new generation and a possible new interconnector will be considered in planning in both Project Marinus and our north-west Tasmania transmission development plan.

Since the NTNDP assessment, there have been market developments that influence the viability of a second interconnector. These include implementation of the majority of the recommendations from the Independent Review into the Future Security of the National Electricity Market, an increase in renewable energy (primarily wind) connection agreements, applications and enquiries in Tasmania; the progress of Hydro Tasmania's Battery of the Nation initiative, further analysis of interconnection between other NEM regions and a change in outlook on the retirement of ageing coal and gas-fired generation.

6.2.4 Rationalisation of Upper Derwent 110 kV network

The Upper Derwent 110 kV network is a critical part of our transmission network in that it:

- connects 946 MW of installed generation capacity;
- supplies about 700 MW of load including the greater Hobart area; and
- forms a critical connection through Waddamana Substation to the northern transmission network, and subsequently to the Victorian region of the NEM via Basslink.

The Upper Derwent 110 kV network includes most of the earliest transmission lines of our 110 kV network, which originated from Tarraleah Power Station in 1938. The 110 kV network was constructed as the main grid at the time to support the then-existing 88 kV network from Waddamana that has since been retired. Our Upper Derwent network also includes some of the earliest transmission lines of our 220 kV network, which originated northwards from Waddamana Power Station (now Waddamana Substation) in 1957, and was extended southwards to Chapel Street Substation in the early 1960s.

91 *National Transmission Network Development Plan, AEMO, December 2016, www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan*

92 *www.energy.gov.au/publications/feasibility-second-tasmanian-interconnector*

The construction in 2011 of the double circuit Waddamana-Lindisfarne 220 kV transmission line has provided a secure 220 kV transmission network to southern Tasmania and relieved constraints that existed on the Liapootah-Chapel Street 220 kV transmission corridor. This reduced the requirement of the Upper Derwent 110 kV network for bulk transmission purposes. The majority of these lines are approaching the end of their economic life due to degrading condition and increasing operational risks, requiring a prospective significant refurbishment or replacement program over the next 25 years.

This forecast expenditure has driven the need for us to consider a program of network rationalisation to deliver better value and service to Tasmanian electricity users in the long term.

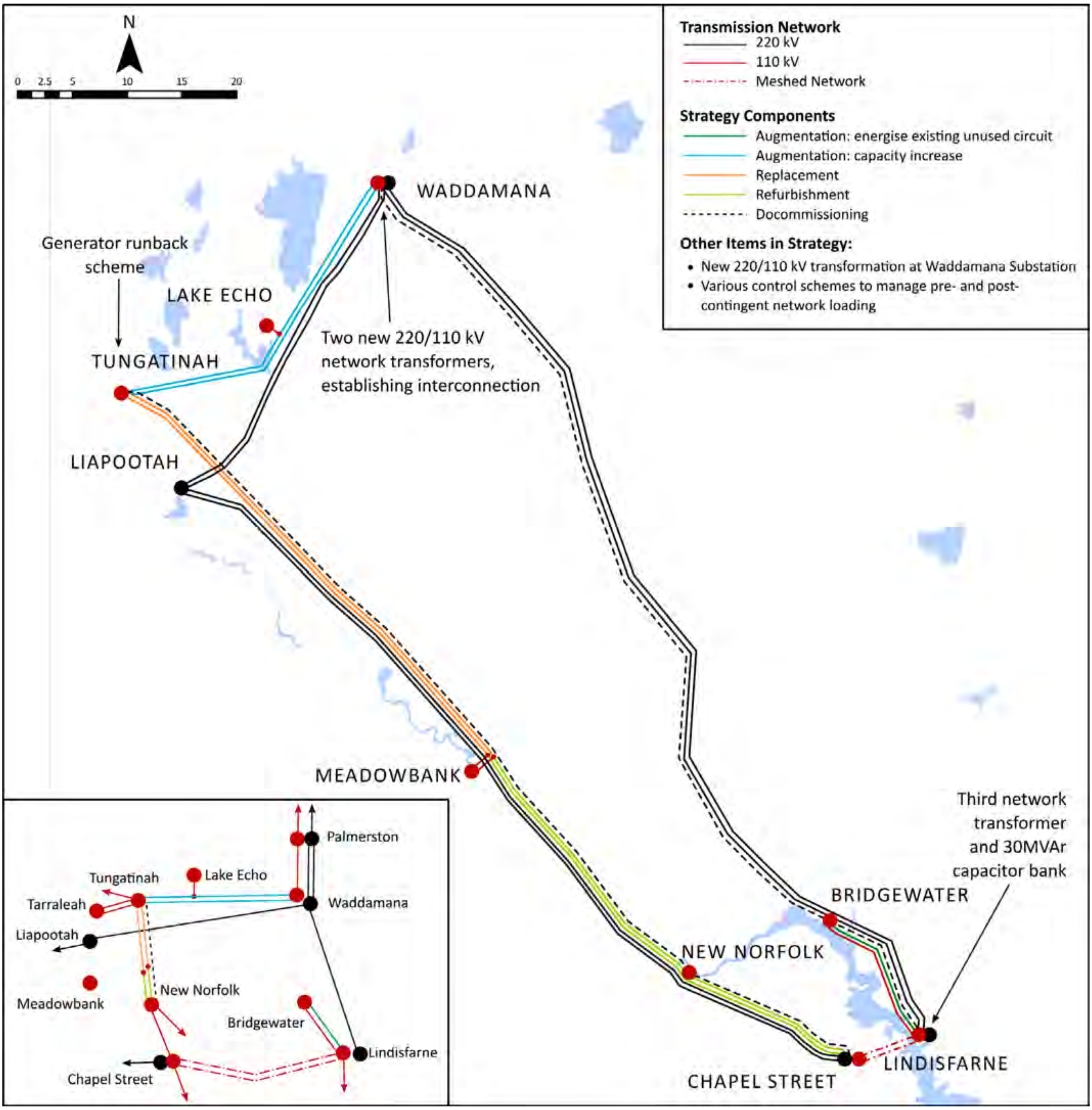

Figure 6-3: Rationalisation of Upper Derwent 110 kV network

Accordingly, we have developed a long-term fully integrated strategy to rationalise the Upper Derwent 110 kV network. This strategy aims to move the main grid function to the 220 kV transmission network, as far as practical, through the introduction of a strategically located connection between the 110 kV and 220 kV transmission networks in the Upper Derwent. This will facilitate the decommissioning of end-of-life 110 kV lines and the refurbishment/replacement of remaining re-functioned 110 kV lines, while maintaining network capacity, lower transmission losses, improving network efficiency and reliability, through reduced circuit lengths, reduced risk and lower lifecycle cost.

Table 6-3 presents the elements of the strategy. Figure 6-3 presents the Upper Derwent 110 kV network, showing the network with the rationalisation strategy fully implemented.

Table 6-3: Rationalisation of Upper Derwent 110 kV network

Stage	Description
1 (committed)	Decommission the Waddamana-Bridgewater 110 kV transmission line
	Establish a second Lindisfarne-Bridgewater 110 kV circuit (energise existing unused circuit)
	Implement a generator runback scheme to avoid thermal overloads (providing higher capacity to generators)
2	Decommission the single circuit Tungatinah-New Norfolk (East) 110 kV transmission line
	Increase the capacity of the Waddamana-Tungatinah 110 kV transmission lines, via structure replacement, from summer/winter ratings of 56/82 MVA to 99/115 MVA
	Install a 220/110 kV network transformer at Waddamana Substation (currently no 220/110 kV interconnection at substation)
	Install a third 220/110 kV network transformer at Lindisfarne Substation and a 30 MVAr capacitor bank in southern area to maintain network strength (reactive margin) following decommissioning of the Tungatinah–New Norfolk (East) 110 kV transmission line
3	Replace the double circuit Tungatinah-New Norfolk (West) 110 kV transmission line between Tungatinah Substation and Meadowbank Substation Tee
	Refurbish the double circuit Tungatinah-New Norfolk (West) 110 kV transmission line between Meadowbank Substation Tee and New Norfolk Substation
	Install a second 220/110 kV network transformer at Waddamana Substation

Stage 1 is committed and currently being implemented (refer Section 6.9.1). This need was the immediate requirement for major refurbishment work on the Waddamana-Bridgewater 110 kV transmission line.

Stages 2 and 3 are forecast to be economic to implement from the 2030s, when major refurbishment work is forecast to be required on the Waddamana-Tungatinah 110 kV transmission lines (stage 2) and the Tungatinah-New Norfolk 110 kV transmission lines (stage 3). Timing of stages 2 and 3 may change over coming years as refurbishment requirements of these transmission lines mature as we continue to monitor their condition. The high-level estimated cost for stages 2 and 3 is $118 million.

We developed this strategy in consultation with Hydro Tasmania in an environment of uncertainty around the future of Tarraleah Power Station with the first stage being required irrespective of the future for Tarraleah. Hydro Tasmania is undertaking a pre-feasibility study for the replacement and relocation of Tarraleah Power Station.[93] The second and third stages will be impacted by any new network connection arrangements for the replacement power station. Changes in connection of Tarraleah and possibly Tungatinah from 110 kV to 220 kV will have a material impact on the power flows in the southern transmission network. We will continue to engage with Hydro Tasmania as it develops the likely connection arrangements and timing of the Tarraleah Power Station upgrade.

Due to the uncertainty regarding Hydro Tasmania's requirements for the replacement of Tarraleah Power Station, we have included the funding for rationalisation of our Upper Derwent 110 kV network as a contingent project in our revenue submission for the 2019-24 regulatory period. We will not develop these projects unless the relative triggers are met and approved by the AER. Components of this plan with costs exceeding thresholds will be subject to the RIT-T. Stages 2 and 3 of this strategy will be subject to the RIT-T.

6.2.5 National transmission planning alignment

As the national transmission network planner, AEMO produces an annual NTNDP. AEMO states the NTNDP is an independent, strategic assessment of, and appropriate course for, efficient transmission grid development in the NEM over the next 20 years.

93 www.hydro.com.au/clean-energy/battery-of-the-nation/hydro-system-improvement

In October 2016, COAG energy ministers agreed to an independent review of the NEM. The Independent Review into the Future Security of the National Electricity Market makes recommendations to enhance the NEM to optimise security and reliability, and to do so at lowest long-term cost while meeting emissions reduction targets.[94] As part of the recommendations into improved system planning, the report recommended AEMO, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan (now ISP) to facilitate the efficient development and connection of renewable energy zones across the NEM.[95]

As the ISP's purpose and scope encompass those which would normally be covered in the NTNDP, the AER has permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the ISP.

6.2.5.1 Integrated System Plan

The ISP is a plan to facilitate the efficient development and connection of renewable energy zones across the NEM. The first ISP will be published in June 2018. AEMO states the ISP will deliver a strategic infrastructure development plan, based on sound engineering and economics, which can facilitate an orderly energy system transition under a range of scenarios. This ISP will particularly consider:

- what makes a successful renewable energy zone and, if they are identified, how to develop them; and
- transmission development options.

Over time, AEMO considers the ISP[96] will (by necessity) consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines and DER.

In consultation for the initial ISP , AEMO identified the following items particularly relating to Tasmania:

- potential renewable energy zones align well with the Battery of the Nation initiative;[97]
- additional interconnection between Tasmania and Victoria, with a second and possible third Bass Strait interconnector;
- transmission options being proposed to connect renewable energy in western Victoria can have a major impact on the justification for transmission links to Tasmania and other states; and
- without remediation, poor system strength within Tasmania is projected to decline further in Tasmania, and other states.

To support additional interconnection between Tasmania and Victoria, the ISP Consultation identified a number of network augmentations required. In Tasmania, these were capacity increases in the following 220 kV transmission corridors:

- Sheffield-Port Latta;
- Sheffield-Farrell;
- Palmerston-Sheffield; and
- Tungatinah-Palmerston.

Following publication of the ISP, a subsequent recommendation of the Independent Review into the Future Security of the National Electricity Market is to identify a list of priority projects that governments could support. We will work with the AEMC, AEMO and others on the development of the framework to evaluate priority projects.

Independent Review into the Future Security of the National Electricity Market, recommendation 5.2

By mid-2019, AEMO, in consultation with TNSPs and consistent with the integrated grid plan, should develop a list of potential priority projects in each region that governments could support if the market is unable to deliver the investment required to enable the development of renewable energy zones.

AEMC should develop a rigorous framework to evaluate the priority projects, including guidance for governments on the combination of circumstances that would warrant a government intervention to facilitate specific transmission investments.

94 www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market

95 Recommendation 5.1

96 Integrated System Plan Consultation, AEMO, December 2017, www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

97 www.hydro.com.au/clean-energy/battery-of-the-nation

6.2.5.2 2016 National Transmission Network Development Plan

The NTNDP's analysis focuses on the adequacy of the main transmission network and national transmission flow paths over a 20-year study period. In Tasmania, our 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 NSCAS in a five-year period. NSCAS relate to the capability to control active and reactive power flow into or out of our transmission network.

Sections 6.2.5.3 and 6.2.5.4 describe the manner in which our proposed augmentations to our transmission network relate to the 2016 NTNDP and the development strategies for national transmission flow paths specified in the NTNDP. The most recent NTNDP was published in December 2016.[98] The 2017 NTNDP will be integrated into the ISP published in June 2018.

6.2.5.3 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 an additional flow path between Tasmania and Victoria, i.e. a second Bass Strait interconnector. It suggests marginal net market benefits for a second Bass Strait interconnector under its "Neutral" scenario.

As detailed in Section 6.2.3, we will be undertaking a detailed feasibility and business case assessment for a second Bass Strait interconnector. As part of this assessment, we are engaging with AEMO, generation customers, our transmission-connected customer base and other stakeholders.

6.2.5.4 Relationship of our proposed augmentations and replacement network assets to the NTNDP

Our proposed augmentations and replacement network assets identified in this APR are not within the scope of the 2016 NTNDP.

The 2016 NTNDP identified a number of projected economic dispatch limitations under differing scenarios.[99] These limitations and descriptions are summarised, as presented in the 2016 NTNDP, in Table 6-4 with their relationship to this APR.

We continue to engage with AEMO and affected existing and potential customers on these potential limitations. Any proposed augmentations to address these limitations will be identified in future APRs and, where required, undergo the RIT-T.

The 2016 NTNDP did not identify any reliability limitations or any NSCAS gaps for maintaining power system security in Tasmania.

98 www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan

99 AEMO 2016 NTNDP, Table 9

Table 6-4: Relationship of 2016 NTNDP to TasNetworks APR

Potential transmission limitations	Dispatch conditions	NTNDP possible solutions	Scenarios	Relationship to our APR
Transmission limitations on the Palmerston-Sheffield 220 kV line	High wind generation in the north-west Tasmania area High import from Victoria to Tasmania through a second Bass Strait interconnector	Reduce wind and/or hydro generation from north-west and west Reduce import to Tasmania via second interconnector Uprating of existing Sheffield-Palmerston 220 kV circuit for a higher thermal rating, or a second Sheffield-Palmerston 220 kV circuit	Neutral	We propose to construct a new Palmerston-Sheffield 220 kV transmission line, driven by market benefits of relieving potential limitation (refer Section 6.2.2)
Transmission limitations on the George Town-Sheffield 220 kV line	High wind generation in the north-west and West Tasmania areas High Basslink export from Tasmania to Victoria	Reduce wind and/or hydro generation from north-west and West Reduce Basslink export from TAS to VIC Uprating of existing George Town-Sheffield 220 kV circuits for a higher thermal rating, or a third George Town-Sheffield 220 kV circuit	All Neutral except 2BSI[100]	We consider a second Bass Strait interconnector plausible, which would relive this constraint. Prior to this, generation or Basslink export would be reduced as required (refer Section 6.2.3)
Voltage collapse at George Town Transient over-voltage at George Town 220 kV	High export from Tasmania to Victoria at times of no gas powered generation units in Tamar Valley Reduced number of hydro units in northern Tasmania (current issue to continue in future)	Reduce export from TAS to VIC Constrain on generation in Tamar Valley and hydro units in northern Tasmania Installation of additional dynamic reactive support at George Town Substation	Neutral Low Grid Demand	We have installed a 40 MVAr capacitor bank at George Town Substation (refer Section 6.6.1), and propose to install a +/-50 MVAr STATCOM driven by market benefits of reducing Basslink export constraints (refer Section 6.2.1)
Basslink inverter commutation instability due to low fault level at George Town 220 kV	High import from Victoria to Tasmania via Basslink and low or no gas powered generation units online in Tamar Valley Low or no hydro units in northern Tasmania (current constraint to continue)	Constrain on generation in Tamar Valley and hydro units in northern Tasmania Operate existing gas and hydro units as synchronous condensers Installation of new synchronous condensers. Generation re-dispatch or constrain Basslink import into Tasmania	Neutral Low Grid Demand	We are investigating with generation customers to include frequency control services as part of the proposed STATCOM at George Town Substation (refer Section 6.2.1) which will relieve these constraints
High RoCoF	High wind generation in Tasmania and/or increased import from Victoria to Tasmania Reduced Tasmania hydro units on line	Constrain on gas and hydro units in Tasmania Operate existing gas and hydro units as synchronous condensers Inertia support services from wind generation Non network solutions to provide fast frequency services	Neutral	
High RoCoF	Unavailability of existing frequency control ancillary support services with retirement of smelters in Tasmania	Reduce Basslink import from Victoria to Tasmania	Low Grid Demand all	We continue to engage with our major industrial customers and do not anticipate the near-term closure of Tasmanian smelters. We acknowledge this potential limitation under this planning scenario

6.3 Area planning

6.3.1 Planning areas

Our 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 major supply points and the geographical coverage of the distribution network. Figure 6-4 and the associated notes show the seven planning areas in Tasmania with a brief description.

100 Second Bass Strait interconnector

Figure 6-4: Geographical planning areas

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 from the 220 kV backbone network at Burnie and Sheffield substations.
Northern	The greater Launceston area, George Town and the far north¬east of Tasmania. This area is supplied from the 220 kV backbone network 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. The area is 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 the 220 kV backbone network 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 from the 220 kV backbone network 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 via a 110 kV transmission line from Chapel Street Substation.

6.3.2 Notes for all geographic planning areas

6.3.2.1 Planning area diagrams

The diagrams show the transmission and sub-transmission networks of the planning area and the distribution supply area of each connection point substation. In combination with planning area commentary, the diagrams also indicate the location of planned investments and forecast limitations for each area.

6.3.2.2 Committed and completed developments

This section for each planning area presents the material network projects that are committed or that have been completed since our 2017 APR. Our definition of committed projects is as used in the RIT-T and RIT-D. We will report on the progress of our committed projects in future APRs.

6.3.2.3 Future connection points

This section for each planning area presents our forecast of future transmission-distribution connection points over the planning period. We include the location and description of the future connection point, along with future loading level, and estimated timing and cost.

6.3.2.4 Network developments

Network development sections provide detail on our proposed augmentation projects over the next 10 years that address forecast network limitations. These limitations identify points on the network that are inadequate for forecast demand on the network, due to capacity, a network performance requirement, or other technical limits.

We include information on the limitation and our preferred network solution, with timing and cost, and other potential solutions. We identify where a reduction in load or improvement in power factor may defer the limitation. None of our proposed network developments will have a material inter-network impact.

We did not have any investments to address urgent or unforeseen network issues arising in the past year. We do not have any proposed new or modified emergency frequency control schemes from AEMO's most recent power system frequency risk review. We do not have any planned investments for future zone substations or sub-transmission lines. 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.

6.3.2.5 Network asset retirements and replacements

This section for each planning area presents our forecast network asset retirements over the next 10 years. Almost all our retirements are due to assets reaching their service life. These are identified through our asset management process, outlined in Section 1.5.1 of this APR.

Following asset retirement, investment is almost always needed to maintain service levels. Where investment is required, we present the proposed solution, with forecast timing and cost, and other potential solutions considered. Section 6.11 presents the statewide and program-based asset replacement investments.

We do not have any planned de-ratings of network assets over the next 10 years.

6.3.2.6 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.

This section gives the spare continuous firm capacity currently available at each connection point substation. For single-transformer substations, we show the spare capacity available of the transformer. We will work with proponents of any new load proposals to develop the optimal technical and cost-efficient solution.

6.4 West Coast planning area

The West Coast planning area covers the area that is supplied from Farrell Substation, extending from Strahan and Queenstown north to Savage River and Waratah. The area is characterised by mining loads, supplied from both the transmission and distribution networks, and tourism centres.

The load in the area is supplied from our main transmission network at 110 kV from Farrell Substation (near Tullah), with a 110 kV transmission circuit from Burnie Substation available as alternate supply. Rosebery Substation is supplied by two transmission circuits, with other substations radially supplied. Distribution feeders in the area are supplied from four terminal substations and one zone substation.

There is a significant amount of transmission-connected generation in the West Coast area that is exported to the bulk transmission network via the Sheffield-Farrell 220 kV transmission line.

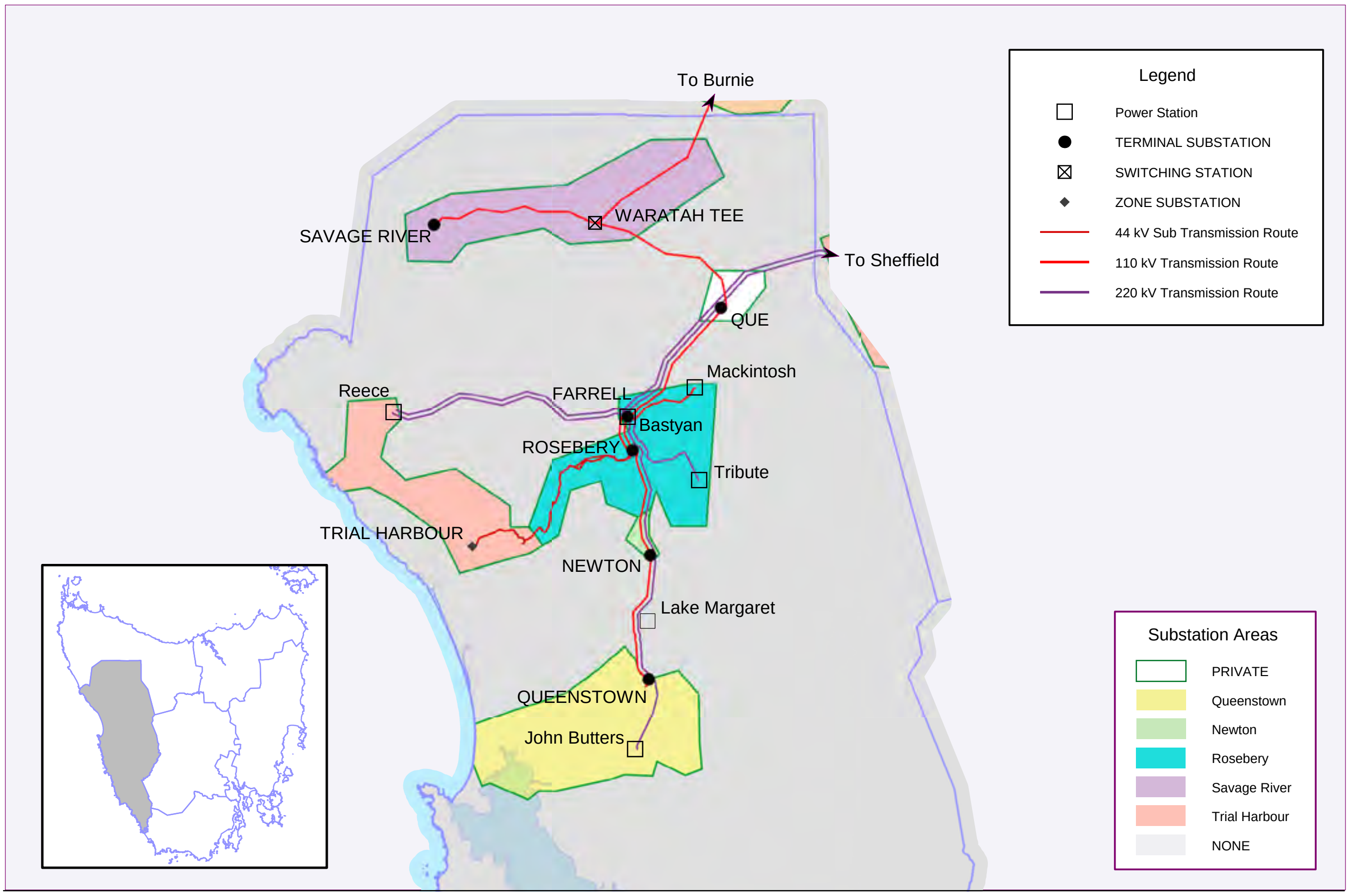

Figure 6- 5: West Coast planning area network

6.4.1 Completed and committed developments

There has been one completed project since last year's APR. This project decommissioned the Queenstown-Newton 110 kV transmission line and rationalised supply to Newton Substation by providing a tee-off from an existing circuit. There are currently no material committed projects in the area.

Table 6-5: West Coast planning area completed and committed developments

Project	Status	Description	Timing	Cost ($m)
Queenstown-Newton 110 kV transmission line decommissioning	Completed	Queenstown-Newton 110 kV transmission line was decommissioned due to its poor condition. Supply to Newton Substation was established through a tee-off into the neighbouring Farrell-Rosebery-Queenstown 110 kV transmission circuit	June 2017	2.4

6.4.2 Network developments

The proposed network developments in the West Coast planning area are outlined in Table 6-6. Where reduction in demand or improvement in power factor will defer a limitation, the required amount is identified in Table 6-7.

Table 6-6: West Coast planning area network developments

Project	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Rosebery Substation capacity upgrade	By 2019, forecast increase in demand at Rosebery Substation will exceed firm rating of supply transformers and loss of one transformer will result in more than 300 MWh unserved energy	Install a third supply transformer, relocated from elsewhere in the network	2018	2.5	Replace existing transformers with two new, larger units Demand management
Renison 44 kV Switching Station redevelopment	Configuration, condition and location of switching station contributes to poor downstream reliability	Redevelop Renison 44 kV Switching Station	2019	0.8	No identified credible alternatives
Waratah Tee disconnector replacement	Currently, manual disconnectors result in extended supply interruptions until alternate supply switching can occur following fault	Replace existing disconnectors with new motorised units	2021	0.5	No identified credible alternatives
Farrell Substation security augmentation	Currently, a 220 kV busbar fault for a bus coupler stuck condition will result in loss of supply to West Coast area and under high West Coast generation may give rise to system instability and system-wide supply interruptions or, in worst case, a black system exceeding jurisdictional network performance requirement	Install a second in-series 220 kV bus coupler circuit breaker	2021	0.8	No identified credible alternatives

Table 6-7: West Coast planning area limitation deferral requirements

Project	Location of load reduction	Existing power factor	Load reduction to defer constraint (MVA)		Improved in power factor required	
			1 year	5 years	1 year	5 years
Rosebery Substation capacity upgrade	Rosebery Substation	0.95	10	30	N/A[100]	N/A[101]

6.4.3 Network asset retirements and replacements

The asset retirements forecast within the West Coast planning area are identified in Table 6-8. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified. Investment is in the replacement of switchgear and supply transformers at three substations.

Table 6-8: West Coast planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Farrell Substation	Protection equipment at the end of life	Protection scheme replacements	2019	0.7	No identified credible alternatives
	220 kV circuit breakers at end of life	Replace circuit breakers	2025	3.0	No identified credible alternatives
Rosebery Substation	Supply transformers at end of life	Provide short term life extensions	2018	0.2	Credible life extension
		Replace supply transformers	2029	4.8	No identified credible alternatives
	Protection equipment at the end of its service life	Protection scheme replacement	2019	0.5	No identified credible alternative
	44 kV switchgear, bus and gantries at end of life	Replace switchgear and bus work	2022	2.8	No identified credible alternatives
Savage River Substation	Supply transformers at end life	Replace switchgear and supply transformers	2022	3.8	No identified credible alternatives

101 Power factor improvement is not a viable option to defer this limitation as the MW load is in excess of the MVA rating of the transformers

6.4.4 Deferred or averted limitations

6.4.4.1 Savage River Substation transmission reliability

Our Farrell-Que-Savage River-Hampshire 110 kV transmission circuit supplies a distribution network from Savage River Substation and transmission-connected customers at both Savage River and Que substations. Currently, loss of the Waratah Tee-Savage River circuit section could result in more than 300 MWh of unserved energy, exceeding our jurisdictional network planning requirement.

We have an agreement under the network planning requirements with our transmission customers supplied from Savage River Substation that there is insufficient benefit for a network augmentation solution to address this limitation. We are thus exempt under Clause 8(4) of the network planning requirements from planning the network to meet this requirement. The exemption will cease five years from publication of this APR (i.e. in 2023), 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.

6.4.5 Availability to connect to the network

Table 6-9 presents the spare continuous firm capacity currently available at substations in the West Coast planning area. Newton and Que substations are single-transformer substations and therefore inherently operate non-firm. For these substations, the available capacity shown is to the transformer capacity rather than the firm capacity. Available capacity at Rosebery Substation will increase following the installation of the third supply transformer, presented in Section 6.4.2.

Table 6-9: West Coast planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Newton	0	18.9
Queenstown	25	19.6
Rosebery	36	0
Savage River	22.5	0
Trial Harbour Zone	20	17.5

6.5 North-West planning area

The North-West planning area covers the north-west geographic area of Tasmania. It extends from Port Sorell to Smithton and the far north-west, including the Burnie-Devonport urban area, and inland to Deloraine, Sheffield and Hampshire. The load in the area consists of residential, commercial, and small to medium scale industries. There are two customers connected directly to the transmission network. Figure 6-6 presents a diagram of the North-West area and substation supply areas showing forecast limitations and planned investments.

The area is supplied from the backbone 220 kV transmission network at Sheffield Substation. Emu Bay and Wesley Vale substations are lightly loaded as they were built to serve paper manufacturing industries that have since closed. They supply pockets of 11 kV to Burnie CBD and a single customer near Wesley Vale.[102]

A large amount of hydro generation is connected to the backbone network at Sheffield Substation. Existing wind farms at Bluff Point and Studland Bay connect to Smithton Substation at 110 kV. A runback scheme prevents overloads on our Burnie-Smithton 110 kV transmission line during periods of high wind farm output.

There is significant interest in regards to large-scale wind and solar development in the North-West planning area. We are consulting and engaging with renewable generation developers, relevant stakeholders, customers and AEMO in regards to the transmission expansion required to integrate these projects efficiently into the network.

102 Wesley Vale Substation is being converted to 22 kV to supply the surrounding distribution network in the Port Sorell area. There will be no 11 kV supply from Wesley Vale Substation once completed, by June 2018

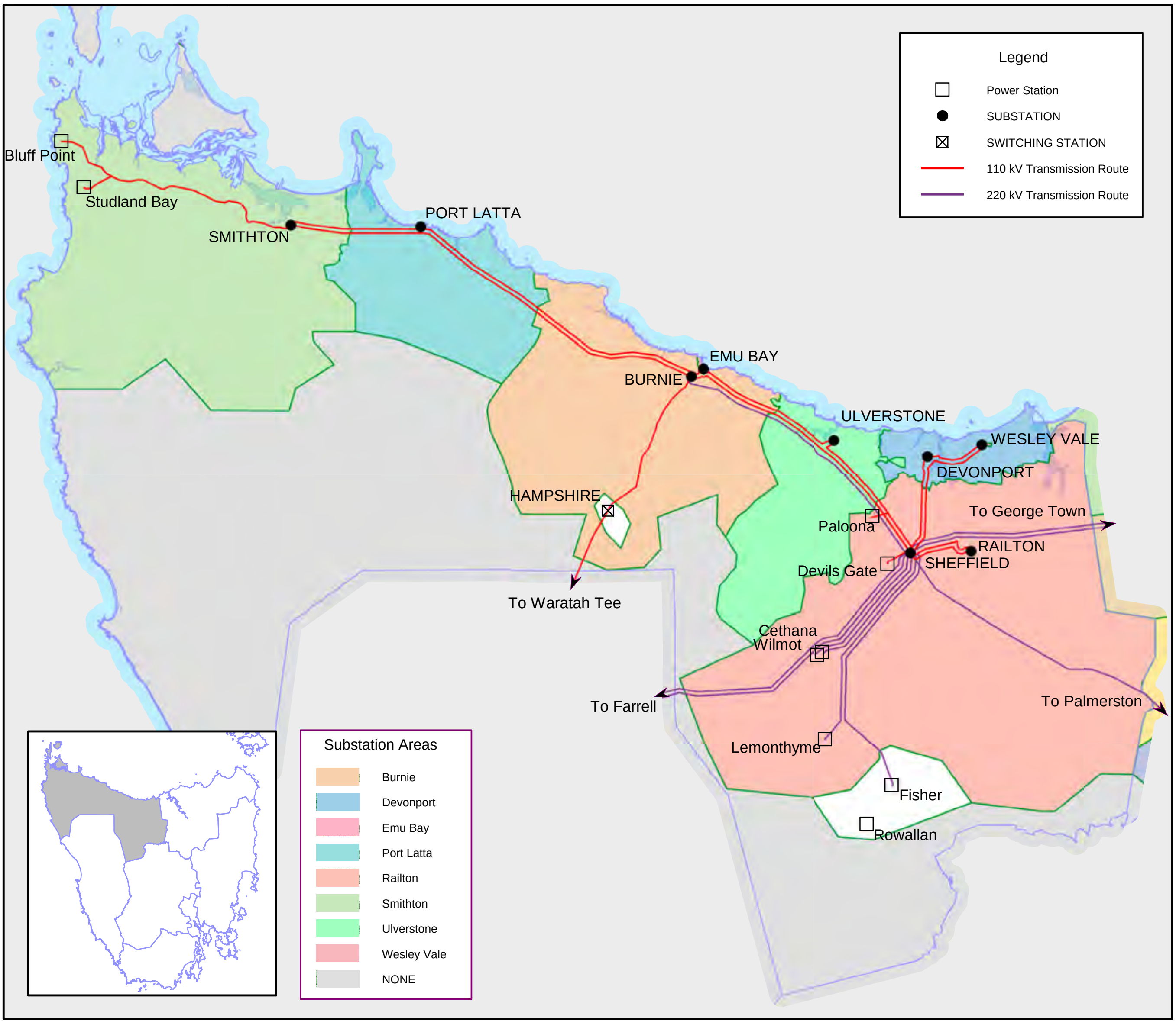

Figure 6-6: North-West planning area network

6.5.1 Completed and committed developments

There is one committed project to convert Wesley Vale Substation to 22 kV supply voltage. This will match the surrounding distribution network and allow it to expand its supply area, de-loading Devonport Substation and supporting Railton Substation. There have been no material completed projects since last year's APR.

Table 6-10: North-West planning area completed and committed developments

Project	Status	Description	Timing	Cost ($m)
Wesley Vale Substation voltage conversion	Committed	Conversion of supply voltage from 11 kV to 22 kV to match surrounding distribution network to improve local supply reliability. Will allow future load transfers from Devonport and Railton substations. Initially, 12 MW will be transferred from Devonport Substation	June 2018	1.3

6.5.2 Future connection points

We propose two connection point projects in the North-West planning area. We propose to convert the supply voltage at Emu Bay Substation to match the surrounding distribution network. At Sheffield Substation we propose to utilise an existing spare supply transformer as an in-service spare to improve local supply reliability.

Table 6-11: North-west planning area future connection points

Location	Description	Future loading level	Timing	Cost ($m)
Emu Bay Substation	The 11 kV switchboard is being replaced due to safety and asset condition issues. As part of the replacement, we will convert the supply voltage to 22 kV to match surrounding distribution network, enabling future load transfer from Burnie Substation	Initially no additional loading	2019	4.8
Sheffield Substation	Establishment of a new connection point at Sheffield Substation to reduce the supply area of Railton Substation, with aim to improve local supply reliability. Project will utilise an existing spare supply transformer located at Sheffield Substation	Up to 10 MW	2022	3.4

6.5.3 Network asset retirements and replacements

The asset retirements forecast within the North-West planning area are identified in Table 6-12. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified. Investment is in the replacement of switchgear and supply transformers at various substations and the continued replacement of wood pole structures on our Burnie-Waratah 110 kV transmission line.

Table 6-12: North-West planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Burnie Substation	Supply transformers at end of life	Replace supply transformers	2025	4.9	No identified credible alternatives
Emu Bay Substation	110 kV switchgear at end of life	Replace 110 kV switchgear	2018	4.9	No identified credible alternatives
	Feeder control equipment at end of life	Replace feeder control systems	2019	2.5	No identified credible alternatives
	11 kV switchgear at end of life	Replace 11 kV switchgear	2021	4.9	No identified credible alternatives
	Supply increased load to Burnie supply area.	Reconfigure 110/22–11 kV transformers to supply 22 kV	2022	2.5	No identified credible alternatives
Port Latta Substation	Supply transformers at end of life	Replace supply transformers	2022	3.7	No identified credible alternatives
Sheffield Substation	220 kV switchgear at end of life	Replace 220 kV switchgear	2025	3.0	No identified credible alternatives
	Network transformer T1 at end life	Replace network transformer T1	2025	5.0	No identified credible alternatives
Railton Substation	22 kV switchgear at end of life	Replace 22 kV switchgear	2024	1.9	No identified credible alternatives
Ulverstone Substation	22 kV switchgear at end of life	Replace 22 kV switchgear	2022	2.0	No identified credible alternatives
Burnie–Waratah 110 kV transmission line	Wood H-pole structures at end of life	Replace wood H-pole structures with spun concrete pole	2019 2023	2.4 2.0	No identified credible alternatives

6.5.4 Deferred or averted limitations and network developments

6.5.4.1 Burnie and Railton substations transformer capacity

Our 2017 APR identified the maximum demand at Burnie and Railton substations were forecast to exceed the short-term firm ratings of the supply transformers in 2026 and 2022, respectively. Due to a reduction in forecast load growth, these limitations are now not forecast to occur within the current planning period.

6.5.5 Availability to connect to the network

Table 6-13 presents the spare continuous firm capacity currently available at substations in the North-west planning area. Available capacity at Wesley Vale Substation will decrease following load transfer from Devonport Substation, where available capacity will increase, as presented in Section 6.5.1.

Table 6-13: North-West planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Burnie	60	0
Devonport	60	0
Emu Bay	38	31.0
Port Latta	22.5	3.6
Railton	50	1.8
Smithton	35	12.5
Ulverstone	45	14.9
Wesley Vale	25	24.8

6.6 Northern planning area

The Northern planning area covers the north and north-east of Tasmania. It is centred around Launceston and the Tamar area, and extends to Poatina, Deloraine, George Town and the north-east. The load profile in the area is diverse with the urban and commercial area in greater Launceston and the Tamar, industrial load in and around George Town including major energy users connected directly to the transmission network, and large rural areas of the northern midlands and the north-east of Tasmania. Figure 6-7 presents a diagram of the Northern area with substation supply areas and showing forecast limitations and planned investments.

The area is supplied from the backbone 220 kV transmission network at Hadspen, George Town and Palmerston (near Poatina) substations. The connection from Hadspen Substation provides a 110 kV supply into Launceston and the north-east, and Palmerton Substation provides supply to the northern midlands. George Town Substation predominantly supplies the industrial load in the area, and it provides the connection point for Basslink to mainland Australia. There are two major energy users and one other transmission connected customer, all supplied from George Town Substation.

Musselroe Wind Farm is connected to Derby Substation via the 110 kV network. Tamar Valley and Poatina power stations provide significant generation into the backbone network at George Town and Palmerston substations, respectively.

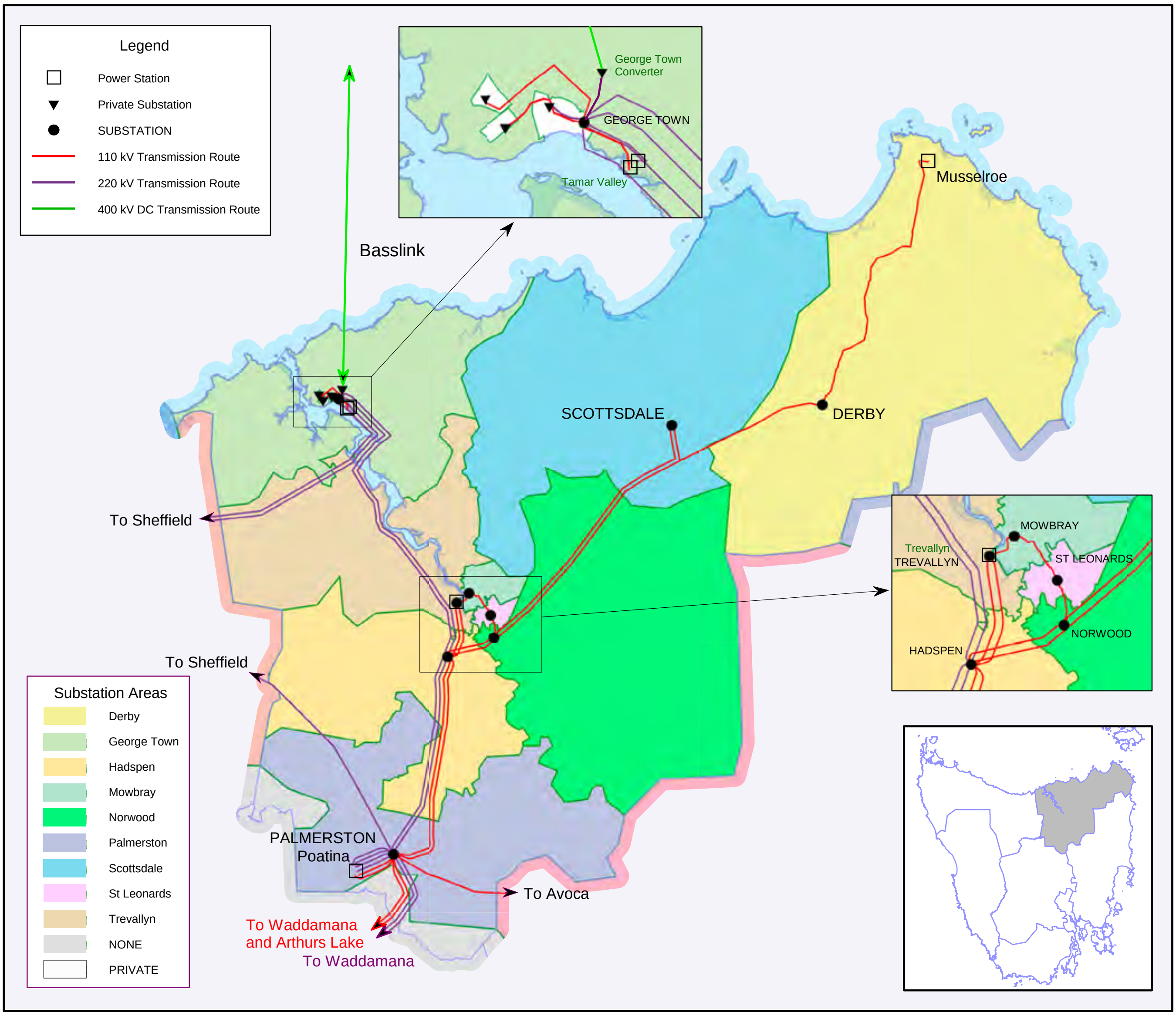

Figure 6-7: Northern planning area network

6.6.1 Completed and committed developments

There is one committed project to replace our George Town-Comalco 220 kV transmission line. The one completed project since last year's APR was to install a new 110 kV capacitor bank at George Town Substation.

Table 6-14: Northern planning area completed and committed developments

Project	Status	Description	Timing	Cost ($m)
Transmission line dead-end assembly upgrade program	Completed	We upgraded the dead-end assemblies of the Hadspen-Norwood 110 kV transmission line which were limiting the capacity of the transmission line	March 2018	0.1
George Town Substation reactive power compensation	Completed	We installed a 110 kV 40 MVAr capacitor bank at George Town Substation to reduce Basslink export constraints due to voltage control limitations	March 2018	3.1
George Town-Comalco 220 kV transmission line replacement	Committed	The George Town-Comalco 220 kV transmission line has reached end of life and is being replaced with a new transmission line	September 2019	5.6

6.6.2 Network asset retirements and replacements

The asset retirements forecast within the Northern planning area are identified in Table 6-15. Our proposed solution for these retirements is to replace the assets like-for-like with new, modern equivalents. No other credible potential options have been identified. Investment is in the replacement of a transmission line and a SCADA replacement at Norwood Substation.

Table 6-15: Northern planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
St Marys Substation	Switchgear has reached the end of life	Replace EHV switchgear	2019	0.8	No identified credible alternatives
Norwood Substation	Switchgear has reached the end of life	Replace EHV switchgear	2019	1.5	No identified credible alternatives
	Substation SCADA system has reached end of life	Replacement of SCADA equipment	2022	0.2	No identified credible alternatives
George Town-Temco 110 kV transmission line	Transmission line has reached end of life	Replace transmission line	2024	5.3	No identified credible alternatives

6.6.3 Local supply area limitations

6.6.3.1 Westbury urban area reliability improvement

The Westbury urban reliability area is supplied from two distribution feeders from Hadspen Substation. Within this area, feeder 67082 (approximately 37 km supply length) supplies the 724 customers in the Westbury township and feeder 67084 (approximately 27 km supply length) supplies the 57 customers in the portion of the Westbury industrial estate. Supply to the community does not meet its reliability requirements; both SAIFI and SAIDI.

Our preferred option is to reduce the community exposure to outages through reducing the length, and hence exposure, of the feeders supplying it. We propose a project to rationalise the supply to Westbury urban reliability area, enabling the main feeder, feeder 67082, a cleaner, more direct route to Westbury urban reliability area.

The estimated cost of this project is $1.7 million and it is planned to be operational by June 2023.

6.6.4 Deferred or averted limitations and network developments

6.6.4.1 Hadspen Substation transformer capacity

Our 2017 APR identified the maximum demand at Hadspen Substation was forecast to exceed the short-term firm ratings of the supply transformers in 2025. Due to a reduction in forecast load growth, this limitation is now not forecast to occur within the current planning period.

6.6.4.2 Palmerston Substation disconnector replacement and earth switch renewal

Our 2017 APR proposed the replacement of Stanger type DR2 disconnectors at Palmerston Substation which are unreliable and at their end of life, with spare parts no longer available. This project has now been incorporated into a wider disconnector and earth switch replacement program, and is not presented as a separate project in this APR. This program forms part of the transmission substation asset replacement and upgrade expenditure, presented in Table 6-35.

6.6.5 Availability to connect to the network

Table 6-16 presents the continuous firm spare capacity currently available at substations in the Northern planning area. Derby Substation is a single-transformer substation and the available capacity shown here is to the transformer capacity rather than the firm capacity.

Table 6-16: Northern planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Derby	0	18.1
George Town	50	31.7
Hadspen	50	0
Mowbray	50	12.0
Norwood	50	23.0
Palmerston	25	14.3
Scottsdale	31.5	19.6
St Leonards	60	30.6
Trevallyn	100	34.0

6.7 Central planning area

The Central planning area encompasses Tasmania's Central Highlands, the Derwent Valley and part of the Midlands. It also includes the supply at Strathgordon. Figure 6-8 presents a diagram of the Central area with substation supply areas and showing forecast limitations and planned investments.

The majority of the distribution-connected load is in the New Norfolk township. The remaining substations supply low-load density areas in the highlands with limited, if any, transfer capability between feeders. There is one customer supplied directly from our transmission network.

The transmission-connected generation in the Central area is critical to supplying southern Tasmanian load. Power stations in the Derwent scheme have a capacity of more than 500 MW and connect into both the 110 kV and 220 kV networks. Gordon Power Station has a capacity of 432 MW and supplies into Chapel Street Substation at 220 kV.

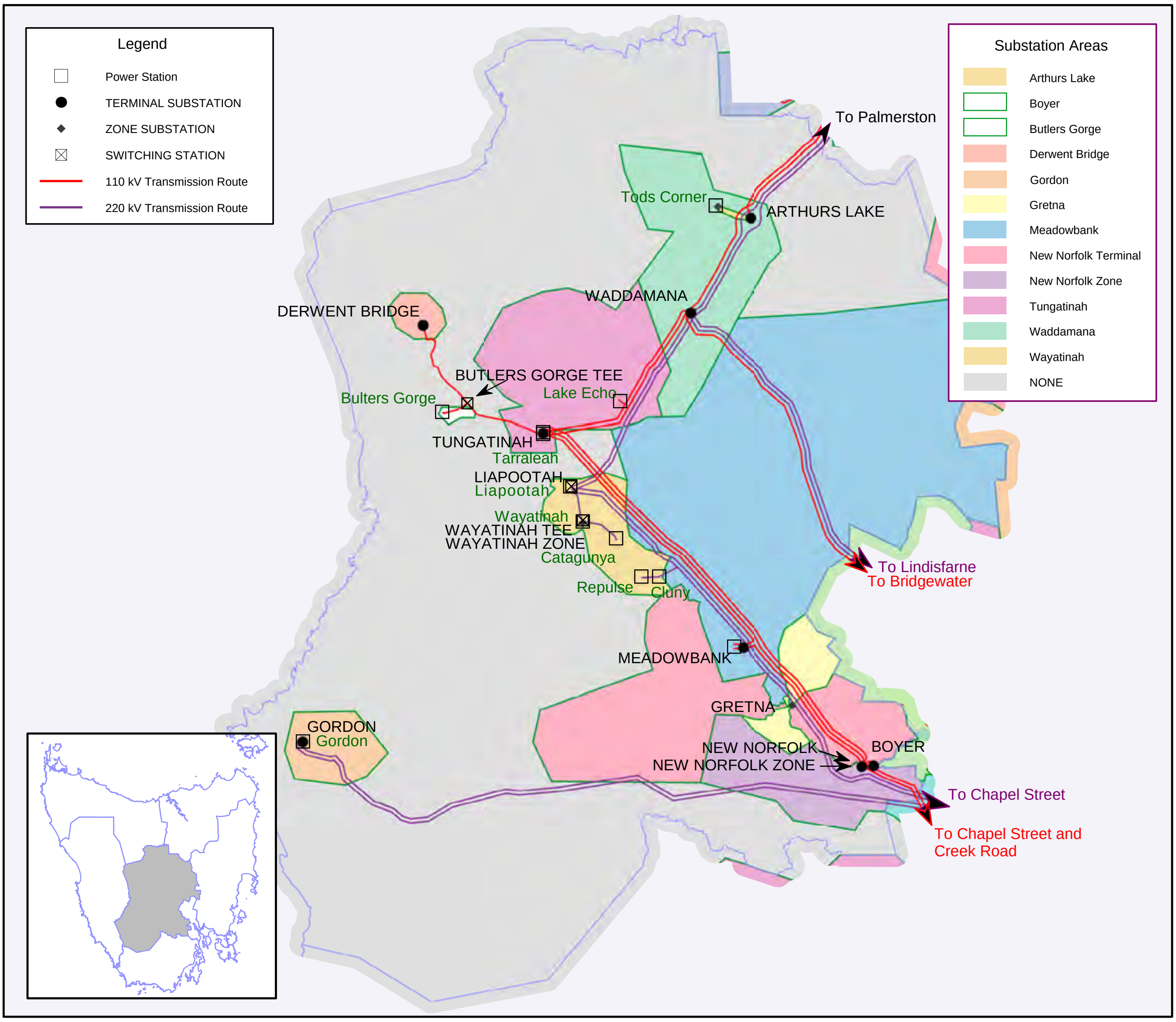

Figure 6-8: Central planning area network

6.7.1 Completed and committed developments

There is one committed project to redevelop New Norfolk Zone Substation, replacing the supply transformers and relocating the zone substation within New Norfolk Substation. There have been no material completed projects since last year's APR.

Table 6-17: Central planning area completed and committed developments

Project	Status	Description	Timing	Cost ($m)
Transmission line dead-end assembly upgrade program	Completed	We upgraded the dead-end assemblies of the Liapootah-Chapel Street 220 kV transmission line which were limiting the capacity of the transmission line	March 2018	0.1
New Norfolk Zone Substation redevelopment	Committed	The supply transformers and other assets at New Norfolk Zone Substation have reached end of life. The supply transformers will be replaced and the site relocated to within New Norfolk Substation	December 2018	2.4

6.7.2 Network developments

The proposed network developments in the Central planning area are outlined in Table 6-18. A reduction in demand may defer the limitation at Meadowbank Substation and the requirement for this is identified in Table 6-19.

Table 6-18: Central planning area network developments

Project	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Meadowbank Substation reliability improvement	Currently, loss of single supply transformer exceeds jurisdictional network performance requirement of 300 MWh of unserved energy	Establish a new feeder from Waddamana Substation to assist supply and reduce impact of loss of transformer at Meadowbank Substation	June 2022	0.8	No identified credible alternatives

Table 6-19: Meadowbank Substation reliability improvement deferral requirements

Location of load reduction	Load transfer capability (MVA)	Load reduction to defer constraint (MVA)	
		1 year	5 years
Meadowbank Substation	3.4	6.3	6.6

6.7.3 Network asset retirements and replacements

The asset retirements forecast within the Central planning area are identified in Table 6-20. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified.

Table 6-20: Central planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Boyer Substation	Supply transformers T13 and T14 at end of life	Replace supply transformers	2024	5.4	No identified credible alternatives
	6.6 kV switchgear at end of life	Replace 6.6 kV switchgear	2025	4.0	No identified credible alternatives
	Supply transformer T2 at end of life	Replace supply transformer	2026	1.7	No identified credible alternatives
Boyer, Gordon, Liapootah, Wayatinah substations	Protection schemes at end of life	Replace protection schemes	2019	1.1	No identified credible alternative
Derwent Bridge Substation	It is economic to retire Derwent Bridge Substation when opportunity arises to use the supply transformer elsewhere in the network rather than purchase a new unit	Decommission Derwent Bridge Substation and provide supply via new distribution line from Tungatinah Substation	TBD	2.6	Maintain Derwent Bridge Substation in service
	SCADA system at end of life	Replace SCADA equipment	2022	0.2	No identified credible alternative
Gretna Zone Substation	Switchgear and supply transformer at end of life	Replace switchgear and transformer	2022	1.9	No identified credible alternatives
New Norfolk Substation	22 kV switchgear at end of life	Replace 22 kV switchgear	2018	1.8	No identified credible alternatives
Waddamana Substation	Supply transformer T1 at end of life	Replace supply transformer with unit recovered from St Marys Substation	2023	0.3	No identified credible alternatives

6.7.4 Availability to connect to the network

Table 6-21 presents the continuous firm spare capacity currently available at substations in the Central planning area. All substations except New Norfolk Substation are single-transformer substations and inherently operate non-firm. For these substations, the available capacity shown is to the transformer capacity rather than the firm capacity.

Table 6-21: Central planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Arthurs Lake	0	18.2
Derwent Bridge	0	5.7
Meadowbank	0	2.7
New Norfolk	30	12.9
Tungatinah	0	23.9
Waddamana	0	4.4

6.8 Eastern planning area

The Eastern planning area extends along Tasmania's east coast from the Tasman Peninsula to St Helens, and extends inland to Campbell Town, Oatlands and Richmond. The area is largely rural with low population density, and with the main economic activities being agriculture and tourism along the east coast. Figure 6-9 presents a diagram of the Eastern area with substation supply areas and showing forecast limitations and planned investments.

The area is supplied from the main transmission network at 110 kV from Palmerston (near Poatina) and Lindisfarne substations. Sorell Substation is supplied via two circuits, with all other substations radially supplied. Our distribution network in the Eastern area is characterised by overhead feeders supplying large areas, with limited interconnection. There is no transmission-connected generation in the area.

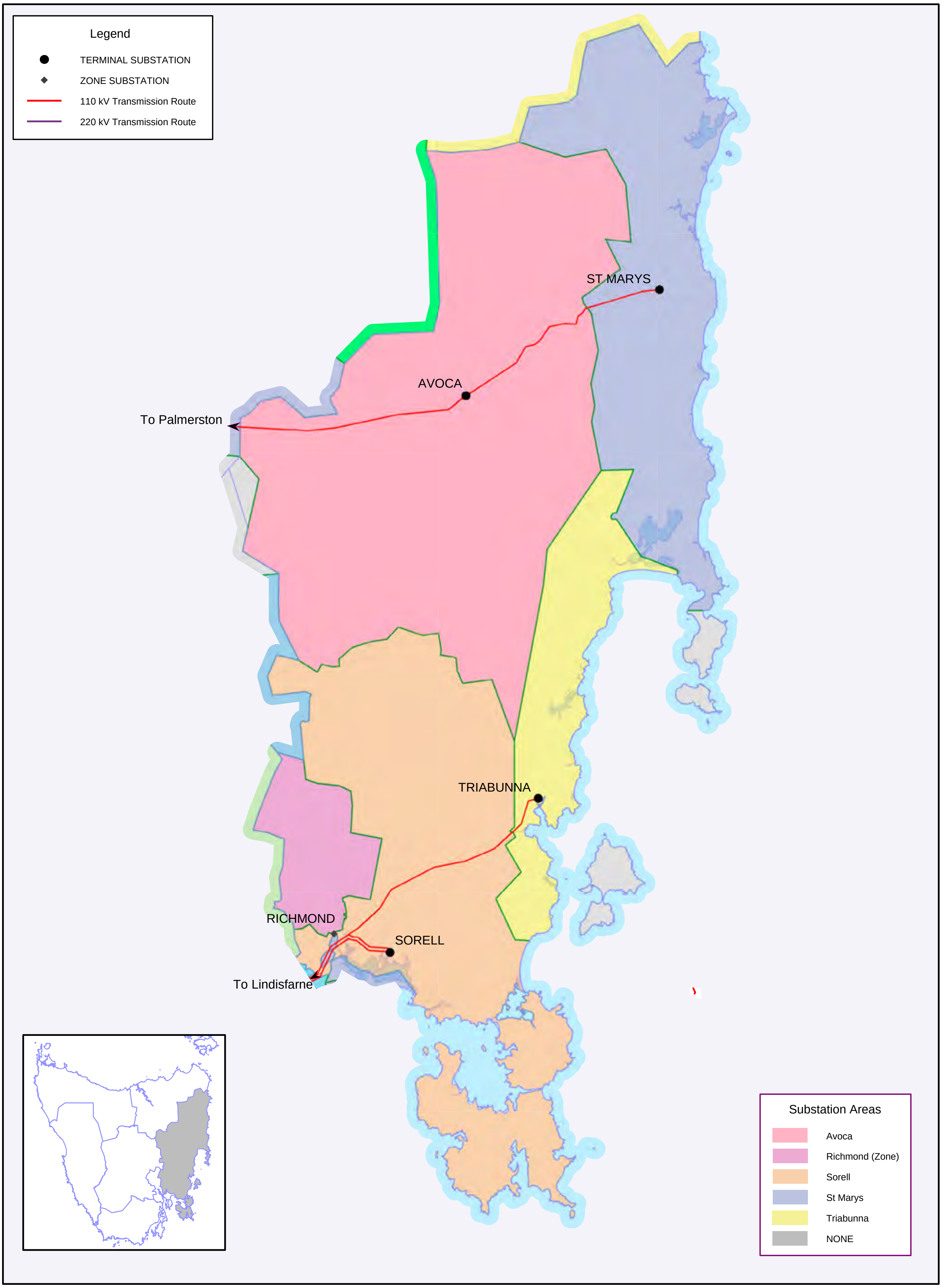

Figure 6-9: Eastern planning area network

6.8.1 Completed and committed developments

There are no committed projects in the Eastern planning area and there have been no material completed projects since last year's APR.

6.8.2 Network asset retirements and replacements

The asset retirements forecast within the Eastern planning area are identified in Table 6-22. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified.

Table 6-22: Eastern planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Sorell	22 kV switchgear at end of life	Replace switchgear	2019	1.9	No identified credible alternatives
Triabunna Spur 110 kV transmission line	Kay pole support structures assessed as approaching end of life by 2019	Replace Kay pole support structures	2019	0.5	No identified credible alternatives
St Marys Substation	Supply transformers at end of life	Replace supply transformers	2023	3.8	No identified credible alternatives

6.8.3 Local supply area limitations

6.8.3.1 St Marys Substation supply capacity

Maximum demand currently exceeds the short-term firm rating of supply transformers at St Marys Substation. We currently manage this limitation through a post-contingency load-shedding scheme. Unserved energy following a contingency is forecast to remain within our network planning requirement of 300 MWh over the planning period. The load transfer capability shown is the operational capability for short periods and under certain network conditions.

Table 6-23: St Marys Substation capacity limitation

Substation	Firm capacity (MVA)		Timing	Load transfer capability (MVA)	Load reduction to defer constraint (MVA)	
	Continuous	Short term			1 year	5 years
St Marys	10	12	Current	11.3	2.9	4.0

We propose to continue operating the post-contingency load-shedding scheme until the supply transformers are replaced due to asset condition as outlined in Table 6-22. The new standard units have sufficient capacity for existing and forecast demand growth at St Marys Substation.

6.8.3.2 Swansea, Bicheno and Coles Bay supply area capacity increase

The Swansea, Bicheno and Coles Bay supply area is supplied from two distribution lines – one each from Triabunna and St Marys substations. The network supplying this area has reached its capacity, with no capacity to supply any future load growth in the area.

Our preferred option is to increase supply capacity to the Swansea, Bicheno and Coles Bay supply area. We propose to extend an existing distribution line from Avoca Substation to the supply area to support our existing distribution lines.

The estimated cost of this project is $2.7 million and it is planned to be operational by June 2024.

6.8.4 Availability to connect to the network

Table 6-24 presents the continuous firm spare capacity currently available at substations in the Eastern planning area. Avoca Substation is a single-transformer substation and the available capacity shown here is the transformer capacity rather than the firm capacity. Available capacity at St Marys Substation is expected to increase following replacement of supply transformers, as highlighted in Section 6.8.3.1.

Table 6-24: Eastern planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Sorell	60	29.2
Triabunna	25	17.3
Avoca	0	7.3
St Marys	10	0

6.9 Greater Hobart planning area

The Greater Hobart planning area covers the eastern and western shores of Hobart, predominately the Hobart CBD and the municipalities of Glenorchy, Clarence and much of Brighton. It also includes the supply area from Bridgewater Substation which extends north to Kempton. There area is mostly urban, with rural supply into the area extending north. The majority of the load in the Greater Hobart area is a mixture of commercial, industrial and urban residential load. The area north to Kempton and South Arm, supplied from Rokeby Substation, is a predominately rural load. Figure 6-10 presents the Greater Hobart area with substation supply areas and showing forecast limitations and planned investments.

The area is generally supplied from our backbone transmission network at Chapel Street and Lindisfarne substations. The Greater Hobart planning area is the one area in Tasmania with a material sub-transmission network. Eleven zone substations are supplied from four connection points to supply Hobart's western and eastern shores. The distribution network is also supplied directly from transmission substations, as it is in the majority of our network. The area is supplied through a highly interconnected 11 kV distribution network. This allows load transfers between substations in outage and emergency situations. Rural areas are generally supplied via long 11 kV feeders with limited interconnection. There is one major energy user directly connected to our transmission network.

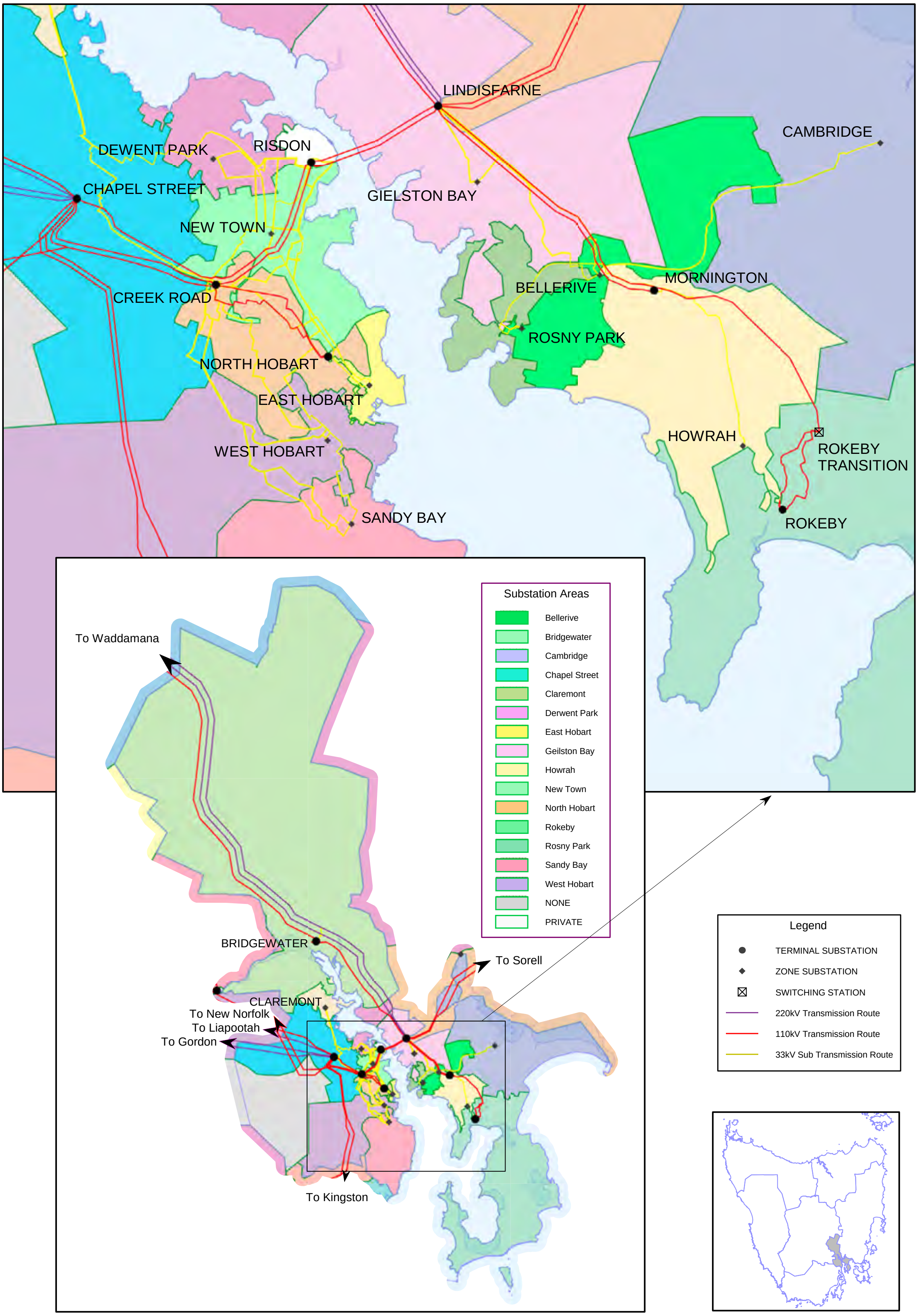

Figure 6-10: Greater Hobart planning area network

6.9.1 Completed and committed developments

There are two committed projects in the Greater Hobart planning area. There have been no material completed projects since last year's APR.

Table 6-25: Greater Hobart planning area completed and committed developments

Project	Status	Description	Timing	Cost ($m)
Lindisfarne Substation supply transformer replacements	Committed	The supply transformers at Lindisfarne Substation are being replaced due to their poor condition	June 2019	7.0
Waddamana-Bridgewater Junction 110 kV transmission line decommissioning	Committed	The Waddamana-Bridgewater Junction 110 kV transmission line is being decommissioned due to its poor condition. A second supply will be provided to Bridgewater Substation by energising an existing unused circuit from Lindisfarne Substation	September 2019	5.0

6.9.2 Network developments

The proposed network developments in the Greater Hobart planning area are outlined in Table 6-26. Reduction in demand may defer the limitations on our 33 kV sub-transmission network and the requirement for this is identified in Table 6-27. Power factor improvement is not a viable option to defer this limitation as the MW load is in excess of the MVA rating of the sub-transmission lines.

Table 6-26: Greater Hobart planning area network developments

Project	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Hobart CBD supply upgrade	The 11 kV distribution network supplying the Hobart CBD supply area has a number of capacity, reliability and asset condition issues	Program to redevelop feeder interconnections and distribution solutions	2019 to 2029	3.5	No identified credible alternatives
Hobart 33 kV sub-transmission upgrade	Currently in summer, demand exceeds the firm rating of five sub-transmission corridors in Hobart	Upgrade sub-transmission capacity through conductor replacement, increased operating temperature and re-rate or short-term rate underground cable sections	June 2025	2.0	No identified credible alternatives

Table 6-27: Hobart 33 kV sub-transmission upgrade limitation deferral requirements

Sub-transmission lines	Location of load reduction	Load reduction to defer constraint (MVA)	
		1 year	5 years
Risdon-New Town	New Town Zone Substation	4.8	6.2
Risdon-Derwent Park	Derwent Park Zone Substation	1.5	2.7
Creek Road-West Hobart	West Hobart Zone Substation	1.0	2.7
Risdon-East Hobart	East Hobart Zone Substation	1.8	4.3
Creek Road-Claremont	Creek Road Zone Substation	0.4	1.5

6.9.3 Network asset retirements and replacements

The asset retirements forecast within the Greater Hobart planning area are identified in Table 6-28. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified. Investment is in the replacement of supply transformers, transmission cables, switchgear, and protection and control systems utilised in our Hobart CBD distribution network.

Table 6-28: Greater Hobart planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Bellerive Zone Substation	Station service transformer at end life	Replace transformer	2021	0.1	No identified credible alternatives
	Supply transformers at end of life	Replace transformers	2025	3.3	No identified credible alternatives
Chapel Street Substation	Busbar and transformer protection schemes at end life	Replace busbar and transformer protection schemes	2019	2.0	No identified credible alternatives
	11 kV switchgear at end life	Replace 11 kV switchgear	2023	3.7	No identified credible alternatives
Lindisfarne Substation	Busbar protection scheme at end life	Replace busbar protection scheme	2019	0.4	No identified credible alternatives
Claremont Zone Substation	Supply transformers at end of life	Replace transformers	2019	3.0	No identified credible alternatives
Derwent Park Zone Substation	Supply transformers at end of life	Replace transformers	2019	3.0	No identified credible alternatives
	Station service transformer at end life	Replace transformer	2020	0.2	No identified credible alternatives
Geilston Bay Zone Substation	Station service transformer at end life	Replace transformer	2020	0.1	No identified credible alternatives
	Supply transformers at end of life	Replace transformers	2025	3.3	No identified credible alternatives
Hobart CBD supply area	Control and protection schemes at end life	Replacement and upgrade of protection and control schemes	2018 to 2028	3.7	No identified credible alternatives
New Town Zone Substation	Station service transformer at end life	Replace transformer	2022	0.1	No identified credible alternatives
North Hobart Substation	11 kV switchgear assessed as approaching end of life	Replace 11 kV switchboard	2019	4.6	No identified credible alternatives
	Supply transformers T1 & T2 approaching end of life	Life extension refurbishments	2019	0.4	Life extensions
	Control and protection schemes at end of economic life	Replace transformer and feeder protection and control systems	2019	0.6	No identified credible alternatives
Zone substations	Batteries, HMI & security systems at end of economic life	Equipment replacements	2028	1.4	No identified credible alternatives
	AVR replacements at Derwent Park, New Town & Sandy Bay at end of economic life	Replace AVR	2020	0.1	No identified credible alternatives

6.9.4 Deferred or averted limitations and network developments

6.9.4.1 Chapel Street Substation 110 kV security augmentation

In last year's APR, we proposed installing a second, in-series, 110 kV bus coupler circuit breaker at Chapel Street Substation. This project was to minimise the impact of a bus coupler circuit breaker fault, which would result in loss of both 110 kV busbars. This project formed part of our NCIPAP investment plan for the 2014-19 regulatory period. Subsequently, the proposed cost for this project increased from the original estimate and a more efficient solution was identified. We will alter the arrangement of particular assets in the 110 kV switchyard to minimise the impact of a bus coupler circuit breaker fault. The security augmentation project has since been removed from our NCIPAP investment plan for the 2014-19 regulatory period.

6.9.4.2 Derwent Park Zone, New Town Zone and North Hobart substations transformer capacity

Last year's APR identified the maximum demands at Derwent Park Zone, New Town Zone and North Hobart substations were forecast to exceed the short-term firm ratings of the supply transformers in 2023 (Derwent Park Zone), 2018 (New Town Zone) and 2025 (North Hobart). Due to a reduction in forecast load growth, and an actual reduction in load at New Town Zone Substation, these limitations are now not forecast to occur within the current planning period.

6.9.5 Availability to connect to our network

Table 6-29 presents the continuous firm spare capacity currently available at substations in the Greater Hobart planning area. Available capacity at Lindisfarne Substation is expected to increase following replacement of supply transformers, as presented in Section 6.9.3.

Table 6-29: Greater Hobart planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Creek Road	120	27.2
Risdon	100	29.3
Bridgewater	35	2.8
Chapel Street	60	20.8
North Hobart	45	8.3
Claremont Zone	22.5	0.2
Derwent Park Zone	22.5	2.1
New Town Zone	22.5	0.7
East Hobart Zone	60	32.2
West Hobart Zone	60	21.9
Sandy Bay Zone	60	26.2
Lindisfarne	45	9.3
Mornington	60	15.2
Rokeby	35	15.0
Bellerive Zone	22.5	11.5
Cambridge Zone	20	4.5
Geilston Bay Zone	22.5	4.8
Howrah Zone	22.5	0.5
Rosny Park Zone	0	8.9

6.10 Kingston-South planning area

The Kingston-South planning area covers the area south of Hobart and includes the Kingborough and Huon Valley areas of Tasmania, including Bruny Island. The area is characterised by the urban area around Kingston, with the rest of the area predominantly rural. Figure 6-11 presents a diagram of the Kingston-South area with substation supply areas and showing forecast limitations and planned investments.

The area is supplied via a double-circuit 110 kV transmission line from Chapel Street Substation. The distribution network is operated at 11 kV.

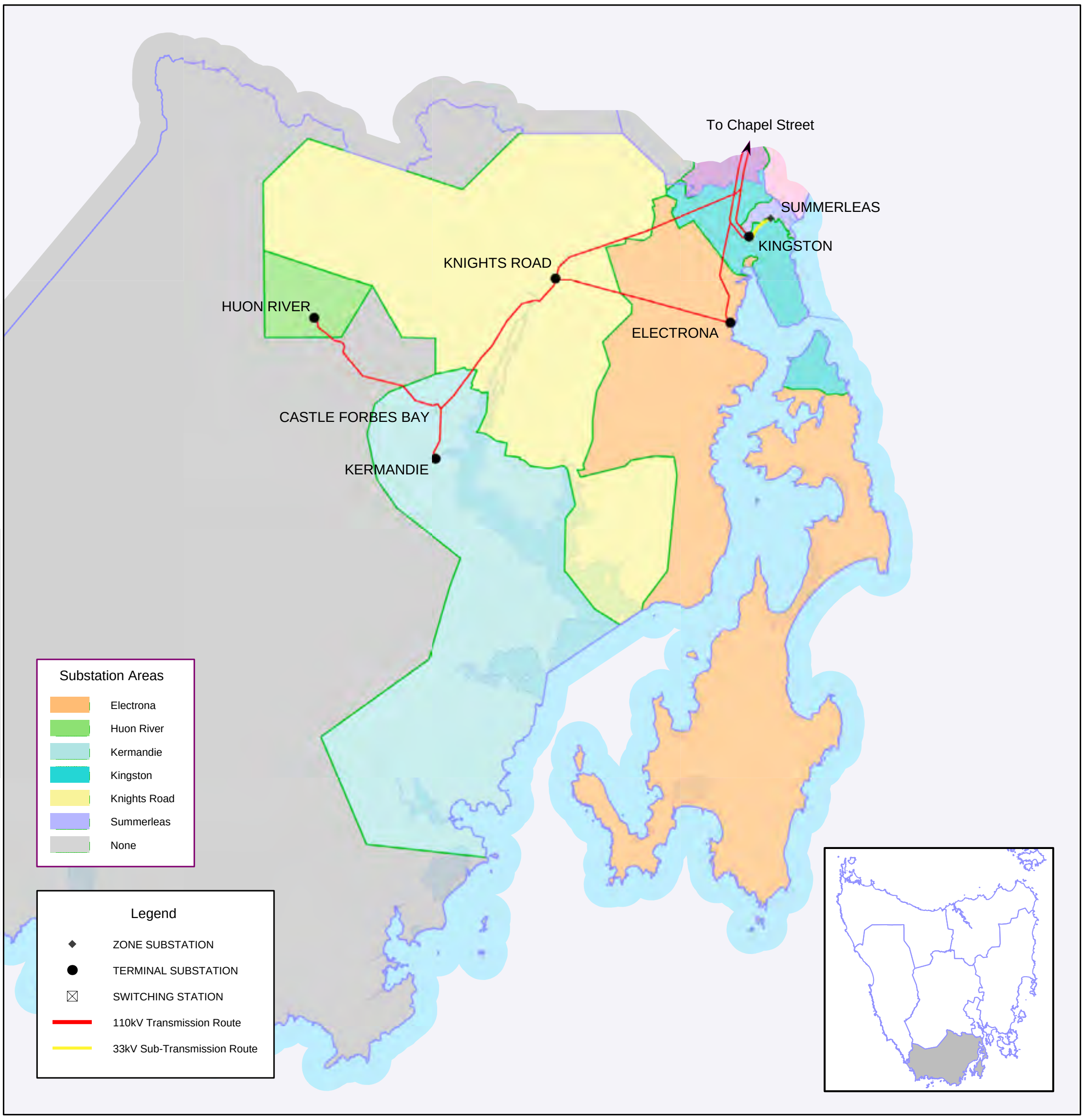

Figure 6-11: Kingston-South planning area network

6.10.1 Completed and committed developments

There are no committed projects in the Kingston-South planning area and there have been no material completed projects since last year's APR.

6.10.2 Network developments

The one proposed network development in the Kingston-South planning area, presented in Table 6-30, is to establish a new distribution feeder from Knights Road Substation to address the overload on an existing distribution feeder from the substation. The requirement in demand reduction to defer the limitation is identified in Table 6-31. Power factor improvement is not a viable option to defer this limitation as the MW load is in excess of the MVA rating of the distribution feeders.

Table 6-30: Kingston-South planning area network developments

Project	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Knights Road Substation new distribution feeder	Currently in summer, distribution feeder 30603 from Knights Road Substation is overloaded	Establish a new distribution feeder from Knights Road Substation	June 2019	0.9	Establish a new distribution feeder from Huon River Substation

Table 6-31: Knights Road Substation new distribution feeder limitation deferral requirements

Project	Location of load reduction	Existing power factor	Load reduction to defer constraint (A)	
			1 year	5 years
Knights Road Substation new distribution feeder	Knights Road Substation feeder 30603	0.99	34	27

6.10.3 Network asset retirements and replacements

The asset retirements forecast within the Kingston-South planning area are identified in Table 6-32. Our proposed solution for these retirements is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified. Investment is in the replacement of switchgear transformers at Kermandie and Knights Road substations.

Table 6-32: Kingston-South planning area network asset retirements and replacements

Location	Description	Proposed solution	Timing	Cost ($m)	Other potential solutions
Kermandie Substation	Switchgear and supply transformers at end of life	Replace switchgear and supply transformers	2024	3.1	No identified credible alternatives
Knights Road Substations	Switchgear and supply transformers at end of life	Replace switchgear and supply transformers	2024	1.8	No identified credible alternatives

6.10.4 Local supply area limitations

6.10.4.1 Summerleas Zone Substation distribution feeder 32379 overload

Currently, distribution feeder 32379 from Summerleas Zone Substation is overloaded in winter. To address this limitation, we propose work in our distribution network to permanently transfer load away from the affected feeder. Table 6-33 identifies the load reduction requirements to defer this constraint.

Table 6-33: Summerleas Zone Substation distribution feeder 32379 overload

Location	Capacity (A)	Timing	Load reduction to defer constraint (A)	
			1 year	5 years
Summerleas Zone Substation feeder 32379	239	Current	18	30

6.10.5 Availability to connect to the network

Table 6-34 presents the continuous firm spare capacity currently available at substations in the Kingston-South planning area. Summerleas Zone Substation is a single-transformer substation and the available capacity shown here is to the transformer capacity rather than the firm capacity. Available capacity at Kermandie Substation is expected to increase following replacement of supply transformers, as presented in Section 6.10.3.

Table 6-34: Kingston-South planning area substation capacity availability

Substation	Firm capacity (MVA)	Available capacity (MVA)
Electrona	25	5.4
Kermandie	10	3.3
Kingston (33 kV)	60	45.8
Kingston (11 kV)	35	9.9
Knights Road	20	0.6
Summerleas Zone	0	12.7

6.11 Statewide asset investment programs

This section presents our investments in statewide asset programs. These investments are predominantly replacement programs for assets we have identified to be retired due to reaching at end of life because of asset condition, economics, obsolescence and other factors defined in our asset management strategies. For these assets, our proposed solution is to replace the asset like-for-like with new, modern equivalents. No other credible potential options have been identified.

Table 6-35 presents our statewide asset investment programs, classified by network and asset class. It provides a description of the programs and our annual investments over the planning period 2018 to 2028. Our expenditure for 2018-19 was correct at the time of writing, however will change as we finalise our program of work for this coming year. Expenditure here includes the individual asset replacement expenditure presented in each planning area.

Table 6-35: Statewide asset investment programs

Network, asset class and description	Cost ($m)									
	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
Distribution network										
Distribution overhead										
Asset replacement and upgrade	46.9	34.5	32.7	31.3	30.7	32.9	33.6	35.3	37.8	37.9
Initiatives to limit the potential of assets initiating bushfires	8.7	17.3	17.3	17.3	9.1	9.1	7.9	7.9	7.9	7.9
Innovations and equipment trials	0.1	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Threatened bird species fatality mitigation	0.74	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
High voltage regulators										
Asset replacement	0.0	0.5	0.06	0.5	0.06	0.5	0.06	0.5	0.06	0.5
Safety and environmental programs	0.4	0.4	0.0	0.4	0.0	0.4	0.0	0.4	0.0	0.4
High voltage and low voltage cables										
Asset replacement and upgrade (underground cables)	1.7	2.7	1.7	2.7	1.2	2.5	1.0	3.1	1.0	2.5
Replacement of low voltage Consac cables	5.3	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Ground substations										
Asset replacement and upgrade	6.5	3.7	3.7	3.8	4.0	4.0	3.6	3.8	3.8	4.0
Safety and environmental programs	0.05	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Transmission network										
Transmission lines										
Asset replacement and upgrade	5.8	5.3	5.6	7.3	4.0	5.2	6.0	5.6	7.5	7.1
Substandard clearance rectification	1.0	1.2	1.2	1.2	0.2	0.2	0.2	0.2	0.2	0.2
Transmission substations										
Asset replacement and upgrade	12.9	2.9	12.6	10.8	2.2	4.2	9.8	4.3	6.6	13.9
Substation and management system innovations and improvements	0.0	0.3	0.8	1.5	0.8	0.3	0.3	0.0	0.3	0.3
Protection and control (distribution and transmission)										
Asset replacement and upgrade	3.8	6.1	5.4	5.4	5.8	5.8	7.4	7.7	7.7	7.7
Innovation and key projects	0.6	0.3	0.5	0.2	0.2	0.2	0.05	0.05	0.05	0.05
Low voltage services										
New and refurbishment of assets to customer installations	5.7	8.4	8.1	8.0	8.0	7.8	5.5	5.5	5.5	5.5
New and refurbishment of public lighting assets	3.7	3.9	3.7	2.1	2.0	2.1	2.1	2.1	2.1	2.1
Residual metering, meter panel and instrument transformer responsibilities	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

6.12 Investments in network information and communication systems

6.12.1 Network information systems programs

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

- reduced risk of asset failure;
- enhanced network performance;
- enhanced compliance with regulatory and governance requirements;
- effective collection and management of asset knowledge;
- effective resource utilisation; and
- optimum infrastructure investment.

This section details our investments in regulated information systems programs in our distribution and transmission network.

6.12.1.1 Investment in 2016-17

Our regulated investments in network information systems programs in 2016–17 is summarised in Table 6-36.

Table 6-36: Regulated investment in network information systems in 2016-17

Project	Description	Investment ($000)
Asset knowledge management	Deliver a suite of integrated data standards to support our asset management information system	429
Vegetation management system design	Design a replacement vegetation management system to fulfil business requirements	285
Geovisualisation technology implementation	Implement foundation spatial viewing technology in preparation for SAP and WebMap replacement project	709
WebMap replacement	Commence replacement of out of date geovisualisation tool (WebMap)	425
Network asset data model development and transformation	Commence development of new asset data models, asset data configuration and transformation in readiness for SAP	600

6.12.1.2 Investment in forward planning period

Our planned investments in network information systems programs in the forward planning period is in Table 6-37.

Table 6-37: Network information systems expected investment forward planning period

Project	Description	Timing	Investment ($000)
Vegetation management system	Complete the design and implementation of the vegetation management system	2018	2539
Asset knowledge management	Deliver a suite of integrated data standards to support the asset management information system	2018	17
WebMap replacement project	Implement the NetMap solution and decommission the legacy WebMap solution	2018	611
Network asset data model development and transformation	Complete development of new asset data models, asset data configuration and transformation in readiness for SAP	2018	1400
Asset condition monitoring	Improving and consolidating asset condition monitoring and reporting capability. This includes asset inspection and condition, asset defects and incidents	2021 to 2022	572
Asset technical drawings	Enhancing the engineering drawing management system	2019 to 2020	1500
Asset planning	Improving and consolidating asset planning capability. This includes asset repair/refurbish/replace decision making	2020 to 2021	500
Asset risk management	Developing and enhancing systems and models to assess asset criticality and failure probabilities	2022 to 2028	1500
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	2018 to 2028	4200
Asset register enhancement, technical, operational and geospatial information improvements	Undertake a program to enhance asset modelling systems, the asset register and network data configuration to support business priorities and continual improvement in asset management maturity	2018 to 2028	7000

6.12.2 Communications systems

Our telecommunications network supports operation of our electricity network interfacing protection, control and data, phone handsets and mobile radio transceivers. It also serves customers in the electricity supply industry, and is utilised by other parties under commercial agreements. Our 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 powerline carrier equipment.

This section details our investments in regulated communications systems programs in our distribution and transmission network.

6.12.2.1 Investment in 2016-17

Our regulated investments in communications systems programs in 2016-17 is summarised in Table 6-38.

Table 6-38: Regulated investment in communications systems in 2016-17

Project	Description	Investment ($000)
Infrastructure	Telecommunication sites	612
Bearer systems	Backbone bearers for telecommunications	559
Ethernet systems	Ethernet equipment	155
Phone systems	Phone / speech network	809
Multiplexer systems	Multiplexer systems in the networks	80
Telecommunications NMS systems	Telecommunications NMS system	0

6.12.2.2 Investment in forward planning period

Our planned regulated investments in communications systems programs in the forward planning period is in Table 6-39. The majority of these are ongoing programs, with the investment our commitment over the duration of the program.

Table 6-39: Regulated investment in communications systems in the forward planning period

Project	Description	Timing	Investment ($000)
Infrastructure	Telecommunication sites	2018 to 2028	1293
Bearer systems	Backbone bearers for telecommunications	2018-19	7362
Ethernet systems	Ethernet equipment	2018 to 2028	3744
Phone systems	Phone / speech network	2018 to 2027	5493
Multiplexer systems	Multiplexer systems in the networks	2018 to 2027	10,361
Telecommunications NMS systems	Telecommunications NMS system	2018 to 2028	3331

7 INFORMATION FOR NEW TRANSMISSION NETWORK CONNECTIONS

This chapter presents information that 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 that make it unique in the NEM. These characteristics can have an impact on the connection of generating systems or large loads.

Significant changes to the Rules will occur from 30 June 2018 in relation to the management of rate of change of power system frequency and power system fault levels. We have already implemented the NEM's first RoCoF constraint equation and supported AEMO in the development of its system strength impact assessment guidelines.[103]

7.1 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 network successfully, without interference or mal-operation of electrical equipment.

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

7.1.1 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.

7.1.2 Performance criteria

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 and 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.

7.1.3 Planning levels and strategies

7.1.3.1 Voltage fluctuations and voltage waveform distortion

Schedules 5.1.5 and 5.1.6 of the Rules require a NSP to determine "planning levels" for connection points in its network. Our calculated planning levels are presented in Appendix E.

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.

7.1.3.2 Under voltage performance

The Rules do not contain a system standard for recovery from under voltage. We have therefore developed an under-voltage recovery guideline, which we use as the basis for assessing whether the voltage recovery

103 www.aemo.com.au/Stakeholder-Consultation/Consultations/Power-System-Model-Guidelines-and-System-Strength-Impact-Assessment-Guidelines

performance of equipment is acceptable. This guideline is included in Appendix E.

While 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.

7.1.4 Performance monitoring

The increasing participation of power electronic sources of energy over the past decade has resulted in the power system being operated closer to technical 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 our 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, 110 kV and 22 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 E.

(a) Temporary over voltage performance

Some remote parts of our 110 kV network are at risk of single phase TOV during unbalanced line-ground faults. In particular, our 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 suitable transformers are specified to block zero phase sequence voltages.

(b) Voltage unbalance performance

Voltage unbalance is within planning levels for at least 95% of the time (annual probability) at all monitored busbars except Smithton 110 kV. For less than 5% of the time, the 10-minute average values vary typically between 0.5% and 1.6% of nominal voltage, outside of the specified level of 1%.

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

Voltage unbalance has not caused operational limitations for either our transmission network or customer plant. We are continuing to monitor voltage unbalance at multiple locations to ensure our transmission network continues to operate within system standards and Rules. In doing so, we are ensuring 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% of the time (annual probability) with some excursions above the planning levels noted for less than 1% of the time.

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

(d) Harmonic performance

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

The 5th harmonic is of particular interest for our 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 our 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 our network is influenced by the connected equipment of our customers. As customers' equipment changes over time, the harmonic performance of our 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.

7.2 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, known as Market Ancillary Services under the Rules[104], 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 TNSP; it is a service supplied by the market and thus AEMO is responsible for ensuring sufficient FCAS is dispatched. During each dispatch interval, AEMO must enable sufficient FCAS to meet system requirements.

There are eight 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 generating units. The provision of FCAS in the longer timeframes of 60 seconds and five minutes is easier to achieve, as hydro generating units are generally unhindered by temperature and fuel supply issues that tend to constrain the ramping capability of thermal generating units.

To limit the requirement for Fast Raise FCAS, the Tasmanian Frequency Operating Standards[105] limit the maximum credible generation contingency size to 144 MW. Generating units operating above this output must implement suitable measures to effectively limit the maximum generation contingency to 144 MW. This may be accomplished via a tripping scheme to quickly disconnect an appropriately sized load in response to the generation'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. We are 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. Its impact on the Tasmanian frequency is mitigated through the implementation of a FCSPS. The FCSPS acts to limit frequency deviations in Tasmania by rapidly disconnecting appropriate generation 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. We own and maintain 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 asynchronous generation (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 with our RoCoF constraint equation. The constraint equation limits asynchronous generation and/or Basslink import, to contain the rate of change of frequency following a credible contingency event. This achieves two outcomes:

1. ensures 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; and
2. ensures RoCoF elements forming part of the existing design of the Tasmanian Under Frequency Loading Shedding Scheme do not operate for credible contingency events

A recent rule change[106] associated with limiting RoCoF will come into force on 1 July 2018 and provided for us to become an Inertia Service Provider[107] and AEMO to:

- divide the connected transmission systems forming part of the national grid into inertia sub-networks,
- determine the inertia requirements for each inertia sub-network;
- as part of market operations, enable inertia network services; and
- assess whether there is or is likely to be an inertia shortfall in any inertia sub-network and accordingly publish and advise inertia service providers.

As an Inertia Service Provider we must:

- use reasonable endeavours to make the inertia network services available;

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104 *Market Ancillary Services, the Rules, Clause 3.11.2*

105 *www.aemc.gov.au/markets-reviews-advice/tasmanian-reliability-and-frequency-standards-revi*

106 *www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque*

107 *Inertia Service Provider, the Rules, Clause 5.20B.4(a)*

- make a range and level of inertia network services available such that it is reasonably likely that inertia network services when enabled are continuously available; and
- maintain the availability of those inertia network services until the date the Inertia Service Provider's obligation ceases, as specified by AEMO.

The inertia network services that qualify to provide inertia are inertia network services made available:

- by the Inertia Service Provider investing in its network through the installation, commissioning and operation of a synchronous condenser; and
- to the Inertia Service Provider by a registered participant and provided by means of a synchronous generating unit or a synchronous condenser under an inertia services agreement.

AEMO must develop and publish a methodology setting out the process it will use to determine the inertia requirements for each inertia sub-network. The methodology is developed as part of the NTNDP process. However, AEMO is preparing an ISP and as the ISP's purpose and scope encompass those which would normally be covered in the NTNDP, the AER has permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the ISP.[108]

7.3 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 PV) are such that they are not equivalent and cannot be directly substituted in place of synchronous machines. Two characteristics that 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 PV 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 asynchronous generation en masse. Modifications to FCAS calculations, and the implementation of the first RoCoF 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 asynchronous generation if sufficient inertia and/or fault level is not available. 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), asynchronous 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 to reduce or eliminate constraints that are in accordance with the latest rule changes.

We are committed to understanding the issues outlined above. We continue to work 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.

7.4 Connection and integration of additional wind or solar generation

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

Connection issues can be considered the local issues that asynchronous generation 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 asynchronous generation. Integration issues apply more broadly to any type of asynchronous generation.

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108 www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

7.4.1 Connection issues

7.4.1.1 Short circuit ratio

Most asynchronous generation requires 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 three phase fault level (in MVA) at the connection point by the MW rating of the asynchronous generation. Many of Tasmania's best wind resource areas are often remote from our main network and present inherently low short circuit ratios. Existing wind farms may have already absorbed much of the available fault level in their locality, meaning future wind farms will connect to an effectively weaker power system.

A recent rule change[109] associated with managing power system fault levels in relation to a new or altered generating system or market network service facility requires NSPs to undertake and provide a system strength impact assessment comprising:

- a preliminary assessment; and
- a full assessment if the preliminary assessment indicates one is required.

In addition, should the connection applicant not implement a system strength remediation scheme agreed under their connection agreement, then NSPs must undertake system strength connection works at the cost of the applicant if the full assessment indicates the new connection or the alteration to a generating system will have an adverse system strength impact.

AEMO must develop and publish system strength impact assessment guidelines that set out the methodology to be used by NSPs when undertaking system strength impact assessments. Accordingly, AEMO has developed Power System Model and System Strength Impact Assessment Guidelines.[110]

7.4.1.2 Reactive power requirements

The reactive power capability (i.e. its size and response characteristics) asynchronous generation requires to meet network access standards is heavily influenced by the network location at which the asynchronous generation is to be connected.

7.4.2 Integration issues

7.4.2.1 Displacement of synchronous generation

At a higher level, consideration must be given to the impact asynchronous generation will have on the overall power system and in particular the displacement of traditional synchronous generation that could occur. Since synchronous generation supplies the power system with the bulk of its FCAS and the bulk of its inertia, its displacement makes these services scarcer. Further displacement of synchronous generation by asynchronous generation could ultimately place constraints upon the level of wind and other asynchronous 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 generation by asynchronous generation will reduce the fault level at George Town Substation, making the voltage at George Town Substation more difficult to control.

7.4.2.2 Isolated operation

If asynchronous generation is located where it (along with other loads or generation) could become isolated from our main network, the asynchronous generation must incorporate an anti-islanding protection scheme. We require this, as part of the Rules, to ensure the security and power quality of our network for our customers is not compromised.

7.4.3 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 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.

109 www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

110 www.aemo.com.au/Stakeholder-Consultation/Consultations/Power-System-Model-Guidelines-and-System-Strength-Impact-Assessment-Guidelines

GLOSSARY

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 our electricity network to mainland Australia.
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 our 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 that 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 that has received board commitment, funding approval, has satisfied the RIT (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 our transmission network to meet Tasmanian energy sales. It comprises the energy sent 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 used in Tasmania for a particular period.
extra-high voltage (EHV)	In our network, nominal voltages of 110 kV and 220 kV.
fault level	The amount of current that would flow if a short circuit occurred at a specified location in the network. From a power system planning and operation perspective, fault level is also an indicator of network resilience: a portion of the network with high fault levels is less likely to be affected by faults elsewhere in the network.

firm	Indicates 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.
high voltage (HV)	Voltage greater than 1 kV. [R]
inertia	The rotating mass inside a generator. The more inertia a power system contains, the more slowly its frequency will deviate from 50 Hz following a contingency event. Only generators that are running (and therefore spinning) contribute inertia to a power system.
island	A part of our network that 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 2018.
kilo-Volt	One kilo-Volt equals 1000 Volts. See also: voltage.
low voltage (LV)	In the Tasmanian network, nominal voltage of 400 Volts or 230 Volts.
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 NSP 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 AER. Basslink is the only MNSP in the NEM. [R]
medium voltage (MV)	In the Tasmanian network, nominal voltages of 11kV, 22kV, 33kV and 44kV.
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 a contingent event in 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 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	National Electricity Rules.
static compensator (STATCOM)	A device that helps regulate voltage in the network.

substation	An installation of electrical infrastructure at a strategic location in 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 in 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 (i.e. coal-fired) turbines. 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 customers. In Tasmania, the transmission network comprises 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]

ABBREVIATIONS

AC	Alternating current
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMP	Asset Management Plan
APR	Annual Planning Report
ARENA	Australian Renewable Energy Agency
AS	Australian Standards
CAPEX	Capital expenditure
CBD	Central business district
CCGT	Combined cycle gas turbine
CESS	Capital Expenditure Sharing Scheme
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	Direct current
DER	Distributed energy resources
DLF	Distribution loss factor
DMIA	Demand Management Innovation Allowance
EBSS	Efficiency Benefit Sharing Scheme
EHV	Extra-high voltage
ESI	Electricity Supply Industry
FCAS	Frequency control ancillary services
FCSPS	Frequency Control System Protection Scheme
GSL	Guaranteed Service Level
GSP	Gross state product
GWh	Gigawatt-hour
Ha	Hectare
HV	High voltage
HVDC	High voltage direct current
Hz	Hertz
IEC	International Electrotechnical Commission

ISP	Integrated System Plan
kA	Kiloamps
kV	Kilovolts
LOS	Loss of supply
MAIFI	Momentary System Average Interruption Frequency Index
MAR	Maximum allowable revenue
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
NEO	National Electricity Objective
NEMDE	National Electricity Market Dispatch Engine
NIEIR	National Institute of Economic and Industry Research
NSCAS	Network Support and Control Ancillary Services
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
NZS	New Zealand Standards
OCGT	Open cycle gas turbine
OPEX	Operational expenditure
OTTER	Office of the Tasmanian Economic Regulator
PASA	Projected assessment of system adequacy

POE	Probability of exceedance
PSFR	Power system frequency risk
PU	Per unit
PV	Photovoltaic [solar generation system]
RAPS	Remote area power supply
RIT	Regulatory investment test
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
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
STATCOM	Static compensator
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission network service provider
TOV	Temporary over voltage
TR	Technical report
TS	Technical specification

APPENDIX A INCENTIVE SCHEMES

As part of the regulatory framework, both the AER and OTTER apply a number of incentive schemes to encourage NSPs to make efficient spending decisions in the long-term interests of customers. Balanced incentives encourage businesses to continually improve spending efficiency without compromising network service and performance.

Most incentives are recovered through adjustments to our MAR. This is passed to customers as an increase or decrease to network prices annually or as part of our revenue setting process (depending on the incentive scheme).

A.1 Service Target Performance Incentive Schemes

STPIS for transmission and distribution provide financial rewards to network businesses for improvements in performance, and penalties for reduction in performance.

The STPIS for transmission comprises three components: service, market impact and network capability. The STPIS for distribution has two components: reliability of supply and customer service.

A.2 Guaranteed Service Level

We are subject to a GSL administered by OTTER. The STPIS includes a GSL scheme but where there is already a state scheme in place, the state scheme applies.

The purpose of the scheme is to encourage us to restore power in a timely manner following an outage. Where an outage is not restored within the required timeframe, or exceeds the acceptable number of outages for a year, we are required to make a payment to affected customers. The acceptable duration and number of outages depends on the reliability classification of the customer connection.

A.3 Efficiency Benefit Sharing Scheme

The EBSS provides financial rewards to network businesses that underspend on regulated services OPEX and sustain the savings over time. The EBSS also penalises network businesses that overspend against the allowance and/or do not sustain savings over time. There are separate schemes for transmission and distribution based on very similar principles.

The EBSS works on the principle that OPEX in a year "resets" the efficient level of OPEX under the EBSS. Performance is measured against this new EBSS target and the operating allowance that is set as part of a regulatory determination cycle. A network may retain any annual efficiency gain for a period of five years and is penalised for any inefficiency for five years.

A.4 Capital Expenditure Sharing Scheme

The CESS creates an incentive for network businesses to undertake efficient CAPEX during each regulatory control period. Businesses are rewarded for spending less than the regulatory allowance or penalised for spending over the allowance.

The AER conducts reviews of CAPEX in setting the CAPEX allowance and again at the end of each regulatory period to ensure customers do not bear the costs of inefficient overspend compared to the allowance. CESS bonuses or penalties are taken into account when calculating allowed revenue in the next revenue decision.

A.5 Demand Management Innovation Allowance

The DMIA is utilised by us as part of the Demand Management Incentive Scheme applied by the AER. It provides an allowance for networks to investigate innovative demand management solutions. We have been utilising the DMIA to fund development of customer-owned storage as a peak demand management tool and for investigating the impact of demand-based tariffs for reducing peak demand.

APPENDIX B FAULT LEVEL AND SEQUENCE IMPEDACES

We calculate fault currents at transmission network substations in accordance with the recommendations of 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 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/2 fR.

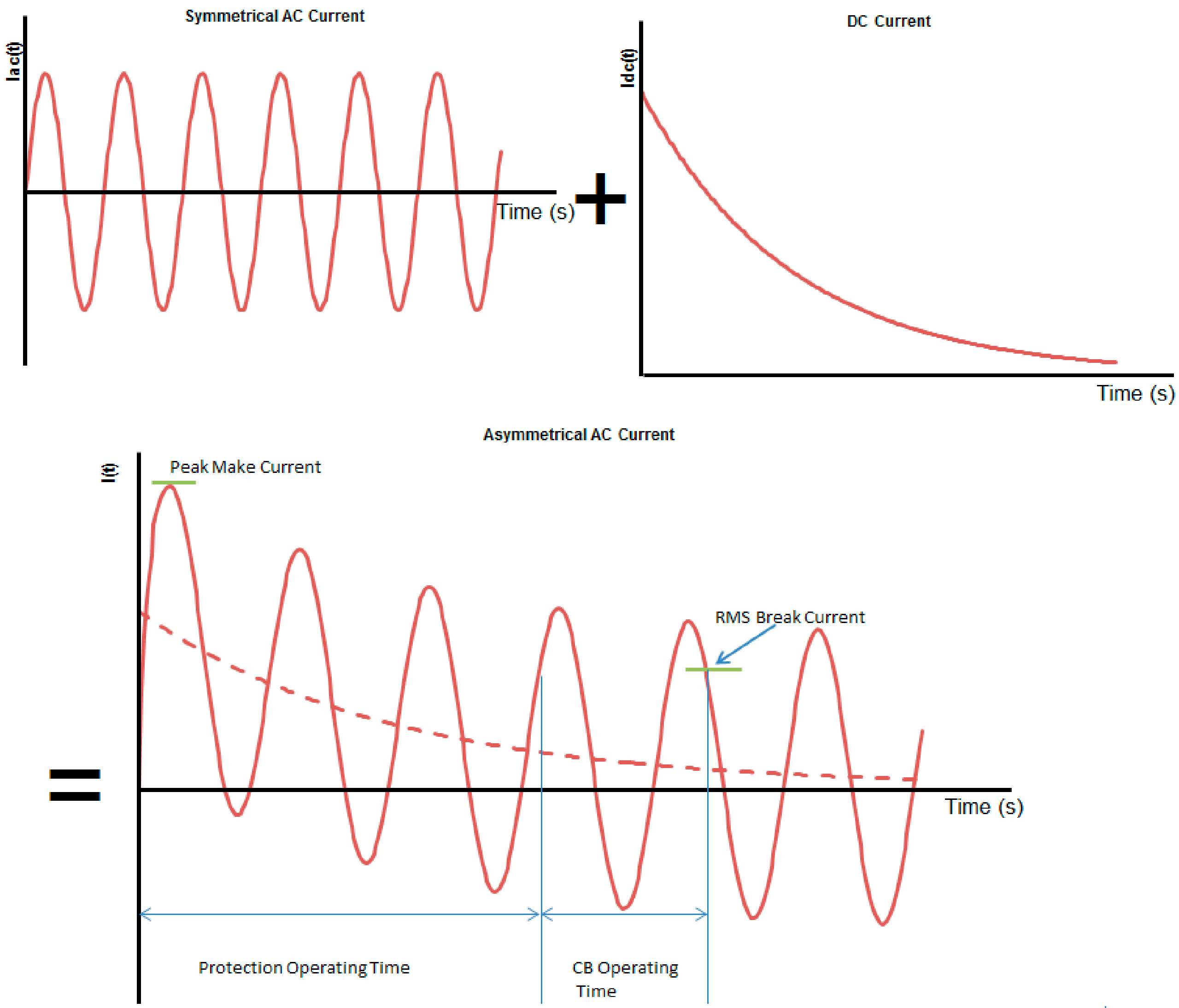

Figure B-1: Components of AC fault current

The maximum current 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 4.5.2. The information presented here is our performance against the standards set out in the Code and by the AER over the past five years.

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 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)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure	0.2	0.27	0.21	0.34	0.25	0.36
High-density commercial	1	0.43	0.47	0.33	0.26	0.14
Urban and regional centres	2	0.92	0.85	1.25	1.24	1.14
High-density rural	4	2.36	2.18	2.94	3.12	3.01
Low-density rural	6	3.49	3.11	4.04	3.86	3.49

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

Supply reliability category	Standard (minutes)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure	30	30	16	57	34	27
High-density commercial	60	77	43	27	23	12
Urban and regional centres	120	94	164	169	141	140
High-density rural	480	269	521	582	521	530
Low-density rural	600	547	740	931	725	659

C.1.2 Supply reliability communities

In addition to performance requirements for supply reliability categories, 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 area 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)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure (1)	0.2	1	0	1	1	1
High-density commercial (8)	2	0	0	0	0	0
Urban and regional centres (32)	4	2	3	3	4	3
High-density rural (33)	6	2	6	4	2	4
Low-density rural (27)	8	1	2	0	1	1
Total (101)		6	11	8	8	9

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

Supply reliability category (number of communities)	Standard (minutes)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure (1)	30	1	0	1	1	0
High-density commercial (8)	120	3	0	0	1	0
Urban and regional centres (32)	240	5	12	13	10	6
High-density rural (33)	600	4	11	13	5	7
Low-density rural (27)	720	6	14	12	8	10
Total (101)		19	37	39	25	23

C.2 Performance against AER targets

C.2.1 Reliability of supply

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 STPIS and are calculated on our actual performance for the past 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.

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

Supply reliability category	Standard (2012-17) (interruptions)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure	0.22	0.17	0.13	0.19	0.16	0.25
High-density commercial	0.49	0.30	0.32	0.27	0.19	0.10
Urban and regional centres	1.04	0.82	1.21	0.85	0.97	0.84
High-density rural	2.79	2.21	3.00	2.10	2.61	2.58
Low-density rural	3.20	3.00	4.65	2.77	3.22	2.89

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

Supply reliability category	Standard (2012-17) (minutes)	2012-13	2013-14	2014-15	2015-16	2016-17
Critical infrastructure	20.79	4.65	6.83	23.29	14.57	4.84
High-density commercial	38.34	33.61	27.66	23.22	11.37	4.97
Urban and regional centres	82.75	64.19	101.89	76.88	78.06	64.79
High-density rural	259.48	203.25	289.29	239.17	254.26	263.68
Low-density rural	333.16	358.41	533.00	360.34	370.53	356.79

C.2.2 Customer service

As part of the AER's distribution STPIS and OTTER regulatory reporting requirements, we report on customer service performance in terms of a phone answering parameter. This is defined as the number of calls answered in 30 seconds, divided by the total number of calls received (after removing exclusions).

Table C-7: Customer service performance

Phone answering	2012-13	2013-14	2014-15	2015-16	2016-17
Number of calls	76,065	80,584	52,973	44,455	40,944
Number of calls answered in 30 seconds	59,915	59,192	37,585	32,314	33,504
Percentage of calls answered within 30 seconds	78.77	73.45	70.95	72.69	81.83
Performance target (%)	73.6	73.6	73.6	75.8	73.39

APPENDIX D GENERATOR INFORMATION

Table D-1 lists the Tasmanian power stations connected to the transmission network.

Table D-1: Transmission-connected generation

Generator	Capacity (MW)	Our planning area	Connecting substation or transmission line
Gas			
Tamar Valley OCGT	178	Northern	George Town
Hydro			
Bastyan	81	West Coast	Farrell
Butlers Gorge and Nieterana[111]	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

Table D-2 lists the embedded generation sites within our 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 our distribution network, however may export to our transmission network.

111 *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 D-2: Embedded generation over 0.5 MW

Location	Source	Capacity (MW)	Export (MW)	Our 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 E POWER QUALITY PLANNING LEVELS

This appendix provides our 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.

E.1 `Planning levels for over and under voltages

The Rules illustrate the allowable TOV envelope in S5.1a.4, which is reproduced in Figure E-1.

The Rules do not specify a standard for transient voltage recovery following under-voltage events. We have compiled the under-voltage characteristic in Figure E-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 E-2 for general assessment of under voltage performance, but we reserve the right to apply alternate performance metrics as required.

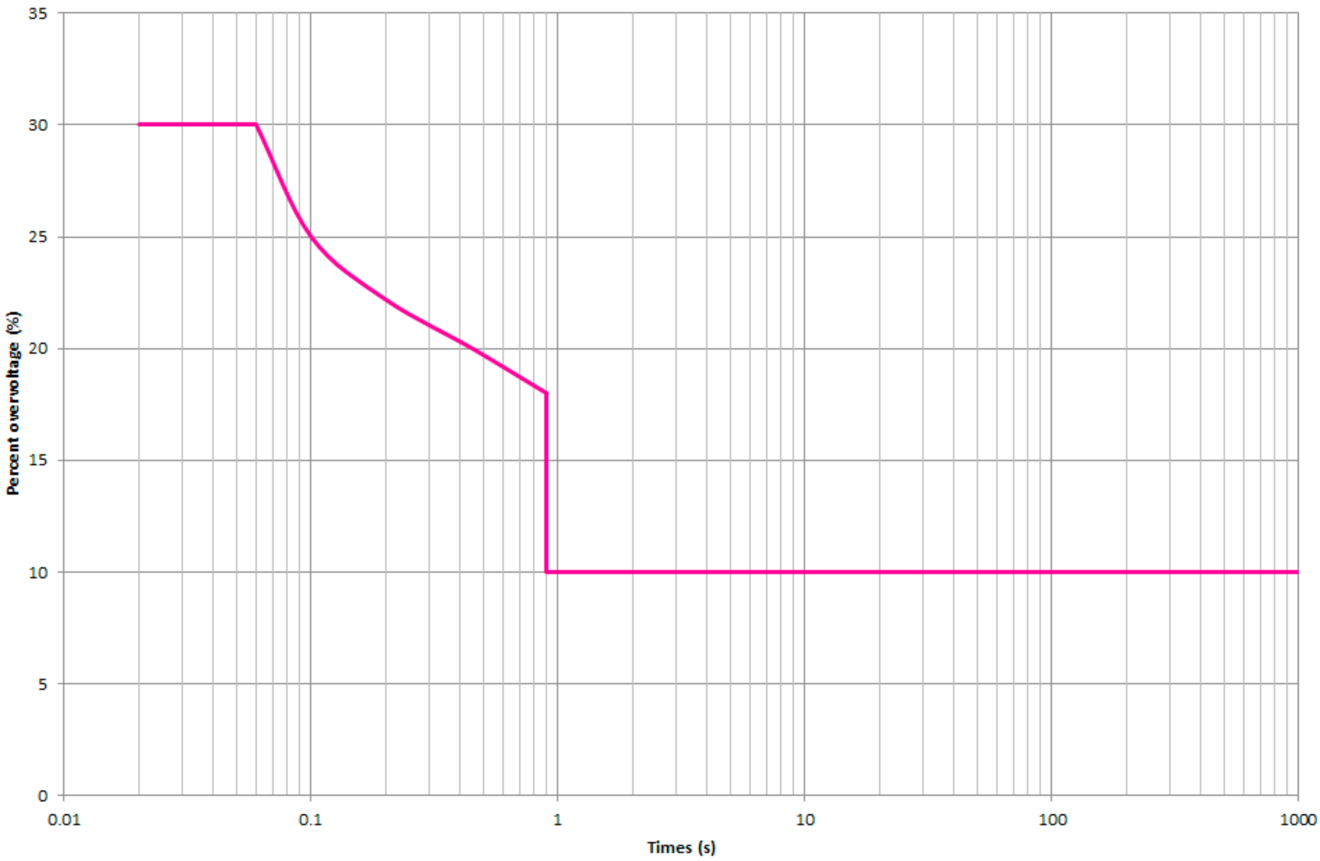

Figure E-1: The over-voltage requirements (reproduced from the Rules S5.1a.1)

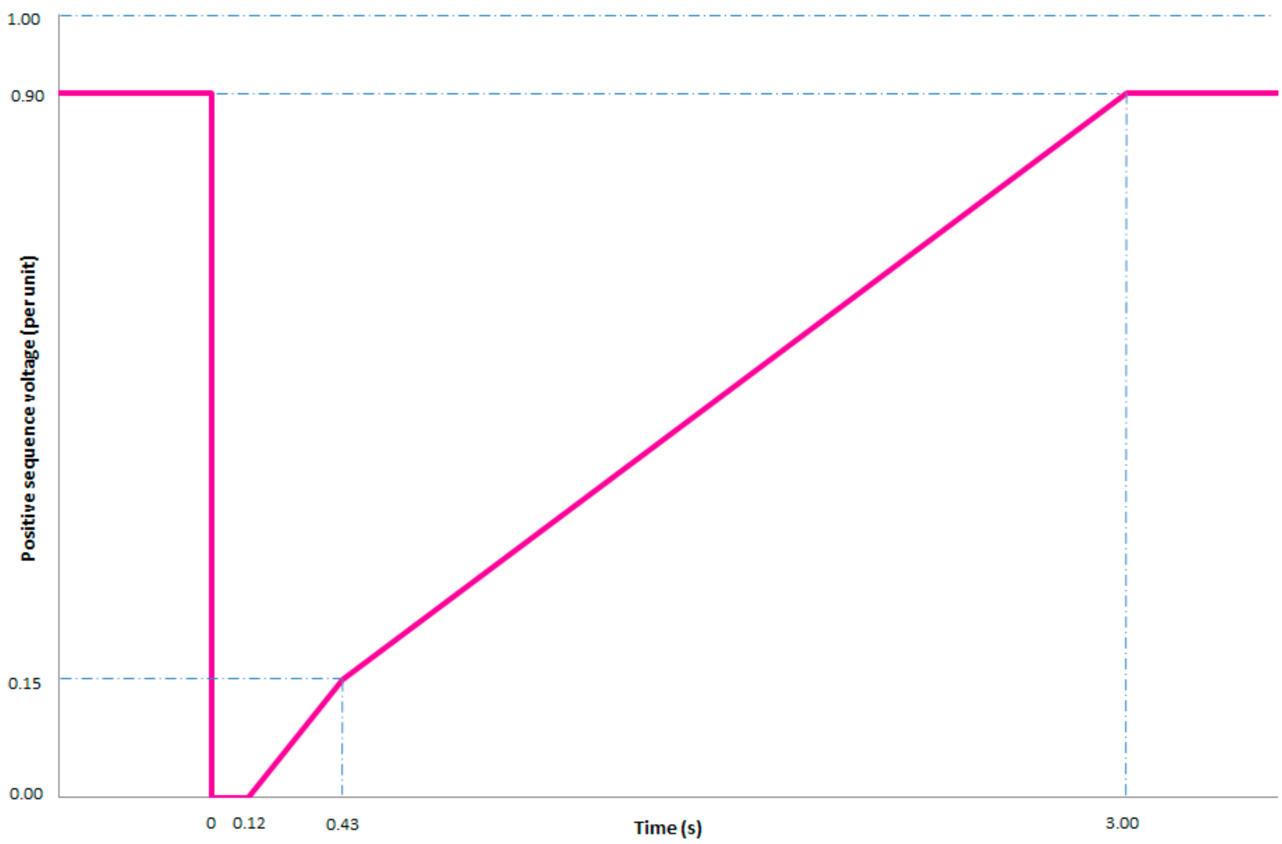

Figure E-2: Voltage recovery requirements following network under-voltage events

E.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% 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: frequency and magnitude. 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 E-1 has been derived and adopted for our transmission network. Note that TR IEC 61000.3.7:2012 should be referenced for further details.[112]

Table E-1: Voltage fluctuation planning levels

Flicker level	Bus voltage	
	HV [113]	MV [114]
P_{ST}	0.8	0.9
P_{LT}	0.6	0.7

112 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

113 HV: 35 kV < Un ≤ 230 kV

114 MV: 1 kV < Un ≤ 35 kV

P_{ST} 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.

P_{LT} Long-term flicker level

This is an average of P_{ST} values evaluated over a period of two hours. An index level of less than 0.9 is considered acceptable.

E.3 Planning levels for harmonic voltage

With respect to planning levels for harmonic voltages, Table E-2 has been derived and adopted for our transmission network. Note that TR IEC 61000.3.6:2012 should be referenced for further details.[115]

Table E-2: Harmonic planning levels for the Tasmanian network

	Permissible voltage level (% of the nominal voltage)			
	Transmission or sub-transmission busbars		Load busbars	
Harmonic number	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

115 *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*

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
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[116]	3.00	4.36	6.61	6.93

Planning levels at generating unit busbars (terminal connection voltage) are to be taken as half of these values, recognising there is a cost associated with specifying a higher level of required harmonic immunity for such plant.

E.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 E-3.

Table E-3: Planning levels for voltage unbalance (from the Rules Table S5.1a.1)

Nominal supply voltage (kV)	Maximum negative sequence voltage (% of nominal voltage)			
	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

116 *Total harmonic distortion*

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