Tasmanian Distribution Regulatory Proposal

Regulatory Control Period
1 July 2017 to 30 June 2019

29 January 2016

Tasmanian Networks Pty Ltd
ABN 24 167 357 299
PO Box 606
Moonah TAS 7009

Enquiries regarding this document should be addressed to:
John Sayers
Program Leader Revenue Resets
PO Box 606
Moonah TAS 7009
Email: john.sayers@tasnetworks.com.au

Tasmanian Networks Pty Ltd

Tasmanian Distribution Regulatory Proposal
Regulatory Control Period: 1 July 2017 to 30 June 2019

Amendments and Version History

Version No.	Date of Revision	Authorised by	Details of amendment
0.1	7 Jan 2016	John Sayers	draft
0.2	11 Jan 2016	John Sayers	Final draft
0.3	15 Jan 2016	John Sayers	As submitted to Board for approval
1.0	19 Jan 2016	TasNetworks Board	Approved by Board for submission to the AER
1.1	29 Jan 2016	Bess Clark	As submitted to the AER

Amendments to each version of this document will be tracked through TasNetworks' document management system.

Table of Contents

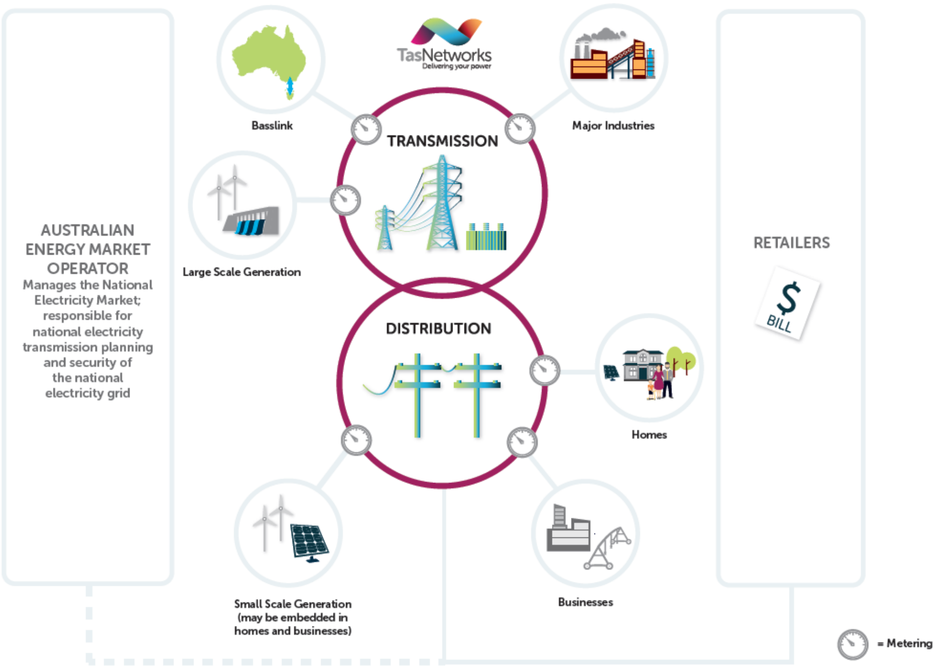
Executive Summary

Who we are and what we do

Tasmanian Networks Pty Ltd (TasNetworks) is a State Owned Corporation that commenced operations on 1 July 2014 by bringing Tasmania's electricity distribution and transmission networks into one network business.

We own, operate and maintain the network that delivers electricity to more than 280,000 households, businesses and organisations on mainland Tasmania. Our role in the electricity supply chain and our customer service relationships are shown below.

TasNetworks' customer service relationships



Overview of our proposal

This Regulatory Proposal outlines our plans for improving, maintaining and operating our distribution network efficiently to serve the long-term interests of our customers.

Our direction and priorities consultation with our customers identified the following themes to guide our plans for the forthcoming regulatory period:

1. improving how we communicate with, and listen to our customers;
2. ensuring the safety of our customers, employees, contractors and the community;
3. keeping the power on, maintaining service reliability;
4. innovating in a changing world; and
5. delivering services for the lowest sustainable cost.

Consistent with our direction and priorities, for the two-year period from 1 July 2017 to 30 June 2019, we have proposed:

- a capital program consistent with recent levels;

- further reductions to our operating expenditure;
- to maintain our service levels; and
- to align our weighted average cost of capital or 'WACC' with the Australian Energy Regulator's approach, as updated to reflect market data and any changes required as a result of Tribunal decisions.

Our revenue forecasts are based on a WACC of 6.04 per cent. This rate will be updated to reflect market conditions closer to the final regulatory decision in April 2017. Using this rate, we forecast:

- an initial reduction in annual revenue of approximately $30 million from 1 July 2017, which is a 12.9 per cent annual reduction in real terms; and
- an additional small decrease in revenue in real terms on 1 July 2018.

Customer engagement

We are committed to engaging with, informing and educating our customers about our activities and plans for the future.

We have undertaken a range of activities to gather feedback, and to understand the issues and concerns that are important to our customers. The key messages emerging from our customer engagement activities are summarised below:

- We are meeting most customers' needs from an overall performance perspective.
- Our most valued services include reliability and restoration of supply, followed by the management of the network to safely and reliably deliver electricity.
- Overall satisfaction with current reliability levels is quite high. The majority of customers support our proposed strategy to maintain reliability rather than investing more to improve it.
- While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices for these improvements.
- Cost is the greatest concern and lower prices - without reducing service quality - would lead to the greatest uplift in satisfaction.
- Customers recognise that technology is changing the electricity industry, particularly in relation to solar panels, battery storage and electric vehicles.

In relation to areas for improvement, customers highlighted the following issues:

- providing services at lower cost without compromising service quality;
- providing customers with better information about restoration times;
- addressing meter reading concerns;
- addressing quality of supply issues such as voltage complaints;
- ensuring that customers or stakeholders have sufficient information to make informed decisions on our future plans and network pricing reform;

- improving the way we communicate with our stakeholders on how we are innovating and considering new technologies; and
- using more responsive and modern communication tools (for instance, SMS automatic messaging for outage updates) and improved online communication, especially for outages.

Capital and operating expenditure

Capital expenditure

One of the five key themes underpinning our plans for the forthcoming regulatory period is ensuring the safety of our customers, employees, contractors, and the community. In accordance with this theme, we are committed to achieving our Zero Harm goals of:

- no harm to our people and the public; and
- minimising our impact on the environment.

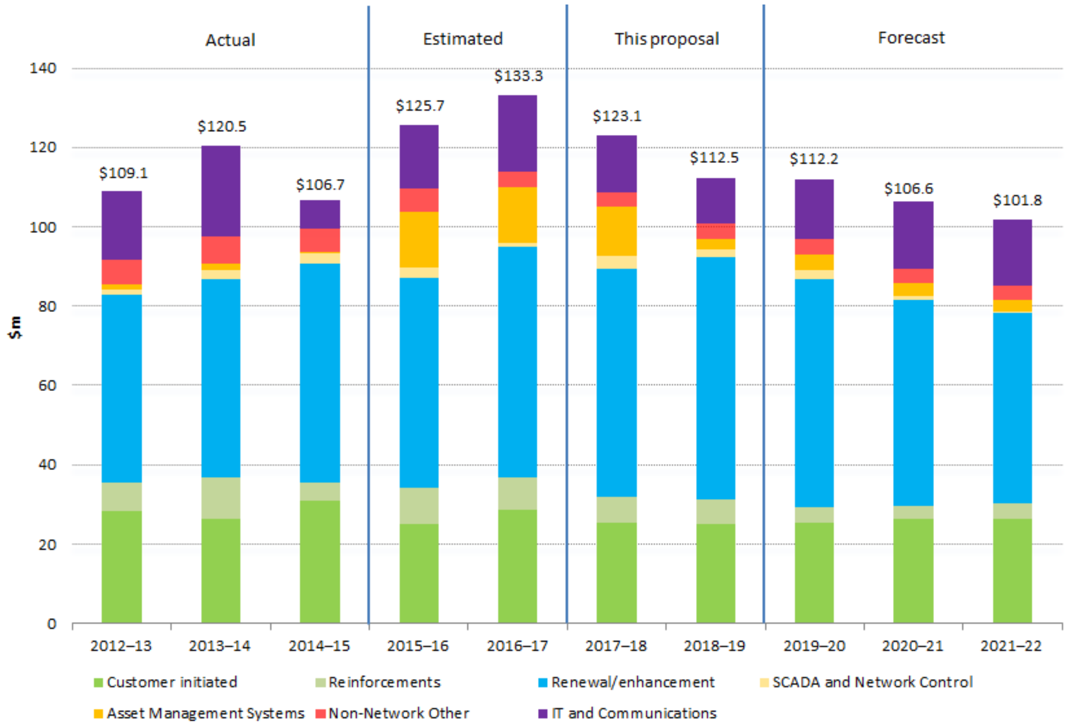
Our commitment to our Zero Harm policy underpins our expenditure plans for the forthcoming regulatory period.

Our forecasts indicate that state-wide demand growth will not be a significant driver of investment in the forthcoming regulatory period. Instead, our program reflects continued customer initiated and reinforcement investment to facilitate new connections and emerging technologies. In addition, we forecast a modest increase in renewal/enhancement expenditure from current levels to maintain network safety and reliability.

We will also continue to invest in information technology and communications systems to support efficient service delivery to our customers.

The figure below presents a five year forecast (two years covering the forthcoming regulatory period plus an additional three years) in order to facilitate comparisons with the current regulatory period. The figure shows that total capital expenditure is expected to decline gradually from current levels. An explanation of the different capital expenditure categories is provided in Chapter 7.

Overview of actual and forecast capital expenditure including customer contributions (June 2017 $m)



Actual and forecast capital expenditure by category (June 2017 $m)

Category	Regulatory allowance for 2012-13 to 2016-17	Actual expenditure for 2012-13 to 2016-17	Forecast expenditure for 2017-18 to 2021-22
Development	**272.3**	**179.7**	**152.9**
Customer initiated	206.2	139.9	128.7
Reinforcements	66.1	39.8	24.2
Renewal/enhancement	**225.9**	**263.4**	**276.3**
Operational Support Systems	**43.8**	**41.4**	**33.8**
SCADA and Network Control Systems	20.0	9.6	8.8
Asset Management Systems	23.8	31.7	25.0
Non-Network Other	**43.1**	**28.7**	**18.5**
IT and Communications	**41.6**	**82.2**	**74.7**
Total	**626.7**	**595.3**	**556.2**

The above table shows that our total capital expenditure in the current five year period is expected to be $595.3 million compared to the AER's allowance of $626.7 million, which is a reduction of five per cent. Over the next five-year period (from 2017-18 to 2021-22) our forecast capital expenditure reduces by a further 6.6 per cent, to $556.2 million per annum.

The reductions achieved in the current period were despite unexpected additional capital costs associated with bushfire recovery and investment in the IT systems needed to facilitate full retail competition in Tasmania. We could have sought financial relief by seeking AER approval to 'pass though' the additional costs to customers. Instead, Aurora Energy and TasNetworks decided to absorb these cost increases and manage expenditure within the existing AER allowances.

Our expenditure for the forthcoming regulatory period includes indicative forecast expenditure to support the metering Rule change recently made by the Australian Energy Market Commission. The application of this Rule change in Tasmania remains uncertain and we will update our expenditure forecasts, if necessary, to the extent permitted by the National Electricity Rules (the Rules).

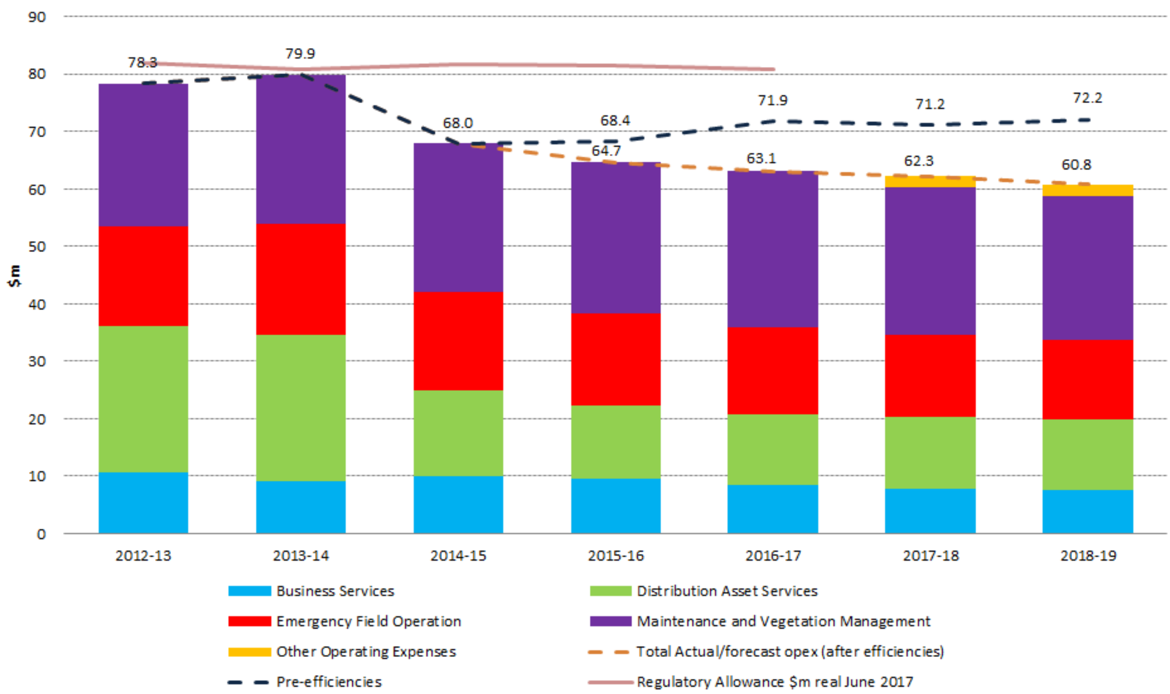
Operating expenditure

Our operating expenditure forecast is built on the significant efficiencies that we have already achieved by improving our business processes and reducing labour and contracted services costs across a range of functions. In fact, our cost base in 2014-15 is approximately 16 per cent below the allowance set by the AER. This improvement in cost performance provides confidence that our base year (2014–15), from which future costs are projected, is efficient.

Our analysis shows that operating expenditure in the forthcoming regulatory period is forecast to be 13.1 per cent lower in real terms than our average expenditure for the current period. Meeting these targets will require us to find efficiency savings. We are committed to delivering these improvements and our revenue proposal, if accepted by the AER, will pass these savings onto customers.

The figure below shows our actual operating expenditure for the current regulatory period alongside our forecast for the two-year regulatory period, commencing in 2017-18. It also shows that our costs are reducing in real terms, reflecting the expected efficiency savings in the forthcoming regulatory period

Overview of forecast and actual operating expenditure (June 2017 $m)



The table below shows our actual and forecast annual operating expenditure by category.

Actual and forecast operating expenditure by category (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Emergency Field Operations	17.5	19.3	16.9	16.1	15.0	14.3	13.9
Maintenance and Vegetation Management	24.7	25.9	26.0	26.3	27.3	25.7	25.1
Distribution Asset Services	25.3	25.6	15.0	12.7	12.3	12.4	12.3
Business Services	10.8	9.1	10.0	9.5	8.5	7.9	7.6
Other Operating Expenditure	n/a	n/a	n/a	n/a	n/a	1.9	1.9
Total operating expenditure	**78.3**	**79.9**	**68.0**	**64.7**	**63.1**	**62.3**	**60.8**

Note: Other operating expenditure is shown as n/a during the current regulatory period as actual costs are not reported in this category. Other operating expenditure comprises benchmark debt raising costs and a self-insurance allowance. Our actual debt raising cost is reported as part of our financing costs, not operating expenditure. In addition, self-insured losses are currently allocated to the expenditure category where the loss arises, as no self-insurance allowance was provided during the 2012-17 regulatory period.

Revenue calculation

The table below summarises the revenue building block calculation for each year of the forthcoming regulatory period alongside the final year of the current period, which is 2016-17.

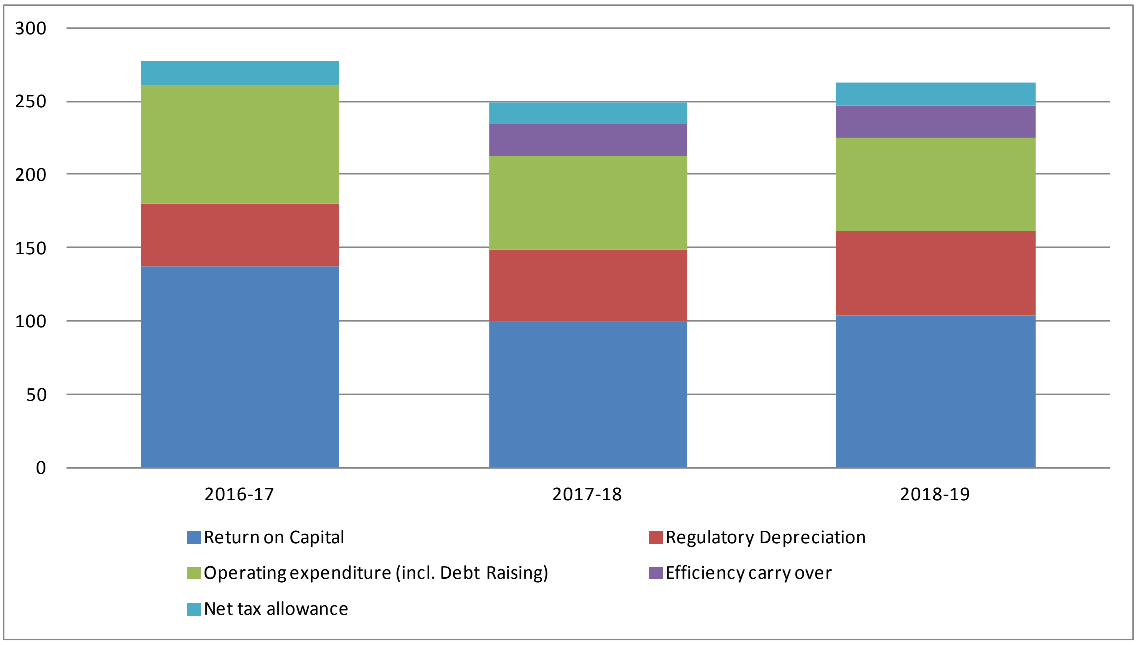
Summary of Building Block Unsmoothed Revenue Requirements ($m nominal)

	2016–17	2017-18	2018-19	Total
Return on Capital	137.7	99.5	103.5	203.0
Regulatory Depreciation	42.2	49.6	57.6	107.2
Operating expenditure (incl. Debt Raising)	81.2	63.8	63.9	127.7
Efficiency carry over[1]	0.0	21.5	22.0	43.5
Net tax allowance	16.7	15.0	15.9	30.9
Total Revenue Requirement (unsmoothed)	**277.8**	**249.4**	**262.9**	**512.3**

The figure below shows the significant reduction in our proposed revenue in 2017-18, followed by a modest increase in 2018-19.

[1] This includes the allowances provided under the Demand Management and Embedded Generation Connection Incentive Scheme (formerly the Demand Management Incentive Scheme, or DMIS).

Summary Building Block Unsmoothed Revenue Requirement ($m nominal)

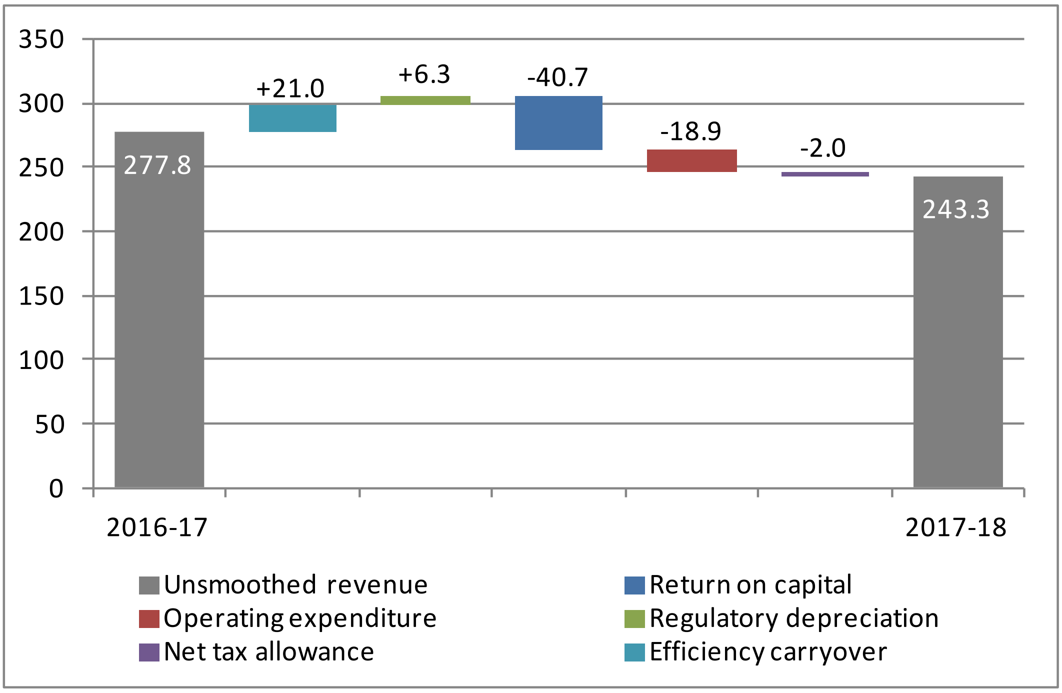


When the above revenue profile is smoothed, it results in proposed X factors of 12.89 per cent for 2017-18 and 2 per cent for 2018-19. Our proposed X factors mean that:

- our allowed revenue in 2017–18 is 12.89 per cent lower in real terms compared to 2016–17; and
- our allowed revenue will be subject to a further modest decrease of 2 per cent in real terms in 2018-19.

The key elements in our proposal that result in this significant reduction in our 2017-18 revenue requirement are shown in the waterfall chart below. In contrast to the earlier data, the figure below is expressed in real terms to exclude the effects of inflation.

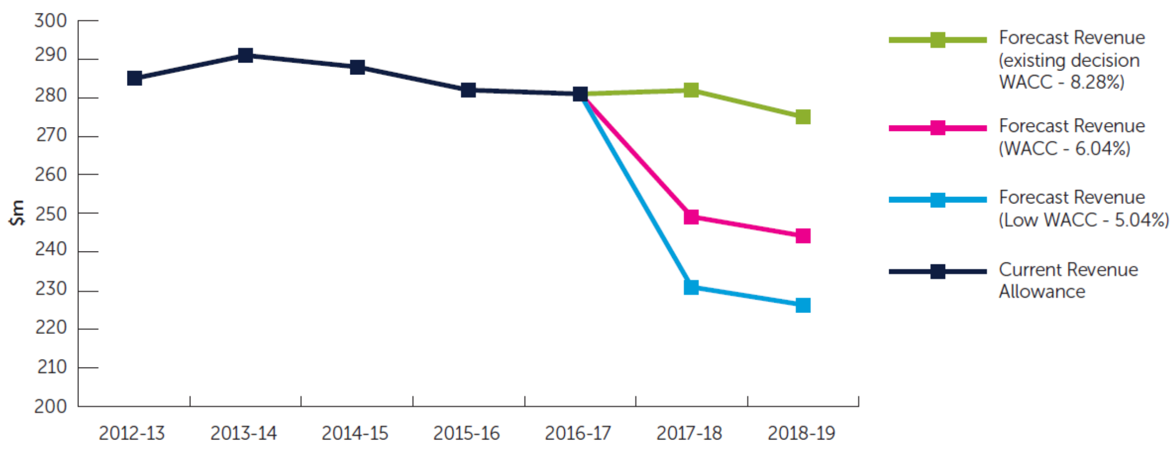
Changes in unsmoothed revenue from 2016-17 to 2017-18 (June 2017 $m)



The Regulatory Proposal provides a detailed explanation for each of these changes.

Our revenue proposal adopts a WACC of 6.04 per cent. Two other WACC scenarios are presented in the figure below to illustrate the sensitivity of our revenue requirements to changes in the WACC.

Revenue allowance for distribution services (June 2017 $m)



Our proposal is based on the Australian Energy Regulator's approach to setting the WACC, and will be updated to reflect market data and any changes required as a result of Tribunal decisions.

appeals.

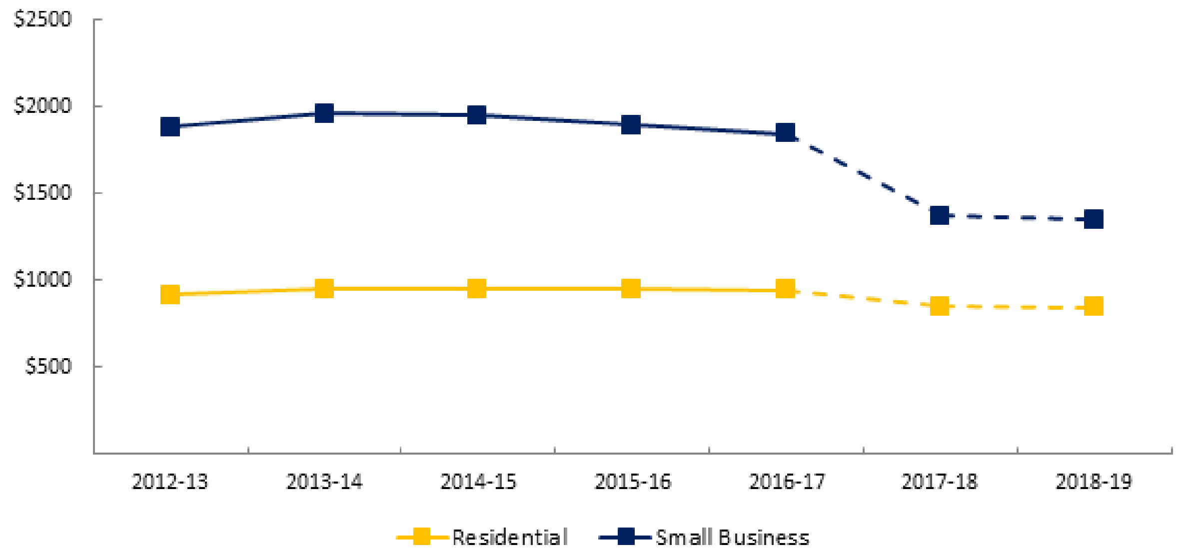
The revenue we recover each year will be adjusted for over- or under-recoveries from previous years, incentive payments or penalties received as a result of our performance, and annual adjustments to the WACC to reflect the benchmark cost of debt. Because of these adjustments, actual revenue recovered in a year is likely to vary from the forecast allowance.

Customer pricing outcomes

Transmission and distribution network costs presently make up around 50 per cent of the average Tasmanian residential and small business customer electricity bill.

Our forecast distribution revenue allowance (at a WACC of 6.04 per cent), together with our current transmission revenue allowance, are inputs to the revenue we recover from our distribution customers. Using this forecast revenue and our forecast consumption, the indicative average annual total network charges for residential and small business customers is shown below.

Indicative average annual total network charges (June 2017 $)



1 Introduction

1.1 Purpose of this document

Under the National Electricity Law (NEL) and the National Electricity Rules (the Rules), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services.

In accordance with the Rules, the AER conducts a periodic review to determine our revenue requirements and other matters relating to the provision of regulated electricity distribution services. Normally, a regulatory period lasts for five years. However, under a recent Rule change[2], our forthcoming distribution regulatory period will commence on 1 July 2017 and end on 30 June 2019. This enables the AER's future revenue determinations for our transmission and distribution networks to be aligned from 1 July 2019 onwards.

Our Regulatory Proposal includes:

- an overview paper which explains the Regulatory Proposal in plain language and how our customer engagement has informed our proposal;
- a tariff structure statement which explains how we propose to set our network tariffs and prices for a range of regulated distribution services; and
- completed templates and supporting information as required by the Rules and the AER's Regulatory Information Notice (RIN).

1.2 Overview of service classification

Under the Rules, the various services we provide are subject to classification by the AER. The service classification affects the form of regulation that may apply, including whether the AER:

- directly controls revenues and prices and sets performance targets; or
- allows parties to negotiate services and prices and arbitrates if any disputes arise; or
- does not regulate the service at all.

The table below provides an overview of the different classes of distribution services for the purposes of economic regulation under the Rules.

[2] AEMC, Rule Determination: National Electricity Amendment (Aligning TasNetworks' regulatory control periods) Rule 2015, 9 April 2015.

Table 1-1: Classification of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services such as building and maintaining the shared distribution network that are central to electricity supply and therefore relied on by most (if not all) customers. Most distribution services are classified as standard control.	The AER regulates these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers.
	Alternative control service	Customer specific or customer-requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.	The AER sets service-specific prices to enable the distributor to recover the full cost of each service from customers using that service.
Negotiated service		Services that the AER considers require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the Rules. The AER arbitrates if necessary.
Unclassified service		Services that are not distribution services or services that are contestable.	The AER has no role in regulating these services.

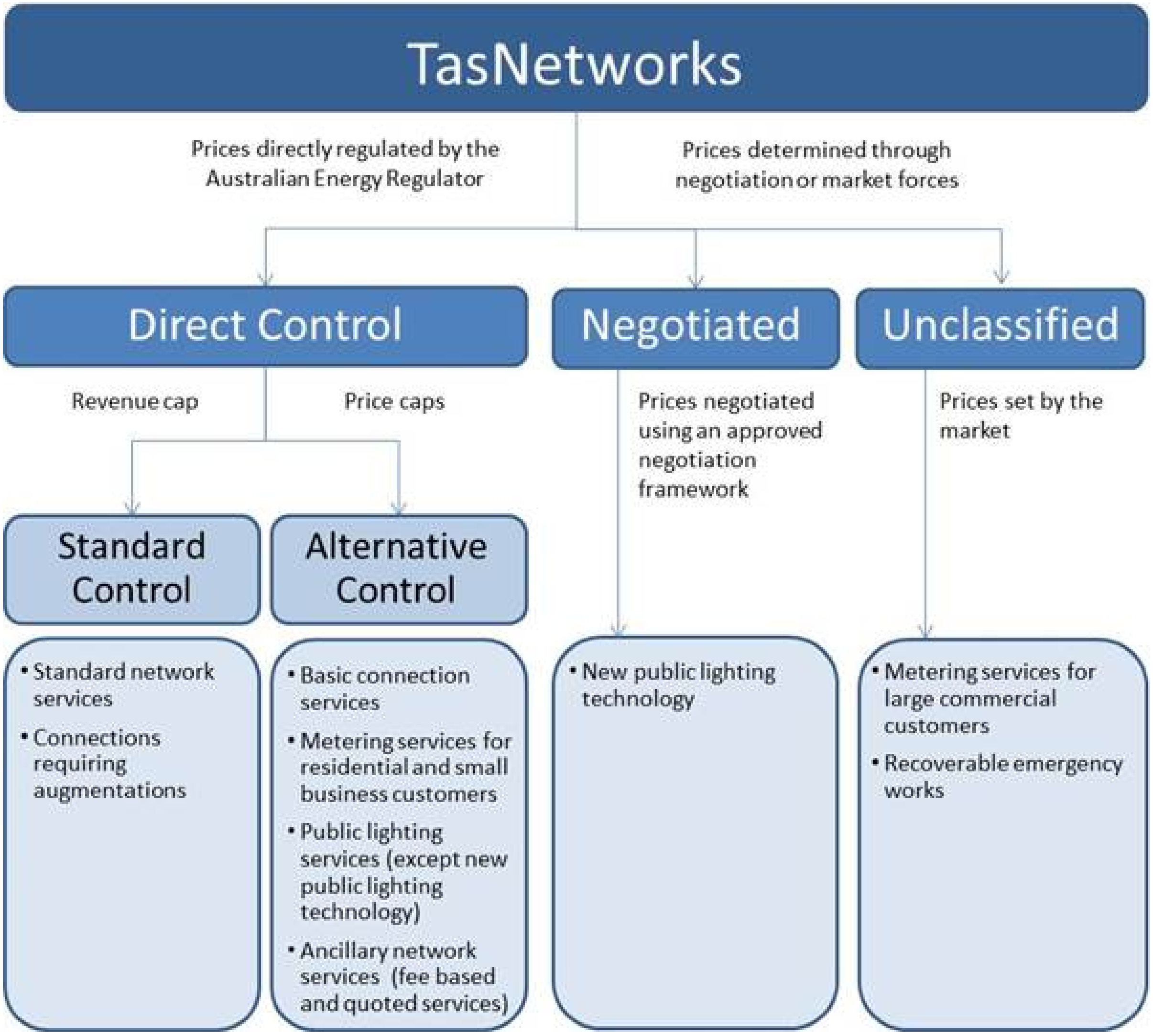
The AER issued its Final Framework and Approach Paper for TasNetworks on 9 July 2015[3]. We accept the AER's service classification with one exception. In our view, connection services relating to the provision or alteration of a basic connection service should be classified as Alternative Control Services instead of Standard Control Services. We understand that this is consistent with the treatment of basic connection services in Victoria. Our recent decision to promote the contestable provision of some connection services also supports the AER reassessing our proposed classification.

Under clause 6.8.2(c) of the Rules, we are required to explain why our proposed service classification differs from the AER's Final Framework and Approach Paper. We think our approach will provide fairer outcomes to existing and future customers. It will also facilitate the development of competition in the provision of connection services which we have introduced from 1 January 2016. Chapter 21 provides a more detailed explanation of the reasons for our proposed classification of basic connection services as an Alternative Control Service.

3 AER, Framework and approach for TasNetworks Distribution for the Regulatory control period commencing 1 July 2017, July 2015.

Our proposed classification of services is shown in the figure below. Further information on the service classification for each alternative control service is provided in Part 3 of this Regulatory Proposal.

Figure 1-1: Proposed classification of TasNetworks Distribution Services



1.3 Structure of this Regulatory Proposal

This Regulatory Proposal is presented in four parts, as explained below.

- Part One sets out background information which provides important context for our expenditure plans for the forthcoming regulatory period.

  Part One provides information on our services, our network and our customers. We explain how we plan and deliver our expenditure to meet customer needs as efficiently as possible. We provide details of how we have engaged with customers in developing our proposals.

- Part Two focuses on Standard Control Services.

  We commence Part Two by explaining what our customers have told us about our distribution services and how we can improve. In light of this feedback, we detail our expenditure plans, which will enable us to meet our customers' expectations for safe, reliable and efficient distribution services and improved information and communication channels.

We calculate our total revenue requirements for the forthcoming regulatory period, taking account of our expenditure plans; our regulated asset base; our proposed WACC and tax allowance. We also explain how we propose to set network tariffs so that we recover our revenue requirements from our customers in a way that is efficient and equitable.

- Part Three focuses on Alternative Control Services. We begin Part Three by explaining what our customers have told us about Alternative Control Services and how this feedback is factored into our proposal. As already noted, these services are customer-specific (for example, street lighting provided to a particular council); or customer-requested services (for example, remote de-energisation); or services that will be subject to competition (such as some connection services and metering services).

  Similar to Part Two, we explain our revenue requirements for these services and our proposed charging arrangements.

- Part Four explains our connection policy and our negotiating framework. Both documents are provided as attachments to this Regulatory Proposal (TN017 and TN020), (each supporting document is given a TasNetworks or 'TN' document number).

  In broad terms, the connection policy explains the different types of connection services and the charging arrangements that apply. The negotiating framework is principally concerned with ensuring that customers can obtain negotiated distribution services on fair and reasonable terms.

  We also provide details of our proposed cost pass through arrangements. This regulatory mechanism allows us to 'pass through' unexpected significant changes in costs (positive or negative) if particular kinds of uncertain events occur during the forthcoming regulatory period.

We do not claim confidentiality in relation to any part of this Regulatory Proposal document. Where confidentiality is claimed in respect of any appendices or supporting documents, a redacted version is provided along with details of the claim for confidentiality.

1.4 Global assumptions

We have adopted a number of assumptions in preparing this Regulatory Proposal that apply to our capital and operating expenditure forecasts. These global assumptions are outlined below:

- The direction outlined in TasNetworks' 'Strategy on a Page 2015-16'[4] will underpin our strategic direction across the entire 2017-19 regulatory control period.
- Consistent with our 'Strategy on a Page', we will adopt an innovative approach to network development and operation that delivers customer outcomes at the lowest sustainable price.

[4] Our 'Strategy on a Page' is shown in section 2.8.

- There will be no material amendments to the legislative and regulatory framework in the 2017-19 regulatory control period, over and above regulatory changes anticipated and accounted for in our expenditure forecasts.
- The Metering Contestability Rule change will be implemented in Tasmania on 1 December 2017. The implementation of this rule will require significant investment in our standard control distribution services, including investments in new customer processes and information technology systems.
- The financial impact of the Embedded Networks Rule change has not been included in this Regulatory Proposal as the application of the rule requires changes to jurisdictional instruments and these changes are not yet determined.
- Any adjustments to forecasts resulting from these Rule changes will be provided to the AER, as total implementation costs are understood and refined to the extent permissible in the Rules, we will revisit our expenditure forecasts following the AER's draft decision.
- We will meet our compliance obligations, including those relating to reliability requirements, physical security, safety, environment and other matters.
- Our expenditure plans reflect our customers' preferences in relation to reliability and price trade-offs.
- Our asset management plans and strategies are consistent with good asset management and accurately reflect our future expenditure requirements.
- We will have the resource availability and capability to deliver the programs as forecast for the 2017-19 regulatory control period.
- Our forecasts of labour and non-labour escalation rates are reasonable.
- Our operating environment and external factors which are beyond our control, will not undermine our ability to achieve the projected productivity improvements and cost savings.

In accordance with the Rules requirements the Directors of TasNetworks have certified that these assumptions are reasonable. Assumptions that only apply to either operating or capital expenditure are addressed in the relevant chapters of this proposal.

1.5 Presentation of costs

The actual and forecast expenditures in this proposal reflect our cost allocation methodology as approved by the AER and are consistent with:

- our capitalisation policy, which remains unchanged from the current regulatory period; and
- the application of the AER's incentive schemes that encourage cost and service efficiencies over time.

As required by the Rules, our capitalisation policy is provided as a supporting document. The Rules require the AER to have regard to whether expenditure forecasts include any transactions with related parties. We can confirm that our expenditure forecasts do not contain any costs arising from transactions with related parties.

In terms of the financial data presented in this submission, it should be noted that:

- all monetary values presented exclude GST;
- unless stated otherwise, monetary values are presented in June 2017 dollars;
- where data is presented in nominal terms an inflation forecast of 2.5 per cent per annum has been applied; and
- numbers in tables may not add up due to rounding.

To aid comparison with the current five year regulatory period, the capital expenditure forecasts set out in this Regulatory Proposal provide a five year view from 1 July 2017. It should be noted, however, that:

- The forecasts that apply for the purpose of the AER's determination are limited to the two-year period commencing 1 July 2017.
- Forecasts beyond 30 June 2019 are indicative and intended to enable the forecasts for the period from 1 July 2017 to 30 June 2019 to be seen in the context of TasNetworks' current five year plans.
- Forecasts beyond 30 June 2019 do not form part of the Regulatory Proposal. They will be subject to revision by TasNetworks when we submit our Regulatory Proposal for the next regulatory period (commencing 1 July 2019).
- Cost information presented in the supporting documents is expressed in 2014-15 dollars and excludes overheads. Therefore, while the cost information in our supporting documents is consistent with the Regulatory Proposal, adjustments are needed to reconcile direct and total costs.
- A number of supporting documents, such as fleet, facilities and IT infrastructure, are shared services across the transmission and distribution networks. The strategies, plans and cost information provided as supporting documents to this Regulatory proposal are company-wide documents. This Regulatory Proposal identifies the relevant portion of these shared costs in accordance with our cost allocation methodology and the AER's Regulatory Information Notice. Templates information is provided which sets out the allocation.

Part One:

Background

2 Business and operating environment

2.1 About TasNetworks

Tasmanian Networks Pty Ltd (TasNetworks) is a Tasmanian state-owned energy corporation which commenced operations on 1 July 2014. TasNetworks was established as an integrated network business to drive efficiencies in the networks and to deliver better outcomes for Tasmanian customers. We were formed as a result of the integration of Transend Networks Pty Ltd (Transend), the previous owner and operator of the Tasmanian electricity transmission network, and the distribution business of Aurora Energy Pty Ltd (Aurora), the previous owner and operator of the Tasmanian electricity distribution network.

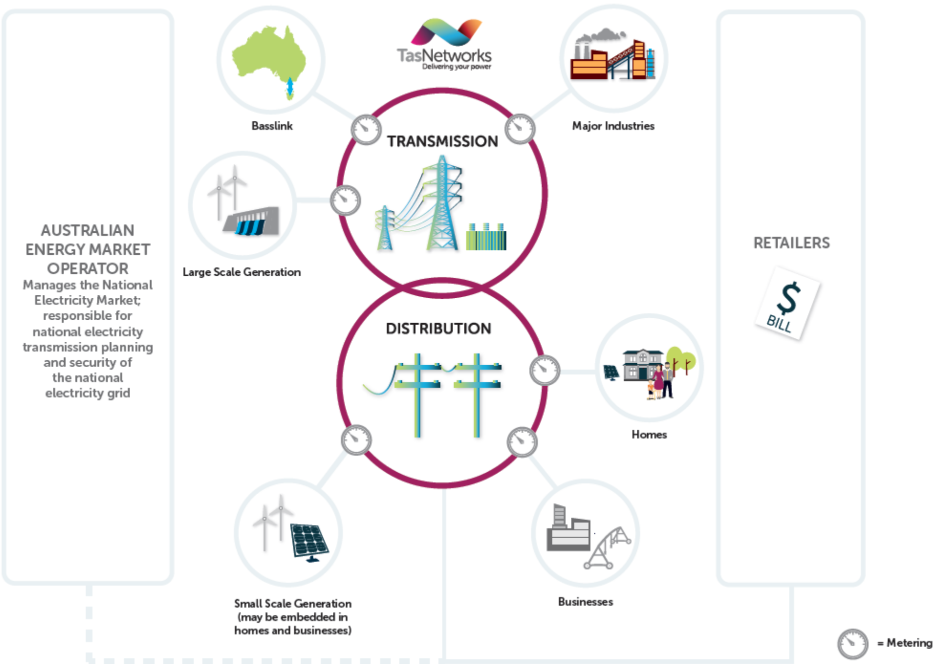
We own, operate and maintain the electricity network that delivers electricity to more than 280,000 connected Tasmanian customers. In delivering our services, we seek to create value for our customers, our owners and our community.

Our integrated network comprises:

- transmission assets, which include 3,516 circuit kilometres of transmission lines; 7,852 transmission line support structures; 49 substations; seven switching stations; two transition stations; 11,176 hectares of easements; and 37 communications repeater sites; and
- distribution assets, which include approximately 15,100 kilometres of overhead high voltage lines; 5,000 kilometres of overhead low voltage lines; 2,500 kilometres of high and low voltage underground cables; 30,000 ground and pole-mounted substations; and almost 221,000 poles.

We also own, operate and maintain telecommunication network infrastructure to enable the safe and efficient operation of the electricity system. The figure below shows our role in Tasmania's electricity supply industry and customer service relationship.

Figure 2-1: Our place in Tasmania's electricity supply industry and our service relationship with customers



This Regulatory Proposal is concerned with distribution services only, as the regulatory arrangements currently provide for transmission and distribution services to be examined separately. From 2019 onwards, however, the AER will examine both of our network services simultaneously.

2.2 Focus on innovation

Our vision is to be trusted by our customers to deliver today and create a better tomorrow. As a recently merged business, we are on a journey of transformation to deliver the lowest sustainable prices to customers and appropriate returns to shareholders. We are already delivering efficiencies as an integrated network business and have commenced a key business initiative to support business transformation. This is a business-critical transformation program that we call Ajilis which will be delivered over the three years to 2018. The project is streamlining business processes and information platforms to improve the way we deliver essential energy services to customers.

We are striving to realise our vision by:

1. listening to our customers and considering their needs in our plans;
2. working to deliver a predictable and sustainable price path for network services;
3. applying robust governance processes and a risk-based approach to asset management; and
4. seeking further efficiencies in everything we do.

Delivering on this vision means recognising and embracing the significant changes in the electricity sector which are being driven by technology and customer preferences. In particular:

- Consumers are becoming more active in managing how their energy needs are met, and emerging technologies including battery storage are opening up customer choice in terms of products and providers.
- Distributed generation is playing an increasing role in the supply of electricity.
- Structural changes in the economy are impacting on energy demand, including the growth of the services sector relative to traditional, more energy intensive industries.
- Improvements in monitoring asset condition and performance provide opportunities to deliver better targeted, more efficient expenditure.

These technological changes remind us that we must constantly innovate to ensure that the transmission and distribution networks continue to serve our customers' changing needs as efficiently as possible. It is not always appropriate to build long-lived network assets, especially if technological advances are able to provide more flexible, lower cost options. Our expenditure plans explain how we intend to embrace technological change and innovate to deliver lower cost energy solutions.

2.3 Our customers

A number of large industrial and commercial customers are connected directly to TasNetworks' transmission network. More than half the energy delivered in the state is transmitted to these transmission customers. The balance of customers in the state are connected via TasNetworks' distribution network. The distribution network serves the following customer groups:

- residential, comprising nearly 239,000 customers or 84 per cent of the customer base and approximately 45 per cent of the electricity delivered by the distribution network;
- small business, commercial and industrial, comprising approximately 15 per cent of the customer base, but consuming approximately 54 per cent of the electricity delivered by the distribution network; and
- unmetered supplies, which include public lights; electric fences; public telephone boxes; and traffic signals.

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 are 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 that we consider our customers' perspectives and 'voice' in our activities and decisions;
- implementing a customer segmentation model and engagement framework;
- establishing the TasNetworks Customer Council 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;
- undertaking monthly customer satisfaction surveys; and
- undertaking quarterly customer net promoter score surveys.

Chapter 3 explains our approach to customer engagement in developing this Regulatory Proposal.

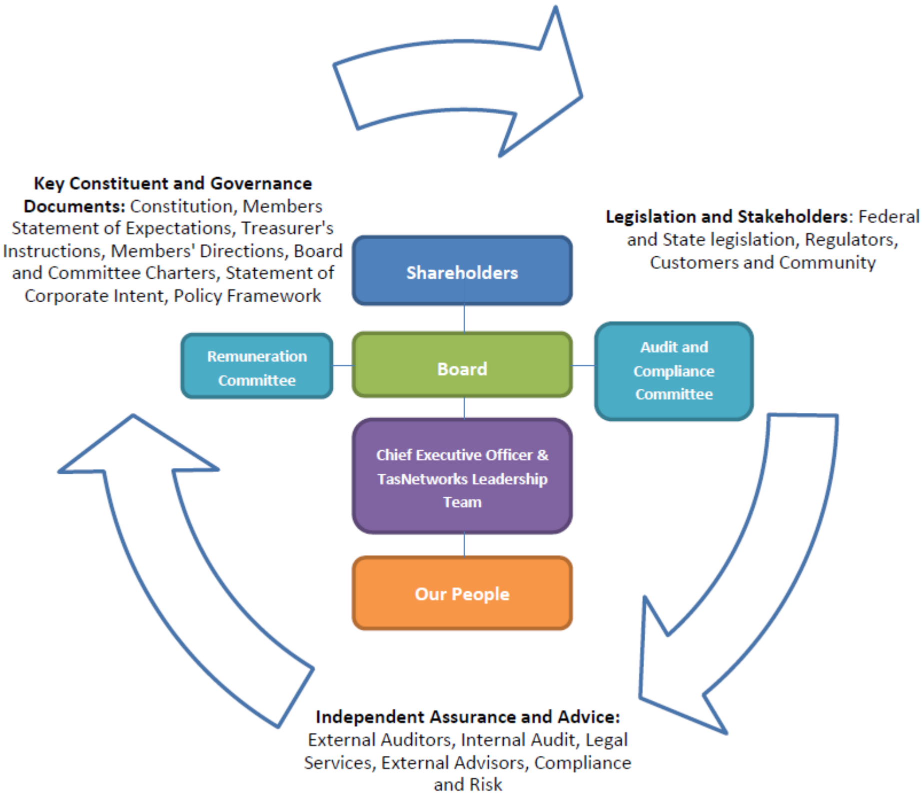
2.4 Corporate governance

As the owner of TasNetworks, the Tasmanian Government sets out its broad policy expectations and requirements for the company in an instrument issued by the Treasurer and Minister for Energy, titled the Members' Statement of Expectations[5]. The company operates in accordance with this guidance, the TasNetworks Constitution and the Corporations Act 2001.

Our corporate governance structure is shown below.

[5] A copy of the Statement can be viewed at: http://www.tasnetworks.com.au/TasNetworks/media/pdf/electricity_network/tariffs/2014-15/Members-Statement-of-Expectations-Tasmanian-Networks-Pty-Ltd-1.pdf

Figure 2-2: TasNetworks' corporate governance structure



The TasNetworks Board is responsible for the strategic guidance and oversight of the company.

TasNetworks' Board Charter provides the framework for TasNetworks' corporate governance structure and practices. The Charter describes the responsibilities of the TasNetworks Board of Directors and the TasNetworks Leadership Team. The Board is responsible for:

- oversight of the company, including its control and accountability systems;
- appointing and removing the CEO and Company Secretary;
- input into, and final approval of, corporate strategy and performance objectives developed with the TasNetworks Leadership Team;
- input into and final approval of Regulatory Proposals to the AER;
- reviewing, ratifying and monitoring systems of risk management and internal compliance and control, codes of conduct, and legal compliance;
- monitoring management's performance and implementation of strategy, and ensuring that appropriate resources are available;
- monitoring the performance and setting the remuneration for the CEO and management;
- approving and monitoring the progress of major capital expenditure and capital management, and any acquisitions and divestitures;
- approving and monitoring regular financial and other reports;
- approving annual financial statements and reports; and

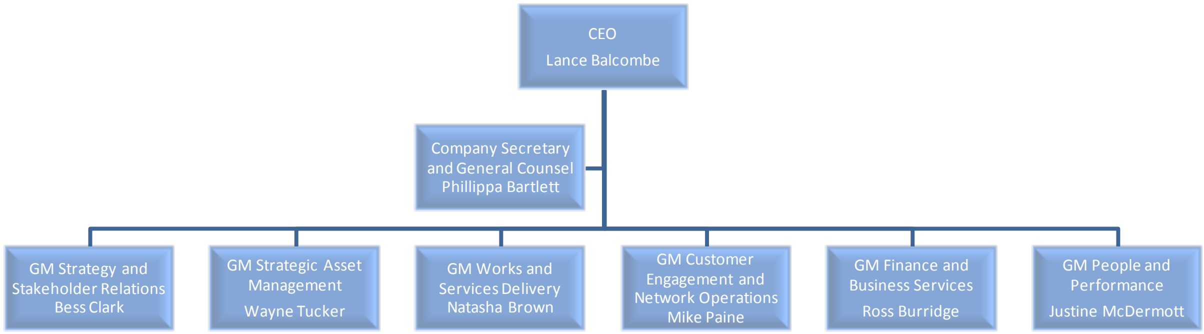
- communication with the shareholders about matters that may affect TasNetworks' ability to achieve its objectives or financial targets.

TasNetworks' Board Charter is based on the ASX Corporate Governance Council's Corporate Governance Principles and Recommendations, as adjusted to apply to an unlisted, State-owned company in line with the Tasmanian Government Business Corporate Governance Principles.

2.5 Our organisational structure

TasNetworks' executive management team comprises a Chief Executive Officer and seven executive managers. The organisational structure is shown below.

Figure 2-3: TasNetworks organisational structure



2.6 Our regulatory environment

TasNetworks operates in the National Electricity Market (NEM) and in accordance with a range of national and state legal frameworks that set out our obligations as a distribution network service provider.

As noted in section 1.1 the AER is responsible for the economic regulation of electricity distribution services in accordance with the NEL and the Rules. The AER's economic regulation functions and powers include:

- the determination of our allowed revenues for a regulatory period; and
- the design and application of various schemes that provide us with incentives to pursue efficiency gains in operating and capital expenditure, and to maintain service standards.

The Office of the Tasmanian Economic Regulator (OTTER) also has regulatory responsibilities. OTTER publishes and maintains the Tasmanian Electricity Code (the Code). The Code sets out the detailed arrangements for the regulation of the Tasmanian electricity supply industry and is enforceable under the Electricity Supply Industry Act 1995 (ESI Act), the principal Act governing the operation of the electricity supply industry in Tasmania.

Following Tasmania's entry into the NEM in 2005 many Code provisions were superseded by the National Electricity Rules. However, key provisions of the Code that affect the provision of distribution services remain in force, including:

- Chapter 2 of the Code, which requires TasNetworks to hold a Network Service Provider licence (issued by OTTER) in accordance with the ESI Act;

- Chapter 8, which sets out provisions governing distribution system operation, including the voltage standards and supply reliability standards with which TasNetworks must comply; and
- Chapter 8A which prescribes requirements relating to distribution power line vegetation management.

More broadly, we are required to comply with the Electricity Companies Act 1997, the ESI Act 1995, and all other applicable legislative, policy and other requirements including, but not limited to work health and safety, environmental and industrial relations obligations.

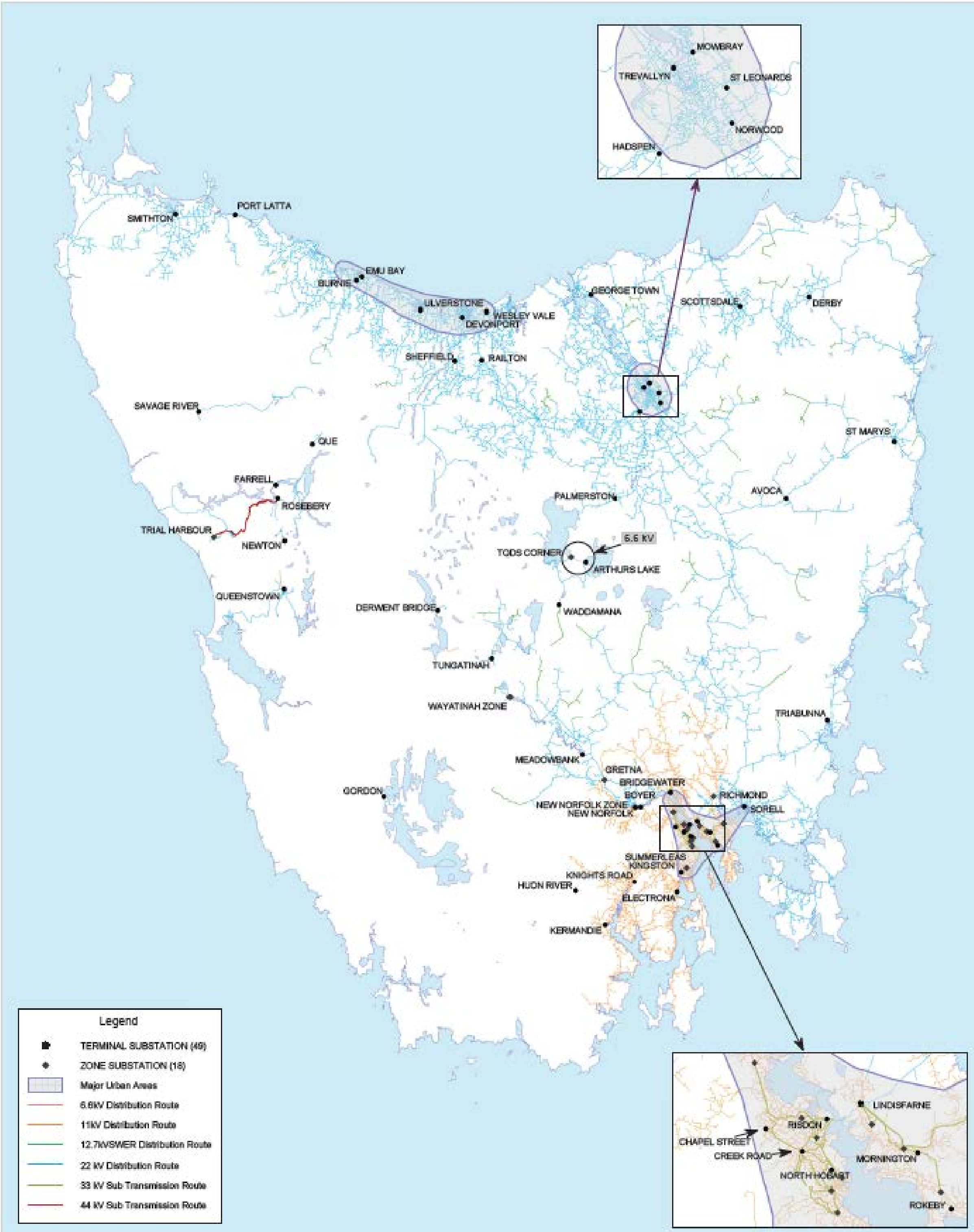
Further details of our compliance obligations and their implications for our expenditure forecasts are set out in chapters 6 and 8 of this Regulatory Proposal.

2.7 Key features of the Tasmanian distribution network

The Tasmanian distribution network is principally a ‘poles and wires’ business, with the high voltage substations and transformation equipment between transmission and distribution networks generally classified as transmission system assets in Tasmania. This network boundary is similar to the Western Power integrated network business, but different to other distribution networks regulated by the AER.

A map of the distribution network is provided in Figure 2-4 below which shows the high voltage distribution network by voltage.

Figure 2-4: Tasmanian distribution voltage areas



The Tasmanian distribution network comprises:

- a sub-transmission network in greater Hobart, including Kingston, and one sub-transmission feeder on the west coast of Tasmania that provides connection points for the high voltage distribution network. These sub-transmission connection points are in addition to the connection points between the high voltage distribution network and the transmission terminal substations;
- a network of high voltage feeders that distribute electricity from the transmission terminal substations and the distribution zone substations to the low voltage network and a small number of customers connected directly to the high voltage network; and
- distribution substations and low voltage feeders providing supply to the majority of customers in Tasmania.

A high-level summary of the composition of our distribution network infrastructure is presented in the table below.

Table 2-1: Distribution Network Infrastructure

Infrastructure	Nominal voltage (kV)	Quantity
Connection points		
Sites	44, 33, 22, 11 and 6.6	45
Sub-transmission feeders	44, 33 and 22	26
Minor zone source feeders	22 and 11	6
Distribution feeders	22, 11 and 6.6	240
Zone substations		
Major	44, 33 and 22	13
Major zone distribution feeders	22 and 11	117
Minor	22 and 11	3
Minor zone distribution feeders	22 and 11	7
Distribution substations		
Overhead		29,738
Ground-mounted		1,901
Route data		
High voltage overhead	6.6 to 44	15,125 km
High voltage underground		1,222 km
Low voltage overhead	0.4	4,959 km
Low voltage underground		1,235 km
Poles	All voltages	221,405

Source: TasNetworks

Feeders supplying rural and urban areas tend to have different characteristics.

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

The majority of feeders 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 and New Norfolk. Planning issues on feeders supplying rural areas are characterised by reliability performance due to vegetation; voltage and power quality issues due to the feeder length; and disturbing loads, such as pumping load.

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

Feeders supplying urban areas of greater Hobart, Kingston and a pocket of the Burnie commercial area, are operated at 11 kV. Those in Launceston, Devonport and Burnie are operated at 22 kV. Feeders supplying urban areas are generally capacity constrained and sometimes have issues with high fault level. Such issues are considered in developing our distribution feeder strategy, which is an input to our reinforcement capital expenditure.

2.8 Our plans for the business

Our strategic goals are to:

- understand our customers by making them central to all we do;
- enable our people to deliver value; and
- care for our assets, delivering safe and reliable network services while transforming our business.

Our strategic goals are based on three pillars: Customers, People and One Business. The figure below outlines how we will deliver on our strategic goals under these three pillars.

Figure 2-5: Our 'strategy on a page'

Vision	Trusted by our customers to deliver today and create a better tomorrow.			
Purpose	We deliver electricity and telecommunications network services, creating value for our customers, our owners and our community.			

	Customers	People	One business	Sustainable shareholder outcomes:
Strategic goals What do we need to focus on to achieve our vision?	We understand our customers by making them central to all we do.	We enable our people to deliver value.	We care for our assets, delivering safe and reliable network services while transforming our business.	• Returns on assets and equity • Dividends • Corporate reputation • Robust balance sheet
Strategic measures How do we know when we have achieved it?	• Customer net promoter score • Lowest sustainable prices	• Culture score • Engagement score	• Zero harm • Network service performance maintained • Sustainable cost reduction	
Initiatives What are the enterprise-wide initiatives we need to focus on now?	• 'Voice of the Customer' program • Framework for predictable and sustainable pricing	• Culture development through leadership • TasNetworks Enterprise Agreement	• Business excellence framework • TasNetworks integrated business solution	

HOW WE WORK

We care for our people and the community	We collaborate to deliver real value to customers	We innovate and we are a fast follower	We challenge the status quo	We are fit for purpose	We are one business

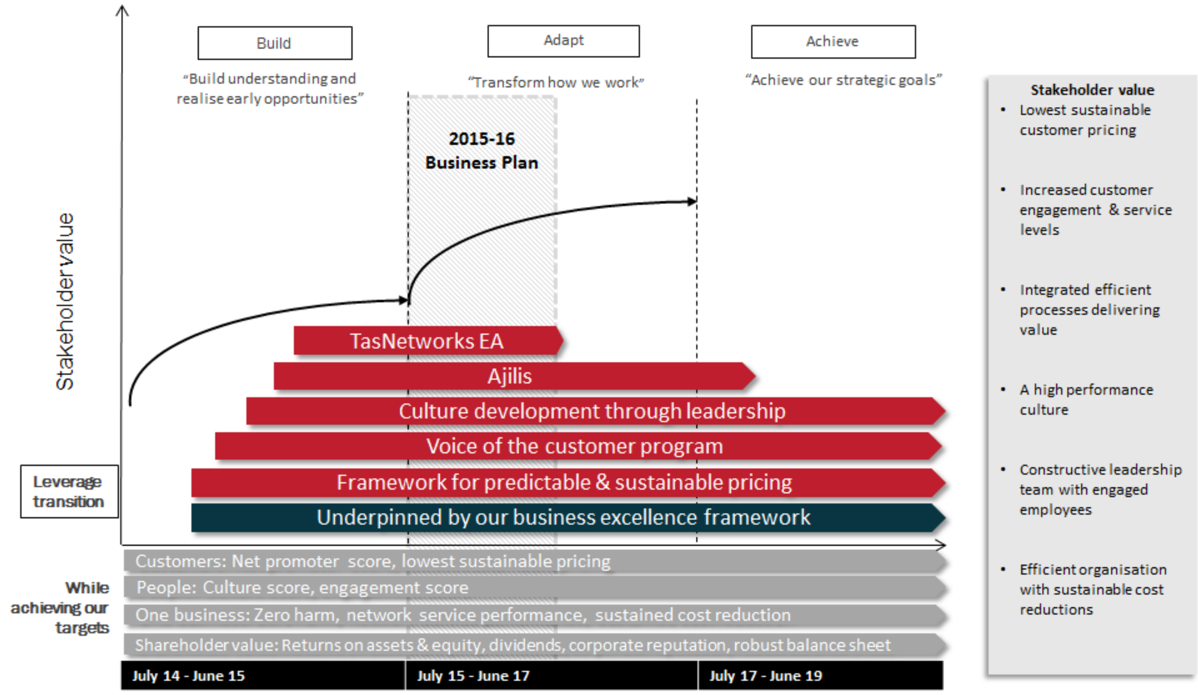
As a recently formed business we are implementing a demanding agenda and working hard to achieve efficiency gains from the integration of Tasmania's transmission and distribution networks.

TasNetworks has adopted a phased approach to transforming the business and achieving its strategic goals, based on the following principles:

1. ***Build*** understanding and capability, while delivering safe and reliable network services by:
    - continuing to build understanding and capability to enable our people to deliver value;
    - realising early opportunities to reduce operating expenses; and
    - establishing baseline culture and customer-focused performance measures.
2. ***Adapt*** by transforming how we work by:
    - delivering a high-performance culture and change how we work to deliver improved outcomes for our customers and our shareholders;
    - developing a TasNetworks enterprise agreement that supports our strategic goals;
    - delivering tactical information technology (IT) solutions that are appropriate for the new business;
    - implementing our 'Voice of the Customer' framework and initiatives to deliver improved customer service, tailored to our customer segments; and
    - providing predictable and sustainable pricing to our customers.
3. ***Achieve*** our strategic goals and increased stakeholder value by:
    - providing efficient integrated business systems which support the business; and
    - transitioning to a single revenue reset for transmission and distribution.

Our phased approach to transforming the business is depicted in the figure below.

Figure 2-6: Transforming our business



Phased approach to transforming our business

As a result of our work in transforming the business during the first year of operation we have delivered recurrent operating savings across the business (including transmission and distribution networks) of $25.9 million. This is in addition to the $8 million in savings established upon the integration of the two businesses. However, more will be done to build on these initial improvements and deliver higher value, lower cost outcomes for our customers.

2.9 Lowest sustainable electricity prices

We recognise the challenges currently facing the Tasmanian economy and the importance of delivering the lowest sustainable electricity prices to support economic growth. The Tasmanian Government emphasised this point in developing its Tasmanian Energy Strategy. The Government's vision is to restore energy as a competitive advantage for Tasmania by:

- delivering affordable energy at competitive and predictable prices that are amongst the lowest in Australia;
- empowering consumer choice;
- ensuring an efficient energy sector that is customer focused;
- utilising energy to facilitate State growth; and
- maximising Tasmania's renewable energy opportunities.

We strongly support the Government's vision. Our expenditure plans and initiatives outlined in this Regulatory Proposal will contribute to the achievement of the Tasmanian Energy Strategy. We are committed to:

- delivering the lowest sustainable electricity prices for customers; and
- becoming more efficient and customer focused.

With network costs presently making up over half of the average Tasmanian electricity bill, we have a key role to play in keeping prices low, while delivering safe and reliable services. We are focusing on reducing costs and increasing efficiency. We are also transitioning to more cost reflective tariffs, in accordance with the Tasmanian Energy Strategy and new Rules requirements introduced by the Australian Energy Market Commission (AEMC).

3 Customer engagement

3.1 Our focus on customers

We are committed to engaging with, informing and educating our customers about our activities and plans for the future. Our customer strategic goal is to ‘understand our customers and make them central to all we do’, with the ultimate aim of improving price, service and reliability outcomes for customers.

We recognise that we must understand and respond to each of our customer segments if we are to deliver service propositions that meet their varied needs. With this in mind we apply a very broad definition of our customers, which extends to include partners, stakeholders and the broader Tasmanian community, as well as the customers who are connected to our network. This approach ensures that we adopt a customer-centric approach in our relationships with all stakeholders. Our Customer Segmentation Model is shown below.

Figure 3-1: TasNetworks’ Customer Segmentation Model

We have developed a 'Voice of the Customer Program' to sharpen our focus on delivering quality service outcomes for our customers. Under the program, we are committed to earning the trust of our customers, and engaging with our customers about our activities and plans for the future. The Voice of the Customer Program ensures that we take the customer perspective and 'voice' into consideration in our activities and decisions. It establishes a platform from which customer engagement initiatives, customer culture and satisfaction measurement will evolve, and is a key input to service excellence improvement planning. It includes an engagement framework that assists us to drive a culture of 'Customer First'.

TasNetworks' customer engagement framework defines the different levels of participation available to us when engaging with our customers. The framework is used to determine the most appropriate level of customer participation that should be used when undertaking community consultation on particular issues. The framework is based on the International Association of Public Participation Spectrum (IAP2).

As shown below, five levels of public participation are identified, and these range from 'inform' to 'empower'. We identify the appropriate level of engagement on a case by case basis. It is not always possible to provide customers with a decision making role, for instance in relation to safety issues.

Figure 3-2: TasNetworks' customer engagement framework

Increasing Level of Customer Participation

	Inform:	Consult:	Involve:	Collaborate:	Empower:
Customer Engagement Goal	To provide our customers with balanced and objective information to assist in understanding the problem, alternatives, opportunities &/or solutions.	To obtain customer feedback on analysis, alternatives and/or decisions.	To work directly with our customers throughout the process to ensure that customer concerns and aspirations are consistently understood and considered.	To partner with our customers in each aspect of the decision, including the development of alternatives and the identification of the preferred solution.	To place final decision making in the hands of our customers.
Promise to our Customers	We will keep you informed.	We will keep you informed, listen and acknowledge concerns and provide feedback on how customer input influenced the decision.	We will work with you to ensure your concerns and issues are directly reflected in alternatives we develop and provide feedback on how customer input influenced the decision.	We will look to you for direct advice and innovation in formulating solutions and will incorporate your recommendations into decisions where possible to the maximum extent.	We will implement what you decide.
Customer Engagement Tools	Fact Sheets Newspaper/TV/Radio Letters/Customer Cards Social Media Customer Charter Brochures	Focus Groups Community Forums Public Meetings Trade Nights Surveys	Workshops Consumer Engagement Forums	Advisory committees Contracts/Legal Agreements	Delegated decisions

Through our Voice of the Customer program, our focus on customers will:

- help us to provide quality service outcomes for our customers; and
- enable the successful achievement of our vision, which is to be trusted by our customers to deliver today and create a better tomorrow.

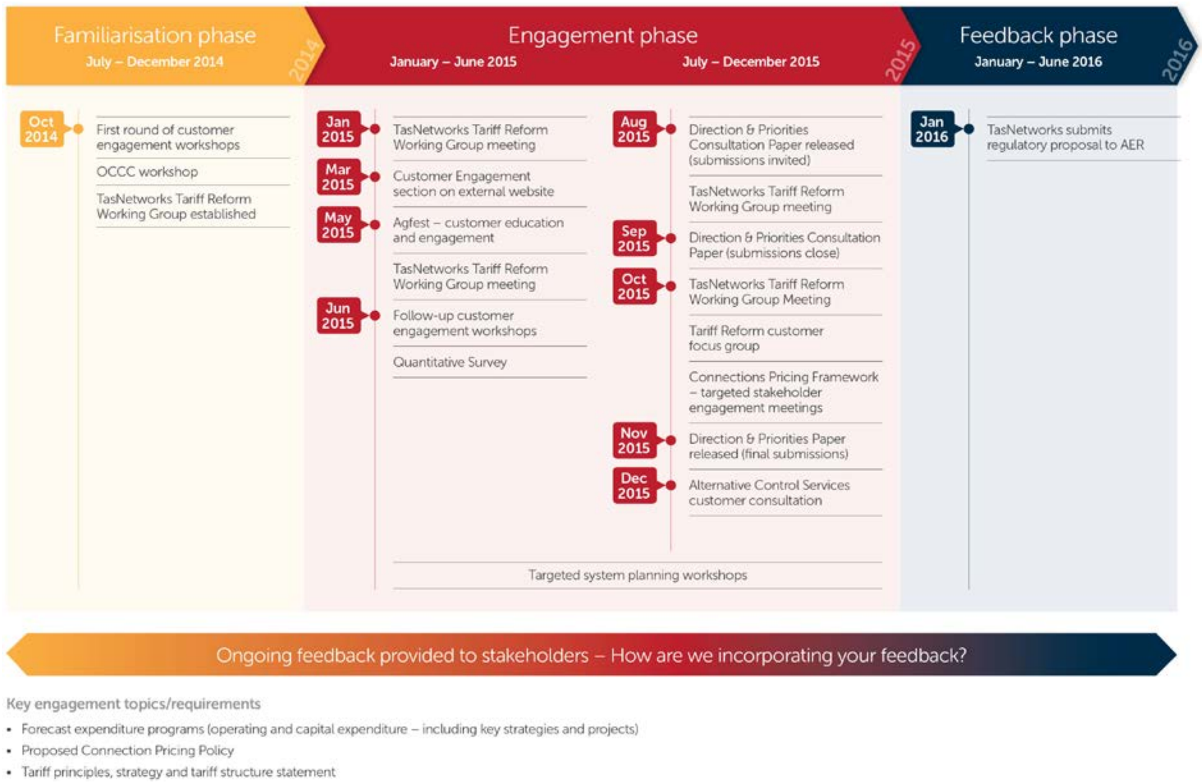
3.2 Our Revenue Reset Engagement Plan

To inform our Revenue Reset activities, we gathered information and feedback from our customers and other stakeholders in a variety of different ways, as shown below.

Figure 3-3: Our engagement activities

In addition to the 'business as usual' engagement activities outlined in section 3.1, we developed a customer engagement plan to guide discussions with our customers on key aspects of our Regulatory Proposal. Our customer engagement plan is outlined below.

Figure 3-4: TasNetworks' Revenue Reset Engagement Plan



The key milestones of our customer engagement activities under the plan are outlined below.

First round of customer engagement workshops

In October 2014 we held the first round of workshops with end-use customers, to obtain a better understanding of customer preferences regarding the trade-off between network reliability and cost. We held two workshops (one in Hobart and the other in Launceston) which were attended by approximately 50 of our customers from around the state. The workshops were facilitated by an external consultant and supported by TasNetworks' team members from across our business.

Workshop held with a number of stakeholder groups

A workshop was held with a number of OTTER's Customer Consultative Committee (OCCC) members in October 2014. Attendees included the Tasmanian Council of Social Services, Tasmanian Small Business Council, Renewable Energy Alliance and Local Government Association of Tasmania. The key outcome was to understand stakeholders' preferences, and ensure they were considered when developing our forward work program.

Tariff Reform Working Group

The Tariff Reform Working Group (TRWG) was established to provide advice on stakeholder needs and issues in respect to network tariff arrangements. The group acts as a link to and from member organisations and is chaired by TasNetworks. The TRWG includes electricity retailers, customer advocacy groups, business associations and energy advisors. The purpose of the TRWG is to provide a forum where member organisations can contribute to the direction of TasNetworks' network tariff framework, provide feedback and to explore stakeholder views in relation to network tariff reform.

Agfest

TasNetworks participated in the Agfest rural symposium from 7 to 9 May 2015. Various customer activity stations formed part of our display, providing the opportunity to engage with customers on the services that we provide and how those services are outlined in our Regulatory Proposal. During this activity, we surveyed 362 patrons and the information collected was included as part of the quantitative research discussed below.

Quantitative research

Telephone and online surveys were conducted by an external facilitator in May 2015 to gain consumer insights on aspects such as price, quality, safety, reliability and security of supply. A sample size of 1,000 participants was drawn from a broad group of demographics. Additional interviews were completed at Agfest 2015 (noted above) and via the TasNetworks website. The results of the survey built on the key themes and issues that emerged from our first round of engagement workshops.

Second round of customer engagement workshops

Follow up workshops were held in June 2015, using the same external consultant from the October 2014 sessions. The objective of these workshops was to outline what we had heard from our customers and demonstrate how those preferences and feedback had been integrated into our future expenditure programs and service standards. We also used these workshops to test our plans and seek further feedback from our customers.

A summary of the outcomes of this workshop is published on TasNetworks' website.

System planning engagement

Over the period from April to December 2015 we met with representatives of developers, customers and external planning bodies (such as TasWater, Department of State Growth, and various councils) to discuss our strategies and plans in various areas of the network. Using our Annual Planning Report as the focal point for discussions, we consulted on our network development and asset management strategies and opportunities. These meetings assisted us in understanding our customers' expectations and issues regarding our future plans for the network and project deferment opportunities.

Direction and priorities consultation

Insights collected through all of our engagement activities, along with our knowledge of the network, future trends and regulatory obligations, were collated in the Direction and Priorities Consultation Paper. This consultation initiative provided customers with an opportunity to respond to our proposed distribution expenditure programs in more detail prior to submitting our Regulatory Proposal.

Our direction and priorities consultation identified the following themes to guide our plans for the forthcoming regulatory period:

1. improving how we communicate with, and listen to, our customers;
2. ensuring the safety of our customers, employees, contractors, and the community;
3. keeping the power on and maintaining service reliability;
4. innovating in a changing world; and
5. delivering services for the lowest sustainable cost.

Together, these key themes provide the foundation for all of our proposed expenditure and service plans for the forthcoming period. Further details on how these themes are reflected in our capital and operating expenditure plans are provided in chapters 7and 8.

3.3 Summary of customer feedback

We have undertaken a range of activities to gather feedback, and to understand the issues and concerns that are important to our customers. The key messages emerging from the customer engagement are summarised below:

- TasNetworks is meeting most customers' needs from an overall performance perspective.
- Our most valued services include reliability and restoration of supply, followed by the management of the network to safely and reliably deliver electricity.
- Overall satisfaction with current reliability levels is quite high. The majority of customers support TasNetworks' proposed strategy to maintain reliability rather than investing more to improve it.
- While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices for these improvements.

- Cost is the greatest concern and lower prices - without reducing service quality - would lead to the greatest uplift in satisfaction.
- Customers recognise that technology is changing the electricity industry, particularly in relation to solar PVs, battery storage and electric vehicles.

In relation to areas for improvement, customers highlighted the following issues:

- providing services at lower cost without compromising service quality;
- providing customers with better information about restoration times;
- addressing meter reading concerns;
- addressing quality of supply issues such as voltage complaints;
- ensuring that customers or stakeholders have sufficient information to make informed decisions on our future plans and network pricing reform;
- improving the way we communicate with our stakeholders on how we are innovating and considering new technologies; and
- using more responsive and modern communication tools (eg: SMS automatic messaging for outage updates) and improved online communication, especially for outages.

In Parts Two and Three of this Regulatory Proposal we explain how we plan to address the issues raised by customers in relation to Standard Control Services and Alternative Control Services. An initiative is planned to commence in early 2016 to help address meter reading concerns.

Our customers also provided us with suggestions as to how we can improve the quality of our engagement and communication with them. In particular, customers said:

- consultation should focus on regional areas, not just the big cities;
- TasNetworks needs to provide stakeholders with sufficient time and support to allow them to analyse and respond to questions posed as part of our engagement; and
- expenditure forecasts should be scrutinised and debated. However the average consumer is unlikely to be qualified or sufficiently knowledgeable to be able to provide detailed comments on complex technical issues.

Recognising that customers are on a ‘learning curve’ in terms of understanding the electricity industry and our network business, our approach to engagement in preparing this Regulatory Proposal has been to:

- provide stakeholders with basic background information on the industry and our role in it;
- explain our expenditure and service proposals in broad terms; and
- seek feedback on service, price and reliability trade-offs at a high-level.

We recognise that there are many opportunities for us to improve the way we engage and communicate with our customers. On the basis of the feedback we have received, we intend to engage in a way that ensures customers from regional areas have more opportunities to be heard in the future. We are also investigating ways we can inform and educate customers on an ongoing basis to assist them in providing meaningful and informed feedback.

4 Planning processes and performance

4.1 Introduction

This chapter provides background information on our planning processes and recent cost and service performance, with a focus on our network investment and reliability. We explain that our planning processes have changed as a result of the merger of the transmission and distribution networks. While these changes are currently in the ‘bedding down’ phase, the benefit of transmission and distribution integration is reflected in our expenditure plans, which are presented in Chapters 6 and 8 of this Regulatory Proposal.

To understand our plans for the forthcoming regulatory period, it is helpful to recap on our recent cost and service performance. We also comment on how we benchmark compared to our peers. This additional background information provides useful context for our expenditure plans.

The remainder of this chapter is structured as follows:

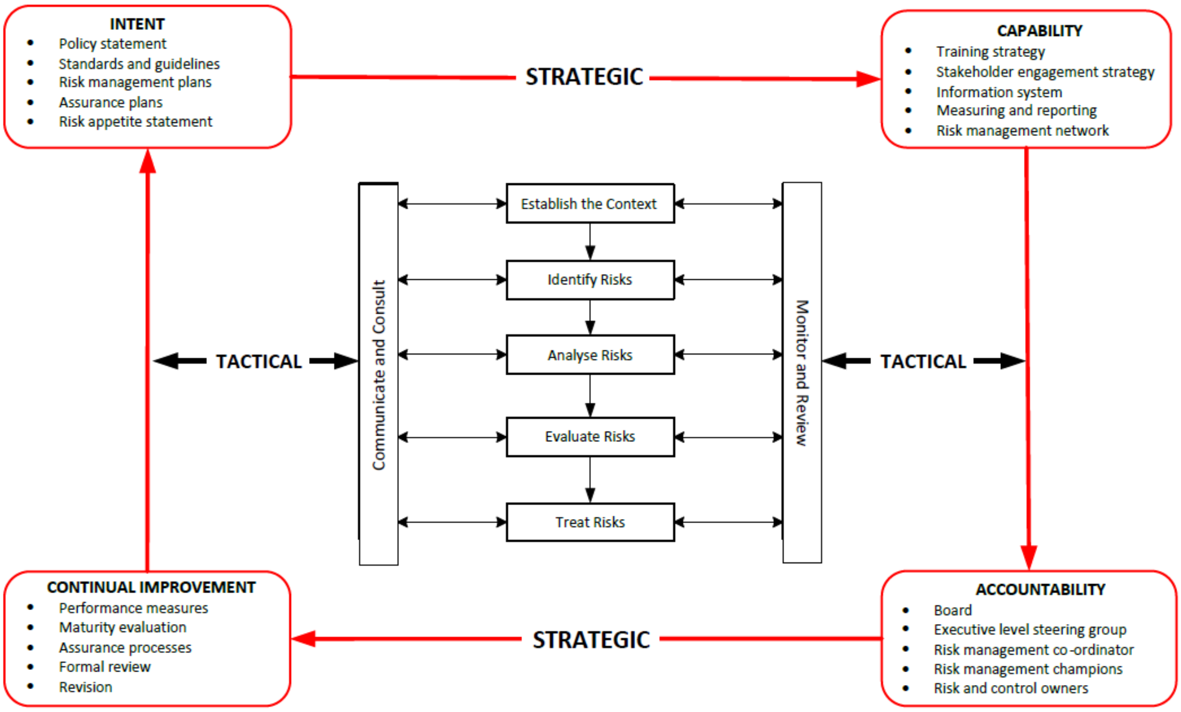
- Section 4.2 outlines our approach to risk management, which is expressed in our risk management framework.
- Section 4.3 explains that we have a single planning process covering the transmission and distribution networks. The output from the planning process is a capital plan that seeks to optimise expenditure between transmission and distribution, as well as between operating and capital expenditure.
- Section 4.4 provides a high level overview of our asset management framework, which shows the relationship between our corporate plan; asset management policy; strategic asset management plans; through to works delivery; performance evaluations and improvements.
- Sections 4.5 and 4.6 provide an overview of our investment governance and works delivery arrangements, which are focused on ensuring that every dollar of expenditure is efficiently and prudently incurred.
- Section 4.7 discusses our recent service and cost performance with reference to our service targets and AER expenditure allowances.
- Section 4.8 provides some high-level benchmarking information on our performance.
- Section 4.9 sets out concluding comments.

4.2 Risk management

The effective management of risk is central to the core business and efficient management of TasNetworks. Our approach to risk management involves an appropriate balance between realising opportunities for gains while minimising adverse impacts. Risk management is viewed as an integral part of good management practice and an essential element of good corporate governance.

Our risk management framework governs our approach to managing the effects that uncertainty has on achieving our strategic objectives. The framework also facilitates compliance with legislation, rules, codes, guidelines and various industry standards. The figure below shows our risk management framework with both its strategic and tactical (operational) components. The operational process we apply when managing risk is in accordance with AS/NZS ISO31000:2009 Risk Management – Principles and Guidelines.

Figure 4-1: Risk Management Framework



Many of our assets are older than those of our network peers, and a key focus for us is to effectively manage the risk due to poor asset condition to achieve our asset management service and cost performance objectives.

With regard to asset condition and risk, we continue to set service-based targets for assets within our asset management plans to balance the risk of asset failure, and the associated reliability impacts, with cost.

We are also pursuing strategies to:

- expand the use of condition based risk management across key asset fleets; and
- continue to develop and implement processes for capturing, registering, assessing, and tracking asset related risks and associated risk controls and treatments to better match service performance with our customers' requirements.

4.3 A single planning process

In previous regulatory periods, Aurora and Transend undertook joint planning to ensure distribution and transmission plans were aligned. Following the merger of the two businesses, the transmission and distribution planning functions are now integrated into one business function.

The Network Planning team is responsible for the following transmission and distribution planning activities:

- preparing the future supply-demand outlook;

- forecasting electricity consumption for terminal substations, zone substations and feeders;
- analysing the performance of the existing transmission and distribution network;
- identifying current and emerging transmission and distribution issues;
- undertaking network analysis and identifying network and non-network solutions;
- consulting with our customers on network planning strategies;
- managing customer connection enquiries;
- undertaking options analysis and investment evaluation associated with regulatory investment tests;
- integrating asset management strategies into the planning process;
- preparing the Annual Planning Report; and
- establishing long-term network strategies.

To ensure effective integration and delivery of our operational and capital works plans TasNetworks develops an overall works plan, encompassing all projects on the transmission and distribution networks.

The capital plan is a combination of area development plans and asset management plans for the various asset classes. These plans are integrated using information systems and tools to develop an integrated investment plan. This ensures that opportunities are realised to minimise expenditure and maximise asset availability, for example:

- Asset renewals and maintenance at sites affected by augmentations are coordinated to minimise outages and rework.
- Maintenance is minimised, or not undertaken, for assets that are to be replaced by new assets.
- Renewal and development expenditure project contracts are bundled to achieve economies of scale.

4.4 Asset management framework

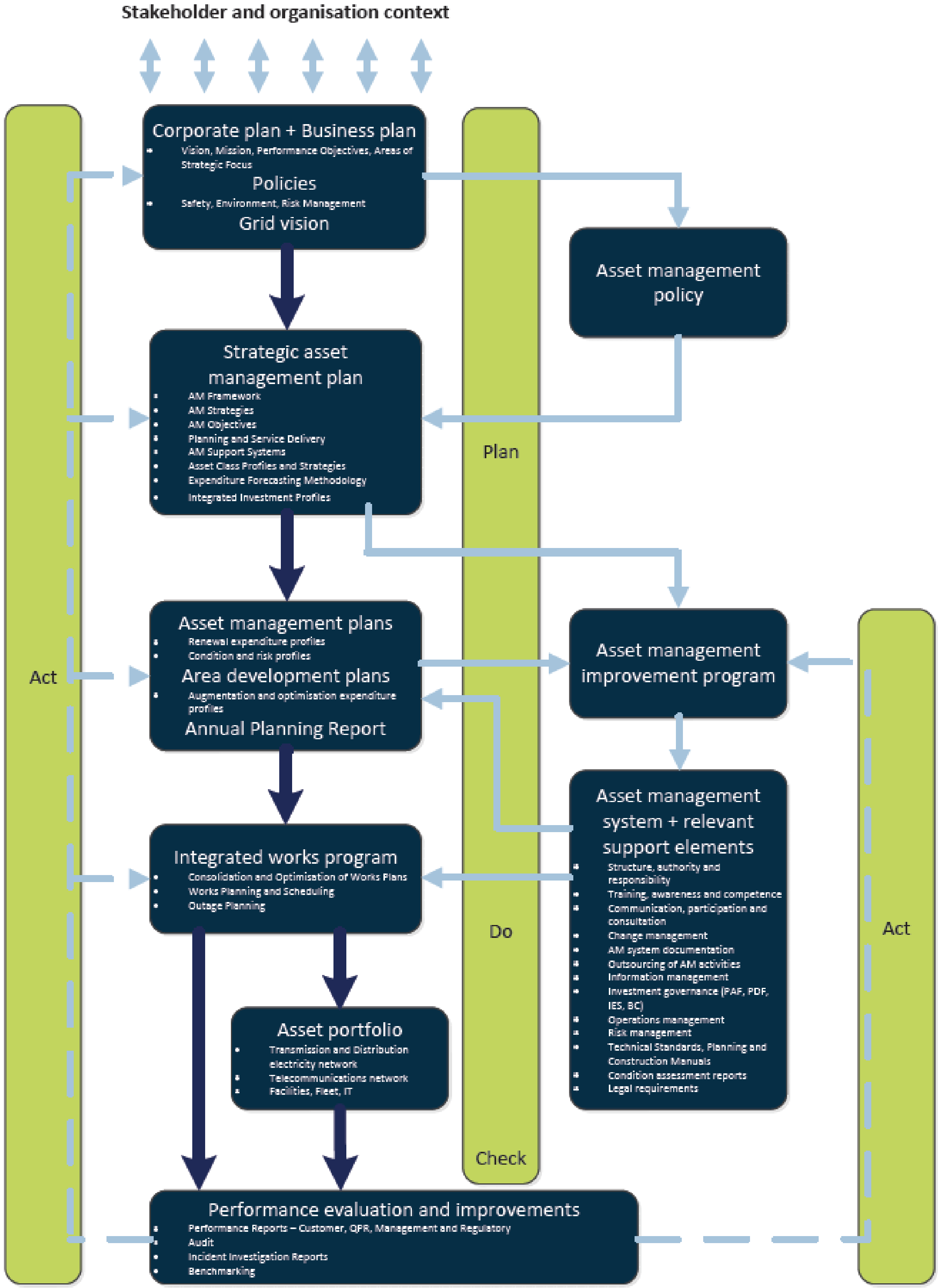
TasNetworks is implementing an integrated asset management framework, together with supporting processes and systems that support our combined network service responsibilities. The framework ensures that our approach to asset management delivers prudent and efficient outcomes that optimise the performance of the transmission and distribution networks.

The goal of infrastructure asset management is to deliver the required level of service in the most cost effective manner, through the prudent and efficient management of assets for present and future network users. Assets are replaced on the basis of asset condition and risk, rather than age. Efficiencies are achieved by adopting a holistic approach to asset renewals, augmentations and decommissioning, across both transmission and distribution networks. We ensure that our asset management plans align with our development plans to drive the most efficient outcome.

Our Strategic Asset Management Plan (which is submitted along with this Regulatory Proposal) explains that our asset management system is being developed in alignment with the ISO 55000 series of standards, which is the internationally accepted standard for asset management.

The figure below presents our asset management framework.

Figure 4-2: Asset Management Framework



Our asset management objectives, which are detailed in the Strategic Asset Management Plan, have been designed to align with the asset management policy and the organisational objectives, and thereby ensure clear 'line of sight' from strategy to implementation. The asset management objectives define the outcomes required from the asset management system and the program of work to ensure TasNetworks' strategic goals are met.

The asset management objectives focus on the six key areas below:

- **Zero Harm** will continue to be our top priority and we will ensure that our safety performance continues to improve.
- **Customer Engagement** will be improved to ensure that we understand customer needs and incorporate these into our decision making to maximise value to them.
- **Service Performance** will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet regulatory requirements.
- **Cost Performance** will be improved through prioritisation and efficiency improvements that enable us provide predictable and lowest sustainable pricing to our customers.
- Our **Program of Work** will be developed and delivered on time and within budget.
- Our asset management **Capability** will be continually improved to support our cost and service performance, and efficiency improvements.

4.5 Investment governance

Our investment governance arrangements are centred around robust investment evaluation processes, and a gated investment approval framework, as outlined below.

We have developed guidelines that specify the key considerations and steps that need to be undertaken during the investment evaluation of projects involving system assets. These guidelines provide assistance to personnel involved in the justification of investment projects by:

- identifying the various types of projects;
- specifying the evaluation needs for each step in the process;
- providing guidelines as to how these steps are to be implemented;
- identifying the inputs and outputs to various steps of project evaluation; and
- linking various systems, processes and tools to provide a consistent basis for project evaluations.

TasNetworks maintains a gated investment approval framework. Under this framework we apply the required technical, managerial and financial governance processes to ensure that:

- we engage with customers on our investment plans and take feedback into account in developing and implementing optimal solutions;
- investments meet mandated legal and regulatory obligations in a cost-effective manner and comply with the specific capital expenditure objectives and criteria stipulated in the Rules;

- investments are aligned with justified development plans and strategies, provide a reliable electricity network service, add capacity efficiently to meet forecast load growth and cater for new connections to the transmission and distribution networks; and
- capital expenditure is prudent and efficient.

4.6 Organisational arrangements for works delivery

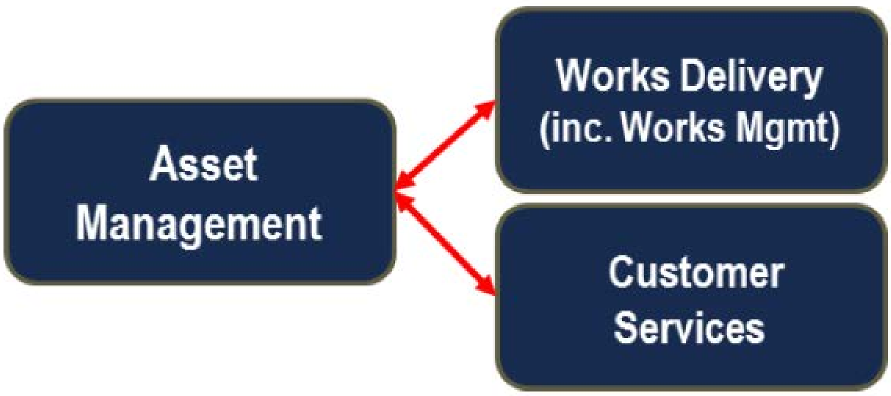
To maximise the benefits of merging the distribution and transmission networks we have adopted an organisational structure, which we call an 'empowered services model'.

Under the model:

- Customer services functions include large customer relationship management, customer contact centre, connection point management and charging, meter data management and publishing, billing enquiries and dispute resolution, and network and customer management.
- Asset management focuses its efforts on developing strategic asset management related priorities and the definition of what work needs to be undertaken and by when.
- A combined works management and delivery function is empowered to decide how the program of work is developed and delivered. Works management involves the development of resourcing and procurement plans and optimisation of the program of work. Works Delivery is responsible for asset stewardship, including design and estimation, works program management and reporting, project and program works delivery, contract management, field operations, works schedule and dispatch, safety and environmental policy. These combined functions are known as Works Delivery and the group in our business is now called Works and Service Delivery.

The model is illustrated in the figure below.

Figure 4-3: TasNetworks' empowered services model



We examined a number of alternative structures and we selected the empowered services model because it:

- provides the 'leanest', lowest cost model;

- ensures that Asset Management is focused on the needs of the assets and customers, without the distraction of planning or monitoring the delivery of work;
- affords Works Delivery the flexibility to choose between its own internal workforce and contract resources;
- tightens the links between the delivery of work and the ‘enablers’ required to facilitate this delivery (i.e. plant, equipment, materials, etc. are in a single group);
- ensures a lean and stable Asset Management group in which resourcing does not need to be varied significantly in response to changes in the works program over time; and
- facilitates efficient capture of asset data and other field intelligence for use in asset decisions.

4.7 Recent service and cost performance

Our recent service and cost performance provides useful background information in understanding our future expenditure plans. For example, it may indicate trends (positive or negative) in service and cost performance that influence our forecasts.

As explained in further detail in sections 7.3 and 8.2:

- Our actual capital expenditure is forecast to be approximately five per cent lower than the AER’s allowance for the current regulatory period. This reduction has been achieved despite a number of unexpected events, including the costs of bushfire recovery.
- Our actual operating expenditure in 2014-15 is 13 per cent below the allowance set by the AER. This is a very significant saving, which we will build on over the forthcoming regulatory period.

In summary, we have worked hard to keep costs down.

In relation to service performance, the analysis is more complex because there are a number of dimensions to measuring performance. As described below, Tasmania has been divided into 101 supply reliability communities, each of which is categorised into one of five supply reliability categories:

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

Reliability in a number of communities has not met the target standards in the last two years, predominantly due to a number of major event days and other weather events.

The table below shows the number of communities where performance – measured by the average outage duration for each customer served (SAIDI) – has fallen below the required standard set by the Code over the last five years. We recognise that more needs to be done to bridge the performance gap in these communities.

Table 4-1: Number of poor performing communities (SAIDI) that did not meet the standard by year – Code reliability standards

Supply reliability category (number of communities)	Standard (minutes)	2010-11	2011-12	2012-13	2013-14	2014-15
Critical infrastructure (1)	30	0	0	1	0	1
High density commerical (8)	120	0	1	3	0	0
Urban and regional centres (32)	240	5	5	5	12	13
High density rural (33)	600	2	3	4	11	13
Low density rural (27)	720	9	6	6	14	12
Total (101)		16	15	19	37	39

In addition to the performance standards set by the Code, our performance is subject to the AER's service target performance incentive scheme (STPIS). Our performance has generally met the AER's targets, although performance has been worse than target for customers served by the low density rural network.

Based on the AER's STPIS guideline methodology, the STPIS targets for the forthcoming regulatory period will reflect historic average performance over the most recent five-year period. These targets are consistent with the feedback from our customers that they expect us to maintain current performance. Further details of our target performance under the STPIS are set out in section 13.4 and the supporting spreadsheet (TN067).

The achievement of target performance is an important capital expenditure driver, which we discuss in further detail in chapter 6. As noted in section 7.5.2, our reliability reinforcement programs include targeted projects to restore the performance of the poorest performing reliability communities and worst performing feeders.

4.8 Benchmarking

Our distribution operating expenditure performance benchmarks favourably with our peers. In particular:

- The pre-merger level of distribution network operating expenditure appears efficient using the AER's current approach and efficiency target. When environmental factors are considered, in addition to our cost efficiencies since the merger, we consider that our performance benchmarks in the top quartile.
- The category analysis benchmarking confirms TasNetworks' strong operating expenditure performance, with TasNetworks comparing favourably to peers and broader industry in most categories.

Further details on our operating expenditure benchmarking is provided in a report from Huegin, which is provided as an attachment to this proposal (TN075).

In addition to the operating expenditure benchmarking results, it is useful to examine overall measures of productivity that combine operating expenditure and capital expenditure performance. The AER employs Multifactor Total Factor Productivity (MTFP) analysis as an overall benchmark measure.

In relation to the AER's MTFP analysis for our transmission and distribution businesses, there is a paradox to resolve. According to the AER's analysis, TasNetworks is one of the most efficient transmission companies, but one of the least efficient distributors. The benchmarking results are reproduced below.

Figure 4-4: Relative MTFP performance of transmission networks 2006-14[6]

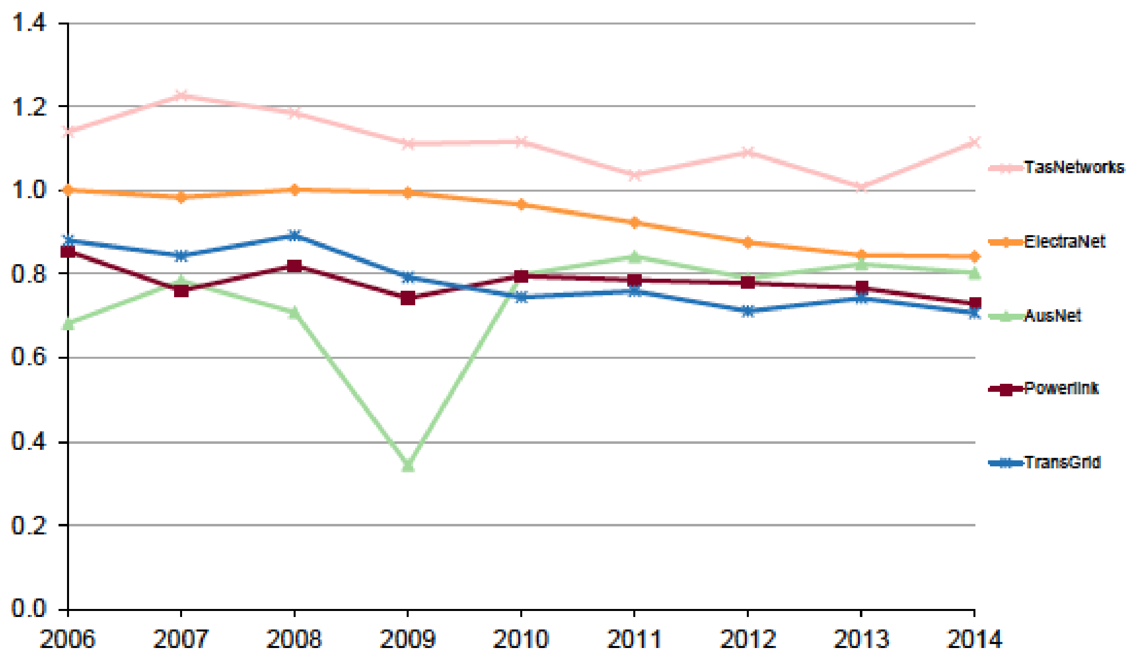
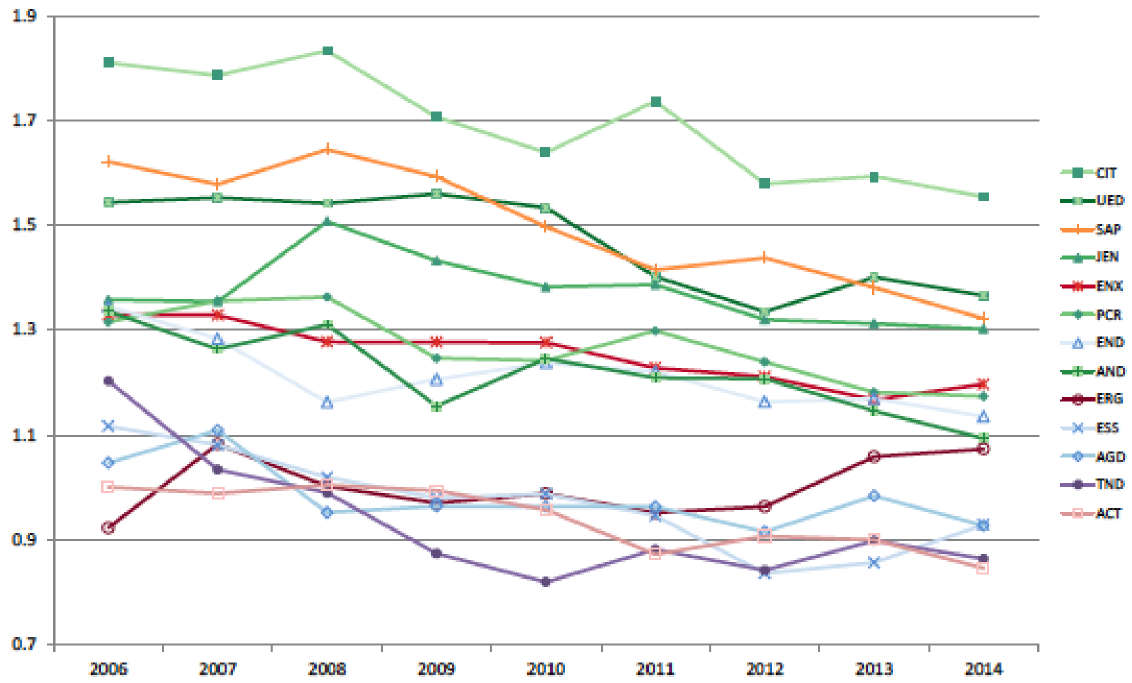


Figure 4-5: Relative MTFP performance of distribution networks 2006-14 [7]



6 AER, Electricity Transmission Network Service Providers, Annual benchmarking report, November 2015, Figure 2, page 5.

7 AER, Electricity Distribution Network Service Providers, Annual benchmarking report, November 2015, Figure 4, page 8.

In addition to the contradictory MTFP results for the transmission and distribution networks, a previous study undertaken by Economic Insights for the AER in July 2014 assessed our distribution network more positively. This earlier report indicated that the distribution network was middle-ranking which contrasts sharply with the results set out above.

We have investigated these conflicting benchmarking results with the assistance of Huegin, and we have written to the AER setting out our findings. In summary, it appears that the specification of the benchmarking model was amended after July 2014. This change penalises TasNetworks for our high proportion of 11kV overhead lines compared to other distributors.

It is recognised, however, that we cannot change the design of our network without exposing our customers to excessive and unnecessary costs. The choice of line capacity was a decision made many years ago, and appropriately reflects Tasmania's electricity demand, which is less dense than our peers. Our position is that the AER should not penalise the company for historic design choices.

We also consider that the AER benchmarking model penalises us because it measures transformer capacity as a proxy for the capital stock input. Our obligation to connect customers (including small rural loads) and the characteristics of our customer base has resulted in approximately 3000 single transformer customers. In addition, we must install sufficient capacity to cater for the very peaky start-up load of irrigators. Under the AER's model, these factors combine to make us appear significantly over-capitalised relative to other Australian distributors. Given our obligations, density and customer characteristics the level of transformer capacity installed on our distribution network is efficient.

These observations, coupled with the results of our investigation reinforces the widely held view that benchmarking needs to be applied cautiously, recognising that the conclusions may be materially affected by data limitations. The AER has acknowledged the uniqueness of our circumstances in its latest annual electricity network benchmarking report, in which it urges caution when interpreting our MTFP benchmarking score, given our "comparatively unusual system structure".

As explained in chapters 6 and 8 of this Regulatory Proposal, our expenditure plans incorporate future efficiency improvements. Therefore, while the AER's benchmarking analysis for TasNetworks provides some mixed results, we remain confident that our forecast expenditure satisfies the efficiency and prudency tests specified in the Rules.

4.9 Concluding comments

Our planning processes are undergoing important change as a result of the merger between the transmission and distribution networks. Our approach to business and asset management planning, investment governance and works delivery are consistent with industry best practice, and reflect our new business structure. We also have an eye to the future, to consider the impact of new energy services technologies and support efficient integration with our network.

The overall drivers for change are improved customer outcomes, efficiency and performance. While further investment in systems and processes is required to exploit fully our potential network synergies and economies of scale, our expenditure plans for the forthcoming regulatory period reflect the benefits of integration.

Our service performance for some customers remains below the standards and targets set by the jurisdiction and the AER. In the forthcoming regulatory period, these standards and targets are important drivers for our expenditure plans. As explained in Chapter 3, our customers have emphasised the importance of delivering cost savings and have indicated that they are generally happy with present reliability levels. Our planning has highlighted a number of asset classes that are in poor condition, and reaching end of life. We will maintain and renew our assets to sustain customer reliability and support the safety of our people and our community.

We recognise that benchmarking against our peers provides a useful cross-check on whether there is scope to push the business to the 'efficiency frontier'. The evidence in this regard is mixed and some doubts are raised as to how well the present national benchmarking accommodates Tasmanian network and customer characteristics. We will continue to work with the AER so that benchmarking becomes a more useful aid to understand our performance, and identify further improvement opportunities.

We must find ways to manage a range of new obligations and technologies, meet customer requirements, and do this at the lowest sustainable cost. This view is reflected in our expenditure plans through the application of a top-down discipline, which is focused on driving efficiency without compromising customer service, compliance, safety or reliability.

5 Demand, energy and customer connection forecasts

5.1 Introduction

Our expenditure plans for the forthcoming regulatory period must be calibrated to meet customer demand. We must also set network tariffs so that we recover the correct amount of revenue, as determined by the AER. In this chapter, therefore, we provide the following historic and forecast information:

- Section 5.2 provides information on our maximum demand, which is a key driver of our reinforcement capital expenditure.
- Section 5.3 presents information on energy consumption. While energy consumption does not drive our capital expenditure plans, it is relevant for setting network tariffs which presently include energy-based charges.
- Section 5.4 provides information on customer connections, which drive our customer initiated capital expenditure.

5.2 Maximum demand

Our maximum demand forecasts are based on three economic scenarios – medium, high and low. These scenarios are built on key energy market policies and economic conditions. We engaged the National Institute of Economic and Industry Research (NIEIR) to prepare forecasts of economic variables and regional energy and demand forecasts for Tasmania for each scenario.

The key drivers of the forecasts of maximum demand for Tasmania are:

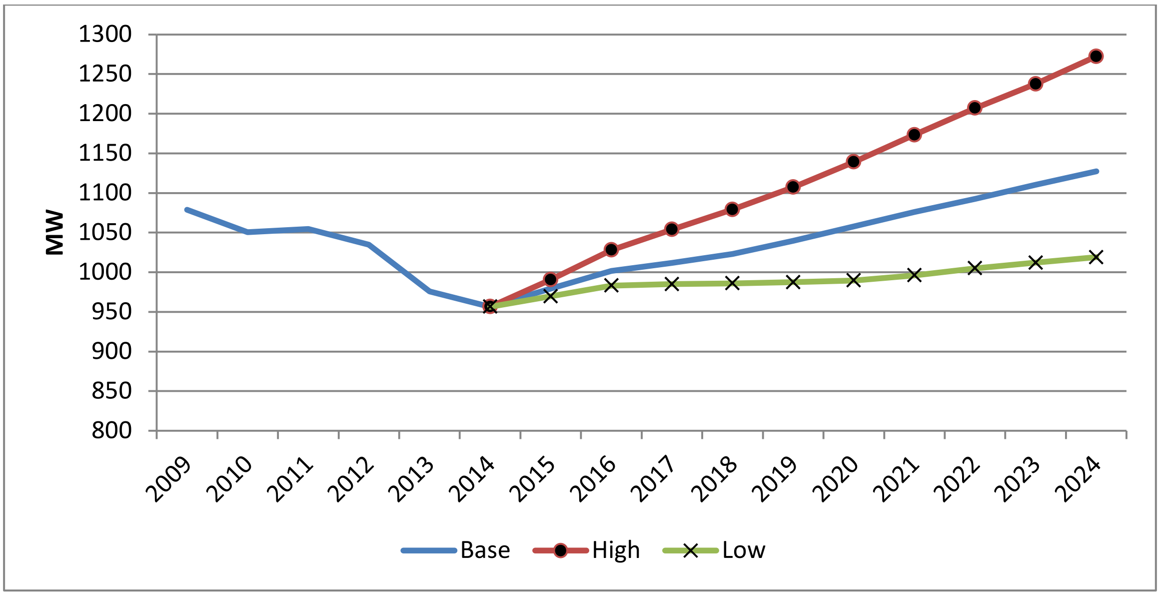
- gross state product growth;
- temperature sensitive load growth; and
- the indirect impact of electricity prices and other policies on demand.

Temperature is the most important influence on daily maximum demand. In Tasmania, higher demand occurs in winter at times of lower temperature. Forecasts of winter and summer maximum demands are formulated from historical equations estimated by NIEIR from data supplied by TasNetworks, weather data supplied by the Bureau of Meteorology, and economic data collated by the Australian Bureau of Statistics.

NIEIR regularly re-estimates these maximum demand forecast equations and performs diagnostic checks on the models fitted to the peak demand data. NIEIR also conducts ‘backcasting’, which uses the model to produce forecasts for historic periods to validate the model. This analysis is presented in Appendix B of NIEIR’s report, which is provided as a supporting document (TN076).

The figure below shows our forecast of maximum demand on the Tasmanian distribution network at 50 per cent probability of exceedance, using the modelling approach described above[8]. The demand forecasts presented in the RIN are derived from and consistent with the NIEIR report.

Figure 5-1: Actual and forecast Maximum Demand on the Tasmanian distribution network



Our demand forecasts for the period to 2024 reflect the following average growth rates:

- 1.6 per cent per year for the base economic scenario;
- 2.8 per cent per year for the high scenario; and
- 0.6 per cent per year for the low economic scenario.

Using the base forecast, the maximum demand on the distribution network in 2009 will not be exceeded until 2022.

5.3 Energy consumption

Energy sales forecasts are based on econometric models. To model energy sales accurately, it is important to examine the particular drivers for each sector of the economy. In broad terms, however, Tasmanian energy sales are driven by economic growth, electricity prices, weather conditions and trends in energy consumption per residential dwelling. The energy forecasts for the forthcoming regulatory period assume an increasing penetration of rooftop solar panels, which has a negative effect on energy sales across the state.

In developing its forecast, NIEIR employed three scenarios – a base case, a high scenario and a low scenario. While the details are provided in NIEIR's report, it is helpful to highlight the following commentary in relation to the base case:

- Growth in the residential market has been relatively flat over the last decade. The extension of the gas distribution and reticulation network leads to a very small but gradual loss of space heating and water heating load. Residential sales remain relatively flat in absolute

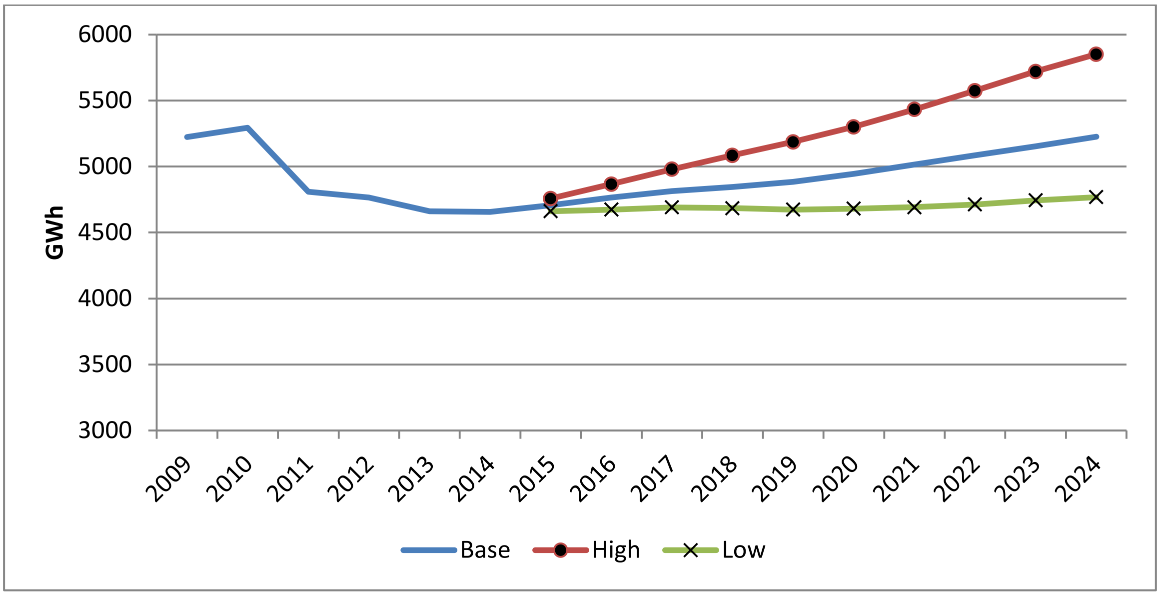
8 NIEIR, Electricity sales and maximum demand forecasts for Tasmania to 2045, Table D8, pages 142-144.

terms between 2014 and 2025. Residential electricity sales in Tasmania rise by 0.7 per cent per annum between 2014 and 2025.

- Commercial sales growth over the 2014 to 2025 period is partly dampened by the substitution of natural gas for electricity in area heating and hot water, as well as cooking. Commercial sector sales growth averages 2.4 per cent per annum between 2014 and 2025.

The following figure shows the actual and forecast total energy sales employing NIEIR's base, high and low case scenarios.

Figure 5-2: Actual and forecast energy sales on the Tasmanian distribution network



Our energy consumption forecasts for the period to 2024 reflect the following average growth rates:

- 1.2 per cent per year for the base economic scenario;
- 2.4 per cent per year for the high scenario; and
- 0.3 per cent per year for the low economic scenario.

Using the base forecast, energy sales from the distribution network are not forecast to return to the levels seen in 2010 until 2024.

5.4 New customer connections

TasNetworks applies an econometric methodology to forecast new customer connections to the distribution network. This approach requires the estimation and testing of statistical relationships between the number of new connections and the underlying drivers that influence the number of new connections, most notably the projected economic growth in Tasmania.

For forecasting purposes, we distinguish between:

- Residential customers and residential subdivisions;
- Commercial customers; irrigators; and embedded generation.

We also provide separate forecasts for 'basic' and 'complex' connections. In contrast to basic connections, customers with complex connections are required to contribute to the cost of upstream network augmentation. Residential subdivisions are also forecast separately, recognising that the drivers are somewhat different to basic and complex connections. In order to inform our capital expenditure plans, we further estimate the proportion of overhead and underground connections, and new connections for each service region.

We provide a summary of the residential customer connections in section 5.4.1, while section 5.4.2 summarises the connection information for commercial customers, irrigators and embedded generation. A more detailed explanation is provided in the supporting paper, TasNetworks Customer Connection Forecasts 2015.

5.4.1 Residential customer connections

Our actual and forecast residential customer connections are detailed in the figures below.

Figure 5-3: New residential connections – basic

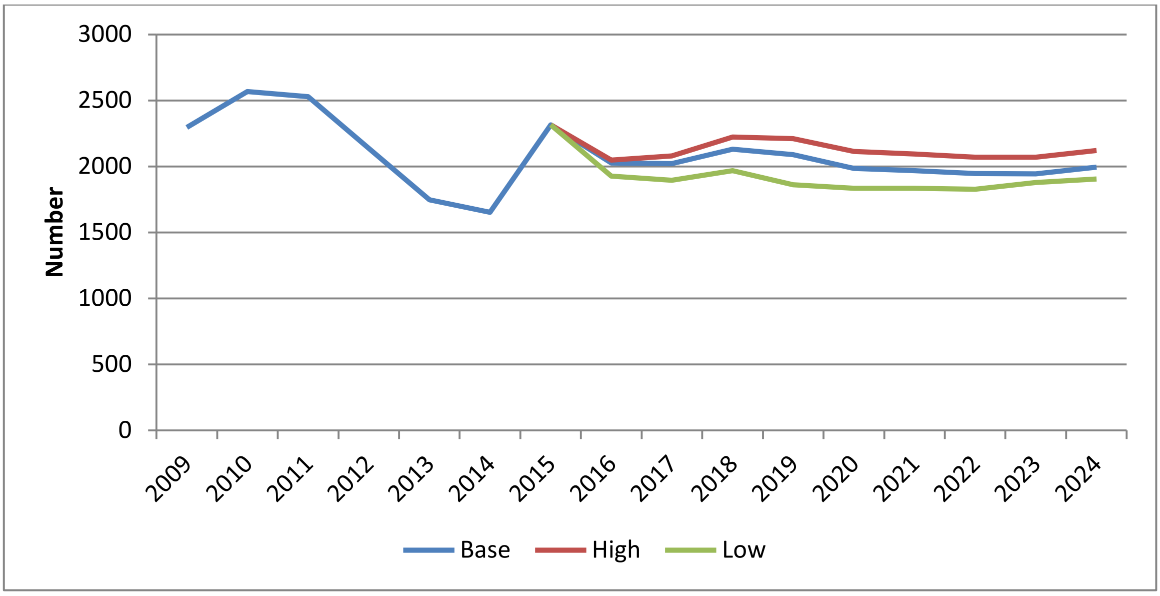


Figure 5-4: New residential connections – complex

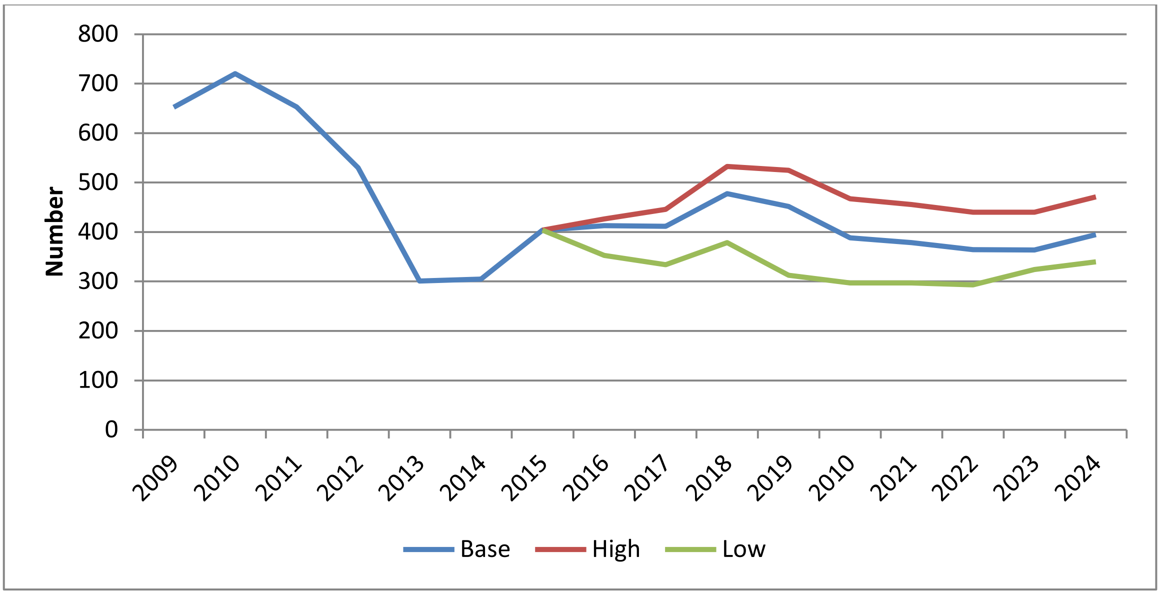
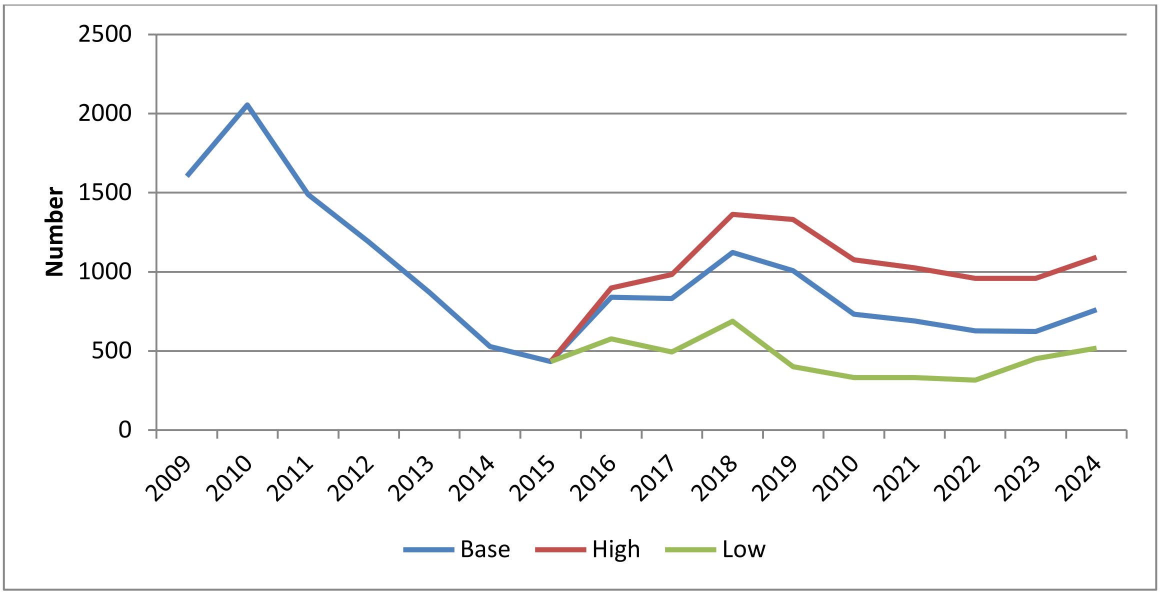


Figure 5-5: New residential subdivisions (lots)



5.4.2 Commercial customers, irrigators and embedded generation

The figures below show our actual and forecast customer growth for basic and complex commercial connections and irrigators. In each case, the central forecast is slightly above the most recent actual data, but remains lower than connection rates observed in 2011-12 and prior years.

Figure 5-6: New commercial connections – basic

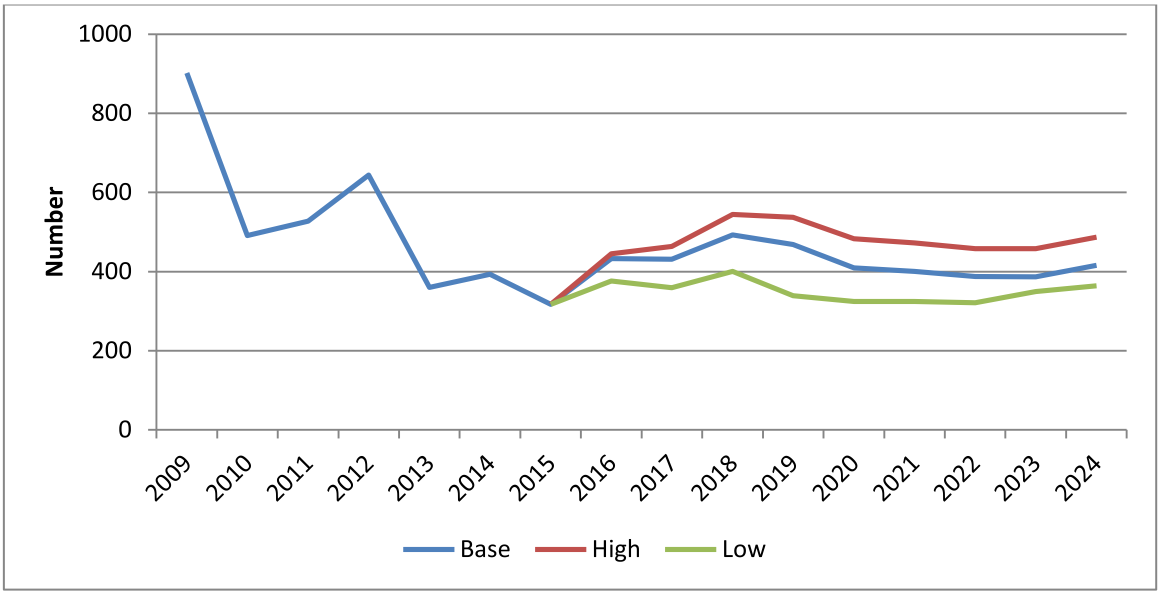


Figure 5-7: New commercial connections – complex

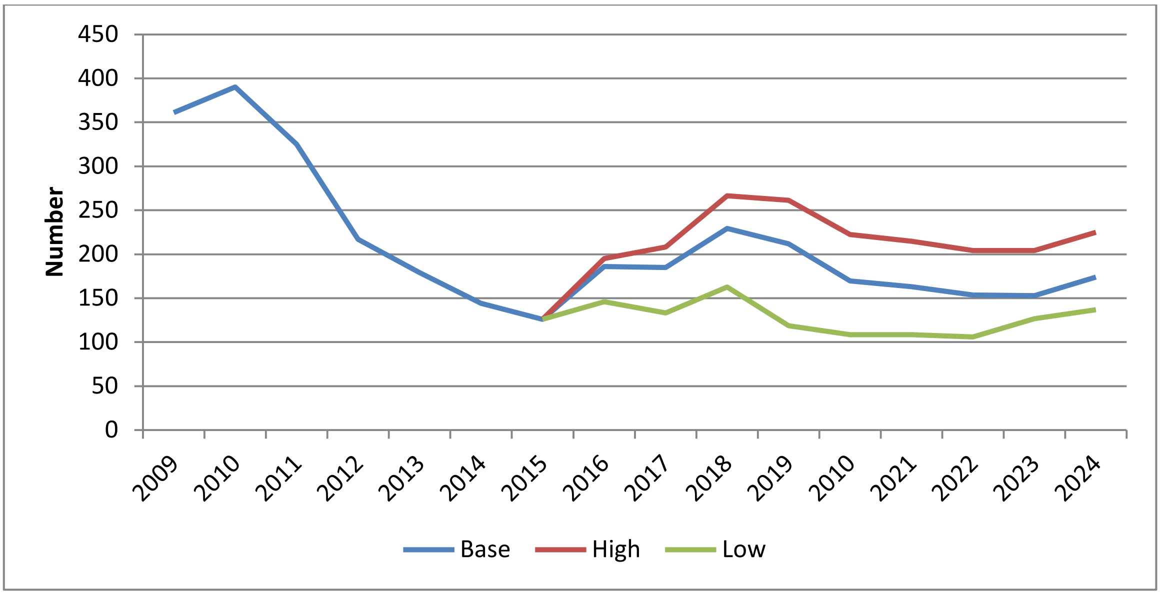
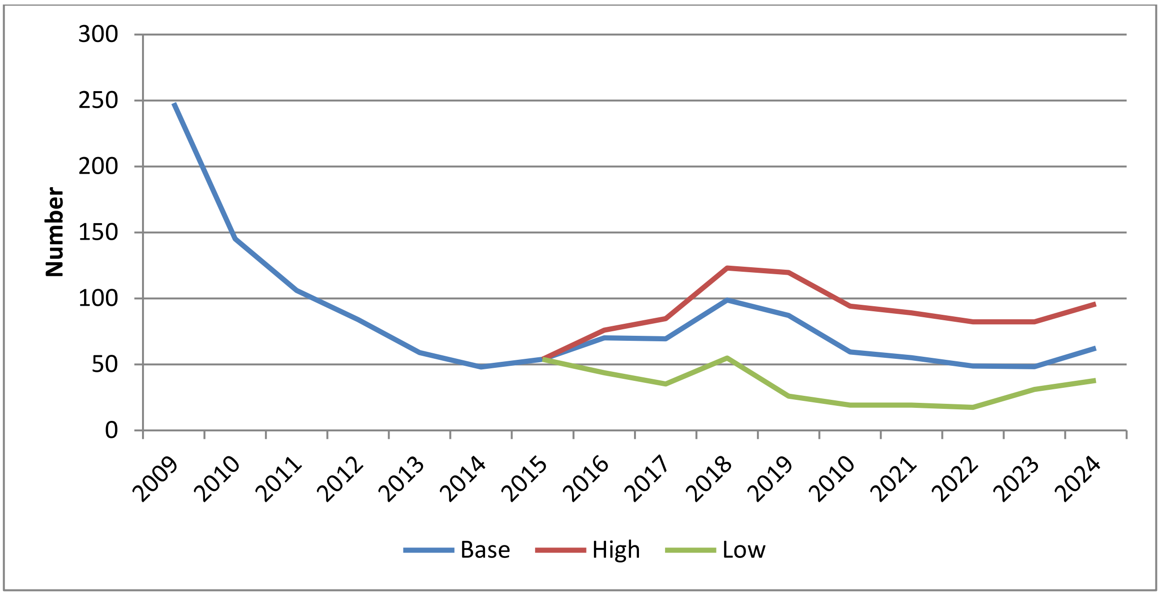
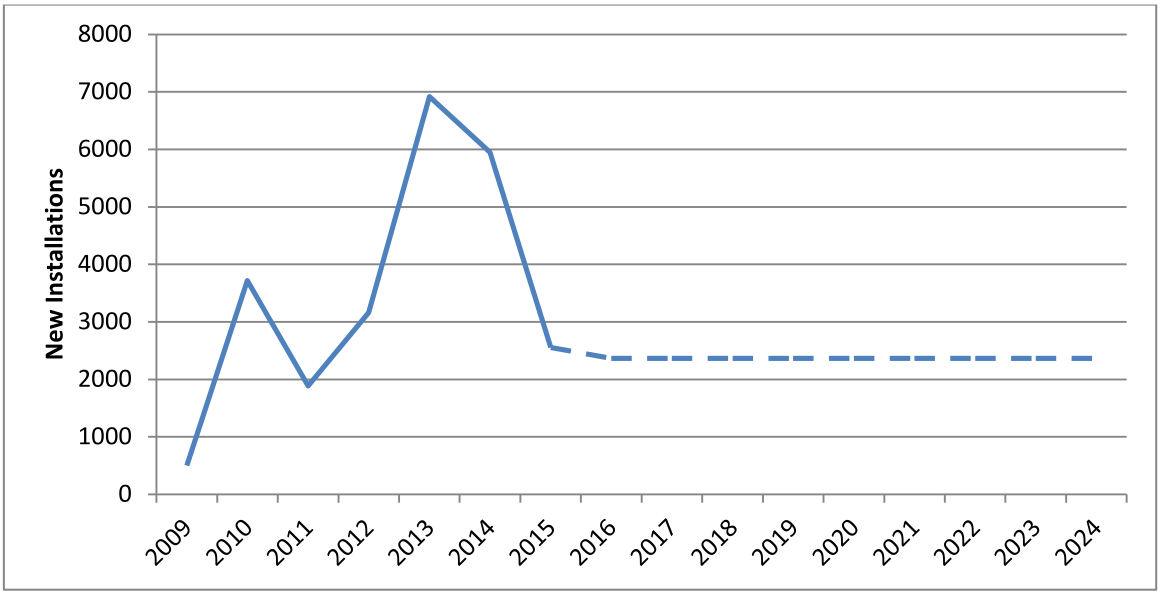


Figure 5-8: New irrigation connections



We have also developed forecasts for embedded generation connections, which are predominantly household solar connections. In relation to this connection category, it is difficult to develop a robust forecasting model because historic rates have been affected by the rapid growth in the solar market and the impact of Government policy, including changes in renewable energy targets and feed-in tariffs. The introduction of battery storage is expected to have a further, but uncertain impact on future solar connections. Given these difficulties, our forecasts for the forthcoming regulatory period reflect average historic connection volumes, as shown in the figure below.

Figure 5-9: Historical and forecast embedded generation connections



We note that AEMO forecasts a high trend growth in rooftop PVs in Tasmania[9]. However, our view is that the large decline in new installations from 2013-14 to 2014-15, and the influence of policy initiatives on historic data, casts significant doubt on AEMO's trend growth scenario. In these circumstances, our forecast may be a more reasonable approach.

9 AEMO, Detailed Summary of 2015 Electricity Forecasts, June 2015, pages 85 and 86.

Part Two:

Standard Control Services

Part Two of the Regulatory Proposal sets out information relating to Standard Control Services. It provides an overview of the feedback we have received from our customers on Standard Control Services and how our proposal responds to that feedback. This part also provides information on our capital and operating expenditure proposals, as well as information on our regulatory asset base and each of the Standard Control Services revenue ‘building blocks’ (being, return on capital, regulatory depreciation, operating expenditure, corporate tax allowance and efficiency payments). It also provides information on the incentive schemes that provide financial rewards or penalties depending on our service and cost performance.

Part Two concludes by setting out our proposed total revenue allowance and indicative outcomes for customers in terms of average price paths. An overview of our network tariff reforms and transition to more cost reflective network tariffs is also provided.

6 Customer feedback on Standard Control Services

Section 3.3 provided a high level summary of the key messages from our customer engagement process. To recap, customers generally expressed satisfaction with current reliability levels and did not want us to invest more to improve them. Instead, customer satisfaction would be improved if we could reduce network costs (and electricity bills) and maintain existing levels of reliability.

We agree with customers that we must do more to reduce the costs of providing network services. As already noted, a primary objective of merging the transmission and distribution networks is to drive efficiency improvements and deliver lower cost electricity for Tasmanian customers. Our expenditure plans for the forthcoming regulatory period provide the next step in the journey towards a more efficient network business.

The table below provides a summary of customer feedback and describes how we have addressed customers' concerns and views in framing our proposals regarding Standard Control Services.

Table 6-1: Addressing customer feedback on Standard Control Services

Issue or theme	Customer Feedback	Our Proposal
Ensuring the safety of our customers, employees, contractors and the community	Safety should be a top priority for TasNetworks. TasNetworks should continue to inform and educate the public on safety around electricity assets.	Safety is our top priority. The majority of our Renewal and Enhancement capital expenditure is required to ensure the safety of our customers, employees, contractors and the community. Further details are provided in section 7.6. We will continue to inform and educate the public through a range of targeted activities and information campaigns. Our current operating expenditure includes the costs of promoting safety awareness.
Price levels and reliability	Customers and stakeholders have expressed broad support for maintaining existing levels of reliability, rather than investing more to improve it. While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices for these improvements. Cost and affordability are the greatest concerns to customers. Lower prices - without reducing service quality - would lead to the greatest uplift in customer satisfaction.	Our Service Performance Management Plan for the forthcoming regulatory period aims to maintain current overall network service levels, in accordance with the preferences expressed by customers. Our investment will be focused on communities with poorer reliability performance, and particularly on seven critical underperforming feeders. Further details are provided in section 7.6. We have imposed a top-down discipline on capital and operating expenditure forecasts to ensure that our costs are efficient and prudent, and contribute to lower revenues and prices.

Issue or theme	Customer Feedback	Our Proposal
Capital expenditure plans	Customers expressed concern in response to our initial plans which involved increasing capital expenditure. Customers were concerned that any increase would lead to higher prices. A number of stakeholders queried the level of planned network investment in our Reliability and Quality Maintained expenditure category to maintain existing levels of reliability. A number of customers also identified the challenge of cost effectively providing increased reliability in more remote locations.	In response to customer feedback and based on a rigorous top-down analysis, we have reduced our proposed total capital expenditure from the level originally planned. While this lower capital expenditure entails a moderate increase in performance risks, we consider that the lower level of expenditure represents an efficient balance between cost and reliability. The majority of our planned network investment is focused on replacing unreliable and aged assets that are in poor condition, to ensure they do not present unacceptable safety or bushfire risks, or increased rates of power outages. This expenditure is critical in helping us maintain safe and reliable network services. We will be targeting our capital expenditure to address reliability on seven critical underperforming feeders. Chapter 7 provides an overview of our capital expenditure proposals and provides cross references to our asset management plans and other detailed supporting documents.
Operating expenditure plans	In response to our initial operating expenditure proposals, stakeholders said they would like to see more savings in operating expenditure. This is also an expectation, given the proposed level of capital investment in the network and new IT systems.	In response to customer feedback we have rigorously examined our original operating expenditure plans which would maintain expenditure at 2014-15 levels in real terms. We now propose to maintain operating expenditure at 2014-15 levels in nominal terms. This delivers cumulative savings from 2014-15 to 2018-19 of $33.1 million compared to a bottom-up assessment of our asset management plans. The savings we expect to make in the forthcoming two-year regulatory period have been included in our operating expenditure forecasts and these expected savings will flow directly to customers. Our operating expenditure forecast is presented in chapter 8.

Issue or theme	Customer Feedback	Our Proposal
Innovation and technology	Customers want us to explain how we are innovating to make best use of new technology, and how we intend to respond to risks to our operating model due to new technologies and 'disruption'. Some customers suggested that TasNetworks should take a greater role in supporting increased use of electric vehicles. Some also suggested that we should play a greater role in supporting new technologies, both in terms of research and development and funding. Councils and some customer groups want us to find alternatives to traditional network investment to meet growing peak demand.	We have developed our Network Innovation Strategy to guide our responses to the opportunities and challenges associated with new and emerging technology. An overview of the strategy is provided in section 7.1. A full copy of the Network Innovation Strategy (TN032) is provided along with this Regulatory Proposal. We are working with our peers, stakeholders and the CSIRO through the Energy Networks Association's Network Transformation Roadmap to identify and manage risks and opportunities arising from new technologies and disruption. Electric vehicles are an opportunity to further utilise the network and we are currently sponsoring a feasibility study to encourage uptake by Tasmanian car fleet managers. We are considering how to best achieve successful integration of this technology with our network. We will continue to pursue non-network solutions including demand-side initiatives and technology. As noted in section 7.1, our Demand Management Plan (TN035) describes how we will implement innovative solutions to avoid network investment.
Quality of supply	Customers said that TasNetworks could improve its performance addressing quality of supply issues such as voltage complaints.	The uptake of solar PV embedded generation continues to contribute to quality of supply issues. Our capital expenditure plans include expenditure to address compliance issues in relation to quality of supply.
Better communication on outages and restoration times	Customers want better information faster, when the lights go out.	We recognise the need to provide customers with better information about restoration times. We have upgraded our automatic call answering system, which links to our website outage information. We are planning to further improve our systems over time to enable more responsive and modern communication tools (e.g. SMS automatic messaging for outage updates) and improved online communication, especially in relation to outages.

Issue or theme	Customer Feedback	Our Proposal
Network tariffs	Customers have expressed concern with a number of aspects of tariff reform.	We have responded to stakeholder feedback through amendments to our Network Tariff Strategy. We will continue to work with stakeholders to consider any changes required to concession arrangements. An overview of our network tariff proposals is provided in chapter 15 and further detail is contained in our Tariff Structure Statement.

In the following chapters, we provide more detailed explanation of our proposed expenditure plans, revenue requirements and tariffs for Standard Control Services which address customers' feedback.

7 Capital expenditure forecast

7.1 Introduction

This chapter outlines our capital expenditure requirements for the forthcoming regulatory period. It explains that our expenditure plans are focused on efficiently achieving the capital expenditure objectives specified in the Rules. These objectives include the requirement to provide safe and reliable distribution services to our customers and to comply with our regulatory obligations.

While our forthcoming regulatory period is only two years in duration (1 July 2017 to 30 June 2019), and the forecasts that apply for the purpose of the AER's determination are limited to the two year period, we consider that a five year forecast of our proposed capital expenditure provides a transparent comparison with the expenditure during our current regulatory period. The indicative expenditure forecasts beyond 30 June 2019 also provide context for TasNetworks' expenditure plans for the two year regulatory period.

In addition to our network performance obligations in the Rules, we must comply with the Code, which is published and maintained by OTTER. The Code includes technical standards for power quality, standards of service for embedded generators and reliability of supply standards for the distribution network.

One of the five key themes underpinning our plans for the forthcoming regulatory period is ensuring the safety of our customers, employees, contractors, and the community. In accordance with this theme, we are committed to achieving our Zero Harm goals:

- no harm to our people and the public; and
- minimising our impact on the environment.

Our commitment to our Zero Harm policy underpins our capital expenditure plans for the forthcoming period.

The national regulatory regime provides incentives for us to maintain and improve network performance. The AER's service incentive scheme adjusts our revenue (up or down) depending on our network performance. We are also required to make payments to individual customers who are affected by poor service. We support the continuation of these incentives arrangements which encourage better service.

We also recognise that our customers have told us they are generally happy with the current level of distribution reliability. Price, not service improvement, is the most significant issue for customers. In view of this feedback, our objective is to maintain current levels of performance and to deliver this outcome efficiently. This objective is reflected in our Service Performance Management Plan.

At the same time, we are mindful of the need to respond to the challenges and opportunities associated with technological change. As noted in section 2.2, new technology is empowering customers with greater choice and changing the way in which their energy service needs are met. To guide us in responding to and embracing these developments, we have prepared a Network Innovation Strategy (TN032) and a Demand Management Plan (TN035). Specifically:

- The Network Innovation Strategy provides a framework to focus our efforts to be truly innovative in how we apply and make use of emerging technologies. It also provides guidance on the use of innovation more broadly across TasNetworks' business.

  The strategy focuses on the key innovations that will drive TasNetworks' evolution in response to technological change, including the increasing penetration of disruptive technologies. The strategy aims to support and manage technological change and the efficient use of our network in the changing energy landscape.

  The strategy is underpinned by three network innovation objectives, which are to facilitate customer choice; to facilitate customer interaction; and to increase network efficiency.

- Our Demand Management Plan recognises that demand management offers increasingly viable solutions for managing network issues, which are sometimes significantly cheaper than traditional network expansion. The plan describes how TasNetworks will innovate to avoid network investment. The plan also encompasses consideration of approaches for controlling customer demand and generation, deploying additional generation, and use of energy storage.

Our Network Innovation Strategy (TN032) and Demand Management Plan (TN035) underpin the capital expenditure forecasts set out in this chapter. Copies of both documents are provided as supporting documents to this Regulatory Proposal.

As explained in our earlier submission to the AER[10], we adopt different forecasting methodologies for each capital expenditure category so they are tailored to the relevant expenditure drivers. For example:

- development capital expenditure is driven principally by growth in customer connections and maximum demand;
- renewal and enhancement capital expenditure is driven by safety, asset condition, performance and risk.

The forecasting methodologies for these two categories of capital expenditure must therefore reflect these different drivers.

Our forecasting methodology for each capital expenditure category is unchanged from the approach notified to the AER, available at https://www.tasnetworks.com.au/TasNetworks/media/pdf/our-network/TasNetworks-Expenditure-Forecast-Methodology.pdf. Below we explain why our forecasts satisfy the Rules requirements and should be accepted by the AER.

As explained in this chapter, our capital expenditure requirements for the next five-years will decrease by 6.6 per cent in total compared to the current regulatory period. Over the next five-years, we expect to increase our renewal capital expenditure in order to address emerging network safety risks. However, the declining state-wide demand on the Tasmanian distribution network since

10 TasNetworks, 2017–19 TasNetworks Regulatory Proposal Expenditure Forecasting Methodology, June 2015.

2009 has reduced the need for network augmentation, and this more than offsets the required increase in replacement capital expenditure.

The remainder of this chapter is structured as follows:

- Section 7.2 sets out an overview of our Service Performance Management Plan, which is a key foundation of our capital expenditure forecasts.
- Section 7.3 provides an overview of our capital expenditure forecasts.
- Section 7.4 outlines the key assumptions underpinning the capital expenditure forecasts.
- Sections 7.5 to 7.9 explain our plans for each sub-category of capital expenditure.
- Section 7.10 comments on capital expenditure benchmarking.
- Section 7.11 outlines the deliverability of our capital expenditure forecasts.
- Section 7.12 concludes by explaining the expected benefits of our capital expenditure program.

Further supporting information and analysis to justify our forecast capital expenditure is provided in a number of appendices that are referenced in these sections. In addition to examining our capital expenditure requirements based on the key drivers for each expenditure category, these supporting documents also consider opportunities for non-network solutions and substitution between operating and capital expenditure.

7.2 Our Service Performance Management Plan

Our Service Performance Management Plan outlines our strategies for the management of reliability and service. Our plan is to maintain current overall network service levels, so that we meet the expectations of all stakeholders, whilst also meeting our Zero Harm goals. The key inputs to our Service Performance Management Plan are summarised in the figure below.

Figure 7-1: TasNetworks' Service Performance Management Plan

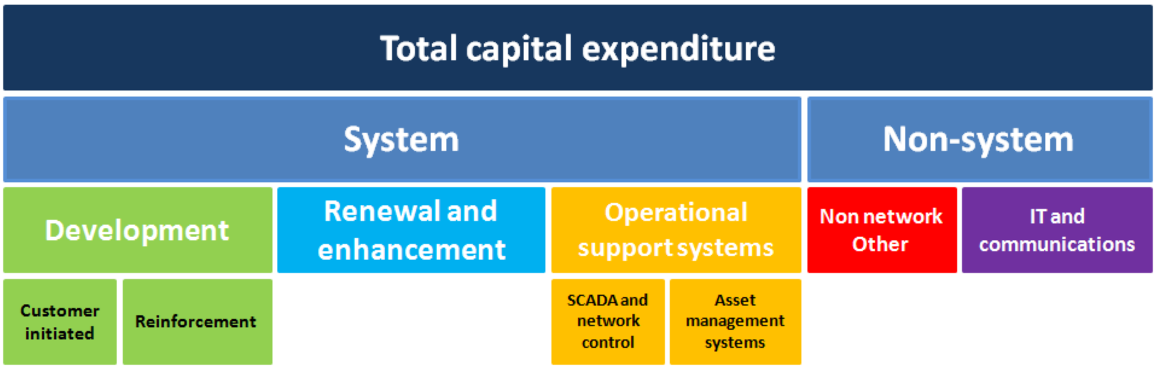
The capital expenditure forecasts presented in this chapter will enable us to maintain current levels of network performance efficiently, in accordance with our customers' preferences. A copy of our Service Performance Management Plan is provided as a supporting document to this Regulatory Proposal.

7.3 Overview of capital expenditure forecast

The Rules require us to present our expenditure forecasts with reference to well accepted categories of expenditure. As a practical matter, we also recognise that our forecasts should be presented in a manner that assists the AER in its review.

In relation to capital expenditure, we have applied a categorisation that is consistent with Regulatory Information Notice (RIN) categorisations adopted by the AER in recent distribution reviews, as shown in the figure below.

Figure 7-2: TasNetworks' capital expenditure categories



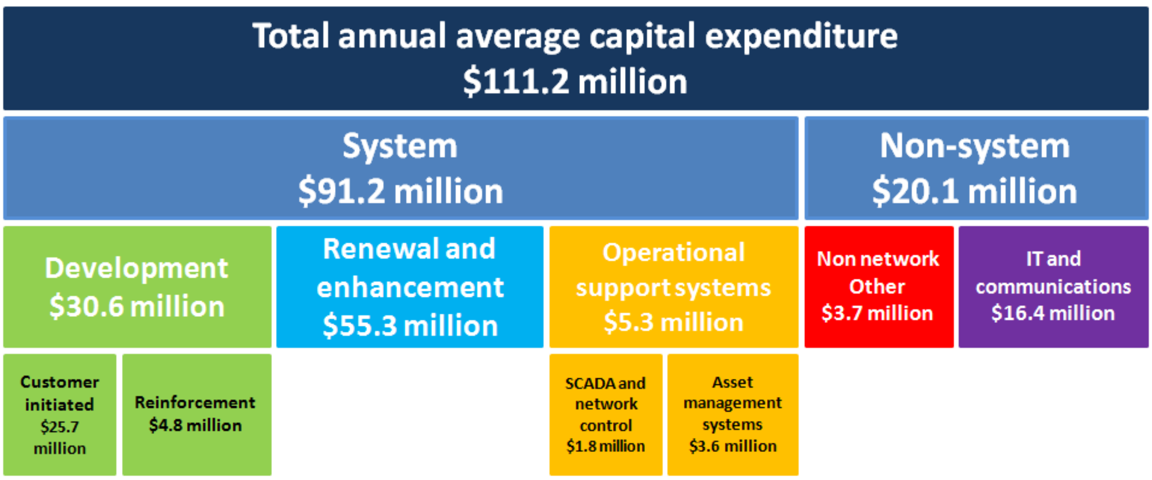
TasNetworks' total capital expenditure is derived by aggregating expenditure forecasts developed at the sub-category level. The capital forecast that is included in our revenue requirements is net of the customer-initiated works that our connecting customers fund directly.

At each stage of the forecasting process we apply a 'top down' check to ensure that the forecast is reasonable. This validation process includes comparisons with historic expenditure and the application of the AER's 'Augex' and 'Repex' models to the Development, and Renewal and Enhancement categories.

In developing our plans, we have sought to respond to our customers' concerns regarding the upward pressure that increased investment would place on prices. Accordingly, in finalising our plans, we have applied a rigorous top-down analysis to reduce our proposed total capital expenditure from the level we originally planned. The lower level of expenditure that we now propose represents the minimum efficient investment we require in order to meet our compliance obligations, and to maintain an efficient balance between cost and reliability. Our capital expenditure proposal contains no 'ambit claims'.

The figure below shows the forecast average annual capital expenditure amounts over the five years from 2017-18 to 2021-22 in the relevant categories. This includes capital expenditure that customers contribute to their connection-related works. We do not propose any contingent projects for the forthcoming regulatory period.

Figure 7-3: Forecast annual average capital expenditure over 2017-18 to 2021-22 (June 2017 $m)



Note: Numbers may not sum exactly due to rounding.
Boxes are not intended to represent the relative size of expenditure in each category.

The table below shows that our total capital expenditure in the current five year period is expected to be $595.3 million compared to the AER's allowance of $626.7 million, which is a reduction of 5 per cent. This is despite incurring unfunded capital costs during the current period for bushfires, full retail contestability and to facilitate metering contestability as a distributor. Over the next five year period (from 2017-18 to 2021-22) our forecast capital expenditure reduces by a further 6.6 per cent, to $556.2 million per annum.

Table 7-1: Actual and forecast capital expenditure inclusive of customer capital contributions by category (June 2017 $m)

Category	Regulatory allowance for 2012-13 to 2016-17	Actual/Estimated expenditure for 2012-13 to 2016-17	Forecast expenditure for 2017-18 to 2021–22
Development capex	**272.3**	**179.7**	**152.9**
Customer initiated	206.2	139.9	128.7
Reinforcements	66.1	39.8	24.2
Renewal/enhancement capex	**225.9**	**263.4**	**276.3**
Operational Support Systems	**43.8**	**41.4**	**33.8**
SCADA and Network Control Systems	20.0	9.6	8.8
Asset Management Systems	23.8	31.7	25.0
Non-Network Other	**43.1**	**28.7**	**18.5**
IT and Communications	**41.6**	**82.2**	**74.7**
Total	**626.7**	**595.3**	**556.2**

Our total forecast capital expenditure for the forthcoming regulatory period is $235.6 million, which covers the two year period from 1 July 2017 to 30 June 2019 (our total net capital expenditure forecast is $213.4 million, which recognises expected customer contributions of $22.2 million.)

Further detailed information on the variation between historic and forecast capital expenditure is provided in the balance of this chapter.

Figure 7-4 below provides a breakdown by expenditure category and a comparison with the current period gross of capital contributions.

Table 7-2 below provides a breakdown by expenditure category and a comparison with the current period gross and net of capital contributions.

Figure 7-4: Overview of forecast and actual capital expenditure (June 2017 $m)

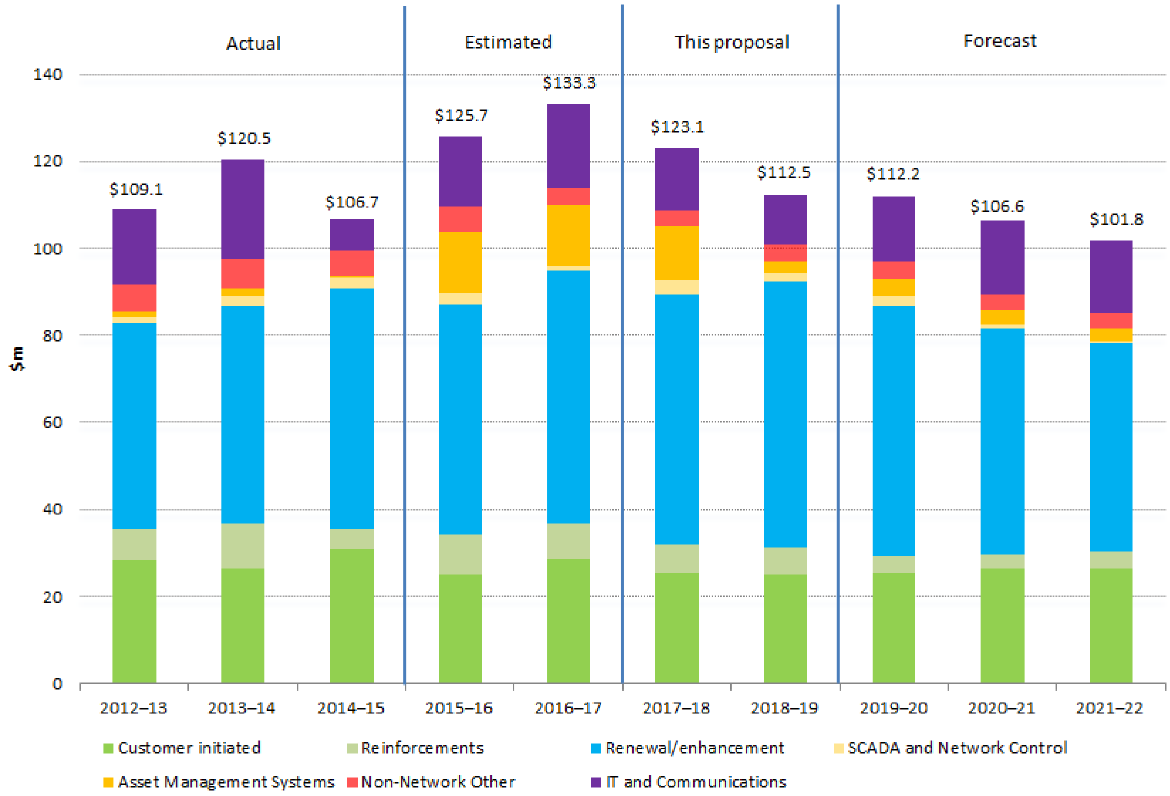


Table 7-2: Actual and forecast net capital expenditure for the current and forthcoming regulatory period (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Development	35.7	36.9	35.6	34.4	37.0	31.9	31.5	**29.4**	**29.9**	**30.2**
Customer initiated	28.5	26.3	30.9	25.3	28.9	25.4	25.2	25.3	26.4	26.4
Reinforcements	7.2	10.6	4.8	9.1	8.1	6.5	6.2	4.0	3.5	3.9
Renewal/enhancement	47.3	49.9	55.2	52.7	58.2	57.7	60.9	**57.6**	**51.9**	**48.1**
Operational Support Systems	2.7	4.0	2.9	16.8	15.0	15.5	4.7	6.0	4.1	3.4
SCADA and Network Control Systems	1.1	2.4	2.5	2.6	1.0	3.2	2.0	2.2	1.0	0.5
Asset Management Systems	1.5	1.6	0.4	14.2	14.0	12.3	2.8	3.8	3.1	2.9
Non-Network Other	6.1	7.0	5.8	6.0	3.8	3.7	3.7	3.9	3.7	3.5
IT and Communications	17.2	22.7	7.1	15.8	19.2	14.2	11.7	15.3	17.0	16.5
Total capital expenditure	**109.1**	**120.5**	**106.7**	**125.7**	**133.3**	**123.1**	**112.5**	**112.2**	**106.6**	**101.8**
Customer capital contributions	(8.3)	(10.6)	(12.9)	(10.3)	(10.2)	(11.2)	(11.0)	(10.9)	(11.3)	(11.3)
Total net capital expenditure	**100.8**	**109.9**	**93.8**	**115.4**	**123.1**	**112.0**	**101.4**	**101.2**	**95.3**	**90.5**

The savings achieved in the current period were despite additional capital costs associated with bushfire recovery and investment in IT systems to facilitate full retail competition in Tasmania. Decisions were made by Aurora Energy and TasNetworks respectively not to seek pass-through of either set of costs, although being eligible to do so. Our expenditure for the current period also includes forecast expenditure to support the metering Rule change, also eligible for pass through. TasNetworks does not intend to seek a pass through for any such costs incurred in the current period.

Figure 7-5 below shows our forecast capital expenditure for the next five years by category compared to the actual expenditure for the 2012–17 period.

Figure 7-5: Comparison of past and forecast capital expenditure by major category (June 2017 $m)

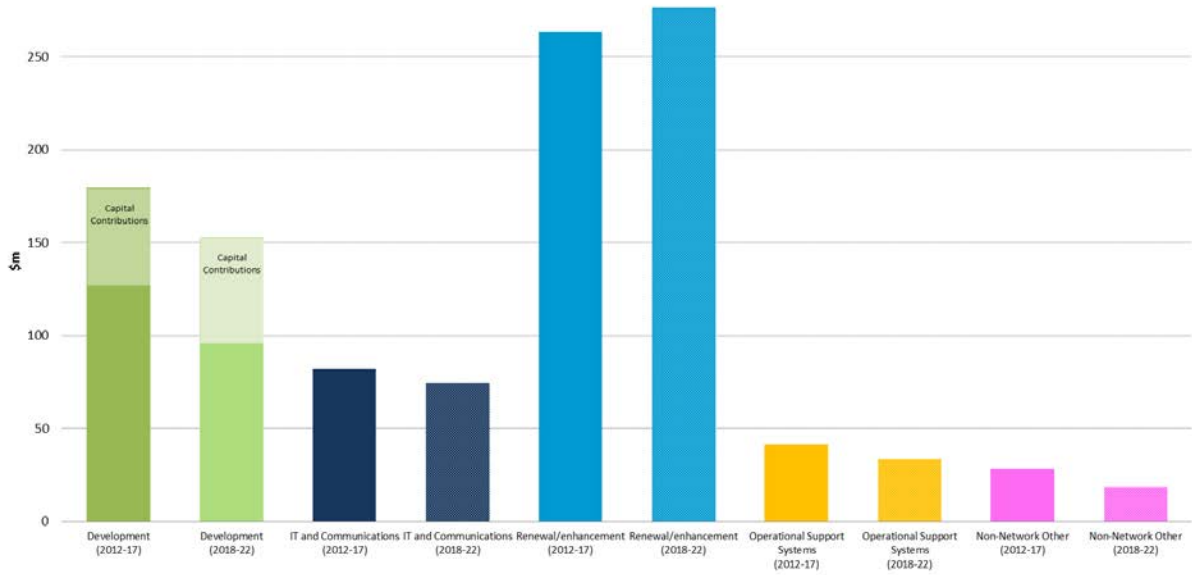


Figure 7-5 shows the change in forecast expenditure for the 2017-18 to 2021-22 period compared to the current period. It shows that we are forecasting:

- reductions in capital expenditure for development, IT and communications, operational support and non-network other; and
- increases in capital expenditure for renewal / enhancement.

The proposed increase in renewal / enhancement capital expenditure will enable us to efficiently manage increasing safety and reliability risk associated with age-related deterioration of our asset base.

Notwithstanding the increased expenditure in renewal / enhancement, as already noted our forecasts of total capital expenditure reflect a reduction of $39.1 million (6.6 per cent) compared to the current period. This reduction builds on previously achieved savings compared to the AER’s capital expenditure allowance.

The reduction in our forecast capital expenditure should provide stakeholders with confidence that our proposed expenditure is efficient, in accordance with the Rules requirements. Our prudent and efficient capital investment in the current period has provided a solid foundation for our investment plans for the forthcoming five-year period and beyond.

7.4 Key assumptions

In addition to the global assumptions set out in section 1.4 the following assumptions underpin our capital expenditure forecasts:

- our forecasts for demand, new customer connections and capital contributions, together with the projections of distributed generation, are soundly based and reasonable; and
- our investment evaluations, including the project and program scopes and estimating practice, are soundly based and accurately reflect our capital expenditure requirements.

In accordance with schedule S6.1.1(5) of the Rules, the directors have provided a certification of the reasonableness of these key assumptions (supporting document, TN002). It should be noted that although these key assumptions are reasonable, there is no guarantee that they will eventuate. If our assumptions prove to be incorrect, there may be a material impact on our capital expenditure.

7.5 Development capital expenditure

Table 7-3 shows our annual actual and forecast development capital expenditure inclusive of capital contributions.

Table 7-3: Development capital expenditure (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Customer Initiated	28.5	26.3	30.9	25.3	28.9	25.4	25.2	25.3	26.4	26.4
Reinforcement	7.2	10.6	4.8	9.1	8.1	6.5	6.2	4.0	3.5	3.9
Total Development Capex	**35.7**	**36.9**	**35.6**	**34.4**	**37.0**	**31.9**	**31.5**	**29.4**	**29.9**	**30.2**

Our forecast development capital expenditure for the five-years commencing 1 July 2017 is $152.9 million compared to actual expenditure of $179.6 million for the current regulatory period. We are therefore forecasting a reduction of $26.7 million or 14.9 per cent.

Each of the two components of development capital expenditure is discussed in turn below.

7.5.1 Customer initiated capital expenditure

Customer Initiated capital expenditure arises directly from the connection of new customers to the distribution network, or changes to existing customer connections, where the associated activities are primarily due to meeting the specific requests of customers.

In determining the scope of work for a specific customer connection there are two areas where infrastructure investment may be required:

- connection assets, which are specific to that customer connection; and
- network augmentations to strengthen the network specifically to facilitate a customer connection.

Customers make a contribution towards the cost of the required infrastructure investment in accordance with our customer connection policy.

The table below shows our historic and forecast for customer initiated capital expenditure and customer capital contributions. The expenditure categories presented below reflect the nature of the capital works required, rather than the customer connection categories in Chapter 5.

Table 7-4: Customer Initiated capital expenditure and capital contributions (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Customer Initiated Connection Assets	3.4	4.1	4.6	3.1	3.4	0.6	0.6	0.6	0.6	0.7
Customer Initiated Major Works	1.6	1.8	1.2	2.4	2.6	2.4	2.4	2.5	2.7	2.7
Customer Initiated Non-Major Works	15.3	12.9	15.1	14.2	16.5	15.8	15.8	16.1	16.9	16.9
Customer Initiated Subdivisions	5.0	4.5	5.8	5.4	4.9	5.1	5.0	4.6	4.7	4.6
Customer Initiated Substations	3.1	3.1	4.2	0.2	1.5	1.4	1.4	1.4	1.5	1.5
Total Customer Initiated - Gross	**28.5**	**26.3**	**30.9**	**25.3**	**28.9**	**25.4**	**25.2**	**25.3**	**26.4**	**26.4**
Customer capital contributions	8.3	10.6	12.9	10.3	10.2	11.2	11.0	10.9	11.3	11.3
Total Customer Initiated - Net	**20.2**	**15.7**	**18.0**	**15.0**	**18.7**	**14.2**	**14.2**	**14.4**	**15.1**	**15.1**

The net customer initiated capital expenditure is the amount that is included in our regulatory asset base. Our customer initiated capital expenditure forecasts for the forthcoming five-year period reflect our forecasts of new customer connections which are set out in section 5.4.

Over the current period, actual customer initiated capital expenditure inclusive of customer capital contributions totalled $139.9 million. Our forecast expenditure for the forthcoming five-year period is $128.7 million, which is $11.2 million (8 per cent) lower.

Further detailed information on our management strategy for customer initiated work and our expenditure forecasts for the forthcoming regulatory period is provided in the supporting document titled Customer Initiated Management Plan.

7.5.2 Reinforcement capital expenditure

In contrast to customer initiated capital expenditure, which is specific to new customers, reinforcement expenditure[11] addresses capacity issues – and includes expenditure to address fault levels - on the shared distribution network. Demand growth and new generation connected to the network can change flows on the network. If inadequate reinforcement work is undertaken, there may be an increased risk of load shedding, system performance issues and/or asset failure.

TasNetworks' requirements for developing the distribution network are driven principally by five factors:

- demand forecasts (as set out section 5.2);
- new load connection requests (driven by new customer connections, forecasts of which are set out in section 5.4);
- new generation connection requests;

[11] This includes expenditure referred to by the AER as 'augmentation'.

- network performance requirements and the associated supply reliability standards set out in the Code; and
- Rules compliance requirements.

Our Network Development Management Plan defines our management strategy for distribution network development. The plan sets out:

- TasNetworks' approach to demand and performance driven reinforcement strategies, as reflected through our legislative and regulatory obligations and strategic plans;
- the key projects and programs underpinning our network development activities; and
- forecast network development capital and operating expenditure, including the basis upon which those forecasts are derived.

The Network Development Management Plan is provided as a supporting document along with this Regulatory Proposal. It describes our planned reinforcement projects for the 2016-17 to 2026-27 period. The following points highlight a number of key elements driving our forecast reinforcement capital expenditure in the forthcoming regulatory period.

For Major System reinforcement capital expenditure:

- In contrast to previous regulatory periods, no zone substation developments will be required in the two-year determination and may not be required within the 10 year planning horizon.
- For sub-transmission circuits, a large number of capacity issues arise under contingency conditions. We propose addressing a number of these issues by re-rating the relevant sub-transmission overhead feeder sections at a higher operating temperature. This solution requires a line audit and minor augmentation such as re-tensioning and taller poles.
- Some 33 kV overhead sections will not be able to operate at a higher temperature due to pole top construction, conductor condition, and location/route limitations. These sections require augmentation or undergrounding.

For our High Voltage System our reinforcement capital expenditure includes the following program of work:

- We plan to establish a 11-22 kV interconnection to transfer capacity between the 11 and 22 kV networks of Richmond Rural and Sorell. This project will defer the need to augment the existing voltage regulator at Colebrook (T580156), which is identified as an existing constraint. The project will also improve network performance and deliver operational benefits.
- Our reliability reinforcement programs include targeted projects to restore the performance of the poorest performing reliability communities and worst performing feeders. An on-going program will address the existing worst seven performing and 50 per cent of all existing non-compliant communities by the end of the forthcoming regulatory period. Our proposed approach is a prudent and efficient response to our performance obligations in the Tasmanian Code.
- We have identified a need to install new, or upgrade of existing voltage regulators to manage asset loading, and/or feeder steady state voltage control under normal or

contingent network configurations. This expenditure is also driven by our compliance obligations.

- We have identified a requirement to augment some HV Feeders to address capacity or fault level issues.
- Other HV system reinforcement work to improve operational flexibility has also been identified and is included in our development plan.

For Low Voltage System reinforcement capital expenditure, the following projects are planned:

- We will continue with our program of upgrading distribution transformers (ground, or pole mounted) for capacity. It is expected that volumes will be similar to historic levels.
- We plan to upgrade a number of LV feeders to address capacity issues.
- Our reliability reinforcement programs for worst served customers will also include some LV augmentation, such as rectification of transformers, installation of control stations and installation of bird diverters.

Each project has been developed following a detailed analysis of the 'needs' case, and a cost-benefit analysis of the feasible options. In addition, we engaged Nuttall Consulting to assess whether our forecast reinforcement capital expenditure was validated by the AER's augex model. Nuttall Consulting's analysis provided strong support for our forecasts. Nuttall Consulting's report, titled 'AER augex model - Assessing the TasNetworks augex forecast' is provided as a supporting paper (TN080).

A further detailed explanation of our proposed reinforcement programs is set out in our Network Development Management Plan, which is provided as a supporting document (TN034).

The table below shows our actual and forecast reinforcement capital expenditure. The forecast expenditure for each project reflects the planned scope of work and costs based on similar projects.

Table 7-5: Reinforcement capital expenditure (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Distribution Substations	0.1	0.6	0.1	0.1	0.8	0.8	0.8	0.8	0.8	0.8
HV Feeders	4.2	3.1	2.1	3.0	6.8	4.4	3.2	2.1	2.4	1.9
LV Feeders	0.1	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Zone Substations	2.8	6.8	2.4	5.8	0.2	1.0	2.0	0.9	-	0.9
Total Reinforcement Capex	**7.2**	**10.6**	**4.8**	**9.1**	**8.1**	**6.5**	**6.2**	**4.0**	**3.5**	**3.9**

Our total reinforcement capital expenditure for the current regulatory period is expected to be $39.8 million. Our forecast expenditure for the forthcoming five year period is $24.1 million, which is $15.7 million (39.4 per cent) less than the amount spent in the current period.

7.6 Renewal and enhancement capital expenditure

Renewal and enhancement capital expenditure is driven by two primary objectives:

- satisfying our regulatory obligations, including the requirement to maintain the safety of the distribution system; and
- maintaining network reliability in accordance with our customers' preferences.

While it is possible to sub-divide renewal and enhancement capital expenditure into these two elements, inevitably the allocation requires an exercise of judgment. For example, expenditure to ensure the safety of the distribution network in accordance with our Zero Harm policy may require the replacement of equipment that will also contribute to maintaining reliability.

In earlier presentations and discussions with customers, we attempted to allocate costs to these two sub-categories. In this Regulatory Proposal, however, we consider it more appropriate to revert to the parent category of renewal and enhancement capital expenditure, which aligns with the AER's category of 'replacement capital expenditure.'

The key expenditure drivers for renewal and enhancement capital expenditure are:

- safety and environmental performance and compliance requirements;
- asset condition and risk;
- asset performance;
- spares availability and product support;
- technical obsolescence; and
- physical security.

Essentially, our forecasts are developed through a careful 'bottom up' evaluation of investment requirements for each asset class, combined with a top down discipline to optimise program synergies. The forecasts are derived and verified through:

- asset specific condition assessment;
- asset life and failure rate modelling;
- trending of historical volumes;
- reliability centred maintenance;
- an analysis of risk, which adopts a systematic approach to assessing consequences and likelihood of asset failures or events; and
- benchmarking/validation, including through the application of the AER's repex model.

The table below shows our actual and forecast renewal and enhancement capital expenditure.

Table 7-6: Renewal and enhancement capital expenditure (June 2017 $m)

Sub-category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Renewal and enhancement	47.3	49.9	55.2	52.7	58.2	57.7	60.9	57.6	51.9	48.1

Our total renewal and enhancement capital expenditure in the current period is $263.3 million. For the forthcoming five-year period we are forecasting an increase of $12.9 million (4.9 per cent) in expenditure to $276.2 million. The need for increased expenditure is driven mainly by the need to address increased safety and reliability risks associated with age-related asset deterioration.

Our detailed asset management plans set out the rationale for the proposed level of renewal and enhancement capital expenditure in the forthcoming regulatory period, for each asset category. We provide a brief summary of the key areas of expenditure below:

Table 7-7: Actual and forecast renewal and enhancement capital expenditure by asset class (June 2017 $m)

Description	Average historic expenditure (5 years) ($m)	2017/2018 ($m)	2018/2019 ($m)	Objective
Pole Replacements	13.0	8.0	8.0	The objective of this program is to replace poles identified from the pole inspection program, damaged by weather events or damaged by third parties.
Low Conductor Span Rectification - Low Clearance LV	1.8	3.9	3.8	This proposed program will address the health and safety risk to members of the public through the presence of low conductor spans. Key objectives of this project are: • Rectification, (or otherwise removal where appropriate) of low conductor span defects currently in the defect pool; and • Rectification of defects identified in the future.
Replace cross-arms	2.2	3.3	3.3	To undertake asset repairs to the cross-arms within the overhead system to reduce the risk of fire starts, harm to the public, and to maintain network reliability.
Replacement of HV Ground Mounted Distribution Substations - Oil-filled Switchgear	1.4	3.1	3.1	The objective is to replace/renew ground mounted substations containing oil-filled switchgear to minimise safety risks to operational personnel and the public, and to ensure the current network performance levels are maintained.
Replace low voltage CONSAC cable	2.0	2.5	2.5	The objective of this project is to continue the replacement of the low voltage CONSAC cable on the distribution network to reduce the likelihood of electrical shocks/electrocution occurring as a result of defect cables.
Replacement of HV Ground Mounted Distribution Substations - Non Oil-Filled	1.1	2.4	2.4	The objective is to replace/renew ground mounted substations (non oil-filled) switchgear to minimise safety risks to operational personnel and the public, and to ensure the current network performance levels are maintained.
Replace Transformers	3.0	2.4	2.4	TasNetworks proposes that the management of overhead transformers continues the same practices as existing. That is, no preventative maintenance is undertaken on transformers. Transformers are replaced at failure, or when they are identified during other routine inspections as in sufficiently poor condition (e.g. dripping oil).
Fire Mitigation Projects	1.2	2.3	2.3	The purpose of these projects is to reduce the risk of distribution assets starting fires. The projects included in the work category include vibration damper installation, spreader installation and HV fuse replacements. It also includes a change of non-routine programs to routine.
Replace transformers at Claremont Zone		3.0	-	The objective of this project is to replace the power transformers due to condition drivers at Claremont Zone. Replacement will ensure the security of supply is maintained for the site, long term.

We engaged Nuttall Consulting to prepare a report that analyses our renewal and enhancement capital expenditure forecasts using the AER's repex model. Nuttall Consulting's analysis provides strong support for our forecasts. Nuttall Consulting's report, titled 'AER repex model - Assessing the TasNetworks replacement forecast' is provided as a supporting paper (TN081).

7.7 Operational Support Systems

The table below presents our actual and forecast Operational Support Systems capital expenditure.

Table 7-8: Operational Support Systems capital expenditure (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
SCADA and Network Control	1.1	2.4	2.5	2.6	1.0	3.2	2.0	2.2	1.0	0.5
Asset Management Systems	1.5	1.6	0.4	14.2	14.0	12.3	2.8	3.8	3.1	2.9
Total Operational Support Systems	**2.7**	**4.0**	**2.9**	**16.8**	**15.0**	**15.5**	**4.7**	**6.0**	**4.1**	**3.4**

Each of the two components of development capital expenditure is discussed in turn below

7.7.1 SCADA and Network Control

SCADA and Network Control capital expenditure includes replacement, installation and maintenance of SCADA and network control hardware, software and associated IT systems. This includes costs associated with the provision of appropriate information gathering, information management and information analysis hardware, software and systems to allow TasNetworks to provide standard control services efficiently.

This capital expenditure sub-category also includes the systems that collect data for asset management purposes and provide the mainstay for monitoring and remote operation of the power network. Related SCADA and Network Control technologies include system-related telecommunications, operational systems, operational technology security and cyber security systems specific to the distribution network.

Network Control capital expenditure relates to protection and control assets that are critical to maintaining the safety and reliability of the network. These assets monitor and operate plant, detect network faults and operate circuit breakers in substations and downstream distribution feeders. These asset types have a natural physical life, as well as an economic and technological support life. Electronic microprocessors provide the basis for modern protection and control assets such as remote terminal units, relays, and reclosers, while older protection assets use electro-mechanical technologies.

Investment requirements for general and minor assets associated with this category are often driven by the economic life cycles, and the condition and performance of those assets. To identify the potential need for SCADA and Network Control investment we use our asset management system. Details of our asset management system are provided in our Strategic Asset Management Plan (TN023).

Our SCADA and Network Control 'bottom up' capital expenditure forecast includes recurrent and non-recurrent costs. Recurrent SCADA and Network Control capital expenditure typically relates to life cycle refresh programs, while non-recurrent expenditure is driven to a particular business need. Any proposed increase in capital expenditure is explained with reference to a specific driver or business case.

This 'bottom up' forecast is subject to a 'top down' review based on historic expenditure and trend analysis. The 'top down' assessment for non-recurrent capital expenditure includes benchmarking analysis, which assists in verifying whether our proposed expenditure is efficient with reference to costs incurred by other network companies.

The table below presents our capital expenditure forecast for the forthcoming regulatory period alongside our actual expenditure for the current period.

Table 7-9: SCADA and Network Control capital expenditure (June 2017 $m)

Sub-category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
SCADA and Network Control	1.1	2.4	2.5	2.6	1.0	3.2	2.0	2.2	1.0	0.5

Our actual SCADA and Network Control capital expenditure for the current regulatory period totalled $9.6 million. For the forthcoming five-year period, we are forecasting a slightly lower total expenditure of $8.9 million.

Further details of our SCADA and Network Control expenditure requirements are provided in the Protection and Control Asset Management Plan (TN045).

7.7.2 Asset Management Systems

Asset Management Systems (AMS) is the second component of the Operational Support Systems capital expenditure. The AMS category includes replacement, installation and maintenance of asset management business processes, business systems, and associated tools and software.

AMS is concerned with asset information gathering, asset information management and asset information analysis. These activities are essential prerequisites to achieving efficient asset management. We employ a number of related asset management systems, including:

- Ajilis – a business transformation project to replace a range of unsupported asset management and delivery platforms, and implement new asset management processes. This work is integrated with replacement and transformation of a number of related business applications and processes. Ajilis costs are therefore allocated between the Asset Management Systems and IT and Communications expenditure categories.
- Asset Management Information System (AMIS) – the primary system that supports the strategic, tactical and lifecycle management of distribution network assets, including asset risk management, asset condition monitoring, asset performance management and works management.
- Geographic Information Systems (GIS) – the primary systems that support the geographic modelling of network assets.

The table below shows our actual and forecast of AMS capital expenditure.

Table 7-10: Asset Management Systems capital expenditure (June 2017 $m)

Sub-category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
AMIS and GIS	1.5	1.6	0.4	3.4	3.2	5.3	2.8	3.8	3.1	2.9
Ajilis	0.0	0.0	0.0	10.8	10.8	7.0	0.0	0.0	0.0	0.0
Total Asset Management Systems	**1.5**	**1.6**	**0.4**	**14.2**	**14.0**	**12.3**	**2.8**	**3.8**	**3.1**	**2.9**

As detailed in Table 7-10, we are planning to decrease our AMS capital expenditure from a total of $31.7 million in the current period to $24.9 million over the forthcoming five-year period.

Following the merger of the transmission and distribution businesses, we inherited a number of core information applications that were at or near end of life, not supported by vendors, and heavily customised. This situation reflected the efficient deferral of business systems expenditure in anticipation of the merger.

The merger resulted in duplicate systems and processes. In practical terms, this led to poor data visibility, no 'single source of truth', difficulties in works planning and scheduling, excessive data entry and a plethora of manual processes and workarounds.

The Ajilis project is a business-critical initiative which will:

- Replace a number of critical applications, including multiple asset management applications that are at end of life.
- Deliver a seamless, integrated platform to replace a large number of disparate and disjointed IT systems and customised interfaces.
- Result in process efficiencies that will enable us to deliver cost savings over the next 10 years.

Ajilis will transform how we work and contribute to achieving our strategic objectives across the three pillars that underpin our strategy:

- One Business: It will deliver consistent, simplified business processes, underpinned by a single, enabling IT platform. The project will minimise a number of key business risks, remove duplication, and improve data quality and reporting.
- Customers: It will support delivery of effective and efficient services both internally and externally to our customers.
- People: It will assist in driving an uplift in capability, new skills and cultural integration through a consistent, new way of working.

The Ajilis project commenced in 2015-16 and some stages will be completed prior to the commencement of the forthcoming regulatory period. Nevertheless, it is key project in the forthcoming regulatory period.

During the forthcoming regulatory period, to complement Ajilis, TasNetworks will be establishing a unified AMIS across our asset management operations. This approach consists of identifying, specifying, developing and deploying a number of key projects and initiatives to support evidence-based decision making in accordance with the strategic, tactical and operational asset management practices of the business.

The projects and initiatives are in the areas of, but not limited to:

- asset knowledge management;
- asset planning;
- asset condition monitoring;
- asset risk management;
- network performance; and
- a number of supporting asset management processes.

Investment is also required in asset management systems to strengthen our asset condition and geographical information; enhance our risk management and asset analysis tools; and renew our operational systems. That investment will enable us to minimise our asset life cycle costs and to progress our distribution grid development program.

In summary, the key benefits and outcomes we expect to be delivered by our proposed AMS capital expenditure in the forthcoming regulatory period include:

- reducing the risk of asset failure;
- maintaining overall network performance;
- ensuring compliance with regulatory and governance requirements;
- effective collection and management of asset knowledge;
- effective resource utilisation; and
- optimum infrastructure investment.

7.8 Non-network Other capital expenditure

The table below shows our annual actual and forecast Non-network Other capital expenditure.

Table 7-11: Non-network Other capital expenditure (June 2017 $m)

Sub-category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Non-network Other	6.1	7.0	5.8	6.0	3.8	3.7	3.7	3.9	3.7	3.5

Our total Non-network Other capital expenditure reduces from $28.7 million in the current period to $18.5 million for the forthcoming five year period.

This expenditure category includes:

- fleet; and
- land and buildings.

The key drivers for investment are asset age and condition, the business environment and corporate strategy.

Each category is discussed briefly below.

- Fleet expenditure needs are determined in accordance with the fleet management strategy. The forecast is based on a bottom up view and top down approach from the business with regard to the replacement and investment needs in TasNetworks' vehicle fleet. The forecast is based on an assessment of the fleet's age and kilometres travelled, condition assessment of useful life, fleet size and resourcing requirements of the business.
- Land and Buildings capital expenditure requirements are based on the corporate facilities and property strategy. This plan identifies the land and property requirements to support the accommodation of staff (in offices and depots) and the overall property strategy. The property needs are aligned to the facility requirements to support the efficient delivery of services.

The table below provides details of our actual and forecast capital expenditure for each of these categories.

Table 7-12: Non-network other capital expenditure forecast (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Fleet	4.9	5.5	2.3	2.5	2.4	2.5	2.5	2.4	2.3	2.2
Land & Buildings	1.2	1.5	3.5	3.5	1.4	1.3	1.2	1.5	1.4	1.4
Non-network Other	6.1	7.0	5.8	6.0	3.8	3.7	3.7	3.9	3.7	3.5

For each category of expenditure, our forecast capital expenditure is lower than our recent actual expenditure. On a trend basis, the AER should be comfortable that the forecast expenditure is reasonable.

Further information on our non-network other capital expenditure is provided in our strategies and plans for facilities and fleet assets (TN024, TN025, TN026 and TN027). It should be noted that these documents are company-wide documents that relate to both the transmission and distribution networks. The capital expenditure attributable to standard control distribution services has been determined in accordance with our cost allocation methodology.

7.9 IT and communications capital expenditure

The table below shows our annual actual and forecast IT and communications capital expenditure.

Table 7-13: IT and communications capital expenditure (June 2017 $m)

Sub-category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
IT and communications	17.2	22.7	7.1	15.8	19.2	14.2	11.7	15.3	17.0	16.5

This expenditure category is concerned with the provision of information technology and communication services to the distribution customers, including:

- stakeholder management systems such as billing and call centre management to support the provision of distribution services and information for our customers and stakeholders;
- network management systems to support the management of distribution systems including responding to faults;

- information management systems to manage large amounts of structured and unstructured information across the business;
- a share of the Ajilis project; and
- IT management, which refers to IT capabilities enabling operations and supporting planning and management of the business, including managing applications, IT portfolio, infrastructure, architecture, security and IT services.

Similar to our forecasting approach for SCADA and Network Control, our IT and communications capital expenditure requirements are developed by considering the recurrent and non-recurrent cost components. The recurrent capital expenditure typically relates to life cycle refresh programs, while non-recurrent expenditure is driven by our business needs.

Our IT capital expenditure forecasts also include an allowance for distribution network IT costs to facilitate the introduction of metering competition. The introduction of competition will require us to have the appropriate systems and processes in place that enable us, as the owner and operator of the network, to work with other metering providers. For example, our systems will need to accept metering data from a variety of different meter providers. New processes will also need to be developed to make sure the competitive provision of meters works seamlessly for our customers.

As noted in our global assumptions in section 1.4, our IT capital expenditure forecasts will be provided to the AER, as total implementation costs are understood and refined to the extent permissible in the Rules, we will revisit our expenditure forecasts following the AER's draft decision. Further discussion of the metering Rule change is provided in Chapter 17. Section 1.4 also explains that the financial impact of the Embedded Networks Rule change has not been included in this Regulatory Proposal.

Table 7-14 sets out our actual and forecast IT and Communications capital expenditure. As noted above, Ajilis costs are allocated between the Asset Management Systems (Table 7-10) and IT and Communications expenditure categories.

Table 7-14: IT and communications capital expenditure (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Full Retail Competition Capex	10.3	15.4	-	-	-	-	-	-	-	-
Infrastructure and systems	6.9	7.3	7.1	9.2	5.1	5.8	11.7	15.3	17.0	16.5
Ajilis	-	-	-	6.6	6.6	4.3	-	-	-	-
Metering Rule change	-	-	-	-	7.5	4.1	-	-	-	-
IT and Communications Capex	**17.2**	**22.7**	**7.1**	**15.8**	**19.2**	**14.2**	**11.7**	**15.3**	**17.0**	**16.5**

Further detail on our IT and communications capital expenditure is provided in our Software Asset Management Plan (TN048), the IT Infrastructure Asset Management Plan (TN049) and the Ajilis Business Case (TN050). As previously noted, these documents are company-wide documents that describe the strategy across the transmission and distribution networks.

7.10 Benchmarking our capital expenditure

When comparing network companies, performance is affected by factors such as the location of their customers and the local terrain. For example, TasNetworks serves 280,000 customers spread out over a service area of 67,800 square kilometres, while CitiPower in Victoria serves 325,000 homes and businesses across Melbourne's central business district and inner suburbs, packed into a service area of only 157 square kilometres.

Our network configuration is markedly different from other distribution networks in the NEM. For example, whereas many other distributors own and operate the terminal substations which step down transmission network voltages to the lower voltages used in the distribution network, in Tasmania those assets are included in the regulatory asset base of the transmission network.

As a result of these and other differences, we can appear much less efficient in terms of our raw benchmarking scores.

Our investigations indicate that the AER's Multilateral Total Factor Productivity (MTFP) benchmarking model, for example, does not take into account the impact that the quantum, location and density of demand in Tasmania's rural areas have on several key inputs which inform the AER's calculations, especially overhead lines and transformers. As mentioned in section 4.8, the AER has acknowledged the uniqueness of our circumstances and has urged caution when interpreting our benchmarking score, given our "comparatively unusual system structure".

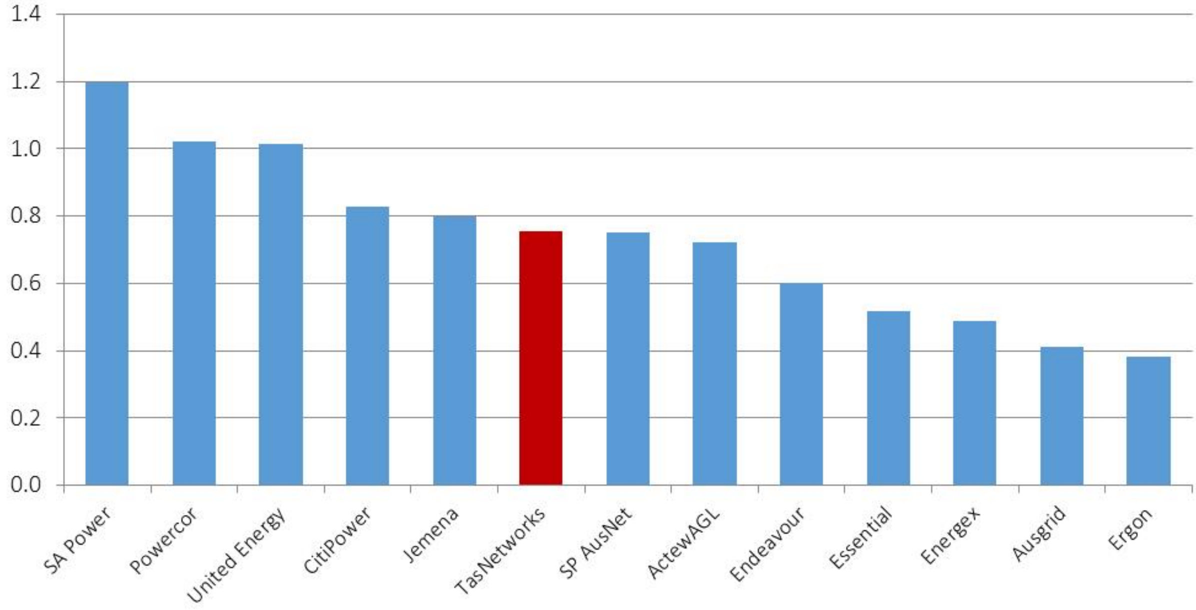
Whereas the AER's current MTFP benchmarking model, in addition to operating expenditure, uses quantities of inputs such as transformer capacity as a proxy for capital expenditure, we have undertaken benchmarking analysis using the same model which is based on the sum of operating and capital expenditure (totex).

Totex benchmarking is used by the Office of Gas and Electricity Markets (Ofgem) in the United Kingdom as a cost assessment technique for the 13 electricity networks it regulates, and the Ontario Energy Board also employs total cost benchmarking to monitor the performance of the more that 70 distribution networks it regulates. Advocates of benchmarking based on total cost contend that compared to other costs assessments approaches, totex has the advantages of providing a good proxy for the overall network complexity which drives total costs, and is not affected by categorisation issues.

The MTFP benchmarking analysis of network totex elevates our standing to sixth place amongst our peers, in terms of capital productivity. Apart from the improvement in our relative performance, the results of this analysis for other networks are also quite consistent with the MTFP benchmarking analysis undertaken for the AER by Economic Insights, with the top five performers against our alternative benchmark also being the top five performers against the AER's benchmark, albeit in a slightly different order. The fact that our alternative benchmarking produces results for most other networks that are consistent with those published by the AER illustrates the sensitivity of the AER's capital benchmarking to the specification of its MTFP model.

The above observations suggests that our capital expenditure productivity and efficiency is comparable with our relative standing in relation to operating expenditure.

Figure 7-6: Average Totex productivity 20016-14 (MTFP model)



7.11 Deliverability of our capital expenditure program

We have developed a works delivery strategy for the forthcoming regulatory period and beyond. The strategy encompasses plans for the delivery of our operating and capital expenditure programs. It aims to:

- optimise the mix of internal and external resources we use to deliver the works program; and
- maximise efficiency in the delivery of the works program, whilst also ensuring efficient risk management.

Our internal resources provide us with an on-going capability and competency to deliver the core elements of the works program. These resources are complemented by our use of outsourced service providers in the cost-effective delivery of a range of functions including vegetation management; meter replacement, reading and testing; street lighting; civil works; construction; pole testing and staking; and routine maintenance. External service providers also increase our flexibility in managing peak workloads by providing supplementary resources.

In relation to our works delivery requirements for the forthcoming regulatory period, the following points are noted:

- The forecast volume of work to be delivered using in-house labour for the forthcoming period and is consistent with the level that we expect to deliver in 2015-16. Our delivery performance in the current period demonstrates our ability to deliver in the forthcoming period.
- Planned hours of work over the forthcoming regulatory period exceeds available hours by approximately 11 per cent of available internal labour. This observation, coupled with our delivery performance in the current regulatory period indicates that the present level of

internal resourcing is reasonable for the forthcoming period. The introduction of customer choice in relation to connections may also reduce the pressure on internal resources.

- We have an appropriate mix of external service providers across both distribution and transmission disciplines with some service providers currently providing services across both areas. Through our predecessor businesses, we have established a robust service provider market in Tasmania with some service providers mobilising satellite operations from mainland Australia.
- Service providers have become very knowledgeable and experienced in dealing with TasNetworks' equipment standards, design standards, technical specifications, processes, work practices, accreditations and compliance requirements. Forecast volumes of outsourced work for the forthcoming regulatory period are well within the delivery capability of our external service providers.

We are committed to continually improving our works delivery arrangements and we have a number of initiatives underway that will enable us to achieve further efficiency improvements. These initiatives include:

- a review and strengthening of our Works Delivery Framework;
- an 'end to end' program of work process review, to strengthen the clarity of roles and responsibilities of employees and to ensure that TasNetworks responds to the challenges of developing and delivering its program of work efficiently and prudently;
- initiatives focused on developing and growing our people, to build a high performance culture and strengthened employee engagement, to ensure that a sustainable and flexible workforce exists that can meet the future demands of the business; and
- the introduction of customer choice for connections, which should lead to greater customer satisfaction. It will also provide an additional channel for resourcing this category of work.

Our performance in delivering our capital works over the current period demonstrates our ability to efficiently deliver the forecast capital works program. We are confident that our works delivery strategy will enable us to deliver the forecast works program prudently and efficiently in the forthcoming period.

Further information on our delivery strategy is provided in the supporting document, Works Delivery Plan (TN015).

7.12 Expected benefits of capital program

As explained at the outset, our capital expenditure forecasts have been calibrated to address the objectives in the Rules, which require us to deliver the following outcomes efficiently:

- to meet the expected demand for our services;
- to comply with our safety and regulatory objectives;
- to maintain network reliability; and
- to maintain the safety of our distribution network.

Our approach to determining our requirements for each capital expenditure category is focused on examining the key drivers; identifying improvement opportunities, including opex-capex substitutions; validating through modelling and benchmarking; and applying a top-down discipline to the forecasts.

The overall benefit of the capital expenditure program is the achievement of the Rules objectives at lowest life cycle cost. Our capital expenditure plans look beyond the current period to consider the implications for cost, performance and risk in subsequent periods. The benefit to our customers that the reliability and safety of the distribution services will be maintained at the lowest sustainable cost.

As noted in section 7.3, we have responded to customer feedback regarding the need to contain any upward pressure on prices by rigorously reviewing our capital expenditure plans on a top-down basis. Our capital expenditure proposal contains no ‘ambit claims’. It represents the minimum efficient investment we need to meet our compliance obligations and to maintain an efficient balance between cost and reliability.

8 Operating expenditure forecast

8.1 Introduction

This chapter presents our operating expenditure forecasts for the forthcoming regulatory period. It explains that our forecasts are focused on enabling us to efficiently achieve the operating expenditure objectives specified in the Rules. These objectives include providing safe and reliable distribution services to our customers and complying with our regulatory obligations.

Our directions and priorities identified the following themes to guide our plans for the forthcoming regulatory period:

1. improving how we communicate with, and listen, to our customers;
2. ensuring the safety of our customers, employees, contractors and the community;
3. keeping the power on, maintaining service reliability;
4. innovating in a changing world; and
5. delivering services for the lowest sustainable cost.

The operating expenditure forecasts set out in this chapter reflect efficient levels of expenditure that will enable us to deliver all of these outcomes.

As explained in our forecasting methodology paper[12], we have adopted the AER's 'base-step-trend' approach to develop our operating expenditure forecasts. This methodology projects future expenditure by building from an efficient base year. It is a simple method that is effective in identifying the operating expenditure drivers for the forecast period.

The AER's forecasting methodology recognises that operating expenditure is primarily recurrent in nature. As such, extending our operating expenditure forecast beyond the two-year regulatory period would not provide any additional context or insights regarding the reasonableness of the forecast. Therefore, in contrast to our capital expenditure forecasts, the forecasts presented in this chapter are limited to the two-year regulatory period.

The remainder of this chapter is structured as follows:

- Section 8.2 provides an overview of our operating expenditure forecasts.
- Section 8.3 explains our operating expenditure forecasting methodology.
- Section 8.4 outlines the key variables and assumptions and issues underpinning the operating expenditure forecasts.
- Section 8.5 identifies the base year we have selected to develop our forecasts of recurrent operating expenditure and demonstrates that the proposed base year expenditure is efficient.

---

12 TasNetworks, 2017–19 TasNetworks Regulatory Proposal Expenditure Forecasting Methodology, June 2015.

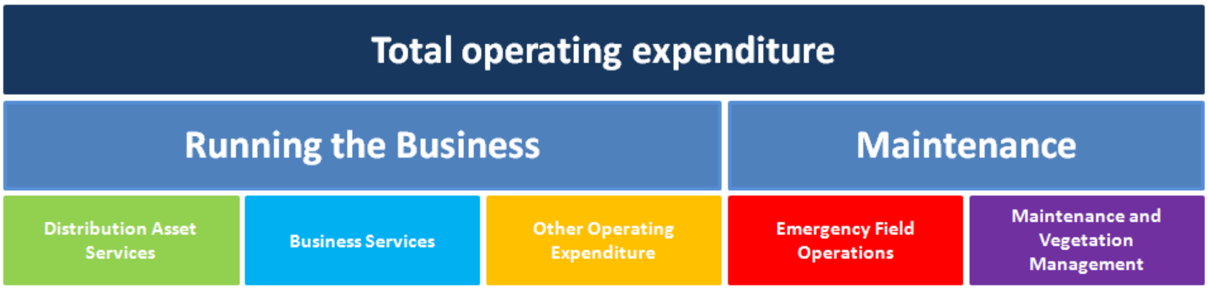
- Section 8.6 sets out details of step change costs we have considered in developing our operating expenditure forecasts.
- Section 8.7 explains how we have accounted for the impact of business growth and economies of scale on our future operating expenditure requirements.
- Section 8.8 sets out our expenditure forecasts in relation to those items where we have applied a zero based forecasting approach.
- Section 8.9 sets out the cost escalation rates used in the expenditure forecasts.
- Section 8.10 explains how we have incorporated productivity growth into our operating expenditure forecasts.
- Section 8.11 sets out our forecasts of 'Other' operating expenditure.
- Section 8.12 sets out our total operating expenditure forecasts for the forthcoming regulatory period.
- Section 8.13 presents concluding comments.

Further supporting information and analysis to justify our forecast operating expenditure is provided in a number of documents that are referenced in this chapter.

8.2 Overview of operating expenditure forecast

Our operating expenditure forecasts are presented by reference to well accepted categories[13], as illustrated in the figure below.

Figure 8-1: TasNetworks' operating expenditure categories

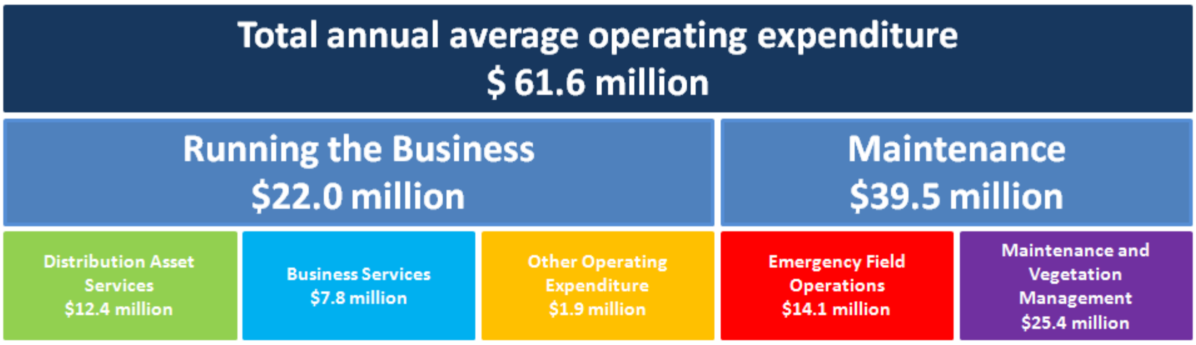


Our operating expenditure forecast is built on the significant efficiencies that we have already achieved since merger, by improving our business processes and reducing labour and contracted services costs across a range of functions. This improvement in cost performance provides confidence that our base year (2014-15), from which future costs are projected, is efficient. This is discussed in further detail in section 8.5.

The figure below shows the forecast average annual operating expenditure amounts over the regulatory period in the relevant categories.

13 In accordance with schedule S6.1.2(1) of the Rules.

Figure 8-2: Forecast annual average operating expenditure (June 2017 $m)

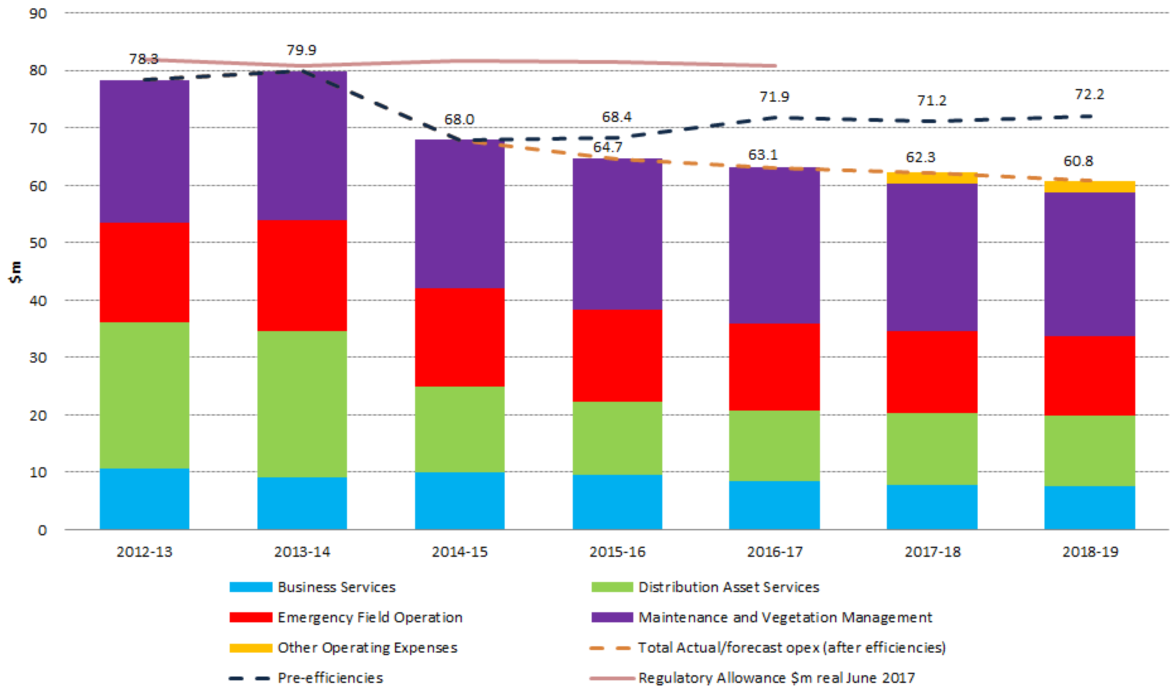


Note: Numbers may not sum exactly due to rounding.
Boxes are not intended to represent the relative size of expenditure in each category.

This chapter explains that we plan to achieve further cost reductions during the forthcoming regulatory period, primarily as a result of realising further synergies from the merger of the distribution and transmission businesses. The operating expenditure forecasts presented in this chapter reflect these expected efficiency improvements. The inclusion of these gains into our forecasts results in the anticipated cost savings being passed on to customers with immediate effect.

The figure below shows our actual operating expenditure for the current regulatory period alongside our forecast for the two year regulatory period, commencing in 2017-18.

Figure 8-3: Overview of forecast and actual operating expenditure (June 2017 $m)



Our average operating expenditure for the forthcoming regulatory period is forecast to be 13.1 per cent lower in real terms than our average for the current period. This represents a significant reduction in operating expenditure. As already noted, this saving flows straight though to customers. This reduction is from a cost base in 2014-15 which is approximately 16 per cent below the allowance set by the AER, as shown in Figure 8-3. Further detailed information on the variation between historic and forecast operating expenditure is provided in the RIN templates[14].

The table below shows our actual and forecast annual operating expenditure by category. The total forecast operating expenditure for the forthcoming regulatory period is $123.1 million.

Table 8-1: Actual and forecast operating expenditure by category (June 2017 $m)

Category	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Emergency Field Operations	17.5	19.3	16.9	16.1	15.0	14.3	13.9
Maintenance and Vegetation Management	24.7	25.9	26.0	26.3	27.3	25.7	25.1
Distribution Asset Services	25.3	25.6	15.0	12.7	12.3	12.4	12.3
Business Services	10.8	9.1	10.0	9.5	8.5	7.9	7.6
‘Other’ Operating Expenditure	n/a	n/a	n/a	n/a	n/a	1.9	1.9
Total operating expenditure	**78.3**	**79.9**	**68.0**	**64.7**	**63.1**	**62.3**	**60.8**

Note: ‘Other’ operating expenditure is shown as n/a during the current regulatory period as actual costs are not reported in this category. As explained in section 8.11, ‘Other’ operating expenditure comprises benchmark debt raising costs and a self-insurance allowance. Our actual debt raising cost is reported as part of our financing costs, not operating expenditure. In addition, self-insured losses are currently allocated to the expenditure category where the loss arises, as no self-insurance allowance was provided during the 2012-17 regulatory period.

8.3 Forecasting methodology

Our operating expenditure forecasting methodology essentially follows the base-step-trend approach adopted by the AER in its recent revenue cap decisions.

Under the operating expenditure forecasting methodology:

- the audited 2014–15 total standard control services operating expenditure will be used as a starting point for projecting future recurrent operating expenditure requirements; and
- certain operating expenditure items - referred to here as ‘Other’ operating expenditure - are forecast separately and included in the total operating expenditure forecast.

Our methodology comprises the following three steps.

- Step 1 Derive and verify the recurrent operating expenditure forecast as follows:
  - (a) commence with actual standard control services operating costs for the 2014–15 base year;
  - (b) adjust the base year cost by deducting:
    - (i) non-recurrent operating expenditure items;

[14] The information in this section and in the RIN templates is provided in accordance with clause S6.1.2(8) of the Rules.

(ii) any other categories of expenditure which are not reflective of future expenditure requirements and which should therefore be subject to a zero-based (bottom-up) forecast; and

(iii) the actual costs of the 'Other' operating expenditure items that are to be subject to separate forecasts in Step 2;

(c) add the forecast cost of step changes;

(d) scale up the sub-total of the adjusted base year cost and forecast step change costs annually by using applicable growth factors which reflect the increase in operating expenditure requirements driven by growth of the business;

(e) add to that scaled-up sub-total the forecast non-recurrent operating expenditure for items (i) and (ii) deducted in step (b). These forecasts are to be derived using zero-based cost estimates for each year of the forthcoming period;

(f) scale up the total obtained in step (e) annually by using applicable labour and non-labour escalation factors to derive the unadjusted forecast of operating expenditure for the forthcoming regulatory period; and

(g) reduce the total obtained in step (f) by an annual productivity target to derive the productivity-adjusted forecast of total operating expenditure, including further synergy benefits from the merger of the transmission and distribution networks for the forthcoming regulatory period. It is noted that for the purpose of this Regulatory Proposal we have adopted a productivity target in order to deliver on our commitment to manage our total operating expenditure so that it remains flat in nominal terms relative to the 2014-15 base year. Our approach differs from the AER's empirical approach to assessing productivity.

- Step 2 Include the forecast for 'Other' operating expenditure elements.

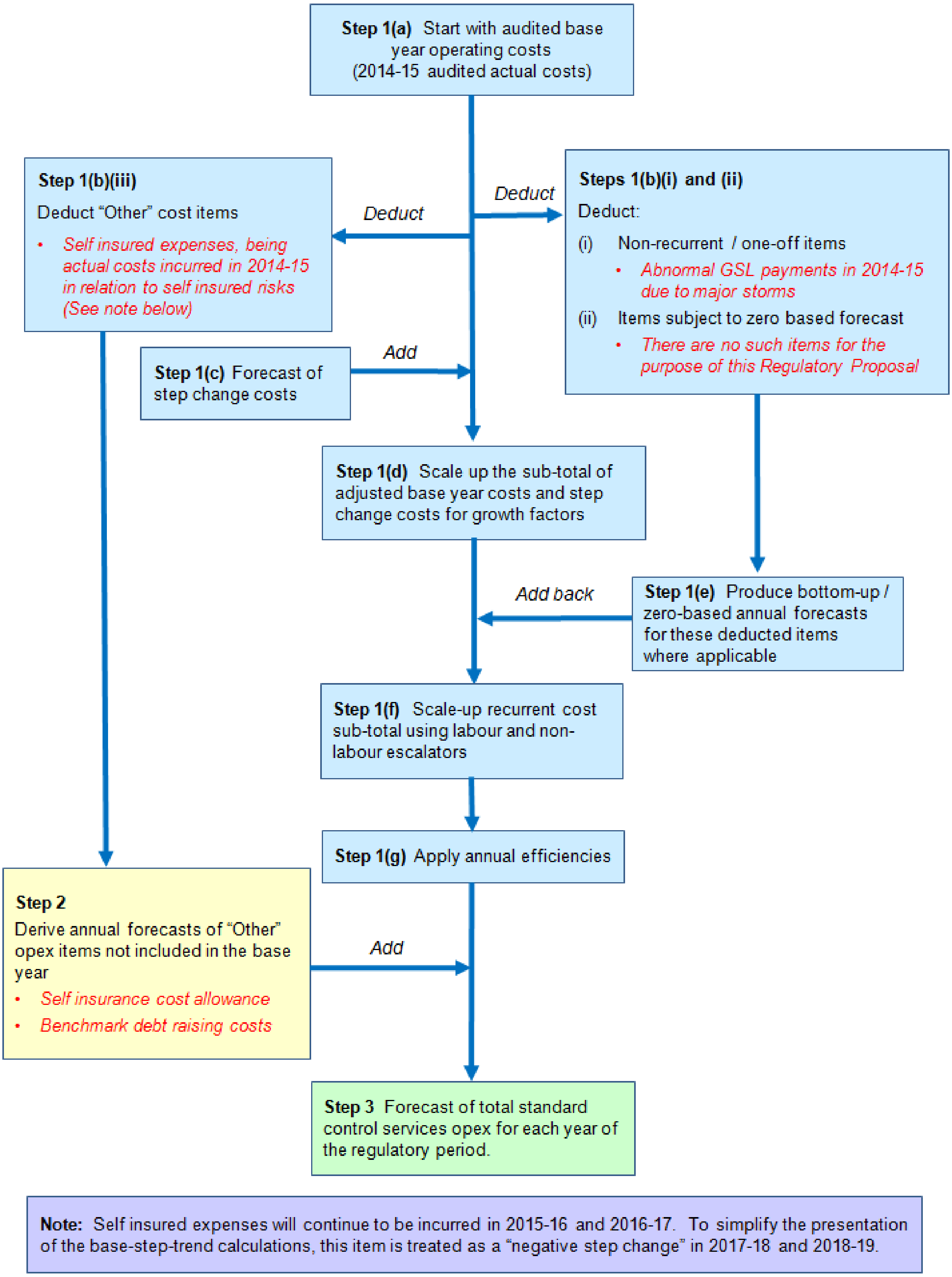
  A forecasting methodology is adopted for each element, which reflects the relevant drivers.

- Step 3 Derive the standard control services operating expenditure forecast as follows:

  Recurrent operating expenditure and 'Other' operating expenditure annual forecasts will be summed to provide the total operating cost forecast for each year of the forthcoming regulatory period.

A pictorial overview of the development of TasNetworks' forecast operating expenditure using the forecasting methodology is illustrated in the figure below.

Figure 8-4: TasNetworks' operating expenditure forecasting methodology



8.4 Key assumptions

In addition to the global assumptions set out in section 1.4 the following assumptions underpin our operating expenditure forecasts:

- our 2014–15 base year operating expenditure is efficient, and therefore provides a reasonable basis for projecting future operating expenditure requirements;
- the historic relationship between asset growth and operating expenditure will continue in the forthcoming regulatory period;
- our provisions account is held static year on year; and
- our forecast productivity improvements and resulting cost efficiencies are achievable.

As noted in relation to our capital expenditure assumptions, the directors have provided a certification of the reasonableness of the above assumptions. While these assumptions are reasonable, there is no guarantee that they will eventuate. If these assumptions prove to be incorrect, there may be a material impact on our future operating expenditure.

Further information on the efficient base year, asset growth scaling factors and labour and non-labour escalation rates is provided below.

8.5 Recurrent base year costs - Steps 1(a) and 1(b)

The 2014–15 regulatory year is the base year for determining the recurrent component of the operating expenditure forecast. We have chosen 2014-15 as our base year for operating expenditure forecasting because:

- it is the most recent full regulatory year of actual reported operating expenditure at the time of preparing this Regulatory Proposal;
- it is representative of our underlying operating conditions for the current and forthcoming regulatory periods;
- it incorporates the efficiency gains that we have achieved to date; and
- its selection is consistent with the design of the incentive mechanisms, which provides a constant incentive to deliver efficiency savings.

In accordance with step 1(b)(i) we have deducted abnormally high guaranteed service level (GSL) payments made in 2014-15 due to the major storms that occurred in that year. We do not expect this level of GSL payments to be recurrent and therefore a $2 million reduction has been applied to the base year operating expenditure.

In relation to step 1(b)(ii) we are not proposing any zero-based forecasts for the forthcoming regulatory period.

In relation to step 1(b)(iii) we propose removing the actual costs we have incurred in relation to self insured risks.[15] These costs relate principally to our fleet and distribution assets where losses are not

[15] We add back an allowance for efficient self insurance costs in step 2 of the calculations.

insured through commercial insurance. In the forthcoming regulatory period, we propose including a self insurance allowance based on actuarial estimates of the risks we face.

In order to present our proposed efficiency gains relative to our actual costs in 2016-17, self insured expenses are treated as 'negative step changes' from 2017-18. The same treatment is also applied to recoverable asset damage costs, which in future will be recovered as an unregulated charge.

While our approach does not affect the resulting forecasts, it provides a clearer presentation of the operating expenditure changes compared to the current period. On this basis, it is preferable to making adjustments to the base year.

The table below shows the derivation of the efficient base year operating expenditure.

Table 8-2: Efficient base year operating expenditure (June 2017 $m)

Audited operating expenditure for 2014–15	68.0
Deduct non-recurrent / one-off items: abnormal GSL payments	-2.0
Deduct items subject to zero based forecast	0.0
Base year efficient operating expenditure	**66.0**

Before proceeding to the next steps of the forecasting methodology, we must first verify that the base year operating expenditure is efficient. This verification provides confidence that the resulting operating expenditure forecasts, which build from the base year, reasonably reflect efficient costs[16]. As explained below, the AER's benchmarking analysis which it applied to the NSW, ACT, Queensland, South Australian and Victorian distributors provides strong evidence that our base year operating expenditure is efficient.

The AER's benchmarking analysis is complex, but it essentially involves four steps:

1. Determine each distributor's 'raw efficiency score' for the period 2006-2013, using Economic Insights' model, which is described as a Cobb Douglas Stochastic Frontier Analysis (Cobb Douglas SFA).
2. Choose a comparison point, which defines the efficient score. In the AER's most recent decisions, it has selected AusNet Services as the comparison point or the 'efficiency frontier'.
3. Adjust the comparison point to take account of the cost impact of operating environment factors (OEF). The OEFs attempt to explain cost differences (both positive and negative) that are not captured in the Economic Insights model.
4. The subject distributor (in this case TasNetworks) is regarded as inefficient if its efficiency score is below the adjusted comparison point. In these circumstances, the AER may regard the base year operating expenditure as inefficient and reduce it accordingly.

[16] Clause 6.5.6(c)(1) of the National Electricity Rules.

The raw efficiency scores from the Cobb Douglas SFA are set out in the table below[17].

Table 8-3: Raw efficiency scores for each network

Rank	Network	Efficiency score
1	CitiPower	0.950
2	Powercor	0.946
3	SA Power	0.844
4	United	0.843
5	AusNet Services	0.768
6	**TasNetworks**	**0.733**
7	Jemena	0.718
8	Energex	0.618
9	Endeavour	0.593
10	Essential	0.549
11	Ergon	0.482
12	Ausgrid	0.447
13	ActewAGL	0.399

The table highlights in yellow the efficiency frontier (AusNet Services), which has a raw efficiency score of 0.768. TasNetworks has a raw efficiency score of 0.733, which is approximately 5 per cent below the unadjusted comparison point. As already noted, the comparison point must be adjusted to reflect the operating environment factors that may impose additional costs on TasNetworks.

In the absence of detailed analysis and dialogue with the AER, we cannot be certain of the appropriate OEF adjustment for TasNetworks. In order to conclude that our base year operating expenditure is efficient, the AER would need to apply an OEF adjustment of 5 per cent or more. This adjustment is modest compared to the AER's recent decisions[18], where OEF adjustments have varied between 11 and 13 per cent for NSW distributors and 17 and 26 per cent for Queensland distributors[19].

As explained in chapter 2, our distribution network is exposed to cost pressures driven by its topography; a sparsely populated customer base; vegetation management issues; and significant bushfire risk. Given these factors, there is strong justification for our OEF adjustments at least matching the level applied to the NSW distributors. On this basis, we expect the AER's analysis to conclude that TasNetworks' base year operating expenditure is efficient.

---

17 AER Final decision Endeavour Energy distribution determination - Endeavour Energy 2015 - Opex base year adjustment, April 2016.

18 It is noted that no OEF adjustment was considered in the AER's decision for SA Power Networks, as the company's raw efficiency score was superior to the comparison point.

19 Ergon Energy determination 2015−16 to 2019−20, Attachment 7 - Operating expenditure, October 2015, page 7-32.

As explained in section 4.9, we have delivered several efficiency initiatives during the current regulatory period. These initiatives provide additional comfort that the base year operating expenditure is efficient. As explained later in this chapter, we are also projecting further cost savings as a result of the merger with the transmission network.

8.6 Forecasting step changes – Step 1(c)

The base year operating expenditure derived in step 1(b) reflects the scope of the distribution business activities (including self-insured expenses and recoverable asset damage costs) in 2014-15. However, the scope of our business activities and obligations may change in the forthcoming regulatory period. Such changes may result in increases or decreases in our forecast of recurrent operating expenditure, relative to the 2014-15 base year. These changes in costs are termed 'step changes'.

As explained in sections 8.10 and 8.12, our operating expenditure forecast also takes into account our productivity improvement targets. While we explain the material step changes in the table below, our proposed productivity improvement has the effect of absorbing these cost increases.

Table 8-4: Step changes

Activity	Details
Damage to assets caused by third parties	The AER's Framework and Approach paper stated that where it is clear that damage to the network has been caused by the actions of a third party, the costs should be recovered from that party and this activity should not be classified by the AER. The offending parties' ability to pay those costs is a risk borne by TasNetworks and not the general customer base. Accordingly, asset damage costs able to be recovered from third parties are to be classified as unregulated from 1 July 2017, so the associated costs are removed from the efficient base year by applying a negative step change from 2017-18.
Self-insured expenses	The actual costs incurred in 2014-15 in relation to self-insured risks are deducted from the efficient base year because a self-insurance allowance is to be included for the forthcoming regulatory period. The deduction of actual self-insured expenses from the base year costs is achieved by applying a negative step change from 2017-18.
Metering Rule change	Additional operating expenditure will be required to administer new distribution processes and systems associated with metering contestability, which is expected to commence in December 2017.
Overhead switchgear and overhead system asset repair	Additional operating expenditure is programmed to address recent failures associated with air break switches and to maintain the efficacy of the current asset repair program.
Increase in access track and corridor maintenance	We plan to increase track and corridor maintenance to ensure the continuation of prudent vegetation management practices.

Activity	Details
Increase in inspection of overhead lines and structures and increase in overhead system asset repair	Inspection will enable us to better understand the health and risk associated with overhead assets. This knowledge will enable more efficient decision-making and planning of work prior to asset failure (as opposed to run to failure). We expect to increase the ratio of the planned component of the work program and to reduce the reactive component to achieve efficiency improvements and improved safety outcomes in the longer term.
Increase in low conductor span rectification	We plan to increase expenditure on low conductor span rectification.

For each of the step changes described in the table above, we have taken care to ensure that the forecast expenditure reflects the efficient costs of providing the required outcomes. The table below sets out our forecasts of efficient costs for each ‘step change’.

Table 8-5: Forecast step changes to include in base costs (June 2017 $m)

Category	2015–16	2016–17	2017–18	2018–19
Damage to assets			-0.8	-0.8
Self-insured expenses			-0.4	-0.4
Metering Rule change			0.3	0.5
Overhead switchgear and overhead system asset repair	0.6	1.8		
Increase in access track and corridor maintenance	1.1	1.1	1.1	1.1
Increase in inspection of overhead lines and structures		1.1	0.9	1.1
Increase in low conductor span rectification		0.8	0.8	0.8
Total additional expenditure above base year	**1.7**	**4.8**	**1.8**	**2.3**

These ‘step changes’ have been incorporated into our forecast of operating expenditure, as shown in section 8.12. As already explained, our operating expenditure forecast reflects our intention to absorb these cost increases over the forthcoming regulatory period.

It should be noted that uncertainty remains regarding the cost implications of the Metering Rule change and the AEMC’s Rule change in relation to Embedded Networks. Any adjustments to forecasts resulting from these Rule changes will be provided to the AER, as total implementation costs are understood and refined to the extent permissible in the Rules, we will revisit our expenditure forecasts following the AER’s draft decision.

8.7 Output growth - Step 1(d)

In broad terms, our operating expenditure requirements increase as the size of the distribution business grows, both in terms of assets and customer numbers. However, there is not a simple one-for-one relationship between business growth and its operating costs, as a result of economies of scale.

As noted above, we have adopted the base-step-trend approach to forecast our operating expenditure. This method identifies growth and new obligations affecting operating expenditure, but does not further distinguish between fixed and variable costs.

It has become common practice for the AER to take into account the impact of business growth and economies of scale on future operating expenditure requirements. However, the AER's method for making this adjustment has evolved in recent determinations.

In its current determination for the (then) Aurora distribution business, the AER adopted the following approach to estimate the impact of growth on Aurora's scale factors[20]:

- estimated scale escalators for Aurora based on forecast growth in customer connection numbers, line length, zone substation capacity and number of distribution transformers;
- used Aurora's forecast growth rates for customer connection numbers, line length, zone substation capacity and distribution transformer numbers to estimate its network growth; and
- used the average of the Victorian DNSP's economies of scale factors as an estimate for Aurora.

In its most recent determinations for the NSW, Queensland and South Australian distributors, the AER has not accounted for economies of scale in the growth factor. Instead, the AER captures economies of scale in a single productivity adjustment, which we discuss in section 8.10.

In its most recent decisions, the AER adopted Economic Insights' operating expenditure cost function to estimate the impact of forecast growth on operating expenditure. This cost function combines the forecast change in customer numbers, circuit length and ratcheted demand to produce a weighted average growth rate in operating expenditure. Under the AER's approach:

- Forecast operating expenditure is a function of 'ratcheted maximum demand', which is the record peak demand either historically or forecast. In our case, the highest maximum demand of 1,198 MW was recorded on the distribution network in the 2006-07 financial year. Our forecast maximum demand is not expected to exceed this historic peak until after the end of the forthcoming regulatory period.
- Economies of scale are accounted for in the productivity factor and operating expenditure is forecast to increase in line with the weighted average growth.

The table below applies the AER's methodology for growth to our data.

20 AER, Draft Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17, November 2011, page 174.

Table 8-6: Output growth forecasts per cent and cost impact (June 2017 $m)

Driver	2015-16	2016-17	2017–18	2018–19
Ratcheted maximum demand (MW)	1,198	1,198	1,198	1,198
Customer numbers	285,369	287,679	289,989	292,299
Circuit length (km)	22,784	22,920	23,077	23,223
Weighted average growth per cent	0.62%	0.62%	0.61%	0.61%
Cost impact $m	0.4	0.9	1.3	1.7

8.8 Zero based expenditure items - Step 1(e)

As explained in section 8.2 (in relation to step 1(b)), any zero based expenditure items are subject to a separate forecast on the grounds that the base year expenditure does not reflect the recurrent costs. For the purpose of this Regulatory Proposal there are no such items.

8.9 Real price escalation – Step 1(f)

This component of the rate of change calculation captures the impact of the increases in the prices of our inputs, which feed through to higher operating expenditure. There are three different types of inputs:

- internal labour costs;
- external labour costs; and
- non-labour costs, which include materials, motor vehicle expenses, tools, media and marketing costs.

Each of these elements may be subject to different market conditions (essentially ‘supply and demand’) and therefore it is appropriate to forecast them separately. The cost escalators are relevant to both operating and capital expenditure, as already noted in Chapter 6.

We engaged Jacobs to estimate non-labour cost escalation rates. Across all of our distribution asset categories, Jacobs forecasts the average non-labour cost escalation rate to be 3.3 per cent in nominal terms for the period to 2022, compared to a forecast CPI of 2.5 per cent over the same period.

We recognise that real rates of change in labour and non-labour costs can vary materially over time. We also recognise that evidence may exist to support a positive real rate of increase in some forecast labour and non-labour costs over the forthcoming regulatory period. Notwithstanding this, we have not applied any escalation. This decision reflects our commitment to addressing customers’ concerns about electricity prices and the need for us to strive to deliver services for the lowest sustainable cost.

8.10 Productivity growth – Step 1(g)

The productivity growth factor in the rate of change formula is intended to capture future productivity improvements. In principle, we consider that three sources of productivity improvement should be included in an operating expenditure forecast:

- economies of scale as a result of growing output;
- efficiency improvements to 'catch up' to the efficiency frontier; and
- efficiency improvement targets that are adopted by a business in the pursuit of further efficiency gains.

In relation to the second source, this may already be addressed if the AER adjusts the base year operating expenditure to reflect a finding that the distributor is inefficient. However, as noted in section 8.5 we expect the AER's analysis to conclude that TasNetworks' base year operating expenditure is efficient.

In the AER's recent decision for the NSW, Queensland and South Australian distributors, the AER has applied a zero per cent productivity growth. This reflects recent productivity trends and Economic Insights' recommendation that this trend is likely to continue.

We note that the regulatory framework provides incentives for companies to deliver efficiency gains over time. As a matter of principle, we do not consider it appropriate to capture these prospective efficiency improvements in the productivity growth factor. To do so, would effectively undermine the incentive properties of the regime – such as the Efficiency Benefit Sharing Scheme – which have been designed to provide a fair sharing of efficiency gains over time.

However, for the purpose of setting our operating expenditure forecast for the forthcoming regulatory period we are targeting - and offering - further efficiency gains. We have incorporated these expected efficiencies into our operating expenditure forecast. This reflects our response to the feedback of customers and other stakeholders, who reasonably expect the merger of the transmission and distribution networks to deliver further cost savings, and that we should be working hard to deliver such savings. For this reason, we consider it appropriate to forecast a productivity gain over the forthcoming regulatory period that delivers a cumulative total cost saving of $32.8 million in real terms over the four years from 2015-16 to 2018-19, relative to the 2014-15 efficient base year costs.

Our forecast productivity gains reflect our commitment to managing our total operating expenditure so that it remains flat in nominal terms relative to the 2014-15 base year. We note that for the purpose of this Regulatory Proposal our approach to assessing productivity growth differs from the empirical approach applied by the AER.

The table below shows our forecast productivity savings in percentage terms and the corresponding dollar amounts. The savings shown are relative to the 2014-15 efficient base year costs.

Table 8-7: Productivity improvements per cent (real) and annual savings (June 2017 $m)

Input	2015-16	2016-17	2017–18	2018–19
Productivity savings in this year relative to the base year (2014-15)	5.4%	12.2%	12.9%	16.2%
Annual Cost savings ($m)	3.7	8.8	9.0	11.3
Cumulative cost savings since 2014-15 ($m)	3.7	12.5	21.4	32.8

8.11 'Other' expenditure items - Step 2

As explained in relation to step 1(b) in section 8.2, the nature of the 'Other' expenditure items requires a separate forecasting approach that sits outside the base-step-trend forecasting methodology.

There are two 'Other' expenditure items that must be included in our calculations to derive a forecast of efficient operating expenditure for the forthcoming period, as follows:

- A self-insurance allowance of $0.9 million per annum is included in the forecast. As already noted, this allowance reflects the expected cost of self-insured risks in relation to our vehicle and mobile plant fleet and distribution assets, which are not covered by external insurance.
- A benchmark debt raising cost allowance of $1.1 million per year has been included. Our actual debt raising costs are reported as finance charges, rather than operating expenditure, and therefore a separate debt raising allowance must be included to align with the regulatory treatment. Further details on the estimation of our benchmark debt raising cost allowance are provided in section 11.5.

The table below provides a summary of forecasts for the 'Other' operating expenditure items.

Table 8-8: 'Other' operating expenditure (June 2017 $m)

Expenditure item	2017–18	2018–19
Self-insurance allowance	0.9	0.9
Debt raising costs	1.1	1.1
Total 'Other'	1.9	1.9

8.12 Total operating expenditure forecast - Step 3

Our operating expenditure forecasts are summarised in the table below. Please note that numbers may not sum exactly due to rounding.

Table 8-9: Total operating expenditure forecasts (June 2017 $m)

Element / Driver	Details in	2015-16	2016-17	2017–18	2018–19
Audited Base year expenditure	Section 8.5	68.2	68.2	68.2	68.2
Base year adjustments to derive efficient base year expenditure - deduct abnormal GSL payments	Section 8.5	-2.0	-2.0	-2.0	-2.0
Step changes	Section 8.6	1.7	4.8	1.8	2.3
Output Growth	Section 8.7	0.4	0.9	1.3	1.7
Zero based forecasts	Section 8.8	0.0	0.0	0.0	0.0
Labour and non-labour escalation	Section 8.9	0.0	0.0	0.0	0.0
Sub-total before productivity savings		**68.4**	**71.9**	**69.3**	**70.2**
Productivity savings	Section 8.10	-3.7	-8.8	-9.0	-11.3
Total (excluding 'Other')		**64.7**	**63.1**	**60.3**	**58.9**
'Other' expenditure	Section 8.11	n/a[21]	n/a	1.9	1.9
Total Costs $m		**64.7**	**63.1**	**62.3**	**60.8**

The above table reflects the steps in our expenditure forecasting methodology as described in section 8.3. The forecasts reconcile with our proposed expenditure for each business category of operating expenditure, as presented in section 8.2. These categories are:

- Emergency Field Operations;
- Maintenance and Vegetation Management;
- Distribution Asset Services;
- Business Services; and
- 'Other' Operating Expenditure.

8.13 Concluding comments

We have achieved significant operating expenditure efficiencies in the current regulatory period by improving our business and risk management processes and by reducing labour and contracted services costs. We plan to deliver further cost reductions in the forthcoming regulatory period. The operating expenditure forecasts presented in this chapter reflect our achieved and expected efficiency improvements. The savings arising from our planned efficiency gains will flow through to customers in the forthcoming regulatory period.

[21] As explained in the note to Table 8-1, actual costs are not reported in this expenditure category.

Under the Rules our operating expenditure forecast must achieve the operating expenditure objectives, which include the requirement to provide safe and reliable distribution services to our customers and to comply with our regulatory obligations. As explained in this chapter, we have applied a methodology that produces expenditure forecasts that meet the operating expenditure objectives specified in the Rules. In fact, by offering additional prospective efficiency gains, we consider our operating expenditure forecast is even lower than the Rules require. Certainly, our operating expenditure forecast contains no ‘ambit claims’.

In forecasting our operating expenditure requirements we must achieve an appropriate balance between the pressure to reduce expenditure and the importance of maintaining service performance and managing network risks. For the reasons set out in this chapter, we believe that we have achieved an appropriate balance, whilst setting challenging but achievable operating expenditure savings targets for the business over the forthcoming regulatory period.

9 Regulatory Asset Base

9.1 Introduction

This chapter presents information on our regulatory asset base (RAB), which has been calculated in accordance with the Rules, specifically clauses 6.5.5, S6.2.1, S6.2.2A and S6.2.3.

In the AER's 2012 Final Distribution Determination for Aurora's distribution business, the AER applied its roll forward methodology in determining a value for our opening RAB of $1445.2 million, in nominal terms as at 1 July 2012. For the purpose of the AER's forthcoming distribution determination for TasNetworks, it is necessary to estimate an opening RAB as at 1 July 2017 and for the subsequent two years.

In light of these requirements, this chapter is structured as follows:

- Section 9.2 presents information regarding the review of our past capital expenditure under the provisions in clause S6.2.2A.
- Section 9.3 explains the methodology for rolling forward the asset base value to 1 July 2017.
- Section 9.4 explains the derivation of the estimated opening and closing RAB value for each year of the forthcoming two-year regulatory control period.

9.2 Review of past capital expenditure

Clause S6.2.2A of the Rules provides for the AER to conduct a review of past capital expenditure in circumstances where it may be regarded as inefficient. These circumstances include where actual expenditure exceeds the AER's allowance. Under transitional provisions set out in clause 11.62 of the Rules the review period is limited to 2014-15.

Our actual capital expenditure in 2014-15 is below the AER's allowance and therefore the AER's efficiency review is not triggered. In addition, none of the other circumstances specified in the Rules that could trigger an efficiency review apply to us. Accordingly, all capital expenditure incurred during the current regulatory period is regarded as efficient and will be included in the regulatory asset base[22].

9.3 Opening Regulatory Asset Base as at 1 July 2017

Our regulatory asset base as at 1 July 2017 has been calculated in accordance with the roll forward model (RFM) provided by the AER and the requirements of clauses S6.2.1, S6.2.2A and S6.2.3 of the Rules.

In summary, our regulatory asset base as at 1 July 2017 is derived by:

- adjusting for any difference between forecast and actual capital expenditure that is embedded in the 1 July 2012 opening value of $1445.2 million; and then

[22] It is noted that capital expenditure for 2015-16 is a forecast at this time. The amount actually included in our regulatory asset base will be adjusted to reflect any difference between our forecast and actual expenditure for that year.

- rolling forward the 1 July 2012 value for actual additions, disposals, inflation escalation and deductions of actual depreciation[23] using the AER's roll forward model.

The table shows the derivation of the RAB value as at 1 July 2017 (that is, the closing RAB as at 30 June 2017), in accordance with this methodology.

Table 9-1: Roll forward of regulatory asset base from 1 July 2012 to 30 June 2017 ($m nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17
Opening RAB	1,445.2	1,486.9	1,539.3	1,557.0	1,625.5
Net capital expenditure	89.3	99.8	89.2	114.9	125.7
Inflation on opening RAB	36.2	43.6	20.4	38.9	40.6
Straight-line depreciation	-83.8	-90.9	-91.9	-85.4	-88.6
Closing RAB	1,486.9	1,539.3	1,557.0	1,625.5	1,703.1
Add difference between actual and forecast 2011-12 net capital expenditure					-38.4
Add return on difference in 2011-12 net capital expenditure					-18.0
Closing RAB					**1,646.7**

As shown in Table 9-1, the RAB value as at 1 July 2017 (in nominal dollars) is $1,646.7 million. Capital expenditure amounts for 2015-16 and 2016-17 are estimates.

9.4 Forecast of Regulatory Asset Base for the forthcoming period

Table 9-2 presents a summary of the amounts, values and inputs used by us to derive our RAB value for each year of the forthcoming regulatory control period. In accordance with S6A.2.1(f)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of standard control distribution services in accordance with our cost allocation methodology has been included in the RAB. It should be noted that the nominal capital expenditure in the table below excludes capital contributions. As noted in section 7.5.1, the customer initiated capital expenditure included in the RAB is the gross expenditure minus customer capital contributions.

23 Page 106 of the AER's final distribution determination for Aurora's 2012-13 to 2016-17 regulatory period stated that the AER accepted Aurora's proposal to use depreciation based on actual capex for the purposes of rolling forward the RAB to establish the opening RAB at the beginning of the 2017–22 regulatory control period.

Table 9-2: Regulatory asset base roll forward 1 July 2017 to 30 June 2019 ($m)[24]

	2017-18	2018-19
RAB (start period) - nominal	1,646.7	1,713.4
Nominal capex	116.3	107.6
Inflation on opening nominal RAB	41.2	42.8
Nominal straight-line depreciation	90.8	100.4
RAB (end period) - nominal	1,713.2	1,763.2
RAB (end period) - $ June 2017	**1,671.5**	**1,678.3**

24 The data in this table is expressed in nominal terms, with the exception of the final row which is expressed in real June 2017 dollars.

10 Regulatory depreciation

10.1 Introduction

This chapter sets out information on our proposed approach to determining the depreciation building block for the forthcoming regulatory period in accordance with the requirements of clauses 6.5.5(a) and (b) and S6.1.3(12) of the Rules.

The remainder of this chapter is structured as follows:

- Section 10.2 describes our depreciation methodology.
- Section 10.3 provides information on the standard and remaining lives for each asset class within our regulatory asset base.
- Section 10.4 sets out our regulatory depreciation forecasts for the forthcoming period.
- Section 10.5 addresses the use of forecast versus actual depreciation for determining our regulatory asset base at the commencement of our next regulatory period on 1 July 2019.

Please note that information on the calculation of tax depreciation for the purpose of determining TasNetworks' corporate tax allowance is provided in Chapter 12.

10.2 Depreciation methodology

The Rules do not prescribe a method for calculating depreciation. However, the AER has set out its preferred methodology in the post tax revenue model (PTRM). TasNetworks has used the AER's PTRM without amendment and has therefore calculated its depreciation allowance using that methodology.

Under the methodology, straight-line depreciation is applied using standard asset lives for each regulatory asset class. It is noted that straight-line depreciation is a well-established method used to reflect the decline in the service potential of an asset over its economic life.

TasNetworks has depreciated new assets on a straight line basis according to standard lives for each asset class. These are set out in section 10.3 below.

TasNetworks has depreciated its existing assets over their remaining asset lives, details of which are provided in section 10.3. Opening asset values at 1 July 2017 have been calculated by applying the AER's roll forward model (RFM). Chapter 9 provides an overview of these calculations.

10.3 Standard and remaining lives for asset classes

TasNetworks has adopted asset classes, standard and remaining asset lives in accordance with good engineering practice and its own financial records. The asset classes and standard lives are unchanged from those accepted by the AER at our last review, with one exception, as noted below.

Following the merger of the transmission and distribution networks, we are intending to implement a significant asset management and IT solution (Ajilis) to replace numerous legacy systems including key asset management, financial, and human resources systems. Given the nature of the Ajilis solution and its associated cost, it will continue to be used by TasNetworks for a longer life than would normally be associated with asset management systems and IT systems. This is supported by TasNetworks' benefits realisation analysis for the project.

Under TasNetworks' capitalisation policy, expenditure associated with the Ajilis project has been assigned a 10 year asset life. Accordingly, TasNetworks has established a new asset category (Business Management Systems) for this expenditure in its distribution RAB to commence in the 2017-18 financial year, which is the first year of the forthcoming regulatory period.

Any expenditure on the Ajilis project incurred prior to 1 July 2017 will be allocated to the SCADA asset class, which also has a 10 year life. While the Ajilis project forms part of our Asset Management Systems as described in section 7.7.2, attributing the expenditure to the SCADA asset class for depreciation purposes ensures that the project expenditure is depreciated over the appropriate 10 year period.

In its most recent determinations, the AER has modified its approach to calculating the remaining asset lives. Previously, the AER adopted an approach referred to as 'weighted average remaining life' or WARL. However, more recently the AER has accepted submissions from several network companies that a more accurate approach would recognise the specific timing of new additions.

We agree with the AER's updated approach. Therefore, in the roll forward model we have calculated a depreciation allowance based on the timing of new additions and the remaining life previously determined by the AER for the existing asset base. From this depreciation calculation, we have inferred a remaining life for each asset class, which is an input to the PTRM. This approach delivers a more accurate depreciation allowance than the previous WARL approach.

The table below sets out the standard and remaining asset lives by asset class.

Table 10-1: Standard and remaining asset lives as at 1 July 2017

Asset category	Standard life (years)	Remaining life (years)
Overhead subtransmission lines (urban)	50	27.2
Underground subtransmission lines (urban)	60	33.3
Urban zone substations	40	28.0
Rural zone substations	40	29.3
SCADA	10	9.1
Distribution switching stations (ground)	40	28.0
Overhead high voltage lines urban	35	22.0
Overhead high voltage lines rural	35	18.1
Voltage regulators on distribution feeders	40	21.4
Underground high voltage lines	60	38.4
Underground high voltage lines SWER	60	46.4
Distribution substations HV (pole)	40	31.4
Distribution substations HV (ground)	40	18.1
Distribution substations LV (pole)	40	20.0
Distribution substations LV (ground)	40	22.0
Overhead low voltage lines underbuilt urban	35	22.5
Overhead low voltage lines underbuilt rural	35	15.1
Overhead low voltage lines urban	35	15.4
Overhead low voltage lines rural	35	23.7
Underground low voltage lines	60	35.3
Underground low voltage common trench	60	43.1
HVST service connections	40	0.0
HV service connections	40	25.2
HV metering CA service connections	40	6.5
HV/LV service connections	40	24.3
Business LV service connections	35	10.6
Business LV metering CA service connections	25	4.1
Domestic LV service connections	35	20.0
Domestic LV metering CA service connections	20	18.1
Motor vehicles	6	3.6
Minor assets	5	3.6
Non-system property	40	13.1
NEM assets	5	2.0
Business Management Systems	10	N/A

10.4 Depreciation forecasts

The table below shows the depreciation building blocks for Standard Control Services for the forthcoming regulatory period.

Table 10-2: Depreciation building blocks

	2017-18 ($m)	2018-19 ($m)
Straight-line depreciation (June 2017 $)	88.6	95.6
Straight-line depreciation (nominal)	90.8	100.4
Inflation on the opening RAB (nominal)	41.2	42.8
Regulatory depreciation (nominal)	49.6	57.6
Forecast inflation on opening RAB (% per annum)	2.50%	2.50%

Our forecast depreciation allowance reflects:

- the opening asset base and forecast regulatory asset base values set out in chapter 9, which include estimates of capital additions and disposals; and
- the standard and remaining asset lives set out in Table 10-1.

Our forecast regulatory depreciation is calculated in accordance with the requirements set out in clauses 6.5.5(a) and (b) of the Rules. As shown in the table above, the regulatory depreciation is the straight line depreciation (nominal) minus inflation on the opening RAB (nominal).

10.5 Actual or forecast depreciation

The AER's Framework and Approach paper explains that the AER will use forecast depreciation (as opposed to actual depreciation) to establish the regulatory asset base at the commencement of our subsequent regulatory period (i.e. 1 July 2019)[25]. We accept the AER's proposed approach.

It should be noted that this does not affect the calculation of the regulatory depreciation allowance for the forthcoming regulatory period, as set out in section 10.4 above.

[25] AER, Framework and approach for TasNetworks Distribution 2017–2019, July 2015, page 17.

11 Weighted Average Cost of Capital

11.1 Introduction

This chapter sets out our proposed weighted average cost of capital or WACC. It is referred to as the 'weighted' average cost of capital because it combines the cost of equity and the cost of debt in proportion to the weighting under a benchmark capital structure (60 per cent debt and 40 per cent equity). As a capital intensive business, the estimated WACC has a significant impact on our revenue requirements and, ultimately, electricity prices.

In December 2013, the AER published a guideline setting out its proposed approach to estimating the WACC. We provide a brief overview of this guideline in section 11.2 below.

In preparing our WACC estimate, we recognised the significant resources and stakeholder input in developing the AER's Rate of Return Guideline. In our view, it is appropriate that the AER Guideline is applied unless there is a compelling reason for departing from it. We adopted this position in our 2014 revenue proposal for the transmission network. In that submission, we balanced independent expert advice on the WACC – which indicated that the AER's approach is likely to produce an underestimate – against the importance of putting downward pressure on prices to customers.

A further issue is in play for this review. The Australian Capital Territory and New South Wales distributors and the Public Interest Advocacy Centre (PIAC) are currently appealing the AER's Final Decision in relation to the costs of equity and debt and tax allowance. The networks are seeking a higher WACC outcome, while PIAC is seeking a lower WACC. The timing of these appeal outcomes is uncertain, especially as they are to be conducted in accordance with new merit review provisions and judicial review has also been sought in the Federal Court.

If the appeals are successful, this may have implications for the AER's Rate of Return Guideline and the method for estimating our WACC. It is not yet possible for us or the AER to anticipate the outcome of these appeals.

In estimating the WACC for this proposal, we have continued to apply the AER's Guideline. However, we believe that the outcome of the appeals should be taken into consideration for this proposal. Accordingly, we expect the AER to consider our proposal in light of the appeal outcomes and make any necessary changes to its methodology to ensure that the *rate of return objective*[26] is met. Similarly, in responding to the AER's draft decision on our Regulatory Proposal, we reserve the right to revisit this proposal in light of the Tribunal's findings and the AER's draft decision.

As explained in Chapter 12, in relation to estimating corporate tax costs, we propose a departure from the AER's Rate of Return Guideline. The circumstances surrounding this parameter differ from those relating to the WACC because:

- the AER has itself departed from its Guideline in its recent decision for distributors in other States; and

[26] Clause 6.5.2(c) of the Rules.

- the Tribunal has previously addressed this issue and made a specific determination in relation to the relevant parameter value (known as gamma).

In these circumstances, as noted in Chapter 12, it is appropriate for us to adopt a value for gamma consistent with the Tribunal's earlier decision, rather than adhering to the AER's Rate of Return Guideline (which the AER itself is no longer adopting). We also note in Chapter 12 that the Australian Competition Tribunal is currently considering an appeal lodged by PIAC and the NSW, ACT and South Australian distributors in relation to (among other things) the AER's estimate of gamma. If the Tribunal concludes that the AER is correct - contrary to this submission - then we will adopt the Tribunal's findings on gamma in our revised Regulatory Proposal.

The remainder of this chapter is structured as follows:

- Section 11.2 provides an overview the AER's Rate of Return Guideline.
- Section 11.3 presents a summary of our proposed point estimate for the WACC, in light of the requirements of the Rate of Return Guideline.

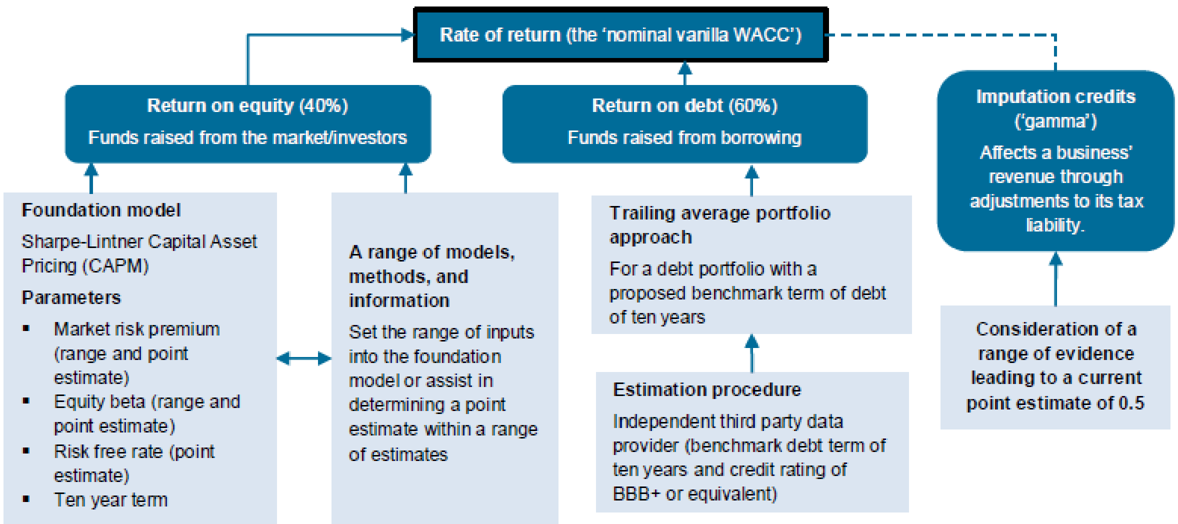
11.2 The Rate of Return Guideline

The Rules set out the following objective, which must guide the WACC estimate:

> "The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services."

In estimating the WACC, the AER must have regard to a wide range of relevant estimation methods, financial models, market data and other evidence as well as considering inter-relationships between parameter values. The figure below (reproduced from the AER's 'factsheet' for the Rate of Return Guideline) provides a summary of the AER's approach to determining the WACC.

Figure 11-1: Overview of the AER's Rate of Return guideline



Under the Guideline, the WACC is estimated for a benchmark efficient entity, being a 'pure play', regulated energy network business operating within Australia. Benchmark gearing is assumed to be

60 per cent debt to total capital. The costs of equity and debt are estimated separately and weighted according to the benchmark gearing to derive a vanilla WACC.

In relation to estimating the cost of equity, the AER will continue to apply the Sharpe-Lintner capital asset pricing model (CAPM) as the 'foundation model'. The AER will also have regard to alternative models and other data to inform:

- the estimation of input parameters to the foundation model; and
- the appropriate point estimate of the cost of equity.

For example, the Rate of Return Guideline explains that the AER will have regard to: historical excess returns; brokers' return on equity estimates; takeover/valuation reports; debt spreads; comparison with return on debt; implied volatility; and other regulators' cost of equity estimates. The AER will also have regard to the model proposed by Professor Stephen Wright (the 'Wright Approach'), which argues that the cost of equity is relatively stable over time and that it is appropriate to recognise this stability in estimating the cost of equity.

The cost of equity allowance will be set (and fixed) for the duration of the regulatory control period. Given the uncertainty inherent in estimating expected equity returns, the final return on equity estimate will reflect either the foundation model point estimate (rounded to a single decimal point), or an alternative value that is a multiple of 25 basis points. The AER has stated that this approach is intended to 'disavow the pursuit of false precision'.

In the AER's explanatory statement that accompanies the Rate of Return Guideline, the AER sets out its reasoning for adopting parameter values for the market risk premium (6.5 per cent) and equity beta (0.7) in estimating the cost of equity.

The Rate of Return Guideline explains that the cost of debt will be estimated using a trailing average approach, which establishes an average cost of debt by assuming that one-tenth of the network business' debt is re-financed annually. The trailing average approach will be introduced over a ten year transitional period. The cost of debt allowance will be updated annually.

Apart from the adoption of a trailing average method, the AER's process for estimating the cost of debt is otherwise unchanged from its previous determinations. Specifically, the AER will estimate the cost of debt using:

- the published yields from an independent third party data provider;
- a credit rating of BBB+; and
- a term to maturity of debt of ten years.

11.3 WACC Estimate

As already noted, we are mindful of the commercial pressures currently facing our customers. A balance must be struck between the objective of ensuring that the true cost of equity is recognised in our revenue allowance and the need to establish a price path that is sustainable for our customers. In weighing these considerations, we propose to adopt the parameter values identified by the AER in its Rate of Return Guideline and explanatory statement.

On this basis, we propose a WACC of 6.04 per cent. It incorporates a cost of equity of 7.30 per cent, which is 139 basis points lower than the cost of equity allowance of 8.69 per cent provided in the current regulatory period. This reduction is due primarily to a decline in market interest rates. Our proposed lower WACC contributes to lower distribution revenue requirements in the forthcoming regulatory period and aligns with similar recent reductions in our transmission revenues.

Table 11-1 shows the parameter values we have adopted for the purpose of calculating the WACC. A brief explanation of the basis for each parameter value is also provided.

Table 11-1: Proposed WACC parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	2.75%	This is the average annualised yield on 10 year Commonwealth bonds (CGS) over the 20 business day period ending 30 September 2015, derived from the Reserve Bank of Australia's statistical publication 'F16 Indicative midrates of selected Australian Government Securities'. In accordance with the AER's Rate of Return Guideline, this value is to be updated to reflect CGS yields as close as practicably possible to the commencement of the regulatory period.
Market risk premium	6.50%	This value is consistent with the AER's Rate of Return Guideline explanatory statement.
Equity beta	0.70	This value is consistent with the AER's Rate of Return Guideline. There is significant evidence to suggest that the value of the equity beta should be higher than 0.7. However, subject to the outcome of the current appeals, we consider it appropriate to adopt a lower value for the equity beta (which reduces our revenue allowance) in order to deliver a sustainable price path for our customers.
Cost of equity	7.30%	This point estimate is derived from the application of the above CAPM parameters. It is rounded to a single decimal point in accordance with the Rate of Return Guideline.
Cost of debt - 10 year BBB+ (nominal)	5.20%	This is an average of Bloomberg data and data published by the Reserve Bank of Australia on the annualised yield on 10-year BBB-rated corporate debt averaged over the 20 business day period ending 30 September 2015. We will agree with the AER, on a confidential basis, the measurement period to be applied for the purpose of estimating the cost of debt allowance.
Expected inflation	2.5%	This is a 10-year forecast of inflation based on the geometric average of the RBA's short–term inflation forecasts for the next two years (as published in the RBA's November 2015 Statement on Monetary Policy) and the mid-point (2.5 per cent) of the RBA's target inflation band for the remaining years in the 10-year forecast period.
Gearing (Debt / total capital)	60%	In accordance with the AER's Rate of Return Guideline.
Vanilla WACC (nominal)	**6.04%**	

The values we have adopted for each parameter are consistent with the AER's Rate of Return Guideline and therefore the AER should accept the resulting WACC estimate, subject to the outcomes of the NSW, ACT and South Australian appeals. Figure 11-2 below shows the composition of our WACC estimate.

Figure 11-2: Proposed WACC estimate in nominal terms

Weighted Average Cost of Capital		
Component	Debt	Equity
Proportion of capital	60%	40%
	x	x
Cost	5.20%	7.30%
	=	=
Contribution	3.12%	2.92%
WACC	6.04%	

Our proposed WACC estimate is based on the Australian Energy Regulator's approach to setting the WACC and is subject to update to reflect market data from the nominated debt and equity averaging periods. The WACC estimate is also subject to the outcomes of the NSW, ACT and South Australian appeals.

11.4 Equity raising costs

Equity raising costs are transaction costs incurred when network service providers raise new equity from outside the business in order to fund capital investment. Equity raising costs are an unavoidable aspect of raising equity that would be incurred by a prudent service provider acting efficiently. Accordingly, the AER provides an allowance to recover an efficient amount of equity raising costs, when a network service provider's capital expenditure forecast requires an external equity injection to maintain the benchmark gearing of 60 per cent.

Our calculations (contained in the completed PTRM submitted with this Regulatory Proposal) indicate that an external equity injection will be required to enable us to maintain the benchmark capital structure over the forthcoming regulatory period. The PTRM calculates an equity raising cost allowance of $190,000 for the forthcoming regulatory period. Accordingly, we are proposing the inclusion of an equity raising cost allowance of $190,000 in the regulatory asset base, in accordance with the approach and calculations set out in our completed PTRM.

11.5 Debt raising costs

Debt raising costs are benchmarked costs associated with raising or refinancing debt. These costs include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are an unavoidable aspect of raising debt that would be incurred by a prudent service provider and data exists such that we can estimate these costs.

As explained in section 8.11, our actual debt raising costs are reported as finance charges rather than operating expenditure. Therefore, a separate debt raising allowance must be included in our operating expenditure to align with the regulatory treatment. This section provides information on the estimation of our benchmark debt raising cost allowance.

A report prepared in June 2013 by PricewaterhouseCoopers[27] estimated the total benchmark debt raising cost for a debt portfolio of $1,000 million to be 25 basis points per annum (bppa). The 25 bppa cost estimate comprises:

- Direct costs of 10.9 bppa. These costs consist mainly of the arrangement fees that are paid to the organisation responsible for the bond issue to prepare and market the issue, and other direct debt raising transaction costs such as legal costs, rating and agency fees.
- Indirect costs of 14.1 bppa. These costs relate to liquidity reserves (ie spare funding capacity) that credit rating agencies require corporate borrowers to hold, and credit rating agencies' requirements regarding management of refinancing risk.

We consider that the PwC report provides a robust estimate of the total direct and indirect debt raising costs that a prudent service provider acting efficiently would incur, because it:

- identifies the types of transaction costs that a prudent service provider acting efficiently would incur in raising debt; and
- quantifies the level of these costs (using benchmark assumptions) with reference to market rates for the relevant services.

That said, as noted earlier, in framing our Regulatory Proposal, we are seeking to balance independent expert advice on the WACC against the importance of putting downward pressure on prices to customers. For this Regulatory Proposal, we are proposing to include an allowance to recover the direct debt raising costs only, with indirect debt raising costs to be absorbed by the business.

PwC's estimate of direct debt raising costs of 10.9 bppa applies to a $1,000 million debt portfolio. PwC has also estimated the direct debt raising costs of a $500 million debt portfolio to be 12.5 bppa. Our benchmark debt value averages approximately $1,000 million over the forthcoming regulatory period. Accordingly, we have included an allowance of 10.9 bppa in relation to our direct debt raising costs. The table below sets out our proposed debt raising cost allowance.

Table 11-2: Debt raising cost allowance

	2017-18	2018-19
Benchmark debt for the year (June 2017 $m)	988.0	1002.9
Debt raising cost allowance (bppa)	10.9	10.9
Debt raising cost allowance (June 2017 $m)	1.08	1.09

27 PwC, Debt financing costs: Report for Energy Networks Association, June 2013.

12 Forecast allowance for corporate tax

12.1 Introduction

This chapter sets out information on our calculation of the allowance for the cost of corporate tax. It is structured as follows:

- Section 12.2 describes the method we have applied for calculating the corporate income tax allowance.
- Section 12.3 sets out our estimate of the value of imputation credits (gamma).
- Section 12.4 provides information on our forecast of depreciation for corporate tax purposes.
- Section 12.5 provides an overview of our calculation of the corporate tax allowance.

12.2 Method for calculating corporate income tax allowance

Our calculation of the cost of corporate income tax for each year (ETC_t) of the forthcoming regulatory period is in accordance with clause 6.5.3 of the Rules, which requires the following formula to be applied:

$$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that *regulatory year* that would be earned by a benchmark efficient entity as a result of the provision of *standard control services* if such an entity, rather than the *Distribution Network Service Provider*, operated the business of the *Distribution Network Service Provider*, such estimate being determined in accordance with the *post-tax revenue model*;

r_t is the expected statutory income tax rate for that *regulatory year* as determined by the *AER*; and

γ is the value of imputation credits.

12.3 Imputation credit value (gamma)

The value of imputation credits (gamma) is an important input to the calculation of the corporate income tax allowance. The gamma value has a direct bearing on the overall returns that are delivered to our owners. Specifically, if the value ascribed to gamma is higher than the value that equity-holders place on imputation credits, the overall return to owners will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity distribution services for the long term interests of consumers.

For the purpose of this Regulatory Proposal, we have applied the estimation method and input values adopted by the Australian Competition Tribunal in its 2011 findings in appeals relating to gamma[28]. Under this approach - which is also consistent with that set out in the AER's Rate of Return Guideline[29] - gamma is estimated as the product of:

- the 'distribution rate', being the extent to which imputation credits that are created when companies pay tax, are distributed to investors; and
- the 'utilisation rate' (also referred to as 'theta'), being the value of distributed imputation credits to investors who receive them.

In its decision, the Tribunal said[30]:

> "Taking the values of the distribution ratio and of theta that the Tribunal has concluded should be used, viz 0.7 and 0.35, respectively, the Tribunal determines that the value of gamma is 0.25."

Consistent with the Tribunal's decision, we have applied a distribution rate of 0.7, which is also consistent with the Rate of Return Guideline.

We propose that the distribution rate (0.7) be combined with the value of theta that the Tribunal has concluded should be used (0.35). Multiplying these two values together leads to an estimate for gamma of 0.25, compared to Guideline's estimate of 0.5.

Our value of theta is a departure from the Guideline, which estimates a value of 0.7. We consider that a value of theta of 0.35 is the best estimate, for the reasons specified by the Tribunal.

In its recent decisions for distributors in other States, the AER has also departed from the Guideline, in adopting a gamma estimate of 0.4. The AER explains its departure from the Guideline's gamma estimate as follows[31]:

> "Our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate of the Guideline."

In light of the AER's recent distribution decisions on gamma, we have reviewed the material submitted by the distributors in support of their gamma estimates of 0.25. We maintain our view that 0.25 is the best estimate of gamma.

We note that the Australian Competition Tribunal is now considering an appeal lodged by PIAC and the ACT, NSW and South Australian distributors in relation to (among other things) the AER's gamma estimate. If the Tribunal concludes that the AER is correct - contrary to this submission - then we will adopt the Tribunal's findings on gamma.

12.4 Forecast regulatory tax depreciation

The calculation of the corporate tax allowance requires a forecast of tax depreciation to be made. TasNetworks has calculated tax depreciation in accordance with the tax law and with the

---

28 Application by Energex Limited (Gamma) (No 5) (2011).

29 AER, Better Regulation - Rate of Return Guideline, December 2013, section 7.3.

30 Application by Energex Limited (Gamma) (No 5) (2011), paragraph 42.

31 AER, Energex preliminary decision 2015–20 Overview, April 2015, page 25.

methodology contained within the PTRM. In accordance with the PTRM, TasNetworks has calculated tax depreciation on a straight line basis, using applicable straight line tax depreciation rates.

12.5 Calculation of corporate income tax allowance

TasNetworks has derived the forecast of its corporate income tax allowance pursuant to clause 6.5.3 of the Rules, using the PTRM in accordance with the AER's preferred method.

The formula set out in section 12.2 assesses the benchmark entity's effective tax rate and calculates the income tax allowance for each year. An adjustment is then made to reduce the tax allowance for the benchmark value of imputation credits.

The table below shows the resulting regulatory allowance for tax.

Table 12-1: Forecast tax allowance from 1 July 2017 to 30 June 2019 ($m nominal)

	2017-18	2018-19
Benchmark income tax payable	20.0	21.2
Imputation credit	-5.0	-5.3
Tax allowance	**15.0**	**15.9**

13 Incentive schemes

13.1 Introduction

We accept the application of the following incentive schemes in the forthcoming regulatory period:

- Efficiency Benefit Sharing Scheme;
- Capital Expenditure Sharing Scheme;
- Service Target Performance Incentive Scheme; and
- Demand Management Incentive Scheme and Embedded Generation Connection Incentive Scheme.

We explain below the application of these schemes in the forthcoming regulatory period. We note that the AER's Framework and Approach[32] confirmed that the small scale incentive scheme will not apply in the forthcoming period, as the AER has not yet developed this scheme.

13.2 Efficiency Benefit Sharing Scheme (EBSS)

The purpose of the EBSS is to provide a mechanism for the sharing between distributors and customers of efficiency gains and losses relating to operating expenditure during the regulatory period.

The design of the scheme ensures that distributors face a consistent incentive to deliver efficiency savings in each year of the regulatory period. In the absence of an EBSS, the incentive to deliver efficiency gains would diminish as the AER's next review approaches. Assuming a five-year regulatory period, the effect of the scheme is to share efficiency savings (or additional costs) in the ratio of 70:30 between customers and the distributor.

Ordinarily, the bonus or penalty payable under the EBSS is applied over the next regulatory period, because the EBSS is designed to operate over a five-year cycle. A complication arises in applying the EBSS for our forthcoming regulatory period, which is only two years in duration. As previously explained, the shortened period will enable the AER to combine its transmission and distribution reviews in future, which will align regulatory practice with our new business structure.

As a consequence of the shortened period the efficiency bonuses payable under the EBSS in relation to the current period (2012-13 to 2016-17) would be split across two regulatory periods. To address this issue we propose to include the later payments (due in 2019-20 and 2020-21) in the revenue allowance for the forthcoming regulatory period. An adjustment reflecting the time value of money will be made to ensure that we do not benefit as a result of bringing forward these amounts to the forthcoming regulatory period.

In relation to efficiency bonuses or penalties payable in the forthcoming regulatory period, these will apply for a five-year period in accordance with the design of the incentive scheme. This approach

---

[32] AER, Framework and approach for TasNetworks Distribution for the Regulatory control period commencing 1 July 2017, July 2015, page 16.

ensures a 70:30 sharing, even though the current regulatory period is only two years in duration. From 2019-20 onwards, we will revert to the standard five-yearly approach.

For the EBSS that will apply to us over the forthcoming regulatory period, we propose that the exclusions applying under our current EBSS will continue to apply, with the addition of self-insurance costs. Specifically, we propose that the following cost categories will be excluded from forecast and actual operating expenditure for the calculation of EBSS carryover amounts in accordance with section 1.4 of the EBSS:

- superannuation costs for defined benefits schemes;
- Demand Management Incentive Allowance (DMIA) expenditure;
- expenditure for non-network alternatives;
- recognised pass through events and recognised regulatory change events or service standard events;
- Electrical Safety Inspection Levy payments which are determined annually by the Minister for Energy in accordance with clause 121B of the ESI Act;
- National Energy Market (NEM) Levy payments as determined by the Minister for Energy each financial year in accordance with clause 121(1) of the ESI Act;
- movements in provisions;
- debt raising costs;
- Guaranteed Service Level (GSL) payments; and
- self-insurance costs.

We propose that the calculation of carryover amounts under the EBSS will include all other operating expenditure costs relating to standard control services in accordance with section 1.4 of the EBSS. It will also include events that qualify as pass through events but do not satisfy the materiality threshold.

13.3 Capital Expenditure Sharing Scheme (CESS)

Incentives for efficient operating expenditure under the EBSS generally correspond to incentives for efficient capex under our scheme for capital expenditure efficiency (CESS).

The capital expenditure sharing scheme (CESS) rewards (penalises) a distributor if actual capex is lower (higher) than the approved forecast amount for the regulatory year. The AER's Framework and Approach paper proposed that version 1 of the CESS should apply to TasNetworks' distribution capital expenditure in the forthcoming regulatory period. We accept the AER's proposal.

Under the CESS, we retain 30 per cent of efficiency gains and losses with the remaining 70 per cent retained by customers. By applying an incentive scheme for capital expenditure that aligns with the EBSS, which applies to operating expenditure, distributors do not have a financial incentive to favour one form of expenditure over another.

In contrast to the EBSS, the operation of the CESS means that no transitional issues arise as a result of the regulatory period only being 2 years in duration.

13.4 Service Target Performance Incentive Scheme (STPIS)

The service target performance incentive scheme (STPIS) provides a financial incentive to distributors to improve service performance. The scheme applies financial rewards or penalties depending on whether performance exceeds or falls short of service performance targets. It ensures that cost savings are not achieved at the expense of service performance.

The AER's framework and approach paper proposed that the guaranteed service level component of the STPIS should not apply, as a separate jurisdictional GSL scheme currently applies. In relation to the s-factor component of the scheme, the AER's Framework and Approach paper proposed the following:

- set revenue at risk within the range ±5 per cent;
- segment the network according to the Code supply reliability categories (critical infrastructure, high density commercial, urban, high density rural and low density rural);
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index or SAIFI) and customer service (telephone answering) parameters;
- set performance targets based on our average performance over the past five regulatory years;
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance targets; and
- apply the methodology and value of customer reliability (VCR) to calculate the incentive rates.

We support the AER's proposed approach, with the exception of the revenue at risk. Our customer consultation has found that customers do not want to pay for improvements in reliability. They want us to maintain existing performance. Customers also support measures to reduce annual price volatility.

In relation to price volatility, TasNetworks acknowledges the AER's observation that this could be managed to some extent through the banking mechanism provided by the scheme. However, an additional uncertainty in the forthcoming regulatory period is the impact on reported performance as manual systems are replaced by automated systems. While we expect the impact to be modest, it has the potential to cause a bonus or penalty which does not reflect underlying changes in actual performance. The banking mechanism cannot address the impact of such windfalls, which are ultimately recovered through network prices.

A further observation in support of this proposed change is that the higher incentive payment is not warranted given our customers' preferences.

As already noted, the AER's application of the scheme would provide us with an incentive to deliver improved performance in exchange for revenue increases of up to five per cent. However, most of our customers have expressly stated that they do not want to pay for improved reliability. This observation implies that the amount of revenue at risk should be lower than that proposed by the AER.

TasNetworks also notes that the AER's proposed rate of revenue at risk in relation to distribution service performance is five times greater than our service incentive for transmission services. We doubt whether a difference of this scale is warranted. As TasNetworks is an integrated transmission and distribution business, the interaction between the two schemes needs to be reconsidered.

In light of the issues raised above, we propose an incentive payment of ± 2.5 per cent. We noted that the CCP has commented that it is not appropriate to move away from a 5 per cent incentive scheme because this creates inconsistencies with other incentive schemes. However, in our view the STPIS, EBSS and CESS are not so finely tuned that our proposed change produces outcomes that would be inconsistent with the National Electricity Objective. In fact, for the reasons already explained, our proposal is an appropriate response to the measurement issues in the forthcoming regulatory period and customer feedback.

As the regulatory period is only two years in duration, we regard our proposal as a pragmatic response to the measurement issues in the forthcoming regulatory period and customer feedback. The operation of the incentive scheme will be revisited in the following regulatory review.

We note that the AER has recently accepted Ergon Energy's proposal to cap revenue at risk under the STPIS at ± 2.0 per cent[33]. The AER also accepted Energex's proposal to cap revenue at risk under the scheme at ± 2.0 per cent[34].

The calculations underpinning our STPIS targets have been undertaken in accordance with the AER's STPIS scheme (November 2009) and comply with the definitions set out in the scheme. The table below sets out our STPIS targets for the forthcoming regulatory period. It includes targets for two measures of reliability, SAIFI and SAIDI, and a requirement for calls to the fault line to be answered within 30 seconds. These targets reflect the performance of the network and call answering at the time they were calculated. It is expected that they will be updated to include more recent data before the final determination is made by the AER.

Table 13-1: STPIS targets for 2017-18 to 2018-19 outage frequency, outage duration and percentage of calls answered in 30 seconds

	SAIFI	SAIDI	Calls answered
Critical Infrastructure	0.29	23.90	
High Density Commercial	0.30	26.07	
Urban	1.03	82.59	
High Density Rural	2.55	242.01	
Low Density Rural	3.38	430.09	
System Target			76.0% within 30 secs

Further details of our STPIS targets and proposed incentive rates are provided in a supporting spreadsheet (TN067).

33 AER, Final Decision, Ergon Energy Determination 2015−16 to 2019−20, Overview, October 2015, page 40.

34 AER, Final Decision, Energex Determination 2015−16 to 2019−20, Overview, October 2015, page 37.

13.5 Demand Management and Embedded Generation Connection Incentive Scheme

A Rule change has amended the name of this scheme which is now the 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS). It was previously known as the Demand Management Incentive Scheme (DMIS). The purpose of this scheme is to provide an incentive for distributors to innovate to implement efficient non-network alternatives, including to manage expected demand. The name change is intended to recognise explicitly the role of embedded generation as a non-network solution.

The scheme is not designed to be the sole or even primary source of funding for demand management expenditure in a regulatory control period. The primary source of funding for demand management expenditure is provided through our operating and capital expenditure allowances. These forecasts already include expenditure for identified non-network alternatives.

The DMEGCIS is therefore designed to supplement our capital and operating expenditure forecasts. The intention of the scheme is to facilitate the investigation and implementation of demand management strategies in the forthcoming regulatory period. It also aims to increase the knowledge and experience of demand management and thereby deliver long term benefits to customers.

The AER reviews funding claims as projects are completed. The AER therefore does not need to make a decision on whether the proposed projects are consistent with, or are likely to be consistent with, the criteria for funding under the DMEGCIS. Instead, the maximum available amount is capped based on the AER's understanding of typical demand management project costs and scaled to the relative size of the distributor.

For the current regulatory period, the AER adopted a demand management incentive allowance for the distribution business of $380,000 ($2009–10) per annum, which equated to $1.9 million over the current regulatory period. In the forthcoming regulatory period, we propose an incentive amount of $400,000 (June 17 $m) per annum. The proposed amounts are consistent with our Demand Management Plan, which has identified the following demand management and embedded generation initiatives for the current and forthcoming regulatory periods:

- Demand Management Internal processes trial;
- Bruny Island energy storage trial;
- Distributed energy storage - other usage;
- Commercial and industrial network support trials;
- Residential demand management trial;
- Power factor correction;
- Advanced metering trial;
- Demand management exchange; and
- Demand management of Electric Vehicle charging.

Further details of these proposed initiatives are set out in our Network Demand Management Plan, which is provided as a supporting document to this Regulatory Proposal (TN035). In addition, our Network Innovation Strategy (TN032) provides a framework to focus our efforts to be truly innovative in how we apply and make use of emerging technologies, including demand management.

14 Annual revenue requirements, X-factors and control mechanism

14.1 Introduction

Our Regulatory Proposal is based on the post-tax building block approach outlined in clause 6.4.3 of the Rules, the post-tax revenue model (PTRM) and the roll forward model (RFM). Information explaining and substantiating the various building block components has been set out in the preceding chapters of this Regulatory Proposal.

The building block formula to be applied in each year of the regulatory period is:

MAR = return on capital + return of capital + Opex + EBSS + Tax

= (WACC x RAB) + D + Opex + EBSS + Tax

where:

MAR = Maximum allowed revenue

WACC = Post tax nominal weighted average cost of capital

RAB = Regulatory Asset Base

D = Economic depreciation (nominal depreciation – indexation of the RAB)

Opex = Operating and maintenance expenditure

EBSS = Efficiency carry over amounts, being revenue increments for the year arising from the operation of the efficiency benefit sharing scheme

Tax = Cost of corporate income tax of the regulated business

The annual revenue stream derived using the building block formula is then smoothed with an X factor in accordance with the requirements of clause 6.5.9 of the Rules. However, it should be noted that the scope for revenue smoothing is limited as the regulatory period is only two years.

This chapter provides information on our total revenue, the treatment of shared assets, the X factors and average price outcomes. The remainder of the chapter is structured as follows:

- Section 14.2 provides an overview of our total revenue requirement for Standard Control Services.
- Section 14.3 sets out the proposed X factors to apply in the forthcoming regulatory period.
- Section 14.4 provides an overview of outcomes for customers in terms of our total allowed revenues and customers’ average annual network changes.

14.2 Overview of our revenue requirement

The table below summarises the building block calculation for the forthcoming regulatory period alongside the final year of the current period, which is 2016-17.

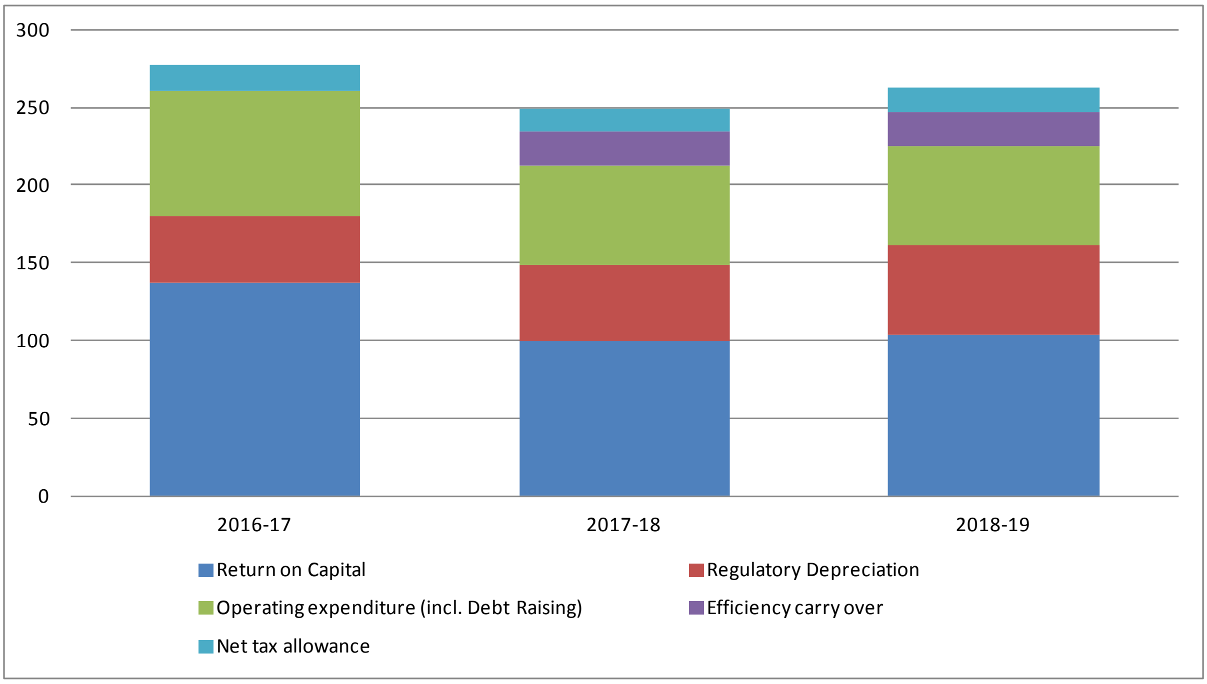
Table 14-1: Summary of Building Block Unsmoothed Revenue Requirements ($m nominal)

	2016–17	2017-18	2018-19	Total
Return on Capital	137.7	99.5	103.5	203.0
Regulatory Depreciation	42.2	49.6	57.6	107.2
Operating expenditure (incl. Debt Raising)	81.2	63.8	63.9	127.7
Efficiency carry over[35]	0.0	21.5	22.0	43.5
Net tax allowance	16.7	15.0	15.9	30.9
Total Revenue Requirement (unsmoothed)	**277.8**	**249.4**	**262.9**	**512.3**

It should be noted that the total revenue requirement is not subject to a shared asset adjustment because our expected annual unregulated revenue from shared assets does not exceed the AER's materiality threshold.

Figure 14-1 shows the significant reduction in our proposed revenue in 2017-18, followed by a modest increase in 2018-19.

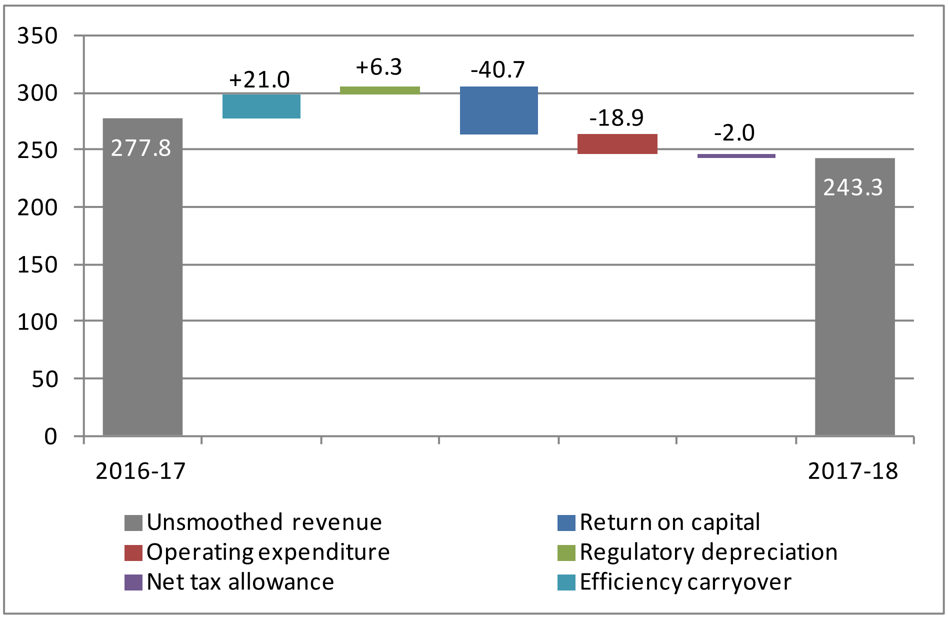
Figure 14-1: Summary Building Block Unsmoothed Revenue Requirement ($m nominal)



The figure below shows the key elements in our proposal that result in this reduced revenue requirement in 2017-18. In contrast to the earlier data, the figure below is expressed in real terms to exclude the effect of inflation.

35 This mainly relates to Efficiency Benefit Sharing Scheme payments and also includes allowances provided under the Demand Management and Embedded Generation Connection Incentive Scheme (formally the Demand Management Incentive Scheme, or DMIS).

Figure 14-2: Changes in unsmoothed revenue from 2016-17 to 2017-18 (June 2017 $m)



Each of the elements in the above figure has been explained in earlier chapters of this Regulatory Proposal.

14.3 X factors and smoothed revenue

As our regulatory control period is only two years, there is limited scope to adopt an X factor to smooth revenues. We have proposed X factors of 12.89 per cent for 2017-18 and 2 per cent for 2018-19. Our proposed X factors ensure that:

- our allowed revenues do not increase in real terms over the regulatory control period; and
- our building blocks costs remain closely aligned in 2018-19, as required by the Rules.

Table 14-2 shows our unsmoothed and smoothed revenue requirement for the forthcoming period.

Table 14-2: Unsmoothed and smoothed revenue 2014–15 to 2018–19 ($m nominal unless stated otherwise)

	2016–17	2017–18	2018–19	Total revenue
Annual building block revenue requirement (unsmoothed)	277.8	249.4	262.9	**512.3**
Maximum allowed revenue (smoothed)	286.0	255.4	256.5	**511.9**
Maximum allowed revenue - smoothed (June 2017 $m)	286.0	249.2	244.2	**493.3**
X factor[36]		12.89%	2.00%	

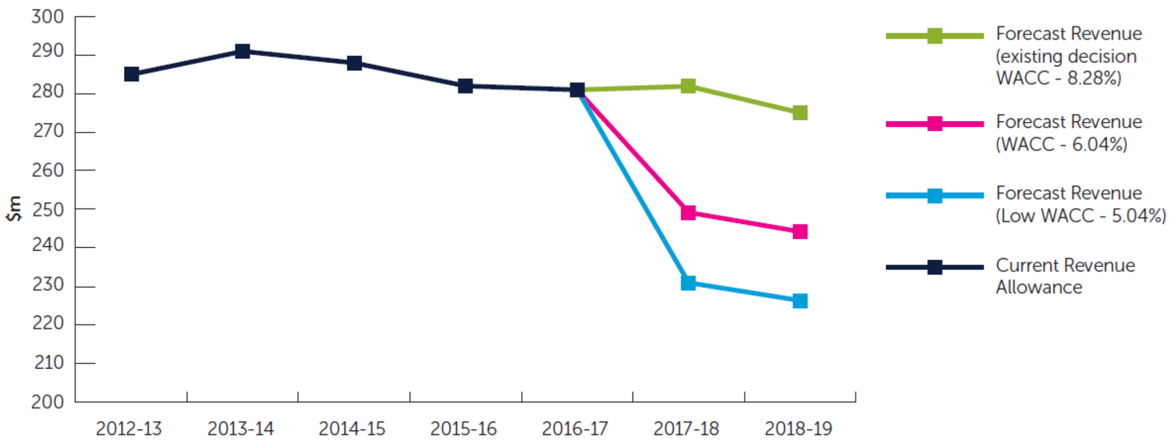
36 The X factor is applied to the nominal revenue escalated by CPI, in accordance with the AER's CPI-X revenue formula.

Our proposed smoothed revenue for 2017–18 is 12.89 per cent lower in real terms than our regulated revenue allowance for 2016–17. Following this significant reduction, the building block calculation indicates a further modest decrease of 2 per cent in real terms in 2018-19.

14.4 Outcomes for customers

Figure 14-3 below shows our revenue allowance for the current period alongside our proposed revenue for the forthcoming regulatory period, based on a WACC of 6.04 per cent. The figure presents two other WACC scenarios to illustrate the sensitivity of our revenue requirements to changes in the WACC. Our proposal is based on the Australian Energy Regulator's approach to setting the WACC, and will be updated to reflect market data and any changes required as a result of Tribunal decisions…

Figure 14-3: Revenue allowance for distribution standard control services (June 2017 $m)



In addition to the impact of different WACC outcomes, our actual distribution revenue may vary from the forecast revenue path or the following reasons:

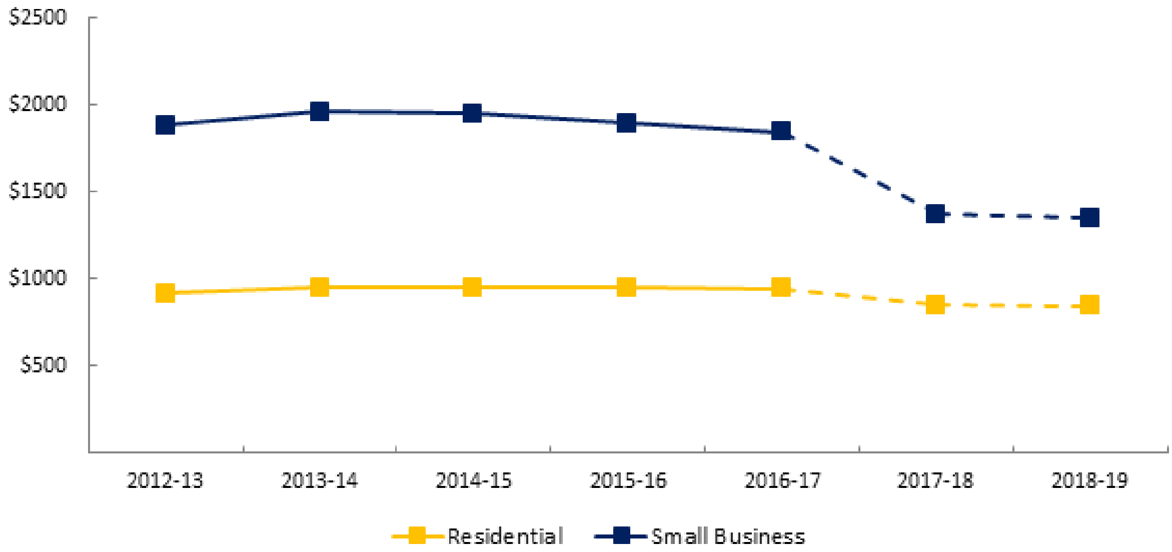
- The AER will re-calculate our allowed return on debt for each year within the forthcoming regulatory period in accordance with the 'trailing average portfolio approach' set out in the Rate of Return Guidelines. This may lead to changes in our allowed return on debt which will flow through to our revenue allowance.
- Our service performance in a year may vary from the targets, resulting in penalties or bonuses being subtracted from or added to our allowed revenue.
- Our total revenue recovery in a year may vary from the total amount we are entitled to recover due to differences in electricity consumption and demand used to establish our network tariffs. These under- or over-recoveries are added to or deducted from our revenue allowance in future years.
- There may be events such as new regulatory obligations that result in us incurring significant additional costs not anticipated as part of our Regulatory Proposal. These are referred to as pass through events. Subject to us seeking to pass through of such costs and the AER's approval, we are permitted to recover the additional costs arising from such events through increased network charges.

Transmission and distribution network costs presently make up around 50 per cent of the average Tasmanian residential and small business customer electricity bill[37]. It has been noted in this Regulatory Proposal that TasNetworks was established as an integrated network business to drive efficiencies in the transmission and distribution networks and to deliver better outcomes for Tasmanian customers.

In our first year of operation (2014-15) we achieved an unprecedented outcome in our transmission revenue determination, with the AER accepting our proposal, resulting in lower prices for our transmission customers. This has already delivered value to our customers and our distribution Regulatory Proposal seeks to build on that positive outcome.

Our proposed distribution revenue allowance, based on a placeholder WACC of 6.04%, together with our current transmission revenue allowance results in the indicative average annual total network bills for residential and small business customers shown below.

Figure 14-4: Indicative average annual total network bills for customers (June 2017 $)



Most network tariffs presently have a large element of consumption-based pricing, so we forecast future energy consumption for customers in order to set our network tariffs. Therefore network pricing outcomes, to a large degree, reflect forecast revenue as well as forecast consumption levels for different types of customers. If consumption turns out to be lower than we presently forecast, network charges may be higher. Conversely, if consumption is higher than forecast, network charges may be lower.

In addition, to simplify the presentation of this information, we have assumed no under-recoveries or incentive payments from the current regulatory period. Our forecasts of network charges (shown above) for residential and small business customers are therefore highly indicative.

We will also begin a gradual process of adjustment to our existing network tariffs for residential and small business customers. The changes will involve rebalancing most of our existing network tariffs,

37 Source: Office of the Tasmanian Economic Regulator, based on 2014-15 standing offer prices.

by increasing the emphasis on service charges and reducing the variable consumption based component. The prices of some network tariffs will also be realigned over time, to unwind some long-standing cross subsidies between different tariffs and different customer groups.

Together with the decrease in our allowable revenue we anticipate that both average residential and small business customers will experience a network price decrease in 2017-18 followed by no real network price increases in 2018-19. Aligned with our tariff strategy to make network charges more cost-reflective, the decrease for small business customers in 2017-18 will be more significant than for residential customers. Further information on our tariff proposals for the forthcoming regulatory period are set out in Chapter 15 and in our Tariff Structure Statement (TN063) documents.

15 Proposed network tariffs and future developments

15.1 Introduction

In November 2014, the AEMC introduced a new Rule governing the setting of distribution network tariffs. The Rule establishes a new pricing objective and pricing principles. The pricing principles require each network tariff to be based on the long run marginal cost of providing network services. The purpose of the new Rule is to provide more cost reflective network pricing, which will encourage customers to make efficient network usage decisions.

The Rules require each distributor to consult with customers and retailers to develop a Tariff Structure Statement (TSS), which outlines the price structures that will apply for the regulatory period. Each distributor is also required to publish an indicative pricing schedule to provide customers and retailers with the most up to date information on likely price levels throughout the regulatory period. The TSS and indicative pricing schedule are intended to improve the certainty, transparency and timeliness of network pricing. These documents are provided alongside this Regulatory Proposal (TN063 and TN065).

The purpose of this chapter is to provide a brief overview of the network tariffs that will apply in the forthcoming regulatory period and our longer term network tariff strategy. Our network tariff proposals have been shaped by our customer engagement, which was discussed in Chapters 3 and 6.

15.2 Why network tariff reform?

We are seeing major changes in the way that customers are using the electricity network. Our network is no longer a one-way transport system from large generators to customers. Instead, customers are generating their own electricity by installing solar panels and exporting excess energy to the grid, which creates two-way flows.

Battery technology is likely to be the next trend, causing another major shift in the electricity market and network operation. As battery technology becomes more cost effective, solar generation and batteries in combination may influence peak demand on our network. This technology will enable customers more capacity to generate and store electricity, either to export to the grid or for their own use, at a time of their choosing.

A further technological change is the likely growth of electric vehicles, which may add increased demand to our network. This demand could be met by using existing network capacity at off-peak times. However, efficient outcomes will not occur by chance. We need network tariffs that are equipped for the new environment. Specifically, network tariffs will need to reflect the underlying costs of network services, in order to provide price signals to customers that promote efficient use of, and investment in the network.

With these changes in mind, we reviewed our existing network tariffs and consulted with customers on our findings, which are summarised below:

- Our network tariffs are too heavily based on energy consumption. This pricing approach encourages customers to reduce energy consumption, including during off-peak times, which may not result in any reductions in network costs.

- Large numbers of customers are responding to the 'incorrect' consumption-based price signals by installing new technology. Whilst this reduces overall energy consumption - and provides customers with reduced electricity bills - it does not necessarily reduce the peak demand on the network. Accordingly, customers' responses to consumption-based network tariffs do not necessarily reduce network costs.

- There are opportunities to improve network price signals to enable customers to make better consumption and investment decisions (which may include decisions relating to electric vehicles, solar panels, battery storage and energy efficiency measures).

- Better consumption and investment decisions produce better outcomes for everybody and help to reduce our costs and our customers' electricity bills.

15.3 Proposed network tariff strategy

We propose moving network tariffs towards time of use demand based pricing. This form of tariff encourages customers to shift demand from peak to off-peak periods. By using existing capacity better, we can deliver more electricity without adding new network capacity.

Our network tariff strategy has two initial phases:

1. Transitioning existing consumption based network tariffs to be more cost reflective.
2. Offering demand based network tariffs as a choice for customers.

15.4 Network tariffs for the 2017-19 regulatory period

In accordance with our longer term transition to cost reflective network tariffs, our focus in the 2017-19 regulatory period is the introduction of time of use demand based network tariffs and transitioning our existing suite of network tariffs towards recovery of total efficient costs from each customer class.

From 1 July 2017, we will introduce three demand based network tariffs which will be available to customers on an opt-in basis though the Retailer. The new tariffs include:

- Residential time of use demand network tariff;
- Low Voltage commercial time of use demand network tariff; and
- Large Low Voltage time of use demand network tariff.

These network tariffs will include a service charge; a demand charge for the maximum demand recorded during the peak period; and a demand charge for the maximum demand recorded during the off-peak period.

Further details on our tariff strategy, proposed network tariffs and indicative prices are provided in our Tariff Structure Statement (TN063) and Indicative Pricing Schedule (TN065). Section 14.4 has already provided an overview of the likely changes to customers' average annual total network charges, based on the revenue requirements set out in this Regulatory Proposal.

Part Three:

Alternative Control Services

Part Three of the Regulatory Proposal sets out information relating to Alternative Control Services. It provides an overview of the feedback we have received from our customers on Alternative Control Services and how our proposal responds to that feedback. This part provides information on metering services, public lighting services and ancillary network services.

16 Customer feedback on Alternative Control Services

Part 2 of this Regulatory Proposal was focused on Standard Control Services. This Part 3 addresses those services – called Alternative Control Services – that are either customer-initiated (e.g. a new connection), customer-specific (e.g. public lighting); or potentially subject to competition (e.g. metering provision).

Similar to the approach adopted in Chapter 6 for Standard Control Services, we commence this section by explaining how we propose to address the feedback we received from the customer engagement exercise described in Chapter 3. The table below provides that information

Table 16-1: Addressing customer feedback on Alternative Control Services

Issue	Customer Feedback	Our Proposal
Cost efficiency and affordability	Cost and affordability are the greatest concerns to customers. Lower prices - without reducing service quality - would lead to the greatest uplift in customer satisfaction.	Our aim is to ensure that the revenues we obtain through the provision of Alternative Control Services are efficient.
Metering services	Customers want us to explain how we are innovating to make best use of new technology. Advanced metering is one area where technology is providing increased customer choice.	The AEMC has recently finalised a Rule change that expands competition in metering services. This will provide customers with the opportunity to benefit from advanced metering. Our metering proposals recognises and facilitate this change, noting that any particular arrangements that may apply in Tasmania are not yet confirmed.
Public lighting	Our customers expect our prices to be efficient and fair.	In developing our proposal, we have engaged with the Local Government Association of Tasmania (LGAT) and local councils. That engagement has involved: • negotiating prices for LED and other new light types; • presenting information on the regulatory framework and the methodology for calculating prices; and • consulting on our intended plans to substantially replace the four year maintenance cycle for 80 Watt Mercury Vapour lights with a four year capital replacement program of LEDs. We have also started negotiating another customer funded accelerated replacement program for three northern councils for completion during 2016-17 and Facility Access Agreements with other councils. We have revisited our current prices and improved our modelling to ensure that future prices better reflect the efficient costs of different lighting solutions.
Ancillary Network Services	Our customers expect us to deliver these services in a timely and efficient manner. Customers support the introduction of competition in the provision of connection services.	Our Customer Charter imposes penalties on us if we fail to meet minimum service performance standards. This scheme will continue to apply in the forthcoming regulatory period. Our proposed charges for quoted and fee-based services are at the lowest sustainable level. We are also introducing competition in the provision of some connection services to promote customer choice.

In the following chapters, we provide a more detailed explanation of our Alternative Control Services.

17 Metering services

17.1 Introduction

The AEMC has recently completed changes to the National Electricity Rules and the National Energy Retail Rules in relation to the provision of metering services. These changes establish a competitive framework for the provision of advanced meter services for residential and small commercial customers, and new arrangements in relation to embedded networks[38].

An important component of the competitive framework for advanced meters is the new role of Metering Coordinator, responsible for arranging the installation, provision and maintenance of the advanced meter and the collection, processing and delivery of metering data.

As a transitional measure each local distributor, such as TasNetworks in Tasmania, will become the initial Metering Coordinator for connection points where it is currently providing accumulation and manually read interval meters. The local distributor will continue in this role until another Metering Coordinator is appointed or these services cease to be classified by the AER as direct control services.

The new metering arrangements are expected to impact both our standard control expenditure (in our role as a distributor) and alternative service control expenditure (in our present role as the local network service provider for metering services, and our new role as the initial Metering Coordinator for existing regulated meters).

The forecasts presented in this chapter are based on the assumption that metering competition will commence in Tasmania from 1 December 2017. The forecasts also reflect our current understanding of the Rule requirements, noting that the Rule has only recently been finalised.

The AEMC's final determination states that[39]:

> "If a Minister in a jurisdiction that does not currently have effective retail electricity competition considers that the specific circumstances of that jurisdiction mean that the costs of the final rule could exceed the benefits for a period of time, specific jurisdictional issues of that nature would best be addressed by the Minister requesting a jurisdictional derogation from specific aspects of the final rule for a limited period of time. Any such jurisdictional derogation request would be considered by the AEMC through a separate rule change consultation process during 2016."

The financial impact of the Embedded Networks Rule change has not been included in this Regulatory Proposal as the application of the rule requires changes to jurisdictional instruments and these changes are not yet determined.

---

38 AEMC Rule Determination – Expanding competition in metering and related services, November 2015 and AEMC Final Rule Determination – Embedded networks, December 2015.

39 AEMC, Expanding competition in metering and related services, Rule Determination, 26 November 2015, page 46.

Any adjustments to forecasts resulting from these Rule changes will be provided to the AER, as total implementation costs are understood and refined. To the extent permissible in the Rules, we will revisit our expenditure forecasts following the AER's draft decision.

The remainder of this chapter is structured as follows:

- Section 17.2 outlines the classification and form of regulation to apply to metering services.
- Section 17.3 sets out our proposals in relation to metering capital charges.
- Section 17.4 provides information on our building block costs for regulated metering services.
- Section 17.5 sets out the X factors and indicative prices to apply to regulated metering services.

17.2 Service classification and form of regulation

Before describing the AER's proposed service classification and form of regulation for metering services, it is helpful to explain the different types of meters in Tasmania. The table below provides a short description of Type 1 to 4 meters; Type 5; Type 6 and Type 7 metering.

Table 17-1: Metering installation types

Metering type	Description
Type 1 to 4 meters	Large customers use type 1 to 4 meters which provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication capability. Type 1 to 4 meters are competitively available and are not subject to price or revenue regulation in Tasmania or in most other jurisdictions.
Type 5 meters	These are manually read interval meters with capability to record time of use of energy. Type 5 meters are not permitted in the Tasmanian jurisdiction.
Type 6 meters	These are manually read accumulation meters which simply record total electricity usage. TasNetworks is the monopoly service provider of Type 6 meters.
Type 7 meters	Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Rather, electricity use by these connections is calculated. Charges associated with type 7 metering services relate to the process of calculating electricity use.

In relation to Type 1 to 4 meters, the AER observed that these services will continue to be provided on a competitive basis and therefore their 'unclassified' status should be retained, which means that they are not subject to price or revenue regulation. We agree with the AER's proposed approach in relation to these services.

Under the National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, new meters installed by the Metering Coordinator will be Type 4 and will therefore not be subject to regulation.

The AER also proposed retaining the current classification of type 5, 6 and 7 metering services as 'alternative control services'. In adopting this position, the AER's Framework and Approach Paper commented that[40]:

- TasNetworks is the monopoly supplier of type 5, 6 and 7 metering services in Tasmania;
- there is limited prospect of competition in the provision of type 5, 6 and 7 metering;
- the costs of providing these services can be directly attributed to individual customers; and
- the proposed classification promotes the unbundling of metering costs and services from network services, which is consistent with promoting metering competition.

TasNetworks supports the AER's proposed classification for type 6 and 7 metering services for the reasons outlined above. We note that as small customers receive advanced meters, the volume of type 6 metering services will diminish. The AER's proposed application of a price control is the most appropriate form of control because it adjusts our Alternative Control Services revenue downwards as the volume of type 6 metering services declines.

As already noted, the new framework developed by the AEMC requires advanced metering services to be provided on a competitive basis. It follows that the provision of these services will not be subject to revenue or price control regulation. Competitive Metering Coordinators will provide advanced meters on an unregulated basis, including as faulty meters are replaced.

17.3 Metering capital charges

The introduction of the competitive framework for the provision of advanced meters exposes the distribution businesses to the risk that the sunk capital costs of existing meters cannot be recovered. This risk of 'asset stranding' arises because the capital costs of a customer's existing meter is recovered over its expected operational life. If the existing meter is replaced with an advanced meter, the operational life of the present meter is unexpectedly cut short, resulting in the possibility of the meter's residual value being unrecovered.

The AER has recently considered how best to address this issue of asset stranding in its distribution determinations for the NSW and Queensland businesses[41]. The AER concluded that where a customer wishes to replace an existing meter with a new advanced meter, the customer will continue to pay a capital charge in relation to the existing meter. This capital charge would continue to apply to all customers until the distributor recovers the residual value of the existing metering stock.

The AER concluded that allowing the distributor to levy a charge until the residual value of the existing meter stock is recovered is a fair approach. In particular, the AER's view is that the approach

---

[40] AER, Framework and approach for TasNetworks Distribution for the Regulatory control period commencing 1 July 2017, July 2015, pages 29 and 30.

[41] The AER's decision for Victoria is to maintain a lump sum metering fee. However, the Victorian metering charging arrangements are governed by a jurisdictional instrument and do not reflect the AER's preferred approach. In South Australia, SA Power Networks did not propose metering capital charges in its revised regulatory proposal.

is better than either applying a one-off lump sum payment or applying no charge at all. The customer would not be required to pay the distributor's operating costs (such as meter reading), as these costs would no longer be incurred.

TasNetworks supports the AER's approach to metering capital charges as set out in its final decisions for the NSW and Queensland distributors. TasNetworks' proposed capital charge for each meter type, are set out in the Indicative Pricing Schedule (TN065) that accompanies this Regulatory Proposal.

17.4 Building block costs for regulated metering services

The AER's Framework and Approach paper explains that a building block approach is likely to be adopted to determine the revenue requirement for regulated metering services.

In forecasting the building block components, we have assumed that the volume of type 6 meters will decline by 1 per cent per annum following the introduction of metering competition. This estimate, while highly uncertain, is consistent with the views expressed by at least one Victorian distributor[42].

To facilitate the introduction of competition, we will need to have systems and processes in place to enable the efficient churning of metering service providers, while still ensuring accurate billing. Our systems will need to accept metering data and meter register data for every meter type from any accredited party. In addition, we will need to follow up missing data with meter data requests and receive transactions from a range of new parties.

We have apportioned our shared costs, including those associated with the introduction of metering competition, between standard control and alterative control services in accordance with our cost allocation methodology. Our regulated asset base for alternative control metering services and the building block calculation are presented in the tables below.

The table shows the derivation of the metering RAB value as at 1 July 2017 (that is, the closing RAB as at 30 June 2017) for type 6 metering services.

42 United Energy, Alternative Control Services, Revenue Capped Metering Services, April 2015, page 11.

Table 17-2: Roll forward of metering regulatory asset base from 1 July 2012 to 30 June 2017 ($m nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17
Opening RAB	41.73	43.75	47.34	48.00	47.27
Capital expenditure	4.91	6.79	5.07	2.97	3.15
Inflation on opening RAB	1.04	1.28	0.63	1.20	1.18
Disposals	0.07	0.07	0.07	0.07	0.07
Straight-line depreciation	3.86	4.40	4.98	4.83	4.90
Closing RAB	43.75	47.34	48.00	47.27	46.63

As shown in the table above, the metering RAB value as at 1 July 2017 (in nominal dollars) is $46.6 million. Capital expenditure for 2015-16 and 2016-17 is an estimate.

The forecast metering RAB is presented in the table below. Forecast capital expenditure is comparatively low because new meters are assumed to be provided on a competitive basis from 1 December 2017.

Table 17-3: Metering regulatory asset base roll forward 1 July 2017 to 30 June 2019 ($m nominal unless stated otherwise)

	2017-18	2018-19
RAB (start period) - nominal	46.63	44.78
Nominal capex	1.76	0.62
Inflation on opening RAB	1.17	1.12
Nominal straight-line depreciation	4.71	5.02
Disposals	0.06	0.07
RAB (end period) - nominal	44.78	41.42
RAB (end period) - $ June 2017	41.36	38.87

The table below summarises the building block calculation for type 6 and 7 metering services the forthcoming regulatory period.

Table 17-4: Summary of Building Block Revenue Requirement for type 6 and 7 metering services ($ million nominal)

	2017-18	**2018-19**	**Total**
Return on Capital	2.82	2.70	5.52
Regulatory depreciation	3.54	3.89	7.43
Operating expenditure	5.33	5.37	10.70
Estimated cost of corporate income tax	0.93	0.96	1.89
Total Revenue Requirement (unsmoothed)	12.63	12.92	25.55

A detailed explanation of the cost forecasts is provided in Asset Management Plan - Metering Type 6 (TN041), which is provided as a supporting document. It should be noted that the cost data presented in the Asset Management Plan excludes shared capital expenditure and overheads.

A detailed description of our pricing approach and proposed prices is provided in the Tariff Structure Statement and the accompanying indicative pricing schedule.

17.5 X Factor and indicative prices

Our proposed meter prices for the forthcoming regulatory period are derived from the building block annual revenue requirements and our meter volume forecasts. The proposed X factor, which is reflected in the prices, is eighteen per cent for 2017-18 and two per cent for 2018-19.

The capital and non-capital charges are detailed in the Indicative Pricing Schedule (TN065) which is provided alongside this Regulatory Proposal. As explained in section 17.3, the capital charge would continue to apply if an existing meter is replaced with a new advanced meter. The capital charge will cease when the residual value of the existing metering stock is recovered.

18 Public lighting services

18.1 Introduction

Public lighting services have generally been provided as monopoly services by TasNetworks to specific customers—usually local government councils—while the emergence of new lighting technologies and providers is increasing the potential for alternative supply arrangements. The AER has classified public lighting as follows:

- Repair, maintenance, like-for-like replacement and the provision of new public lighting assets are classified as Alternative Control Services.
- Installation of new public lighting technologies is classified as a negotiated service. The provision of negotiated services is governed by our negotiating framework, which is provided as an attachment to this Regulatory Proposal (TN020).

We accept the AER's proposed classification of services.

The purpose of this chapter is to provide a brief explanation of the methodology that we have applied to develop our public lighting charges for the forthcoming regulatory period.

18.2 Annuity model approach

Our current lighting charges are based on an annuity approach, rather than a building block model. The annuity approach was preferred because we have sufficient information on the replacement cost and expected lives of new assets, but limited historical information on our public lighting assets that can be used to calculate the regulated asset base value.

While TasNetworks is continuing to improve its asset information, the information gaps regarding installation dates and installation costs persist. For this reason, we propose to continue to apply our annuity model, noting that the information inputs have been improved since the previous AER determination.

Replacement costs are one of the key inputs into the public lighting annuity model and have a significant impact on the prices for public lighting.

For the public lighting annuity model, the relevant replacement costs relate to:

- lamp (light globe);
- luminaire (globe housing, diffuser and electrical supply);
- bracket; and
- installation costs.

In developing the annuity model for the forthcoming regulatory period, we revisited the cost information and the allocation of costs to different lighting types. As explained in further detail in the Tariff Structure Statement (TN063) that accompanies this Regulatory Proposal, these improvements to the public lighting cost model have substantially improved the cost reflectivity of the proposed charges. Cost reflective prices enable our customers to make efficient decisions in relation to public lighting solutions and they also deliver equitable outcomes for our customers.

We provide our public lighting model (TN054) and Public Lighting Asset Management Plan (TN031) as a supporting documents.

18.3 Proposed public lighting charges

Detailed information on our proposed public lighting charges are provided in the Tariff Structure Statement (TN063) and the accompanying Indicative Pricing Schedule (TN065).

19 Ancillary network services

19.1 Introduction

The AER’s Framework & Approach paper explains that ancillary network services share the common characteristic of being non-routine services provided to individual customers on an 'as needs' basis. Examples include customer requested appointments or after hours service provision.

The provision of ancillary network services involves work on, or in relation to, parts of our distribution network. Therefore, as with network services, only the distributor can undertake the work associated with provision of ancillary network services. For this reason, the AER categorises these services as Alternative Control Services.

Ancillary network services are further sub-divided into fee-based and quoted services.

Fee based services are largely homogenous in nature, so that the cost inputs involved in providing these services do not involve significant variations between customers. Given these characteristics, fee-based services can be priced according to a tariff, which is set for the duration of the regulatory period, subject to an annual CPI-X escalation.

By contrast, the scope of quoted services may vary significantly depending on the scope of the customer’s specific requirements. Accordingly, quoted services are priced according to the labour, materials and other direct costs required to meet the customer’s service request.

In broad terms, the costs of providing ancillary network services have reduced due to the reduction in overheads achieved through synergies from the merger. These savings are reflected in our proposed charges for ancillary network services.

The remainder of this chapter provides an overview of our proposals in relation to fee-based services and quoted services.

19.2 Fee-based services

The fee-based services we propose to provide in the forthcoming regulatory period include but are not limited to:

- energisation;
- de-energisation;
- re-energisation;
- meter alteration;
- meter testing;
- basic connections;
- supply abolishment – removal of meters and service connection;
- renewable energy connection; and
- other miscellaneous services.

A full listing of our proposed fee-based services is included in our Indicative Pricing Schedule (TN065).

The fee-based services we propose to apply are the same as those we have supplied during the current period, except we propose to charge for basic connection services as an Alternative Control Service. We explain the rationale for our proposed classification in section 1.2.

A full description of our fee-based services and the proposed tariffs is provided in the Tariff Structure Statement (TN063) and the Indicative Pricing Schedule (TN065).

19.3 Quoted services

We provide a range of non-standard services on a quoted basis including:

- removal or relocation of our assets at a customer's request;
- services that are provided at a higher standard than the standard service, due to a customer's request for us to do so;
- provision of public lighting schemes;
- provision of overhead and underground subdivisions for developers;
- relocation of assets at the request of a third party; and
- services that are provided through a non-standard process at a customer's request (for example, where more frequent meter reading is required).

Our approach to quoted services has been amended to include a small margin on services. This has been offset by a reduction in overheads. Labour is the most significant cost component in providing quoted services, with materials costs being required for some services. The proposed labour rates are set out in the Indicative Pricing Schedule (TN065). No material changes are proposed from the approved charges that currently apply.

Part Four:

Pass through events, Connection Pricing, Negotiating Framework and other matters

Part Four of the Regulatory Proposal sets out information that is applicable to Standard Control Services and Alternative Control Services. It provides information on pass though events, our connection policy, negotiating framework and other matters.

20 Pass through events

20.1 Introduction

A cost pass through mechanism is an efficient method of managing unpredictable, high cost events that are beyond our control. This mechanism ensures that costs are only recovered from customers if they arise from particular pre-defined events and are efficiently incurred.

The Rules recognise the following as pass through events:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a retailer insolvency event.

In addition to those defined events, the Rules allow the AER's distribution determination to specify additional pass through events, which are known as 'nominated pass through events'[43]. In accordance with these arrangements, we propose that the following additional nominated pass through events should apply in the forthcoming regulatory period:

- insurance cap event;
- terrorism event; and
- natural disaster event.

The proposed definitions set out in this chapter are consistent with the AER's approved nominated pass through events in relation to our transmission business. The alignment of the pass through definitions across transmission and distribution, while not essential, is appropriate given the merger of the two networks.

20.2 Application of pass through provisions to Alternative Control Services

We propose that the pass through provisions for defined and nominated pass through events apply to Alternative Control Services on the basis that the pass through provisions in the Rules apply to direct control services, which includes both standard control services and Alternative Control Services.[44] We note that the application of this approach is consistent with the reasoning set out in the AER's distribution determination for Ausgrid in relation to pass through events. Specifically, the AER stated[45]:

---

[43] NER, clause 6.5.1.

[44] Refer to Chapter 10 of the Rules – definitions of 'negative change event', 'positive change event', 'regulatory change event', 'tax change event', 'service standard event' and 'retailer insolvency event.'

[45] AER, Attachment 15 – Pass through events, Ausgrid Final Decision 2015–19, page 15-9.

"Under clauses 6.6.1(d), (g) and (j) of the NER, we are to make a decision on the costs of providing direct control services as a result of a pass through event occurring. Direct control services include alternative control services and standard control services."

20.3 Insurance cap event

An insurance cap event occurs if:

1. TasNetworks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;
2. TasNetworks incurs costs beyond the relevant policy limit; and
3. the costs beyond the relevant policy limit materially increase the costs to TasNetworks in providing direct control.

For this insurance cap event:

4. the relevant policy limit is the greater of:
   (a) TasNetworks' actual policy limit at the time of the event that gives, or would have given rise to a claim; and
   (b) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.
5. A relevant insurance policy is an insurance policy held during the 2017-19 regulatory control period or a previous regulatory control period in which TasNetworks was regulated.

Note: for the avoidance of doubt, in assessing an insurance cap event cost pass through application under clause 6.6.1, the AER will have regard to:

i. the insurance policy for the event;
ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
iii. the extent to which a prudent provider could reasonably mitigate the impact of the event.

20.4 Terrorism event

A terrorism event is:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to TasNetworks in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

i. whether TasNetworks has insurance against the event;

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event;

iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred; and

iv. the extent to which a prudent provider could reasonably mitigate the impact of the event.

20.5 Natural disaster event

A natural disaster event is:

Any major fire, flood, earthquake or other natural disaster that occurs during the 2017-19 regulatory control period and materially increases the costs to TasNetworks in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider.

The term ‘major’ in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP’s annual revenue requirement for that regulatory year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

i. whether TasNetworks has insurance against the event;

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event;

iii. whether a relevant government authority has made a declaration that a natural disaster has occurred; and

iv. the extent to which a prudent NSP could reasonably mitigate the impact of the event.

21 Connection pricing policy

The Rules require us to prepare a proposed connection pricing policy. The policy sets out the charging arrangements for providing connection service to retail customers or real estate developers. The proposed connection policy must be consistent with the charging principles specified in the Rules[46] and the AER's guidelines[47], which were published in June 2012.

Our proposed connection policy is provided as a supporting document (TN017). It explains:

- the circumstances in which a connection charge applies;
- those aspects of a connection service, such as an extension or augmentation, for which a connection charge may be payable;
- the basis on which connection charges are determined; and
- the payment arrangements, such as capital contributions, prepayments or financial guarantees.

Our current connection policy was approved by the AER in its regulatory determination for the distribution business. Following that approval, however, the AER published its connection charge guidelines. As a consequence, some aspects of our current connection policy must be revisited in order to ensure that we comply with the guidelines and the Rules. In revising our connection policy, we have taken the opportunity to streamline processes and simplify service offerings for our customers.

To assist customers and stakeholders we provide a Connection Pricing Policy Overview as a supporting document to our Regulatory Proposal (TN018).

---

46 NER, clause 5A.E.1.

47 Connection charge guidelines for electricity retail customers, under chapter 5A of the National Electricity Rules, Version 1.0, June 2012.

22 Negotiating framework

We propose to apply a new negotiating framework, which is provided as an attachment to this Regulatory Proposal (TN020). This new framework does not materially depart from the current framework. The negotiating framework governs our approach to negotiating and reaching agreement with customers regarding the provision of Negotiated Distribution Services.

23 Confidentiality

In accordance with the Rules and the AER’s Confidentiality Guideline, we have completed a confidentiality template that we have provided to the AER. This template details the matters in our Regulatory Proposal and supporting documents for which we are claiming confidentiality.

24 Certifications

24.1 Certification statement

Clauses S6.1.1(5) and S6.1.2(6) of the Rules require us to provide a certification by our Directors about the key assumptions that underlie our capital expenditure and operating expenditure forecasts.

The certification statement is provided as an attachment to this Regulatory Proposal (TN002).

24.2 Statutory declaration of Chief Executive Officer

The Regulatory Information Notice requires our Chief Executive Officer to provide a statutory declaration about the information that we have provided to the AER.

The statutory declaration is provided as an attachment to this Regulatory Proposal (TN004).

24.3 Board resolution

The Regulatory Information Notice requires us to provide a Board resolution about the information that we have provided to the AER.

The Board resolution is provided as an attachment to this Regulatory Proposal (TN003).

25 Supporting documents

Key Strategies and Policies

Document ID	Document Title
TN001	Regulatory Proposal Overview Paper
TN002	Directors Certification Of Key Assumptions for Regulatory Proposal
TN003	Directors Certification of Reset RIN
TN004	CEO's Statutory Declaration Reset RIN
TN005	Direction and Priorities Consultation Paper
TN006	Direction and Priorities Paper November 2015
TN007	Asset Management Policy
TN008	Zero Harm Policy
TN009	Procurement Policy
TN010	Capitalisation Policy
TN011	Corporate Plan 2015 - 2016
TN012	Customer Service Strategy
TN013	Annual Planning Report 2015
TN014	Cost Allocation Methodology (CAM)
TN015	Works Delivery Plan
TN016	Stakeholder Engagement Plan - DD17
TN017	Connection Pricing Policy
TN018	Connection Pricing Policy – Overview
TN019	Expenditure Forecasting methodology 2017-19
TN020	Negotiating Framework
TN021	Risk Management Framework
TN022	Customer Connection Forecasts 2015
TN023	Strategic Asset Management Plan

Asset Management Plans

Document ID	Document Title
TN024	Facilities Strategy
TN025	Facilities Asset Management Plan
TN026	Fleet Services Strategy
TN027	Fleet Asset Management Plan
TN028	Service Performance Asset Management Plan
TN029	Bushfire Mitigation Asset Management Plan
TN030	Vegetation Asset Management Plan
TN031	Public Lighting Asset Management Plan
TN032	Network Innovation Strategy
TN033	Customer Initiated Management Plan
TN034	Network Development Management Plan
TN035	Network Demand Management Plan
TN036	Conductors and Hardware Asset Management Plan
TN037	Connection Assets Asset Management Plan
TN038	Emergency Response Asset Management Plan
TN039	Ground Mounted Substations Asset Management Plan
TN040	High Voltage Regulators Asset Management Plan
TN041	Metering (Regulated) Type 6 Asset Management Plan
TN042	Overhead Line Structures Asset Management Plan
TN043	Overhead Switchgear Asset Management Plan
TN044	Pole Mounted Transformers Asset Management Plan
TN045	Protection and Control Asset Management Plan
TN046	Underground Systems Asset Management Plan
TN047	Zone Substations Asset Management Plan

Document ID	Document Title
TN048	Software Asset Management Plan
TN049	IT Infrastructure Asset Management Plan
TN050	Ajilis Business Case

Models and Pricing Tariffs

TN051	Capex Forecast Model - Standard Control
TN052	Opex Base Step Trend Model - Standard control
TN053	Quoted Services Model
TN054	Public Lighting Annuity Model
TN055	Metering Model
TN056	Metering - Post Tax Revenue Model (PTRM)
TN057	Metering - Roll Forward Model (RFM)
TN058	Fee Based Services Model
TN059	Post Tax Revenue Model (PTRM)
TN060	Roll Forward Model (RFM)
TN061	Units Rates - spreadsheet
TN062	Unit Rates - Outline document
TN063	Tariff Structure Statement
TN064	Tariff Structure Statement - overview paper
TN065	Indicative Pricing Schedule
TN066	Alternative Control Services (ACS) Description Paper
TN067	STPIS targets
TN068	Modelling Overview

AER/Audit/RINs

TN069	Reset RIN
TN070	Reset RIN Compliance Checklist
TN071	Reset RIN Basis of Preparation
TN072	KPMG Letter re Reset RIN

Reports

Document ID	Document Title
TN073	Jacobs - Report On Material Cost Escalation
TN074	Frontier Report – Advice on cost escalation rates for material inputs
TN075	Huegin Opex Benchmarking Study
TN076	Electricity Sales and Maximum Demand Forecasts for Tasmania to 2045
TN077	TasNetworks Consumer Engagement Report - August 2015
TN078	TasNetworks Consumer Engagement Report - October 2014
TN079	Nature Customer Engagement Research Report
TN080	AER Augex model - Assessing TasNetworks Augex Forecast by Nuttall Consulting
TN081	AER Repex modelling – Assessing TasNetworks’ Replacement Forecast by Nuttall Consulting
TN082	KPMG Audit Report on TasNetworks' Regulatory Models