TasNetworks

Tasmanian Transmission Revenue and Distribution Regulatory Proposal

Regulatory Control Period
1 July 2019 to 30 June 2024

31 January 2018

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Tasmanian Networks Pty Ltd

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Amendments and Version History

Version No.	Date of Revision	Authorised by	Details of amendment
0.1	1 Nov 2017	Program Leader Revenue Resets	Initial draft
0.2	8 Jan 2018	Revenue Reset TLT	Endorsement
0.3	17 Jan 2018	Revenue Reset Committee	Endorsement
1.0	17 Jan 2018	TasNetworks Board	Approval
1.1	22 Jan 2018	Program Leader Revenue Resets	Cleared for submission

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

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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 after Tasmania's electricity distribution and transmission networks were brought together into one network business.

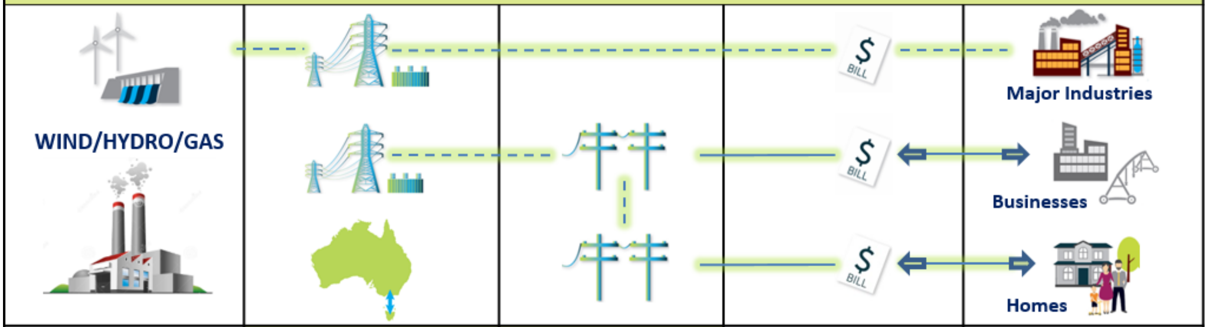
We own and operate the network that delivers electricity to more than 285,000 households, businesses and organisations on mainland Tasmania. Our services to customers include the following:

- building, maintaining and operating the transmission and distribution networks;
- establishing new connections where infrastructure does not currently exist;
- responding to, and repairing, outages and faults;
- operating a 24-hour fault service centre;
- providing education, advice and information about electrical safety;
- delivering nationally accredited training to lineworker apprentices, lineworkers, contractors and sub-contractors, local councils and civil construction organisations; and
- owning and operating a telecommunications business that serves customers in the electricity industry and other industries.

The figure below summarises our role in the Tasmanian electricity industry.

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

How your electricity gets to you



BIG GENERATION	TRANSMISSION	DISTRIBUTION	RETAIL	CONSUMERS
In Tasmania, the majority of electricity is currently generated by large generators at hydro dams, a gas-fired plant or via a number of wind farms in the NW and NE of the State.	Electricity is sent around the state using TasNetworks' high voltage transmission network. The Basslink undersea cable is also used to transmit electricity to and from Tasmania. Major industrial customers can connect directly to the transmission network.	When your electricity arrives at towns and cities it is converted to a lower voltage as it enters TasNetworks' distribution network to be sent to homes and businesses.	Retailers service homes and businesses by managing bills, connection requests and passing on TasNetworks' network charges.	The energy market place is also changing. Customers can now produce their own electricity by installing small scale renewable generation such as solar panels. The excess can be exported back into the network or stored in batteries for later use.

Purpose of this document

This document is our Regulatory Proposal and Revenue Proposal (**Regulatory Proposal**), which outlines our plans to provide prudent and efficient transmission and distribution services that serve the long-term interests of our customers. Our Regulatory Proposal covers our expenditure and revenue requirements for the period from 1 July 2019 to 30 June 2024.

TasNetworks will submit this Regulatory Proposal to the Australian Energy Regulatory (**AER**) for its review. In parallel, this proposal is made available to our customers and stakeholders for their comment and input.

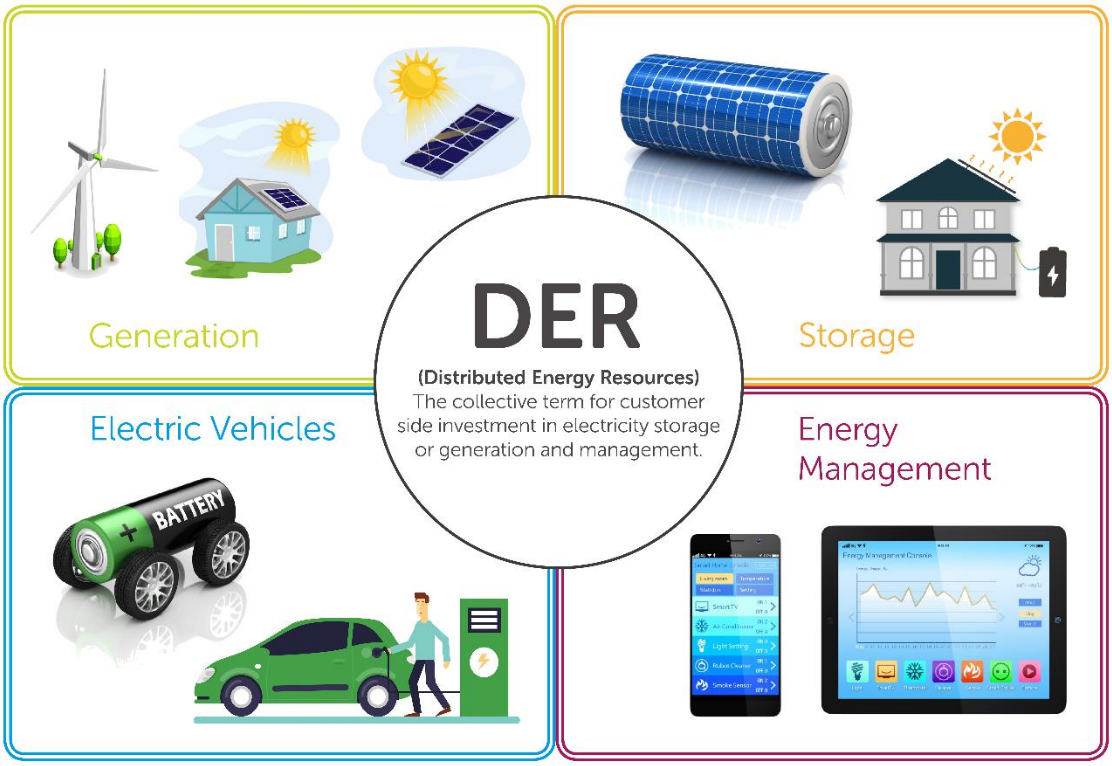
Unprecedented change and uncertainty

Our Regulatory Proposal is being prepared during a period of unprecedented change and uncertainty in the National Electricity Market (**NEM**). The transformation is being driven by customers as they embrace new technologies, take control of their energy use and support action on climate change, as well as changes to the National Energy Rules (the **Rules**) and the regulatory framework more generally.

In the longer term, in a decentralised yet integrated energy future, we must be responsive to the changing demands for traditional services, while enabling new opportunities for energy resource sharing. By connecting growing numbers of customer generators and energy storage systems to each other, our network can act as a platform to help match supply and demand and reduce the need for inefficient duplication of energy investments.

We are starting to see a growing class of customers that can be termed 'early adopters'. These are households and businesses that make investments in electricity storage, generation, or management – collectively referred to as distributed energy resources (**DER**) – or electric vehicles (**EV**) which also create a form of mobile storage.

Figure 2: Distributed energy resources



Large scale generation will continue to play a role in meeting Australia's energy needs with large scale renewables integrated into the network supporting the prospect of Australia's electricity sector achieving zero net carbon emissions by 2050.

We have been receiving more connection enquiries from renewable generators than ever before, with some significant proposals in the North West Tasmanian region. We must be ready to address these enquiries and provide the network capacity required to support increased generation while minimising overall costs for all our customers.

The flat consumption based network tariffs, which have been applied to residential and small business customers in the past, are no longer fit for purpose. Many of our existing network tariffs have their origins in old retail pricing structures which were designed to encourage greater use of energy, without considering the network impacts. In addition, discounted network tariffs were provided to some customer groups at the expense of other customers. As a result, like other network businesses around Australia, we need to change the way we price some of our services so that the prices we charge are more reflective of our underlying costs of operating the network.

At the other end of the market, there are a few major industrial users of electricity who use over half of the electricity consumed in Tasmania. These customers play a vital role in the Tasmanian economy and low energy costs are important to their on-going viability.

Looking forward, we're embarking on a joint study with the Australian Renewable Energy Agency (**ARENA**) into the feasibility of a second Bass Strait interconnector, to help support increased renewable generation connectivity for the NEM.

Interconnection with the NEM is perhaps the most significant strategic issue facing Tasmania over the medium to long term. Greater interconnection could create more revenue opportunities for Tasmanian generators through higher prices in the NEM, although it could also increase prices in Tasmania. It would also require augmentation of the Tasmanian transmission network to facilitate the increased energy flows.

In such a dynamic context, Tasmania's and indeed Australia's energy future may unfold in many different ways. No-one has perfect foresight on what may occur. That's why we've worked with Energy Networks Australia (**ENA**) and CSIRO to develop the Electricity Networks Transformation Roadmap[1], which sets out a pathway for the transformation of electricity networks over the next decade that accommodates the rapid uptake of new technologies and supports better customer outcomes. This pathway has been reinforced by Dr Alan Finkel's review into the future security of the National Electricity Market[2], where 49 of the 50 recommendations were incorporated and subsequently adopted by the Federal Government.

We have also developed our own vision for 2025, which describes how we see our future role in the new energy environment and will help guide our short- and medium-term expenditure plans. It reflects how we expect the use of our networks to change as customers continue to transition to clean energy.

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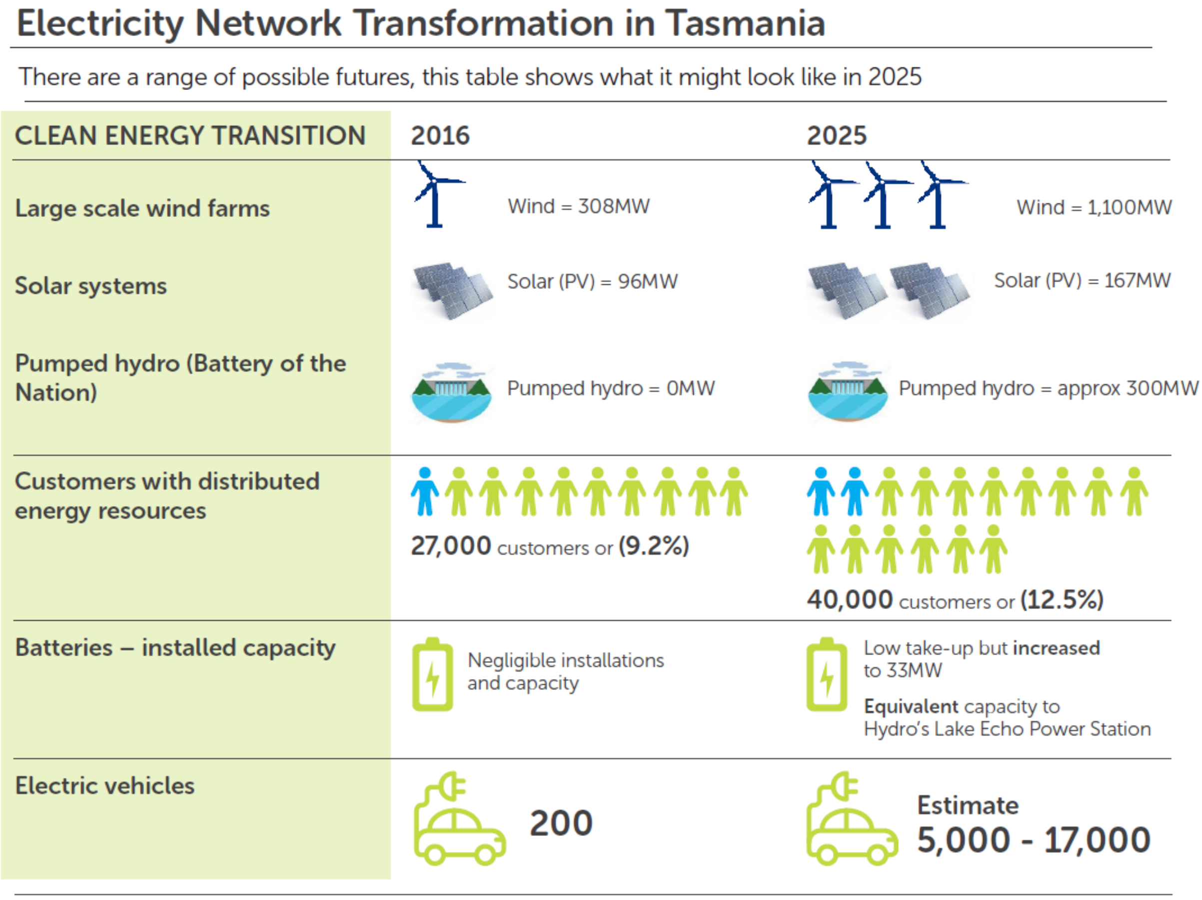
1 For further information please refer to the following link: http://www.energynetworks.com.au/electricity-network-transformation-roadmap

2 For further information please refer to the following link: https://www.environment.gov.au/system/files/resources/1d6b0464-6162-4223-ac08-3395a6b1c7fa/files/electricity-market-review-final-report.pdf

Figure 3 – Tasmanian network transformation



In preparing this Regulatory Proposal we have taken a balanced approach to the unprecedented changes and uncertainty that lie ahead. Specifically, we need to deliver the services that our customers want at network prices that are affordable. Equally, we must make appropriate plans for the future so that we are equipped to meet our customers' changing needs and drive innovation by investing in new technology where it is cost effective to do so.

We have heard loud and clear that our customers consider service levels and reliability to be generally acceptable, but affordability is their primary concern. Our customers expect us to make a clear case for any expenditure decisions that will increase prices. We have taken this feedback into account in finalising this proposal, by ensuring that our expenditure is aimed at *maintaining* current overall performance while meeting our safety and compliance obligations. In addition, compared to our provisional Revenue Proposal[3] we have taken the following specific measures to minimise price impacts on our customers:

- the re-phasing of technology investments relating to market data management systems;
- a 5.0 per cent optimisation of the distribution network capital expenditure forecasts;
- a 0.5 per cent optimisation of the transmission network capital expenditure forecasts;
- a 5.0 per cent optimisation of the shared business services capital expenditure forecasts;

[3] For further information regarding our provisional Regulatory Proposal refer (TN175)

- bringing transmission into alignment with our distribution rate of return, resulting in a reduction to our transmission rate of return of 25 basis points;
- a reduced claim for the costs of additional obligations or 'step changes' that we expect to incur;
- efficiency savings to absorb cost increases from labour and customer growth;
- an additional one per cent annual reduction in our transmission and distribution operating expenditure forecasts for the final three years of the regulatory control period, following on from a 0.5 per cent reduction in the previous year; and
- a rebalancing of our transmission revenue profile to provide a flatter price path over the period.

This package of measures will reduce transmission and distribution revenues, in nominal terms, by $29.8 million and $28.4 million respectively compared to our provisional plans[4]; or $58.2 million in total over the forthcoming regulatory control period. We believe this is a proposal that our customers and the AER can accept and that delivers outcomes consistent with the themes we heard during our customer consultation activities.

Customer engagement and guiding themes

For our 2017-19 distribution review, we developed a customer engagement framework using international best practice models. The framework requires tailored engagement approaches for particular customer groups. In this combined review, our approach differed across our transmission and distribution customers as follows:

- Our transmission customers, being generators and industrial customers, make a significant contribution to the Tasmanian economy. We engaged with these customers through one-on-one discussions and small workshops where appropriate. The majority of generators and industrial customers chose to engage in our process.
- For our distribution customers, we have undertaken a range of activities to gather feedback and understand their concerns. These activities include workshops, public forums and quantitative expenditure and charging analysis. We're also conducting a number of trials, including the commencement of a two-year trial of interval metering and demand based time of use tariffs involving some 600 residential customers, and a trial of solar panels, batteries and advanced energy management systems for approximately 40 customers on Bruny Island.

Based on the feedback received from customers, we developed and explored the following themes for this proposal:

1. ensuring the safety of our customers, employees, contractors, and the community;
2. keeping the power on, maintaining service reliability, network resilience and system security;

[4] For further information regarding our provisional Regulatory Proposal refer (TN175)

3. delivering services for the lowest sustainable cost;
4. improving how we communicate with, and listen to, our customers;
5. innovating in a changing world; and
6. bringing the community on the journey of pricing reform.

These themes have shaped our proposed expenditure and pricing arrangements for the forthcoming regulatory period, which are summarised below.

Transmission

Our focus for the transmission network in the forthcoming regulatory period is on:

- renewing assets in poor condition, primarily through a program-based approach;
- implementing a long-term renewal strategy for the southern 110 kV network, which is linked to Hydro Tasmania's generation renewal;
- managing our capital expenditure to reduce price impacts on our customers;
- facilitating more efficient workforce and outage planning;
- maintaining the system security, and supporting the clean energy transition through:
  - appropriate connection standards;
  - voltage and ancillary services support; and
  - identifying the planning considerations associated with a second Bass Straight interconnector.

We are also continuing to invest in information technology and communications technology across our business. We have a number of duplicated systems as a legacy of merging the transmission and distribution businesses. These systems are being replaced as we move into a more complex operating environment, in which technology will play an increasingly important role in supporting good customer outcomes at the lowest sustainable cost.

The table below provides a comparison of our forecast transmission capital expenditure for the forthcoming regulatory period and our actual expenditure in the current period. It shows that our primary focus is on renewal capital expenditure to ensure that we maintain network safety and reliability. As already noted, we have applied a 0.5 per cent optimisation to our provisional Revenue Proposal[5] transmission capital expenditure plans, in response to customer concerns regarding affordability and anticipated efficiencies in delivery.

[5] For further information regarding our provisional Regulatory Proposal refer (TN175)

Table 1: Actual and forecast transmission capital expenditure by category (June 2019 $m)

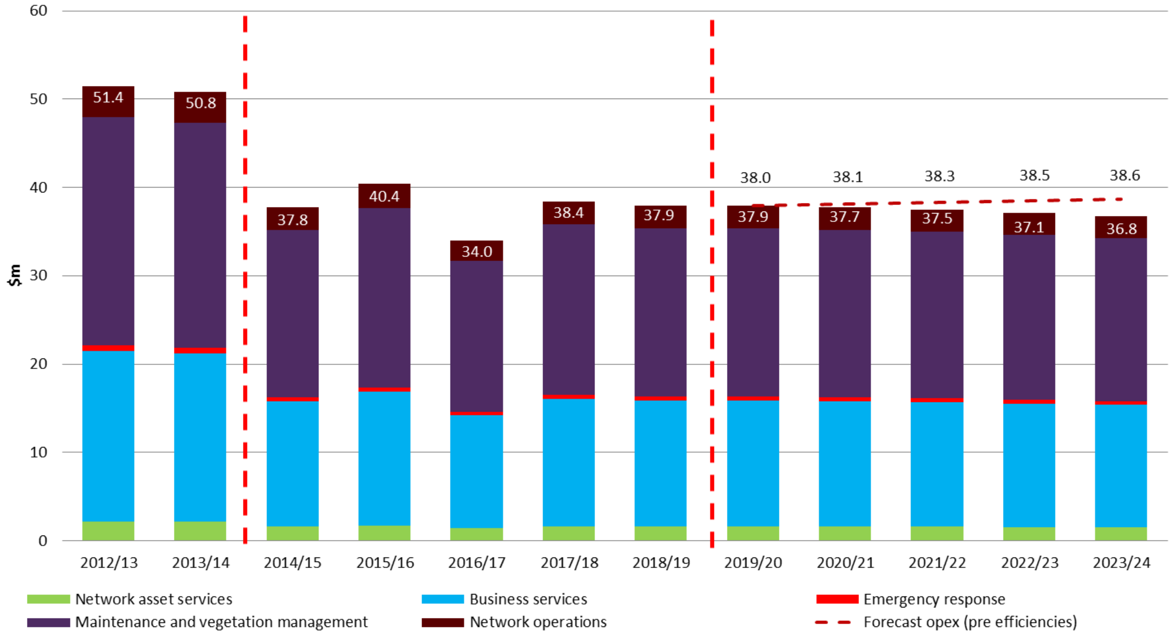
Category	Actual/Estimated expenditure for 2014-15 to 2018-19	Forecast expenditure for 2019-20 to 2023-24
Development	7.7	24.2
Renewal	154.5	204.5
Operational Support Systems	17.0	10.2
IT and Communications	23.1	14.3
Non-Network Other	9.0	7.3
Total	**211.3**	**260.6**

In the forthcoming regulatory period, our development capital expenditure on the transmission network primarily relates to the installation of a dynamic reactive power device at our George Town Substation to support more stable and efficient operation of our transmission network with changing generation and interconnector flows, and to allow dispatch of lower cost generation. This project alone will increase our level of development capital expenditure when compared to the current period, in which little development capital expenditure has been required.

In relation to transmission operating expenditure, we are continuing to seek efficiency savings in the forthcoming regulatory period, even though our costs already benchmark well against our peers. Our approach is to constrain our operating expenditure increases below the rate of inflation. To achieve this outcome, we are absorbing a number of the additional costs or 'step changes' that we expect to incur as a result of new regulatory obligations. We are also seeking efficiency improvements to offset the expected increase in labour costs during the regulatory period and the additional costs associated with serving a growing load and generator customer base.

As a result, we are confident that our proposed transmission operating expenditure allowance will be accepted by our customers and the AER as being prudent and efficient.

Figure 4: Actual and forecast transmission operating expenditure 2012-13 to 2023-24 (June 2019 $m)[6]



The table below summarises the transmission revenue building block calculation for each year of the forthcoming regulatory period, alongside the final year of the current period (2018-19).

Table 2: Summary of our Transmission Revenue Requirements and X Factors ($m nominal)

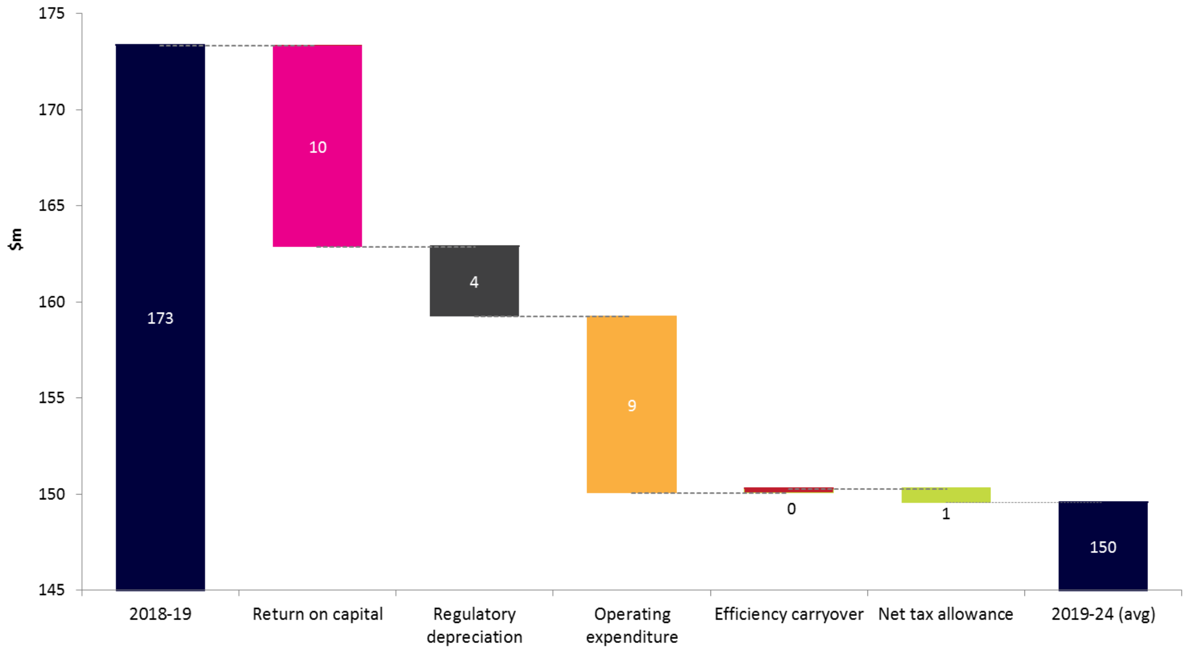
	2018–19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Return on Capital	96.9	86.4	87.7	90.4	93.2	94.7	452.4
Regulatory Depreciation	27.4	18.6	22.2	24.4	27.9	31.8	124.9
Operating expenditure (incl. Debt Raising)	48.8	39.9	40.7	41.4	42.0	42.6	206.7
Efficiency carry over[7]	0.0	7.0	-1.5	0.1	-5.3	0.3	0.7
Net tax allowance	4.6	3.2	3.5	3.9	4.5	5.1	20.1
Transmission Requirement (unsmoothed)	177.7	155.1	152.5	160.2	162.3	174.5	804.7
Transmission Revenue Requirement (smoothed)	**172.9**	**168.4**	**164.1**	**159.8**	**155.7**	**151.6**	**799.6**
X factor (percentage)	**2.00%**	**4.92%**	**4.92%**	**4.92%**	**4.92%**	**4.92%**	

6 This figure presents operating expenditure excluding debt raising costs

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

The figure below shows the change in transmission revenue requirements from the current to forthcoming regulatory periods.

Figure 5: Transmission revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



A major component of our revenue allowance is the return on our regulatory asset base and the recovery of its depreciation over time. Our approach to depreciation of our transmission assets is consistent with the Rules and is the same method that we apply to our distribution assets.

In relation to the rate of return on our regulatory asset base, represented by the Weighted Average Cost of Capital (**WACC**), we are proposing for this review that the WACC applying to our transmission and distribution networks be aligned for the forthcoming regulatory period. Based on past revenue determinations, this means that our rate of return on transmission assets is likely to be lower than might otherwise be determined by the AER. As a result, we have reduced our revenue requirement to deliver the more affordable pricing outcomes set out in our proposal. Furthermore, as distribution customers also benefit from our transmission network services, this decision will benefit all of our customers.

Distribution

In the case of our distribution network, our focus in the forthcoming regulatory period will be on maintaining current levels of reliability and ensuring network safety while increasing efficiencies, and continuing the process of network pricing reform. In the forthcoming regulatory period, we will:

- continue to apply our current asset management strategies.
- increase investment to manage safety related risks, driven by:
  - pole renewal requirements over the next ten years;
  - bushfire mitigation standards;
  - enhanced vegetation management to combat increased bushfire and outage risks;
  - enhanced service connection inspection and renewal; and

- improvements to our storm response.

- increase investment in technology to provide more timely information to customers and facilitate network management, including implementation of a Customer Relationship Management (**CRM**) system, the provision of better information about planned outages and website portals.
- establish new connection standards for two way flows of electricity for micro-embedded generation, electric vehicles and batteries, and support two way flows on the distribution network.
- enable customer choice between traditional network solutions and alternatives such as distributed energy generation.

The following table provides a comparison between our forecast distribution capital expenditure for the forthcoming regulatory period and our actual expenditure in the current period.

Table 3: Actual and forecast distribution capital expenditure, inclusive of customer capital contributions by category (June 2019 $m)

Category	Actual/Estimated expenditure for 2014-15 to 2018-19	Forecast expenditure for 2019-20 to 2023-24
Development	132.2	124.0
Renewal	302.1	463.1
Operational Support Systems	32.0	22.0
IT and Communications	78.5	103.8
Non-Network Other	24.4	25.9
Total	**569.2**	**738.8**

As already noted, we have applied a 5.0 per cent optimisation to our provisional Revenue Proposal[8] distribution capital expenditure plans to ensure that our prices are as low as sustainably possible, without compromising the long term safety and reliability of our network. Despite this further optimisation, the table shows that we intend to increase our renewal capital expenditure in the forthcoming regulatory period. This increased expenditure is required to address our ageing asset base and the associated safety risks

The figure below shows that our distribution operating expenditure increased in 2016-17. Our increased expenditure has been necessary to address emerging risks on our distribution network, such as the bushfire risks posed by vegetation, especially in light of experiences interstate.

As better information became available, we concluded that bushfire and asset-related risks were higher than previously understood. Therefore, we acted prudently to address these risks by

[8] For further information regarding our provisional Regulatory Proposal refer (TN175)

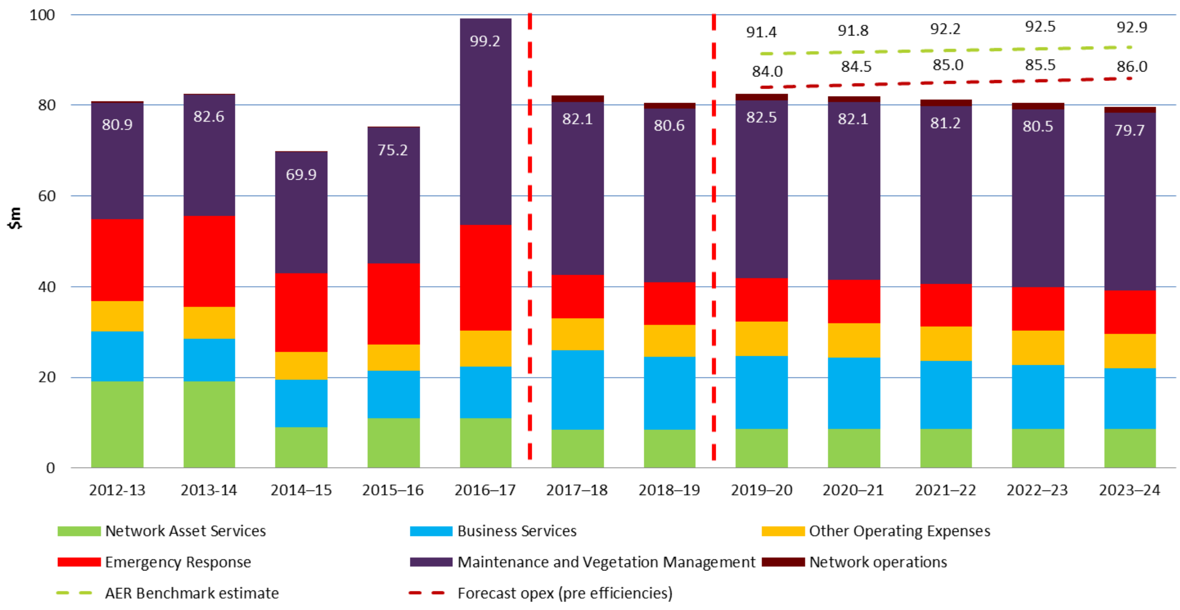
increasing operating expenditure, at the expense of the return to our shareholders rather than our customers.

While we believe that distribution operating expenditure can return to lower levels, it will take time to do so without compromising network safety and performance. Our view is that this lower level of operating expenditure can only be achieved if it is supported by improved processes, practices and business platforms to offset the range of new obligations and increased complexity associated with providing distribution services to a diverse and changing customer and generation base. We are striving to deliver the required efficiency improvements over the course of the current and forthcoming regulatory period.

Our distribution operating expenditure forecasts are projections based on our forecast costs in 2017-18, which we expect to be lower than 2016-17. We have, therefore, chosen to adopt the lower year as our efficient base year, as we consider that this better reflects our future operating expenditure requirements.

There are a number of new obligations that will continue to put upward pressure on our distribution operating expenditure in the forthcoming regulatory period. We are committed to finding efficiency savings that will constrain increases in our operating expenditure to around the rate of inflation. In effect, this means that we are aiming to absorb the cost pressures associated with factors such as increasing labour rates and growth in the customer base, factors that the AER typically accepts in its regulatory determinations as legitimate drivers of higher operating expenditure.

Figure 6: Actual and forecast distribution operating expenditure 2012-13 to 2023-24 (June 2019 $m)



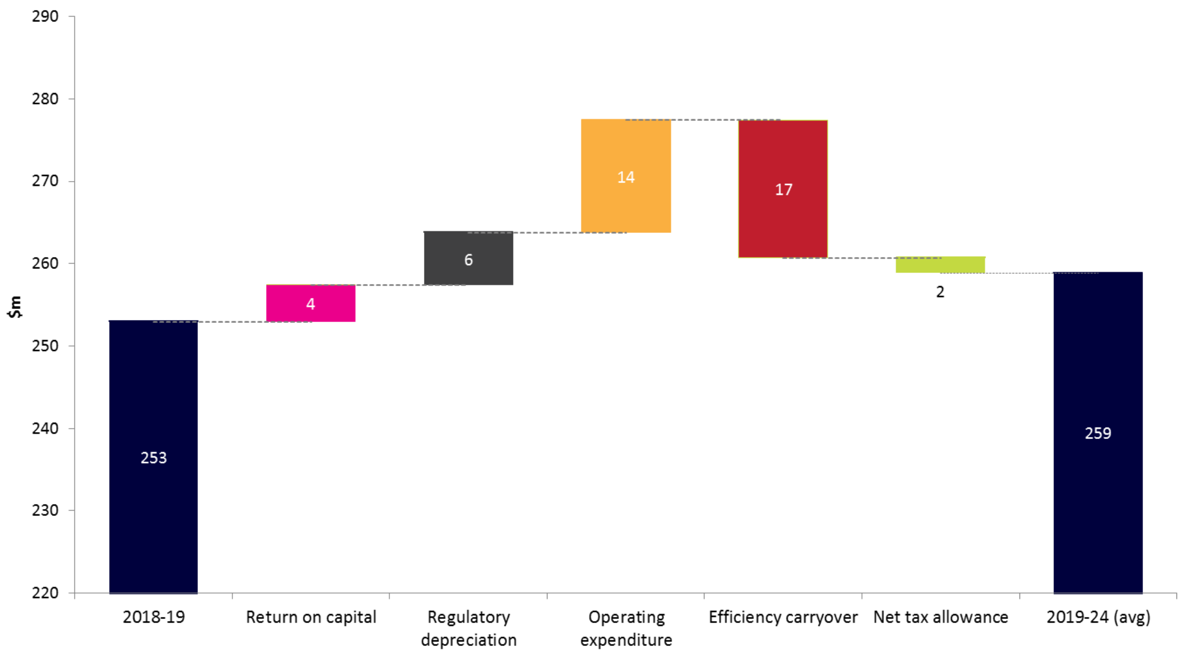
The table below summarises the distribution revenue building block calculation for each year of the forthcoming regulatory period alongside the final year of the current period, which is 2018-19.

Table 4: Summary of our Distribution Revenue Requirements and X Factors ($m nominal)

	2018–19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Return on Capital	101.9	103.3	109.4	115.1	119.7	125.1	572.7
Regulatory Depreciation	57.6	57.7	63.3	69.8	74.6	80.0	345.4
Operating expenditure (incl. Debt Raising)	68.4	85.4	87.7	88.4	89.7	91.0	441.5
Efficiency carry over[9]	12.8	-11.2	-11.4	-11.7	14.0	0.5	-19.8
Net tax allowance	12.2	10.1	10.4	11.0	11.7	12.4	55.7
Distribution Requirement (unsmoothed)	252.9	245.3	258.9	272.6	309.6	309.0	1,395.4
Distribution Revenue Requirement (smoothed)	**241.6**	**252.9**	**265.1**	**277.9**	**291.3**	**305.4**	**1,392.7**
P0 and X factors	**0.00%**	**-2.20%**	**-2.32%**	**-2.32%**	**-2.32%**	**-2.32%**	

The figure below shows the change in distribution revenue requirements from the current to forthcoming regulatory period.

Figure 8: Distribution revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



A major component of our revenue allowance is the return on our regulatory asset base and the recovery of its depreciation over time. These components will experience some growth during the

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

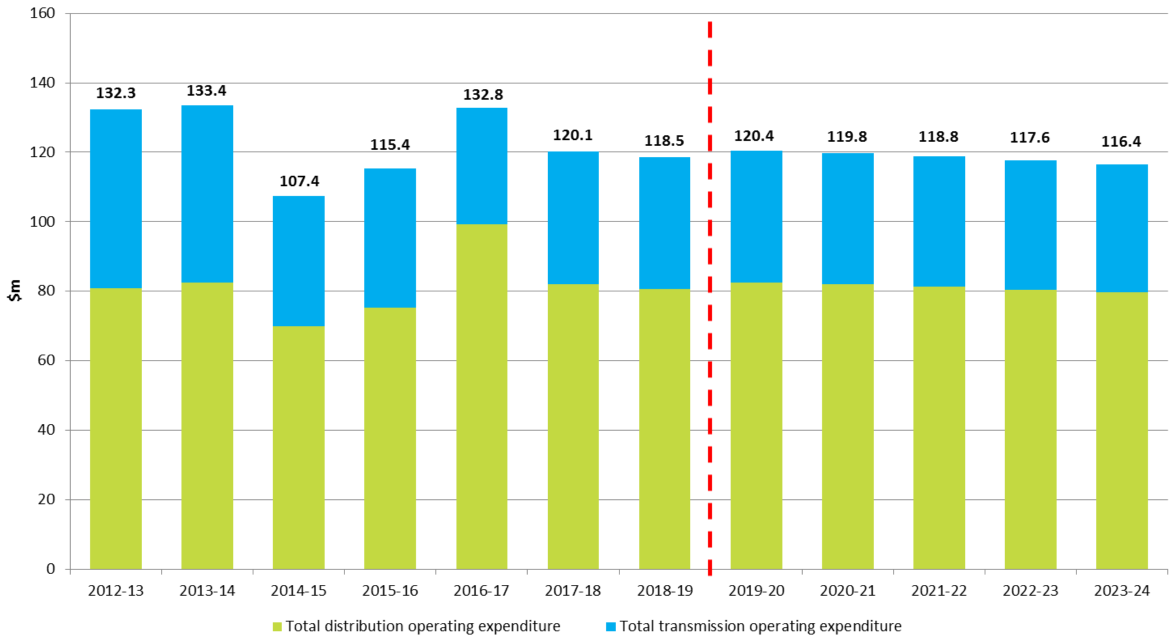
period which reflects ongoing investment in the distribution network to ensure network performance and safety.

Another contributing factor to our proposed modest increase in average distribution revenue is our forecast increase in operating costs as compared to the amount allowed by the AER for the 2017-19 regulatory period. This forecast increase is necessary to address the emerging issues on our distribution network.

Our combined operating costs

As shown in the figure below, our forecast combined operating expenditure remains substantially lower than historical levels. This demonstrates that the merger of two network businesses to create TasNetworks in 2014 has realised a significant reduction in operating expenditure through consolidation and scale economies together with the delivery of operational efficiencies.

Figure 7: Combined transmission and distribution operating expenditure 2012-13 to 2023-24 (June 2019 $m)

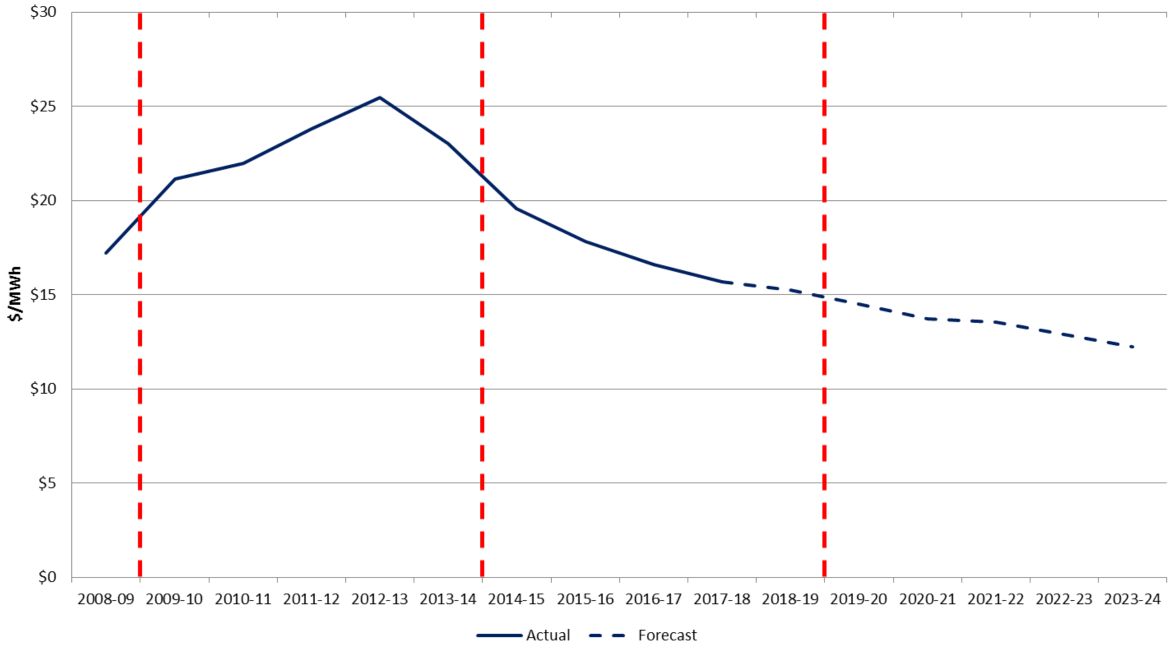


Looking forward, we will be working hard to minimise upward price pressure on our customers by continuously pursuing savings through process improvements that deliver operating efficiencies. However, in doing so, we will not compromise safety or reliability for our customers. We are not prepared to make unsustainable reductions in our expenditure in the short term that would lead to higher costs for customers in the future.

Customer pricing outcomes

The reducing transmission revenue profile means that transmission prices (in real terms) should drop at the end of the current regulatory control period and then remain relatively consistent over the 2019-24 period in nominal terms and continuing to fall in real terms. This is shown in the figure below. The transmission revenue profile translates to an average price of $13.69 per MWh over the forthcoming regulatory period, which is 21 per cent lower than the current five year period.

Figure 9: Indicative average transmission charges ($/MWh) (June 2019 $)

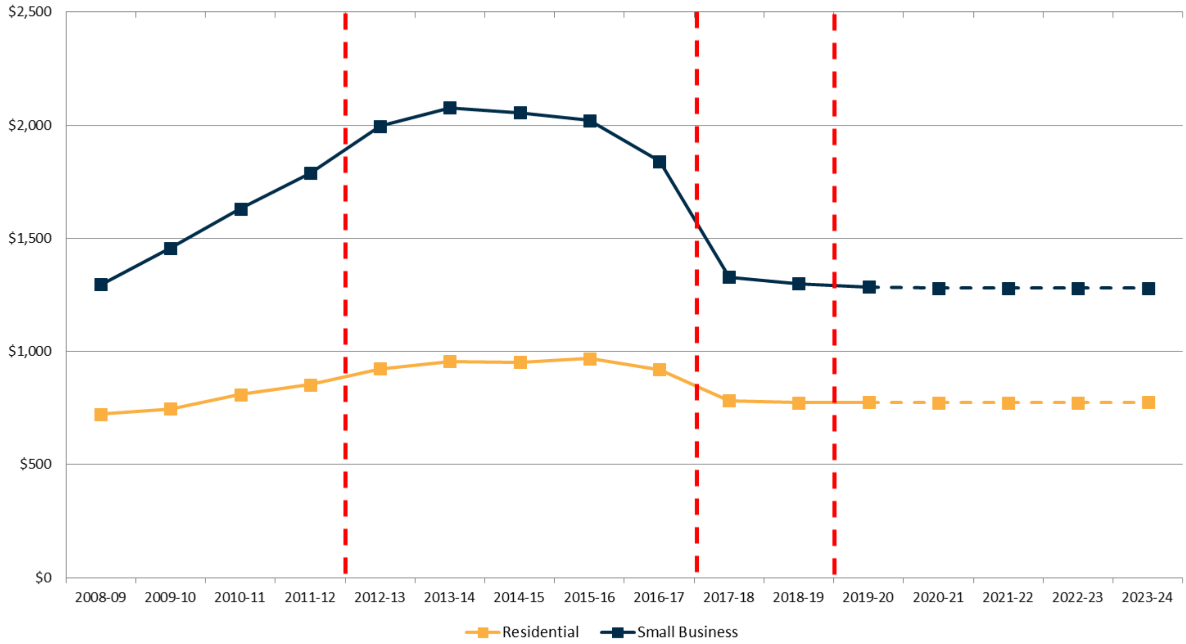


The distribution revenue allowance for each year, together with relevant share of the transmission network charges (around 55 per cent), is recovered from our distribution customers. Our combined transmission and distribution charges are recovered through a framework of network pricing "tariffs" which are applied to each customer and charged to retailers.

Transmission and distribution network costs presently make up around 43 per cent of the typical Tasmanian residential and small business customer's electricity bill. The chart below shows the projected annual network charges for typical residential and small business customers, based on our expenditure proposals.

The forecast customer charge includes forecast transmission charges and distribution charges. The scenarios assume no over or under-recoveries or incentive adjustments.

Figure 10: Indicative average annual network charges per annum (June 2019 $)



Distribution Pricing Strategy

In this 2019-24 period, we will continue to move towards more cost reflective pricing by:

- continuing to progressively reduce longstanding cross subsidies between customers and between tariffs;
- introducing two new demand based time of use tariffs to give residential and small business customers who invest in distributed energy resources (**DER**) like solar generation, batteries and electric vehicles new opportunities to control their electricity costs;
- providing an 'introductory' discount for the off-peak charge component of the demand based time of use tariffs for residential and small business customers, including the tariffs introduced during the current regulatory period, to encourage customers to choose them;
- introducing two new tariffs for embedded networks;
- collecting advanced meter and trial data to help us better manage customer impacts in future phases of network tariff reform; and
- ensuring that we offer tariffs for new energy technologies and customer types.

Our aim is to promote a customer led shift to demand based time of use network tariffs, while transitioning all of our tariffs to reflect efficient costs without creating price shocks for our customers. This will remove any cross subsidies between existing tariffs, between classes of customers and within classes of customers.

Our customers have told us they expect us to engage with electricity retailers to ensure that more cost reflective network pricing is offered to Tasmanian customers. To that end, we will continue to work with retailers and the Tasmanian Economic Regulator to progress our pricing strategy and ensure that our new and adjusted network charges are incorporated into the retail tariffs offered to customers in future.

Over the next five years we aim to improve the quality of information available to support future pricing strategy refinement and help customers understand how they might benefit from new types of network tariffs. This information will reflect the learnings gained from the emPOWERing You and CONSORT Bruny Island trials, and will include an extensive database of interval metering data.

More information is available on our website at: https://www.tasnetworks.com.au/customer-engagement/tariff-reform/

1 Introduction

1.1 Purpose of this document

Under the National Electricity Law (**NEL**) and the National Electricity Rules (**the Rules**), the AER is responsible for the economic regulation of electricity transmission and 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 transmission and distribution services. The regulatory period covered by this Regulatory Proposal commences on 1 July 2019 and ends on 30 June 2024.

Our Regulatory Proposal includes:

- an overview paper which explains the Regulatory Proposal in plain language and how our customer engagement has informed our proposal;
- our transmission pricing methodology;
- 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 Notices (**RIN**).

1.2 Overview of service classification

Under the Rules, the various services we provide are subject to classification which 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.

For transmission services, classification is determined by the Rules, which define the different types of services we provide and how they should be regulated. However, the AER classifies distribution services in accordance with criteria specified in the Rules.

The tables below provide an overview of the different classes of transmission and distribution services for the purposes of economic regulation under the Rules. The AER has proposed a service classification for our distribution services in its Framework & Approach Paper for the forthcoming regulatory period and we accept the AER's proposed classification, with one exception. The AER proposed that the provision of extension services (connection services) should remain classified as an Alternative Control Service. However, extension services are currently classified as a Standard Control Service as detailed in our approved Connection Policy.

We consider that the current classification of extension services as a Standard Control Service should be maintained, in accordance with clause 6.2.1(d)(1) of the Rules, which states that there should be no departure from an existing classification unless a different classification is clearly more appropriate.

Table 1-1: Classification of transmission services

Classification	Description	Regulatory treatment
Prescribed transmission services	Shared transmission services at "standard" service levels. Services required by legislation or the Australian Energy Market Operator (**AEMO**), or which are required to ensure the integrity of the transmission system. Connection services to another Network Service Provider	The AER regulates these services by setting a revenue cap. The pricing of individual services is determined in accordance with the pricing rules in Chapter 6A of the Rules.
Negotiated transmission services	Shared transmission services that exceed "standard" service levels, excluding investments that have system-wide benefits. Connection services to a Transmission User, but not including connection services to another Network Service Provider. Negotiated use of system charges paid by a connection applicant for any network augmentations required to be undertaken to facilitate connection.	Prices are set by negotiation, conducted in accordance with the negotiating principles in Chapter 5 of the Rules.
Non-regulated transmission service	A transmission service that is neither a prescribed transmission service nor a negotiated transmission service.	The AER has no role in regulating these services.

Table 1-2: 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 setting a revenue cap. Distribution tariffs are set to recover the maximum allowed revenue in accordance with pricing principles set out in the Rules
	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.
Unclassified service		Services that are not distribution services or services that are contestable.	The AER has no role in regulating these 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 transmission and distribution expenditure plans for the forthcoming regulatory period.
- Part Two focuses on our transmission and distribution services that are subject to revenue cap regulation. We commence Part Two by explaining what our customers have told us about our transmission and distribution services and how we can improve.

  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 our transmission and distribution tariffs are set 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, which are customer-specific distribution services (e.g. public lighting provided to a particular council), customer-requested services (e.g. de-energisation), services that are potentially subject to competition (such as some connection services) or legacy metering services.
- Part Four explains our proposed cost pass through arrangements, our connection policy and negotiating framework. It also addresses the confidentiality and certification requirements in the Rules.

This Regulatory Proposal is consistent with AEMO's National Transmission Network Development Plan, which was published in December 2016.

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

1.4 Global assumptions

In preparing this Regulatory Proposal, we have adopted a number of assumptions and guiding principles in relation to our capital and operating expenditure forecasts. These assumptions and principles are:

- The direction outlined in TasNetworks' 'Strategy on a Page 2017-18' and 'TasNetworks' Transformation Roadmap 2025' will underpin our strategic direction across the forthcoming regulatory period.
- We will adopt an innovative approach to network development and operation that delivers customer outcomes at the lowest sustainable price for our business.
- We will meet our compliance obligations, including those relating to reliability requirements, physical security, safety, environment, risk 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 practice and reasonably reflect our future expenditure requirements.
- We will have the resources and capability to deliver the programs forecast for the forthcoming regulatory control period.
- Our forecasts of escalation rates are reasonable.
- Any material cost changes arising from amendments to the legislative and regulatory framework in the forthcoming regulatory period will be eligible for pass-through. Therefore, our forecasts do not include provision for any such changes.
- The potential financial impacts of Australian Energy Market Commission (**AEMC**) reviews concluded after September 2017 and before we submit our proposal, including the System Security Market Frameworks Review and the Inertia Rule change, have not been included in this Regulatory Proposal. We will revisit our expenditure forecasts following the AER's draft decision, as the outcomes and expenditure implications arising from these reviews are better understood.
- There will be no changes to the Tasmanian rules and laws regarding the ownership of private infrastructure.
- The level of industry transformation, including significant changes in Australia's generation mix, is creating unprecedented levels of Tasmanian transmission and distribution generation connection activity. Given this uncertainty, and impacts on our forecast expenditure and contingent project requirements, our 2018 Annual Planning Report is likely to include updated forecasts to those in our revenue proposal. If there are material changes, we will revisit our expenditure and contingent project forecasts following the AER's draft decision.

In accordance with the Rules' requirements, the Board of TasNetworks has 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 expenditure in this proposal reflects our cost allocation methodology, as approved by the AER, and is 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 2019 dollars;
- where data is presented in nominal terms, an inflation forecast of 2.45 per cent per annum has been applied; and
- numbers in tables may not add up due to rounding.

Part One: Background

Part One of the Regulatory Proposal sets out background information, which is relevant to both our regulated transmission and distribution services. It provides information about our customers; the electricity sector in Tasmania, including the transmission and distribution networks; and our role and organisation structure. We explain that we operate as an integrated transmission and distribution business, aiming to deliver more efficient network solutions for our customers.

We also discuss the transformation of electricity networks across Australia, which is being driven by technological change. This changing environment is providing customers with a much greater role in the sector, including in making decisions about how their energy needs are met.

2 Business and operating environment

2.1 About us

As Tasmania's integrated electricity network services provider, we have a focus on caring for our customers and making their experience easier. We have made great progress to deliver safe, reliable and secure services to our customers while keeping prices as low as possible. Our customers now receive higher network reliability and lower prices on average than when we started operating three years ago.

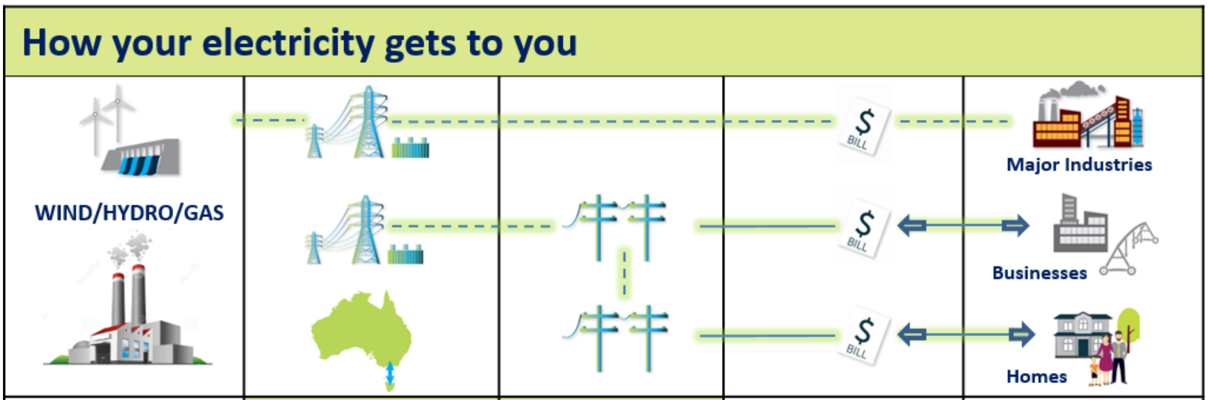
We own, operate and maintain the transmission and distribution electricity network that delivers electricity to more than 285,000 connected Tasmanian customers. In delivering our services, we seek to create value for our customers, our owners and our community.

Our integrated network comprises:

- transmission assets, which include 3,564 circuit kilometres of transmission lines and underground cables, 49 transmission substations and six switching stations; two transition stations; 11,176 hectares of easements; and 37 communications repeater sites; and
- distribution assets, which include 22,400 kilometres of distribution overhead lines and underground cables, 18 large distribution substations and 33,000 small distribution substations and almost 227,000 power poles. There is also 27,364 embedded generation and photovoltaic (**PV**) grid-connected installations connected to the distribution network.

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

Figure 2-1: How your electricity gets to you and our role



BIG GENERATION	TRANSMISSION	DISTRIBUTION	RETAIL	CONSUMERS
In Tasmania, the majority of electricity is currently generated by large generators at hydro dams, a gas-fired plant or via a number of wind farms in the NW and NE of the State.	Electricity is sent around the state using TasNetworks' high voltage transmission network. The Basslink undersea cable is also used to transmit electricity to and from Tasmania. Major industrial customers can connect directly to the transmission network.	When your electricity arrives at towns and cities it is converted to a lower voltage as it enters TasNetworks' distribution network to be sent to homes and businesses.	Retailers service homes and businesses by managing bills, connection requests and passing on TasNetworks' network charges.	The energy market place is also changing. Customers can now produce their own electricity by installing small scale renewable generation such as solar panels. The excess can be exported back into the network or stored in batteries for later use.

This Regulatory Proposal considers both our transmission and distribution services, and the revenue we need to provide these services, recognising that we operate as a single network business.

2.2 Our customers

A number of large industrial and commercial customers are connected directly to our transmission network. In fact, more than half the energy delivered in the state is transmitted to these major industrial customers. The balance of customers in the state are connected to our distribution network. The distribution network serves the following customer groups:

- residential customers comprise approximately 84 per cent of the customer base and 45 per cent of the electricity delivered by the distribution network;
- small businesses, 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; 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 remain committed to engaging with, informing and educating our customers about our activities and plans for the future.

We are prioritising customer engagement in our activities, including through the following initiatives:

- delivering our Voice of the Customer Program, ensuring that we consider our customers' perspectives and 'voice' in our activities and decisions;
- implementing a customer segmentation model and engagement framework;
- establishment of TasNetworks Customer Council and Pricing Reform Working Group with representation across our customer segments;
- adopting a dedicated Customer Service Strategy to assist us in sharpening our focus on delivering quality service outcomes for our customers;
- undertaking monthly customer satisfaction surveys; and
- undertaking monthly customer net promoter score surveys.

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

2.3 Our strategy on a page

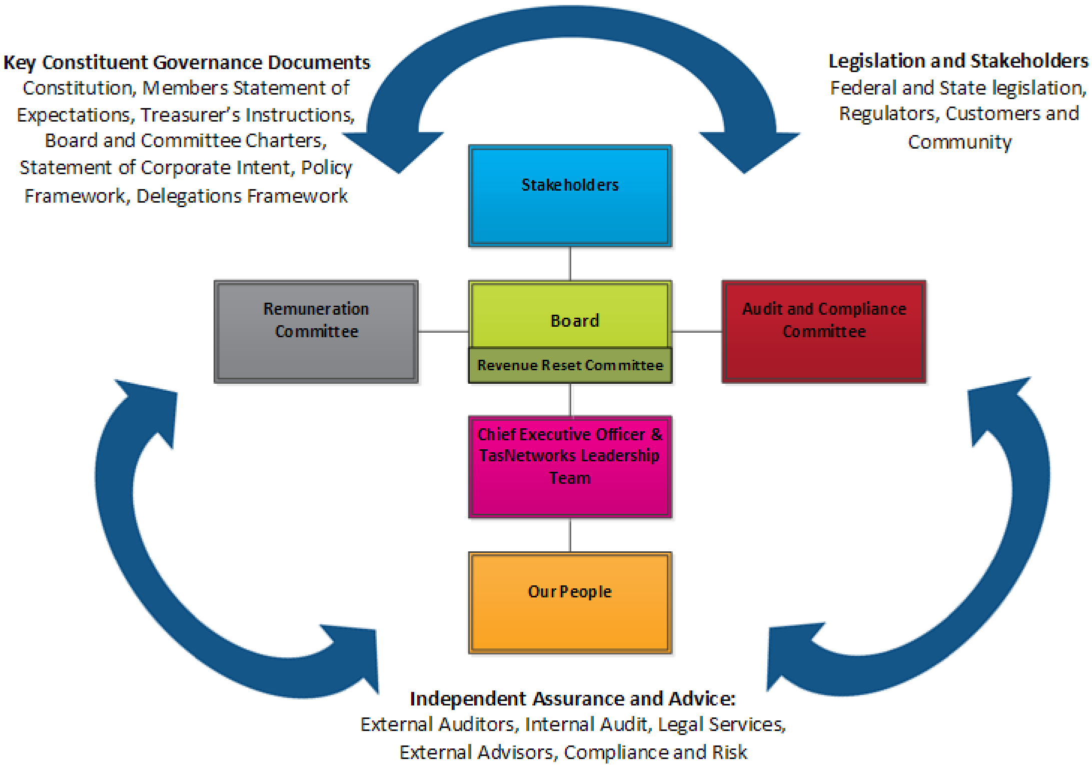
The figure below captures our 'strategy on a page', which guides our approach to the forthcoming and subsequent regulatory periods. It sets out our vision and purpose; explains how we work; and our strategic goals, measures and initiatives across the pillars of our strategy: our customers, our people, our business and our owners.

Figure 2-2: Strategy on a page 2017-18

2.4 Corporate governance

Our corporate governance structure is shown below.

Figure 2-3: Our corporate governance structure



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[10]. The company operates in accordance with this guidance, the TasNetworks Constitution and the Corporations Act 2001.

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.

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.

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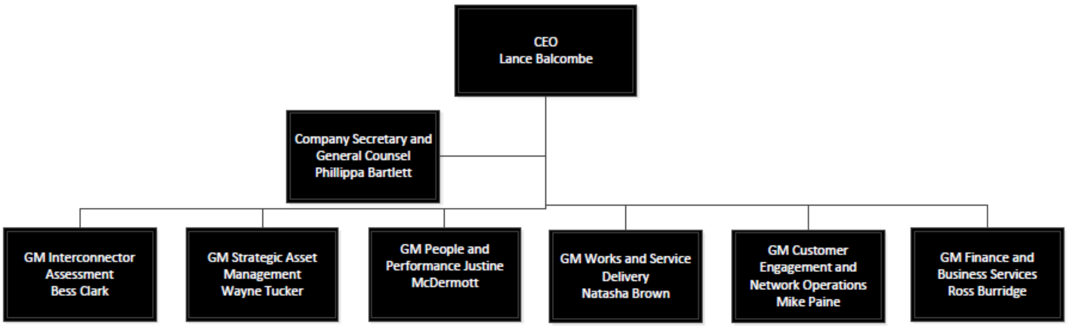
10 A copy of the Statement can be viewed at: http://www.tasnetworks.com.au/TasNetworks/media/pdf/electricity_network/tariffs/2014-15/Members-Statement-of-Expectations-Tasmanian-Networks-Pty-Ltd-1.pdf

2.5 Our organisational structure

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

Figure 2-4: Our organisational structure



2.6 Our regulatory environment

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

As noted in section 1.1, the AER is responsible for the economic regulation of both electricity transmission and distribution services in accordance with the National Electricity Law (**NEL**) and the Rules. The AER's economic regulation functions and powers include the:

- determination of our allowed revenues for a regulatory period; and
- design and application of various schemes to simulate competitive forces and 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 (**the Rules**). However, some provisions of the Code 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 sets out the 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 4, 8 and 9 of this Regulatory Proposal.

2.7 Key features of the Tasmanian transmission and distribution networks

The transmission network comprises:

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

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

A map of the transmission network is provided in the figure below.

Figure 2-5: Tasmanian transmission network

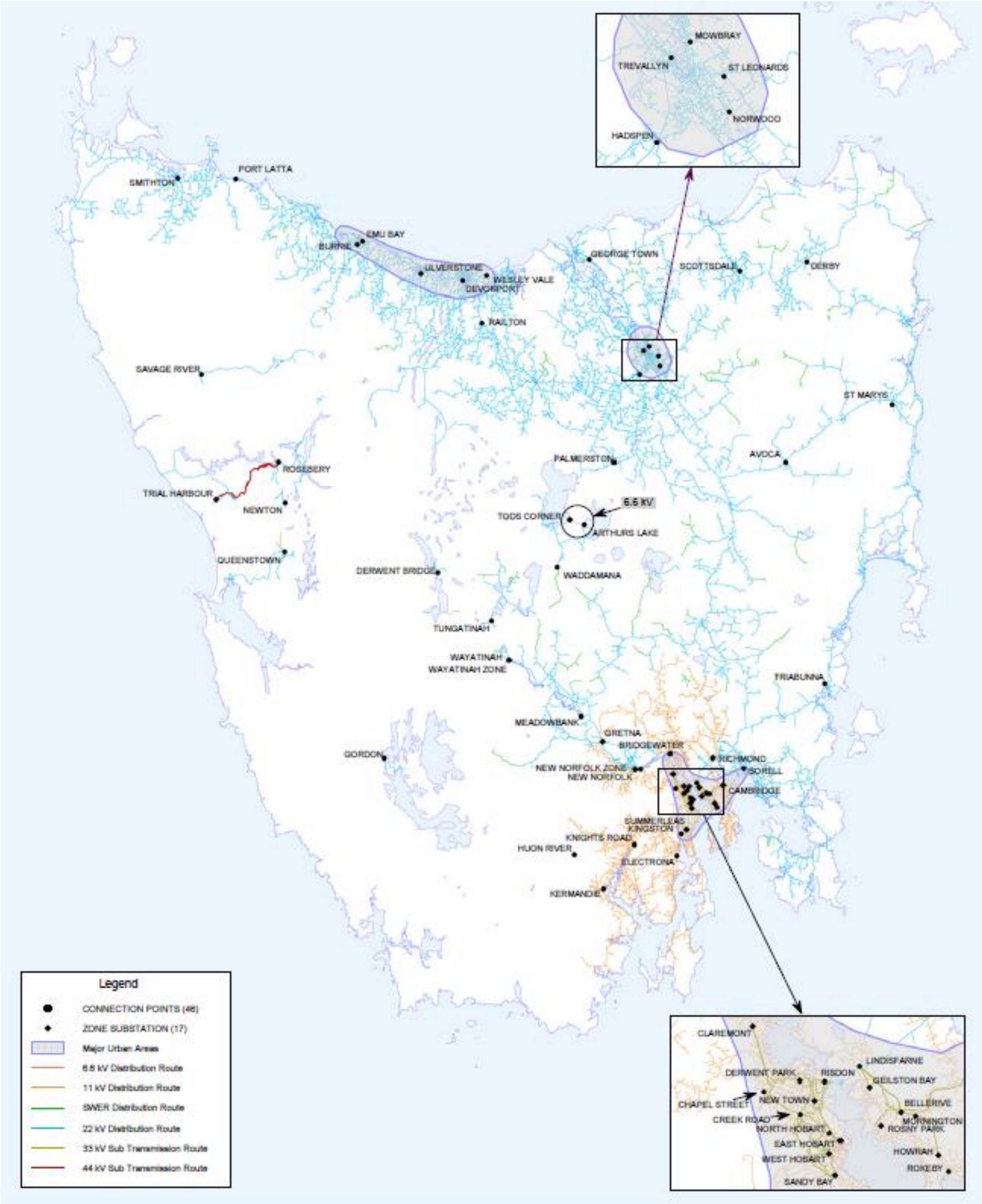
Note: The transmission lines between Smithton Substation and Bluff Point and Studland Bay wind farms, between Derby Substation and Musselroe Wind Farm, and between George Town Substation and George Town Converter Station are private transmission lines.

The Tasmanian distribution network comprises:

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

The figure below provides a geographical overview of the high voltage distribution network by voltage.

Figure 2-6: Tasmanian distribution network



2.8 Transformation on an unprecedented scale

The electricity system supporting Australia's modern economy and lifestyle is experiencing change on an unprecedented scale. The transformation is driven by customers as they embrace new technologies, take control of their energy use and support action on climate change.

By 2050, it is estimated that customers or their agents - not utilities - will determine how over $200 billion in system expenditure is spent and millions of customer owned generators will supply 30-50 per cent of Australia's electricity needs.

In the longer term, in a decentralised yet integrated energy future, we must be responsive to the changing demands for traditional services, while enabling new opportunities for energy resource sharing. By connecting growing numbers of customer generators and energy storage systems to each other, our network can act as a platform to help match supply and demand, facilitate future service offerings and reduce the cost of meeting our customers' energy needs.

We are starting to see a growing class of customers that can be termed 'early adopters'. These are households and businesses that make investments in electricity storage, generation, or management – collectively referred to as distributed energy resources (**DER**) – or electric vehicles (**EV**) which also create a form of mobile storage.

Figure 2-7 – Distributed energy resources

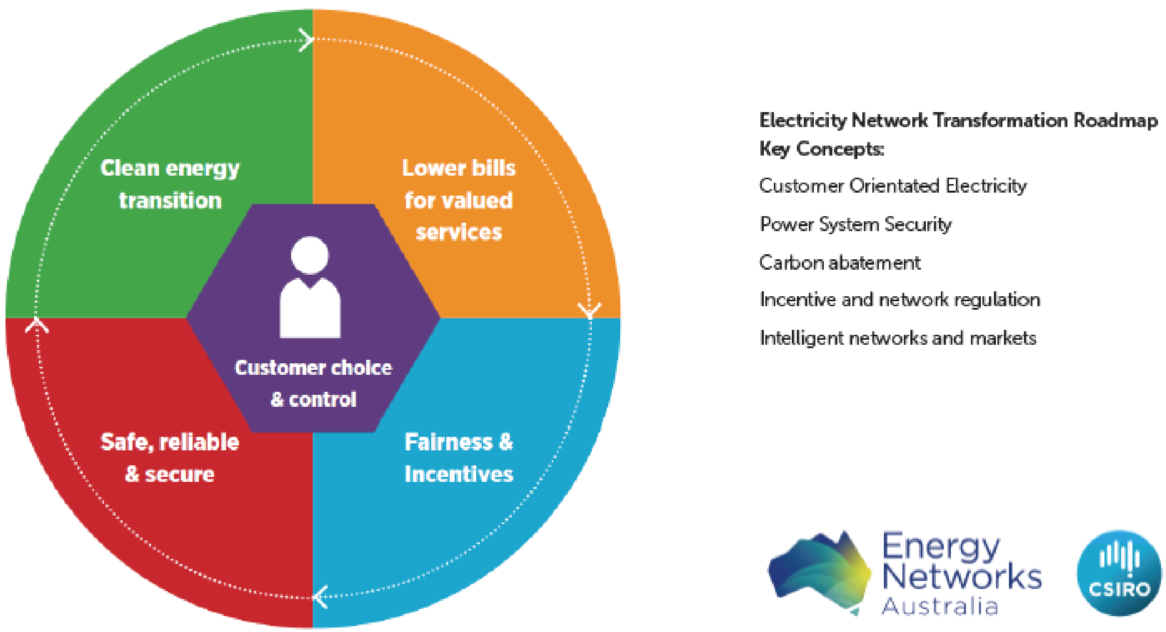
Large-scale generation will continue to play a role in meeting Australia's energy needs, with large scale renewable energy, integrated into the grid, supporting the prospect of Australia's electricity sector achieving zero net carbon emissions by 2050.

We are receiving more connection enquiries from renewable generators than ever before, including some significant proposals in Tasmania's North West. We must be ready to address these enquiries and provide the network capacity required to support increased generation while minimising overall costs for all our customers.

In such a dynamic context, Tasmania's and indeed Australia's energy future may unfold in many different ways. No-one has perfect foresight on what may occur. That's why we've worked with Energy Networks Australia (**ENA**) and CSIRO to develop the Electricity Networks Transformation Roadmap[11], which sets out a pathway for the transformation of electricity networks over the next decade and beyond. The Roadmap accommodates the rapid uptake of new technologies and supports better customer outcomes.

Many aspects of long term transition simply cannot be planned and will depend on the forces of innovation, disruption and competition. Taking a national perspective, the figures below apply the CSIRO's framework to show our current state and the preferred future state.

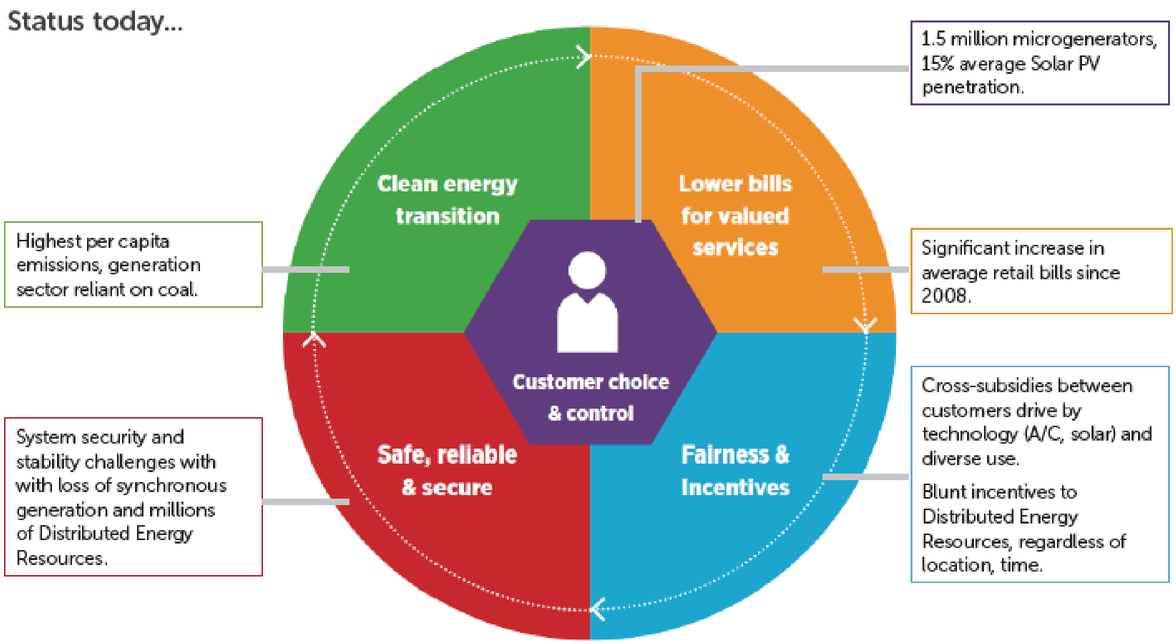
Figure 2-8: Electricity Networks Transformation Roadmap



The figure below applies the roadmap to explain the current state.

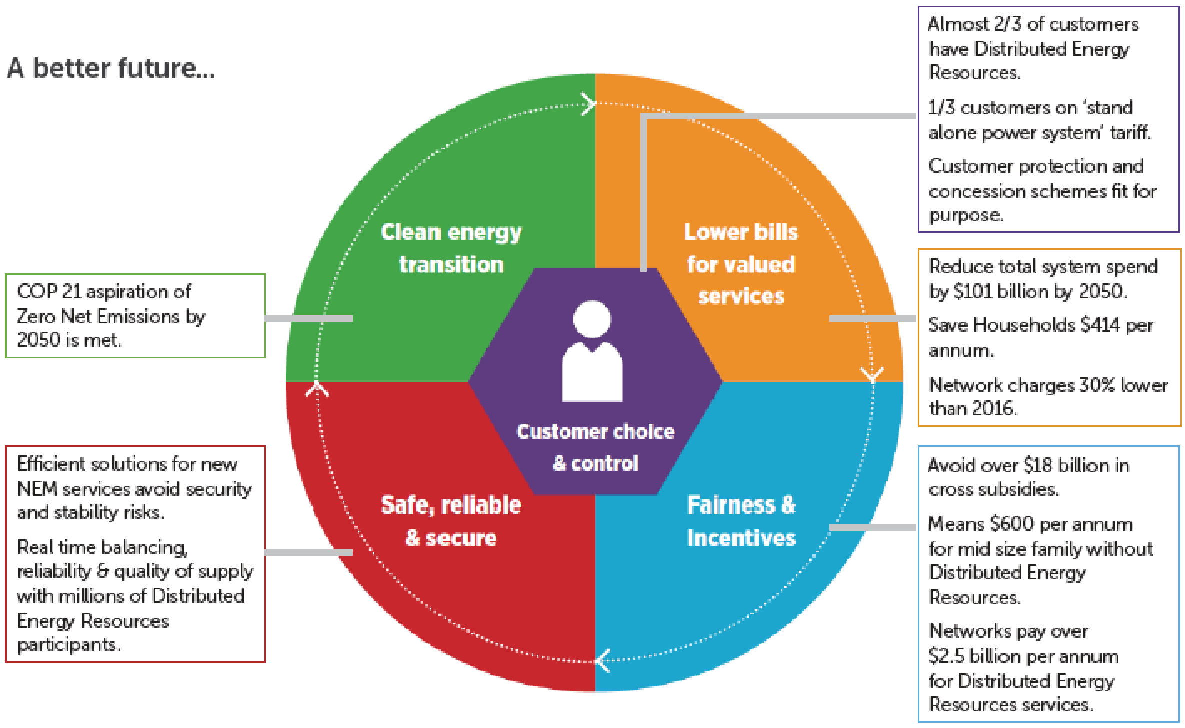
11 For further information please refer to the following link: http://www.energynetworks.com.au/electricity-network-transformation-roadmap

Figure 2-9: A National Perspective - Current State



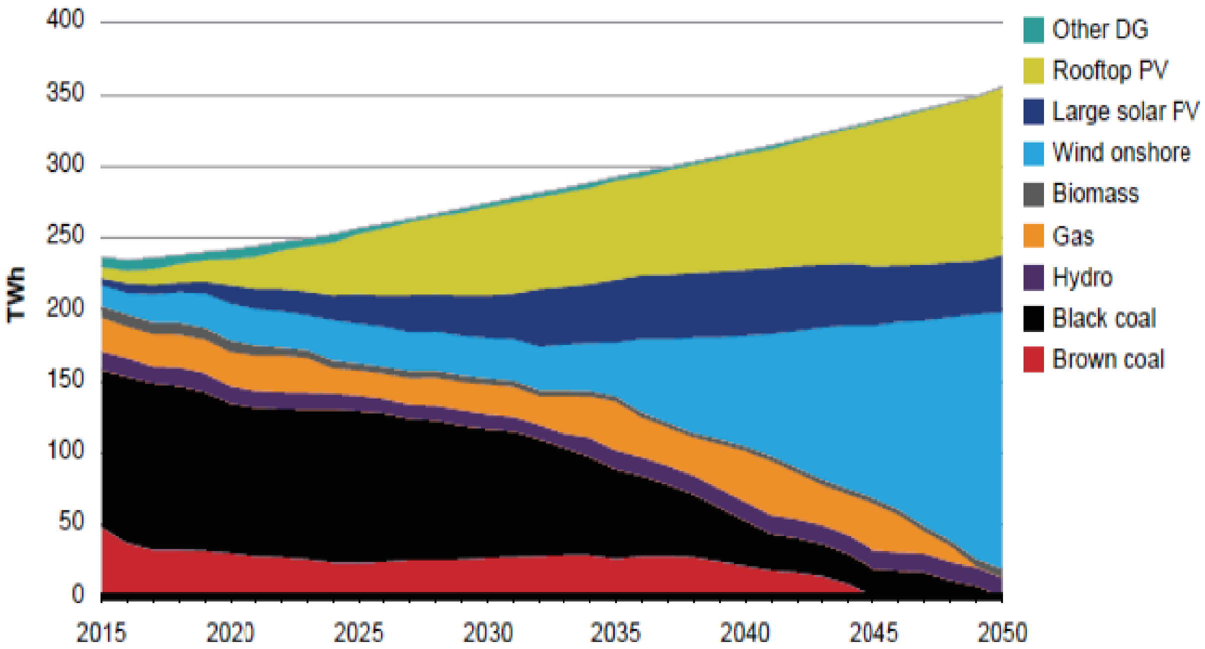
The figure below shows the target future state, again taking a national perspective.

Figure 2-10:A National Perspective - Target Future State



The CSIRO has also examined what this future state means for the generation mix in Australia, as illustrated in the figure below.

Figure 2-11:A National Perspective - Potential changes in the energy mix

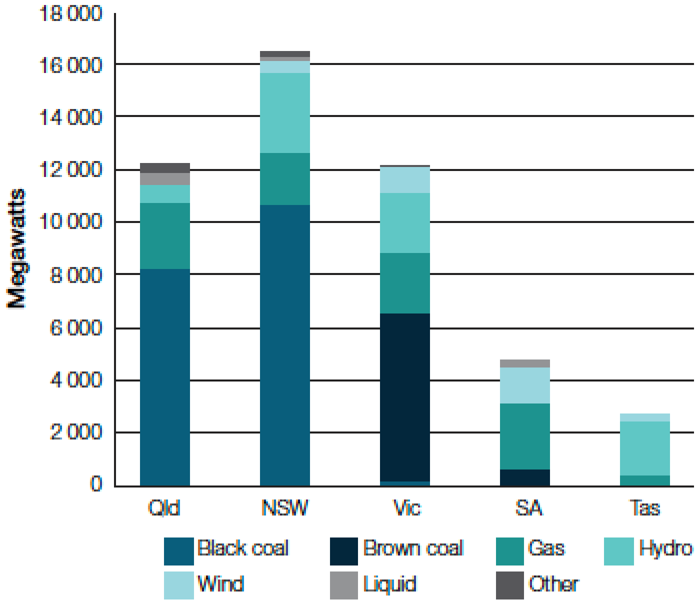


The Roadmap provides a national perspective, which is important in shaping our broad strategic direction. In addition, we must also be ready to address the challenges that are specific to Tasmania, which are discussed in the next section.

2.9 Tasmania's Energy Security

Tasmania's energy security challenges are uniquely different to the rest of Australia. The predominance of fossil fuel generation and the forecast closure of a number of base-load power stations means that electricity demand on mainland Australia is largely constrained by the capacity of available generators and the network to generate and deliver power as required. In contrast, in Tasmania it is the availability of energy – and particularly water in storage – rather than generation plant capacity that is the key constraint.

Figure 2-12: National Electricity Market generation capacity by region and fuel source



In 2014-15, around 99 per cent of total electricity generation in Tasmania was from renewable sources representing the highest penetration of renewable energy generation among all Australian states and territories. Tasmania's energy generation is underpinned by hydropower, which represented around 89 per cent of total electricity output in 2014-15. Wind power provided the second largest contribution to electricity generation, providing an estimated ten per cent of the state's output in 2014-15. Other sources of generation include small-scale solar, natural gas, oil products and biomass.

During 2015-16, Tasmania experienced one of the most significant energy security challenges in its history. The combined impact of two rare events – record low rainfall during spring and the Basslink interconnector being out of service – resulted in Hydro Tasmania's water storage levels falling to historically low levels. An Energy Supply Plan was implemented that included the rapid commissioning of more than 200 MW of temporary diesel generation capacity. The Plan slowed the rate of decline in water storages through the dry period. Water storage levels have now recovered to the mid 40 per cent range, from a low point of 12.5 per cent in late April 2016.

Current estimates indicate that Tasmania has an annual energy deficit between on-island generation and Tasmanian consumption of between 700 GWh and 1,000 GWh. Additional generation sources outside the existing hydro and wind generation are required to prevent an annual reduction in storages under average, or below average, inflow conditions.

The future energy mix in the NEM and how it will be managed to maintain adequate and reliable supply is uncertain. The Tasmanian Government established the Tasmanian Energy Security Taskforce to advise on how Government can better prepare for and mitigate against the risk of future energy security threats. The report set out 36 recommendations, with a number now implemented and others under consideration.

The Commonwealth and Tasmanian Governments have commenced work on a detailed feasibility study into a second electricity interconnector between Tasmania and the rest of the NEM. This follows an earlier study undertaken by Dr John Tamblyn, with support from the Tasmanian Energy

Security Taskforce. Dr Tamblyn concluded that further monitoring of NEM developments and analysis was required to establish an economic case for a second interconnector.

Increased interconnection with the NEM is perhaps the most significant strategic opportunity facing Tasmania over the medium to long term. Greater interconnection is required to realise Tasmania's renewable energy potential, including provision of dispatchable renewable energy to the rest of the NEM. It would require augmentation of the Tasmanian transmission network to facilitate the increased energy flows.

In November 2017, the Federal Government announced that it was supportive of TasNetworks and ARENA undertaking further work to investigate the feasibility of a second interconnector. This work, which will be largely conducted over 2018 and 2019, has the potential to impact on future investment needs which are discussed in section 8.2.8.

In preparing this Regulatory Proposal we have taken a balanced approach to the unprecedented changes and uncertainty that lie ahead. Specifically, we need to deliver the services that our customers want at network prices that are affordable. Equally, we must make appropriate plans for the future so that we are equipped to meet our customers' changing needs and drive innovation by investing in new technology where it is cost effective to do so.

In terms of cost recovery arrangements, we have not included any allowance for the costs of a second interconnector or the consequential transmission augmentation projects that may follow. Instead, we have proposed five transmission contingent projects so that we can address uncertain future investment needs as they arise, and thereby minimise the cost impact on customers. We discuss our contingent projects in further detail in section 8.2.8.

2.10 Our vision for 2025

We have developed our vision for 2025, which describes how we see our future role in the new energy environment and will help guide our short- and medium-term expenditure plans in a Tasmanian context. It reflects how we expect the use of our networks will change as customers continue to transition to clean energy and exercise more choice in the way their energy needs are met. It is a vision that we have shared with our customers as part of the engagement process[12] and is a valid basis for finalising our future plans.

We see our main role as connecting, transferring and balancing energy for all customers. To provide the best outcomes for all our customers, we need to keep delivering safe, reliable and competitive network services – both regulated and unregulated – while also delivering complementary services that are within our capability. We'll do this by operating a lean and efficient business and looking for growth opportunities within a rapidly evolving environment.

We are working with customers on large and small renewable generation projects, ranging from new hydro and wind generation to small scale solar connections on homes and businesses. There are a

[12] TasNetworks Transformation Roadmap 2025, June 2017. https://www.tasnetworks.com.au/TasNetworks/media/pdf/about-us/TasNetworks-Transformation-Roadmap-2025-22-June-2017_1.pdf

number of large projects in the early concept stage that may harness Tasmania's renewable energy resources to support the NEM. Our proposal includes a contingent project which recognises that the large volume of renewable projects in the North West may trigger a need for network augmentation. We will continue to engage with proponents and stakeholders as our planning progresses.

We are also starting to see the emergence of battery storage, electric vehicles and customers who are thinking about different ways of managing their electricity supply. To accommodate these changes, our network pricing strategy includes new pricing arrangements to encourage efficient use of our network and fair pricing outcomes. The figures below show how we expect the Tasmanian electricity sector to change by 2025.

Figure 2-13:Tasmanian network transformation – clean energy transition

Electricity Network Transformation in Tasmania

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

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

Figure 2-14: Tasmanian network transformation – customer choice and control

CUSTOMER CHOICE AND CONTROL	2016	2025
Advanced meters (that allow remote read)	1%	35-45%
New urban micro-grids	-	**2 new significant micro grids** (commercial property precinct, community precinct)
Connected customers	288,000	300,000

3 Customer engagement

3.1 Building on our recent distribution review

We conducted an extensive customer engagement process in developing our regulatory proposals for our 2014 transmission review and more recently in our 2017 distribution review. In this combined transmission and distribution review, we are consolidating our understanding of the price-service offering our diverse customer base wants us to provide.

An important part of developing a deeper understanding of customers' views is the need for on-going engagement outside the revenue and pricing review process. There are strong engagement linkages between our revenue reset and other foundation activities, as shown in the figure below.

Figure 3-1: On-going customer engagement

To support our business, our customers and our engagement activities, we developed an engagement framework using international best practice models. This framework assists in determining the appropriate level of engagement for the various customer segments. We have applied this engagement framework when consulting with customers for the combined transmission and distribution review.

Our transmission customers are large generators and industrial customers that have a material impact on the Tasmanian economy. We engaged with these customers through one-on-one discussions and small workshops where appropriate.

For our distribution customers, we have undertaken a range of activities to gather feedback and understand their concerns, as summarised in the figure below.

Figure 3-2: Our Revenue Reset Engagement activities

Copies of research reports and other information on the results of our customer engagement are available at www.tasnetworks.com.au.

3.2 What our customers have told us

Customers from both our transmission and distribution networks expect us to be the experts.

Our transmission customers provided us with a range of feedback on the current and future operation of our business. The key themes were:

- positive feedback that our costs have remained stable over the past few years;
- sustained low cost is important for forecasting and future viability;
- greater risk to businesses if power is interrupted and although reliability is good, this is still a key focus;
- keen to see TasNetworks demonstrate benefits and efficiencies resulting from investment in technology; and

- engaging with customers before making investment decisions which may impact their electricity prices has been appreciated.

Key messages from our residential and distribution customer engagement activities are summarised below:

- We are meeting most customers' needs from an overall reliability perspective, but for some their needs and expectations are changing.
- 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.
- The same for the same. While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices for these improvements.
- Continual improvement in how we communicate with customers is critical. This includes use of social media platforms, such as Facebook.
- Customers recognise that technology is changing the electricity industry, particularly in relation to solar panels, battery storage and electric vehicles.
- Customers recognise that the nature of the grid is changing and are interested in distributed energy resources and the capacity to use the network to trade energy.
- The majority of our customers are concerned about affordability, but some want new technologies and/or better outcomes and are prepared to pay for these improvements within reasonable bounds.

The following customer quotes summarise the type of feedback received.

"Keep the lights on; don't care how it's done"

"You need to manage the pace of change as best as possible"

"We are already changing the way we use energy at home and being rewarded with lower bills"

"We'd like to know more about solar and renewable energy"

"Thank you for providing updates on Facebook! This is very helpful"

3.3 Annual quantitative research

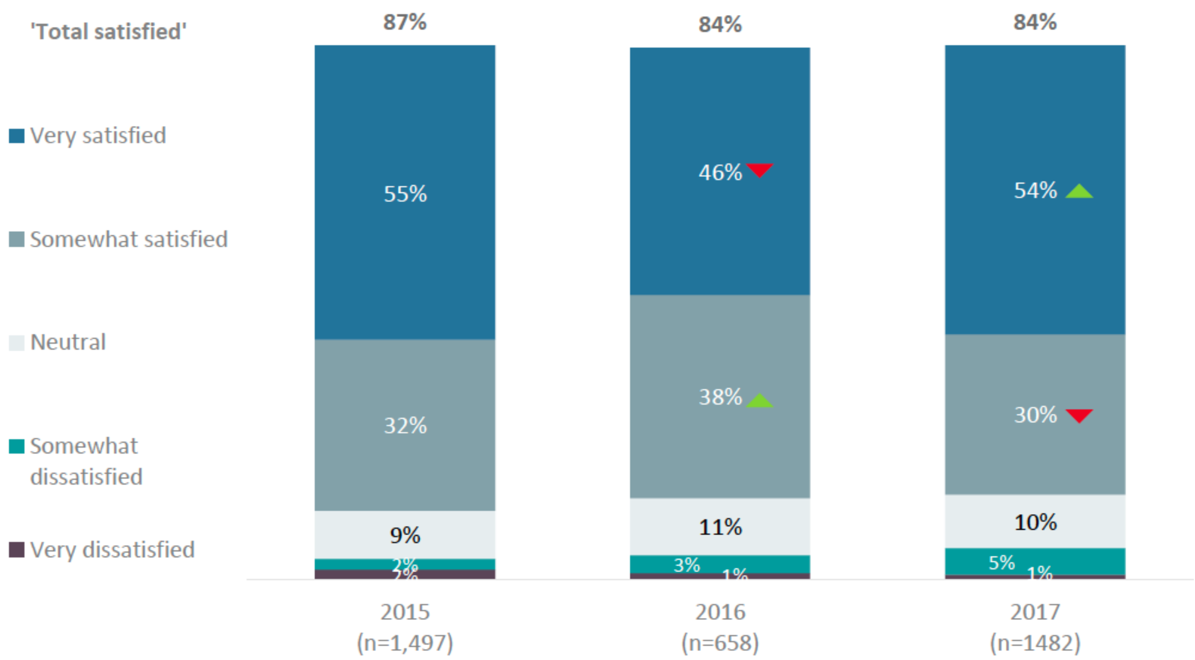
As part of our customer engagement /feedback program, research is undertaken annually to understand customers better and provide guidance on how we could improve our performance. By undertaking this research annually, we can track changes in customer preferences and respond to emerging issues. It also provides a useful cross-check on the feedback received through our qualitative aspects of our engagement process.

The figure below shows the methodology and sample size for this year's quantitative survey.

Figure 3-3: Methodology and sample size

In terms of reliability, the quantitative survey confirms that our customers remain satisfied with our performance, with the 84 per cent of customers surveyed being either very or somewhat satisfied.

Figure 3-4: Satisfaction with network reliability

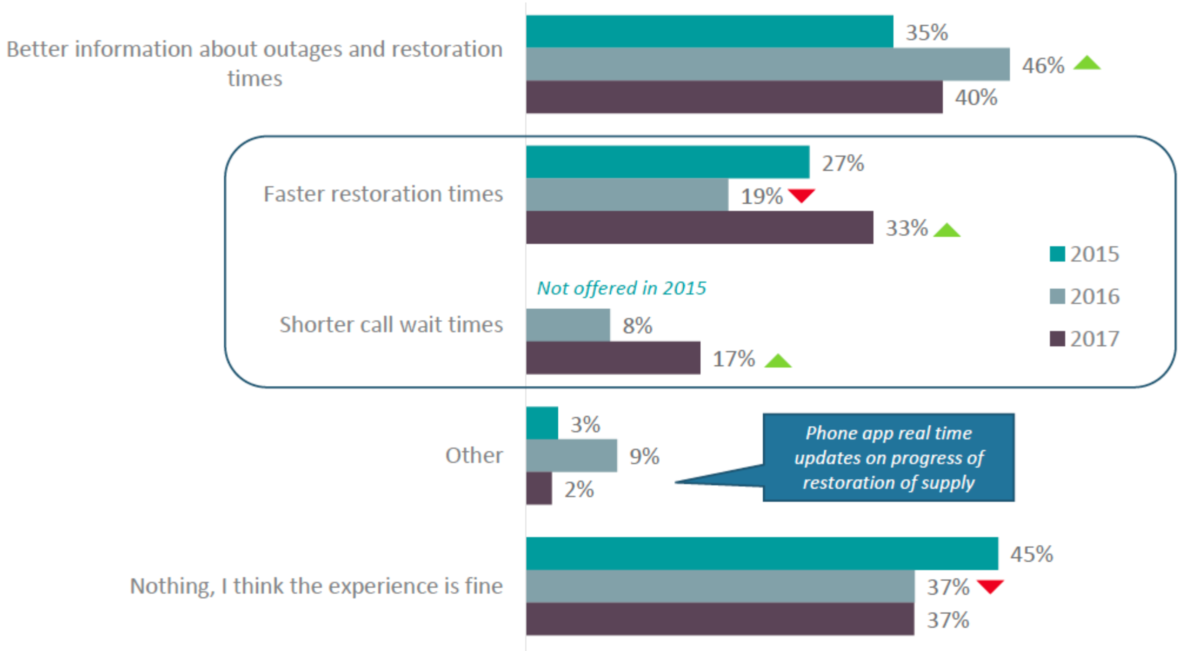


The quantitative research confirmed earlier findings that price remains the most significant issue for our customers. However, although most customers would prefer lower electricity prices, two in three residents are happy with the amount they pay, given the reliability of the network.

In terms of service improvement, the main areas related to outage duration, shorter call wait times and better information on restoration times. Our research also identified a difference in preferences across age groups. Short call wait times are particularly important for pensioners whereas young, tech-savvy customers prefer faster restoration of the network.

The figure below shows the feedback we received on how we should improve our response to outages.

Figure 3-5: How can we improve our response to outages?



In summary, our quantitative research confirms the feedback we received through other aspects of our engagement program – we can lift our performance by reducing outages and improving our communication, although our customers remain primarily focused on affordability.

Copies of research reports and other information on the results of our customer engagement are available at www.tasnetworks.com.au.

3.4 Feedback from the Consumer Challenge Panel

The development of our expenditure and revenue plans has been assisted by the AER's Consumer Challenge Panel (**CCP**). The objective of the CCP is to advise the regulator on:

- whether our proposals are in the long-term interests of consumers;
- the effectiveness of our customer engagement activities; and
- whether customer feedback has been reflected in our proposals.

While the CCP's role is to advise the regulator, the members' input has been invaluable to us as we finalised our proposals. We are pleased that the CCP commended us on our approach to consumer engagement[13], noting that we have presented many of the key issues in an accessible and informative fashion. Equally, however, the CCP also provided helpful advice on areas where issues could be explained better or where further information is required to assist customers. We have endeavoured to address the CCP's feedback in this Regulatory Proposal.

13 Consumer Challenge Panel, Submission to TasNetworks' Directions and Priorities Consultation Paper, September 2017, page 1.

The CCP also emphasised that our customers have not expressed a willingness to accept the rising price path described in our Direction and Priorities paper. We recognise the point raised by the CCP. Our challenge is to balance price pressures against the cost of meeting our obligations in an increasingly complex energy sector, including ensuring we meet reliability and safety requirements. We must have regard to the long term interests of our customers and ensure we are not simply reducing costs for customers now at the expense of future customers.

However, having considered the feedback from our customers, we agree with the CCP that more emphasis should be given to price considerations. For this reason, we revisited our provisional Revenue Proposal[14] expenditure plans to minimise the price impact. Further details of these changes are provided in Chapters 7 and 17. We believe that our updated proposal achieves the lowest price outcome for our customers without compromising our ability to meet our obligations, and deliver appropriate network reliability and safety outcomes.

The CCP also highlighted the following risks for us and our customers:

- **Demand risk**. The Tasmanian electricity network has a small number of users reliant on international prices for their products who consume over 50 per cent of electricity load in Tasmania. The closure of a major customer would have implications for network charges to the remaining customers, as the fixed costs of providing network services are spread over a smaller customer base.
- **Large, uncertain capital projects**. Our Direction and Priorities Consultation Paper identified four major projects ('contingent projects') that may be required in the forthcoming regulatory period. We have subsequently identified an additional contingent project. While we are not proposing to go ahead with these projects now, we will seek additional funding if the projects are required. Although these projects would deliver substantial benefits in terms of energy security or lower generation costs, they could lead to higher network charges.

We agree with the CCP that the above points pose a risk of higher prices for customers. We note, however, that the contingent projects will only go ahead if they deliver an overall benefit to our customers. In relation to demand risk, we are working hard to maintain the sustainability of our major industrial customers in the medium term – and our broader customer base – by ensuring that our prices are as low as we can sustain.

[14] For further information regarding our provisional Regulatory Proposal refer (TN175)

4 Our planning and asset management processes

4.1 Introduction

This chapter provides background information on our planning processes and our recent cost and service performance, with a focus on our network investment and reliability. 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, which are presented in Chapters 8 and 9 of this Regulatory Proposal.

The remainder of this chapter is structured as follows:

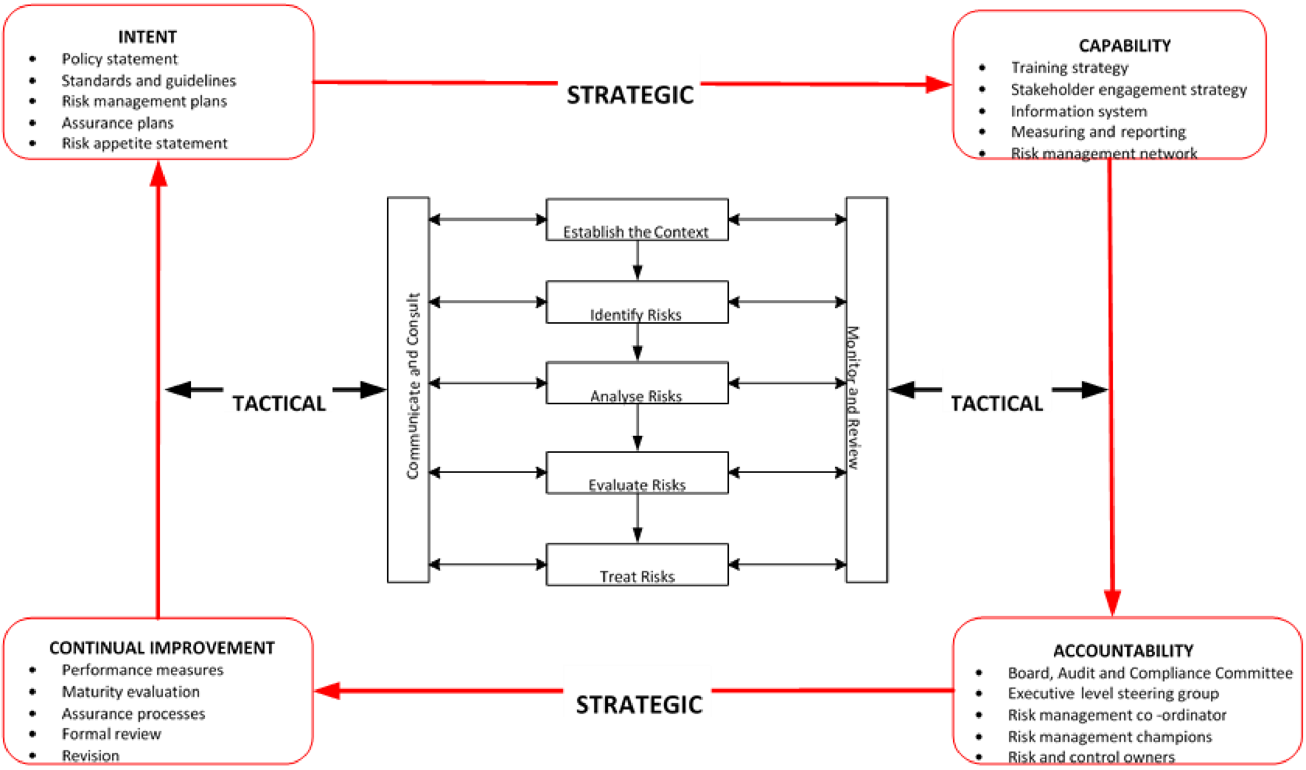
- Section 4.2 outlines our approach to risk management, which is expressed in our risk management framework.
- Section 4.3 explains that we have a single planning process covering the transmission and distribution networks. The output from the planning process is a capital plan that seeks to optimise 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 system framework, which shows the relationship between our corporate plan; asset management policy; strategic asset management plans; through to works delivery; performance evaluations and improvements.
- Section 4.5 explains that our Network Innovation Strategy encourages the business to be innovative by making effective use of emerging technologies to deliver better outcomes for our customers.
- Section 4.6 provides an overview of our investment governance arrangements, which are focused on ensuring that every dollar of expenditure is efficiently and prudently expended.

4.2 Risk management

The effective management of risk is central to the core activities and efficient management of our business. Our approach to risk management involves striking 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.

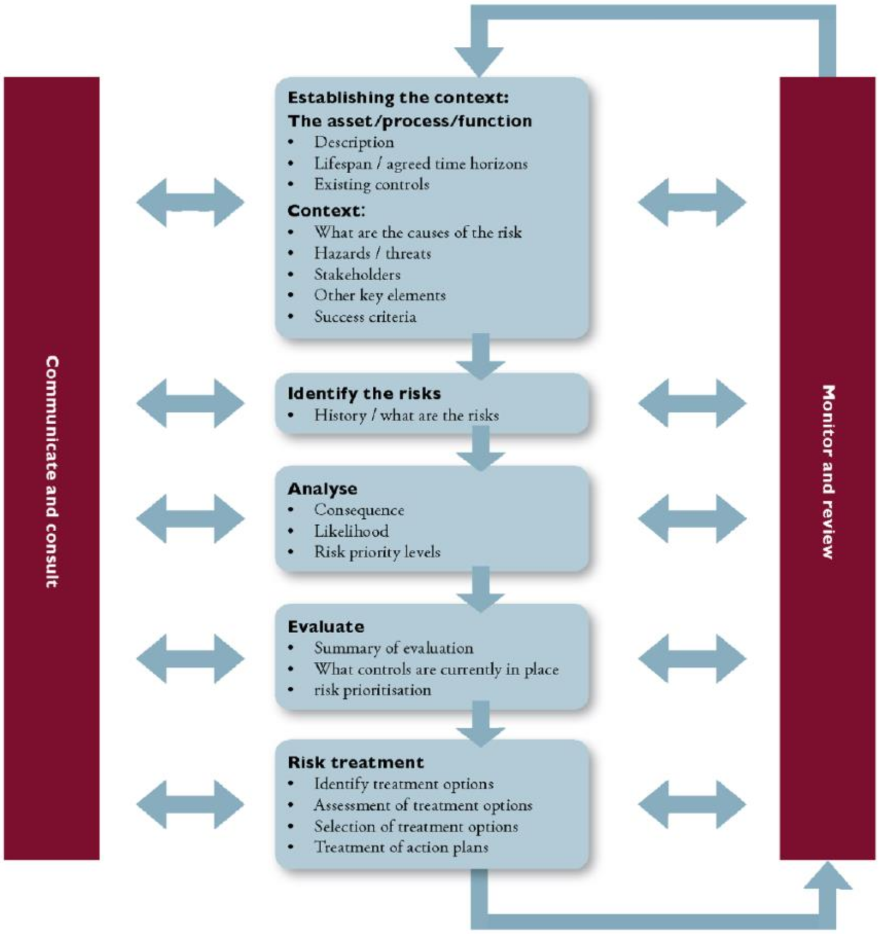
Our risk management framework governs our approach to managing the effects that uncertainty has on achieving our strategic objectives. The framework also facilitates compliance with legislation, rules, codes, guidelines and various industry standards. The figure below shows our risk management framework, which has strategic and tactical (operational) components.

Figure 4-1: Risk Management Framework



Our operational process for risk management is summarised in the figure below. Our process accords with AS/NZS ISO31000:2009 Risk Management – Principles and Guidelines.

Figure 4-2: Risk Management Operational Process



In the forthcoming regulatory period, we will continue to pursue strategies to:

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

Our networks are comprised of many aged assets, a key focus is to manage the risks associated with poor asset condition so that we achieve our asset management service and cost performance objectives. We set service-based targets for assets within our asset management plans to balance the cost of taking action against the risk of asset failure, including the potential safety and reliability impacts.

4.3 Integrated network planning process

Our jurisdictional planning criteria and the Rules specify the minimum reliability and security standards the network must meet in providing network services. More generally, we have a responsibility to ensure that the infrastructure to supply Tasmanians with electricity evolves to meet customer and network requirements, in an economically optimal and sustainable way. We achieve this through our network planning process, to ensure the most economic, technically-acceptable solutions are pursued.

The Strategic Asset Management group is responsible for the following transmission and distribution network planning activities:

- preparing the future supply-demand outlook, using AEMO's forecasts;
- working with AEMO to incorporate planning outcomes into national integrated grid plans;
- 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 Transmission and Distribution Annual Planning Report; and
- establishing long-term network strategies.

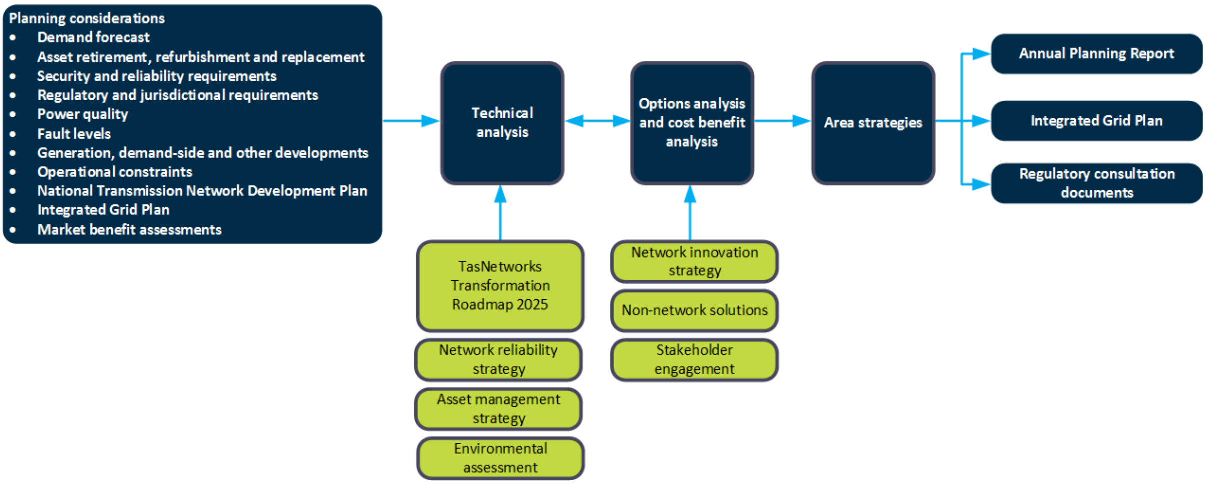
To ensure effective integration and delivery of our operational and capital works plans, we develop an overall works plan, encompassing all projects on the transmission and distribution networks.

The capital plan is a combination of area development plans and asset management plans for the various asset classes. These plans are combined 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 projects are bundled where economically beneficial to do so to achieve economies of scale.

Our planning process is shown in Figure 4-3 below.

Figure 4-3: Overview of our network planning process



4.4 Asset management framework

Consistent with our vision and purpose, our asset management policy strives for excellence in asset management and we are committed to providing a safe working environment, value for our customers, sustainable shareholder outcomes, caring for our assets and the environment, safe and reliable network services, whilst effectively and efficiently managing our assets throughout their life-cycle.

To achieve these outcomes, we have implemented an integrated asset management framework, with associated processes and systems that support our combined network service responsibilities. The ISO 55000 series of standards are the internationally accepted standard for asset management that comprises three separate standards:

- ISO 55000:2014, which provides an overview of asset management;
- ISO 55001:2014, which specifies the requirements for the establishment, implementation monitoring and improvement of an asset management system; and
- IS0 55002:2014, which provides guidance for the application of the asset management system.

Our asset management system continues to be further developed to align it with the ISO 55000 series of asset management standards with the aim of achieving the following benefits:

- improve safety and environmental performance in line with our Zero Harm objectives;
- delivery of our asset management policy;
- improved asset management planning;
- improved customer service and maintaining overall network performance;
- alignment of strategic initiatives across the asset management system;
- increased engagement of our people, including leadership, communications and cross-disciplinary teamwork;
- alignment of processes, resources and functional contributions;

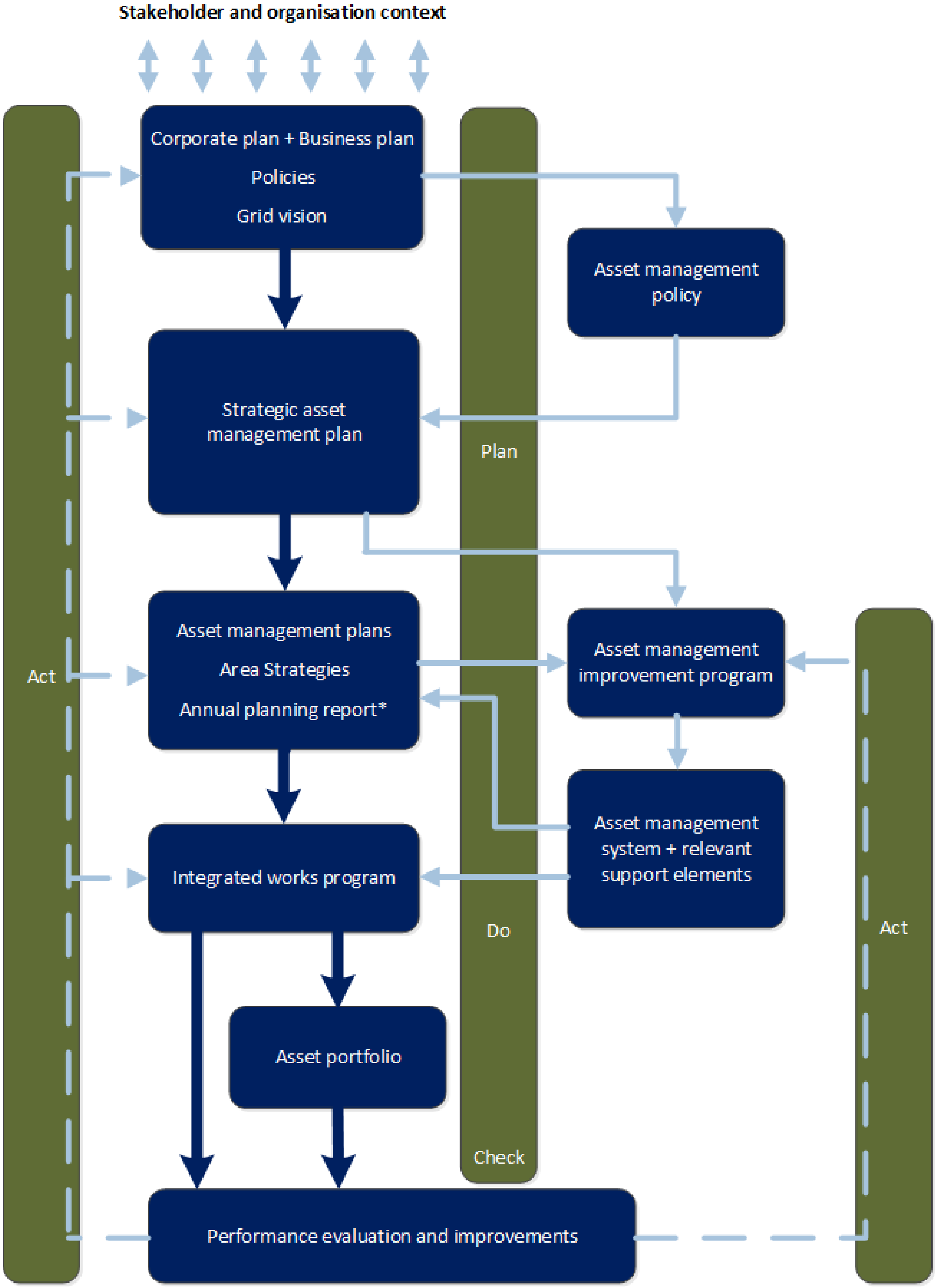
- better understanding and usage of data and information to provide consistent and informed decisions;
- consistent, prioritised and auditable risk management;
- increased auditability across the asset management life-cycle; and
- reduced regulatory risk through implementing robust and demonstrable asset management governance processes.

Our asset management 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.

The figure below presents our asset management framework.

Figure 4-4: Asset Management Framework



* The Annual Planning Report (APR) is a requirement of sections 5.12.2 and 5.13.2 of the National Electricity Rules (NER) and also satisfies a licence obligation to publish a Tasmanian Annual Planning Statement (TAPS). The APR is a compilation of information from the Area Development Plans and the Asset Management Plans.

Our asset management objectives are detailed in our Strategic Asset Management Plan (TN026), which is submitted along with this Regulatory Proposal. Those objectives have been designed to align with our asset management policy and our organisational strategy, thereby ensuring a 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 that our 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, and our asset risks are managed consistent with our Risk Management Framework.
- **Cost Performance** will be improved through prioritisation and efficiency improvements that enable us to provide predictable and lowest sustainable pricing to our customers.
- **Service Performance** will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet prescribed performance criteria.
- **Customer Engagement** will be improved to ensure that we understand customer needs and incorporate these into our decision making to maximise value to them.
- 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.

As already noted, our plans are documented as follows:

- **Asset Management Plans** (**AMPs**), which cover the existing asset base and are prepared for each material asset category. They identify the performance issues and risks presented by each asset type within the category and define specific actions that must be undertaken to sustain asset and system performance. The AMPs also summarise the forecast asset operating and capital expenditure requirements for each asset category. Where appropriate, AMPs are supported by detailed condition assessment reports and maintenance standards to ensure transmission and distribution system assets are appropriately maintained, having regard to the condition and risks of selected assets.
- **Area Strategies** for the transmission and distribution systems, which set out augmentation projects that provide new or modified connection points for customers, respond to increased local demands on the electricity system, or enhance security or quality of supply.
- **Annual Planning Report** (**APR**), which generally covers a ten year planning period and presents the outcomes of our network planning studies, in accordance with our obligations under clauses 5.12.2 and 5.13.2 of the Rules for the publication of Transmission and Distribution Annual Planning Reports. The APR also addresses the requirements of the Tasmanian Annual Planning Statement, in accordance with clause 15 of our transmission licence issued under the Electricity Supply Industry Act 1995. Given the timing differences and the rate of change, some of the information in this Regulatory Proposal may differ from our 2017 APR, being our most recently published APR and our forthcoming APR in 2018. We

will address any material differences in our Revised Regulatory Proposal which we will be submitting to the AER in late 2018.

4.5 Network Innovation Framework

As noted in section 2.8, new technology is driving significant changes in the electricity network. Not only is the technology that we use to solve network issues changing, but the network itself is changing. External influences, such as embedded generation and the 'internet of things' have accelerated this change. We now operate in a highly dynamic environment, with customers having more choices than ever before about how to best meet their energy needs.

Technology also creates challenges in planning and operating our network. PV is a notable example, with significant increases in the number of installations over the past five years. Installation of medium-sized embedded generation in commercial settings is also increasing.

We are committed to finding innovative, least-cost ways to manage our network in an environment where the number and size of embedded generation installations is increasing and energy flows, voltages and customer requirements are also changing. Residential battery technology is likely to be the next trend. We are currently seeing about one battery connection per week, causing another major shift in the electricity market and network operation. In addition, the use of electric vehicles charged from the distribution network is likely to increase in the coming years. We have developed our distribution pricing strategy with this in mind and are proposing new network tariffs for customers who make investments in DER.

To guide us in responding to, and embracing these developments and challenges, we have prepared a Network Innovation Strategy (TN027). Our Network Innovation Strategy enables us 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 our business.

The framework focuses on the key innovations that will drive our evolution in response to technological change, including the increasing penetration of disruptive or new technologies. The framework aims to support and manage technological change and the efficient use of our network in the changing energy landscape. It is underpinned by three network innovation objectives, which are to:

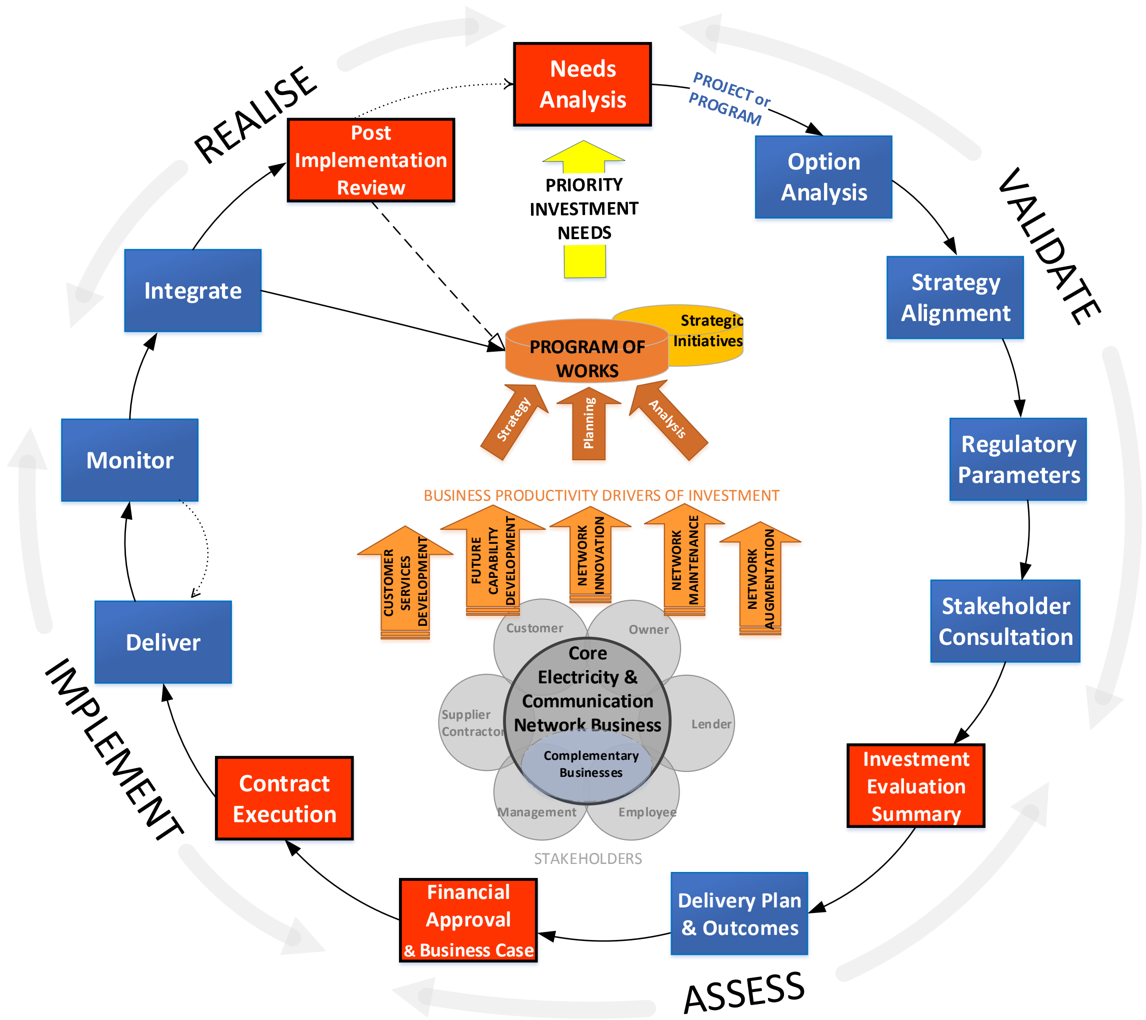
- facilitate customer choice;
- facilitate customer interaction; and
- increase network efficiency through lowest cost solutions.

A copy of our Network Innovation Strategy (TN027) is provided as a supporting document to this Regulatory Proposal.

4.6 Investment governance

Our investment governance arrangements are centred around robust investment evaluation processes and a gated investment approval framework as part of the investment lifecycle, this is shown in the figure below.

Figure 4-5: The Investment Lifecycle



Within the lifecycle, there are five key decision points or 'gates', which are shown in red boxes in the above figure. Each gate represents a specific point of control. The table below provides a description of the purpose of each gate.

Table 4-1: Overview of each decision gate

Gate	Description
Gate 1 - Needs analysis	The purpose of this gate is to determine the rationale for proceeding with an investment based on the business need. This decision point is a filter to test whether the business should commit resources to the detailed analysis required for Gate 2.

Gate	Description
Gate 2 - Investment solution	The purpose of this gate is to evaluate different options in order to identify the preferred investment solution. An approved evaluation is required for all investment projects and programs that are to be included into the Works Program. The Works Program is a key mechanism for forecasting proposed, future works and for tracking the performance of financially approved current works.
Gate 3 - Financial approval	This gate requires investment proposals to be approved for funding prior to commencement of works. Financial approval of an investment is obtained through inclusion of the funding requirement into the annual budget process that is Board approved and may also be subject to further detailed business case assessment.
Gate 4 - Contract Execution	The purpose of this gate is to ensure that financial expenditure relating to an investment is kept in line with the financial approval and any external financial commitments are in line with business approved policies.
Gate 5 - Post Implementation Review (**PIR**)	The purpose of this gate is to ensure the investment deliverables and proposed benefits are realised. The review enables the need for any changes to be identified and actioned. Importantly, it provides an opportunity to capture any lessons learned.

Under our investment governance arrangements, 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 and operating expenditure is prudent and efficient.

5 Recent performance

5.1 Introduction

Our recent performance in terms of service and costs provides a useful backdrop to our future expenditure and service plans. This chapter provides a brief overview of our service and our benchmark cost performance for transmission and distribution.

5.2 Distribution network and customer service performance

In terms of distribution network service performance, we are performing well against our service performance targets, as shown in the table below.

Table 5-1: Our average distribution network performance 2012-17 regulatory period[15]

Category	SAIFI		SAIDI	
	Target	Actual	Target	Actual
Critical Infrastructure	< 0.22	0.18	< 20.79	10.84
High Density Commercial	< 0.49	0.23	< 38.34	19.30
Urban and Regional Centres	< 1.04	0.93	< 82.75	76.26
Higher Density Rural	< 2.79	2.42	< 259.48	244.51
Lower Density Rural	< 3.20	3.13	< 333.16	376.95

Our average performance over the period has been better than target, with the exception of our System Average Interruption Duration Index (**SAIDI**) performance for Lower Density Rural customers. Performance for these communities on our radial rural networks is affected principally by vegetation outside clearance; weather; and outages where the cause was not found. The positive overall customer outcome is consistent with our customers' feedback and expectations, as discussed in chapter 3, which indicates our customers are comfortable with current levels of reliability.

Our customer service performance is also good, although there is room for improvement as shown in the table below.

15 Distribution SAIDI and SAIFI metrics were calculated on a kVA basis in the 2012-17 regulatory period but are calculated on a customer basis from 01 July 2017 onwards.

Table 5-2: Our target and actual customer service performance 2016-17

Performance measure	Target	Actual
Customer net promoter score	> +10	+6
Customer complaints volume	< 3,900	2,560
Connection applications completed within standard or agreed timeframes (%)	100%	100%
Call answering within 30 seconds - combined (%)	> 73.40%	79.30%

Our customer net promoter score of +6 is a significant improvement on the 2015-16 result of -1, and while it did not meet our high benchmark target of +10, it demonstrates that the commitment we have made to "keeping our customers informed" and "doing what we promise" is making a positive difference to the customer experience. While below our target, our score is well ahead of the average of our peers.

Our current area of focus is to improve our efficiency in resolving customer issues by minimising the number of follow up contacts – we are seeking to provide our customers a "one call resolution". This has been highlighted as an area for improvement and we will develop key activities to support increased efficiencies in this area.

The following points are also worth noting in relation to our customer service performance:

- During 2016/17, our customer complaint levels have continued to decrease and were well below our target level. This decrease is due to ongoing efforts to improve customer processes and systems.
- We continue to maintain 100 per cent of connection applications being completed within standard or agreed timelines.

Our combined 'grade of service' measures the percentage of calls to our Customer Service Centre and Fault Centre that are answered within 30 seconds. In 2016-17, we were able to answer 79.3 per cent of calls within 30 seconds against a target of 73.4 per cent, an outstanding result and a significant improvement on 2015-16. We continue to ensure we have additional trained resources to assist with high call volumes during storm events.

5.3 Transmission network service performance

The transmission network service performance over the past five years has seen substantial improvements and we are performing well against our service performance targets, as shown in the table below.

Table 5-3: Transmission network reliability performance 2011-2016[16]

Performance measure	Target	2012	2013	2014	2015	2016
Number of LOS events >0.1 system minute	≤ 10	10	10	4	3	1
Number of LOS events >1.0 system minute	≤ 3	2	1	0	0	1
Average circuit outage duration in minutes	≤ 112	110	160	201	74	15
Market impact of transmission congestion (new in 2014)	≤1,516	n/a	n/a	1,230	247	3,071
Network capability component (new in 2014)	100%	n/a	n/a	100%	100%	100%

Our overall performance illustrates that the significant investment in renewing and strengthening our transmission network over the last 15 years, together with improved operational processes, is bearing fruit.

Our performance against the market impact transmission congestion parameter in 2016 was below the target due to planned asset replacements on the transmission network. Apart from this measure, 2016 was an exceptional year for our transmission service performance, with an average circuit outage duration of only 15 minutes for the transmission network.

5.4 Cost benchmarking

We have been working hard to sustainably reduce the cost of providing our network services across our capital and operating programs. Cost benchmarking plays an important role in understanding our cost and service performance over time and compared to our peers. As such, it provides insights into what may be sustainable levels of cost performance, having regard to the company's particular operational circumstances, network scale and design.

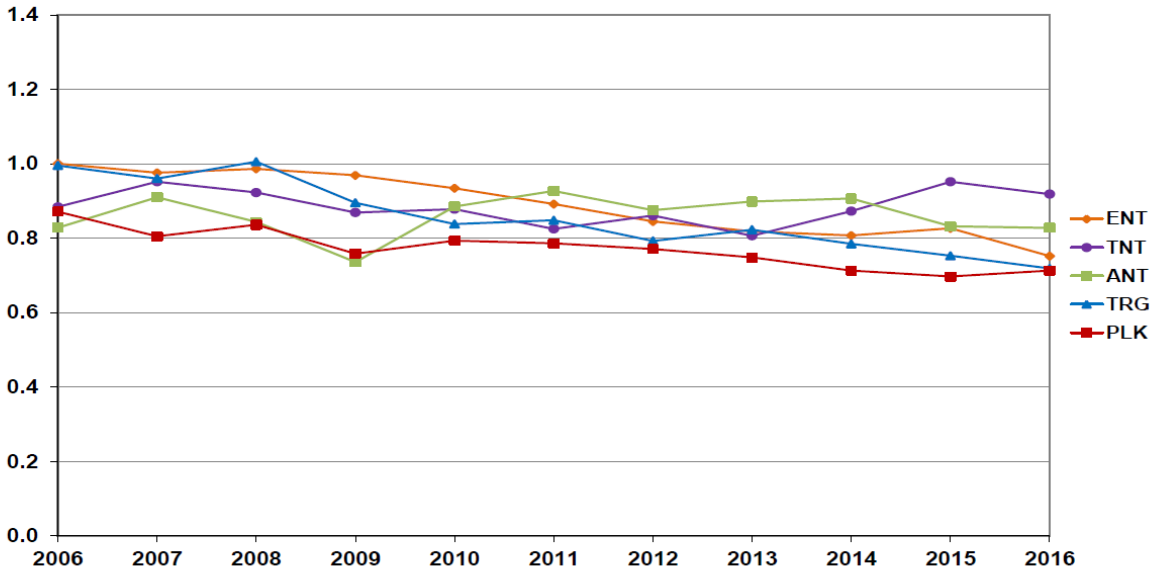
For example, TasNetworks has a different voltage boundary between our transmission and distribution networks than many other Australian states: with connecting substations and transformers classed as transmission rather than distribution assets. Tasmanian peak load is in winter, whereas most states are now summer peaking. Tasmania's transmission network serves a highly variable hydro-based generation fleet and a large interconnector relative to local generation and customer demand. Ideally, benchmarking normalises for these differences so that it reports on the efficiency of each company.

[16] Transmission service performance is reported to the AER and OTTER by calendar and financial year, respectively

The AER uses a form of benchmarking called 'Multilateral Total Factor Productivity'. We have previously highlighted issues with the AER's benchmarking approach, which may understate our distribution performance. In particular, as acknowledged by the AER's benchmarking consultant[17], we serve a dispersed customer base with relatively small numbers of customers in a range of rural areas. As a consequence, we need additional network capacity to reach a small number of outlying customers.

Notwithstanding these concerns, the AER's most recent analysis is reproduced below[18]. The higher the lines on the chart, the better the performance.

Figure 5-1: Multilateral total factor productivity by transmission company 2006-16, TNT = TasNetworks



17 Economic Insights memo, DNSP Economic Benchmarking Results for AER Benchmarking Report, 4 November 2016, page 8.

18 AER, Annual Benchmarking Reports, November 2017.

Figure 5-2: Multilateral total factor productivity by distribution company 2006-16, TND = TasNetworks

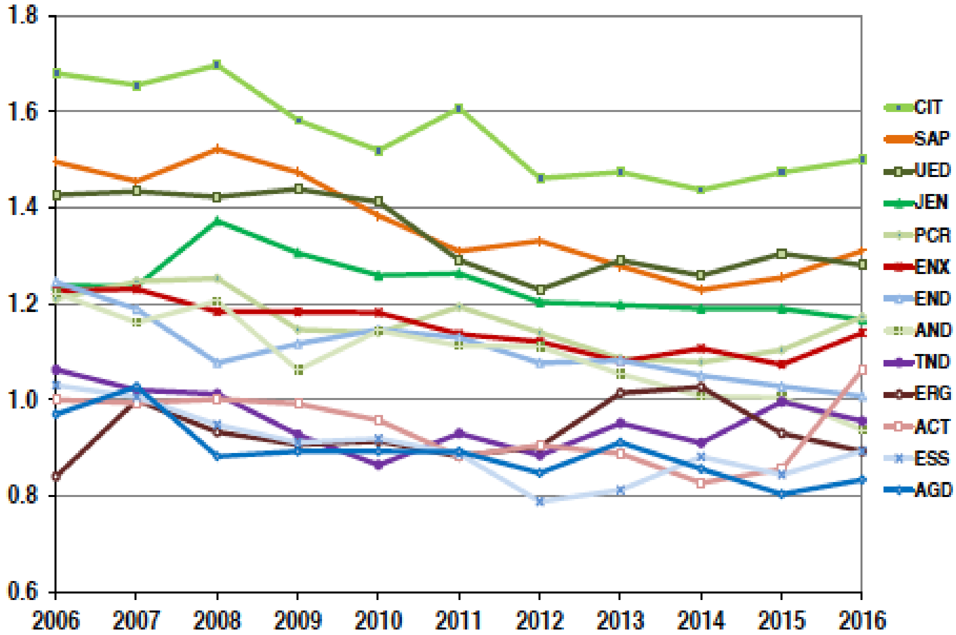


Figure 5-1 shows that we were the best performing transmission network service provider in 2015 and 2016 (refer to TNT data), while

Figure 5-2 indicates that our recent distribution performance (refer to TND data) is generally at the upper end of the lower quartile, having improved since reaching its lowest point in 2010. TasNetworks is one of only three DNSPs to have improved its MTFP performance from that date.

It is important to note that the AER's consultant has recently amended its benchmarking approach for transmission, which has led to a downward revision to our benchmarking results compared to the AER's previously published reports. The sensitivity of the AER's benchmarking results to changes in its model specification highlights the challenges in benchmarking network companies accurately and the importance of treating the results with caution. We are pleased, however, that the AER's benchmarking results for the most recent years indicate that we are the best performing TNSP.

As already noted, our distribution costs are relatively high compared to our peers because we serve a disperse customer base across a large rural area. Our cost performance cannot be compared meaningfully with CitiPower (serving large parts of metropolitan Melbourne), for example, because our networks and the customers we serve are so different.

Nevertheless, we recognise that our distribution costs increased materially in 2016-17, which reduced our benchmarking performance in that year. This cost increase reflects a range of factors, including a decision to increase investment in vegetation management to support longer-term reliability and safety outcomes, increased levels of storm activity and associated increases in GSL payments. We have undertaken a detailed analysis of our performance in 2016-17 and previous years to determine the sustainable, efficient costs for our business.

While our distribution costs were higher in 2016-17 than in the two years immediately following the merger that created TasNetworks, our combined transmission and distribution costs are expected to be significantly lower in 2017-18 and over the 2019-24 regulatory period are forecast to be well below pre-merger levels. This outcome provides strong evidence that the company's overall cost performance is prudent and efficient.

Further information on how we benchmark against our peers is provided in the supporting documents (TN159). Our benchmarking analysis has informed our expenditure forecasts for the forthcoming regulatory period, which are discussed in further detail in Part 2 of this submission.

6 Demand, energy and customer connection forecasts

6.1 Introduction

Our expenditure plans for the forthcoming regulatory period must consider future connection services and network capability needs, including the provision of new and modified connection services and reinforcing our network to meet 'organic' demand growth on our transmission and distribution networks. In this context, this chapter provides the following forecast information:

- Section 6.2 provides information on our maximum demand.
- Section 6.3 presents information on energy consumption. While energy consumption does not drive our capital expenditure plans, it is relevant for setting those network tariffs that presently include energy-based charges.
- Section 6.4 discusses the potential changes in the transmission load and generation, which may affect the future augmentation needs on our transmission network.
- Section 6.5 provides information on new customer connections to our distribution network, which drive our customer initiated capital expenditure.

6.2 Maximum demand

The key drivers 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, the peak demand occurs in winter at times of lower temperature. Similarly, Tasmanian peak summer demand occurs at the start or end of the period, at times of lower temperature.

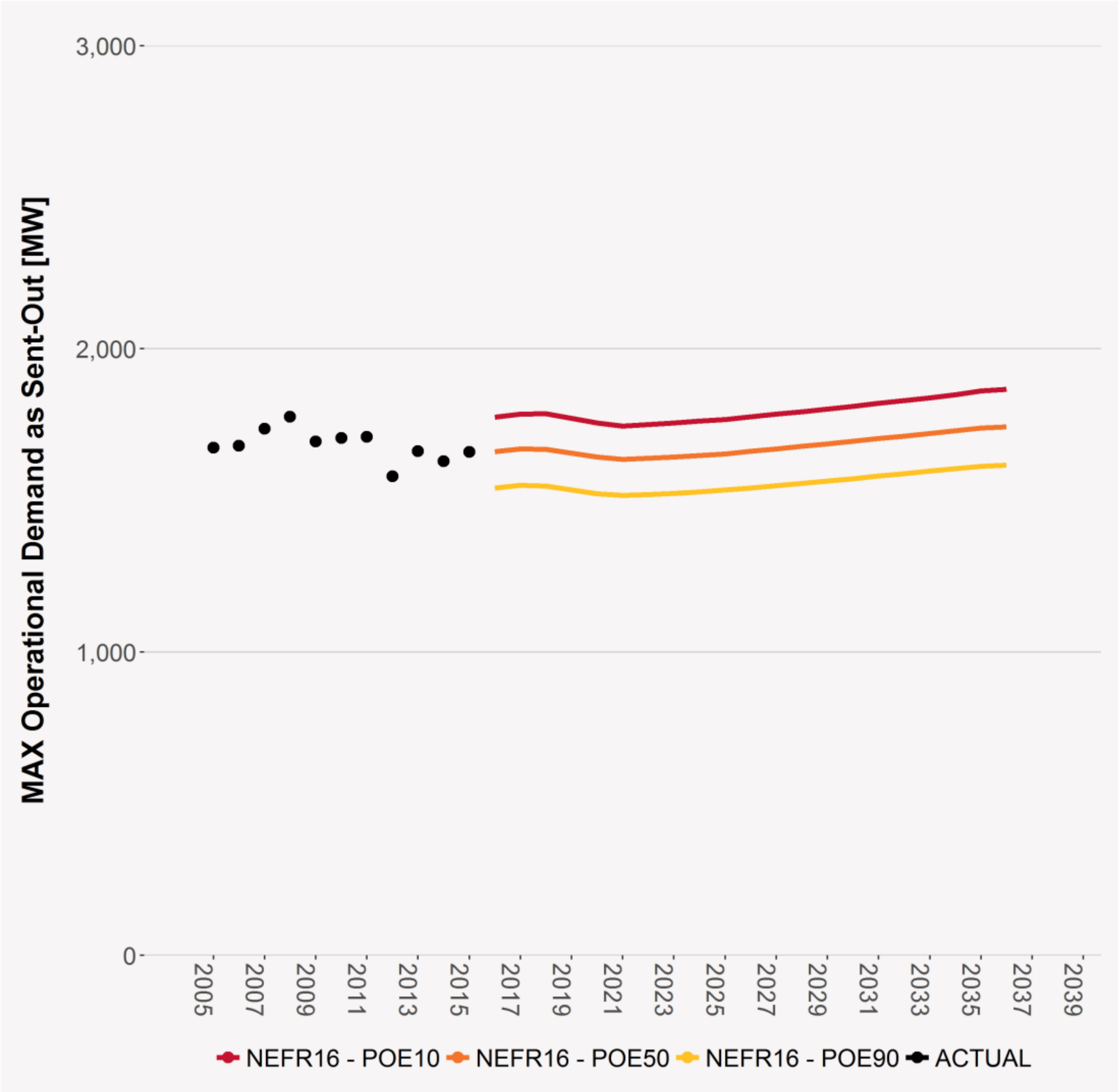
Similarly, AEMO in its role as the national transmission planner, produces an independent regional forecast for Tasmania and connection point maximum demand forecasts for our networks. We have adopted the 2017 AEMO connection point forecasts to assess our constraints and inform our long term development plans[19] for our transmission and distribution networks.

AEMO's connection point forecasts show no significant growth in maximum demand, and as a result, our augmentation expenditure forecasts are largely driven by non-demand related constraints, such as fault level, community reliability, together with renewal strategy and rationalising projects, which are discussed further in Chapter 8.

AEMOs regional forecast for Tasmania, which is used as an input to the connection point forecasts, is reproduced below. Overall, maximum demand forecasts across Tasmania are forecast to be flat, trending slightly upwards over the 20-year forecast period, after a short period of modest decline.

[19] Detailed in our Area Strategy (Area Development Plan) reports.

Figure 6-1: Actual and Forecast Maximum Demand for Tasmania[20]



6.3 Energy consumption

As already noted, energy consumption does not drive our capital expenditure plans. However, it is relevant for setting those network tariffs that presently include energy-based charges. In addition, the Rules require us to provide information on energy consumption in our Regulatory Proposal.

Our 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 results in a reduction on energy sales across the state.

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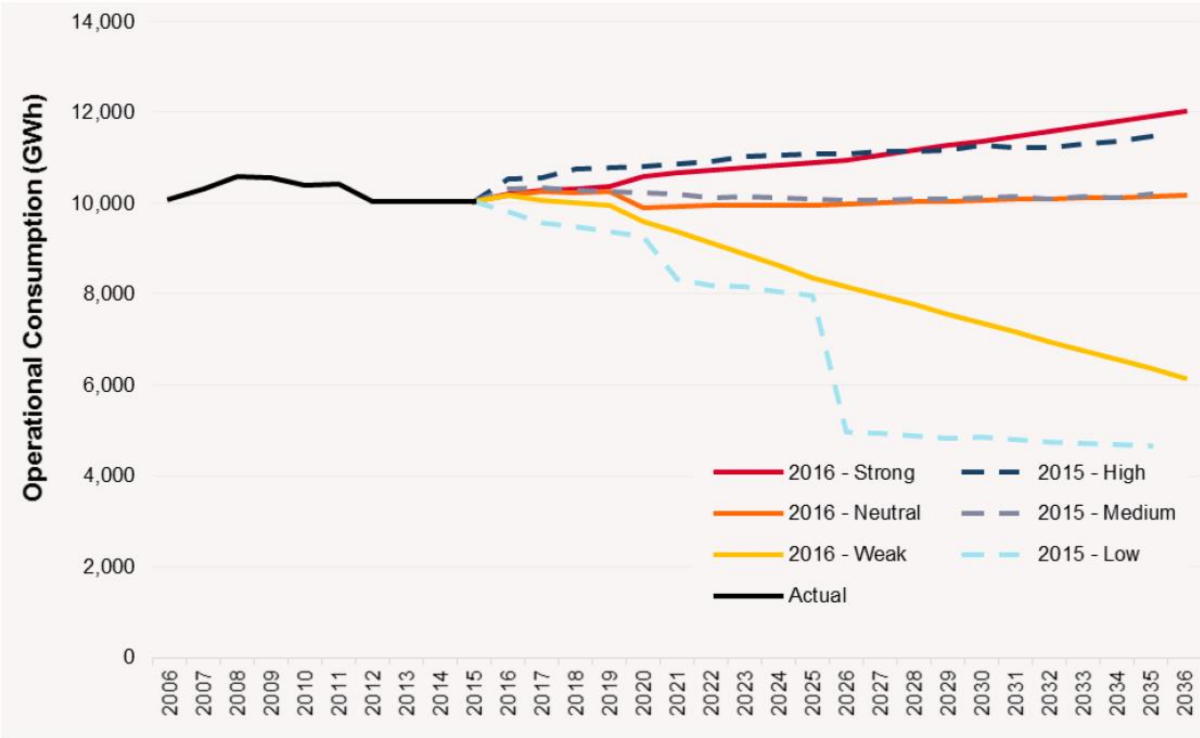
20 AEMO, 2016 National Electricity Forecasting Report Chart Pack, June 2016, slide 7.

The following figure shows the actual consumption on the Tasmanian network and AEMO's forecasts under strong, neutral and weak economic scenarios.

Figure 6-2: AEMO's forecast energy consumption on the Tasmanian network[21]



We note that AEMO's 'weak scenarios' reflect assumptions of business closures if there is a severe economic downturn.

6.4 Transmission load and generation customer connections

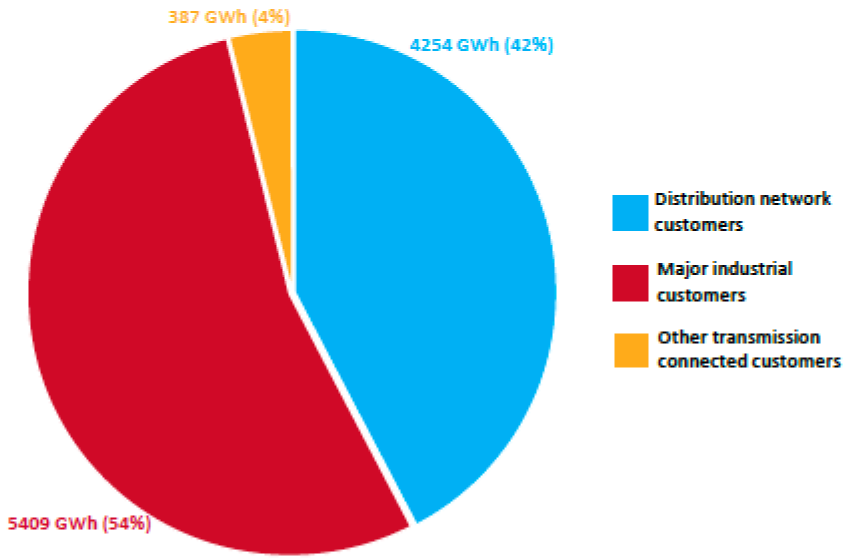
Our transmission system has been shaped by the nature of Tasmania's generation system. The supply of electrical energy in Tasmania is currently dominated by hydro-electric generators.

Looking ahead to the forthcoming period, the pattern of generation on our transmission network may change markedly. For example, we are experiencing unprecedented numbers of connection enquiries from new wind generation and solar in Tasmania. In addition, there is a possibility of a second Bass Strait interconnector, which would place significant new requirements on the Tasmanian transmission network. There have also been changes to the operation of Tamar Valley Power Station in recent years.

As major industrial and other transmission connected customers consume a significant portion of energy transferred through the transmission network, their operation can also have a significant impact upon the power system. Changes to the transmission-connected customer base, such as a permanent reduction in load, would alter the present operation of the power system and impact on such things as power flow and utilisation of the transmission network. The figure below illustrates the relative scale of our major industrial customers.

21 Ibid, slide 12.

Figure 6-3: Energy consumption supplied from the transmission network[22]



In our transmission planning role, we continue to engage with our generation and load customers so that we are cognisant of their operations in our planning activities. We also work with prospective customers, generators and AEMO, as the National Transmission Planner, to ensure that the Tasmanian transmission network is ready to meet the challenges ahead.

6.5 New distribution customer connections

Our capital expenditure allowance includes an amount to cater for the provision of new distribution connection services requested by our distribution customers in the forthcoming regulatory period. This expenditure is associated with the construction of new distribution assets or modification of existing assets, including network extensions and augmentations of the shared network. Our expenditure requirements are based on forecasts of customer connection numbers for different connection types and applying a unit rate, based on historical expenditure, to those forecasts.

In developing the customer connection forecasts, our approach requires the estimation and testing of statistical relationships between the number of new connections and the underlying drivers most notably the projected economic growth in Tasmania.

For forecasting purposes, we distinguish between:

- residential customers and residential subdivisions;
- commercial customers;
- irrigators; and
- small scale embedded generation.

We also provide separate forecasts for 'basic' and 'complex' connections. In contrast to basic connections, customers requesting complex connections are required to contribute to the cost of

22 TasNetworks, Annual Planning Report 2017, figure 3.2.

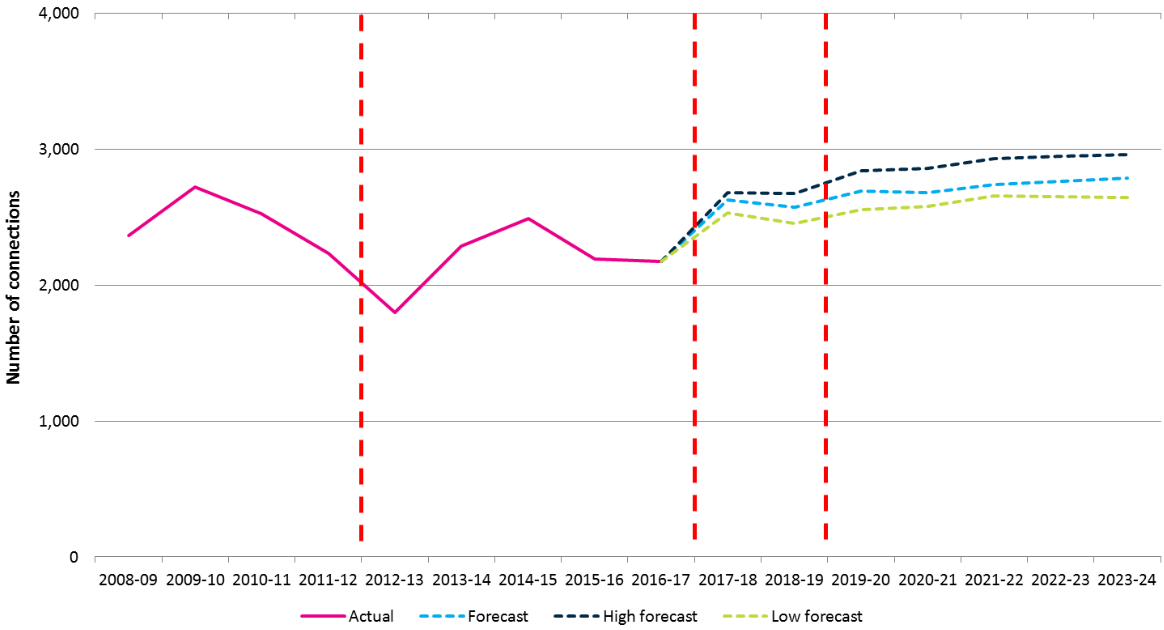
upstream network augmentation. Residential subdivisions are also forecast separately, recognising that the drivers are somewhat different to basic and complex connections.

We provide a summary of the residential customer connections in section 6.5.1, while section 6.5.2 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.

6.5.1 Residential customer connections

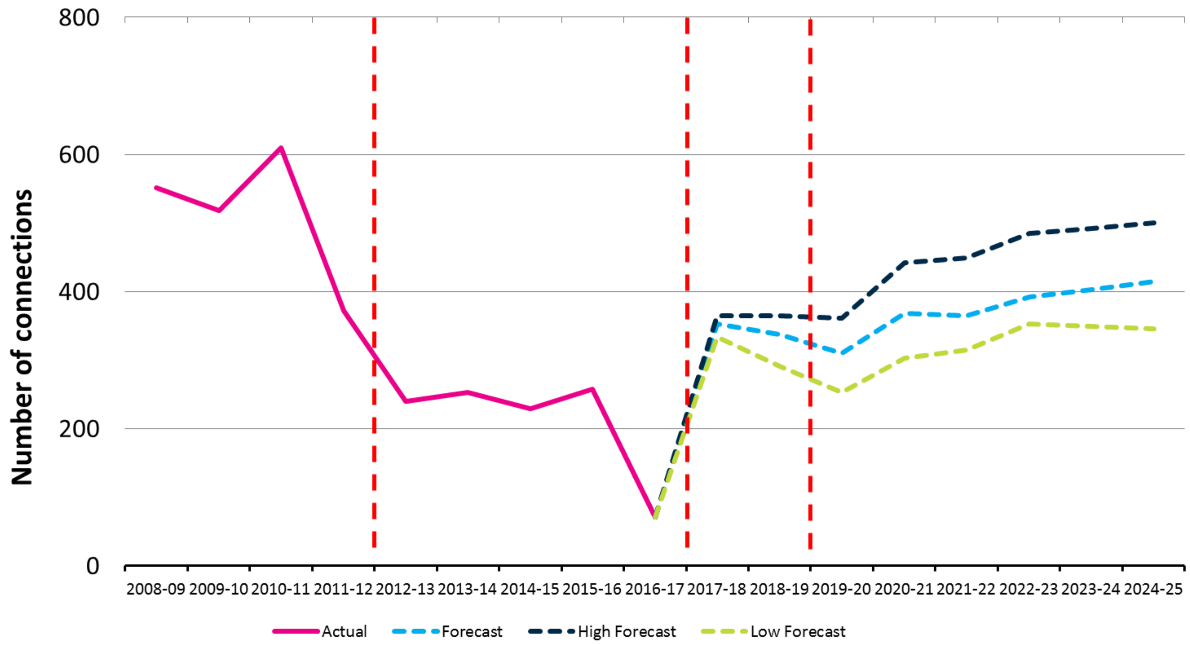
Basic Residential connections are forecast to increase steadily over the forthcoming regulatory period to around 2,800 connections per annum, as shown below.

Figure 6-4: New residential connections – basic



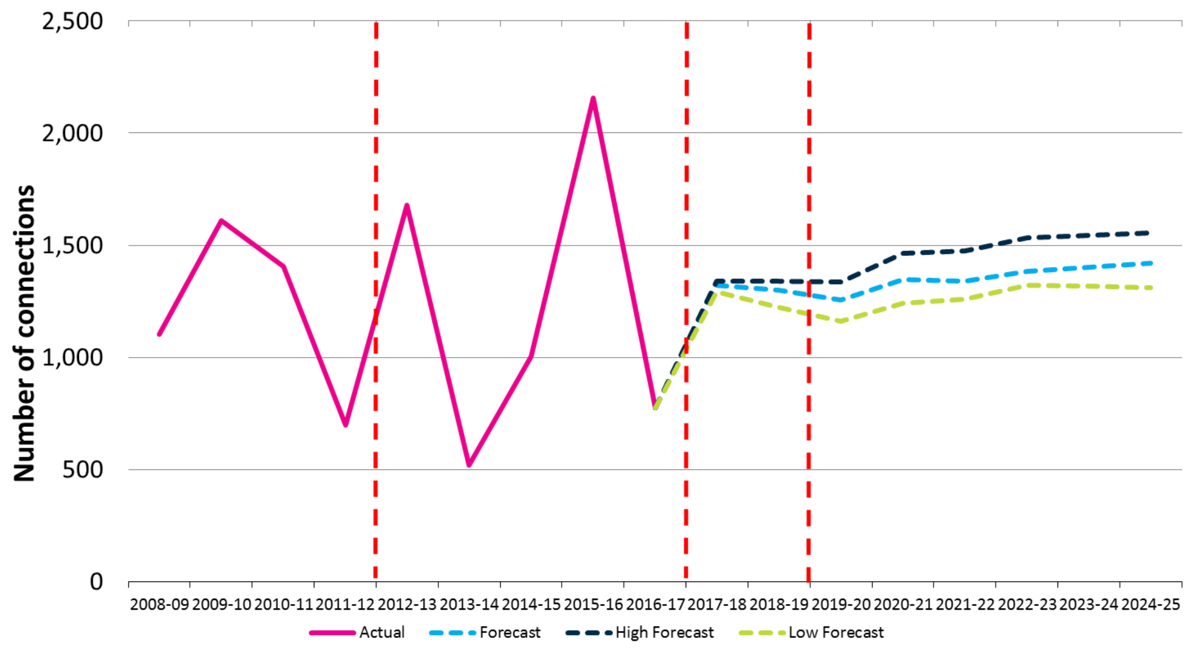
Complex Residential connections are forecast to increase steadily over the forthcoming regulatory period, returning to levels observed prior to 2013 as shown in the figure below.

Figure 6-5: New residential connections – complex



Residential subdivisions lots are forecast to remain relatively flat over the forthcoming regulatory period, as shown in the figure below.

Figure 6-6: New residential subdivisions (lots)



6.5.2 Commercial customers, irrigators and embedded generation

The figures below show our actual and forecast customer growth for basic and complex commercial connections and irrigators.

Basic commercial connections are forecast to increase steadily over the forthcoming regulatory period. There is a reasonable increase from previous years, as shown in the figure below. Complex

Commercial connections are forecast to increase steadily over the forthcoming regulatory period, returning to levels observed prior to 2013.

Figure 6-7: New commercial connections – basic

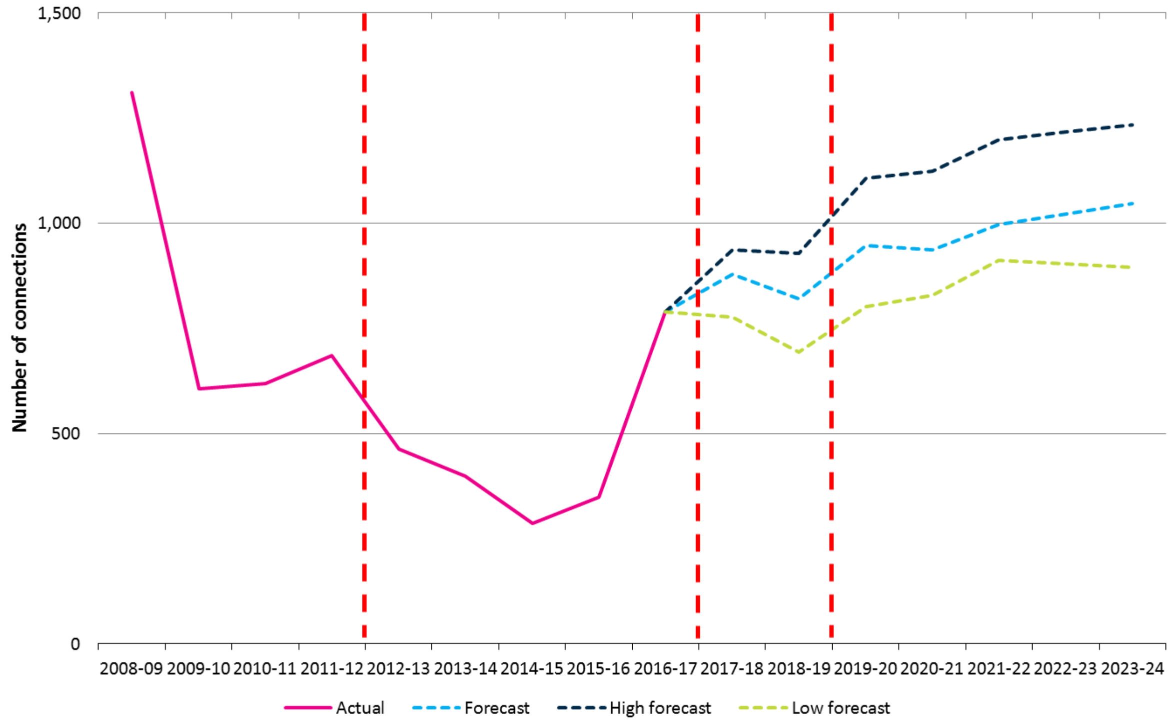
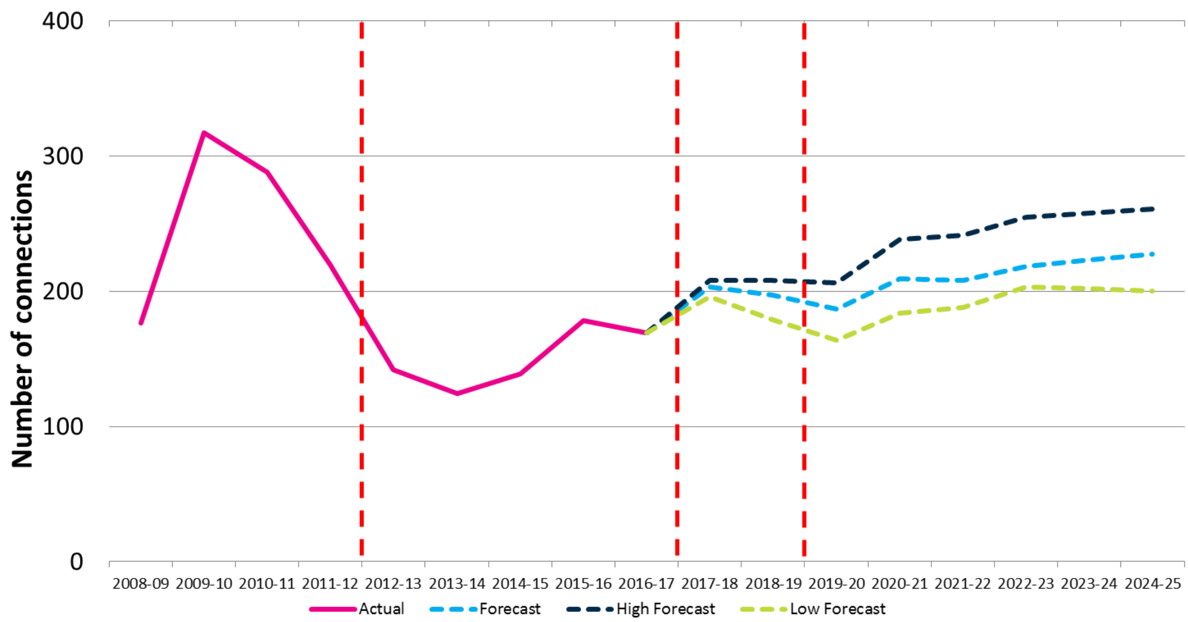
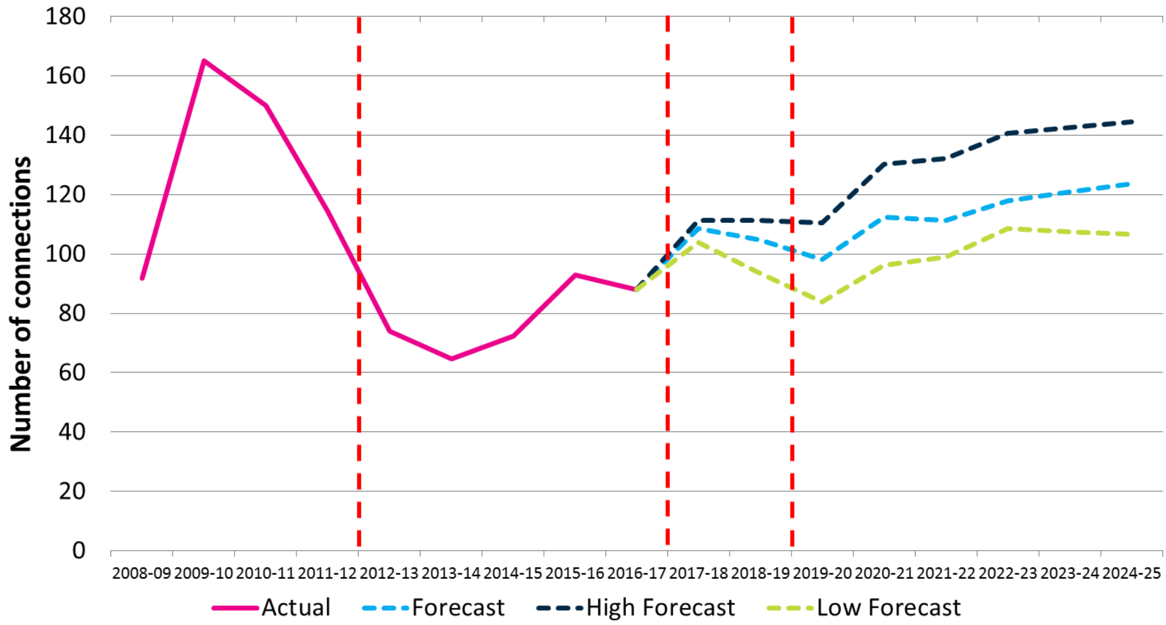


Figure 6-8: New commercial connections – complex



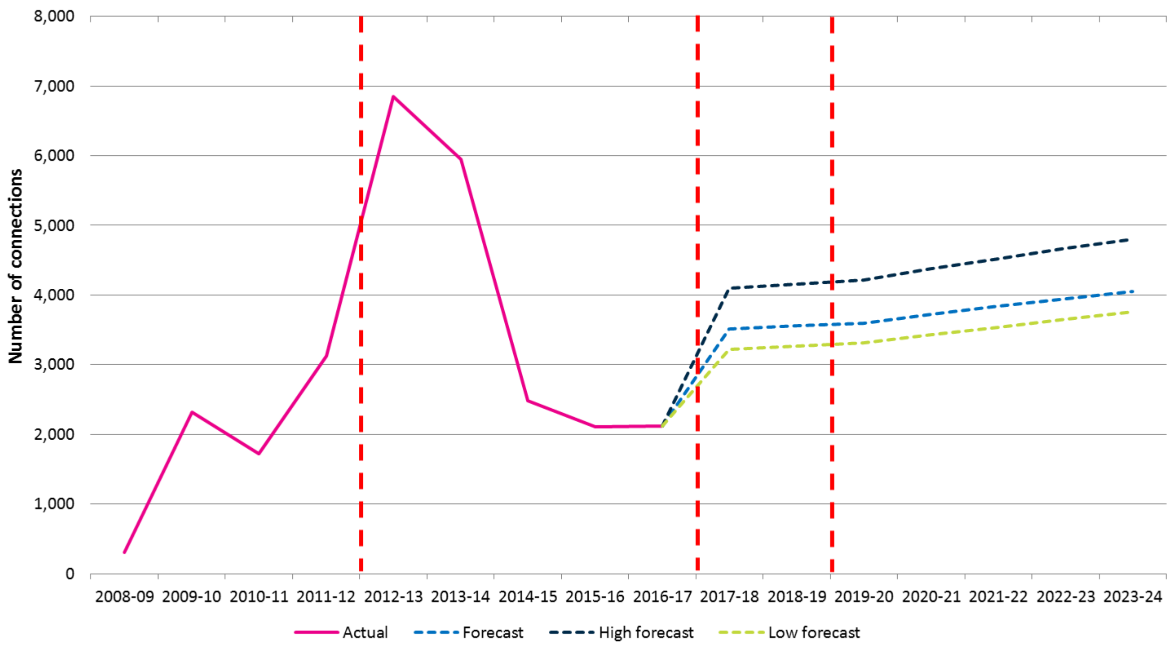
Similarly, irrigation connections are forecast to increase steadily over the forthcoming regulatory period, returning to levels observed prior to 2013, as shown in the figure below.

Figure 6-9: New irrigation connections



We have also developed forecasts for embedded generation connections, which are predominantly household solar connections. Our forecast connections are derived from AEMO's projections of uptake of small-scale systems in Tasmania, which forecasts an increase of 100 MW (doubling of the existing levels) of total installed solar PV systems in Tasmania by the end of the forthcoming regulatory period.

Figure 6-10: Historical and forecast embedded generation connections



Part Two:

Revenue Capped Services

Part Two of the Regulatory Proposal sets out information relating to our revenue capped services. These services comprise Prescribed Transmission Services and Standard Control Distribution Services.

Part Two provides an overview of the feedback we have received from our customers on our transmission and distribution revenue capped 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 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 transmission and distribution revenue allowances and indicative outcomes for customers in terms of average price paths. An overview of our transmission and distribution pricing arrangements is also provided, noting that we are transitioning to more efficient distribution network tariffs to deliver fairer outcomes and lower costs for all customers.

7 Customer feedback on revenue capped services

Chapter 3 summarised the feedback from our customer engagement process. To recap, the initial feedback we received confirmed the messages from our earlier customer consultations:

- For transmission customers (predominantly large generators and major industrial customers) reliable service and cost efficiency remain key issues. Our major industrial customers emphasised the importance of transmission charges as a key input affecting the financial viability of their businesses. Looking forward, these customers want us to drive further efficiencies, just as they focus on efficiency to remain viable in competitive markets.
- Our distribution customers are also concerned about the affordability of the service we provide, and are generally comfortable with the level of network reliability they receive. They want us to improve how we communicate with them – striking a balance between improving services and keeping costs as low as possible.

Following further engagement with transmission and distribution customers, we developed the following themes in our Direction and Priorities Paper to guide our plans for the forthcoming regulatory period:

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

The table below summarises the feedback we received on each of these themes and how we have taken this into account in our proposals for the 2019-24 regulatory period.

Table 7-1: 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	Customers continue to call out safety as a critical priority and focal area for TasNetworks. Many customers consider safety to be a 'hygiene' factor: it's taken for granted that we will operate safely. Aurora Energy, TasCOSS, along with major business customers, reinforced this as a key priority.	Safety is our top priority. Our operating expenditure includes the costs of safety measures and activities expected in our industry. The majority of our Renewal and Enhancement capital expenditure is to support the safety of our customers, employees, contractors and the community. We will continue to inform and educate our customers of safety hazards and safe behaviours through a range of targeted activities and information campaigns, including through our Community Zero Harm initiative. This includes promoting safety awareness to our customers, people, contractors and the broader community.
Keeping the power on, maintaining service reliability, network resilience and system security	Our customers continue to reinforce the importance of a reliable supply and there is a growing recognition following the South Australian 'system black' incident that network resilience and system security are also critical. Most customers are not willing to pay any more for improved reliability, and would prefer we prioritised reducing costs ahead of improving reliability. However, some customers value reliability highly and would be prepared to pay more at a reasonable and stable price.	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 continue to deliver safe and reliable network services. We are continuing to ensure we make the most prudent and efficient investment decisions given the generally long life of our assets and the level of industry disruption.

Issue or theme	Customer Feedback	Our Proposal
Delivering services for the lowest sustainable cost	Customers continue to reinforce the expectation that we continue to operate our business as efficiently as possible, to drive good outcomes for customers today and into the future. This is consistent with the feedback we regularly receive, including in many of the submissions we received as part of this consultation.	We have heard the feedback from our customers that delivering our services for the lowest sustainable cost is very important. We have taken a number of additional measures compared to our provisional Revenue Proposal to meet this expectation including: • the re-phasing of technology investments relating to market data management systems; • a 5.0 per cent optimisation of the distribution network capital expenditure forecasts; • a 0.5 per cent optimisation of the transmission network capital expenditure forecasts; • a 5.0 per cent optimisation of the shared business services capital expenditure forecasts; • bringing transmission into alignment with our distribution rate of return, resulting in a reduction to our transmission rate of return of 25 basis points; • a reduced claim for the costs of additional obligations or 'step changes' that we expect to incur; • efficiency savings to absorb cost increases from labour and customer growth; • an additional one per cent annual reduction in our transmission and distribution operating expenditure forecasts for the final three years of the regulatory control period, following on from a 0.5 per cent reduction in the second year; and • a rebalancing of our transmission revenue profile to provide a flatter price path over the period. This package of measures will reduce transmission and distribution revenues, in nominal terms over the forthcoming regulatory period, by $29.8 million and $28.4 million respectively compared to our provisional Revenue Proposal plans. In addition, our contingent project proposal arrangements ensure that customers do not pay for projects that are not certain to proceed.

Issue or theme	Customer Feedback	Our Proposal
Improving how we communicate with, and listen to, our customers	Customers want us to continue to look into ways in which we can better communicate with them. This includes better communication in real time to customers across different regions and with different demographics, particularly during outages, and improving our approach to customer engagement on strategic issues.	We will continue to pursue our goal of caring for our customers and making their experience easier – using a range of tools and strategies, including continued investment in developing our people to provide good customer service. We will maintain and improve customer facing platforms to make our customers' experience easier. We are also planning to invest in systems that support complaint handling, connection applications and customer interaction tracking.
Innovating in a changing world	Customers are keen to see TasNetworks continue to demonstrate and drive innovation to deliver better customer outcomes. However, there are different views on the pace of change. Some customers believe we are moving too quickly, while others believe we are not moving fast enough.	Building on the Network Transformation Roadmap, our 2025 vision recognises the network challenges as the technological advances and changes in the generation mix place new demands on the Tasmanian network. We have developed an Innovation Framework to ensure that we pursue opportunities for cost-effective innovations. We will leverage the learnings from our CONSORT Bruny Island Battery and emPOWERing You trials, coupled with increased data analytics to better understand our customers and tailor our service provision.
Bringing the community on the journey of pricing reform	Feedback from customers and stakeholders, including our owners and retailers, has reinforced the importance of helping the community to transition to more cost reflective pricing for distribution-connected customers.	Over the next five years we aim to improve the quality of information available to support future pricing strategy refinement and customer understanding of how to benefit from new types of tariffs. This information will reflect learnings from the emPOWERing You and CONSORT Bruny Island trials.

In the remaining chapters in this Part Two, we explain our proposed transmission and distribution expenditure plans, revenue requirements and network pricing, taking into account customer feedback.

8 Capital expenditure forecasts

8.1 Introduction

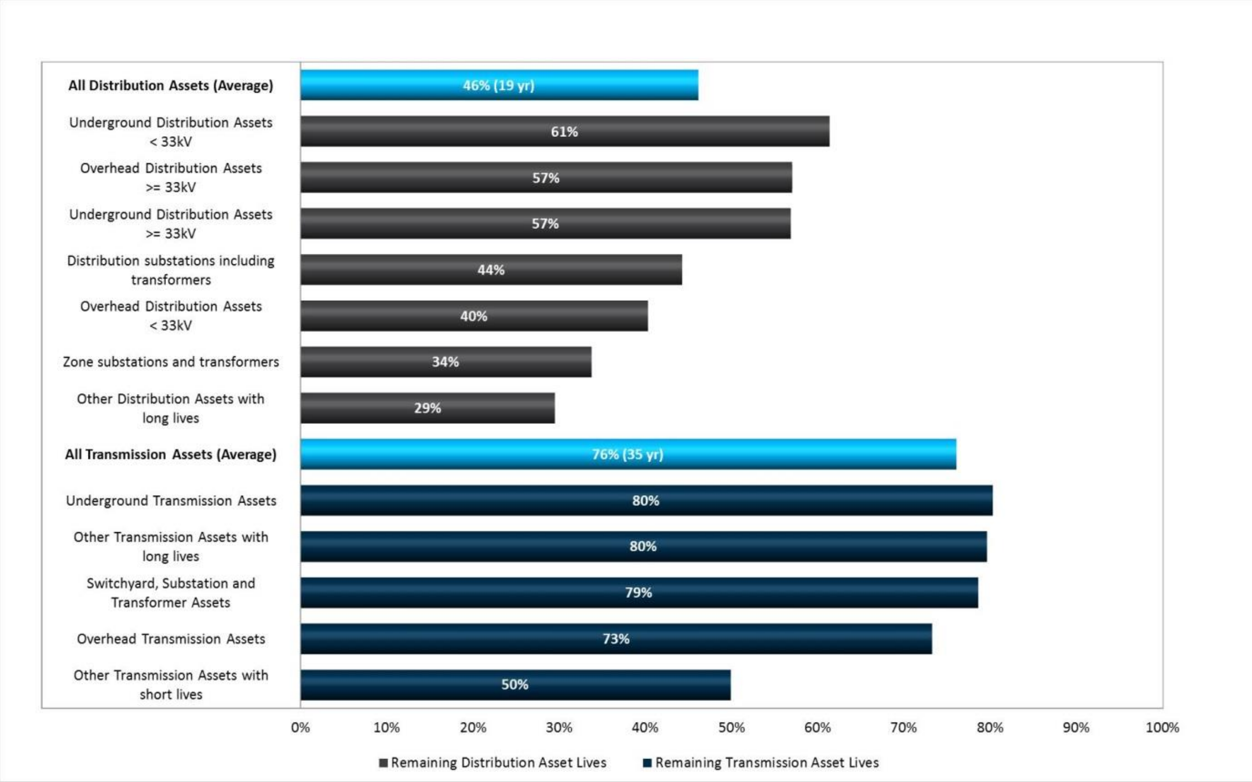
This chapter presents our capital expenditure plans for the forthcoming regulatory period, for both our transmission and distribution networks. As noted in Chapter 7, we have applied a top down discipline to our preliminary capital expenditure forecasts to address our customers' feedback that affordability is of primary concern. As a result, we have reduced our total capital expenditure forecasts by over $42 million, with the majority of this reduction applying to our distribution forecast. Our plan is to deliver the same program for a reduced cost. The greater optimisation of the distribution program reflects the benefits that are expected to flow from the planned investments in business transformation.

While we seek to minimise our capital expenditure, we must also ensure that the safety and reliability of our network services is not compromised. To achieve this objective, our analysis shows that capital expenditure must increase in the forthcoming regulatory period as we renew assets in poor condition, replace technology platforms at end of life, manage increased bushfire related risk and connect new customers.

Our asset management approach is to replace assets on the basis of condition and risk, rather than age. Nevertheless, the remaining life of our transmission and distribution assets provides a useful indication of the relative pressures on our transmission and distribution networks in relation to asset renewal.

The figure below shows the average remaining asset lives by asset class for our transmission and distribution networks. On average, it shows that our distribution assets are substantially older with less remaining life compared to transmission.

Figure 8-1: Remaining life by asset category



In developing our capital expenditure forecasts, we have considered the risks associated with our ageing assets together with the future demands on our network, particularly in response to changing customer use and the growth of renewable generation.

As the transmission and distribution network service provider in Tasmania, we have the responsibility to ensure that the infrastructure that is used to supply electricity to Tasmanians meets the network requirements, and is provided in an economically optimal and sustainable way. To achieve this we consider transmission and distribution planning as one integrated function, and approach planning for one electricity network.

In this Chapter, we explain why our capital expenditure forecasts satisfy the Rules' requirements and therefore should be accepted by our customers and the AER. The chapter is structured as follows:

- Section 8.2 presents our transmission capital expenditure forecasts, including the key assumptions and the forecasts for each sub-category of transmission capital expenditure.
- Section 8.3 presents our distribution capital expenditure forecasts, including our forecasts for the sub-categories of expenditure.
- Section 8.4 explains the steps we have taken to ensure that our transmission and distribution plans are deliverable.
- Section 8.5 summarises how our customers are expected to benefit from our proposed capital expenditure program.
- Section 8.6 explains why our forecast capital expenditure is prudent and efficient, having regard to the capital expenditure factors specified in the Rules.

Our forecasting methodology for each capital expenditure category is unchanged from the approach notified to the AER and available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24/proposal.

Supporting information and analysis 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, where appropriate, and substitution between operating and capital expenditure.

8.2 Transmission capital expenditure forecasts

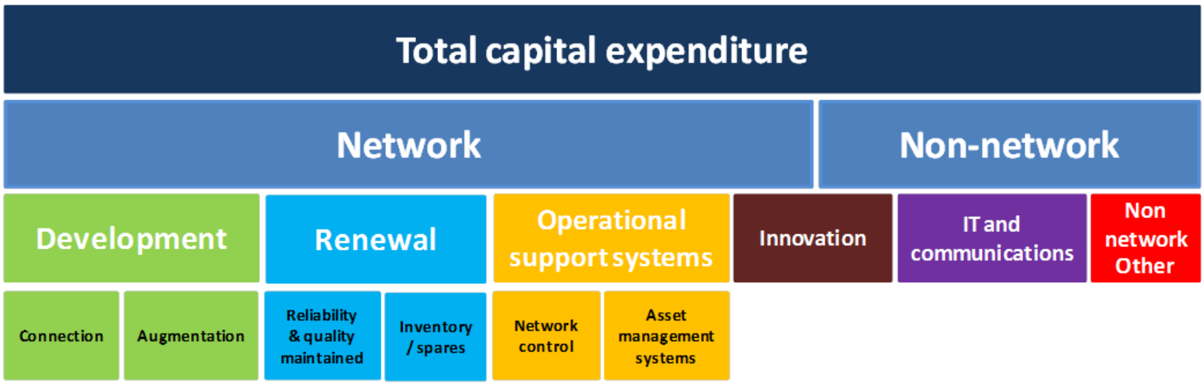
8.2.1 Overview

For the forthcoming regulatory period, we are not expecting any new load customers to connect to the transmission network. On the other hand, the substantial increase in generation connection enquiries we have received, particularly for renewable generation, suggests that it is highly likely that new generation will be connected to the transmission network in the forthcoming regulatory period.

New generation connections are classified as negotiated transmission services, which are not revenue capped, and the connection of new generation has, therefore, been excluded from this Regulatory Proposal. Nonetheless, the connection of new generation is an important driver of augmentation capital expenditure on the shared network and we have proposed five contingent projects to address the potential market benefits from greater system security and energy transfer.

The figure below shows the transmission capital expenditure categories we have adopted for the purpose of presenting our actual and forecast capital expenditure.

Figure 8-2: Transmission capital expenditure categories



The above breakdown of capital expenditure includes an ‘innovation’ category that spans network and non-network activities. In this proposal, however, we have not directly attributed expenditure to the ‘innovation’ category – as innovation is an activity that affects investment decisions across the entire business, rather than being a standalone activity. Our network innovation strategy is provided as a supporting document (TN027).

The table below shows that our total transmission capital expenditure in the current five year regulatory period is expected to be $211.3 million, which is 22.3 per cent below the AER’s total allowance of $271.8 million. This reduction reflects the impact of establishing TasNetworks and reviewing previous practices. As already noted, our forecast capital expenditure of $260.6 million in the forthcoming regulatory period includes a $5.7 million optimisation of our provisional Revenue Proposal transmission capital expenditure plans, in response to customer concerns regarding affordability.

Table 8-1: Actual and forecast transmission capital expenditure by category (June 2019 $m)

Category	Regulatory allowance for 2014-15 to 2018-19	Actual/Forecast expenditure for 2014-15 to 2018-19	Forecast expenditure for 2019-20 to 2023-24
Development	22.7	7.7	24.2
Renewal	199.2	154.5	204.5
Operational Support Systems	35.9	17.0	10.2
IT and Communications	7.7	23.1	14.3
Non-Network Other	6.3	9.0	7.3
Total	**271.8**	**211.3**	**260.6**

During the current regulatory period, our transmission capital expenditure focussed on:

- Renewing assets that were in poor condition which represented a risk to the safe and reliable performance of the transmission system.
- Information technology, communications and operational support systems. These systems are essential in providing the information and analysis required to operate a network with an increasing range of generation technologies connected to it.

Our transmission investment in the forthcoming period will continue these activities, with renewal capital expenditure dominating our forecast transmission capital expenditure. Our focus on renewal expenditure is to ensure our assets are safe, fit for purpose, and reliable. Where appropriate we will continue to maximise asset life, increase utilisation, and defer investment, all within the bounds of managing risk appropriately and employing improved asset management techniques and practices.

Table 8-22, 8-3 and Figure 8-3 below provides a breakdown of our transmission capital expenditure forecasts by expenditure category, and a comparison with historical expenditure.

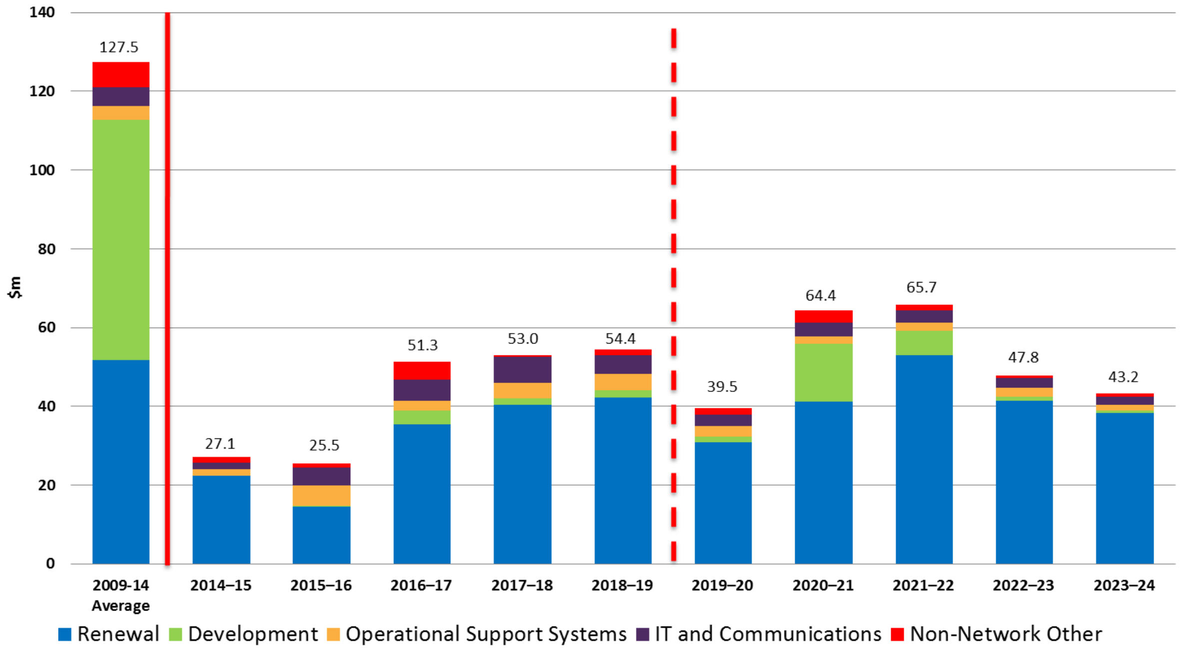
Table 8-2: Historic transmission capital expenditure by category (June 2019 $m)

Category	2009-10	2010-11	2011-12	2012-13	2013-14	2014–15	2015–16	2016–17
Development	129.5	67.9	89.0	13.8	5.1	0.2	0.3	3.5
Connection	8.5	26.0	29.1	2.3	0.1	0.0	0.0	0.2
Augmentation	121.0	41.8	59.8	11.6	5.0	0.2	0.3	3.3
Renewal	18.2	41.2	48.2	75.7	75.2	22.3	14.4	35.4
Reliability & Quality Maintained	18.2	41.2	48.2	75.7	75.2	22.3	14.4	30.9
Inventory and Spares	-	-	-	-	-	-	-	4.5
Operational Support Systems	5.2	4.7	3.8	2.3	2.0	1.5	5.0	2.4
Network Control	3.4	2.9	2.0	0.5	0.3	0.5	3.4	0.8
Asset Management Systems	1.9	1.8	1.8	1.7	1.7	1.1	1.6	1.6
IT and Communications	5.6	5.5	5.3	5.2	2.2	1.7	4.6	5.4
Non-Network Other	5.9	20.9	2.6	0.9	1.4	1.4	1.1	4.6
Total transmission capital expenditure	**164.5**	**140.2**	**148.9**	**97.9**	**85.9**	**27.1**	**25.5**	**51.3**

Table 8-3: Forecast transmission capital expenditure by category (June 2019 $m)

Category	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Development	1.8	1.8	1.5	14.8	6.3	1.0	0.6
Connection	0.1	0.1	-	1.1	1.9	-	-
Augmentation	1.7	1.8	1.5	13.7	4.4	1.0	0.6
Renewal	40.3	42.1	30.7	41.1	52.9	41.5	38.3
Reliability & Quality Maintained	40.3	42.1	30.7	41.1	52.9	41.5	38.3
Inventory and Spares	-	-	-	-	-	-	-
Operational Support Systems	3.9	4.1	2.6	1.9	2.1	2.2	1.4
Network Control	1.9	2.4	0.9	0.5	0.7	0.7	0.4
Asset Management Systems	2.0	1.7	1.8	1.5	1.4	1.5	1.0
IT and Communications	6.5	4.8	3.0	3.5	3.0	2.7	2.2
Non-Network Other	0.4	1.5	1.5	3.1	1.4	0.5	0.8
Total transmission capital expenditure	**53.0**	**54.4**	**39.5**	**64.4**	**65.7**	**47.8**	**43.2**

Figure 8-3: Overview of actual and forecast transmission capital expenditure (June 2019 $m)



As already indicated, renewal capital expenditure will increase substantially in the forthcoming regulatory period as we ensure our assets are safe, fit for purpose, and reliable.

The figure above also shows an increase in our development capital expenditure compared to recent levels. This increase is not driven by demand growth, which remains flat. Instead, it relates principally to a single $15 million[23] project to install a new static var compensator at the George Town Substation. The compensator will support more stable and efficient operation of our transmission network with changing generation and interconnector flows, and allow dispatch of lower cost generation. This project alone will increase our level of development capital expenditure when compared to the current period, in which little development capital expenditure was required.

The other categories of transmission capital expenditure are comparable with current levels of expenditure, each being somewhat lower than the current regulatory period.

8.2.2 Key assumptions for transmission capital expenditure forecasts

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

- our forecasts for transmission system demand and generation requirements are robust; and
- our investment evaluations, including the project and program scopes and estimating practices, are credible and reflect our capital expenditure requirements.

In accordance with schedule S6A.1.1(5) of the Rules, the Board of TasNetworks has provided a certification of the reasonableness of these assumptions in relation to our transmission services (supporting document, TN020).

[23] We plan to commence the 12 month RIT-T process in June 2018.

In preparing our expenditure forecasts, we have escalated our materials and labour costs, however we have:

- limited the escalation of material costs to CPI; and
- applied modest real price escalation in relation to labour rates, based on advice received from Jacob[24] (TN166), as set out in the table below.

Table 8-4: Forecast labour escalation rates, expressed in real terms (%)

Category	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Internal labour	0.00	0.00	0.00	0.49	0.49	0.49	0.49
External labour (contractors)	0.49	1.23	0.98	0.98	0.98	0.98	0.98

8.2.3 Transmission development capital expenditure

The table below shows our annual actual and forecast transmission development capital expenditure. Generation connections are negotiated transmission services, which are not revenue capped and, therefore, are outside the scope of this Regulatory Proposal. As already noted, however, the recent and projected growth in renewable generation in Tasmania has implications for our future transmission development capital expenditure.

Table 8-5: Transmission development capital expenditure (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Connection	0.0	0.0	0.2	0.1	0.1	0.0	1.1	1.9	0.0	0.0
Augmentation	0.2	0.3	3.3	1.7	1.7	1.5	13.7	4.4	1.0	0.6
Transmission Development	**0.2**	**0.3**	**3.5**	**1.8**	**1.8**	**1.5**	**14.8**	**6.3**	**1.0**	**0.6**

Our forecast transmission development capital expenditure for the five-years commencing 1 July 2019 is $24.2 million compared to expenditure of $7.6 million for the current regulatory period. Transmission network development capital expenditure consists of both connection and augmentation components, which are discussed in turn below.

Transmission connection capital expenditure

In the forthcoming regulatory period, we have one transmission connection project with a value of $2.9 million at our Sheffield Substation.

This project involves the establishment of a 22 kV connection point at the Sheffield Substation, by energising an existing spare 110/22 kV transformer as a 'hot spare'. This project will improve the reliability of the 1.4 per cent of customers connected to the distribution network's Railton feeders 85001 and 85003. These feeders are 400 kilometres and 175 kilometres long, respectively. In terms of feeder performance, feeder 85003 has overall average performance while feeder 85001 has the second highest impact on our distribution service performance outcomes when it operates. The

[24] Jacob, Labour Cost Escalation Report, 25 October 2017.

proposed reduced loading on Railton and the new connection point reduces the frequency and duration risk of outages for customers by splitting both feeders into shorter feeders and providing backup supply to more parts of the divided feeders.

Transmission augmentation capital expenditure

In contrast to connection capital expenditure, which is specific to new customers or changes to existing connections, augmentation capital expenditure addresses capacity, reliability and security issues on the transmission network. Transmission network demand growth and new generation connections can cause changes and increases in flows on the network. If inadequate augmentation is undertaken, there may be an increased reliability risk and occurrence of load shedding, generator curtailment, system performance issues and/or asset failure.

Our planning area strategies (which apportion our planning areas geographically) define our transmission and distribution network augmentation strategies by:

- identifying existing and forecast limitations based on the demand forecast, security and reliability requirements, and other factors; and
- selecting the highest net benefit solution to address the identified limitations, having regard to other planning considerations such as asset retirements and operational constraints.

The planning area strategies are provided as supporting documents (TN029 – TN036) along with this Regulatory Proposal.

For our transmission network, augmentation capital expenditure comprises the following key project:

- **Installation of a dynamic reactive power device at George Town Substation**

  Under some system conditions, voltage control at our George Town Substation currently constrains the export of electricity over Basslink. Reductions in generation output from the nearby gas-fired Tamar Valley Power Station, coupled with an expected increase in wind powered generators in the area, will only exacerbate voltage control issues. Furthermore, under certain conditions there is an increased likelihood of a voltage imbalance being generated, and the potential for a localised system disturbance at the George Town Substation which could develop into a widespread system disturbance.

  Installing dynamic reactive support at the George Town Substation will help to maintain compliance with the Rules' clauses S5.1a.5 (voltage fluctuations) and S5.1a.7 (voltage imbalance).

  The proposed project will also assist in alleviating constraints that limit power flows on Basslink. This is expected to lead to lower dispatch costs in the NEM, thereby providing net market benefits that will be assessed in accordance with the Regulatory Investment Test – Transmission (**RIT-T**).

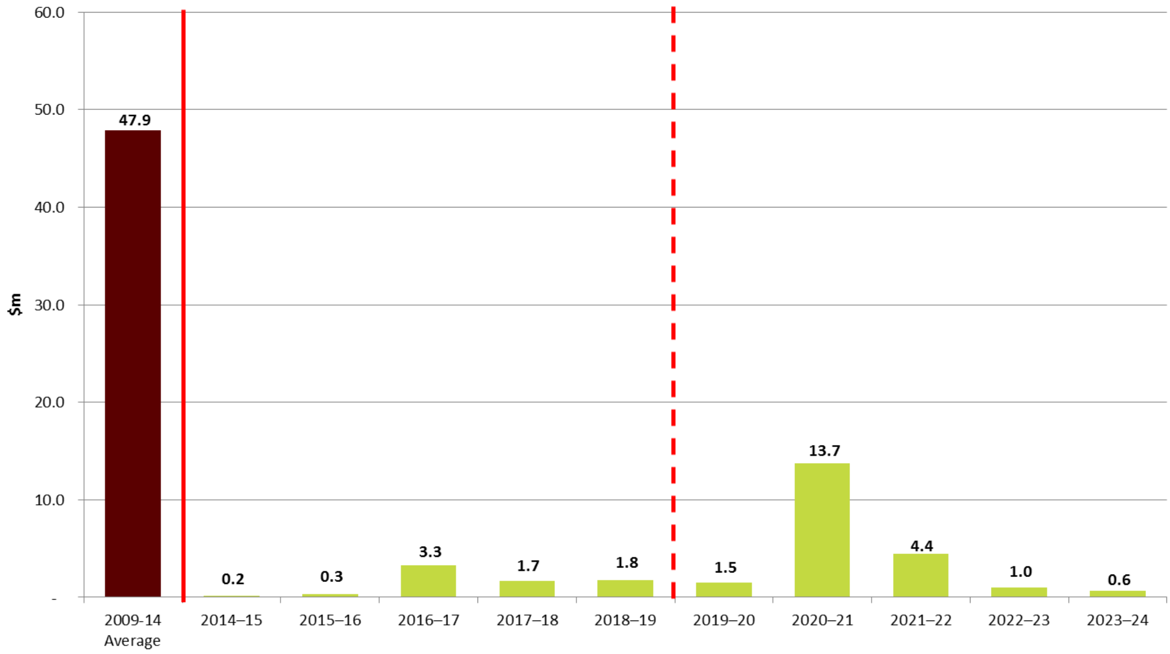
The table below shows our actual, committed and forecast transmission augmentation capital expenditure. The forecast expenditure for each project reflects the planned scope of work and estimated costs based on similar projects. The estimated costs are based on historical data and reasonable assumptions about future requirements, given the best information available to us at the time.

Table 8-6: Transmission augmentation capital expenditure (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission augmentation	0.2	0.3	3.3	1.7	1.8	1.5	13.7	4.4	1.0	0.6

The figure below presents the same information in bar chart format.

Figure 8-4: Transmission augmentation capital expenditure (June 2019 $m)



The above table and figure shows that our forecast transmission augmentation capital expenditure is higher than the current regulatory period. As already noted, this increase is primarily driven by the George Town substation project. In addition, the current regulatory period provides an artificially low point of comparison as augmentation capital expenditure during that period is low when compared with historical trends.

While our forecast transmission augmentation capital expenditure remains modest, we have identified five contingent projects which may lead to a significantly higher network expenditure – offset by greater customer benefits – if particular 'trigger events' occur. The trigger events that may eventuate during the forthcoming regulatory period and require augmentation of the transmission network are:

- implementation of a second HVDC interconnector between Tasmania and Victoria;
- constraints in transmitting energy from Sheffield into the rest of the network, depending on the location of the second Bass Strait interconnector and new wind generation;
- the addition of significant generation in Tasmania's North West requiring augmentation of the Burnie to Smithton 110 kV transmission corridor;

- rationalisation of our ageing 110 kV transmission network in the Upper Derwent region undertaken to align with Hydro Tasmania's connection requirements for the potential replacement and relocation of the Tarraleah Power Station; and
- augmentation of the 220 kV transmission system between Sheffield and Burnie, which includes the establishment of new double circuit transmission line operating at 220 kV between Sheffield and Burnie substations; and reconfiguration and rationalisation of the 110 kV transmission line between these substations to facilitate the new 220 kV transmission line within the existing corridor.

In each case, the contingent projects will only proceed if it can be demonstrated that they will deliver a net benefit in accordance with the RIT-T. Our proposed contingent projects are described in further detail in section 8.2.8.

8.2.4 Transmission renewal capital expenditure

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

Table 8-7: Transmission renewal capital expenditure (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Reliability and quality maintained	22.3	14.4	30.9	40.3	42.1	30.7	41.1	52.9	41.5	38.3
Inventory / spares	0.0	0.0	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total transmission renewal	**22.3**	**14.4**	**35.4**	**40.3**	**42.1**	**30.7**	**41.1**	**52.9**	**41.5**	**38.3**

Our forecast transmission renewal capital expenditure for the five years commencing 1 July 2019 is $204.5 million compared to expenditure of $154.5 million for the preceding five year regulatory period. Our forecast capital expenditure is, therefore, increasing when compared with recent historic expenditure. As already noted, our renewal capital expenditure is focused on maintaining current performance and managing risk, including network safety and reliability, having regard to asset condition.

In terms of inventory and spares, we currently have adequate stock and, therefore, we do not forecast any additional requirements for the forthcoming regulatory period.

The following section discusses reliability and quality maintained renewal capital expenditure in further detail.

Transmission reliability and quality maintained capital expenditure

The key drivers of capital expenditure in the forthcoming regulatory period relating to the maintenance of network reliability and quality are:

- safety and environmental performance and compliance requirements;
- asset condition and risk;
- asset performance;
- technical obsolescence; and

- physical security.

Essentially, our forecasts have been developed through a careful ‘bottom up’ evaluation of investment requirements for each asset class, combined with a top down discipline to optimise program synergies ensuring optimal timing of any proposed expenditure. The forecasts have been derived and verified using the following methods as appropriate:

- asset specific condition assessment;
- asset life and failure rate modelling as an input to our project options analysis;
- 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.

The choice of forecasting technique is dependent on the nature of the asset and the quality of available data. Our capital expenditure on the maintenance of transmission reliability and quality in the current regulatory period will be $154.5 million. Our detailed asset management plans set out the rationale for the proposed level of reliability and quality maintained capital expenditure in the forthcoming regulatory period, for each asset category.

We continue to work hard to safely maximise the lives of our assets. However, many assets, such as power transformers, Extra High Voltage (**EHV**) and High Voltage switchgear and protection, control equipment and telecommunications equipment are in poor condition and are at end of their service life. Therefore a modest increase in replacement volumes is prudent, based on deteriorating health indices and increasing risk profiles.

An increase in the volume of protection and control works is required to replace our fleet of electromechanical and static technologies, which are obsolete, with no manufacturer support and depleted spares. Similarly, telecommunication voice system assets have reached the end of their service life, are no longer supported by manufacturers and is obsolete technology that needs to be replaced to ensure compliance with the Rules.

The increase in expenditure on substations can be attributed to the replacement of our fleet of 220 kV live tank circuit breakers, 110 kV live tank circuit breakers, power transformer replacements and the replacement of 11 kV and 22 kV circuit breakers.

The table below summarises the capital expenditure forecasts relating to the maintenance of transmission reliability and quality, by asset class.

Table 8-8: Composition of transmission reliability and quality maintained capital expenditure forecast (June 2019 $m)

Category	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Transmission Lines	11.3	7.4	12.0	12.6	7.1	50.5
Transmission P&C	8.0	7.7	7.1	7.7	7.8	38.2
Transmission Substations	5.7	23.8	29.7	18.2	18.1	95.5
Transmission Telecommunications	5.9	2.1	4.1	2.9	5.3	20.2
Total	**30.7**	**41.1**	**52.9**	**41.5**	**38.3**	**204.5**

The capital expenditure on asset renewal in the forthcoming regulatory period predominantly comprises programs of work for key infrastructure groups. Below is a summary of the major asset renewal expenditure projects and programs.

- **Transmission lines**

  Our transmission lines, operating at 220 kV and 110 kV, transmit electricity from generators to the distribution system, major industrial customers and Basslink over approximately 7,800 support structures that transverse approximately 11,000 hectares of easements. Our investment portfolio over the forthcoming regulatory period aims to ensure we operate and maintain these assets in a safe manner and maintain current levels of reliability. To achieve this we plan to replace the short 3.1 kilometre Georgetown – TEMCO 110 kV transmission line that was originally built in 1962. We also plan to continue our programs to replace overhead earth wire, insulators and foundations that have reach end of life. In alignment with our bushfire mitigation programs we plan ongoing management of our easements.

- **Supply transformers**

  Supply transformers play a vital role within the transmission network, with a prime function of voltage transformation from one level to another in order to facilitate the efficient delivery of electricity. We currently have around 100 supply transformers and, following probability of failure analysis, we are planning to replace 12 of these in the forthcoming regulatory period. This program has been driven by identified asset degradation, design and manufacturing deficiencies as well as operational stresses. On an ongoing basis, we employ risk based management techniques to monitor asset condition and have undertaken detailed asset condition assessments to identify replacement priorities.

- **High voltage switchgear**

  TasNetworks has an ageing fleet of high voltage switchgear with an increased probability of insulation breakdown which may lead to asset failure. We are therefore proposing to replace assets at six substations that have been identified with a high risk of failure in the forthcoming regulatory period.

- **Extra high voltage switchgear**

  Our EHV switchgear program has been developed such that replacement is targeted on a sequential priority basis as a result of analysis against defined replacement criteria. As a result of this analysis, in the forthcoming regulatory period we are proposing to replace nine 220 kV Mitsubishi circuit breakers, six 220 kV Sprechur and Schuh circuit breakers and 14 110 kV Asea circuit breakers. This proposal is supported by a recent increase in asset failures, a lack of manufacturer support and reduced availability of manufacturer spare parts.

- **Site infrastructure**

  We understand the importance of maintaining the integrity, security and safety of our critical transmission infrastructure sites. To assist in this task, we are proposing to install additional security measures, in the form of security cameras, across 23 of our substation sites, as well as continuing our programs associated with fire detection, suppression and prevention and general site civil works.

Programs and projects with a value of $5 million or greater are listed in Table 8-9. Further details are provided in our asset management plans and investment evaluation summaries.

Table 8-9: Projects and programs with a value of at least $5 million (June 2019 $m)

Category	Total
Transmission Lines	
- George Town - TEMCO 110 kV Transmission Line Replacement	**5.6**
- Transmission Line Access Track Refurbishment Program	**5.2**
- Transmission Line Conductor Assembly Refurbishment Program	**7.0**
- Transmission Line Insulator Assembly Replacement Program	**7.8**
- Transmission Line Tower Foundation Refurbishment Program	**5.2**
Transmission Substations	
- Replace 110 kV live tank circuit breakers	**5.7**
- Replace 220 kV live tank circuit breakers	**6.8**
Transmission P&C	
- Transmission Line Protection Renewal Program	**14.8**

Consistent with the customer feedback received, we have engaged with customers, such as TEMCO prior to making investment decisions which may impact their price.

8.2.5 Transmission Operational Support Systems

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

Table 8-10: Transmission Operational Support Systems capital expenditure (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Network Control	0.5	3.4	0.8	1.9	2.4	0.9	0.5	0.7	0.7	0.4
Transmission Asset Management Systems	1.1	1.6	1.6	2.0	1.7	1.8	1.5	1.4	1.5	1.0
Total transmission Operational Support Systems	**1.5**	**5.0**	**2.4**	**3.9**	**4.1**	**2.6**	**1.9**	**2.1**	**2.2**	**1.4**

It should be noted that we consider our requirements for operational support systems across the transmission and distribution networks as a whole, as explained below. The distribution component of this capital expenditure is presented in section 8.3.5.

Network Control

Network control capital expenditure includes the Supervisory Control and Data Acquisition (**SCADA**) and associated operational information systems which monitor, control, analyse, exchange and record the current state of the electricity network within Tasmania. The Network Operations Control System (**NOCS**) is required to ensure that we can:

- operate the Tasmanian transmission system on a standalone basis, should the provision for Residual Power System Security (**RPSS**) be invoked;
- provide operating and market interfaces between AEMO and Tasmanian market participants; and
- provide a suite of online network modelling tools to assist us in ensuring the network is operated within its technical envelope.

The NOCS forms an essential part of our compliance obligations relating to:

- the remote control and monitoring of devices under the Rules (section 1, clause 4.11); and
- planning and operating the network within acceptable levels of power quality, as specified in the Rules (schedule 5.1) and relevant Australian Standards.

For the forthcoming regulatory period our focus is on maximising the investments already made in this area and planning for future period incremental improvements.

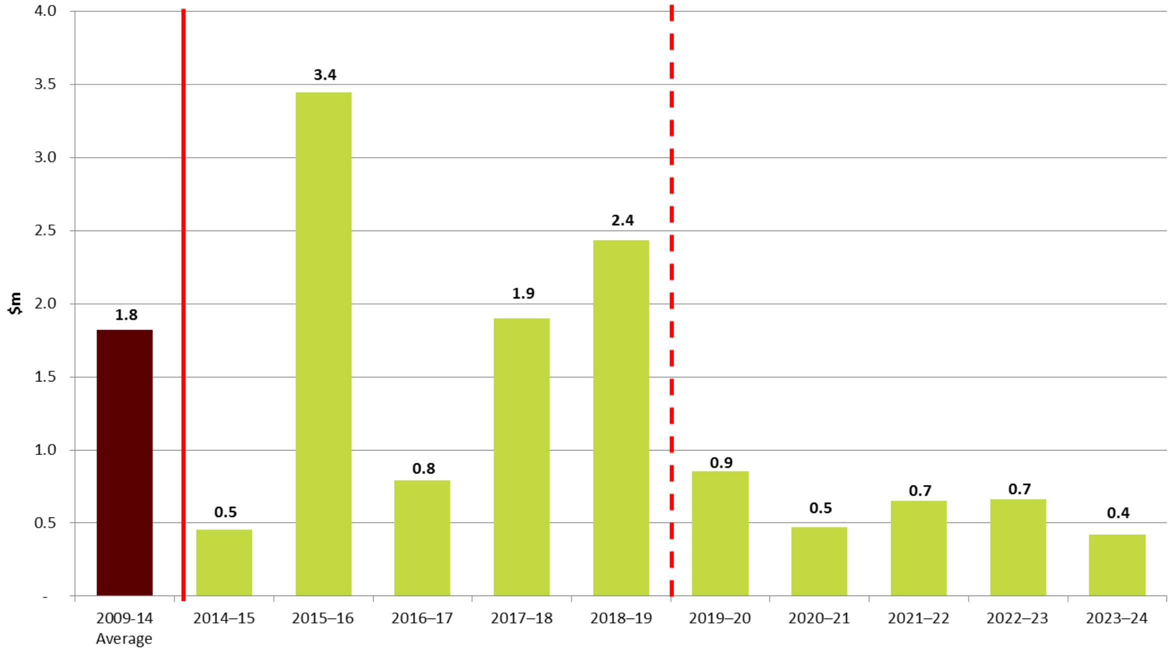
The network control capital expenditure presented below shows the attribution to transmission services in accordance with the Cost Allocation Methodology (**CAM**) approved for TasNetworks by the AER, which has decreased when compared to historic levels. The distribution network's allocation of network control capital expenditure is presented section 8.3.5.

Table 8-11: Transmission Network Control capital expenditure (June 2019 $m)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	0.5	3.4	0.8	1.9	2.4	0.9	0.5	0.7	0.7	0.4

The figure below presents the same information in bar chart format.

Figure 8-5: Transmission Network Control capital expenditure (June 2019 $m)



Our actual transmission network control capital expenditure for the current regulatory period is expected to be $9.0 million. For the forthcoming five-year period, we are forecasting $3.1 million, this is consistent with the focus of consolidation and future planning.

Further details of our transmission network control expenditure requirements are provided in the Network Operations Operational Systems Strategy 2017 – 2025 (TN041), and the Network Operations Asset Management Plan (TN074).

Asset Management Systems

Investment in new and upgraded Asset Management Systems (**AMS**) is the second component of the Operational Support Systems capital expenditure. The AMS category includes development, enhancement, maintenance and replacement of asset management business processes, business systems, and associated tools and software.

AMS is used for asset information gathering, management and analysis. These activities are essential prerequisites to achieving efficient asset management outcomes. We employ a number of related asset management systems broadly categorised under the following domains:

- Asset Management Information System (**AMIS**) – the primary system that supports the strategic, tactical and lifecycle management of transmission 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 and spatial analysis of network assets and power systems.

Historically, improvement initiatives have been implemented to deliver enhancements that have increased the functionality of existing systems as well as developing new systems to address new and emerging business needs. Since 2014, investment in asset management systems has delivered the following major initiatives:

- establishment of a consolidated drawing management repository;
- implementation of contemporary GIS visualisation software; and
- establishment of core asset information management standards.

The principal transmission AMS capital expenditure in the forthcoming regulatory period relates to:

- asset knowledge management (asset registers, geospatial systems and engineering data and drawings);
- asset planning (asset repair/refurbish/replace decision making);
- asset condition monitoring (asset inspections and defect analysis);
- asset risk management (asset failure and criticality assessments);
- network performance (target and performance reporting); and
- asset data analytics and reporting.

Investment in these areas will enable us to minimise our asset life cycle costs, aligning with good asset management practices and our asset management policy. 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.

Recent independent asset management maturity assessments have identified opportunities to further improve asset data, information holding and related business processes. These assessments established the current-state asset management and identified the gap between it and industry best appropriate practice (as defined by ISO55000:2014). The review also highlighted a variation between transmission and distribution asset information management maturity. The proposed investment profile (transmission/distribution) has a focus on uplifting distribution data and processes to more closely align with current levels of transmission asset information management maturity (TN044).

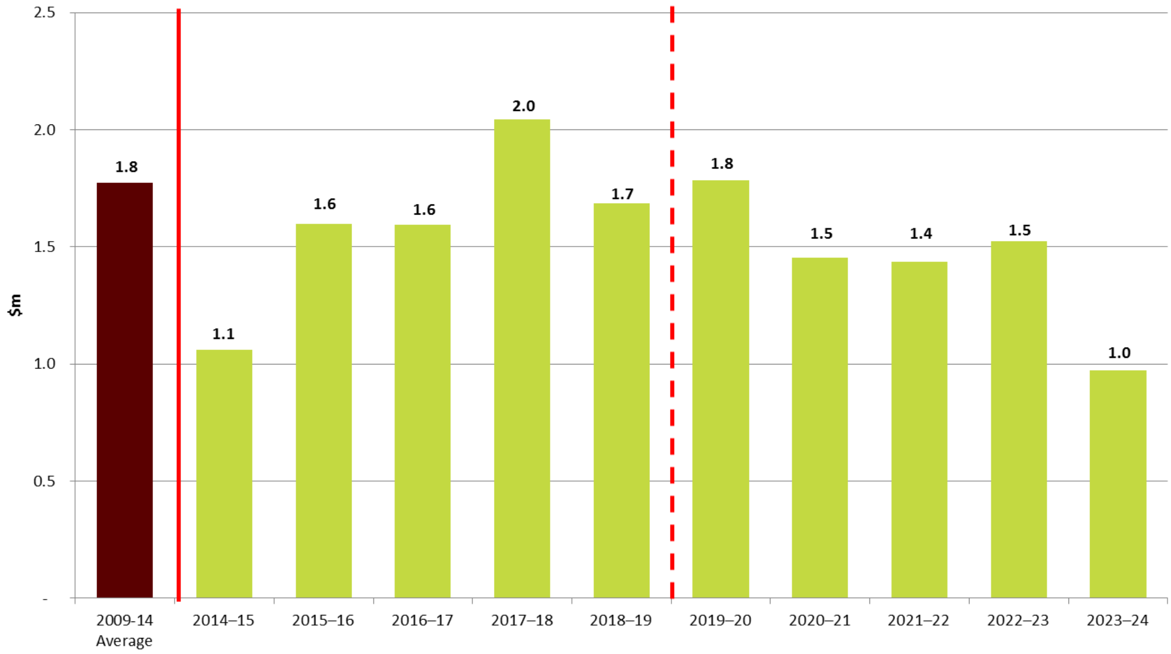
The table below shows our actual and forecast AMS capital expenditure, attributed to transmission in accordance with our CAM. The distribution AMS capital expenditure is presented in section 8.3.5.

Table 8-12: Transmission Asset Management Systems capital expenditure (June 2019 $m)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	1.1	1.6	1.6	2.0	1.7	1.8	1.5	1.4	1.5	1.0

The figure below presents the same information in bar chart format.

Figure 8-6: Transmission Asset Management System capital expenditure (June 2019 $m)



As detailed in Table 8-12 and Figure 8-6, our actual transmission asset management systems capital expenditure for the current regulatory period is expected to be $8.0 million. For the forthcoming five-year period, we are forecasting $7.2 million. For the reasons set out above, we consider that the proposed expenditure is prudent and efficient, noting the need to minimise our asset life cycle costs and drive improvements in our asset management practices.

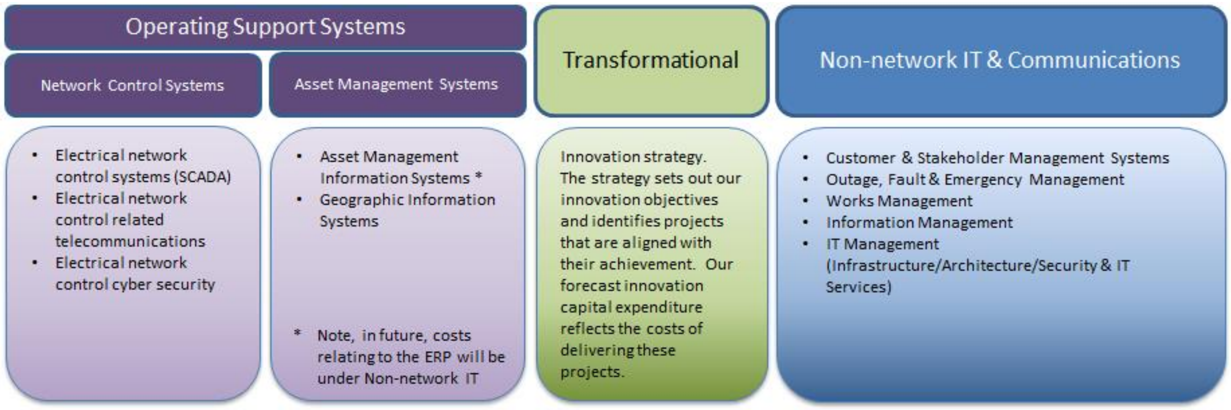
8.2.6 Transmission IT and communications capital expenditure

This expenditure category is concerned with the provision of information technology (**IT**) and communication services, including:

- information management systems to manage large amounts of structured and unstructured information across the business;
- 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; and
- Stakeholder and Customers – systems that support and improve the provision of information and services to our customers and stakeholders and enhance the customer experience.

We have developed a single, combined IT and communications strategy that addresses our transmission and distribution needs together. The figure below shows the scope of IT and communications capital expenditure, illustrating its relationship with the operating support systems and transformational expenditure categories.

Figure 8-7: IT & Communications and other related expenditure categories



As a merger of two businesses in 2014, we inherited two sets of IT systems and processes. Many of these duplicate systems are ageing, use superseded software versions and are becoming increasingly difficult to support. We have already commenced investment to improve our IT systems and are forecasting this investment to continue into the forthcoming regulatory control period.

Looking ahead, we require technology platforms that can be flexible and agile in order to evolve with the market and take advantage of new opportunities as they arise. In this context, at present we carry a 'technology debt'. Furthermore, we are forecasting ongoing requirements to maintain platforms and systems which support an increased focus on system security as the risks associated with cyber security increase. This aligns with the broader cyber work program currently being led by the AEMC and AEMO. Therefore, we anticipate ongoing and increasing cyber security investment both from an internal perspective and also as governance requirements increase to support NEM participation.

Against this backdrop, our Technology Strategy is to:

> "…simplify the Technology environment through the consolidation and integration of applications, infrastructure and vendors to enable the lowest cost to operationally manage and support Technology and deliver corporate and customer expectations."

We will achieve this by:

- operating within the Technology Governance Strategy (TN028);
- building the roadmap for our future IT enterprise architecture, inclusive of investment, prioritisation and phasing;
- delivering IT solutions based on an approach of re-using before buying, buying before building, and building as a last resort, with the choice reflecting the lowest Total Cost of Ownership option;
- actively pursuing strategic outsourcing opportunities by seeking partners, cloud and external agencies to deliver our low value commodity services;
- protecting our IT assets with a risk-based security model; and
- positioning our IT as an enabler of future business agility and increased customer value by transforming the way we operate.

Our approach to developing the proposed IT program of work encompasses both transmission and distribution IT requirements. In addition, our proposal recognises that technology convergence is occurring in this industry, and will continue to occur across traditional IT, Operational Technology (**OT**) and telecommunications domains.

We have developed a combined IT and communications work program that addresses our transmission and distribution requirements. Our total transmission IT capital expenditure during the current regulatory period is expected to be $23.1 million, which is an average of $4.6 million per annum. Our forecast for the forthcoming regulatory period is approximately 37 per cent lower, at $2.9 million per annum.

The key components of our transmission IT and communications capital expenditure are outlined below, by functional area:

- **Business Systems Upgrades**

  Comprises upgrades and replacement of various small applications. The key driver for the upgrade or replacement is that the assets are at the end of their operating life or require a technology uplift.

- **Data Warehouses, Business Intelligence and Analytics**

  We currently use a mixture of technologies and single purpose databases, rather than a single enterprise reporting platform. This issue has led to several gaps in our business processes and reporting, including:

  - the emergence of information silos;
  - time consuming data gathering and compilation processes;
  - low quality and consistency of data;
  - limited business intelligence; and
  - limited historical intelligence.

  Our proposed capital expenditure will address these issues by creating a single Enterprise Reporting and Business Intelligence (**BI**) environment and implementing an Enterprise Data Warehouse (**EDW**), which will provide our internal customers with easier access to structured data and enhanced reporting capabilities. The cost of this initiative is shared across transmission and distribution in accordance with our approved CAM.

- **Digital Customer Engagement**

  Our website is a cost shared across transmission and distribution. These systems require upgrading due to components reaching the end of their operating lives and/or requiring a technology uplift.

- **Enterprise Architecture Evolution**

  We are still working through a gap in the architectural repositories relating to current systems and applications which have been apparent since the start of TasNetworks. This gap impacts on our ability to:

  - plan and forecast change to the technology landscape;

- identify further opportunities for application rationalisation; and
- design solutions.

- **Enterprise Information Management**

  Following the formation of TasNetworks, we inherited a number of Information Management systems that require consolidation. There are inefficiencies involved in multiple systems, gaps around drawing management, and many systems are also reaching their end-of- life. The cost of this initiative is shared across transmission and distribution in accordance with our approved CAM.

- **IT Infrastructure, Security and Support**

  This area involves various expenditures to replace end-of-life assets, and to meet increased capacity requirements in the areas of end-user computing, IT management and toolsets, IT network core services, collaboration tools and application delivery mechanisms.

- **Mobility**

  A number of areas of our business have an increasing need for access to data and systems when 'mobile'. Our technology strategy includes the provision of technology, security and administration of mobile devices.

Further details on our transmission IT and communications capital expenditure is provided in the IT Infrastructure (TN045) and IT Asset Management Plans (Software (TN046), respectively).

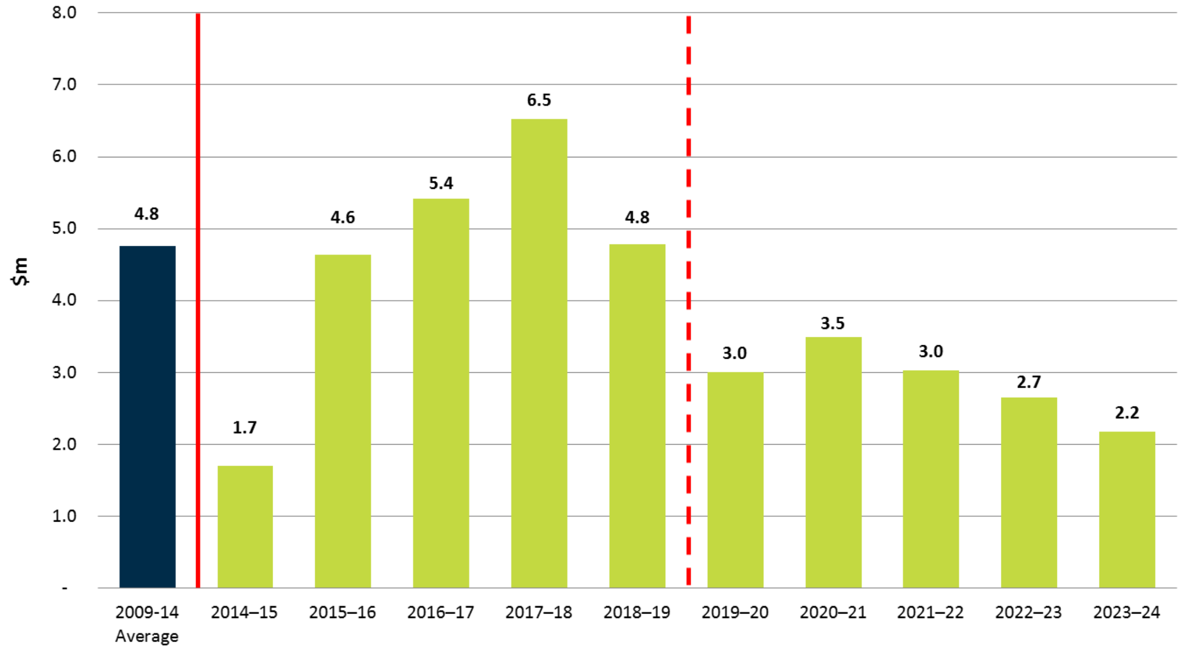
The table below provides details of our actual and forecast transmission IT & Communications capital expenditure. The distribution IT & Communications capital expenditure is presented in section 8.3.6.

Table 8-13: Transmission IT & Communications capital expenditure forecast (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	1.7	4.6	5.4	6.5	4.8	3.0	3.5	3.0	2.7	2.2

The figure below presents the same information in bar chart format.

Figure 8-8: Transmission IT & Communications capital expenditure forecast (June 2019 $m)



8.2.7 Transmission Non-network Other capital expenditure

Non-Network Other capital expenditure includes capital expenditure on our vehicle fleet and facilities (land and buildings). Investment in non-network assets is required during the current regulatory control period to enable us to:

- manage safety risks efficiently;
- meet operational requirements; and
- minimise the total life cycle costs of providing regulated network services.

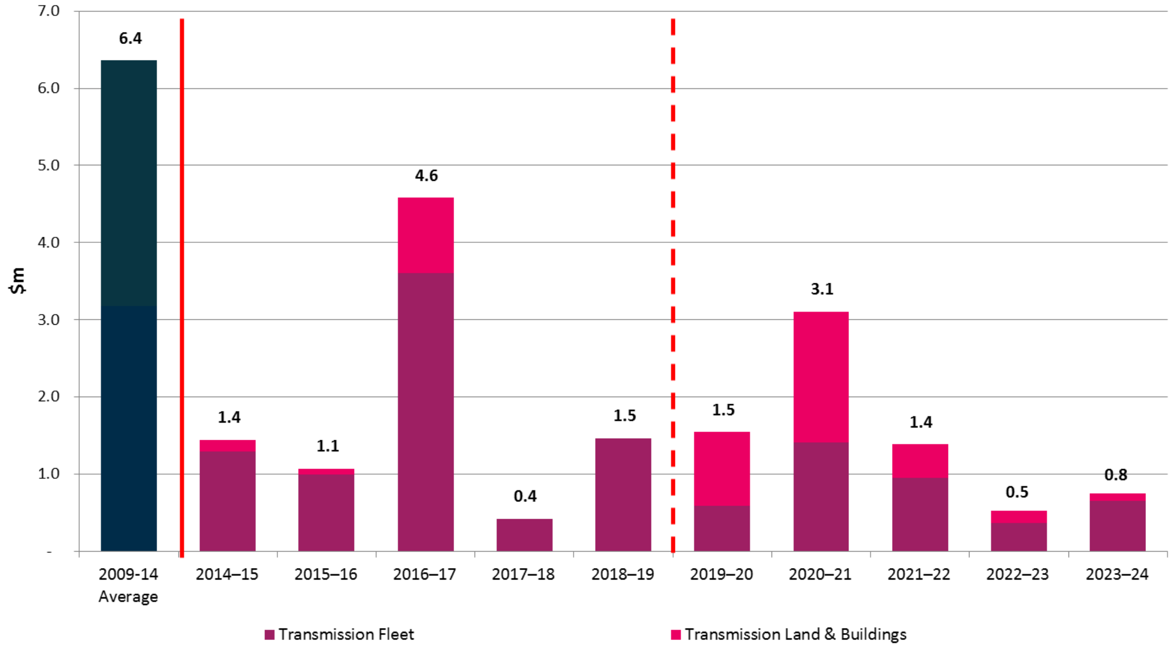
The table below provides details of our actual and forecast transmission non-network other capital expenditure. The distribution non-network other capital expenditure is presented in section 8.3.7.

Table 8-14: Transmission Non-network other capital expenditure forecast (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Fleet	1.3	1.0	3.6	0.4	1.5	0.6	1.4	1.0	0.4	0.7
Transmission Land & Buildings	0.1	0.1	1.0	0.0	0.0	1.0	1.7	0.4	0.2	0.1
Total Transmission Non-network Other	**1.4**	**1.1**	**4.6**	**0.4**	**1.5**	**1.5**	**3.1**	**1.4**	**0.5**	**0.8**

The figure below presents the same information in bar chart format.

Figure 8-9: Transmission Non-network other capital expenditure (June 2019 $m)



As detailed in Table 8-14 and Figure 8-9, our actual transmission non-network other capital expenditure for the current regulatory period is expected to be $9.0 million. For the forthcoming five-year period, we are forecasting $7.3 million.

Our Non-Network investment needs are determined in accordance with our asset management plans and take into consideration the business environment and our corporate strategy. Our vehicle fleet and facilities are managed as shared services, with costs allocated directly to the transmission and distribution functions where appropriate, following which they are allocated in accordance with our approved CAM. Accordingly, the majority of information provided below applies to both our transmission and distribution activities.

Vehicle fleet

Fleet expenditure needs have been determined in accordance with our Tool of Trade Fleet Management Plan. The plan covers our vehicle fleet, which comprise team shared vehicles, pool vehicles, parked at depot vehicles, and vehicles with commuter use or on call use arrangements.

The Tool of Trade Fleet Management Plan (TN048) aims to optimise whole-of-life fleet operating, maintenance and capital expenditure, so that our fleet needs are met safely, efficiently, and in accordance with all applicable statutory compliance obligations. Investment needs are based on a bottom up build and top down approach taking into consideration the fleet's age, kilometres travelled, condition and requirements of the business.

We have recently reviewed our fleet replacement criteria to ensure that the replace/maintain decision is optimised. Further detailed information is provided in our Tool of Trade Fleet Management Plan.

Facilities (land and buildings)

Land and buildings capital expenditure requirements are based on the Facilities Asset Management Plan. This plan identifies the land and property accommodation requirements of our people in our offices and depots to support the efficient delivery of our network services. The plan applies a life cycle approach to asset management and aims to meet our immediate and longer term operational requirements efficiently and safely.

Over the forthcoming regulatory period, our land and buildings capital expenditure forecast includes the following projects:

- Campbell Town upgrade – Due to its geographically central location, this site requires upgrading to make the building more efficient from a whole-of-business perspective.
- Operations building compliance upgrade and refresh – The control rooms at our Maria Street site require some refurbishment to accommodate new technology. The building will also require further modifications to meet contemporary standards.

Further detailed information is provided in our Facilities Asset Management Plan (TN047).

8.2.8 Transmission contingent projects

This section sets out our five proposed transmission contingent projects. We are not proposing any contingent projects for our distribution network.

Contingent projects are significant network augmentation projects that are reasonably required to be undertaken in order to achieve the capital expenditure objectives as defined in the Rules. However, unlike other proposed capital expenditure projects, the need for the project within the regulatory control period and the associated costs are not sufficiently certain.

Consistent with AEMO's Integrated System Plan Consultation[25] that recognises transmission investments have long technical and economic lives, we must account for the material uncertainty facing the industry in the medium to longer-term. Transmission network investments must respond to new generation developments that are commercially driven, which means that location, timing and scale are influenced by market conditions and changes in policy settings, such as renewable targets. As such, forecasting large-scale renewable generation developments in the NEM can prove challenging.

A contingent project is expected to exceed $30 million or five per cent of annual revenue requirement in the first year of the forthcoming regulatory period (whichever is larger). For TasNetworks, the applicable threshold is $30 million. The expenditure for a contingent project does not form part of the total forecast capital expenditure approved by the AER. The Rules provide for contingent projects to be defined with reference to a project-specific 'trigger event'. The occurrence of the trigger event must be probable during the relevant regulatory control period. If the trigger event for an approved contingent project occurs, we may make an application to the AER for a cost allowance to be included in an amended revenue determination.

[25] Integrated System Plan Consultation, December 2017 - http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2017/Integrated-System-Plan-Consultation.pdf

Our proposed transmission contingent projects and cost estimates are described for each contingent project below. These costs have not been included elsewhere in this proposal. At this stage, we envisage that each of the contingent projects would be required to "meet or manage the expected demand for prescribed transmission services" in accordance with clause 6A.6.7(i) of the Rules.

We initially indicated in our Directions and Priorities Consultation Paper that we had identified four contingent projects. As our planning has progressed, more information has become available about potential investments in renewable energy in Tasmania's northwest and west coasts. As a result, we have subsequently refined our provisional plans and categorised them into five discrete projects.

As described below, we have prepared cost estimates for each contingent project, consistent with our forecasting methodology as previously disclosed to the AER in July 2017. Although these cost forecasts are necessarily indicative, in the context of each contingent project, we regard them as satisfying the capital expenditure criteria for the purposes of clause 6A.8.1(b)(2)(ii) of the Rules. The global assumptions that apply to our operating and capital expenditure forecasts are also applicable to each of the contingent projects.

In developing the trigger events for each contingent project, we have had regard to the AER's most recent draft decision for ElectraNet, which explained that the trigger event should be [26]:

- reasonably specific and capable of objective verification;
- a condition or event which, if it occurs, makes the project reasonably necessary in order to achieve the capital expenditure objectives;
- a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole;
- described in such terms that it is all that is required for the revenue determination to be amended; and
- a condition or event, the occurrence of which is probable during the forthcoming regulatory control period but the inclusion of capital expenditure in relation to it (in the total forecast capital expenditure) is not appropriate because either:
    - it is not sufficiently certain that the event or condition will occur during the regulatory control period or if it may occur after that period or not at all, or
    - assuming it meets the materiality threshold, the costs associated with the event or condition are not sufficiently certain.

In December 2017, AEMO published a consultation paper on its inaugural Integrated System Plan (ISP). The ISP will establish Renewable Energy Zones and priority transmission developments. More broadly, it raises the possibility that some transmission project approvals may occur through an alternative pathway to the RIT-T. In its revised proposal, ElectraNet has refined its trigger events to recognise this new development.

26 AER, draft decision, ElectraNet transmission determination 2018 to 2023, Attachment 6 – Capital expenditure, October 2017, pages 72 and 73.

In defining our trigger events, we have had regard to the AER's draft decision for ElectraNet and their revised proposal. We consider that each of the contingent projects described below satisfies the requirements of clause 6A.8.1 of the Rules.

Contingent Project 1: Second Bass Strait Interconnector

The Basslink interconnector has provided significant benefits to Tasmania and mainland customers by allowing the transfer of electricity to minimise total generation costs and improve security of supply.

A second Bass Strait interconnector would mean that Tasmania could expand the amount of renewable energy it provides to the national market, allowing the State to play a greater role in the NEM. It would also facilitate greater investment in wind and solar projects in Tasmania and support efficient use of Tasmania's hydro resource.

In April 2017, Dr John Tamblyn concluded a study into the feasibility of a second Tasmanian Interconnector[27]. The economic modelling in the study was based on construction starting in 2020, with the interconnector being operational by 2026.

Dr Tamblyn's study estimated the total capital cost of a second Bass Strait interconnector, including network augmentation costs to be $1.1 billion, with ongoing operating and maintenance costs of $16.7 million per annum.

We are now embarking on a more detailed feasibility and business case assessment with assistance from the Australian Renewable Energy Agency (**ARENA**). The cost of this study is planned to be jointly funded by TasNetworks and ARENA, and is not included in this Regulatory Proposal. Its scope is likely to include a consideration of:

- the preferred route and optimum capability of the cable and converter assets;
- technical specifications and supply arrangements for the cable;
- environmental considerations;
- cost estimates for the second interconnector;
- economic evaluation of costs and benefits; and
- development of financial and development models to implement the second interconnector.

In advance of the study being completed, we cannot be certain whether the second interconnector will proceed. Additionally, we do not yet understand how the costs may be shared between TasNetworks and AEMO in its role as the Victorian Network Planner. At this stage, for the purpose of defining the contingent project, based on Dr Tambyln's report we consider it reasonable to estimate the Tasmanian network contribution to this project to be $550 million, which is 50 per cent of the $1.1 billion cost estimate.

The proposed trigger event for the AER's assessment of this project as a regulated transmission service would be:

1(a) Successful completion of a RIT-T; or

[27] Feasibility of a second Tasmanian Interconnector, Final study, Dr John Tamblyn, April 2017, Page vii

1(b) A decision by a government, governments(s) or regulatory body that results in a requirement for a second Bass Strait interconnector.

2. TasNetworks Board approval to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Contingent Project 2: Sheffield to Palmerston 220 kV Augmentation

If significant future generation flows from the North West and West Coast transmission networks, there could be significant constraints in transmitting energy from Sheffield into the rest of the network. Similar constraints could also arise if a second Bass Strait interconnector were to connect into the Tasmanian transmission system in North West Tasmania.

The location of the second Bass Strait interconnector or Significant future generation development in the North West and West Coast of Tasmania, or the location of the second Bass Strait interconnector could, therefore, trigger the construction of a new double circuit 220 kV transmission line between Sheffield and Palmerston and converting a section of the existing single circuit 220 kV transmission line into a 110 kV circuit. The current estimated capital cost of this project is $120 million. This forecast is a high-level indicative estimate based on the cost of similar projects, consistent with our forecasting methodology for augmentation capital expenditure.

We propose that the Sheffield to Palmerston 220 kV augmentation should be treated as a contingent project, as the project trigger and the associated costs are uncertain.

The proposed trigger event for the AER's assessment of this project as a regulated transmission service would be:

1(a) Successful completion of a RIT-T; or

1(b) A decision by a government or regulatory body that results in a requirement for the Sheffield to Palmerston 220 kV augmentation.

2. TasNetworks Board approval to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Contingent Project 3: Rationalisation of Upper Derwent 110 kV Network

The southern 110 kV Transmission circuits from Tungatinah to New Norfolk Substation (the Upper Derwent 110 kV network) are approaching end of life. We have developed a strategy to rationalise the existing assets. However, Hydro Tasmania has announced it is undertaking a pre-feasibility study for the replacement and relocation of the Tarraleah Power Station.

The new network connection arrangements for the replacement power station will have a material impact on the power flows in the southern Tasmanian transmission network and hence may also affect the rationalisation of the upper Derwent 110 kV network.

We are in regular contact with Hydro Tasmania regarding this matter, but there is not yet any clarity on the likely timing of the Hydro Tasmania project or the likely connection arrangements.

The estimated capital cost of the originally proposed strategy was $118 million. This included decommissioning the Tungatinah to New Norfolk No 3 circuit, augmenting the Tungatinah to Waddamana circuits and the remaining Tungatinah to New Norfolk circuits, and creating a 110/220 kV connection point at Waddamana Substation. This high-level indicative cost estimate is based on the cost of similar projects, consistent with our forecasting methodology for augmentation capital expenditure.

We propose that the rationalisation of the upper Derwent 110 kV network should be treated as a contingent project because of the uncertainty regarding Hydro's connection requirements for the replacement Power Station and the associated costs.

The proposed trigger event for the AER's assessment of this project as a regulated transmission service would be:

1(a) Successful completion of a RIT-T; or

1(b) A decision by a government or regulatory body that results in a requirement for the rationalisation of the upper Derwent 110 kV network.

2. TasNetworks Board approval to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Contingent Project 4: North West 110 kV Network Redevelopment

We have received connection applications in the North West of Tasmania for 114 MW of new generation projects that are being actively progressed, in addition to enquiries about numerous other generation projects that are being investigated in Tasmania's North West. Feasibility studies are also underway which are examining the possibility of increasing pumped hydro storage capacity in this zone.

The quantity of new generation that ultimately seeks to connect to the network will determine the extent of the 110 kV transmission system augmentation requirements. Based on recent connection enquiries and applications, we also expect that a tripping scheme, similar to the Network Control System Protection Scheme, may be required to maximise the utilisation of the existing assets.

This protection scheme is likely to be followed by augmentation of the 110 kV transmission system at an expected cost in excess of $70 million. At this stage, the cost forecast is a broad estimate based on our best assessment of the required scope of work, in accordance with our forecasting methodology for augmentation capital expenditure. However, the final scope of the required works, including augmentation of the 110 kV corridor, and updated cost estimates will be provided in accordance with the RIT-T. The quantity of new generation that ultimately seeks to connect to the network will determine the extent of the 110 kV transmission system augmentation required. We expect this will be in the order of between 150-200 MW.

The proposed trigger event for the AER's assessment of this project as a regulated transmission service would be:

1(a) Successful completion of a RIT-T; or

1(b) A decision by a government or regulatory body that results in a requirement for the North West 110 kV Network Redevelopment.

2. TasNetworks Board approval to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Contingent Project 5: North West 220 kV Network Redevelopment

As already noted, we have received connection applications in the North West of Tasmania for 114 MW of new wind generation projects that are being actively progressed by a number of parties, in addition to other numerous wind generation enquiries that are being investigated in Tasmania's North West. Feasibility studies are also underway which are examining the possibility of increasing pumped storage capacity in this area.

Based on recent connection enquiries and applications, we expect that a tripping scheme, similar to the Network Control System Protection Scheme, as well as minor under clearance reinforcement along the existing Sheffield-Burnie 220 kV corridor may be required to maximise the utilisation of the existing assets. This protection scheme and minor 220 kV under clearance reinforcements are likely to be followed by:

- augmentation of the 110 kV transmission system between Burnie and Smithton (detailed in Contingent Project 4); and
- augmentation of the 220 kV transmission system between Sheffield and Burnie, which includes:
    - the establishment of new double circuit transmission line operating at 220 kV between Sheffield and Burnie substations; and
    - reconfiguration and rationalisation of the 110 kV transmission line between these substations to facilitate the new 220 kV transmission line within the existing corridor.

The quantity of new generation that ultimately seeks to connect to the network will determine the extent of the 220 kV transmission system augmentation requirements.

The new 220 kV transmission line between Sheffield and Burnie, including associated works, are expected to cost in excess of $80 million based on similar projects in accordance with our forecasting methodology for augmentation capital expenditure. The final scope of the required works, including augmentation of the 220 kV corridor, will be determined in accordance with the RIT-T.

The proposed trigger event for the AER's assessment of this project as a regulated transmission service would be:

1(a) Successful completion of a RIT-T; or

1(b) A decision by a government or regulatory body that results in a requirement for the North West 220 kV Network Redevelopment.

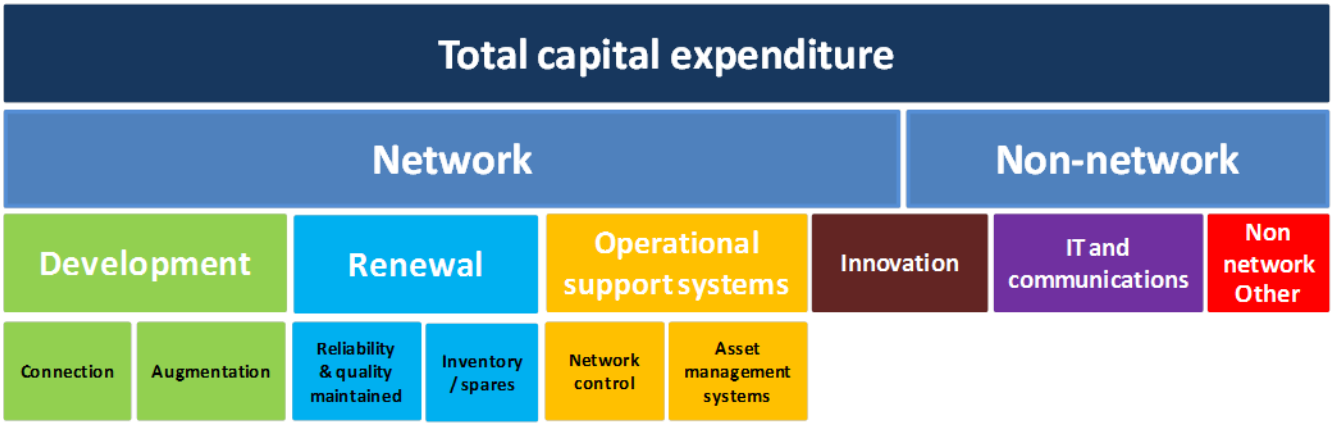
2. TasNetworks Board approval to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

8.3 Distribution capital expenditure forecasts

8.3.1 Overview

The figure below shows the distribution capital expenditure categories we have adopted for the purpose of presenting our actual and forecast capital expenditure.

Figure 8-10: Distribution capital expenditure categories



As noted in relation to transmission capital expenditure, the above figure includes an 'innovation' category that spans both network and non-network activities. While expenditure is not directly attributed to innovation, it is a core business function that affects our investment decisions across the business. In addition, we are proposing Demand Management Incentive Scheme (**DMIS**) project which includes a trade-off between capital and operating expenditure. Our network innovation framework is discussed in further detail in section 4.5 and detail on our Demand Management Incentive Scheme (**DMIS**) project forecast is provided in section 14.6.

Over the five year period from 2019-20 to 2023-24 our gross distribution capital expenditure is forecast to increase by 22.5 per cent, to $154.0 million per annum, compared to the expenditure we expect to incur in the previous five years. Our actual expenditure during the most recent regulatory period (2017-19) is expected to be in line with the allowance approved by the AER.

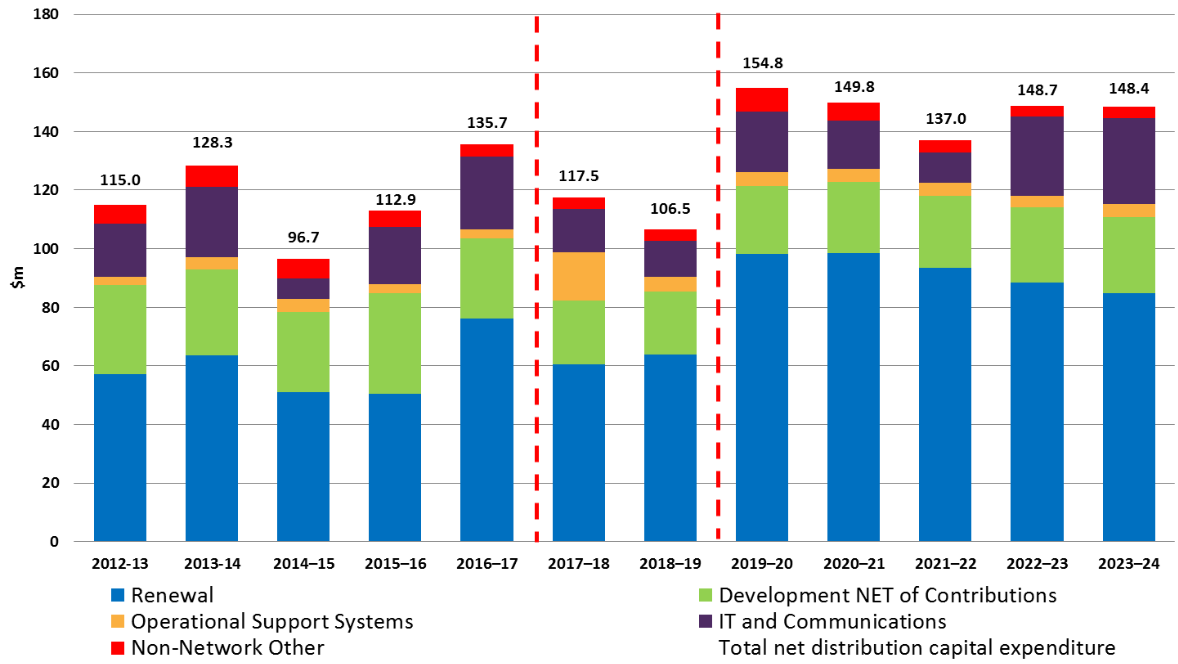
The table below presents the historical and forecast information net of customer contributions.

Table 8-15: Actual and forecast net distribution capital expenditure, by category (June 2019 $m)

Category	Regulatory allowance for 2014-15 to 2018-19	Actual/Forecast expenditure for 2014-15 to 2018-19	Forecast expenditure for 2019-20 to 2023-24
Development	119.9	132.2	124.0
Renewal	297.4	302.1	463.1
Operational Support Systems	57.3	32.0	22.0
IT and Communications	71.2	78.5	103.8
Non-Network Other	24.0	24.4	25.9
Total	**569.8**	**569.2**	**738.8**

The figure below provides a breakdown of forecast distribution capital expenditure by category and a comparison with past expenditure. The amounts shown are net of capital contributions from customers.

Figure 8-11: Overview of actual and forecast net distribution capital expenditure (June 2019 $m)



The following table presents our forecast gross distribution capital expenditure by category and a comparison with recent regulatory periods, and also presents this information net of capital contributions. As already noted, we have applied a top-down optimisation of our provisional distribution capital expenditure plans, resulting in a decrease in our proposed distribution capital expenditure of $36.4 million over the 2019-24 regulatory control period.

The greater optimisation of the distribution program compared to transmission reflects the benefits expected to flow from investments over the current regulatory period in business transformation –

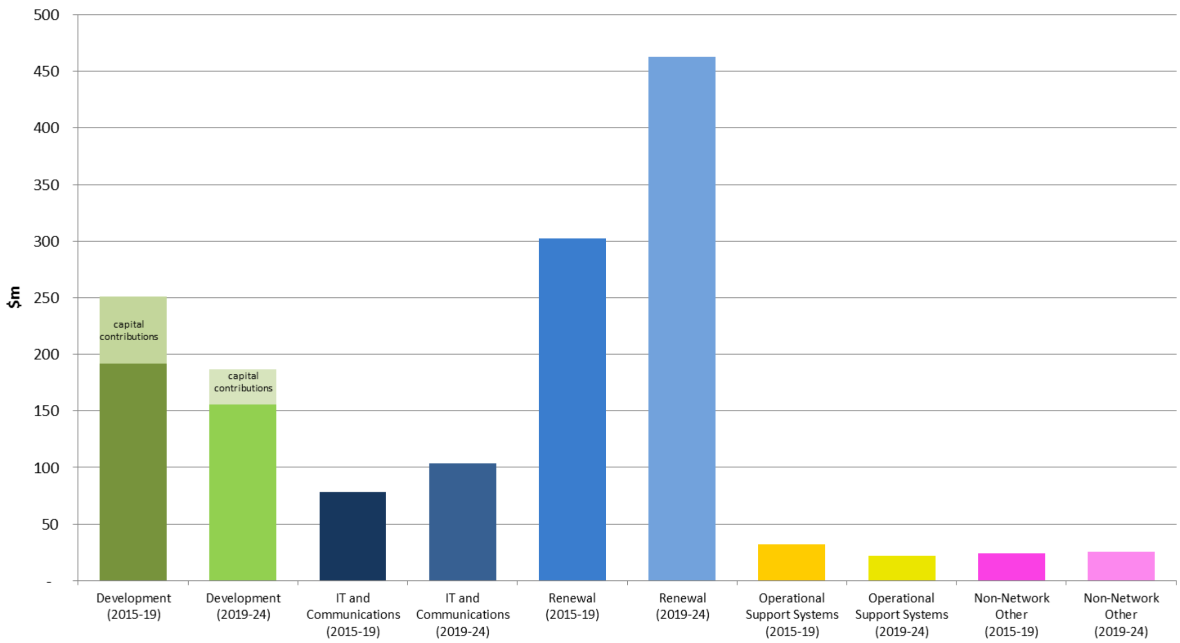
and that we will need to prioritise our investment in new and replacement assets to ensure the network service remains affordable to our small and dispersed distribution customer base.

Table 8-16: Actual and forecast gross and net distribution capital expenditure for the current and forthcoming regulatory period (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Development	39.1	40.5	40.9	45.1	38.9	33.5	33.0	29.3	30.5	31.0	32.2	32.4
Connection	29.9	27.6	31.4	31.8	32.5	26.7	26.5	22.4	24.1	24.6	25.7	26.2
Augmentation	9.2	12.9	9.5	13.4	6.4	6.9	6.5	6.9	6.4	6.4	6.5	6.2
Renewal	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8
Reliability & Quality Maintained	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8
Inventory and Spares	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operational Support Systems	2.8	4.2	4.4	3.2	3.1	16.3	5.0	4.6	4.3	4.3	4.1	4.6
Network Control	1.2	2.5	3.8	2.0	0.8	3.3	2.0	0.8	0.8	0.8	0.5	2.4
Asset Management Systems	1.6	1.7	0.7	1.3	2.3	12.9	2.9	3.9	3.5	3.6	3.6	2.2
IT and Communications	18.1	23.9	7.0	19.4	24.8	15.0	12.3	20.7	16.4	10.4	27.0	29.3
Non-Network Other	6.5	7.3	6.8	5.5	4.3	3.9	3.8	8.0	6.2	4.2	3.6	3.9
Total gross distribution capital expenditure	123.7	139.4	110.2	123.7	147.3	129.2	118.1	160.8	155.9	143.3	155.1	155.0
Customer capital contributions	8.7	122.3	13.5	10.8	11.6	11.7	11.6	6.0	6.0	6.3	6.5	6.6
Total net distribution capital expenditure	**115.0**	**128.3**	**96.7**	**112.9**	**135.7**	**117.5**	**106.5**	**154.8**	**149.8**	**137.0**	**148.7**	**148.4**

The following figure shows our forecast net distribution capital expenditure for the next five years by category, compared to the actual expenditure incurred and estimated for the 2015-19 period.

Figure 8-12: Comparison of historic and forecast net distribution capital expenditure by major category (June 2019 $m)



The above figure shows the change in our forecast capital expenditure on the distribution network for the forthcoming regulatory period, net of capital contributions from customers, compared to the current period. Our distribution investment plans for the forthcoming regulatory period reflect the following considerations and drivers:

- increased investment to manage safety risks (that may not be fully offset by efficiencies elsewhere), including expenditure on:
  - increase in pole renewal and staking. as early staked poles reach end of useful life over the next ten years;
  - targeted bushfire mitigation programs to reduce risk of fire starts from our network;
  - low voltage cable replacement;
  - vegetation management - to manage outage and fire risk;
  - service connection renewal; and
  - improving network resilience in response to changing environmental factors.
- the expectation that the growth in distribution customer connections will remain relatively stable, with new connection standards to support network security and two way flows;
- an increase in technology-related spending to support two way flows in the distribution network, by delivering:
  - increased visibility / situational awareness of the distribution network;
  - efficient asset management investment and operation, including in relation to new technology integration; and
  - timely customer information and network management.

- the continuing need to manage network voltage levels which may be impacted by the growth in embedded generation; and
- increased expectations for technology investments to support improved customer relationship management, including SMS notifications, planned outage information, website portals, and network pricing reform.

8.3.2 Key assumptions for distribution capital expenditure forecasts

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

- forecasts for demand, new customer connections and capital contributions, together with the projections of distributed generation, are soundly based;
- trade-offs between capital and operating expenditure for the Demand Management Incentive Scheme will be accepted by the AER; and
- investment evaluations, including the project and program scopes and estimating practice, are soundly based and reflect our capital expenditure requirements.

In accordance with schedule S6.1.1(5) of the Rules, the TasNetworks Board has provided a certification of the reasonableness of these assumptions in relation to our distribution services (supporting document, TN020).

In preparing our expenditure forecasts, we have escalated our materials and labour costs as follows:

- limited the escalation of material costs to CPI; and
- we have applied modest real price escalation in relation to internal labour and contractor rates, based on advice received from Jacobs[28] (TN166), as set out in section 8.2.2.

As already noted, we have adopted the same materials and labour cost escalators for capital and operating expenditure across our transmission and distribution activities.

8.3.3 Distribution development capital expenditure

The table below presents the gross development capital expenditure proposed for our distribution network in the forthcoming regulatory period.

Table 8-17: Gross distribution development capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Connection	29.9	27.6	31.4	31.8	32.5	26.7	26.5	22.4	24.1	24.6	25.7	26.2
Augmentation	9.2	12.9	9.5	13.4	6.4	6.9	6.5	6.9	6.4	6.4	6.5	6.2
Total Distribution Development	**39.1**	**40.5**	**40.9**	**45.1**	**38.9**	**33.5**	**33.0**	**29.3**	**30.5**	**31.0**	**32.2**	**32.4**

28 Jacob, Labour Cost Escalation Report, 25 October 2017.

Our forecast gross distribution development capital expenditure for the five-years commencing 1 July 2019 is $155.4 million compared to expenditure of $191.5 million which we expect to incur for the preceding five years. Our expenditure forecasts reflect an expected continuation of low demand growth on the distribution system, with localised agricultural growth in regional areas and commercial development in Hobart's central business district (**CBD**).

While our total forecast gross development capital expenditure is in line with current levels of expenditure, we are projecting the following differences at the sub-category level:

- a reduction in expenditure for the establishment of new zone substations; and
- an increase in the expenditure needed to reinforce our regional overhead networks and to underground CBD networks.

The connection and augmentation components of our distribution development capital expenditure are discussed in further detail below.

Distribution connection capital expenditure

Connection capital expenditure arises directly from the connection of new customers to the distribution network, or changes to existing connections in response to a customer's request.

In determining the scope of work for a 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 to facilitate a customer connection.

Customers make a contribution towards the cost of their connection, with the contribution depending on the nature of the connection. The net distribution connection capital expenditure is the amount that is included in our regulatory asset base. Our forecast distribution connection capital expenditure reflects our forecasts of new distribution customer connections which are set out in section 6.5.

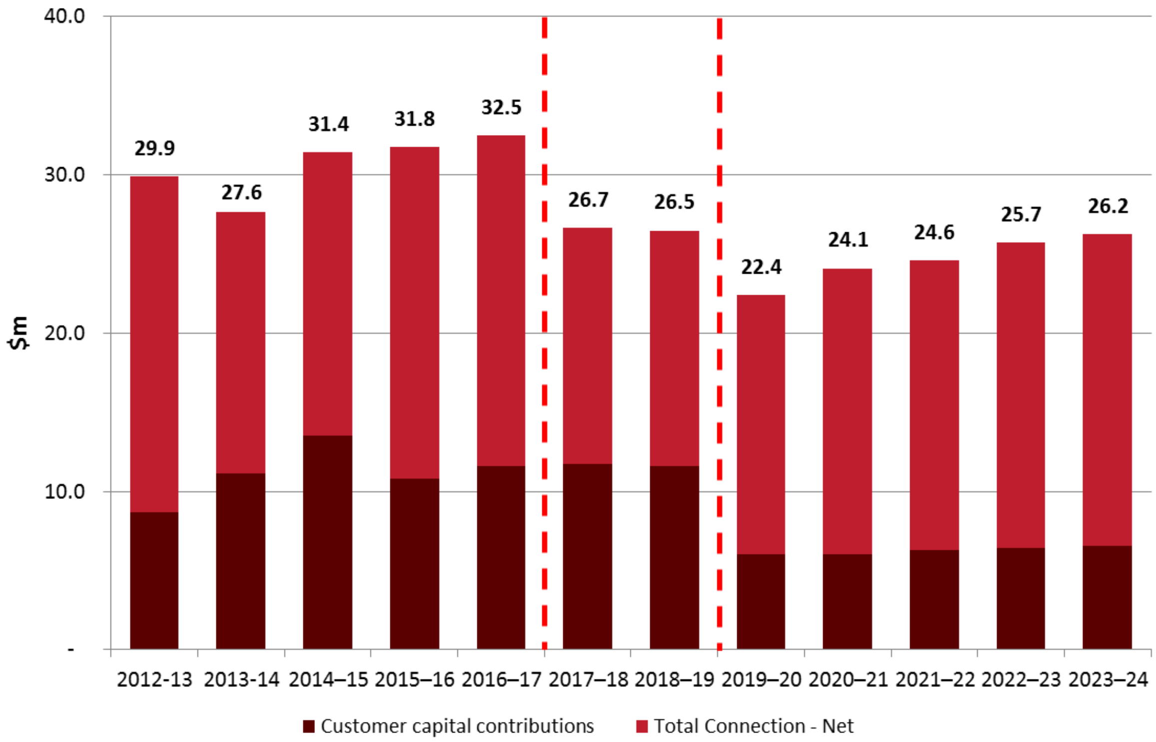
The table below shows our historic and forecast distribution connection capital expenditure and distribution customer capital contributions. The expenditure categories presented below reflect the nature of the capital works required.

Table 8-18: Connection capital expenditure and capital contributions (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Customer Initiated Connection Assets	3.6	4.3	4.7	0.0	0.0	0.7	0.7	0.0	0.0	0.0	0.0	0.0
Customer Initiated Major Works	1.7	1.9	1.2	0.1	0.7	2.5	2.5	1.0	1.0	1.1	1.1	1.1
Customer Initiated Non-Major Works	16.1	13.5	15.4	22.5	24.5	16.6	16.6	11.9	13.0	13.4	14.2	14.6
Customer Initiated Subdivisions	5.3	4.7	5.9	7.1	5.9	5.4	5.3	8.1	8.6	8.7	9.0	9.2
Customer Initiated Substations	3.3	3.2	4.2	2.1	1.4	1.5	1.5	1.3	1.3	1.4	1.4	1.4
Total Connection - Gross	**29.9**	**27.6**	**31.4**	**31.8**	**32.5**	**26.7**	**26.5**	**22.4**	**24.1**	**24.6**	**25.7**	**26.2**
Customer capital contributions	8.7	11.2	13.5	10.8	11.6	11.7	11.6	6.0	6.0	6.3	6.5	6.6
Total Connection - Net	**21.2**	**16.5**	**17.9**	**20.9**	**20.9**	**14.9**	**14.9**	**16.4**	**18.1**	**18.3**	**19.2**	**19.6**

The figure below presents the same information in bar chart format.

Figure 8-13: Total gross distribution connection capital expenditure (June 2019 $m)



Our forecast net distribution connection capital expenditure for the five-years commencing 1 July 2019 is $91.6 million compared to expenditure of $89.6 million which we expect to incur for the preceding five years. Our forecast gross distribution connection capital expenditure is in line with our capital expenditure in the current regulatory period, as well as our historical expenditure.

Further detailed information on our management strategy for connection work and our expenditure forecasts for the forthcoming regulatory period is provided in the supporting document, Customer Development Management Plan (TN043).

Distribution augmentation capital expenditure

Our distribution augmentation capital expenditure is driven principally by five factors:

- demand forecasts (as set out section 6.2);
- considering strategic integrated planning as part of operational processes;
- new load connection requests (driven by new customer connections, forecasts of which are set out in section 6.5);
- network performance requirements and the associated supply reliability standards set out in the Code; and
- compliance with the Rules requirements.

Some of our key programs are associated with reinforcing regional network areas, particularly to address the demands placed on the network by irrigation or primary production land. The growth in demand is causing reliability issues for irrigators both during start up and normal operation at times of high network load. In some instances, we may also relocate power lines as part of the upgrade, to improve public safety.

We have identified approximately 50 sites on our network that we propose to address over the next ten years. As part of the investigation and design process under this program, we will gather feedback from irrigators, power quality logging data and other information that will assist us in evaluating the issues requiring rectification. This information gathering will enable us to prioritise the work prudently and efficiently, having regard to the needs of the irrigators and any safety issues.

Our HV and LV capital expenditure projects and programs are detailed within the Network Development Asset Management Plan (TN042). These projects include:

- **Augmentation of HV feeder networks to support Hobart CBD development**

  This program includes the redevelopment of key distribution substation sites where asset renewal activity has been scheduled. The redevelopment works aim to augment the existing infrastructure to include additional switching capability (increase interconnectivity, remote control and visibility) and develop the cable networks towards meshed 11 kV feeder networks. This program will ensure long term asset renewal solutions, improve the ability to host new commercial developments (including distributed energy resources), improve the service performance of our Hobart Critical Infrastructure community and manage thermal loadings on our ageing underground cable networks.

- **Augmentation of HV overhead Galvanised Iron (GI) feeders**

  GI conductor is used throughout the network to supply small residential loads in challenging terrain or off the main feeder trunks. Over time, these spurs are extended and often developed to supply isolated communities and irrigation developments. Due to the limited thermal capability and high resistive properties of the conductor, as the load at the end of these spurs develops, voltage and power quality issues tend to increase.

  This program includes the augmentation of large 3/12 GI conductor spurs where the loading on these networks has grown in excess of the conductor's capability and is resulting in voltage and power quality issues.

- **Distribution Transformer Upgrade program**

  This program includes the upgrade or installation of new distribution pole and ground mounted substations. This program addresses excessive loading on existing substations and LV circuits where there is risk of asset failure, and an unacceptable risk in relation to network safety and reliability.

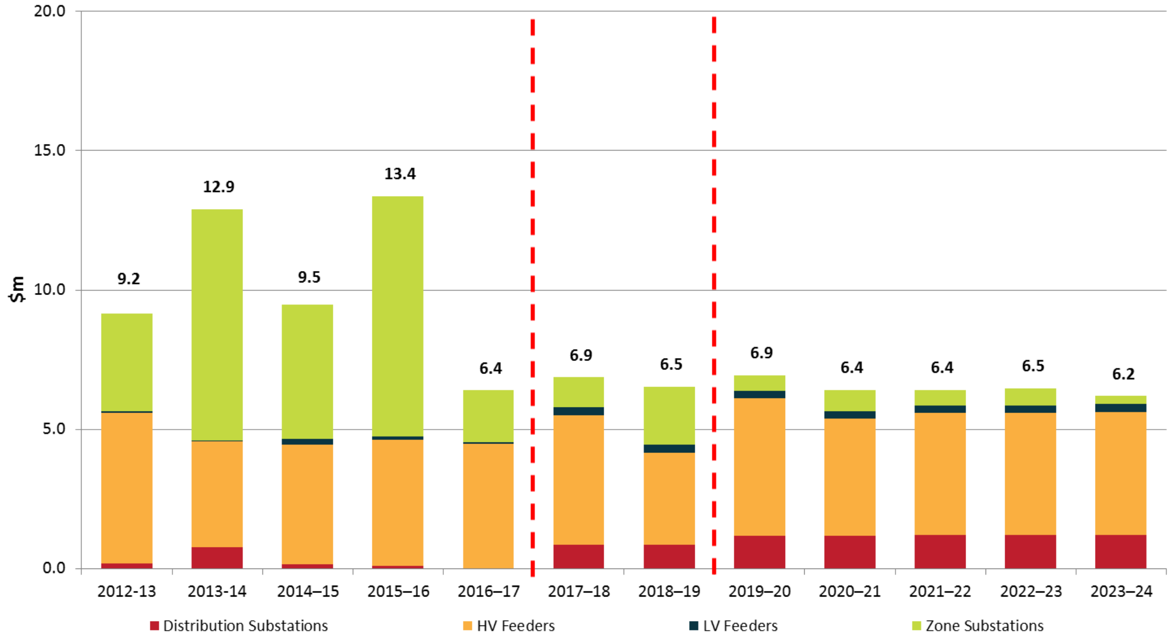
The table below shows our actual and forecast distribution augmentation capital expenditure. The forecast expenditure reflects the planned scope of work and costs based on similar projects.

Table 8-19: Distribution augmentation capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Substations	0.2	0.8	0.2	0.1	0.0	0.9	0.9	1.2	1.2	1.2	1.2	1.2
HV Feeders	5.4	3.8	4.3	4.5	4.5	4.6	3.3	4.9	4.2	4.4	4.4	4.4
LV Feeders	0.1	0.0	0.2	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Zone Substations	3.5	8.3	4.8	8.6	1.9	1.1	2.1	0.6	0.8	0.6	0.6	0.3
Distribution augmentation	**9.2**	**12.9**	**9.5**	**13.4**	**6.4**	**6.9**	**6.5**	**6.9**	**6.4**	**6.4**	**6.5**	**6.2**

The figure below presents the same information in bar chart format.

Figure 8-14: Distribution augmentation capital expenditure (June 2019 $m)



Our forecast distribution augmentation capital expenditure is $32.4 million, which is broadly in line with our current level of expenditure. The forecast expenditure is steady over the forecast period to 2024. The slightly higher expenditure in the initial years is influenced by a number of large development projects associated with the distribution high voltage network.

8.3.4 Distribution renewal capital expenditure

Renewal 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' expectations.

The key expenditure drivers for renewal 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;

- 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.

We also engaged consultants GHD to prepare a report that analyses our distribution renewal capital expenditure forecasts using the AER's repex model, for more information refer TN161. The table below shows our forecasts alongside our recent actual distribution renewal capital expenditure.

Table 8-20: Distribution renewal capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Reliability and quality maintained	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8
Inventory / spares	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total distribution renewal	**57.2**	**63.5**	**51.0**	**50.4**	**76.1**	**60.6**	**64.0**	**98.1**	**98.4**	**93.4**	**88.3**	**84.8**

Our forecast distribution renewal capital expenditure for the five-years commencing 1 July 2019 is $463.1 million compared to actual expenditure of $302.1 million for the previous five year period. The proposed increase in reliability and quality maintained capital expenditure is required to address the assessed safety and reliability risks, which reflect age-related asset deterioration. We currently have adequate stock of inventory and spares and do not forecast any additional requirements for the forthcoming regulatory period.

The following sections discusses the 'reliability and quality maintained' component of distribution renewal capital expenditure in further detail.

Distribution reliability and quality maintained capital expenditure

Below is a summary of our key distribution reliability and quality maintained capital expenditure programs and projects for the forthcoming regulatory period. We are prioritising our forward program with an initial focus, in most instances, on High Bushfire Consequence Loss Areas (**HBCLA**).

- **Pole replacements**

  We own and manage approximately 230,000 poles, the majority of which are treated wood pole structures. We aim to replace poles when they are identified as being at their end of life or following damage due to weather events or third parties. We have an ageing pole population, with many of our poles approaching the end of their useful life. As a result, we are forecasting an increase in our pole condemnation rates and, therefore, an increase in pole replacement expenditure in the forthcoming regulatory period.

- **Pole staking**

  Our pole staking program enables the deferral of pole replacement. With our ageing pole population, we are also forecasting an increase in pole staking rates.

- **Low voltage wooden cross-arms**

  We have approximately 210,000 sawn timber low voltage cross-arms installed across the distribution network, which have relatively short asset lives (15 to 20 years). As a result of improved inspection techniques such as aerial helicopter inspections and infrared thermography, we have identified many cross-arms that need to be replaced and, therefore, forecast an associated expenditure increase. In the first instance, we are prioritising replacements of cross-arms in HBCLA.

- **Overhead pole mounted transformers**

  We have approximately 30,000 overhead distribution pole mounted transformers. As these assets approach 50 years of service life, the probability of failure significantly increases. We have considered and analysed a number of asset replacement strategies. Our preferred approach is to pursue a run-to-failure strategy with transformers being replaced in a timely manner following failure or pending failure. Due to an ageing transformer population, we forecast an associated expenditure increase in the forthcoming regulatory period. This strategy is consistent with our risk appetite and assessment frameworks while aligning to customer feedback in relation to the maintenance of current levels of reliability.

- **Distribution network fuses**

  We have approximately 28,000 expulsion drop out (**EDO**) fuses currently in use across our distribution network. These fuses have a high failure rate and the potential to contribute to increased bushfire risk. To reduce this risk, we are planning to systematically replace EDO fuses with an appropriate modern equivalent. In the first instance, we are prioritising replacements in HBCLA.

- **Substandard overhead conductors**

  We have identified accelerated thermal degradation and corrosion associated with copper, galvanised iron and certain aluminium conductors. Conductor failure reduces overall network reliability, poses a risk to public safety coupled with increasing the probability of bushfire. In the first instance, we are prioritising replacements in HBCLA.

- **Conductor clearance**

  We are obligated to ensure adequate conductor ground clearance. We routinely conduct inspections to assess compliance against the Australian Standards and rectify any identified defects. To assist in this process, we employ a number of innovative programs, including the use of Light Detection and Ranging (**LIDAR**) technology to assess conductor clearance. This innovative technology has led to an increase in the number of defects being identified when compared to traditional inspection methods. As a result, we are forecasting increased expenditure in the forthcoming regulatory period.

- **Overhead low voltage services**

  We have approximately 213,000 overhead low voltage service wires across our distribution network facilitating connection to customers' premises. This asset type is the largest contributor to system faults. Our data shows that a little over half of the low voltage service wire failures can be attributed to 10mm copper service wires. These services are in place in approximately 45,000 installations. We are seeking to actively replace substandard overhead service wires and employing a targeted program to replace 10 mm copper services over a seven year period with two pilot programs currently underway.

- **Low voltage cables**

  TasNetworks experiences an average of 31 low voltage cable failures per annum, of which around 60 per cent can be attributed to Concentric Neutral Solid Aluminium Conductors (**CONSAC**) low voltage cables. As CONSAC cables represents 13 per cent of the low voltage cable network, the failure rate is disproportionally high. CONSAC failures also present a serious public safety risk due to the potential for electric shock. We are currently progressively replacing CONSAC cables and are planning to accelerate this program to replace all CONSAC within our network.

- **Ground mounted substations**

  TasNetworks' owns, maintains and operates approximately 2,000 high voltage ground mounted distribution substations. These substations are actively managed and are subject to routine inspection and maintenance in order to maximise their service life. Many older substations were installed in the early 1960's with approximately 10 per cent of substations, installed prior to 1990, utilising oil as the insulating medium; an obsolete technology which presents a safety risk due to the potential for catastrophic failure. The continued and targeted replacement of high voltage ground mounted distribution substations that have reached their end of life, or that present a significant safety or reliability risk, are forecast to be undertaken in the forthcoming regulatory period based on a detailed risk assessment of each substation.

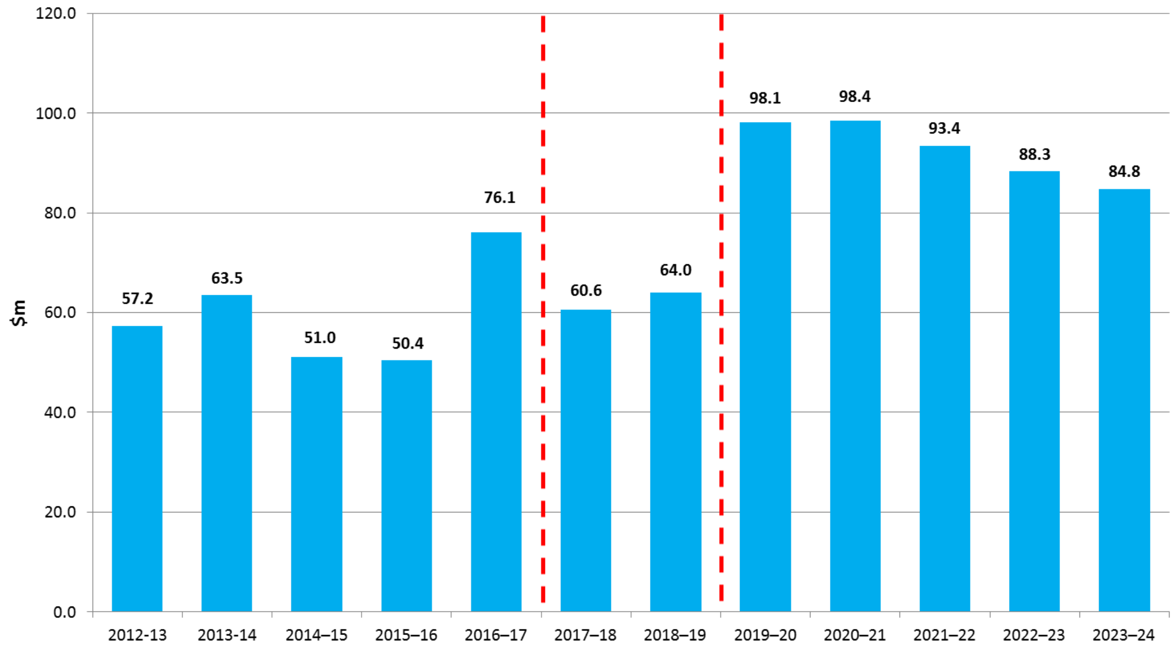
The table below presents our forecast for distribution reliability and quality maintained capital expenditure in the forthcoming regulatory period, alongside our forecast of actual expenditure in the current and previous regulatory periods. Further information is provided in our asset management plans and investment evaluation summaries.

Table 8-21: Distribution reliability and quality maintained capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8

The figure below presents the same information in bar chart format.

Figure 8-15: Distribution reliability and quality maintained capital expenditure (June 2019 $m)



8.3.5 Distribution Operational Support Systems

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

Table 8-22: Distribution Operational Support Systems capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Network Control	1.2	2.5	3.8	2.0	0.8	3.3	2.0	0.8	0.8	0.8	0.5	2.4
Distribution Asset Management Systems	1.6	1.7	0.7	1.3	2.3	12.9	2.9	3.9	3.5	3.6	3.6	2.2
Total distribution Operational Support Systems	**2.8**	**4.2**	**4.5**	**3.3**	**3.1**	**16.3**	**5.0**	**4.6**	**4.3**	**4.3**	**4.1**	**4.6**

Each of the two components of Operational Support Systems capital expenditure is discussed in turn below.

Distribution Network Control

As explained in relation to our expenditure proposals for the transmission network, network control expenditure for the distribution network is driven by our compliance obligations and the technological demands posed as field devices and monitoring equipment become progressively 'smarter.'

Our Network Control 'bottom up' capital expenditure forecast includes recurrent and non-recurrent costs. Recurrent Network Control capital expenditure typically relates to life cycle refresh programs, while non-recurrent expenditure is driven by particular business needs.

Some of the key network control related initiatives proposed for the forthcoming regulatory period include:

- **Smart Grid Support**

  There is an increased reliance on smart grid technology to provide efficiencies when managing the real-time operation of the power system. We forecast that expenditure in this area will be needed to keep up with advances in technology and the associated protocols.

- **Historian upgrades & enhancements**

  The NOCS captures and maintains a large amount of operational information relating to various aspects of the Tasmanian power system. This information is stored in Historian and is used during load shedding to predict how much load could be shed or likely restored to assist with compliance with AEMO's requests; and to assist with outage planning and fault response to ensure the network remains inside its technical envelope when switching occurs.

  This asset is regularly renewed to ensure vendor support and augmented so that it has the capability to meet the increasing data recording and reporting requirements. We are planning such a renewal in the forthcoming regulatory period.

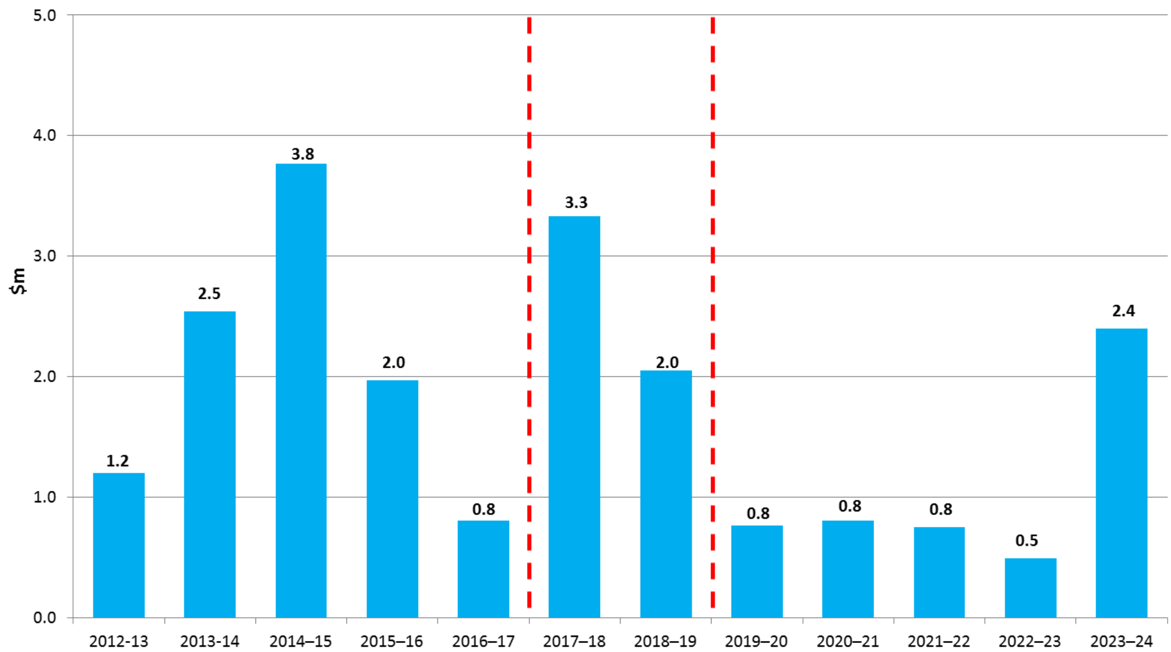
The table below presents our forecast for distribution Network Control capital expenditure in the forthcoming regulatory period, alongside our forecast of actual expenditure in the current and previous regulatory periods.

Table 8-23: Distribution Network Control capital expenditure (June 2019 $m)

	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	1.2	2.5	3.8	2.0	0.8	3.3	2.0	0.8	0.8	0.8	0.5	2.4

The following figure presents the same information as the preceding table in bar chart format.

Figure 8-16: Distribution Network Control capital expenditure (June 2019 $m)



Distribution Asset Management Systems

As explained in relation to transmission Asset Management Systems, the proposed investment profile (transmission/distribution) is focused on enhancing the distribution data and processes to more closely align with current levels of transmission asset information management maturity.

Specifically, we will develop more mature and accurate models of our distribution network and establish robust data acquisition and maintenance practices. Priority will also be given to ensuring that systems and data are available to support risk based asset management for relevant distribution asset classes.

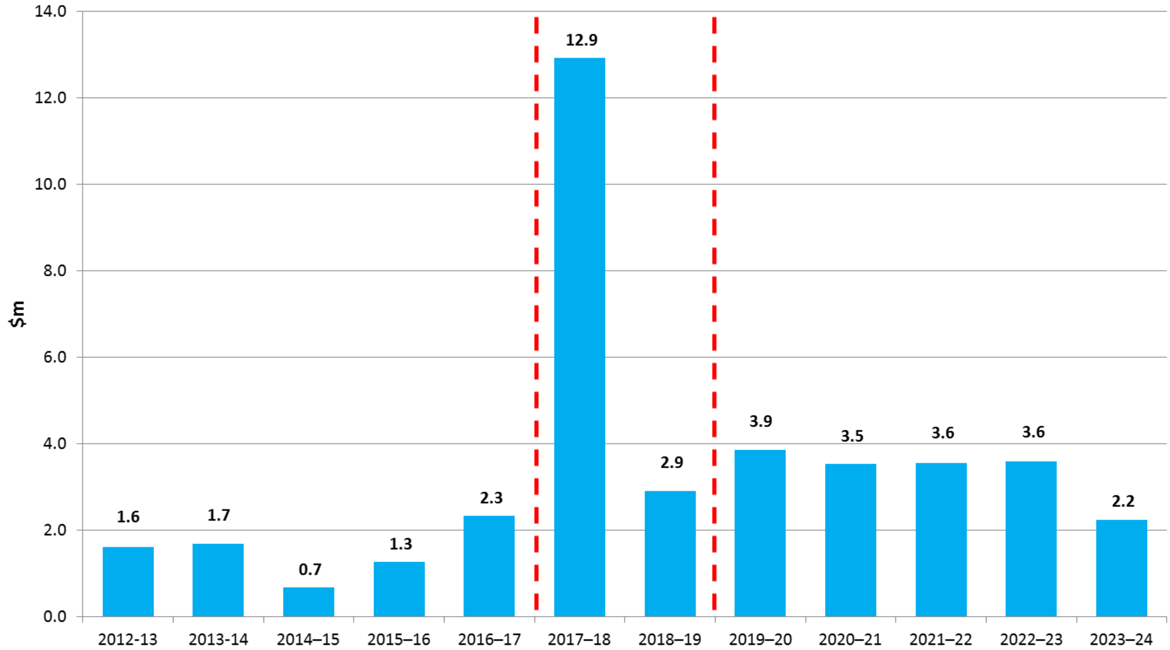
The table below shows our actual and forecast of distribution AMS capital expenditure.

Table 8-24: Distribution Asset Management Systems capital expenditure (June 2019 $m)

	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	1.6	1.7	0.7	1.3	2.3	12.9	2.9	3.9	3.5	3.6	3.6	2.2

The figure below presents the same information in bar chart format.

Figure 8-17: Distribution Asset Management System capital expenditure (June 2019 $m)



As detailed in Table 8-24 and Figure 8-17, our investments in Asset Management Systems are at more stable levels compared to the previous five-year trend. That period saw significant investment renewing our asset management systems in the 2017-18 financial year through our Ajilis transformation program. The forecast in the forthcoming regulatory control period includes building on the current mobility platform and enhancing our operational analytics capabilities.

8.3.6 Distribution IT and communications capital expenditure

As discussed in section 8.2.6 above, the IT program of works has been designed to respond to the business' requirements for maintaining operability and to address both expected market changes and changes in regulatory requirements. A large component of our proposed IT and communications capital expenditure for the forthcoming regulatory period relates to market systems that are specific to the provision of distribution services.

The proposed expenditure is described below, by business functional area:

- **Business Systems Upgrades**

  Proposed expenditure in this area relates to upgrades and replacement of various small applications. Larger expenditure items relating to the distribution network include:

  - Outage Interactive Voice Response (**IVR**) Message Management system upgrade; and
  - GPS Vehicle tracking system improvements.

  The key driver of the upgrades to these business systems is that the assets are at their end-of-life or require a technology uplift.

- **Customer Information Systems**

  Various applications that involve complaint handling, connection applications and customer interaction tracking require a technology uplift, mainly due to the current technology becoming unsupported, and opportunities for consolidation.

- **Data Warehouses, Business Intelligence and Analytics**

  As noted in relation to transmission IT and communications capital expenditure, currently we do not have a single enterprise reporting platform. This situation reflects the historical development of our systems, which originated in two separate businesses. As already explained, it is a source of inefficiency in terms of data management and analysis.

  Our proposed capital expenditure will address these issues by creating a single Enterprise Reporting and Business Intelligence (**BI**) environment and implementing an Enterprise Data Warehouse store (**EDW**), which will provide easier access to structured data and enhanced reporting capabilities to our internal and external customers.

  This initiative will allow increased visibility, improved access and drill-down capability into data across departments and financial periods. It will also support better, data-driven decision making. The costs are shared across transmission and distribution in accordance with our CAM.

- **Digital Customer Engagement**

  Our customer strategy aims to enhance our customers' experience through the ability to interact with customers via the web and through mobile devices. We want to enhance two-way communication so that customers are better able to provide information to the business, such as fault or performance issues, and we can notify customers of issues, such as outages, by SMS.

  To deliver these improvements, our website systems require upgrade. The cost of this initiative is shared between transmission and distribution.

  The developments of these capabilities are strongly supported through feedback from our customers.

- **Enterprise Architecture Evolution**

  The formation of TasNetworks created a challenge in managing the architectural repositories relating to systems and applications used by TasNetworks. The present arrangement impacts on our ability to:

  - plan and forecast change in the technology landscape;
  - identify further opportunities for application rationalisation; and
  - design solutions.

  The cost of building this resource is shared across transmission and distribution.

- **Enterprise Information Management**

  As noted in relation to transmission, this initiative is seeking to consolidate a number of duplicate information management systems. The cost of this initiative is shared across transmission and distribution.

- **Finance, People Management, Asset and Works Systems**

  For the distribution network, expenditure in this area includes:

  - Replacement of Meter Reading Handheld equipment which is at the end of its operating life; and
  - Replacement of the Customer Connections Works Management Tool. This system is past end-of-life. It will be 15 years old in 2021 and there is no upgrade path. The work is vital to ensure the continuity of our customer-facing connection services, which each year deal with around:
    - 4,000 customer connections;
    - 17,000 alterations of customer connections; and
    - 60,000 customers moving in and out.

  There is no proposed capital investment to upgrade the Finance and People Management areas of our integrated ERP system for distribution in the forthcoming regulatory period. Minor maintenance upgrades in these areas will be of an operational nature.

- **IT Infrastructure, Security and Support**

  As noted in relation to transmission, this area involves various expenditures driven by asset end-of-life or increased capacity requirements in the areas of end-user computing, IT management and toolsets, IT network core services, collaboration tools, and application delivery mechanisms. The costs are shared across transmission and distribution.

- **Market Systems**

  Significant initiatives in this area include:

  - *Market Data Management System (**MDMS**) Replacement*

    The MDMS is the primary repository of installation, customer, and metering data. The existing MDMS will be 20 years old and at end-of-life in 2025, when this initiative is planned to be completed. The replacement of the MDMS is programmed to follow on from the replacement of the customer connection works management tool.

    MDMS replacement involves a total cost of $63 million. Based on the expected SAP implementation timeline, this cost is split across the forthcoming regulatory period ($30 million) and the subsequent period commencing in 2024 ($33 million).

    The system is instrumental in the processes of gathering and validating meter readings for the billing of Tasmanian basic metered customers. The ageing system currently in use poses significant market operability and compliance risks relating to:

      - business cash flow (approximately $413 million per annum or 76 per cent of our revenue is processed through market systems);
      - 2.4 million collected meter readings per year, and 90 million generated reads for unmetered sites per year; and
      - compliance / operator licencing. In particular, there is a heightened risk of non-compliance with recent and on-going regulatory changes as our existing technology ages.
  - *Billing System Upgrades*

    The distribution billing system requires upgrades to address emerging technologies in smart streetlights and other expected changes.
  - *MDMS Upgrades*

    The MDMS requires ongoing upgrades to address requirements from the biannual change program from AEMO. This change program alters procedures or data requirements for market participants. This expenditure is compliance driven.

- **Mobility**

  As explained in relation to transmission, we are investing to take advantage of mobile technology to provide improved customer outcomes. Our strategy aims to:
  - enable increased interaction, collaboration and work efficiency by providing our field workforce mobile access to more system functions and by modernising existing access; and
  - provide benefits relating to staff engagement, improved efficiency, increased quality and speed of information exchanged, as well as better cross function collaboration.

  The costs of this initiative are shared across transmission and distribution.

- **Outage Management**

  There are two key distribution initiatives in this area;
  - *Upgrade of Map Migration*

    The connectivity model of the distribution grid is authored in the Geospatial Information System (**GIS**) and is pivotal to the Outage Management processes. The model is exchanged between the GIS and the Outage Management System (**OMS**) by a tool know as Map Migration.

    Replacement of the Distribution GIS system in 2019 will necessitate corresponding work to the Map Migration Tool to ensure the connectivity model can be maintained in the OMS.
  - *Upgrade/Replacement of the Outage Management System*

    The current Outage Management System will reach end-of-life in 2019 and will require major upgrade works or replacement.

Further details on our distribution IT and communications capital expenditure are provided in the IT Infrastructure (TN045) and IT Asset Management Plans (Software (TN046), respectively).

8.3.7 Distribution Non-network Other capital expenditure

As noted in section 8.2.7, our vehicle fleet and facilities (land and buildings) are managed as shared services, with costs allocated to the transmission and distribution functions in accordance with our approved CAM. This expenditure enables us to manage safety risks efficiently, meet operational requirements, and to minimise the total life cycle costs of providing regulated network services.

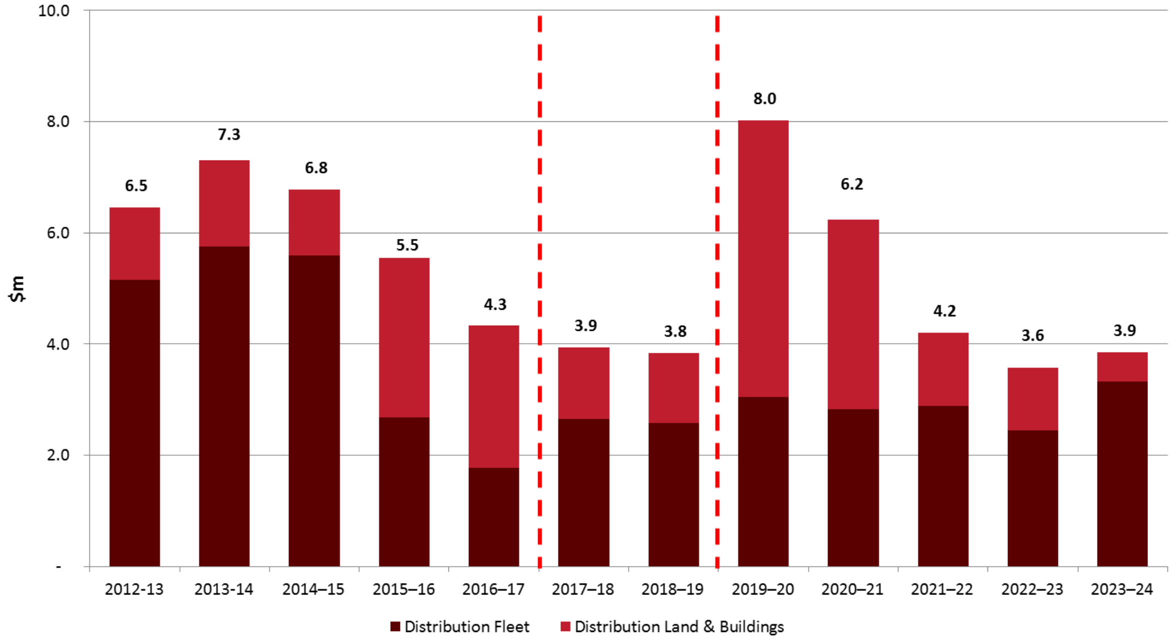
The table below shows our Non-network Other capital expenditure for the distribution network.

Table 8-25: Distribution Non-network Other capital expenditure forecast (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Fleet	5.1	5.7	5.6	2.7	1.8	2.6	2.6	3.0	2.8	2.9	2.4	3.3
Distribution Land & Buildings	1.3	1.6	1.2	2.9	2.5	1.3	1.3	5.0	3.4	1.3	1.1	0.5
Distribution Non-network Other	**6.5**	**7.3**	**6.8**	**5.5**	**4.3**	**3.9**	**3.8**	**8.0**	**6.2**	**4.2**	**3.6**	**3.9**

The figure below presents the same information in bar chart format.

Figure 8-18: Distribution Non-network other capital expenditure (June 2019 $m)



As detailed in Table 8-25 and Figure 8-18, our actual distribution non-network other capital expenditure for the previous five years is expected to be $24.4 million. For the forthcoming five-year period, we are forecasting $25.9 million.

An overview of the drivers of our fleet and facilities capital expenditure forecasts is provided in section 8.2.7. Further detailed information is set out in the following documents:

- Tool of Trade Fleet Management Plan; and

- Facilities Asset Management Plan.

8.4 Deliverability of our capital expenditure plans

We have developed a works delivery strategy for the forthcoming regulatory period and beyond. The strategy encompasses plans for the delivery of our transmission and distribution 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. The internal field based workforce required to operate and maintain the distribution and transmission networks includes asset inspectors, distribution operators, dual-trade electricians/line workers, distribution line workers, live line workers, meter readers and electricians. Our internal resourcing requirements are driven by the scope and composition of future work programs. We have systems and processes in place to assess the skill sets and internal resources required to deliver our forecast work programs, and to fine-tune the current resourcing strategy to enable us to deliver those work programs efficiently.

The antecedent businesses had established a robust service provider market in Tasmania, with some service providers mobilising satellite operations from mainland Australia. External 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. Accordingly, our internal resources are complemented by our use of outsourced service providers in the cost-effective delivery of a range of functions across our transmission and distribution networks. These functions include:

- vegetation management;
- meter reading;
- street lighting;
- civil works;
- major construction;
- pole testing and pole staking;
- specialist testing – thermal, earthing, EHV cables and equipment;
- aerial inspections and surveying;
- tower foundation condition assessment; and
- routine maintenance.

Outsourced programs are packaged in a manner that supports optimised and efficient delivery.

Projects and work programs contracted for external delivery are managed through the Project Delivery and Contracts Group, which operates under ISO 9001 quality accredited processes. We utilise commercial procurement and contract management principles to ensure that we are achieving the most efficient delivery of the required services.

We have recently improved our works delivery arrangements by implementing the following initiatives:

- a review and strengthening of our Works Delivery Framework to ensure that it provides an optimal mix and level of resources;
- an 'end to end' program of work process improvements, to strengthen the clarity of roles and responsibilities of employees and to ensure that we respond to the challenges of developing and delivering our 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.

During the current regulatory period, we have successfully employed a mix of internal and external resources to deliver a work program that is similar to that proposed for the forthcoming regulatory period. 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 Deliverability Plan 2019-24 (TN019).

8.5 Expected benefits of our capital program

As explained at the outset, our transmission and distribution capital expenditure forecasts address the objectives in the Rules, which require us to deliver the following outcomes efficiently:

- meet or manage the expected demand for prescribed transmission services and standard control distribution services over that period;
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and standard control distribution services;
- maintain the quality, reliability and security of supply of prescribed transmission services and standard control distribution services;
- maintain the reliability and security of the transmission and distribution systems through the supply of prescribed transmission services and standard control distribution services; and
- maintain the safety of the distribution system through the supply of prescri bed transmission services and standard control distribution services.

The feedback we received from our customers has been important in guiding our expenditure plans, particularly where we are able to exercise discretion in our expenditure decisions. As such, we have tailored our plans to deliver the following benefits:

- Affordability – We have applied an optimisation across our forecast expenditure reducing our preliminary transmission and distribution capital expenditure forecasts by 0.5 per cent and 5.0 per cent, respectively.
- Safety – Our capital plans aim to deliver programs that are safe and sustainable for the electricity network, our people and contractors, our customers and the communities we serve.
- Reliability – We propose to maintain reliability in accordance with our customers' preferences.
- Efficiency – We are continuing our planned investment in new systems and processes to enable us to drive operating expenditure savings over time.

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 adversely impact our strategy of maintaining current levels of network reliability. This expenditure is critical in helping us maintain safe and reliable network services. Our capital expenditure plans look beyond the current period to consider the implications for cost, performance and risk in subsequent periods.

We are confident that our proposed expenditure plans appropriately balance our customers' preference for lower costs against the risk of deterioration in performance. We consider that our capital expenditure program will deliver the outcomes that our customers expect at the lowest sustainable cost.

8.6 Prudency and efficiency

The Rules require the AER to assess the prudency and efficiency of our transmission and distribution capital expenditure, having regard to 'capital expenditure factors' which include:

- the AER's most recent annual benchmarking reports;
- the actual and expected capital expenditure in previous regulatory control periods;
- the extent to which the forecasts address the concerns of electricity consumers;
- the relative prices of operating and capital inputs;
- the substitution possibilities between operating and capital expenditure;
- whether the forecast is consistent with the applicable incentive schemes;
- whether the forecast reflects arrangements that are not on arm's length terms;
- whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project;

- the extent we have considered, and made provision for, efficient and prudent non-network options; and
- any relevant final project assessment report, as required by the regulatory investment test.

As the AER is required to consider the above factors in reviewing our forecasts, we have taken them into account in developing our expenditure forecasts. In particular, we note the following:

- The AER's benchmarking reports, which are discussed in Part 1 of this Regulatory Proposal, indicate that we perform well compared to our peers. We recognise that our distribution performance can improve further, although the AER recognises that our operating environment in Tasmania places us at a disadvantage.
- Our forecasts are broadly in line with historic expenditure. The principal focus for increased expenditure is renewals, where we need to address emerging reliability and safety issues.
- We have carefully considered the feedback from customers, particularly in relation to affordability issues and adjusted our forecasts accordingly.
- Operating and capital input prices and substitution possibilities are considered in our investment evaluations, so that the optimal solution is selected.
- Our capital expenditure is focused on maintaining reliability, which is consistent with the design of the AER's incentive schemes.
- Our forecasts are not affected by related party arrangements.
- We have proposed contingent projects that comply with the Rules requirements. In preparing our forecasts, we have taken care to ensure that no expenditure relating to these projects has been included in our forecasts.
- We consider non-network options as part of our project evaluation process and in accordance with the regulatory investment test.
- There are no final project assessment reports in relation to our capital expenditure forecasts.

As explained in this chapter, our approach to determining our capital expenditure requirements is focused on examining the key drivers; identifying improvement opportunities; assessing operating and capital expenditure substitution opportunities, including non-network options; validating forecasts through modelling and benchmarking; and applying a top-down discipline to the forecasts.

As noted in section 8.2, we have responded to customer feedback regarding the need to contain any upward pressure on prices by rigorously reviewing our capital expenditure plans and applying a further optimisation to reduce costs. 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.

We are confident that our capital expenditure forecasts comply with the Rules requirements and should be accepted by the AER.

9 Operating expenditure forecasts

9.1 Introduction

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

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

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

The operating expenditure forecasts set out in this chapter reflect efficient levels of expenditure that will enable us to deliver these outcomes. In particular, we are continuing to focus on achieving efficiency savings without compromising safety and reliability for today's customers or future customers.

We explain that while our transmission operating expenditure has been consistently be low the AER's allowance, increased expenditure has been necessary during 2016-17 to address risks on our distribution network. Our priority is to return distribution operating expenditure to lower levels in 2017-18, without compromising safety or reliability. To address customer feedback regarding affordability, we are also constraining our transmission and distribution operating expenditure forecasts to absorb growth on existing expenditure above CPI and to seek further incremental efficiencies to achieve a:

- 0.5 per cent reduction in year two; and
- further one per cent per annum reduction in years three, four and five.

As explained in this chapter, this is achieved by imposing target cost efficiency improvements on the operating expenditure allowance that results from applying the AER's forecast methodology.

The remainder of this chapter is structured as follows:

- Section 9.2 explains our operating expenditure forecasting methodology.
- Sections 9.3 and 9.4 apply the forecasting methodology to derive our forecast transmission and distribution operating expenditure, respectively.

- Section 9.5 explains why our forecast operating expenditure is prudent and efficient, having regard to the operating expenditure factors in the Rules.

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

9.2 Forecasting methodology

As explained in our forecasting methodology paper[29], we have adopted the AER's 'base-step-trend' approach to develop our transmission and distribution operating expenditure forecasts. This methodology projects future expenditure by building from an efficient base year, being 2017–18 for the forthcoming regulatory period. It is a simple method that is effective in identifying the operating expenditure drivers for the forecast period.

Our methodology comprises the following three steps.

- **Step 1 -** Derive and verify the recurrent operating expenditure forecast as follows:
  - (a) commence with actual operating costs for the 2017–18 base year;
  - (b) adjust the base year cost by deducting:
    - (i) non-recurrent operating expenditure items;
    - (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;

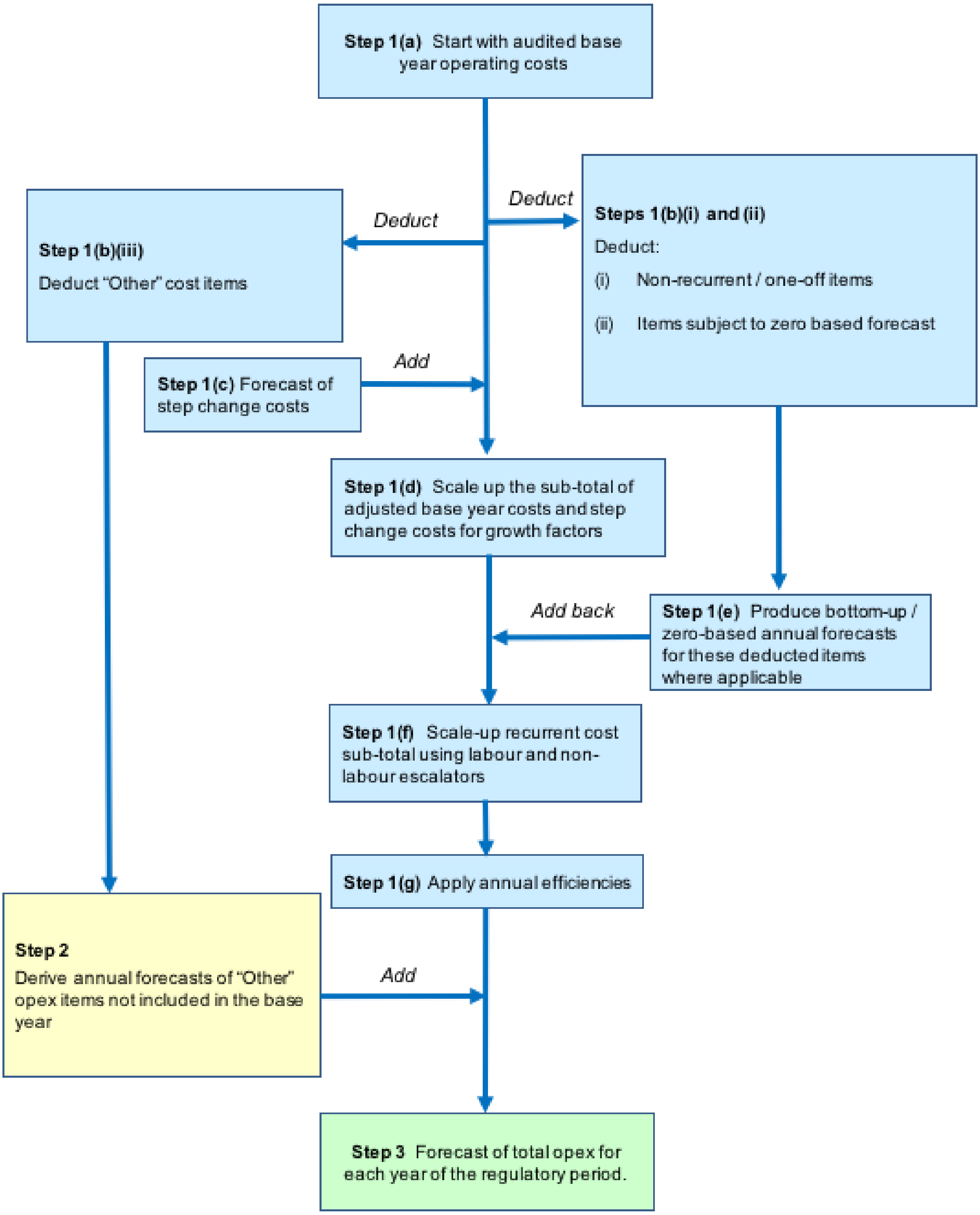
    The adjusted base year for 2017-18 is then converted to an equivalent dollar amount for 2018-19, being the final year of the current period.
  - (c) add the forecast cost of step changes;
  - (d) scale up the sub-total of the adjusted base year cost and forecast step change costs annually by using applicable 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 (if required) 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.

29 TasNetworks, 2019–24 TasNetworks Expenditure Forecasting Methodology, October 2017.

- **Step 2 -** Include the forecast for 'Other' operating expenditure elements. A forecasting methodology which reflects the relevant drivers is adopted for each element.
- **Step 3 -** Derive the total 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 regulatory period.

Our operating expenditure forecasting methodology is illustrated in the figure below.

Figure 9-1: Our operating expenditure forecasting methodology

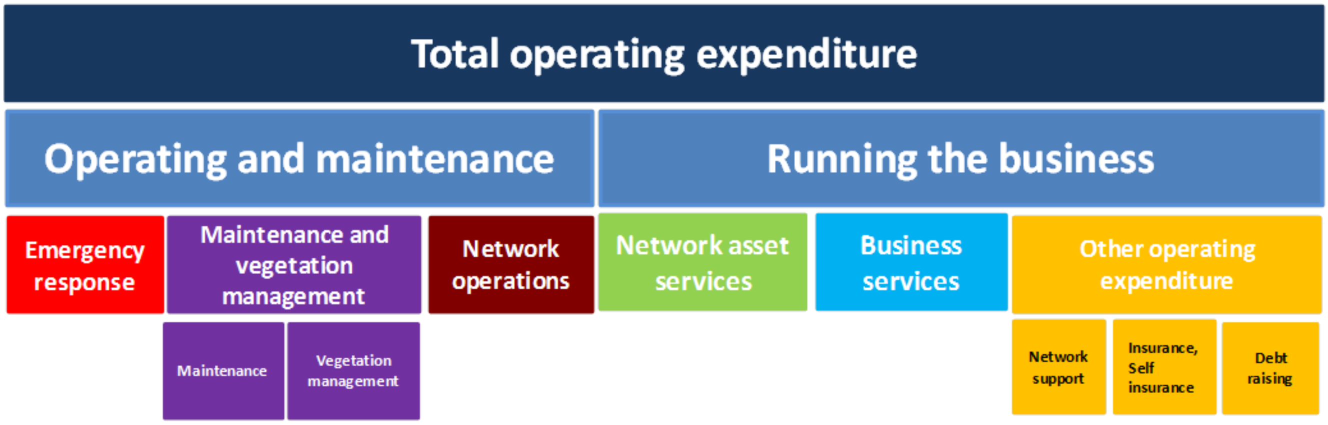


9.3 Transmission operating expenditure

9.3.1 Overview

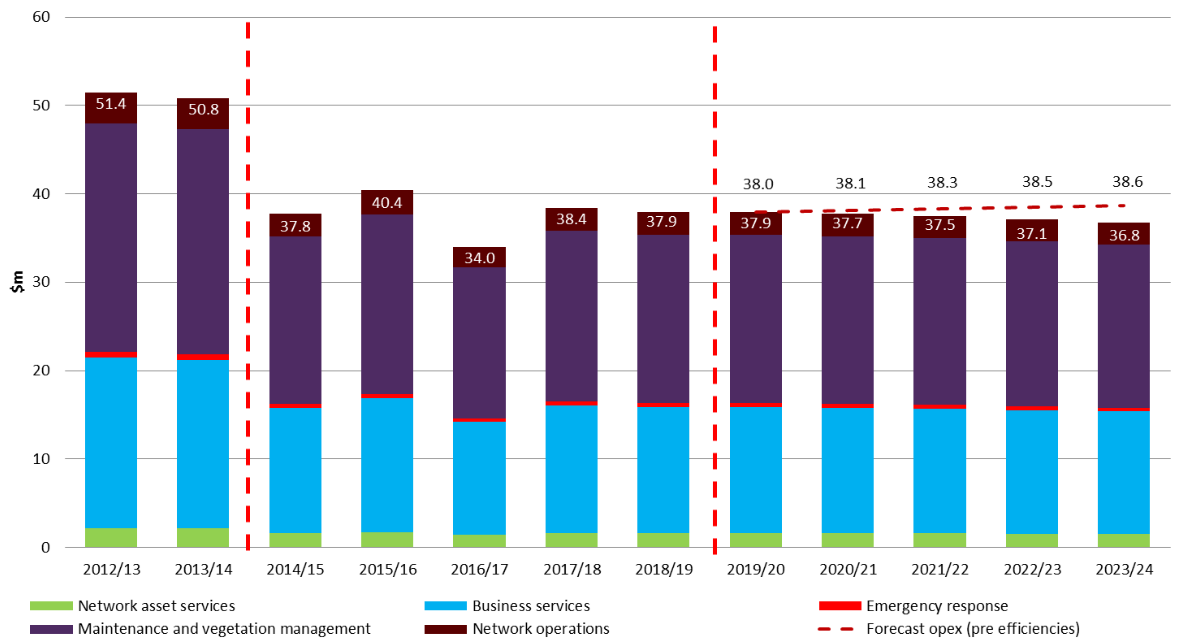
The figure below shows the expenditure categories for transmission operating expenditure for the forthcoming regulatory period.

Figure 9-2: Forecasting methodology categories for transmission operating expenditure categories



The figure below shows our forecast transmission operating expenditure for the forthcoming regulatory period alongside our pre-efficiency forecast together with historic actual and estimated expenditure.

Figure 9-3: Overview of forecast and actual transmission operating expenditure (June 2019 $m)



As shown in the above figure, we have reduced transmission operating expenditure significantly from the levels in 2012-13 and 2013-14. The lower transmission operating expenditure benefits all our customers, as both distribution and transmission customers use our transmission network.

Our average transmission operating expenditure for the forthcoming regulatory period is forecast to fall by 0.5 per cent in real terms in 2020-21 and a further one per cent per annum in real terms for the remaining three years. As already noted, this outcome reflects the inclusion of a 'top down' efficiency factor in response to customer concerns regarding affordability.

Our benchmarking indicates that the proposed operating expenditure is below the AER's model's predicted efficient level, as explained in our Benchmarking Report (TN159). These proposed operating expenditure levels are therefore ambitious – and reflect a continued focus on prioritising our activities and driving our business to achieve the lowest sustainable prices for our customers.

The table below shows our actual and forecast annual transmission operating expenditure by category. The total forecast transmission operating expenditure for the forthcoming regulatory period is $187.1 million compared to $188.5 million for the current period.

Table 9-1: Actual and forecast transmission operating expenditure by category (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Emergency Field Operations	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Maintenance and Vegetation Management	19.0	20.3	17.1	19.3	19.0	19.0	18.9	18.8	18.7	18.5
Business Services	14.2	15.2	12.8	14.5	14.3	14.3	14.2	14.1	14.0	13.8
'Other' Operating Expenditure	4.2	4.5	3.7	4.2	4.2	4.2	4.2	4.1	4.1	4.0
Total transmission operating expenditure	**37.8**	**40.4**	**34.0**	**38.4**	**37.9**	**37.9**	**37.7**	**37.5**	**37.1**	**36.8**

Further detailed information on our historic and forecast operating expenditure is provided in the Regulatory Information Notice (**RIN**) templates[30].

9.3.2 Key assumptions for transmission operating expenditure

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

- our 2017–18 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 TasNetworks Board has certified 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. If new information becomes available prior to the submission of our revised Regulatory Proposal, we may update our forecast transmission operating expenditure accordingly.

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

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

9.3.3 Transmission recurrent base year costs - Steps 1(a) and 1(b)

The 2017–18 regulatory year is the base year for determining the recurrent component of the transmission operating expenditure forecast. We have chosen 2017-18 as our base year for transmission operating expenditure forecasting because:

- it is the most recent actual reported operating expenditure that will be available at the time of the AER's final decision;
- it is representative of our underlying operating conditions for the current and forthcoming regulatory periods; and
- its selection is consistent with the design of the incentive mechanisms, which provides a constant incentive to deliver efficiency savings.

In our forecasting methodology submitted to the AER in October 2016, we indicated that the base year would be 2016-17. On reflection, we regard 2017-18 as a more preferable base year because it falls within the current transmission and distribution determinations, whereas 2016-17 does not. In addition, 2017-18 is the most recent year and therefore best reflects our future recurrent operating expenditure.

The forecasts presented in this submission are based on our estimated operating expenditure for 2017-18 as at November 2017, which is slightly higher in real terms than our actual expenditure in 2016-17. That said, our combined transmission and distribution opex for 2017-18 is forecast to be considerably lower than 2016-17. Therefore, overall, we maintain that 2017-18 is more reflective of our future expected expenditure. Our actual operating expenditure for 2017-18 will be known prior to the AER's draft decision, which will reflect the updated information.

In accordance with step 1(b)(i) we have not identified any non-recurrent costs in our forecast expenditure for 2017-18. Therefore, we are not proposing any adjustment to our base year operating expenditure to remove non-recurrent 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 are not proposing any adjustments. In previous regulatory proposals, we sought an allowance for self-insurance and insurance costs based on a future forecast rather than base year expenditure, which necessitated the removal of these costs from the base year operating expenditure. However, in this regulatory proposal we are not proposing to re-forecast either self-insurance or insurance costs.

The tables below show the derivation of the efficient base year operating expenditure for transmission.

Table 9-2: Efficient base year transmission operating expenditure (June 2019 $m)

Forecast transmission operating expenditure for 2017–18	38.4
Deduct non-recurrent / one-off items:	0.0
Deduct items subject to zero based forecast	0.0
Deduct other cost items	0.0
Base year efficient transmission operating expenditure	**38.4**

The adjusted base year for 2017-18 is then converted to an equivalent dollar amount for 2018-19 being the final year of the current regulatory control period.

9.3.4 Transmission step changes – Step 1(c)

The base year transmission operating expenditure derived in step 1(b) reflects the current scope of the transmission activities in 2017-18. However, the industry is facing increasing cost pressures as a result of additional regulatory, legal and compliance obligations. Therefore, the scope of our business activities and obligations may change in the forthcoming regulatory period. Such changes may result in increases in our forecast of recurrent transmission operating expenditure, relative to the 2017-18 base year. These changes in costs are termed ‘step changes’.

We are not proposing, at this stage, to include any ‘step changes’ in our forecast transmission operating expenditure, even though additional costs may arise. For example, we have not set aside any allowance for undertaking the RIT-T for any of our proposed contingent projects. It may be appropriate to revisit this approach in our revised proposal as our planning progresses or as new information becomes available. In addition, we may seek to pass through costs associated with additional obligations[31] that arise in the forthcoming regulatory period, when the details and/or cost implications become known.

9.3.5 Transmission output growth - Step 1(d)

In broad terms, our operating expenditure requirements increase as the size of the transmission network grows, both in terms of assets, generation and demand served. However, as a result of economies of scale there is not a one-for-one relationship between business growth and its operating 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 most recent determinations, the AER has applied econometric models to estimate the relationship between business growth and operating expenditure, noting that different models apply

[31] Such as the System Security Market Frameworks Review and the Inertia Rule change.

to transmission and distribution. For the forthcoming regulatory period, output change is calculated based on the weighted average of the output measures as determined by the AER's consultant, Economic Insights, comprising:

- Energy throughput. The forecast growth in energy delivered for the Tasmanian network plus net imports.
- Ratcheted maximum demand. Non-coincident historical maximum demand for each individual connection point measured in megawatts (**MW**).
- Weighted entry and exit connections. The summation of the number of connection points weighted by the voltage of each connection point measured in kiloVolts (**kV**).
- Circuit length. Total transmission line circuit length measured in kilometres (**km**).

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

Table 9-3: Cost impact of transmission network growth (June 2019 $m)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Transmission growth factor	0.13%	0.10%	0.24%	0.10%	0.11%	-
Total $m	0.05	0.09	0.18	0.22	0.26	0.79

9.3.6 Transmission zero based expenditure items – Step 1(e)

As explained in section 9.3.3 (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.

9.3.7 Transmission 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 flows through to higher operating expenditure. There are different types of inputs:

- labour costs (internal and contractor); and
- non-labour costs, which include materials, motor vehicle expenses, tools and media 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 section 8.2.2, for the forthcoming regulatory period we are forecasting that:

- materials costs will increase in line with CPI (i.e. no increase in real terms); and
- labour costs will increase slightly faster than CPI, in accordance with independent market advice received from Jacob[32] (TN166) as set out in section 8.2.2.

32 Jacob, Labour Cost Escalation Report, 25 October 2017.

We have adopted the same materials and labour cost escalators for capital and operating expenditure across our transmission and distribution activities.

9.3.8 Transmission 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 three potential sources of productivity improvement may be included in an operating expenditure forecast:

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

In relation to the first potential source of efficiency, this will be addressed if the AER adjusts the base year operating expenditure to reflect a finding that it is inefficient. As already noted, however, we do not expect the AER to make such a finding.

The second potential source of efficiency gain is captured in the AER's methodology for estimating a growth factor. This source of efficiency is therefore already taken into account.

In relation to the third source, we are proposing significant further efficiency improvements as a stretch target for our transmission activities. We have concluded that this further efficiency amount should deliver an operating expenditure allowance for the period that decreases in real terms. Therefore, the efficiency amount is an additional one per cent annual reduction in our transmission operating expenditure forecasts for the final three years of the regulatory control period, following on from a 0.5 per cent reduction in the previous years.

The table below shows our forecast productivity savings in percentage terms and the corresponding dollar amounts in relation to transmission services.

Table 9-4: Transmission productivity improvements per cent (real) and annual savings (June 2019 $m)

Input	2019–20	2020–21	2021–22	2022–23	2023–24
Annual transmission cost savings (%)	-0.13%	-0.53%	-2.07%	-3.45%	-4.82%
Annual transmission cost savings ($m)	-0.0	-0.2	-0.8	-1.3	-1.9
Cumulative transmission cost savings for period (%)	-0.13%	-0.58%	-1.09%	-1.71%	-2.37%
Cumulative transmission cost savings for period ($m)	-0.0	-0.3	-1.0	-2.4	-4.2

As set out in the table above, we are proposing to deliver cumulative savings of $4.2 million in the costs of providing transmission services over the forthcoming regulatory period.

9.3.9 Transmission 'Other' expenditure items - Step 2

The nature of the 'Other' expenditure items means that a separate forecasting approach is required that sits outside the base-step-trend forecasting methodology. In previous regulatory proposals, we sought separate self-insurance and insurance based on a future forecasts rather than base year expenditure, which necessitated the removal of these costs from the base year operating expenditure.

In this review, however, we have not removed the actual costs of uninsured losses and insurance from our base year operating expenditure, which removes the need for a separate forecast allowance. This approach is consistent with the AER's most recent determinations. As a consequence, the only 'other' expenditure item is debt raising costs.

We propose a benchmark debt raising cost allowance of $1.0 million per annum, which accords with the AER's approach to estimating debt raising costs. Our actual transmission 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 this regulatory treatment. Debt raising costs are discussed in further detail in section 12.7.

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

Table 9-5: 'Other' transmission operating expenditure (June 2019 $m)

Expenditure item	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission debt raising costs	1.0	1.0	1.0	1.0	1.0
Total transmission 'Other'	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**

9.3.10 Total transmission operating expenditure forecast - Step 3

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

Table 9-6: Transmission operating expenditure forecasts (June 2019 $m)

Element / Driver	Details in	2019–20	2020–21	2021–22	2022–23	2023–24
Forecast transmission base year expenditure	Section 9.3.3	38.4	38.4	38.4	38.4	38.4
Base year (2017-18) allowance		47.1	47.1	47.1	47.1	47.1
Difference forecast to allowance (2017-18 base year)		**-8.6**	**-8.6**	**-8.6**	**-8.6**	**-8.6**
Final year (2018-19) equivalent allowance		46.5	46.5	46.5	46.5	46.5
Estimated final year expenditure (2018-19)		**37.9**	**37.9**	**37.9**	**37.9**	**37.9**
Base year adjustments to derive efficient base year expenditure	Section 9.3.3	0.0	0.0	0.0	0.0	0.0
Transmission step changes	Section 9.3.4	0.0	0.0	0.0	0.0	0.0
Transmission output Growth	Section 9.3.5	0.1	0.1	0.2	0.2	0.3
Transmission zero based forecasts	Section 9.3.6	0.0	0.0	0.0	0.0	0.0
Transmission labour and non-labour escalation	Section 9.3.7	0.0	0.1	0.2	0.4	0.5
Sub-total before productivity savings		**38.0**	**38.1**	**38.3**	**38.5**	**38.6**
Transmission productivity savings	Section 9.3.8	-0.1	-0.4	-0.8	-1.3	-1.9
Total transmission (excluding 'Other')[33] [34]		**37.9**	**37.7**	**37.5**	**37.1**	**36.8**

The transmission forecasts reconcile with our proposed expenditure for each business category of operating expenditure, which are:

- Network asset services;
- Business services;
- Emergency response;
- Maintenance and vegetation management;

[33] Excludes debt raising costs to provide a like-for-like comparison with historic data

[34] The NER, S6A.1.2, requires that TasNetworks identifies the extent to which forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable. In the short term, operating expenditure can be regarded as variable, however, in the medium to long term, the cost of sustainably managing high value, long life assets is more appropriately regarded as fixed, relative to a particular asset base.

- Network operations; and
- 'Other' Operating Expenditure.

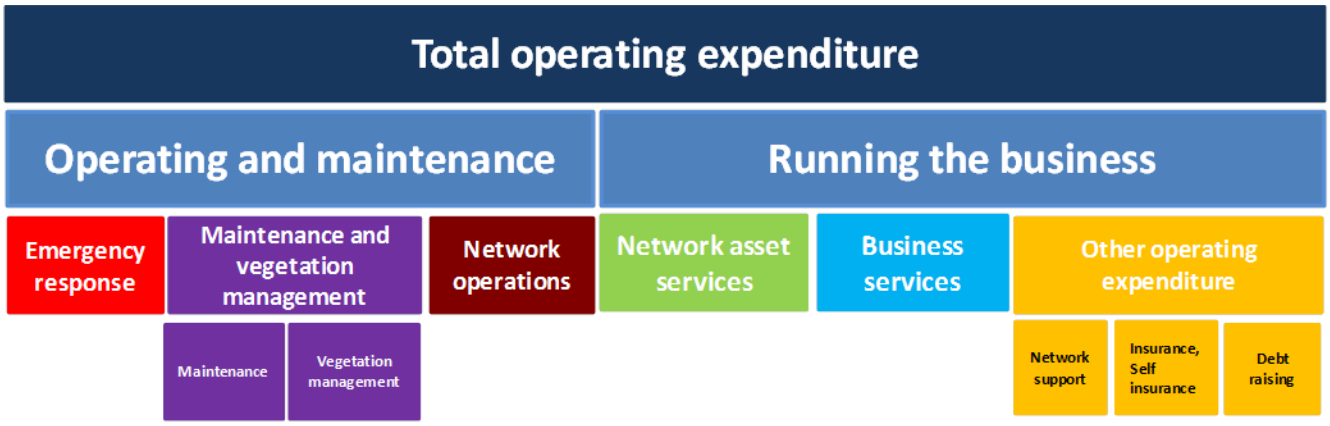
Further our expenditure operating forecasts will allow us to maintain the quality, reliability or security of supply of prescribed transmission services.

9.4 Distribution operating expenditure forecasts

9.4.1 Overview

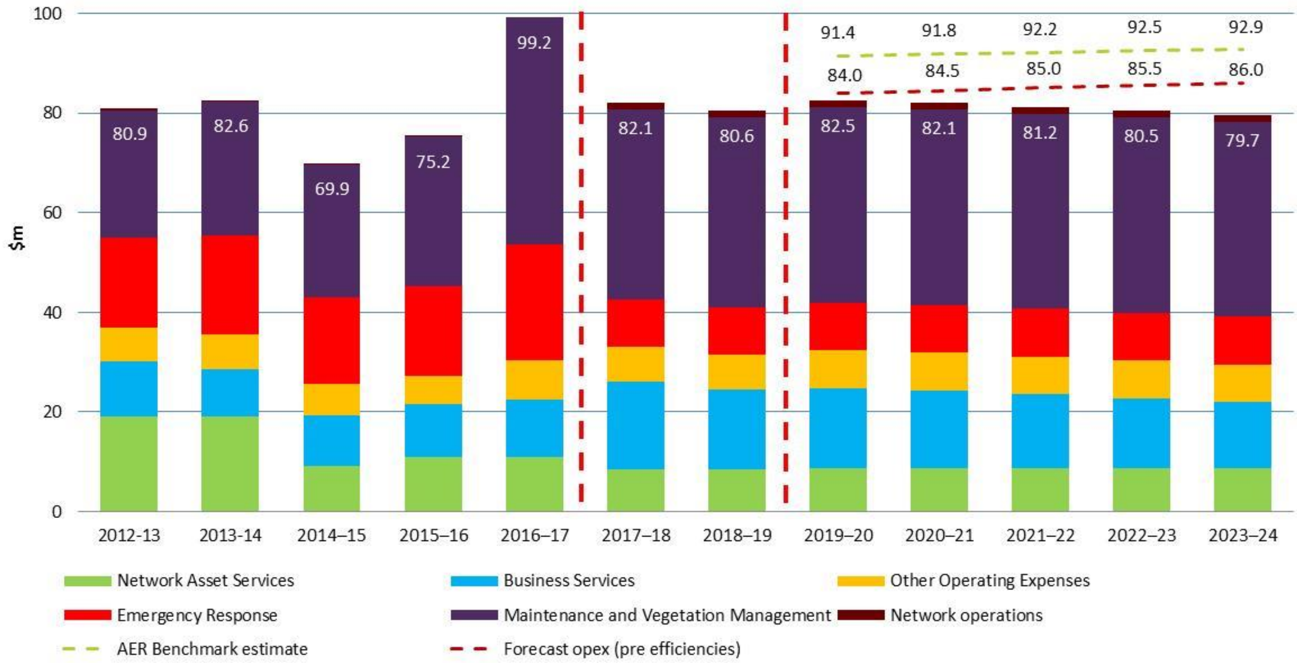
The figure below shows our distribution operating expenditure categories.

Figure 9-4: Distribution operating expenditure categories



The figure below shows our forecast distribution operating expenditure for the forthcoming regulatory period alongside our pre-efficiency forecast together with historic actual and estimated expenditure.

Figure 9-5: Overview of forecast and actual distribution operating expenditure (June 2019 $m)



The table below presents our actual and forecast annual distribution operating expenditure by category, which totals $405.9 million over the forthcoming regulatory period compared to $407.1 million for the previous five year period. As noted in relation to transmission operating expenditure, in response to customer feedback we have imposed a 'top down' efficiency saving to ensure that our distribution operating expenditure allowance reduces in real terms over the forthcoming regulatory period.

Table 9-7: Actual and forecast distribution operating expenditure by category (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Emergency Field Operations	18.1	20.0	17.4	18.0	23.4	9.5	9.5	9.6	9.6	9.6	9.6	9.6
Maintenance and Vegetation Management	25.5	26.7	26.7	30.0	45.6	38.2	38.2	39.2	39.2	39.2	39.2	39.2
Distribution Asset Services	19.1	19.1	9.11	11.0	10.9	8.4	8.4	8.6	8.6	8.6	8.6	8.6
Business Services	11.1	9.4	10.3	10.5	11.5	17.6	16.1	16.1	15.7	14.9	14.1	13.3
'Other' Operating Expenditure	7.0	7.4	6.4	5.7	7.9	8.4	8.4	8.9	8.9	8.9	8.9	8.9
Total distribution operating expenditure	**80.9**	**82.6**	**69.9**	**75.2**	**99.2**	**82.1**	**80.6**	**82.5**	**82.1**	**81.2**	**80.5**	**79.7**

Further detailed information on the variation between historic and forecast operating expenditure is provided in the RIN templates[35].

The figure and table above show that our distribution operating expenditure increased in 2016-17. Our increased expenditure has been necessary to address emerging risks on our distribution network, such as the bushfire risks posed by vegetation, especially in light of experiences interstate.

As better information became available, we concluded that bushfire and asset-related risks were higher than previously understood. Therefore, we acted prudently to address these risks by increasing operating expenditure which meant we exceeded our allowance, this was at the expense of the return to our shareholders rather than our customers.

While we believe that distribution operating expenditure can return to lower levels, it will take time to do so without compromising network safety and performance. Our view is that this lower level of operating expenditure can only be achieved if it is supported by improved processes, practices and business platforms to offset the range of new obligations and increased complexity associated with providing distribution services to a diverse and changing customer and generation base. We are striving to deliver the required efficiency improvements over the course of the current and forthcoming regulatory period.

Whilst we will deliver efficiency savings, we must balance the pressures to reduce costs against our regulatory and performance obligations in an increasingly complex environment. Our approach is to achieve sustainable savings, which means that they do not compromise safety or impose costs on future generations by deferring projects beyond their optimal timeframe.

We expect our 2017-18 distribution operating expenditure to be lower than our actual operating expenditure in 2016-17. On this basis, we regard 2017-18 as a more preferable 'base year' for the purposes of applying the 'base-step-trend' forecasting methodology. We also note that 2017-18 will be our most recent year's cost performance at the time of the AER's determination.

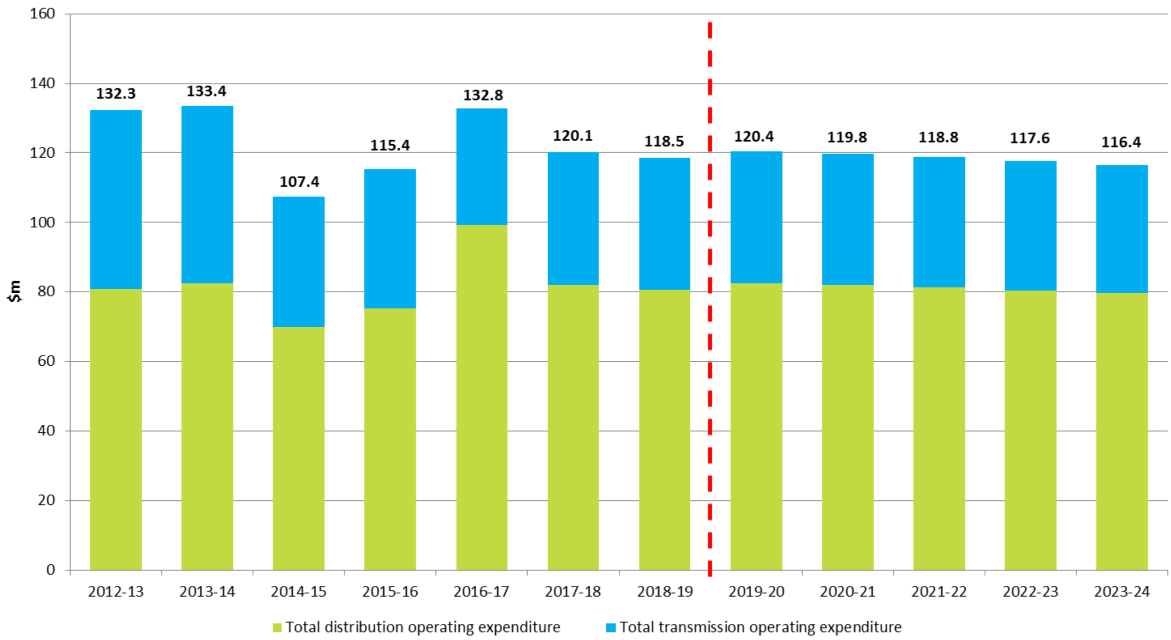
It is important that the same base year should be chosen for transmission and distribution, as resources in the merged business are able to migrate between the two networks in response to

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

particular needs and to drive efficient allocation of resources. If a different base year were chosen for each network, the allocation of costs would not be considered from the same starting point and the resulting total operating expenditure allowance may be materially higher or lower than the total operating expenditure requirements of the merged business.

The figure below shows our combined transmission and distribution operating expenditure. It illustrates that, with the exception of 2016-17, the merger of the two network businesses to create TasNetworks in 2014 is driving lower operating expenditure through consolidation and scale economies together with the delivery of operational efficiencies. It also illustrates that our projected costs for 2017-18 provide a reasonable base year for purpose of forecasting operating expenditure in the next regulatory period.

Figure 9-6: Combined transmission and distribution operating expenditure 2012-13 to 2023-24 (June 2019 $m)



In relation to our forecast distribution operating expenditure, we are projecting real cost reductions, even though we are connecting new customers, seeing increased complexity in providing distribution services and facing additional obligations or 'step changes' that will tend to push our costs higher. Similar to our transmission expenditure, our distribution forecast also reflects ambitious operating expenditure savings, with a continued focus on prioritising our activities and driving efficiency to achieve the lowest sustainable prices for our customers.

9.4.2 Key assumptions for distribution operating expenditure

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

- our 2017–18 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;
- our trade-offs between capital and operating expenditure for the Demand Management Incentive Scheme will be accepted by the AER; and
- our forecast productivity improvements and resulting cost efficiencies are achievable.

As noted in relation to our capital expenditure assumptions, TasNetworks Board has certified 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. If new information becomes available prior to the submission of our revised Regulatory Proposal, we may update our forecast distribution operating expenditure accordingly.

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

9.4.3 Distribution recurrent base year costs - Steps 1(a) and 1(b)

As noted in relation to transmission, the 2017–18 regulatory year is the base year for determining the recurrent component of the operating expenditure forecast. We have chosen 2017-18 as our base year for distribution operating expenditure forecasting because:

- it is the only full regulatory year of actual reported operating expenditure for the current (two year) distribution determination that will be available for the AER's final decision;
- it is representative of our underlying operating conditions for the current and forthcoming regulatory periods;
- its selection is consistent with the design of the incentive mechanisms, which provides a constant incentive to deliver efficiency savings; and
- as noted in relation to transmission, the forecasts presented in this submission are based on our estimated costs for 2017-18. Our actual costs will be known prior to the AER's final decision, which will reflect the updated information.

As explained in section 9.4.1, the historic combined transmission and distribution operating expenditure suggests that 2017-18 is a reasonable base year for forecasting purposes, even though our actual distribution cost performance has been much lower, most notably in 2014-15. For the reasons already noted, however, we do not regard this lower level of expenditure to be sustainable, as it would expose our customers and the broader community to unacceptable reliability and safety risks. Instead, projecting forward from 2017-18 actual distribution operating expenditure will provide the best indication of our efficient and prudent operating expenditure for the forthcoming regulatory period.

In accordance with step 1(b)(i) we have not identified any non-recurrent costs in our forecast expenditure for 2017-18. Therefore, we are not proposing to adjust our base year operating expenditure to remove any non-recurrent operating expenditure. In relation to step 1(b)(ii) we have deducted the expenditure relating to.

- Guaranteed Service Level payments;
- the National Energy Market (**NEM**) levy; and
- the Electrical Safety Inspection (**ESI**) levy.

We note that the Guaranteed Service Level allowance forms part of the service incentive arrangements for our distribution services. The ESI and NEM levy are Tasmanian State Government charges passed through to distribution customers. We are proposing to adjust annually the difference between forecast and actual levies as part of the standard control services revenue formula and pricing adjustments.

A zero based budget amount for these items has been determined separately and included in our operating expenditure forecasts.

In relation to step 1(b)(iii), as noted for transmission operating expenditure, we are not proposing any adjustment to account for 'other' operating expenditure. In previous regulatory proposals our forecasts included a separate self-insurance allowance, but we are not doing so in this proposal.

The tables below show the derivation of the efficient base year operating expenditure for the distribution network.

Table 9-8: Efficient base year distribution operating expenditure (June 2019 $m)

Forecast distribution operating expenditure for 2017–18	82.1
Deduct non-recurrent / one-off items:	0.0
Deduct items subject to zero based forecast	7.0
Base year efficient distribution operating expenditure	**75.1**

The adjusted base year for 2017-18 is then converted to an equivalent dollar amount for 2018-19, being the final year of the current period, as shown in Table 9-14.

9.4.4 Distribution step changes – Step 1(c)

The base year operating expenditure derived in step 1(b) reflects the scope of the distribution activities (including self-insured expenses and recoverable asset damage costs) in 2017-18. As already noted, however, this scope 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 2017-18 base year. These changes in costs are termed 'step changes'.

Our forecast step changes for the distribution network are set out in the table below.

Table 9-9: Distribution Step changes

Activity	Details
Damage to assets	In the forthcoming regulatory period, the recovery of the costs of damage to assets from a third party will be treated as standard control. This is a change from the current approach and therefore a step change to our operating expenditure forecasts is required. This step change reflects the AER's new regulatory approach to the revenue obtained from third parties and will not lead to higher prices to our customers.
Ring-fencing	The implementation of the AER's ring-fencing guidelines will impose additional operating expenditure on our distribution business. These costs are an unavoidable consequence of a regulatory change. Only costs incremental to ring-fencing costs incurred in the 2017-18 base year are included in the step change.
Voltage management	We are forecasting increased expenditure to meet compliance obligations relating to voltage on our network largely, resulting from increased distributed generation.
Capex-opex trade off	We have identified a demand management project that will enable us to defer the replacement of an aging transformer. While this step change will increase our operating expenditure, the net effect of this demand management initiative is to deliver savings to customers.

For each of the distribution 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 distribution step change.

Table 9-10: Forecast distribution step changes to include in base costs (June 2019 $m)

Category	2019–20	2020–21	2021–22	2022–23	2023–24
Damage to assets	0.2	0.2	0.2	0.2	0.2
Ring-fencing	1.2	1.2	1.2	1.2	1.2
Voltage management	1.0	1.0	1.0	1.0	1.0
Capex-opex trade off	0.2	0.2	0.2	0.2	0.2
Distribution step changes base year	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**

To address customer feedback regarding affordability in some instances we have chosen not to seek step changes that we are entitled to claim, such as inspecting private infrastructure which will be paid for by our shareholder. Where we are seeking step changes, we are only seeking 50 per cent of the costs that we are entitled to claim. The remaining costs will be recovered by achieving additional efficiencies in other operating expenditure activities.

9.4.5 Distribution output growth - Step 1(d)

As already noted, this step recognises the impact of growth, both in terms of assets and customer numbers, on our future operating expenditure. For the distribution network, the growth factor is determined by ratcheted maximum demand; customer numbers and circuit length. This approach is consistent with previous AER determinations.

Table 9-11: Cost impact of distribution network growth (June 2019 $m)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Distribution growth factor	0.38%	0.36%	0.34%	0.34%	0.39%	-
Total	**0.3**	**0.5**	**0.8**	**1.1**	**1.3**	**4.0**

9.4.6 Distribution zero based expenditure items - Step 1(e)

As already noted, 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. In relation to distribution services, we are forecasting GSL, NEM levy, ESI levy and distribution debt raising costs.

9.4.7 Distribution real price escalation – Step 1(f)

As already noted, for the forthcoming regulatory period we are forecasting that:

- materials costs will increase in line with CPI (i.e. no increase in real terms); and
- labour costs will increase slightly faster than CPI, in accordance with advice received from Jacobs[36] (TN166) as set out in section 8.2.2.

We have adopted the same materials and labour cost escalators for capital and operating expenditure across our transmission and distribution activities.

9.4.8 Distribution productivity growth – Step 1(g)

The productivity growth factor in the rate of change formula is intended to capture future productivity improvements. As noted in relation to transmission operating expenditure, we have concluded that the business should adopt an efficiency target which results in a distribution operating expenditure allowance that delivers decreases in real terms for the period. Therefore, the efficiency amount is an additional one per cent annual reduction in our distribution operating expenditure forecasts for the final three years of the regulatory control period, following on from a 0.5 per cent reduction in the previous years.

The table below shows the calculated productivity savings in percentage terms and the corresponding dollar amounts for distribution services as compared to the AER's base-step-trend.

Table 9-12: Distribution productivity improvements per cent (real) and annual savings (June 2019 $m)

Input	2019–20	2020–21	2021–22	2022–23	2023–24
Annual distribution cost savings (%)	-1.88%	-2.93%	-4.43%	-5.90%	-7.39%
Annual distribution cost savings ($m)	-1.6	-2.5	-3.8	-5.0	-6.4
Cumulative distribution cost savings for the period (%)	-1.88%	-2.41%	-3.09%	-3.79%	-4.52%
Cumulative distribution cost savings	-1.6	-4.1	-7.8	-12.9	-19.2

36 Jacob, Labour Cost Escalation Report, 25 October 2017.

for period ($m)

As set out in the tables above, we are proposing to deliver cumulative savings of $19.2 million in the costs of providing distribution services over the forthcoming regulatory period. This represents a significant commitment by TasNetworks, and highlights our ongoing focus on business productivity improvement and the pursuit of efficiencies.

9.4.9 Distribution 'Other' expenditure items - Step 2

As already noted, 'Other' expenditure items are subject to a separate forecasting approach that sits outside the base-step-trend forecasting methodology. As noted in relation to transmission, the only 'Other' operating expenditure allowance relates to debt raising costs, which has been calculated in accordance with the AER's most recent determinations.

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

Table 9-13: 'Other' distribution operating expenditure (June 2019 $m)

Expenditure item	2019–20	2020–21	2021–22	2022–23	2023–24
GSL	2.9	2.9	2.9	2.9	2.9
ESI levy	4.0	4.0	4.0	4.0	4.0
NEM levy	0.6	0.6	0.6	0.6	0.6
Distribution debt raising costs	0.9	0.9	0.9	0.9	1.0
Total distribution 'Other'	**8.6**	**8.6**	**8.6**	**8.6**	**8.6**

9.4.10 Total distribution operating expenditure forecast - Step 3

Our distribution operating expenditure forecasts are summarised in the table below.

Table 9-14: Total distribution operating expenditure forecasts (June 2019 $m)

Element / Driver	Details in	2019–20	2020–21	2021–22	2022–23	2023–24
Forecast distribution base year expenditure	Section 9.4.3	82.1	82.1	82.1	82.1	82.1
Base year zero based forecasts		-7.0	-7.0	-7.0	-7.0	-7.0
Forecast distribution base year expenditure (less zero based forecasts)		**75.1**	**75.1**	**75.1**	**75.1**	**75.1**
Base year (2017-18) allowance		68.8	68.8	68.8	68.8	68.8
Difference forecast to allowance (2017-18 base year)		**6.3**	**6.3**	**6.3**	**6.3**	**6.3**
Final year (2018-19) equivalent allowance		67.3	67.3	67.3	67.3	67.3
Estimated final year expenditure (excl. zero based forecasts)		**73.6**	**73.6**	**73.6**	**73.6**	**73.6**
Base year adjustments to derive efficient base year expenditure	Section 9.4.3	0.0	0.0	0.0	0.0	0.0
Distribution step changes	Section 0	2.6	2.6	2.6	2.6	2.6
Distribution output Growth	Section 9.4.5	0.3	0.5	0.8	1.1	1.3
Distribution zero based forecasts (excluding debt raising costs)	Section 9.4.6	7.6	7.6	7.6	7.6	7.6
Distribution labour and non-labour escalation	Section 9.4.7	0.0	0.2	0.5	0.7	0.9
Sub-total before productivity savings		**84.0**	**84.5**	**85.0**	**85.5**	**86.0**
Distribution productivity savings	Section 9.4.8	-1.6	-2.5	-3.8	-5.0	-6.3
Total distribution (excluding 'Other')[37]		**82.5**	**82.1**	**81.2**	**80.5**	**79.7**

As noted in relation to transmission, the above table reflects the steps in our expenditure forecasting methodology as described in section 9.2. The forecasts reconcile with our proposed expenditure for each business category of operating expenditure.

[37] Excludes debt raising costs to provide life-for-like comparisons with historic data

9.5 Prudency and efficiency

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 relation to capital expenditure, the AER is required to consider certain 'expenditure factors' in reviewing our forecasts. The Rules provide an equivalent set of expenditure factors that the AER must consider in reviewing our operating expenditure forecasts.

It should be noted that our earlier comments regarding the capital expenditure factors are equally valid for our operating expenditure. For example:

- Our costs benchmark well against our peers.
- We have taken account of customers' concerns regarding affordability in preparing our operating expenditure forecasts.
- We routinely consider capital and operating substitution possibilities and non-network options in our expenditure decisions.
- Our forecasts are not affected by related party arrangements.

As explained in this chapter, our actual distribution operating expenditure in 2016-17 was significantly higher than the AER's allowance. The increase was necessary in order to address emerging risks on our distribution network. In particular, better information in relation to bushfire and asset-related risks indicated that increasing the level of vegetation management expenditure was in our customers' long-term interests.

We are working hard to deliver efficiency improvements. Our forecast operating expenditure for 2017-18 (our base year) shows a reduction compared with our actual operating expenditure in 2016-17. This outcome demonstrates that we are delivering efficiencies and, looking forward, we are proposing to absorb 50 per cent of our forecast distribution step changes in our operating expenditure and, as noted previously, not claim some step changes at all. Whilst we will deliver efficiency savings, we will continue to balance the pressures to reduce costs against our regulatory and performance obligations.

In developing our operating expenditure forecast for the forthcoming regulatory period, we have applied the AER's preferred base-step-trend methodology. As part of this methodology, we have imposed tough efficiency targets to deliver an overall outcome that we believe our customers will find acceptable. 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 safety and maintaining service performance and managing network risks, both now and into the future. 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.

10 Regulatory Asset Base

10.1 Introduction

This chapter presents information on our Regulatory Asset Base (**RAB**), which has been calculated in accordance with the Rules, specifically:

- clauses 6A.6.1, 6A.6.3, and Schedule 6A.2 in relation to transmission assets; and
- clauses 6.5.1, 6.5.5, and Schedule 6.2 in relation to distribution assets.

In the AER's 2015 Final Transmission Determination, the AER applied its roll forward methodology to determine a value for our transmission RAB of $1,443.8 million, in nominal terms, as at 1 July 2015.

In the AER's 2017 Final Distribution Determination, the AER applied its roll forward methodology in determining a value for our opening distribution RAB of $1,615.2 million, in nominal terms, as at 1 July 2017.

For the purpose of the AER's forthcoming determinations for TasNetworks, it is necessary to:

- estimate our opening transmission and distribution RABs as at 1 July 2019; and
- provide a forecast of our RAB values for each year of the forthcoming five year regulatory period.

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

- Section 10.2 presents information regarding the review of our past transmission and distribution capital expenditure under the provisions in clauses S6A.2.2A, and S6.2.2A, respectively.
- Section 10.3 explains the methodology for rolling forward the asset base values to 1 July 2019.
- Section 10.4 explains the derivation of the forecast opening and closing RAB values for each year of the forthcoming regulatory control period.

10.2 Review of past capital expenditure

Clauses S6A.2.2A and S6.2.2A of the Rules provide 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 clauses 11.62 and 11.63 of the Rules the first year of the review period is 2014-15.

Accordingly, under the Rules, the review periods are:

- in relation to transmission, the three year period from 2014-15 to 2016-17 inclusive; and
- in relation to distribution, 2015-16 and 2016-17.

It is noted that during our previous (2017) distribution determination, the AER reviewed our 2014-15 distribution capital expenditure.

The circumstances specified in the Rules that could trigger an efficiency review of past expenditure do not apply in relation to our actual expenditure in the relevant years.

Accordingly, all our transmission and distribution capital expenditure incurred during the current regulatory period meets the criteria for efficient expenditure and will be included in the regulatory asset base. In addition, Part One of this Regulatory Proposal provides detailed information on our investment and governance planning arrangements which are designed to ensure that every dollar of capital expenditure is spent efficiently.

10.3 Opening Regulatory Asset Base as at 1 July 2019

10.3.1 Opening Transmission RAB

Our transmission regulatory asset base as at 1 July 2019 has been calculated in accordance with the roll forward model (**RFM**) provided by the AER and the requirements of Schedule 6A.2 of the Rules.

In summary, our transmission regulatory asset base as at 1 July 2019 is derived by:

- adjusting for any difference between forecast and actual capital expenditure that is embedded in the 1 July 2014 opening value of $1,410.3 million; and then
- rolling forward the 1 July 2014 value for actual additions, disposals, inflation escalation and deductions of forecast depreciation using the AER's roll forward model.

The table shows the derivation of the RAB value as at 1 July 2019 (that is, the closing RAB as at 30 June 2019), in accordance with this methodology.

Table 10-1: Roll forward of transmission regulatory asset base from 1 July 2015 to 30 June 2019 ($m nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19
Opening RAB	1,410.3	1,407.2	1,399.3	1,410.9	1,438.7
Net capital expenditure	26.0	25.5	52.3	54.6	56.3
Inflation on opening RAB	24.2	23.8	20.7	34.6	35.2
Forecast straight-line depreciation	-53.3	-57.2	-61.3	-61.4	-63.1
Closing RAB	1,407.2	1,399.3	1,410.9	1,438.7	1,467.1
Add difference between actual and forecast 2013-14 net capital expenditure					0.3
Add return on difference in 2013-14 net capital expenditure					0.1
Closing RAB					**1,467.4**

As shown in the table above, the RAB value as at 1 July 2019 (in nominal dollars) is $1,467.4 million. Capital expenditure amounts for 2017-18 and 2018-19 are estimates.

10.3.2 Opening Distribution RAB

Our distribution regulatory asset base as at 1 July 2019 has been calculated in accordance with the 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 distribution regulatory asset base as at 1 July 2019 is derived by:

- adjusting for any difference between forecast and actual capital expenditure that is embedded in the 1 July 2017 opening value of $1,615.2 million; and then
- rolling forward the 1 July 2017 value for actual additions, disposals, inflation escalation and deductions of forecast depreciation using the AER's RFM.

The table shows the derivation of the distribution RAB value as at 1 July 2019 (that is, the closing RAB as at 30 June 2019), in accordance with this methodology.

Table 10-2: Roll forward of distribution regulatory asset base from 1 July 2017 to 30 June 2019 ($m nominal)

	2017-18	2018-19
Opening RAB	1,615.2	1,694.8
Net capital expenditure	117.6	108.9
Inflation on opening RAB	39.6	41.5
Forecast straight-line depreciation	-77.5	-98.8
Closing RAB	1,694.8	1,746.4
Add difference between actual and forecast 2016-17 net capital expenditure		8.3
Add return on difference in 2016-17 net capital expenditure		1.0
Closing RAB		**1,755.8**

As shown in the table above, the RAB value as at 1 July 2019 (in nominal dollars) is $1,755.8 million. Capital expenditure amounts for 2017-18 and 2018-19 are estimates.

10.4 Forecast of Regulatory Asset Base for the forthcoming period

10.4.1 Forecast Transmission RAB

Table 10-3 presents a summary of the amounts, values and inputs used by us to derive our transmission 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 prescribed transmission services in accordance with our approved CAM have been included in the RAB.

Table 10-3: Transmission regulatory asset base roll forward 1 July 2019 to 30 June 2024 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24
RAB (start period) - nominal	1,467.4	1,489.7	1,536.2	1,583.6	1,609.1
Nominal capital expenditure	40.9	68.6	71.8	53.4	49.5
Inflation on opening nominal RAB	36.0	36.5	37.6	38.8	39.4
Nominal straight-line depreciation	-54.6	-58.6	-62.0	-66.7	-71.2
RAB (end period) - nominal	1,489.7	1,536.2	1,583.6	1,609.1	1,626.8
RAB (end period) - $ June 2019	**1,454.1**	**1,463.6**	**1,472.7**	**1,460.6**	**1,441.4**

10.4.2 Forecast Distribution RAB

The table below presents a summary of the amounts, values and inputs used by us to derive our distribution RAB value for each year of the forthcoming regulatory control period.

Table 10-4: Distribution regulatory asset base roll forward 1 July 2019 to 30 June 2024 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24
RAB (start period) - nominal	1,755.8	1,859.6	1,955.2	2,034.3	2,125.2
Nominal capital expenditure	161.5	158.9	148.8	165.6	169.4
Inflation on opening nominal RAB	43.0	45.6	47.9	49.8	52.1
Nominal straight-line depreciation	-100.7	-108.9	-117.7	-124.4	-132.0
RAB (end period) - nominal	1,859.6	1,955.2	2,034.3	2,125.2	2,214.7
RAB (end period) - $ June 2019	**1,815.2**	**1,862.8**	**1,891.8**	**1,929.1**	**1,962.2**

In accordance with clause S6.2.1(e)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of standard control distribution services in accordance with our approved CAM has been included in the RAB. It should be noted that the nominal capital expenditure in the table above excludes capital contributions. Customer initiated capital expenditure included in the RAB is the gross (total) expenditure minus customer capital contributions.

11 Regulatory depreciation

11.1 Introduction

This chapter sets out information on our proposed approach to determining regulatory depreciation for the forthcoming regulatory period in accordance with the requirements of clauses 6A.6.3, S6A.1.3(7), 6.5.5 and S6.1.3(12) of the Rules.

The remainder of this chapter is structured as follows:

- Section 11.2 describes our regulatory depreciation methodology.
- Section 11.3 provides information on the standard and remaining lives for each asset class within our regulatory asset base.
- Section 11.4 sets out our regulatory depreciation forecasts for the forthcoming period.

Please note that information on the calculation of tax depreciation for the purpose of determining our corporate tax allowance is provided in Chapter 13.

11.2 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**). We have used the AER's PTRM without amendment and have therefore calculated the 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.

We have depreciated new assets on a straight line basis according to standard lives for each asset class. We have depreciated our existing assets over their remaining asset lives. The standard lives and remaining lives for each asset class are set out in the next section.

Opening asset values at 1 July 2019 have been calculated by applying the AER's RFM. Chapter 10 provides an overview of these calculations.

We note that Schedule S6A.1.3(7) of the Rules requires us to provide the depreciation schedules in relation to transmission assets by location. We understand that this requirement relates to clause 6A.6.3, which requires special treatment of assets dedicated to one user or a small group of users (not being a DNSP) with a RAB value exceeding $27 million at the beginning of the first regulatory year of the current regulatory control period. We do not have any transmission assets that fall within this category.

11.3 Standard and remaining lives for asset classes

We have adopted asset classes and standard and remaining asset lives in accordance with good engineering practice and our own financial records. The asset classes and standard lives are unchanged from those accepted by the AER in its April 2015 transmission determination, and its April 2017 distribution determination, with the exception noted below.

In our distribution determination, the AER accepted a new asset category (Business Management Systems) with a ten year life for expenditure for the Ajilis and other business system projects, which will replace numerous legacy systems including key asset management, financial, and human resources systems. Given that this project is a company-wide initiative, it is also appropriate to adopt an equivalent asset class for transmission.

In its April 2017 distribution determination, the AER accepted our proposal to use the year-by-year tracking method for depreciating existing assets. We have adopted this method in this Regulatory Proposal for our transmission and distribution assets. In the current transmission determination, we had adopted the AER's weighted average remaining life approach. However, we consider it appropriate to adopt a common method across both transmission and distribution.

The year-by-year tracking method captures the timing of new additions for each asset class in the relevant year, which provides more granular and accurate information on the remaining asset lives. These calculations are made in a separate depreciation model, and the depreciation amounts are substituted directly into the PTRM. Both of these models are supplied as supporting documents to this Regulatory Proposal.

The tables below set out the standard asset lives for transmission and distribution by asset class.

Table 11-1: Transmission - standard asset lives as at 1 July 2019

Asset category	Standard life (years)
Transmission assets	
Transmission line assets—long life	60
Transmission line assets—medium life	45
Transmission line assets—short life	10
Substation assets—long life	60
Substation assets—medium life	45
Substation assets—short life	15
Protection and control—short life	15
Protection and control—very short life	4
Transmission operations—short life	10
Transmission operations—very short life	4
Communication assets—medium life	45
Communication assets—short life	10
Communication assets—very short life	5
Other—medium life	40
Other—short life	9
Other—very short life	4
Business Management Systems	10

Table 11-2: Distribution - standard asset lives as at 1 July 2019

Asset category	Standard life (years)
Distribution assets	
Overhead subtransmission lines (urban)	50
Underground subtransmission lines (urban)	60
Urban zone substations	40
Rural zone substations	40
SCADA	10
Distribution switching stations (ground)	40
Overhead high voltage lines urban	35
Overhead high voltage lines rural	35
Voltage regulators on distribution feeders	40
Underground high voltage lines	60
Underground high voltage lines SWER	60
Distribution substations HV (pole)	40
Distribution substations HV (ground)	40
Distribution substations LV (pole)	40
Distribution substations LV (ground)	40
Overhead low voltage lines underbuilt urban	35
Overhead low voltage lines underbuilt rural	35
Overhead low voltage lines urban	35
Overhead low voltage lines rural	35
Underground low voltage lines	60
Underground low voltage common trench	60
HVST service connections	40
HV service connections	40
HV metering CA service connections	40
HV/LV service connections	40
Business LV service connections	35
Business LV metering CA service connections	25
Domestic LV service connections	35
Domestic LV metering CA service connections	20
Motor vehicles	6
Minor assets	5
Non-system property	40
NEM assets	5
Business Management Systems	10

11.4 Depreciation forecasts

The table below shows the depreciation building blocks for prescribed transmission services for the forthcoming regulatory period.

Table 11-3: Depreciation building blocks - Transmission assets

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Straight-line depreciation (June 2019 $)	53.3	55.9	57.7	60.5	63.1
Straight-line depreciation (nominal)	54.6	58.6	62.0	66.7	71.2
Inflation on the opening RAB (nominal)	36.0	36.5	37.6	38.8	39.4
Regulatory depreciation (nominal)	18.6	22.2	24.4	27.9	31.8
Forecast inflation on opening RAB (% per annum)	2.45%	2.45%	2.45%	2.45%	2.45%

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

Table 11-4: Depreciation building blocks - Distribution assets

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Straight-line depreciation (June 2019 $)	98.3	103.8	109.5	112.9	117.0
Straight-line depreciation (nominal)	100.7	108.9	117.7	124.4	132.0
Inflation on the opening RAB (nominal)	43.0	45.6	47.9	49.8	52.1
Regulatory depreciation (nominal)	57.7	63.3	69.8	74.6	80.0
Forecast inflation on opening RAB (% per annum)	2.45%	2.45%	2.45%	2.45%	2.45%

Our forecast depreciation allowance reflects:

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

Our forecast regulatory depreciation is calculated in accordance with the requirements set out in clauses 6A.6.3 and 6.5.5 of the Rules. As shown in the tables above, the regulatory depreciation is the straight line depreciation (nominal) minus inflation on the opening RAB (nominal).

12 Weighted Average Cost of Capital

12.1 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. The AER has commenced its review of the guideline in accordance with the Rules. We submitted a Rule change proposal in June 2017 requesting that the 2013 Guidelines apply to the distribution and transmission determinations for the forthcoming regulatory period. The Rule change was approved by the AEMC on 26 September 2017.

Accordingly, we have applied the December 2013 Rate of Return Guideline in estimating the WACC for our transmission and distribution assets. In applying these guidelines, we have had regard to the decisions made by the Australian Competition Tribunal on 26 February 2016[38] and the Federal Court on 24 May 2017[39] in relation to the approach for estimating the cost of debt allowance.

As explained later in this chapter, the application of the AER's Guideline would produce a higher WACC for our transmission assets compared to distribution. We have decided to reduce the rate of return on our transmission assets to match the distribution rate of return. This discount benefits all our customers, easing price pressures in an era of unprecedented change.

The remainder of this chapter is structured as follows:

- Section 12.2 provides an overview of the Rules' rate of return objective, the AER's Rate of Return Guideline, and recent judicial decisions relating to the rate of return.
- Section 12.3 presents a summary of our proposed cost of equity, in light of the requirements of the Rules and Rate of Return Guideline.
- Section 12.4 sets out our proposed cost of debt for the transmission and distribution networks.
- Section 12.5 summarises our point estimate for the WACC for the transmission and distribution networks.
- Sections 12.6 and 12.7 set out our proposal for equity raising and debt raising costs for the transmission and distribution networks.

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38 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1 (ACT 1 of 2015, ACT 4 of 2015) (*Ausgrid*); *Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy* [2016] ACompT 2 (ACT 2 of 2015, ACT 6 of 2015); *Applications by Public Interest Advocacy Service Ltd and Essential Energy* [2016] ACompT 3 (ACT 3 of 2015); *Application by ActewAGL Distribution* [2016] ACompT 4 (ACT 5 of 2015); and *Application by Jemena Gas Networks (NSW) Ltd* [2016] ACompT 5 (ACT 8 of 2015) (NSD 420 of 2016).

39 Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79.

12.2 The allowed rate of return objective and guideline, and recent judicial decisions

The Rules[40] 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 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 Network Service Provider in respect of the provision of regulated 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 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.

As already noted, the Australian Competition Tribunal and the Federal Court have made decisions regarding the approach to be applied in estimating the cost of debt allowance. In particular, the Tribunal concluded that the AER was incorrect to apply a 'one size fits all approach' by imposing a transitional arrangement for introducing the trailing average cost of debt. The Tribunal found that the AER's return on debt decisions should be set aside and re-determined according to the reasons given in its judgment.

Subsequently, the Federal Court concluded that the AER has not established any of the grounds of judicial review in relation to return on debt, and therefore essentially upheld the Tribunal's decision.

The Tribunal's decision does not provide clear guidance on the transitional arrangements that should apply in moving to the trailing average approach to estimating the cost of debt. Essentially, the Tribunal requires a case-by-case assessment to be made, having regard to each network company's historic practices in relation to debt financing. We interpret the Tribunal's conclusions as follows:

- Where a company has been applying an economically efficient approach to debt raising (which is closely aligned to the trailing average approach), there is no rationale for adopting a transitional arrangement.
- Conversely, where a company's approach to debt financing has reflected the 'on the day' regulatory approach to estimating the cost of debt, there is a much stronger case for a transitional arrangement.

For TasNetworks, our historic debt financing has reflected the 'on the day' regulatory approach, and therefore we consider the AER's transitional arrangement to be appropriate.

40 Clauses 6A.6.2(c) and 6.5.2(c).

12.3 Cost of equity

The same cost of equity will apply to both transmission and distribution. We have applied the AER's foundation model[41] (the Sharpe–Lintner capital asset pricing model or CAPM) to estimate the cost of equity. The formula for calculating the cost of equity is

$$Cost\ of\ Equity = Risk\ Free\ Rate + Market\ Risk\ Premium\ \times\ Equity\ Beta$$

Our estimate of the cost of equity for the forthcoming regulatory period is set out in the table below.

Table 12-1: Proposed cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	2.64%	This is a place-holder value reflecting the yield on ten year Commonwealth bonds measured over the 20 day period from 4 August to 31 August 2017 for the purpose of this Regulatory Proposal. The risk free rate for the AER's final determination will be measured over a 20 day period to be agreed with the AER.
Market risk premium	6.5%	This value has been adopted consistently by the AER in all of its determinations in recent years.
Equity beta	0.7	This value has been adopted consistently by the AER in all of its determinations in recent years. This value is consistent with the point estimate set out in section 5.3.3 of the December 2013 Rate of Return Guideline.
Cost of equity	7.2%	Sharpe–Lintner CAPM using parameter values noted in this table.

12.4 Cost of debt

TasNetworks have applied the trailing average methodology as outlined in the AER's 2013 Rate of Return Guideline for the calculation of the cost of debt. The formula to be applied for the 2019-2024 regulatory period is provided in Figure 12-1.

Figure 12-1: Trailing Average formula for cost of debt

CoD *XX-XX* is Regulatory Cost of Debt applied for that year.
$R_{xx\text{-}xx}$ is the Return on Debt for that regulatory year.

Distribution

CoD 19-20 = ($R_{17\text{-}18}$ x 0.8)+($R_{18\text{-}19}$ x 0.1)+($R_{19\text{-}20}$ x 0.1)

CoD 20-21 = ($R_{17\text{-}18}$ x 0.7)+($R_{18\text{-}19}$ x 0.1)+($R_{19\text{-}20}$ x 0.1)+($R_{20\text{-}21}$ x 0.1)

CoD 21-22 = ($R_{17\text{-}18}$ x 0.6)+($R_{18\text{-}19}$ x 0.1)+($R_{19\text{-}20}$ x 0.1)+($R_{20\text{-}21}$ x 0.1)+($R_{21\text{-}22}$ x 0.1)

CoD 22-23 = ($R_{17\text{-}18}$ x 0.5)+($R_{18\text{-}19}$ x 0.1)+($R_{19\text{-}20}$ x 0.1)+($R_{20\text{-}21}$ x 0.1)+($R_{21\text{-}22}$ x 0.1)+($R_{22\text{-}23}$ x 0.1)

CoD 23-24 = ($R_{17\text{-}18}$ x 0.4)+($R_{18\text{-}19}$ x 0.1)+($R_{19\text{-}20}$ x 0.1)+($R_{20\text{-}21}$ x 0.1)+($R_{21\text{-}22}$ x 0.1)+($R_{22\text{-}23}$ x 0.1)+($R_{23\text{-}24}$ x 0.1)

[41] AER, Rate of Return Guideline, December 2013, section 5.3.3.

Transmission
CoD 19-20 = $(R_{14\text{-}15} \times 0.5)+(R_{15\text{-}16} \times 0.1)+(R_{16\text{-}17} \times 0.1)+(R_{17\text{-}18} \times 0.1)+(R_{18\text{-}19} \times 0.1)+(R_{19\text{-}20} \times 0.1)$
CoD 20-21 = $(R_{14\text{-}15} \times 0.4)+(R_{15\text{-}16} \times 0.1)+(R_{16\text{-}17} \times 0.1)+(R_{17\text{-}18} \times 0.1)+(R_{18\text{-}19} \times 0.1)+(R_{19\text{-}20} \times 0.1)+(R_{20\text{-}21} \times 0.1)$
CoD 21-22 = $(R_{14\text{-}15} \times 0.3)+(R_{15\text{-}16} \times 0.1)+(R_{16\text{-}17} \times 0.1)+(R_{17\text{-}18} \times 0.1)+(R_{18\text{-}19} \times 0.1)+(R_{19\text{-}20} \times 0.1)+(R_{20\text{-}21} \times 0.1)$ $+(R_{21\text{-}22} \times 0.1)$
CoD 22-23 = $(R_{14\text{-}15} \times 0.2)+(R_{15\text{-}16} \times 0.1)+(R_{16\text{-}17} \times 0.1)+(R_{17\text{-}18} \times 0.1)+(R_{18\text{-}19} \times 0.1)+(R_{19\text{-}20} \times 0.1)+(R_{20\text{-}21} \times 0.1)$ $+(R_{21\text{-}22} \times 0.1)+(R_{22\text{-}23} \times 0.1)$
CoD 23-24 = $(R_{14\text{-}15} \times 0.1)+(R_{15\text{-}16} \times 0.1)+(R_{16\text{-}17} \times 0.1)+(R_{17\text{-}18} \times 0.1)+(R_{18\text{-}19} \times 0.1)+(R_{19\text{-}20} \times 0.1)+(R_{20\text{-}21} \times 0.1)$ $+(R_{21\text{-}22} \times 0.1)+(R_{22\text{-}23} \times 0.1)+(R_{23\text{-}24} \times 0.1)$

12.4.1 Cost of debt allowance for transmission

We have applied the AER's guidelines to calculate a placeholder cost of debt for transmission of 5.44 per cent. This reflects the weighted average of the:

- average of Bloomberg data and data published by the Reserve Bank of Australia on the annualised yield on ten year BBB-rated corporate debt averaged over the placeholder ten business day period from 18 August to 31 August 2017. The actual value cannot yet be determined as it will be calculated during the nominated averaging period close to the commencement of the forthcoming regulatory period; and
- historic cost of debt allowances for the current regulatory period.

12.4.2 Cost of debt allowance for distribution

For distribution, we have applied the same methodology as outlined in relation to transmission. This methodology results in a cost of debt allowance of 5.01 per cent, which reflects the later commencement of the trailing average approach compared to transmission.

12.5 WACC Estimates

For the purpose of estimating the WACCs, we have adopted a benchmark capital structure of 60 per cent debt to total assets, which is consistent with the AER's previous decisions and section 4.3.2 of the December 2013 guideline.

As already noted, the same cost of equity applies to our transmission and distribution activities. However, a strict application of the AER's Guideline would produce different cost of debt allowances for the transmission and distribution activities, and therefore different WACC estimates.

For transmission, the figure below shows that the application of the AER's Guideline would result in a WACC of 6.15 per cent for transmission and 5.89 per cent for distribution, noting that the actual value will be updated as part of the AER's decision and then annually to reflect movement in the cost of debt.

Figure 12-2: Average WACC estimate for transmission in nominal terms

Transmission Weighted Average Cost of Capital		
Component	Debt	Equity
Proportion of capital	60%	40%
	x	x
Cost	5.44%	7.2%
	=	=
Contribution	3.27%	2.88%
WACC	6.15%	

Figure 12-3: Average WACC estimate for distribution in nominal terms

Distribution Weighted Average Cost of Capital		
Component	Debt	Equity
Proportion of capital	60%	40%
	x	x
Cost	5.01%	7.2%
	=	=
Contribution	3.01%	2.88%
WACC	5.89%	

For the forthcoming regulatory period, we have decided to respond to the affordability concerns raised by customers by proposing to align the transmission and distribution WACC estimates to reflect the lower figure, being 5.89 per cent for distribution. In effect this is a decision to provide lower shareholder returns on our transmission services, to contribute to affordable customer pricing outcomes. This requires a one-off adjustment to the transmission WACC to align it to the lower distribution WACC for the duration of the forthcoming regulatory period. We recognise that this approach requires an adjustment (reduction) to the transmission WACC determined under the Guideline so that it aligns with the lower distribution WACC determined under the Guideline.

From an operational perspective, as the WACC is updated annually, we would ask the AER to continue to apply the adjustment to the transmission WACC so that it aligns to the lower distribution WACC for the period.

It should be noted that because the lower WACC applies to transmission, it will reduce the total revenue and charges for our transmission customers and our distribution customers, as transmission revenue forms a component of our distribution network charges or tariffs.

12.6 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 the costs of raising equity that would be incurred by a prudent service provider acting efficiently. Accordingly, the AER provides a benchmark 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 PTRMs submitted with this Regulatory Proposal) indicate that under the AER's modelling approach an external equity injection is required to maintain the benchmark capital structure over the forthcoming regulatory period. The PTRMs calculate an equity raising cost allowance of $0.6 million for the forthcoming regulatory period. Accordingly, we are proposing the inclusion of an equity raising cost allowance of $0.4 million in the transmission regulatory asset base and $0.2 million in the distribution regulatory asset base, in accordance with the approach and calculations set out in our completed PTRMs.

12.7 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 to enable us to estimate these costs.

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.

Our financial modelling treats the debt portfolios of our transmission and distribution activities separately, so it is necessary to estimate separate debt raising costs for these two debt portfolios.

12.7.1 Debt raising cost allowance for transmission

We have included an allowance of 11.5 basis points per annum (bppa) in relation to our direct debt raising costs, this is consistent with the allowance approved by the AER for our current regulatory period. The table below sets out our proposed debt raising cost allowance.

Table 12-2: Debt raising cost allowance for transmission

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Benchmark debt for the year (June 2019 $)	880.5	872.5	878.2	883.6	876.4

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Debt raising cost allowance (June 2019 $m) (11.5 bppa)	1.0	1.0	1.0	1.0	1.0

12.7.2 Debt raising cost allowance for distribution

Our approach for estimating debt raising costs for distribution is consistent with the approach for transmission. We have included an allowance of 8.3 bppa in relation to our direct debt raising costs, this is consistent with the allowance approved by the AER for our current regulatory period.

Table 12-3: Debt raising cost allowance for distribution

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Benchmark debt for the year (June 2019 $)	1,053.5	1,089.1	1,117.7	1,135.1	1,157.5
Debt raising cost allowance (June 2019 $m) (8.3 bppa)	0.9	0.9	0.9	0.9	1.0

13 Forecast allowance for corporate tax

13.1 Introduction

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

- Section 13.2 describes the method we have applied for calculating the corporate income tax allowance.
- Section 13.3 sets out our estimate of the value of imputation credits (gamma).
- Section 13.4 provides information on our forecast of depreciation for corporate tax purposes.
- Section 13.5 provides an overview of our calculation of the corporate tax allowance.

13.2 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 clauses 6A.6.4 and 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.

13.3 Imputation credit value (gamma)

The value of imputation credits (gamma) is an important input to the calculation of the corporate income tax allowance. Under the Australian imputation tax system, shareholders may receive imputation tax credits with dividends, which offset tax liabilities. Therefore, investors would accept a lower rate of return for an investment with imputation credits attached than if there were no imputation tax credits attached.

In effect, the assumed value of gamma has a direct bearing on the overall returns that are delivered to network business owners. Specifically, if the value ascribed to gamma is higher than the value that equity-holders place on imputation credits, the overall benchmark return to owners will be less than the level required to promote efficient investment in, and efficient operation and use of, electricity transmission and distribution services for the long term interests of consumers.

The value of gamma has been highly contentious in recent years. In 2016, the Australian Competition Tribunal heard appeals by the NSW electricity distributors, in which The Tribunal found that the AER's set value for gamma at 0.4 that was too high. It ordered the AER to make its decision using a gamma of 0.25.

Subsequently, the Federal court upheld the AER's contention that the Tribunal erred in its construction of the expression 'the value of imputation credits', which led the Tribunal to reject the AER's preferred estimation methods. The court concluded that it was not a reviewable error for the AER to prefer one theoretical approach to considering the determination of gamma over another. In effect, the AER did not make an error in adopting a gamma value of 0.4.

For the purpose of this Regulatory Proposal, we propose to adopt a gamma value of 0.4, which is the AER's preferred estimate and consistent with the decision of the Federal Court.

13.4 Forecast regulatory tax depreciation

The calculation of the corporate tax allowance requires a forecast of tax depreciation to be made. We have calculated tax depreciation in accordance with the tax law and with the methodology contained within the PTRM. In accordance with the PTRM, we have calculated tax depreciation on a straight line basis, using applicable straight line tax depreciation rates.

13.5 Calculation of corporate income tax allowance

Our forecast of the regulatory corporate income tax allowance has been derived pursuant to clauses 6A.6.4 and 6.5.3 of the Rules, using the PTRM in accordance with the AER's preferred method.

The formula set out in section 13.2 calculates the benchmark entity's income tax allowance for each year of the regulatory period. An adjustment is then made to reduce the tax allowance for the benchmark value of imputation credits.

The tables below show the resulting regulatory allowance for tax. Our tax asset bases for transmission and distribution are modelled separately, so separate tax allowances are calculated.

Table 13-1: Forecast tax allowance from 1 July 2019 to 30 June 2024 - Transmission ($m nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Benchmark income tax payable	5.2	5.9	6.4	7.4	8.5
Imputation credit	-2.1	-2.4	-2.6	-3.0	-3.4
Tax allowance	**3.1**	**3.5**	**3.9**	**4.5**	**5.1**

Table 13-2: Forecast tax allowance from 1 July 2019 to 30 June 2024 - Distribution ($m nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Benchmark income tax payable	16.8	17.4	18.4	19.5	20.7
Imputation credit	-6.7	-7.0	-7.4	-7.8	-8.3
Tax allowance	**10.1**	**10.4**	**11.0**	**11.7**	**12.4**

14 Incentive schemes

14.1 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 innovation allowance mechanism.

We explain below the application of these schemes in the forthcoming regulatory period in relation to our transmission and distribution services. We note that the AER's Framework and Approach paper[42] confirmed that the small scale incentive scheme will not apply in the forthcoming period, as the AER has not yet developed this scheme.

14.2 Efficiency Benefit Sharing Scheme (EBSS)

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

The design of the scheme ensures that network service providers 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 efficient costs) in the ratio of 70:30 between customers and the network business.

The AER has developed a common EBSS for transmission and distribution network service providers. For the EBSS that will apply to us over the forthcoming regulatory period, we propose to apply the AER's published schemes for the transmission and distribution networks.

14.2.1 Transmission

We propose that the exclusions applying under our current EBSS for transmission will continue to apply in the forthcoming regulatory period. These exclusions are:

- debt raising costs;
- network support; and
- operating expenditure on network capability incentive projects under the service target performance incentive scheme.

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

In addition to the excluded cost categories our actual operating expenditure will be adjusted to reverse any movements in provisions for the purposes of calculating the EBSS. We propose that the calculation of carryover amounts under the EBSS will include all other operating expenditure in accordance with the published scheme.

For the current regulatory period, we have calculated the transmission EBSS payments in accordance with the AER's transmission determination. These EBSS payments, which are incorporated in the building blocks for the forthcoming regulatory period, are included as part of the efficiency carry-over in Table 15.5.

14.2.2 Distribution

For distribution, our proposed EBSS exclusions are:

- debt raising costs;
- GSL payments;
- ESI levy payments; and
- NEM levy payments.

As noted in relation to transmission, for the forthcoming regulatory period we also propose that the calculation of carryover amounts under the EBSS will include all other operating expenditure in accordance with the published scheme. For the purposes of calculating the EBSS payments, our actual distribution operating expenditure will also be adjusted to reverse any movement in provisions.

For the current regulatory period, the operation of the EBSS is affected by the two year duration of the 2017-19 regulatory determination. As a consequence, if the scheme were applied as set out in the AER's distribution determination it would not operate as intended. In particular, contrary to the purpose of the scheme, it would reward us for any efficiency loss in 2016-17 and impose penalties for any efficiency gain.

We have discussed this issue with the AER to agree a remedy that gives effect to the scheme. The AER has proposed that three years of EBSS penalties or bonuses relating to actual performance in 2016-17 should apply to correct for the effect of the shorter regulatory period.

While the AER's proposed remedy is not consistent with its determination, and creates a material net penalty that we did not anticipate, we accept that it gives effect to the intention of the scheme. We have therefore applied the AER's approach in calculating the EBSS payments that are included in the building block revenue requirement for the forthcoming regulatory period. The EBSS payments are included as part of the efficiency carry-over in Table 15.6.

14.3 Capital Expenditure Sharing Scheme (CESS)

Incentives for efficient operating expenditure under the EBSS generally correspond to incentives for efficient capital expenditure under the CESS scheme.

The CESS rewards or penalises a network service provider if actual capital expenditure is lower or higher than the approved forecast amount for the regulatory year. The AER's Framework and Approach paper proposed that the CESS should apply to TasNetworks as set out in the AER's capital expenditure incentives guideline. We accept the AER's proposal noting that the AER, through the TransGrid determination process for 2018-23 regulatory period is considering potential calculation modifications. We assume any calculation modifications to be consistently applied to all NSPs over time.

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, network service providers do not have a financial incentive to favour one form of expenditure over another.

The CESS will apply to our transmission and distribution capital expenditure in accordance with the published scheme.

14.4 Service Target Performance Incentive Scheme (STPIS) - Transmission

The AER has service target performance incentive schemes that apply to transmission and distribution networks. The transmission STPIS consists of three components:

- a service component, which has four main parameters and various sub-parameters which act as key indicators of network reliability;
- a market impact component, which encourages TNSPs to minimise the impact of network outages on the efficient dispatch of generation; and
- a network capability component, which encourages TNSPs to undertake low cost projects to promote efficient levels of network capability from existing assets when most needed, while maintaining adequate levels of reliability.

In the remainder of this section we detail our approach for the STPIS components for transmission. We conclude this section with a request for the AER to adopt common reporting arrangements for transmission and distribution.

14.4.1 Service component

Our proposed performance targets, caps, collars and weightings for the parameters satisfy the requirements of version 5 of the STPIS. In calculating our proposed performance targets, we have applied the methodologies specified in the scheme and the AER's final Framework and Approach for TasNetworks (2019-24). In particular, we have:

- established targets to equal our average performance over the last five years in accordance with clause 3.2(f) of the scheme;
- proposed weightings for each performance measure that are consistent with table 3.1 of the scheme; and
- proposed caps and collars, which are set using a reasonable methodology as explained below.

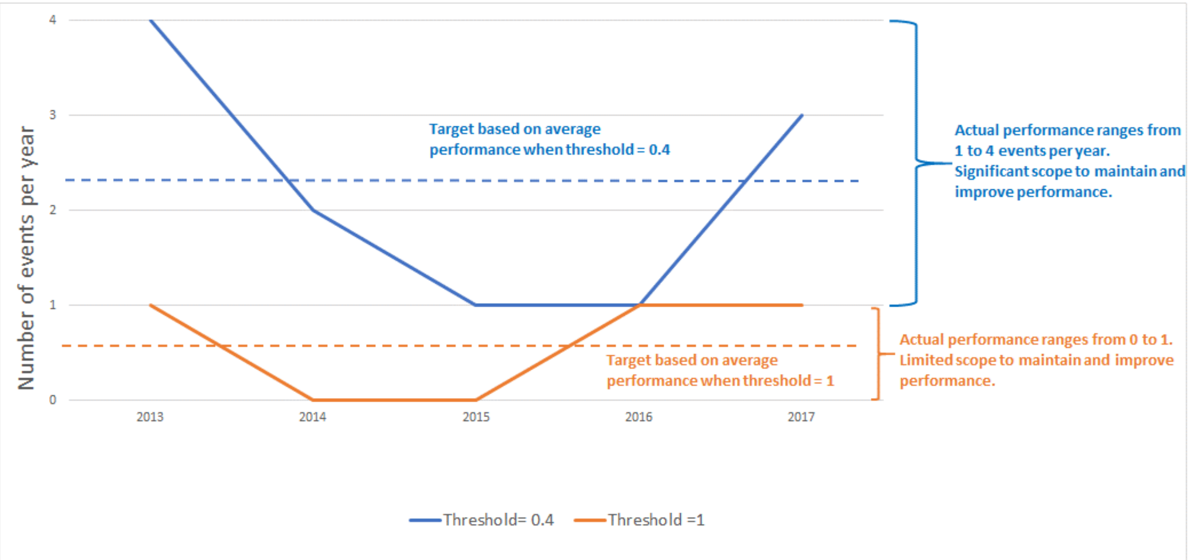
The caps and collars are in general the targets plus or minus one standard deviation of actual performance over the years 2013 to 2017. Some adjustment is made where this results in an unreasonable outcome, for example, if the cap is a negative number. The results have been charted to ensure that the associated S curves give a reasonable spread of annual results along the sloping part of the S curve.

While the proposed targets reflect the operation of the STPIS, we are concerned that the loss of supply event frequency targets are inappropriate. The problem arises because the performance measure identifies loss of supply events that exceed x and y thresholds of 0.1 and one system minutes, respectively. This results in a target of one event for events that exceed one system minute, and caps of zero for both measures.

As a consequence of our improved performance in relation to loss of supply events, we believe that these parameters do not provide appropriate incentives to improve and maintain performance. In effect, the parameters provide an 'all or nothing' incentive scheme, which presents TasNetworks with limited scope to manage network service performance over time. Such a target may also create increased pricing volatility for our customers. As such, the continued application of the current thresholds would not be consistent with the objectives of the scheme, and would be contrary to the interests of our customers due to the potential for increased pricing volatility.

With these considerations in mind, and to better balance risks and rewards, we propose a reduction in our loss of supply event frequency thresholds. The figure below illustrates the improvements that can be made to the effectiveness of the scheme by reducing the y threshold from one to 0.4 system minutes. Although the alternative measures and targets shown below use exactly the same historic data, reducing the threshold increases the number of outage events that are subject to the scheme.

Figure 14-1: Improving incentives by reducing the y threshold



As shown above, maintaining the current threshold of one leads to a very narrow range of performance outcomes, which gives TasNetworks an indistinct and ineffective incentive to maintain performance. By contrast, the lower threshold provides a clearer incentive to maintain performance because it provides more granular data on our historic performance. As a result, our proposed change provides more effective incentives for us to maintain performance to the benefit of our customers, in accordance with the objectives of the STPIS.

If the y threshold is reduced to 0.4, it is appropriate to also reduce the x threshold from 0.1 to 0.05. This change will also provide a modest enhancement to the incentive properties of the scheme. It would also align both thresholds with those of Powerlink.

Full details of the service component of the STPIS with reduced x and y thresholds are provided in our transmission STPIS model (TN133) and discussed in supporting document 2019-24 Transmission STPIS Transitional Approach (TN177).

14.4.2 Market impact component

The market impact component currently operates as a bonus-only scheme. This will change at the start of the 2019-24 regulatory period to a symmetrical scheme that provides an incentive of +/- 1 per cent of maximum allowed revenue each year. The scheme is designed to provide an incentive to TNSPs to minimise planned transmission outages that can affect wholesale market outcomes. It measures performance against the market impact parameter, which is the number of dispatch intervals where an outage on the TNSP's network results in a network outage constraint with a marginal value greater than $10/MWh.

Under version 5 of the STPIS, we are required to submit data for the market impact component in accordance with Appendix C of the scheme for the preceding seven regulatory years. We must also submit a proposed value for a performance target, unplanned outage event limit and dollar per dispatch interval incentive.

In calculating our proposed performance target, unplanned outage event limit and dollar per dispatch interval incentive, we have applied the methodologies specified in version 5 of the scheme and the AER's final Framework and Approach for TasNetworks. In particular, the:

- maximum revenue increment and decrement that apply under this component will be determined by the performance measure and dollar per dispatch interval incentive;
- value of performance target (T) for the market impact component is set based on the average performance over the most recent seven calendar years, excluding the maximum and minimum performing years;
- value of the performance measure (M) is the annual performance adjusted by the unplanned outage event limit. Each unplanned outage event will be limited to a count of no more than 17 per cent of the performance target (T); and
- dollars per dispatch interval ($/DI) is calculated by taking one per cent of the Maximum Allowable Revenue (**MAR**) for the first year of the regulatory control period and dividing it by the performance target calculated.

Full details of the market impact component of the STPIS is provided in our transmission STPIS model (TN133).

14.4.3 Network Capability

We have implemented a number low cost priority projects to improve network capability in the current regulatory period, summarised in the table below. The Network Capability Incentive Parameter Action Plan (**NCIPAP**) projects were identified based on analysis of the project rankings, in consultation with AEMO and the AER, to ensure that the selected projects delivered the best outcome for our customers.

Table 14-1: NCIPAP projects completed during the current regulatory period

Reason to undertake project	Completed project	Completion year
Better use of the available generation through a refinement of the Basslink export >300 MW fault level constraint	George Town Automatic Voltage Control Scheme (GTAVCS)	2014-15
Replacement of terminal equipment with limits below transmission line thermal limits to minimise thermal constraints	Replacement disconnectors on K and L bay on Sheffield-George Town 220 kV transmission Circuits	2015-16
Improve reliability and minimise return to service time though installation of motorised disconnector switch	Castle Forbes Bay Tee Switching Station disconnector upgrade	2015-16
Installation of dynamic ratings on supply transformers	Boyer Substation Knights Road Substation	2015-16
Replacement of dead end assembly with limits below transmission line thermal rating	George Town-Comalco No 4 and 5 220 kV transmission circuits Liapootah-Waddamana No 1 220 kV transmission circuit	2015-16
Minimise return to service time though installation of fault location functionality on identified transmission circuits	Palmerston-Sheffield 220 kV transmission circuit	2015-16
Transmission conductor to ground clearance verification and rectification	Waddamana-Liapootah No 1 220 kV Waddamana-Tungatinah No 1 and 2 110 kV circuits Palmerston-Avoca 110 kV transmission circuit	2016-17

For the forthcoming regulatory period, we have identified the priority projects as shown in the table below. The proposed NCIPAP has been developed in accordance with the requirements of version 5 of the STPIS. The NCIPAP represents approximately 0.8 per cent out of the one per cent of the maximum allowed revenue that can be included within the NCIPAP.

A process to identify the NCIPAP was undertaken with key stakeholders, noting this process will continue. New information may identify additional projects which provide a demonstrable market benefit to our customers and other participants in the NEM, to constitute the additional 0.2 per cent allowed.

Table 14-2: Proposed NCIPAP projects for the next regulatory period

Project No	Project Description	Payback period in years	Project Cost Level 1 estimate[43]	Project Drivers
1	Waratah Tee Switching Station disconnector motorisation	1.2	$610,000	TasNetworks targets to reduce supply restoration time at Savage River Substation from an average of 228 minutes to approximately 1 minute for sustained faults on the Farrell-Que-Savage Rive or Burnie-Hampshire-Savage River 110 kV transmission circuit. Market benefits based on a reduction in expected unserved energy due to reduced restoration time after an outage.
2	Weather stations Burnie-Smithton 110 kV corridor	3.0	$365,000	TasNetworks has received connection applications for new wind generation up to 112 MW in the North-West Coast of Tasmania (not currently considered committed by AEMO). We expect that some of this generation will connect prior to the forthcoming regulatory period. Benefits under a range of generator connection scenarios have been calculated, including 20 MW, 30 MW and 40 MW. As a relatively conservative assumption, the 30 MW scenario was used to rank this project.
3	Lightning withstand capability improvement on Norwood-Scottsdale-Derby 110 kV transmission corridor	4.2	$800,000	Proposed augmentation is to significantly reduce the probability of a double circuit outage of Norwood-Scottsdale 110 KV circuits and remove this non-credible contingency from the reclassification list. This project: • Allows Musselroe windfarm to deliver its full output to the market when there is lighting in the area. • Increases the reliability of supply to Derby and Scottsdale substations and reduces unserved energy at these substations. The market benefits for this project are based only on fuel cost savings.

[43] 30 per cent accuracy

4	Farrell Substation 220 kV second bus coupler installation	13.5	$1,250,000	Farrell 220 kV Substation No 1 and No 2 busbars are connected by a single bus coupler circuit breaker. A failure to open this circuit breaker during a fault would result in the loss of supply to Roseberry, Newton, Queenstown, Que and Savage River Substations, and a loss of generation connected to Farrell Substation. The proposed second bus coupler circuit breaker is to prevent loss of supply following this potential failed circuit breaker operation, and to reduce the risk of a wide-spread blackout due to load and generation imbalance. The market benefits for this assessment were based on a reduction in expected unserved energy.
5	Transmission conductor to ground clearances improvement program	20.4	$3,000,000	This project addresses potential de-rating of existing transmission capacity and generation congestion due to insufficient ground clearances. This project: • Reduces the safety and environmental risks presented by insufficient ground clearances • Provides increased transfer levels of hydro generation • Reduces unserved energy Market benefits include only reduced cost of generation rescheduling and does not include the value of unserved energy.

In accordance with the Rules, the proposed NCIPAP for 2019-24 regulatory period was released to AEMO for review and endorsement in early August 2017. Following its review of our proposed NCIPAP projects, AEMO agreed with the assessment of the proposed project need, improvement targets, likely material benefits and ranking of proposed projects.

Full details of our NCIPAP is provided in as an attachment to this proposal (TN167).

14.4.4 Common reporting arrangements

In its Framework and Approach paper, the AER proposes to apply version 5 of the transmission STPIS for our forthcoming regulatory period. As explained above, we have proposed a modification to the thresholds specified in the scheme, which is a technical change that promotes the objective of the scheme.

We also propose the application of a common reporting period for transmission and distribution. To align with other reporting obligations, we propose that the transmission performance reporting is changed to a financial year basis. While the AER has yet to accept this proposal, we note that the proposal has customer benefits due to business efficiency gains and, in our view, this warrants the AER's reconsideration of the reporting arrangements. In addition, consistency in reporting periods supports our customers in understanding the linkages between consistent annual period service performance, and resulting revenue adjustments and charge or pricing implications.

We understand that a change to the reporting arrangements will require a transitional period between the two methods. We propose a six month target for this transition period that is simply half of our existing targets and no changes to our incentive rates during this period. This approach is consistent with past transition arrangements agreed to by the AER.

14.5 Service Target Performance Incentive Scheme (STPIS) – Distribution

The calculations underpinning our STPIS targets have been undertaken in accordance with the AER's STPIS scheme (November 2009) and the AER's final Framework and Approach for TasNetworks. We note that the AER is currently undertaking a review of the Distribution STPIS and in the Framework and Approach Final decision indicated that we may need to apply the revised STPIS for the 2019-24 regulatory period. Given the review was not completed at the time of submitting this proposal, the proposal below is based on the current STPIS.

Our STPIS targets for the forthcoming regulatory period include targets for two measures of reliability, outage frequency (**SAIFI**) and outage duration (**SAIDI**); and telephone answering – measured by the percentage of calls to our fault line answered within 30 seconds.

In calculating our proposed reliability and telephone answering targets, we have applied the methodologies specified in the scheme and the AER's final Framework and Approach for TasNetworks. In particular, we have:

- established targets to equal our average performance over the last five years in accordance with clauses 3.2.1(a) and 5.3.1(a) of the scheme;
- proposed incentive rates for each performance measure that are consistent with section 3.2.2 and 5.3.2 of the scheme;
- applied exclusions to events as per section 3.3 of the scheme; and
- established major event day thresholds as per the Institute of Electrical and Electronics Engineers Standards (**IEEE**) Guide for Electric Power Distribution Power Reliability Indices (the '2.5 beta method').

Further detail of our STPIS targets and proposed incentive rates are provided in our distribution STPIS models TN131 and TN132.

14.6 Demand management incentive scheme and innovation allowance mechanism

The AER has recently finalised its new Demand Management Incentive Scheme (**DMIS**) and Demand Management Incentive Allowance (**DMIA**), which will apply to us in the forthcoming regulatory period. There are two parts of the framework under the Rules:

- The DMIS, the objective of which is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.
- The DMIA, the objective of which is to provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs for customers.

The DMIS is one of a suite of measures which aims to provide stronger incentives for networks to invest in more efficient demand side management over time. In order to provide better outcomes for customers, we will be seeking to identify projects which can cost-effectively address network constraints through demand management. We also note the potential for the DMIS to apply to non-network solutions that address power quality, aging assets and network security issues.

At present, we have identified an initial project which will be financed through the DMIS. North Hobart is supplied by two 45 MVA (continuous) transformers. Due to load growth in the Hobart CBD, these transformers are forecast to become overloaded at some time during the forthcoming regulatory period, as described in our Greater Hobart area strategy. This project aims to allow us to defer capital expenditure (approximately $6 million) by encouraging customers to install demand response capability (with a forecast annual operating expenditure of $0.2 million), so that we have sufficient demand response capability to manage network loading when the transformers reach their loading limits. This project will include:

- a program to engage with customers in the area to explain the potential opportunities; and
- targeted incentives to encourage uptake of demand response capacity using a market approach.

The DMIA plays an essential role in facilitating demand management solutions. In particular, the DMIA enables us to test solutions so we can quantify their costs and benefits. With this information, we can accurately plan and implement demand management solutions.

In the forthcoming regulatory period, we are proposing to undertake the following DMIA projects:

- The smart inverter program aims to encourage customers who are already considering a battery purchase to select a smart battery. The project will enable us to better manage the challenges associated with embedded generation, thereby reducing future network costs.
- The peer to peer energy trading trial will enable us to better understand the issues associated with this form of trading and how it may contribute to lower network costs. We are currently engaging with a proponent and research institutions to initiate the project.
- Advanced load control trials will provide us with an opportunity to work more closely with particular customers to understand how deeper integration with their energy control systems may provide network benefits. Any 'behind the meter' aspects of this trial will be conducted by ring-fenced service providers.

We propose to incur expenditure of approximately $410,000 per annum under the DMIA.

15 Annual revenue requirements, X-factors and control mechanism

15.1 Introduction

Our Regulatory Proposal is based on the post-tax building block approach and complies with the clauses 6.4.3 and 6A.5.4 of the Rules, the 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 clauses 6.5.9 and 6A.5.8 of the Rules.

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:

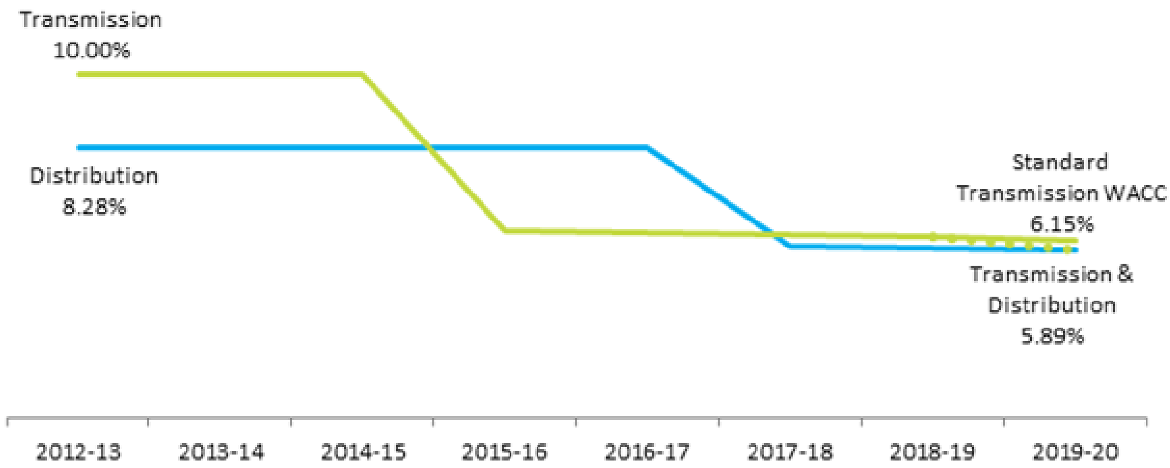
- Section 15.2 summarises the outcomes for customers and our total revenue requirement for our revenue capped transmission and distribution services.
- Section 15.3 sets out the transmission and distribution building block calculations and the proposed X factors to apply in the forthcoming regulatory period.

15.2 Outcomes for customers

As already explained, the WACC is a key driver of our revenue requirement. The figure below shows how the WACC has changed over time for the Tasmanian transmission and distribution networks. These movements, which are driven primarily by changes in financial markets, have a significant impact on the maximum allowed revenues for these networks.

The figure also shows that the current WACC for both transmission and distribution is above the 5.89 per cent that we are proposing for both networks in the forthcoming regulatory period. Customers will benefit from this reduction in the proposed WACC for the forthcoming regulatory period.

Figure 15-1: Changes in the regulated WACC for Tasmania's transmission and distribution networks



The figure below and the accompanying table show our transmission revenue allowance for the current and forthcoming regulatory period, based on a WACC of 5.89 per cent.

Figure 15-2: Revenue allowance for prescribed transmission services (June 2019 $m)[44]

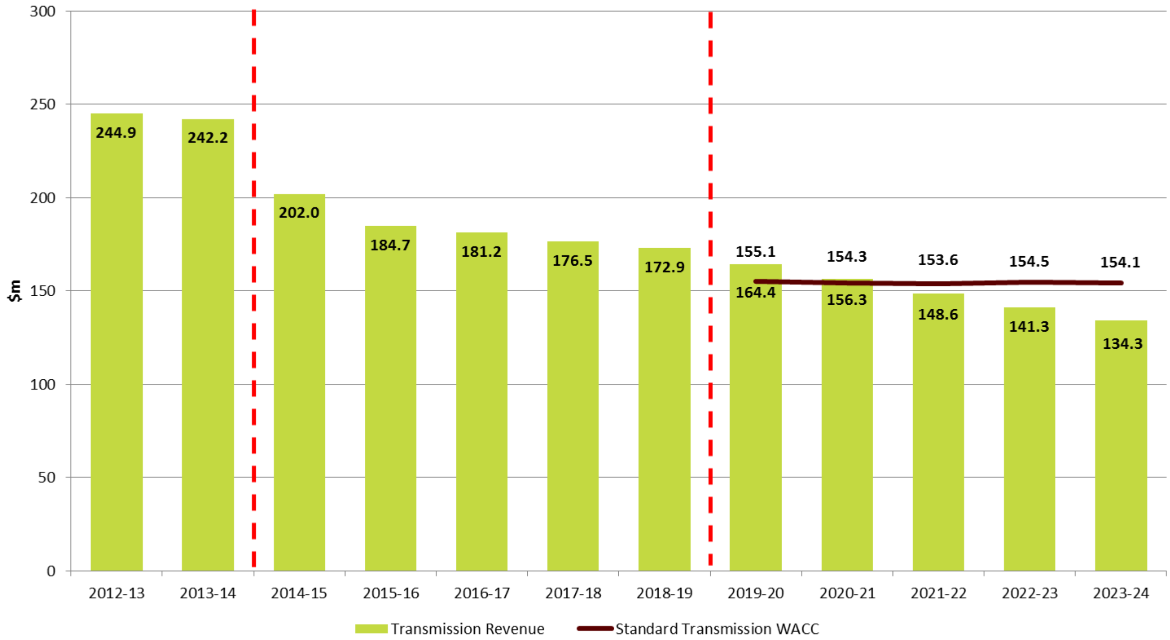


Table 15-1: Current and proposed transmission revenue requirement (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Transmission Revenue Requirement (smoothed)	172.9	164.4	156.3	148.6	141.3	134.3

44 Figure compares the proposed transmission revenue profile to an application of standard transmission WACC and revenue smoothing.

Similarly, our actual and forecast revenue requirement for our distribution network is shown in the figure and table below, also based on a WACC of 5.89 per cent.

Figure 15-3: Revenue allowance for standard control distribution services (June 2019 $m)

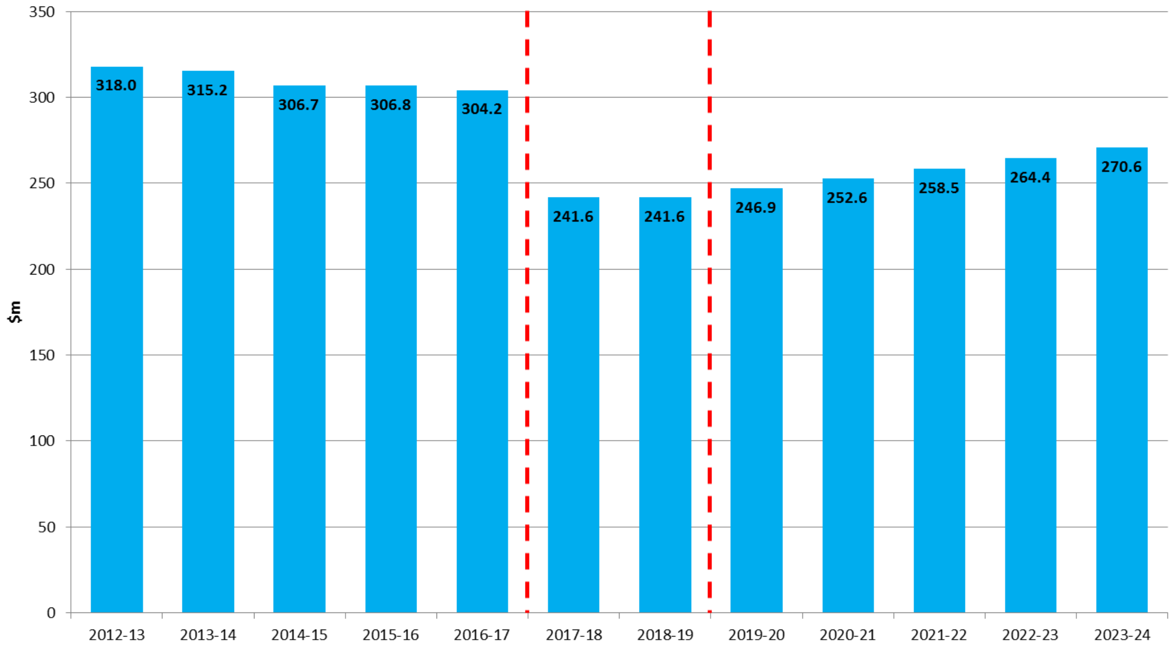


Table 15-2: Current and proposed distribution revenue requirement (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Distribution Revenue Requirement (smoothed)	241.6	246.9	252.6	258.5	264.4	270.6

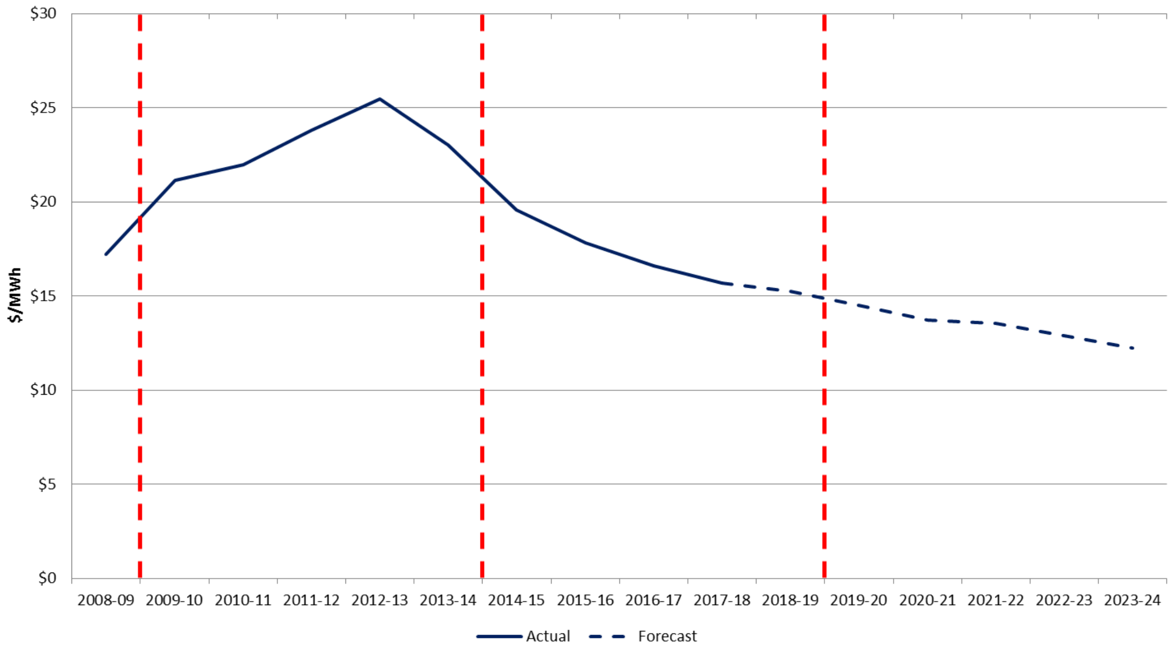
It should be noted that our actual transmission and distribution revenue may vary from the forecast revenue path for the following reasons:

- As explained in section 12.4, the AER will update our allowed return on debt for transmission and distribution for each year within the forthcoming regulatory period. This is likely to change our allowed return on debt which will flow through to our revenue allowance. As explained in Chapter 12, we have decided to reduce the rate of return on our transmission assets to align to the distribution rate of return; this alignment will be continued as part of the annual update process.
- 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.
- For a range of reasons, our actual transmission and distribution revenue recovery each year may vary from the total amount we are entitled to recover, which may lead to the need for adjustments in subsequent years.
- Contingent projects and pass through events may lead to additional costs which, subject to AER's approval that the expenditure is in the long-term interests of consumers, may be recovered from customers.

For transmission customers, our prices are set in accordance with our pricing methodology (TN092) which has been prepared in accordance with the Rules. Transmission charges for our Tasmanian customers are affected annually by intra-regional settlements residue payments from AEMO and inter-regional charging between Tasmania and Victoria.

The price impact of our proposal will vary for particular customers, depending on their particular circumstances and the annual adjustments described above. As such, the figure below provides a broad indication of the implications of our proposal for average transmission prices over the forthcoming regulatory period, which we expect to be 21 per cent lower in real terms than the previous five year period.

Figure 15-4: Average price impact of transmission proposal ($/MWh) (June 2019 $)



Transmission and distribution network costs presently make up around 43 per cent of the average Tasmanian residential and small business customer electricity retail bill[45].

The distribution revenue allowance for each year, together with relevant share[46] of the transmission network charges (around 55 per cent), is recovered from our distribution customers. This revenue recovery is achieved through a framework of distribution network pricing “tariffs” which are applied to each customer and charged to retailers. The table below outlines our forecast revenue to be recovered from distribution customers.

[45] Based on 2017-18 Aurora Energy retail standing offer prices.

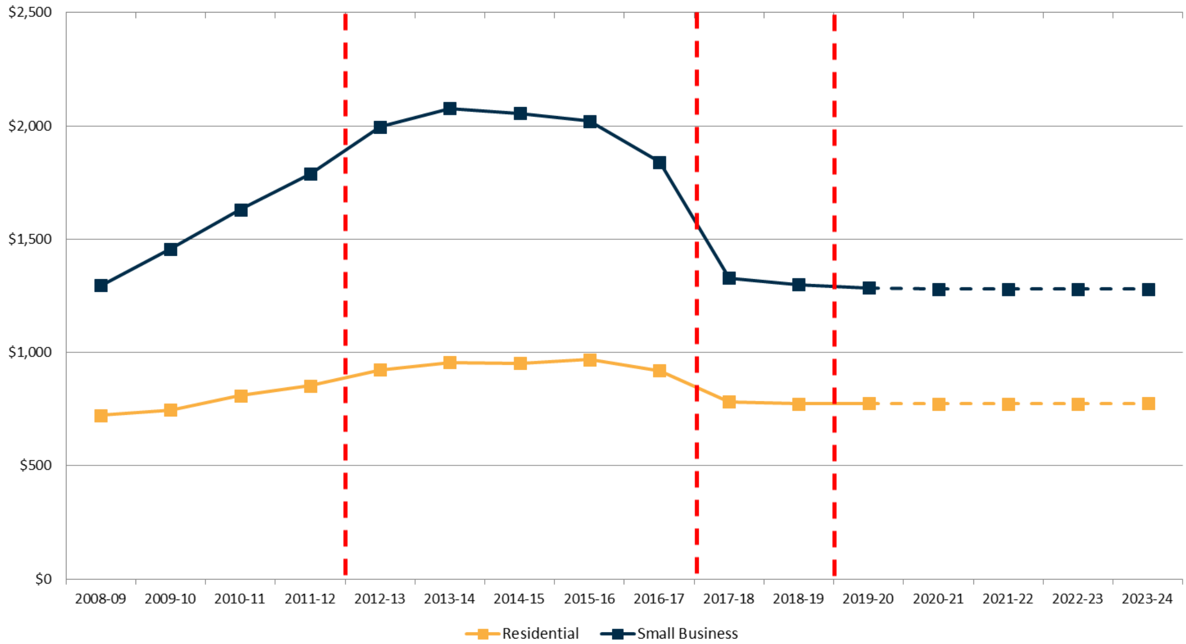
[46] Determined via the application of our Transmission Pricing methodology.

Table 15-3: Revenue to be recovered from distribution customers (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Transmission Revenue	90.9	89.8	85.8	82.0	78.3	74.8
Distribution Revenue	241.6	246.9	252.6	258.5	264.4	270.6
Total Revenue	**332.5**	**336.7**	**338.4**	**340.5**	**342.7**	**345.4**

Our proposed transmission and distribution revenue allowance results in the indicative average annual network charges for residential and small business customers as shown below. Consistent with our strategy of sustainable and predictable pricing, our proposal results in most customers' network charges increasing only slightly above CPI and remaining well below pre-merger levels.

Figure 15-5: Average annual total network charges for distribution customers (June 2019 $)



15.3 Transmission and distribution building blocks and X factors

The tables below show our total revenue requirements, broken down by transmission and distribution.

Table 15-4: Our Total Smoothed Revenue Requirements ($m nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total Smoothed Revenue requirement	**414.5**	**421.3**	**429.2**	**437.7**	**447.0**	**457.0**
Transmission revenue requirement	172.9	168.4	164.1	159.8	155.7	151.6
Distribution revenue requirement	241.6	252.9	265.1	277.9	291.3	305.4
Transmission revenue as a % of total	41.71%	39.97%	38.23%	36.51%	34.83%	33.17%
Distribution revenue as a % of total	58.29%	60.03%	61.77%	63.49%	65.17%	66.83%

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. The table below shows the transmission building block calculation for the forthcoming regulatory period alongside the final year of the current period, which is 2018-19.

Table 15-5: Summary of Transmission Building Block Revenue Requirements and X Factors ($m nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	96.9	86.4	87.7	90.4	93.2	94.7
Regulatory Depreciation	27.4	18.6	22.2	24.4	27.9	31.8
Operating expenditure (incl. Debt Raising)	48.8	39.9	40.7	41.4	42.0	42.6
Efficiency carry over[47]	0.0	7.0	-1.5	0.1	-5.3	0.3
Net tax allowance	4.6	3.1	3.5	3.9	4.5	5.1
Transmission Revenue Requirement (unsmoothed)	177.7	155.0	152.5	160.2	162.3	174.5
Transmission Revenue Requirement (smoothed)	**172.9**	**168.4**	**164.1**	**159.8**	**155.7**	**151.6**
X factor (percentage real reduction)	2.00%	4.92%	4.92%	4.92%	4.92%	4.92%

Clause 6A.6.8(c)(2) of the Rules governs the setting of the X factor for transmission. It requires that the expected maximum allowed revenue for the final year of a regulatory period is as close as reasonably possible to the annual building block revenue requirement for that year. The AER's PTRM

47 This mainly relates to Efficiency Benefit Sharing Scheme payments

handbook[48] comments that the AER has considered a divergence of up to three per cent to be reasonable, if this can achieve smoother price changes for customers over the regulatory period.

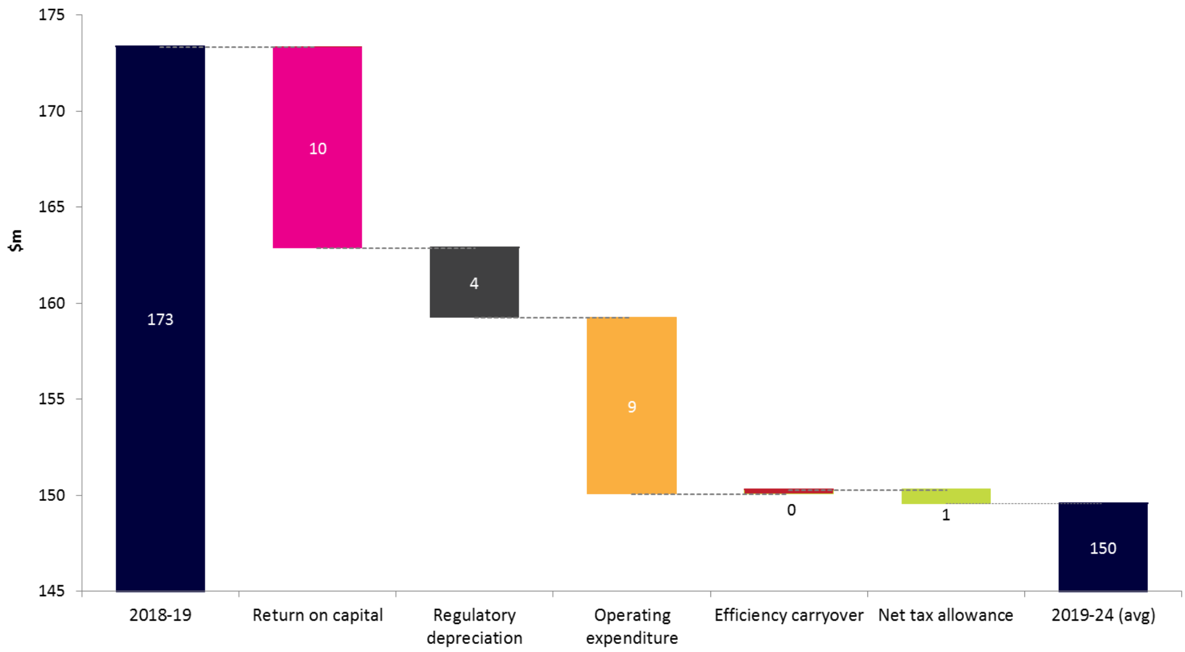
The transmission unsmoothed revenue profile provides for a significant drop in the first year followed by modest increases for the final four years. Our experience has been that customers welcome price reductions but are far more concerned about price increases.

In setting the X factor for our prescribed transmission services, we have considered the price implications for all our customers, including those connected to the distribution network. Given our unique position in submitting a combined transmission and distribution proposal, we regard this consideration as consistent with delivering prices that promote the achievement of the National Electricity Objective.

In considering the combined effect of our proposals on our transmission and distribution customers, we have concluded that transmission revenues should be lower in the final year of the regulatory period. This approach delivers a steady reduction in transmission charges over the period, while delivering an acceptable price path for our distribution customers.

The figure below shows the key drivers for the change in transmission revenue compared to the current period.

Figure 15-6: Transmission revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



The table below presents our distribution building block requirement.

[48] AER, Electricity transmission network service providers, Post-tax revenue model handbook, 29 January 2015, page 25.

Table 15-6: Summary of Distribution Building Block Revenue Requirements and X Factors ($m nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	101.9	103.3	109.4	115.1	119.7	125.1
Regulatory Depreciation	57.6	57.7	63.3	69.8	74.6	80.0
Operating expenditure (incl. Debt Raising)	68.4	85.4	87.1	88.4	89.7	91.0
Efficiency carry over[49]	12.8	-11.2	-11.4	-11.7	14.0	0.5
Net tax allowance	12.2	10.1	10.4	11.0	11.7	12.4
Distribution Revenue Requirement (unsmoothed)	252.9	245.3	258.9	272.6	309.6	309.0
Distribution Revenue Requirement (smoothed)	**241.6**	**252.9**	**265.1**	**277.9**	**291.3**	**305.4**
X factors[50] (annual percentage reduction in revenue from CPI))	0.00%	-2.20%	-2.32%	-2.32%	-2.32%	-2.32%

As noted in relation to transmission, our distribution revenue requirement is also not subject to a shared asset adjustment.

A major component of our revenue allowance is the return on our regulatory asset base and the recovery of its depreciation over time. These components will exhibit some growth during the period, which reflects recent and ongoing investment in the distribution network and supporting technology to ensure safety, reliability and network performance.

As explained in Chapter 9, our forecast distribution operating expenditure is higher than the AER's allowance in the current period, as a result of the increased vegetation management costs, step changes and growth. As a consequence, our revenue allowance is reduced by a negative carryover amount under the AER's EBSS.

The figure below shows the key differences in our proposed distribution revenue compared to the final year of the current regulatory period.

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[49] 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).

[50] A negative X factor is an increase in revenue above CPI

Figure 15-7: Distribution revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)

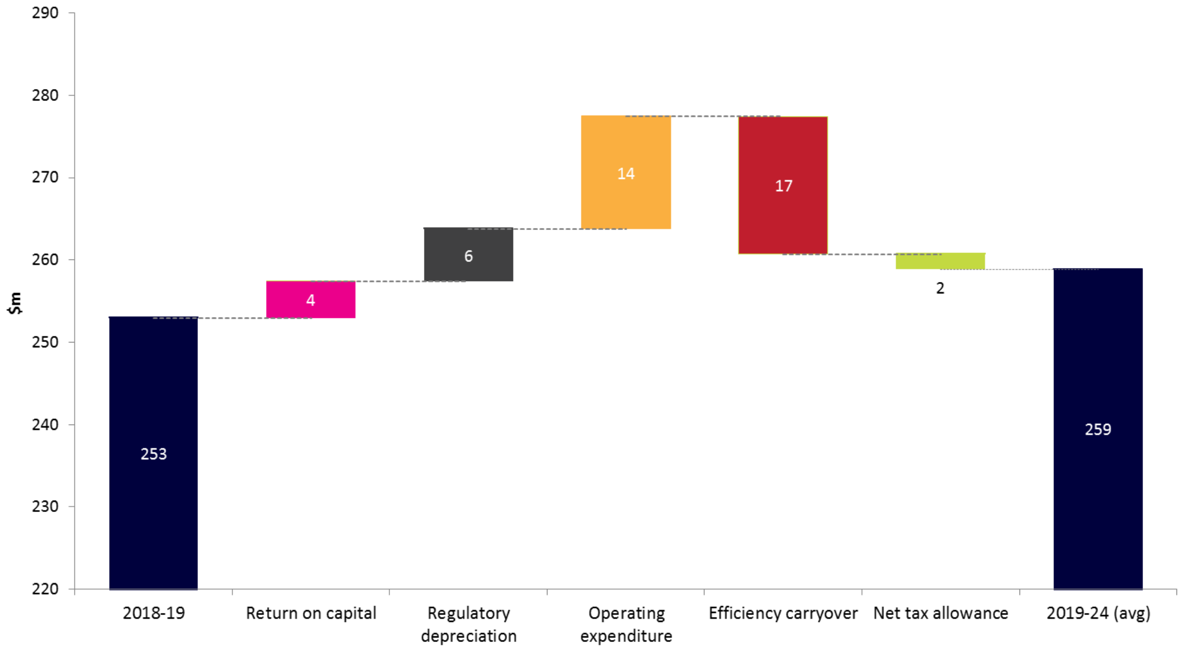
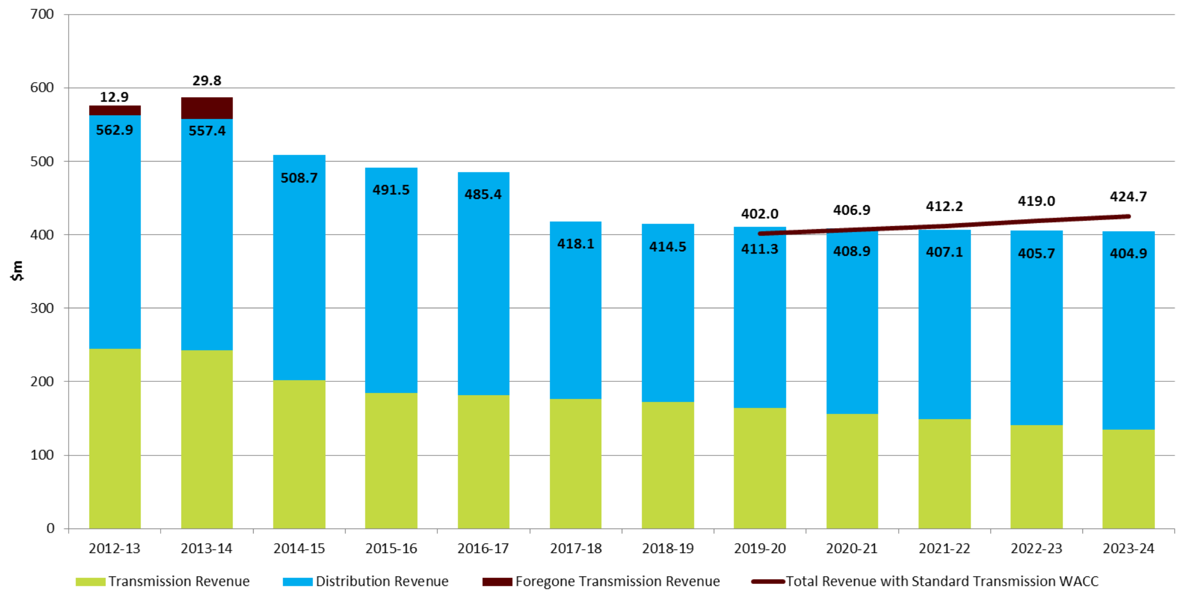


Figure 15-8 shows our total smoothed revenue over the forthcoming regulatory period compared with historic levels. The figure also shows our combined revenue has we not applied the expenditure optimisations and transmission WACC alignment. Our proposed combined transmission and distribution revenue is significant less than pre-merger levels.

Figure 15-8: Total Network Smoothed Revenue Requirement (June 2019 $m)[51]



[51] Figure compares the proposed transmission revenue profile to an application of standard transmission WACC and revenue smoothing.

16 Network pricing

16.1 Transmission pricing methodology

Our transmission pricing methodology determines how our total revenue allowance is recovered from our customers. In broad terms, the pricing methodology:

- allocates the aggregate annual revenue requirement to the categories of prescribed transmission services that we provide, and to the connection points of network users; and
- determines the structure of prices for each category of prescribed transmission services.

The pricing methodology relates only to prescribed transmission services. The pricing arrangements for negotiated services are determined bilaterally in accordance with the negotiating principles in Chapter 5A.

Our transmission pricing methodology complies with the pricing principles in part J of the Rules and the AER's Pricing Methodology Guidelines. The Rules provide limited scope for discretion in relation to transmission pricing. We have discussed our current pricing methodology with our transmission customers, who indicated that there is no desire to change the current arrangements.

Our proposed transmission pricing methodology is provided in supporting document (TN092).

16.2 Network pricing for distribution customers

Since commencing operations on 1 July 2014, we have embarked on a process of pricing reform which has seen us gradually moving towards cost reflectivity. The AER approved our first distribution Tariff Structure Statement for the 2017-19 period. This was an 'establishment' phase of our distribution pricing reforms that set a pathway for the future by:

- introducing the concept of network tariff reform to our stakeholders;
- introducing consumption and demand based time of use network tariffs for small customers and providing our customers with future investment and price signals; and
- progressing the multi-period process of unwinding inefficient legacy price levels and cross-subsidies.

We are building on the ground work undertaken to date, considering other networks' experiences, AER feedback and further analysis we have undertaken. For the 2019-24 period, we will continue pricing reform through the following measures:

- Ongoing gradual tariff rebalancing

  We will continue the gradual process of unwinding legacy cross-subsidies between different customer types. This will occur through annual pricing adjustments and is likely to be modest in terms of the impact between regulatory years on customers' network charges.

- Introduce[52] two new demand based network tariffs as an option for customers with distributed energy resources (**DER**).

  We propose introducing new demand based time of use network tariffs for residential and small business customers who install DER, which will allow us to:

  - provide price signals to encourage customers to use their DER to shift their peak load, reducing their network costs and, in the longer term, avoiding costs for us and other customers;
  - advance the use of the network as a platform for two way flows of electricity, demand side management and the provision of network support services by customers – in line with the vision set out in *The Electricity Network Transformation Roadmap* developed by CSIRO and Energy Networks Australia in 2016 and TasNetworks' Transformation Roadmap 2025; and
  - identify DER customers so we can learn how best to integrate their energy use, energy export, and network support capabilities into our network operational practices and network planning.

  The off-peak demand charges which are part of these new tariffs will be discounted during the 2019-24 regulatory period, to encourage customers via their retailer to switch to the new network tariffs, with TasNetworks funding the cost of providing the discount by under-recovering our maximum allowable revenue. The discounts will be offered on a transitional basis only and will decline progressively over the course of the 2019-24 regulatory period, to the point that no discounts will be offered from 1 July 2024. TasNetworks will fund the discount cost directly through reduced revenue recovery, meaning that the cost of offering the discounts will not be passed on to other customers.

- Offer introductory discounts for our new demand based time of use tariffs

  To incentivise a customer led shift to the demand based network tariffs introduced in 2017 for residential and small business customers, we intend discounting the off-peak demand charges which are part of these new tariffs. The discounting arrangements will mirror those described above, which means that TasNetworks will also fund the discount cost over the forthcoming regulatory period.

- Introduce new network tariffs for embedded networks

  We propose introducing two new tariffs for embedded networks – one for embedded networks connecting to our distribution network at low voltage and another for embedded networks connecting at high voltage. By introducing network tariffs which are specifically designed for embedded networks we can ensure that, in the future, embedded network operators and their customers make an equitable, cost reflective contribution towards the

[52] We are proposing to introduce new demand based network tariffs for DER customers from 1 December 2018, this timing aligns with the each of the Transitional Feed-in-Tariff arrangements (Tasmanian jurisdictional arrangements)

cost of the shared network, while still being able to use their diversity and scale to reduce their network charges.

The new network tariffs will provide proponents of this alternative energy supply model with consistent, predictable price signals about the value of their network connection, making it easier to weigh up the costs and benefits of setting up an embedded network.

- Obtaining data

  We will continue our work to obtain and analyse the interval metering data gathered from customers participating in our emPOWERing You and Bruny Island Battery trials to inform our tariff design and pricing strategies. These trials are helping us better explain demand based tariffs to customers and what switching to a demand based tariff might mean for them.

  During the 2017-19 regulatory period, we commenced the emPOWERing You Trial, which includes the deployment of advanced meters, to support our ongoing pricing strategy development and implementation. Through the trial we have been able to engage with some 600 residential customers, collect interval data and test customer understanding of and responses to different network tariff offerings. Participants have also been provided with a web-based interface (or smart-phone app) displaying their household's consumption and demand.

  We will continue to look for further trial opportunities in the forthcoming regulatory period, where these will allow us to learn more about specific customer types and test fit-for-purpose pricing solutions.

In developing our distribution tariff strategy for the forthcoming regulatory period, we have engaged extensively with a range of stakeholders, including retailers, end-use customers and their advocates, regulators and the AER's Consumer Challenge Panel. We have done this to understand their preferences and seek their guidance in relation to network tariff reform.

In particular, we have been supported by a core group of highly engaged stakeholders in the form of our Pricing Reform Working Group (**PRWG**), which includes representatives from business and industry, local government, the community sector, the electricity industry and renewable energy advocates. While the diversity of the PRWG's makeup has, on occasions, been reflected in the views expressed in relation to specific aspects of tariff reform, in relation to the move to cost reflective network pricing and our plans to get there, the majority of PRWG members are supportive of our approach.

More broadly, we recognise that a successful transition to more cost reflective network tariffs requires not only a change in pricing structures, but the provision of information to help customers understand demand based tariffs and what these tariffs may mean for them. In this regard, we see effective communication as an important element of our tariff strategy. Through customer engagement and research initiatives, such as our emPOWERing You Trial and the trial of solar panels, batteries and energy management software on Bruny Island, we are continuing to learn how best to explain tariff reform to customers.

Further details on our approach to network tariff reform are provided in our Tariff Structure Statement (TN093), which is submitted alongside this Regulatory Proposal.

Part Three:

Distribution 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 services.

17 Customer feedback on Alternative Control Services

Part 2 of this Regulatory Proposal was focused on revenue capped services. This Part 3 addresses those distribution 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).

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 17-1: Addressing customer feedback on Alternative Control Services

Issue	Customer Feedback	Our Proposal
Metering services	We discussed our metering services plan with our Pricing Reform Working Group, including our proposal for accelerated depreciation, resulting in the metering capital charge ceasing from 1 July 2024, when the residual value of the existing metering stock is expected to be fully recovered. We received varying feedback from customers on our proposed metering services approach. Some stakeholders expressed concern regarding the increase in metering charges resulting from accelerating the depreciation of the metering RAB. These stakeholders noted that the increase in metering charges may present difficulties for people on low incomes who are already struggling with electricity prices and cost of living pressures. However, other stakeholders maintained that the benefits of advanced metering technology provide customers with the opportunity to off-set a short term increase in metering charges. Aurora Energy noted that it appreciated our support as customers transition to advanced metering arrangements.	We are supportive of the mandatory advanced meter rollout for new and replacement meters in Tasmania from 1 December 2017. The uptake of advanced meters will: • markedly improve the availability of data, assuming we can access it at a reasonable cost • enable us to test and refine our network tariff offerings and explain to customers the impacts of switching to more cost reflective tariffs; • improve our network planning; and • allow customers to better understand how they can manage their electricity demand to save money. However, the mandatory introduction of advanced meters from 1 December 2017 has implications for TasNetworks' metering charges during the forthcoming regulatory period. This is because the accumulation meters (Type 6) that have been used in Tasmania, some of which will have been deployed only very recently, are likely to be retired from service before they reach the end of their normal operating life. As a result, our plan is to accelerate the recovery of the metering regulated asset base, to reflect the expected shorter average remaining life, and to reduce the number of customers paying both a capital charge for a retired regulated meter and a charge for a new advanced meter. We do not believe customers will be supportive of continuing to pay for the recovery of our metering regulated asset base as our type 6 meters are progressively removed. We are proposing to fully recover our regulated metering capital costs by June 2024. Thereafter, customers will experience an ongoing reduction in their metering charges, to reflect only the regulated service operating costs, until such time as their meter is replaced, through their retailer, with an advanced meter.

Issue	Customer Feedback	Our Proposal
Public lighting	We have engaged extensively with the Local Government Association (LGAT) and LGAs on the provision of public lighting. Our customers are keen for us to continue supporting the take up of more energy efficient fittings and we are working with a number of LGAs to accelerate the rollout of these fittings. In many cases, this is also driving a change in ownership from us to local government. The provision of public lighting services for the lowest sustainable cost is an ongoing concern and a number of LGAs have engaged with us on our charging arrangements as part of this process.	We have identified through more accurate tracking of costs that we are currently under-charging for the provision of public lighting services. A proposed move to fully cost-reflective charges would result in a step change in public lighting prices. Consistent with our strategy of sustainable and predictable pricing, and our transition approach for network tariffs, to manage customer impacts we are proposing a smooth transition path for public lighting prices. Our proposed transition price path over a ten year period results in an increase of CPI + 2.5 per cent. As we transition to cost reflective public lighting charges, we will reduce shareholder returns by approximately $12 million over the forthcoming regulatory period (in $2018-19 terms).
Ancillary Services **(fee-based services and quoted services)**	We discussed our plans for the provision of ancillary services with our Pricing Reform Working Group, however we did not receive any feedback.	Consistent with our strategy of sustainable and predictable pricing, we have sought to keep our charges as low as possible. For the forthcoming regulatory period, we are proposing average ancillary services price increases which closely align with CPI. As the ancillary network market expands and competition increases, we are aware of our obligation to ensure that our prices reflect the principle of competitive neutrality. At this stage many of our ancillary services are not subject to competition, however in time this may change. For our quoted services, we are therefore proposing a modest margin to assist in promoting the development of competition and ensure fair pricing across all our services.

In the following chapters, we provide a more detailed explanation of our Alternative Control Services.

18 Metering services

18.1 Introduction

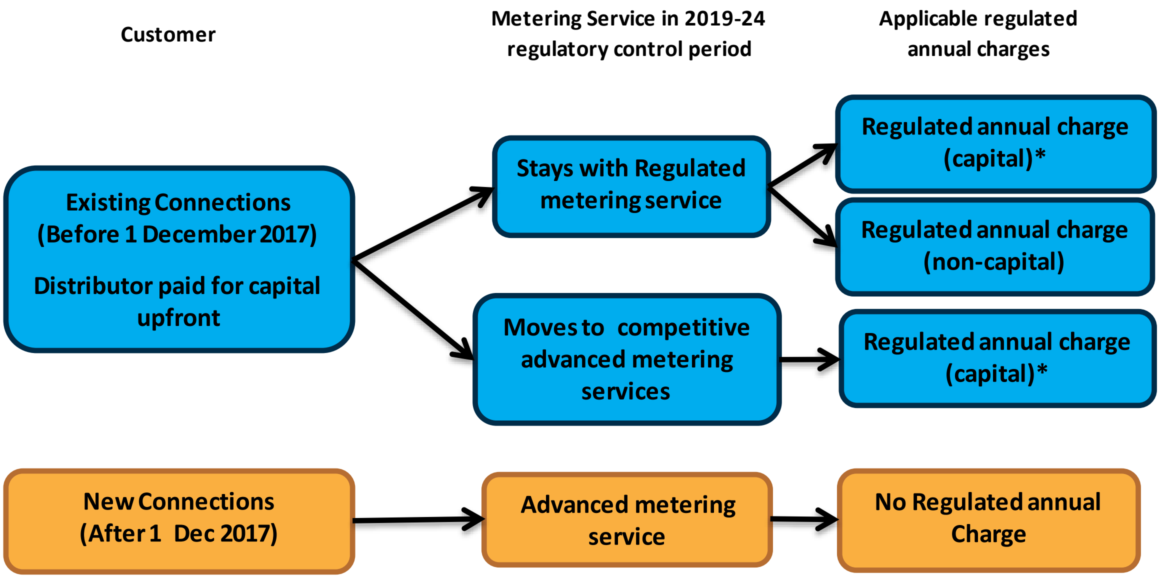
On 26 November 2015, the AEMC made a final rule that will open up competition in metering services and provide customers with more opportunities to access a wider range of metering services. The final rule changes responsibilities for the provision of metering services by introducing the role of Metering Coordinator to facilitate competition. Retailers are required to appoint the Metering Coordinator for their retail customers, except where a party has appointed its own Metering Coordinator.

The new arrangements commenced on 1 December 2017. From that date, we are not permitted to install or replace existing meters with type 6 meters. Therefore, we will not provide these services during the 2019–24 regulatory control period. However, we are able to continue to provide services for existing type 6 metering equipment as an alternative control service. Our charging arrangements for this service distinguish between the:

- capital component, which recovers the cost of the metering Regulated Asset Base (**metering RAB**) and tax; and
- non–capital component, which recovers the operating expenditure.

The figure below illustrates how the charges apply following the introduction of competition. In particular, if customers switch to a competitive advanced metering service provider, the customer will continue to pay the capital component but will not pay the non-capital charge.

Figure 18-1: Current charging structure for type 6 metering



*Except for Siemens PAYG Meters

We propose to continue to apply this charging structure. However, we propose that the cost of the existing metering assets should be recovered over a period that reflects their likely economic life. For this reason, we propose to apply accelerated depreciation to recover the existing metering capital costs by June 2024. Our analysis shows that accelerating depreciation will increase metering charges by approximately an additional $9.29 per annum per metering register for the majority of our customers, with a small number of customers paying up to an additional $24.85 per annum per metering register for more complex metering. However, while metering charges will increase during the 2019-24 regulatory period, for any Type 6 accumulation meter that remains in use at 30 June 2024, there will be no further capital charge. Thereafter, customers will experience an ongoing reduction in their metering charges, to reflect only the regulated service operating costs, until such time as their meter is replaced, through their retailer, with an advanced meter.

PAYG meters have previously been treated as unregulated assets, but are now allocated to alternative control services. The capital cost for these meters will be fully depreciated by the end of 30 June 2019. As such, the capital charge will not be applicable for customers with these meters during the 2019-24 regulatory period. Other meters supporting the PAYG product that are already included in our metering RAB, will continue to incur the capital charge until the end of the 2019-24 regulatory period.

The remainder of this chapter is structured as follows:

- Section 18.2 provides information on our building block costs for regulated metering services.
- Section 18.3 sets out the X factors and indicative prices to apply to regulated metering services.

18.2 Building block costs for regulated metering services

The AER's determination accepted our opening metering RAB as of 1 July 2017 of $48.6 million ($ nominal). We have adjusted this balance due to estimate data being replaced by actuals in previous financial years, which were higher than forecast, providing a revised metering RAB as of 1 July 2017 of $53.4 million ($ nominal). For the forthcoming regulatory period, we have rolled forward the metering RAB using the AER's RFM to derive the opening metering RAB value as at 1 July 2019 (that is, the closing metering RAB as at 30 June 2019) for type 6 metering services.

Table 18-1: Roll forward of metering RAB from 1 July 2017 to 30 June 2019 ($m nominal)

	2017-18	2018-19
Opening RAB	53.4	50.1
Capital expenditure	1.6	0.0
Inflation on opening RAB	1.3	1.2
Disposals	-0.1	-0.1
Straight-line depreciation	-6.1	-6.3
Closing RAB	50.1	45.0

As shown in the table above, the metering RAB value as at 1 July 2019 (in nominal dollars) is $45.0 million.

The forecast metering RAB is presented in the table below. There is no forecast capital expenditure because new meters have been provided on a competitive basis since 1 December 2017.

Table 18-2: Metering RAB roll forward 1 July 2019 to 30 June 2024 ($m nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
RAB (start period) - nominal	45.0	36.6	27.7	18.5	9.6
Nominal capital expenditure	0	0	0	0	0
Inflation on opening RAB	1.1	0.9	0.7	0.5	0.2
Nominal straight-line depreciation	-9.5	-9.8	-9.9	-9.3	-9.6
Disposals	0	0	0	0	0
RAB (end period) – nominal	36.6	27.7	18.5	9.6	0.3
RAB (end period) – $ June 2019	35.7	26.4	17.2	8.8	0.3

The table below summarises the building block calculation for type 6 metering services for the forthcoming regulatory period, showing the capital and non-capital components separately.

Table 18-3: Summary of Building Block Revenue Requirement for type 6 and 7 metering services ($ million nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	2.6	2.2	1.6	1.1	0.6
Regulatory depreciation	8.4	8.9	9.2	8.9	9.3
Estimated cost of corporate income tax	1.4	1.5	1.5	1.5	1.6
Capital component	12.5	12.5	12.4	11.5	11.5
Non-capital component (operating expenditure)	6.2	6.2	6.3	6.6	6.6
Total Revenue Requirement (unsmoothed)	18.7	18.7	18.6	18.1	18.1

A detailed description of our pricing approach and proposed prices is provided in the Tariff Structure Statement (TN093).

18.3 Control mechanism, X factor and indicative prices

Our proposed metering services 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 -49.06 per cent for 2019-20 and 0.53 per cent for each year thereafter.

The capital and non-capital charges are detailed in the Tariff Structure Statement (TN093), which is provided alongside this Regulatory Proposal. As already noted, the capital charge will continue to apply if an existing meter is replaced with a new advanced meter, but the non-capital charge will not. The capital charge will cease from 1 July 2024, when the residual value of the existing metering stock is expected to be fully recovered.

Our proposed control mechanism for alternative control metering services for the forthcoming regulatory period is identical to that set out by the AER in section 2.4.6 of the Framework and Approach paper[53].

For direct control services classified under the proposal as alternative control services, clause 6.8.2(c)(3) of the Rules requires us to demonstrate the application of the control mechanism, as set out in the Framework and Approach paper, and the necessary supporting information.

We propose to satisfy this requirement by providing the calculations, as part of the annual pricing proposal, which demonstrates that the proposed prices comply with the constraints of the control mechanism formula. By approving the pricing proposal, the AER will effectively confirm that we have complied with the requirement.

53 AER, Framework and approach, TasNetworks electricity transmission and distribution, Regulatory control period commencing 1 July 2019, July 2017, page 46.

19 Public lighting services

19.1 Introduction

Public lighting services have generally been provided as monopoly services by us 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 the following public lighting services as Alternative Control Services:

- the provision, construction and maintenance of our public lighting assets owned by us (public lighting);
- the maintenance of public lighting assets owned by customers (contract lighting); and
- the provision, maintenance and replacement of new/emerging public lighting technology services. This service was previously classified as a ‘negotiated distribution service’.

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.

19.2 Annuity model approach

Our current lighting charges are based on an annuity approach, rather than a building block model. The annuity approach is 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.

We propose to continue to apply the annuity approach in the forthcoming regulatory period. Our Public Lighting Model (TN099) and Public Lighting Asset Management Plan (TN063) are provided as supporting documents.

Internal and external labour costs have been forecast to increase slightly faster than CPI, in accordance with advice received from Jacobs[54] (TN166).

19.3 Control mechanism and proposed public lighting charges

As noted in section 18.3, our proposed control mechanism for alternative control services for the forthcoming regulatory period is identical to that set out by the AER in section 2.4.6 of the Framework and Approach paper. Detailed information on our proposed public lighting charges is provided in the Tariff Structure Statement (TN093).

19.4 Price path

TasNetworks’ public lighting service arrangements and pricing are largely a continuation of agreements and charges that were previously offered by Aurora Energy in its capacity as a DNSP. We

[54] Jacobs Labour Cost Escalation Report, 25 October 2017.

are now in our fourth year of operations and, as such, our level of understanding of the costs associated with the provision of all services, including public lighting, has matured.

TasNetworks' first regulatory proposal, for the 2017-19 regulatory period, was submitted to the AER in January 2016, and largely reflected a continuation of the status quo in relation to public lighting. Since then, thorough analysis of the available asset and expenditure data by TasNetworks, as well as a review of the time and resources being expended by TasNetworks on the delivery of public lighting services, has revealed that the public lighting prices currently on offer fall significantly short of full cost recovery. The loss-making nature of the provision of public lighting services is further evidenced within the data provided via the AER's Annual RIN process. Accordingly, to be cost reflective the prices charged for public lighting services need to increase significantly.

Introducing a significant step change in prices would, however, be inconsistent with our strategy of providing predictable and sustainable prices for our customers. As shown in the figure below, we are therefore proposing to use a gradual glide path for public lighting prices spanning the 2019-24 and 2024-29 regulatory periods, to transition public lighting to fully cost reflective pricing. The revenue foregone during this transitional phase will be absorbed by TasNetworks, resulting in reduced shareholder returns, and will not be passed on to other customers.

Figure 19-1: Indicative revenue impact of price path (June 2019 $m)

20 Ancillary services

20.1 Introduction

Ancillary 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 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 services. For this reason, the AER categorises these services as Alternative Control Services.

Ancillary 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.

The remainder of this chapter provides an overview of our proposals in relation to fee-based services and quoted services.

20.2 Fee-based services

These services are provided upon request and are typically initiated by way of a service request from a retailer. 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 testing;
- basic connections;
- supply abolishment – removal of meters and service connection; and
- other miscellaneous services.

In the forthcoming regulatory period, the Power of Choice metering reforms mean that meter alterations and renewable energy connections will no longer be offered as a service.

We are proposing to include under connection services an additional service for providing temporary disconnection and reconnection in response to a retailer's request for an outage. The following additional services will also appear as 'miscellaneous services', to reflect the AER's updated Framework and Approach paper[55]:

- creation of National Metering Identifier (**NMI**);
- statutory right – access prevented;
- network tariff change (back office);
- emergency maintenance contestable meters;
- meter recovery and disposal; and
- tiger tails.

In the forthcoming regulatory period, we are proposing an increase in the prices of our fee-based services. This increase reflects an updated allocation of our overhead costs in accordance with our CAM. Internal and external labour costs have been forecast to increase slightly faster than CPI, in accordance with advice received from Jacobs[56]. While the costs attributable to, and therefore recoverable from, Alternative Control Services will experience an increase, our costs attributable to Standard Control Services will be lower by an offsetting amount. Our proposed approach to fee-based services ensures that customers pay the appropriate prices for the services they request, and are not cross-subsidised by other customers.

A full description of our fee-based services is provided in the Alternative Control Services Descriptors Paper (TN094) and the proposed charges are outlined in the Tariff Structure Statement (TN093).

20.3 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 or third party 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 overhead and underground subdivisions for developers;
- services that are provided through a non-standard process at a customer's request (for example, where more frequent meter reading is required);
- network safety services;
- customer vegetation defect works;
- premises connection services and extension;
- connection application services (other than those provided as fee based services);
- design work for a new connection;

55 AER, Framework and approach, TasNetworks electricity transmission and distribution, Regulatory control period commencing 1 July 2019, July 2017.

56 Jacobs Labour Cost Escalation Report, 25 October 2017.

- access permits, oversight and facilitation;
- notices of arrangement;
- network related property services;
- planned interruption – customer requested; and
- provision of training to third parties for network related access.

We propose to expand and amend our categories of labour to reflect our current practice, as follows:

- General Administration; Engineer and Senior Engineer are to be included as new categories;
- 'Pole Tester' is to be removed; and
- 'Electrical Inspector' is to be renamed 'Asset Inspector'.

We propose to apply the following formula for our quoted services:

$$Price = Labour + Contractor\ Services + Materials + Margin$$

These terms are defined as follows

- Labour consists of all labour costs directly incurred in the provision of the service which includes labour on-costs, fleet on-costs and overheads. Our proposed labour rates are set out in the Tariff Structure Statement (TN093) and will be escalated annually by CPI-X, as defined in the AER's Framework and Approach paper.
- Contractor Services includes all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.
- Materials includes the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.
- Margin is an amount equal to 5.89 per cent of the total costs of labour, contractor services and materials.

The first three terms are defined in accordance with the AER's Framework and Approach paper[57]. For the forthcoming regulatory period, we propose to include a margin as a fourth term, so that customers pay an amount that is commensurate with the prices that would be observed in a competitive market. The inclusion of a margin is consistent with the principle of competitive neutrality, which is that publicly owned businesses should not enjoy a competitive advantage simply because they are publicly owned.

While many of our quoted services are not currently subject to competition, this situation may change over time. The inclusion of a modest margin will assist in promoting the development of competition and ensure fair pricing across all our services.

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[57] AER, Framework and approach, TasNetworks electricity transmission and distribution, Regulatory control period commencing 1 July 2019, July 2017, page 48.

Part Four:

Pass through events, Connection, Negotiating Framework and other matters

Part Four of the Regulatory Proposal sets out information that is applicable to our revenue capped services (namely, prescribed transmission services and distribution Standard Control Services). It provides information on pass though events, our connection policy, negotiating framework and other matters.

21 Pass through events

21.1 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 transmission and distribution determination to specify additional pass through events, which are known as 'nominated pass through events'[58]. 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 for our transmission and distribution activities. To ensure that we are treated consistently with other transmission and distribution businesses, the thresholds for pass through events will apply to each activity separately. This proposed approach is consistent with the Rules definitions of *positive change event* and *negative change event*.

21.2 Application of pass through provisions to Alternative Control Services

We propose that the pass through provisions for defined and nominated pass through events also 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.[59]

21.3 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;

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58 NER, clause 6.5.1.

59 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.'

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 services or prescribed transmission services.

For this insurance cap event:

a relevant insurance policy is an insurance policy held during the 2019-24 regulatory control period or a previous regulatory control period in which TasNetworks was registered as a NSP for the purposes of s.11 of the NEL.

Note: In making a determination on an insurance cap event, the AER will have regard to, amongst other things:

i. the relevant 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. any assessment by the AER of TasNetworks' insurance in making its transmission overview document distribution determination for the relevant period.

21.4 Terrorism event

A terrorism event occurs if:

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 increases the costs to TasNetworks in providing direct control services or prescribed transmission 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; and
iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

21.5 Natural disaster event

Natural disaster event means:

Any natural disaster including but not limited to fire, flood, or earthquake that occurs during the 2019-24 regulatory control period and that increases the costs to TasNetworks in providing direct control services or prescribed transmission services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider.

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; and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

22 Connection pricing policy

The Rules require us to prepare a connection pricing policy for the AER's approval. The policy sets out the charging arrangements for providing connection service to retail customers or real estate developers. The connection policy must be consistent with the charging principles specified in the Rules[60] and the AER's guidelines[61], which were published in June 2012.

A connection policy sets out the nature of connection services offered by a distributor, when connection charges may be payable by retail customers and how those charges are calculated. A connection policy must detail:

- the categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed;
- the aspects of a connection service for which a connection charge may be made the basis on which connection charges are determined;
- the manner in which connection charges are to be paid (or equivalent consideration is to be given); and
- a threshold (based on capacity or any other measure identified in the connection charge guidelines) below which a retail customer (not being nonregistered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation other than an extension.

Our proposed connection policy is provided as a supporting document (TN023). It is unchanged from the current connection policy, which was approved by the AER in its 2017-19 determination for the distribution business.

60 NER, clause 5A.E.1.

61 Connection charge guidelines for electricity retail customers, under chapter 5A of the National Electricity Rules, Version 1.0, June 2012.

23 Negotiating framework

The Rules requires a distributor to provide negotiated distribution services in accordance with a negotiated agreement or as a result of a determination by a commercial arbitrator. These processes are facilitated by:

- a negotiating framework; and
- negotiated distribution service criteria (NDSC).

A distributor must prepare a negotiating framework that sets out procedures for negotiating the terms and conditions of access to a negotiated distribution service. The AER determines the NDSC, in consultation with stakeholders, which set out criteria that a distributor must apply in negotiating those terms and conditions, including the prices and access charges for negotiated distribution services. The NDSC also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.

For the forthcoming regulatory period, we propose to maintain our current distribution negotiating framework, which is provided in supporting document TN025.

The AEMC's National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule Determination 2017 removes the requirement for us to prepare a transmission negotiating framework for approval by the AER. Instead, negotiated transmission services must now be provided in accordance with the transmission negotiating principles set out in Schedule 5.11.

In this Regulatory Proposal, we are therefore only submitting a distribution negotiating framework for the AER's approval.

24 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.

25 Certification

25.1 Certification statements

Clauses S6.1.1(5), S6.1.2(6), S6A.1.1(5) and S6A.1.2(6) of the Rules require us to provide a certification by TasNetworks' Board for the underlying key assumptions for our transmission and distribution capital expenditure and operating expenditure forecasts. The certification statement is provided in supporting document TN020 as an attachment to this Regulatory Proposal.

25.2 Statutory declaration of Chief Executive Officer

The Regulatory Information Notices require our Chief Executive Officer to provide statutory declarations about the information that we have provided to the AER.

The statutory declarations are provided in supporting documents TN110 and TN111 as attachments to this Regulatory Proposal.

26 Table of attachments

Key Summary Documents

Document ID	Document Title	Confidential
TN001	Transmission and Distribution Regulatory Proposal 2019-2024 Overview Paper	N
TN002	Tasmanian Transmission and Distribution Regulatory Proposal 2019-2024 Fact Sheet	N
TN003	Tasmanian Transmission Revenue Proposal 2019-2024 Fact Sheet	N
TN004	Tasmanian Distribution Regulatory Proposal 2019-2024 Fact Sheet	N
TN005	Tasmanian Transmission Regulatory Proposal 2019-2024 Contingent Projects Fact Sheet	N
TN006	Transmission Pricing Fact Sheet	N
TN007	Residential Network Fact Sheet – Take Charge of Your Energy Costs	N
TN008	Small Business Network Tariffs Fact Sheet	N
TN009	Large Business Network Tariffs Fact Sheet	N
TN010	Embedded Networks Fact Sheet	N
TN011	Irrigation Network Tariffs Fact Sheet	N

Key Strategies and Policies

Document ID	Document Title	Confidential
TN012	Residential Fact Sheet – It's Time To Change How We Use Power	N
TN013	Transformation Roadmap 2025 – January 2018	N
TN014	Annual Planning Report 2017	N
TN015	Corporate Plan 2017-2018	N
TN016	Themes from Reset 2019 Customer Engagement – February 2017	N
TN017	Directions and Priorities - Consultation Paper 2019 - 2024	N
TN018	Directions and Priorities - Summary of Submissions and Key Themes	N

Document ID	Document Title	Confidential
TN019	Directions and Priorities - Stakeholder Response Matrix	N
TN020	Directors Certification of Key Assumptions for the Regulatory Proposal	N
TN021	Asset Management Policy	N
TN022	Zero Harm Policy	N
TN023	Distribution Connections Pricing Policy	N
TN024	Capitalisation Policy 2014-15	N
TN025	Distribution Negotiating Framework	N
TN026	Strategic Asset Management Plan	N
TN027	Network Innovation Strategy	N
TN028	Technology Governance Strategy	Y
TN029	Area Strategy - Core Grid	N
TN030	Area Strategy - Greater Hobart	Y
TN031	Area Strategy - Central	Y
TN032	Area Strategy - Eastern	Y
TN033	Area Strategy - Kingston South	N
TN034	Area Strategy - North West	Y
TN035	Area Strategy - Northern	Y
TN036	Area Strategy - West	Y
TN037	Fleet Strategy 2015 - 2020	Y
TN038	Customer Strategy 2015	N
TN039	Expenditure Forecasting Methodology	N
TN040	Cost Allocation Methodology - AER Approved	N

Document ID	Document Title	Confidential
TN041	Network Operations Operational System Strategy	N

Asset Management Plans

TN042	Network Development Asset Management Plan	N
TN043	Customer Development Management Plan	Y
TN044	Asset Management Information System (AMIS) Asset Management Plan	N
TN045	IT Infrastructure Asset Management Plan	Y
TN046	IT Software Asset Management Plan	Y
TN047	Facilities Asset Management Plan	Y
TN048	Tool of Trade Fleet Management Plan	Y
TN049	Service Performance Asset Management plan	N
TN050	Bushfire Risk Mitigation Plan	N
TN051	Vegetation Asset Management Plan	N
TN052	Conductors and Hardware Asset Management Plan	N
TN053	Connection Assets Asset Management Plan	N
TN054	Demand Management Asset Management Plan	N
TN055	Emergency Response Asset Management Plan	N
TN056	Ground Mounted Substations Distribution Asset Management Plan	N
TN057	High Voltage Regulators Asset Management Plan	N
TN058	Metering (Regulated) Type 6 Asset Management Plan	N
TN059	Overhead Line Structures Asset Management Plan	N
TN060	Overhead Switchgear Asset Management Plan	N
TN061	Pole Mounted Transformers Asset Management Plan	N

Document ID	Document Title	Confidential
TN062	Protection and Control Distribution Asset Management Plan	N
TN063	Public Lighting Asset Management Plan	N
TN064	SCADA Systems Asset Management Plan Transmission	N
TN065	Underground Systems Asset Management Plans	N
TN066	Zone Substation Asset Management Plan	N
TN067	Circuit Rating and Weather Monitoring System Asset Management Plan	N
TN068	AC Distribution System Asset Management Plan	N
TN069	DC Distribution System Asset Management Plan	N
TN070	EHV Circuit Breaker Asset Management Plan	N
TN071	EHV Current Transformer Asset Management Plan	N
TN072	EHV Disconnector and Earth Switch Asset Management Plan	N
TN073	High Voltage Switchgear Asset Management Plan	N
TN074	Network Operations Asset Management Plan	N
TN075	Power Cable Asset Management Plan	N
TN076	Power Transformer Asset Management Plan	N
TN077	Structures and Busbars Asset Management Plans	N
TN078	Substation Site Infrastructure Asset Management Plan	N
TN079	SCADA and Automation Distribution Asset Management Plan	N
TN080	Voltage Transformer Asset Management Plan	N
TN081	Transmission Line Easements Asset Management Plan	N
TN082	Transmission Line Insulator Assemblies Asset Management Plan	N
TN083	Transmission Line Protection and Control Asset Management Plan	N

Document ID	Document Title	Confidential
TN084	Transmission Line Support Structure Asset Management Plan	N
TN085	Transmission Line Support Structure Foundations Asset Management Plan	N
TN086	Telecommunications Site Infrastructure Asset Management Plan	N
TN087	Telecommunications Bearer Network Asset Management Plan	N
TN088	Telecommunications Telephony and Voice Systems Asset Management Plan	N
TN089	Transmission Line Conductor Assemblies Asset Management Plan	N
TN090	Telecommunications Network Management Systems (TNMS)	N
TN091	Works Deliverability Plan 2019-2024	N

Models and Pricing Tariffs

TN092	Transmission Pricing Methodology	N
TN093	Tariff Structure Statement 2019 - 2024	N
TN094	Alternative Control Services Descriptions Paper	N
TN095	Capex Forecast Model - Standard Control - Summary Output	N
TN096	Distribution Operating Expenditure Model	N
TN097	Transmission Operating Expenditure Model	N
TN098	Quoted Services Labour Rates Model	N
TN099	Public Lighting Annuity Model	N
TN100	Metering Post Tax Revenue Model Distribution (PTRM)	N
TN101	Metering - Roll Forward Model (RFM)	N
TN102	Fee Based Services Model Distribution	N
TN103	Roll Forward Model (RFM) Transmission	N
TN104	Roll Forward Model (RFM) - Standard Control Distribution	N

Document ID	Document Title	Confidential
TN105	Post Tax Revenue Model (PTRM) Transmission	N
TN106	Post Tax Revenue Model (PTRM) – Standard Control Distribution	N
TN107	Customer Forecasts Model	N
TN108	Transmission Regulated Asset Base and Tax Depreciation Model	N
TN109	Distribution Regulated Asset Base and Tax Depreciation Model Standard Control	N

AER/Audit/RIN

TN110	CEO Statutory Declaration Reset RIN Transmission	Y
TN111	CEO Statutory Declaration Reset RIN Distribution	Y
TN112	Reset RIN Response Compliance Checklist Transmission	N
TN113	Reset RIN Response Compliance Checklist Distribution	N
TN114	Reset Category Analysis RIN Response – Basis of Preparation Transmission	N
TN115	Reset RIN Response - Economic Benchmarking Basis of Preparation Transmission	N
TN116	Reset RIN Response – Basis of Preparation Distribution	N
TN117	Reset RIN FINAL Template 1 – Revenue Determination Transmission	N
TN118	Reset RIN FINAL Template 1 - Regulatory Determination Distribution	N
TN119	Reset RIN FINAL Template 2 - New Historical Category Analysis Data Distribution	N
TN120	Reset RIN FINAL Template 2 - Market Impact Component 2011 Transmission	N
TN121	Reset RIN FINAL Template 2 - Market Impact Component 2012 Transmission	N
TN122	Reset RIN FINAL Template 2 - Market Impact Component 2013 Transmission	N
TN123	Reset RIN FINAL Template 2 - Market Impact Component 2014 Transmission	N
TN124	Reset RIN FINAL Template 2 - Market Impact Component 2015 Transmission	N
TN125	Reset RIN FINAL Template 2 - Market Impact Component 2016 Transmission	N

Document ID	Document Title	Confidential
TN126	Reset RIN FINAL Template 2 - Market Impact Component 2017 Transmission	N
TN127	Reset RIN FINAL Template 5 - Capital Expenditure Sharing Scheme Transmission	N
TN128	Reset RIN FINAL Template 5 - Efficiency Benefits Sharing Scheme Distribution	N
TN129	Reset RIN FINAL Template 6 - Efficiency Benefits Sharing Scheme Transmission	N
TN130	Reset RIN FINAL Template 6 - Capital Expenditure Sharing Scheme Distribution	N

Incentive Schemes

TN131	STPIS Model Customer Service Distribution	N
TN132	STPIS Model Reliability of Supply Distribution	N
TN133	STPIS Targets by Financial Year Transmission	N
TN134	STPIS Targets by Calendar Year Transmission	N

Investment Evaluation Summaries

TN135	Pole Replacements	N
TN136	Market Systems MDMS Replacement	Y
TN137	Replacement of Substandard Overhead Copper Conductor (REMCU)	N
TN138	Replace Crossarm (Safety)	N
TN139	Low Conductor Span Rectification - Low Clearance LV CAPEX	N
TN140	IT Core Services	Y
TN141	BFM project - replace aged/deteriorated Cu conductor	N
TN142	Market Systems - MDMS Upgrades	Y
TN143	BFM Replace/relocate open wire HV with insulated alternative (re vegetation management)	N
TN144	Replacement of HV Switchgear in Ground Mounted Substations	N
TN145	Customer Initiated Non-Major Works Commercial	N

Document ID	Document Title	Confidential
TN146	Fleet Program 01674	Y
TN147	Customer Initiated Non-Major Works Residential	N
TN148	Replacement of Ground Mounted Substations	N
TN149	Replace Transformers	N
TN150	Customer Initiated Subdivisions	N
TN151	Asset Management Information System (AMIS) Improvement Program	N
TN152	Replace Low Voltage CONSAC Cable	N
TN153	Customer Initiated Non-Major Works Irrigation	N
TN154	Replace OH LV Services	N
TN155	BFM - Replace EDOs with alternative device 01518 (i.e.: boric acid fuses or fault tamers)	N
TN156	Dynamic Reactive Power Device for George Town Substation	N
TN157	Transmission Line Protection Renewal Program	N
TN158	BFM Replace aged/deteriorated galvanised iron (GI Conductor)	N

Reports

TN159	TasNetworks Benchmarking Report	N
TN160	KPMG ACS Model Review Report	N
TN161	GHD Modelled Repex Forecast 2019-24 (TasNetworks Distribution)	N
TN162	Nature Research - TasNetworks Customer Engagement Report June 2016	N
TN163	Nature Research - TasNetworks Customer Engagement Report May 2017	N
TN164	Straight Talk - TasNetworks Customer Engagement Report September 2016 Workshops	N
TN165	Straight Talk Customer Engagement Report June 2017 Workshops	N
TN166	Jacobs Labour Cost Escalation Report 2019-2024	N

Document ID	Document Title	Confidential
TN167	AEMO Review of TasNetworks' Network Capability Incentive Parameter Action Plan (NCIPAP)	N

Supporting Documentation

TN168	TasNetworks Enterprise Agreement	N
TN169	Network Capability Incentive Parameter Action Plan (NCIPAP)	N
TN170	Incident Management Framework	N
TN171	Procurement Policy	N
TN172	Mobile Devices, Wireless Service and Remote Access Policy	N
TN173	Information and Communications Acceptable use of Technology Services Policy	N
TN174	Information and Communications Security Policy	N
TN175	Approach to Regulatory Proposal Development 2019-2024	N
TN176	Vegetation Audit Example	Y
TN177	2019-24 Transmission STPIS Transitional Approach	N