TasNetworks
Delivering your power

Tasmanian Transmission and Distribution Revised Proposals

November 2018

OVERVIEW

Regulatory Control Period
1 July 2019 to 30 June 2024

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Message from the CEO

This paper provides an overview of our updated plans for the five year regulatory period from 1 July 2019 to 30 June 2024, which we originally submitted to the Australian Energy Regulator (the **regulator**) in January 2018. Our updated plans and revised revenue requirements address the issues raised by the regulator in its draft decision.

We engaged with our customers and stakeholders in developing our original Regulatory Proposal and throughout the regulator's subsequent review. Our extensive engagement has been a learning experience for the business, which we intend to build on as we work through the challenging period ahead. We thank all our customers, stakeholders and the regulator for engaging with us and contributing to the development and refinement of our expenditure plans.

Through its draft decision, the regulator has asked the business to work harder to explain and justify our proposed expenditure plans, particularly in relation to asset replacement and IT. Our revised Regulatory Proposal has responded constructively to the issues raised by the regulator, by accepting proposed reductions in our original plans where it is appropriate to do so and providing further information to substantiate our revised positions. The difference between our revised total revenue requirement over the 5 year period and the regulator's draft decision is only 1.75 per cent, which is a modest difference considering the complexity of the forecasting task and the uncertainty that lies ahead.

As explained in our original Regulatory Proposal, the electricity sector is facing a period of unprecedented change. This transformation arises from a combination of new technology, which is changing how customers use the electricity networks, and a shift to renewable generation that is driven by climate change policies and projected coal plant closures. These changes are creating new challenges for electricity networks across Australia and the national electricity market in which they operate – as illustrated by the numerous independent reviews and policy initiatives in recent months.

While the future is more uncertain than ever before, we are responding in a balanced way by being prepared where we can and staying flexible in other areas to respond to changing circumstances as they arise. One issue of strategic importance for Tasmania is whether a second interconnector with the mainland should be constructed. Evidence from overseas, where similar changes are also taking place, is that increased interconnection delivers significant benefits to electricity customers by providing much needed diversity in generation sources.

In Tasmania, we benefit from low cost, high value hydro generation. With increased interconnection, Tasmania can provide clean, dispatchable generation to mainland NEM regions when demand outstrips supply from intermittent renewable generation, such as solar and wind. With the support of ARENA and the Tasmanian Government, we are carefully undertaking the feasibility study and business case assessment, Project Marinus, of a second Bass Strait interconnector. Our Project Marinus interim report will be issued in December this year.

While these investigations continue, we are working with numerous renewable generation connection proponents and we are connecting a growing number of solar panels for residential and commercial customers. We remain focused on our 'business as usual' activities, including the replacement of aged assets in order to manage the risk of asset failure and to maintain supply reliability. We also continue to invest in our systems and processes to ensure that we provide our customers with the best service at the lowest sustainable cost. A component of our investment plans relates to cyber security, which is recognised to be a growing risk to modern electricity networks and businesses in general.

In preparing our revised Regulatory Proposal, we have carefully considered the regulator's draft decision and the feedback from our customers. As noted in our original Regulatory Proposal, a consistent and clear message from our customers is that affordability is their primary concern, while significant importance is also placed on maintaining current service and reliability performance. We must also ensure that our operations and asset strategies manage safety risks, both to the general public and to our team members who work on and operate our assets. Inevitably, a judgment needs to be made on how best to balance these competing objectives, while addressing the specific matters raised by the regulator in its draft decision.

At the start of the next regulatory period, our proposed network charges for a typical residential customer will be 22 per cent lower in real terms compared to our charges in 2013-14. The reduction for a typical small business customer over the same period will be even greater at 39.6 per cent in real terms. These are significant savings, which should provide confidence to our customers and stakeholders that we are responding to their concerns regarding affordability.

Our revised Regulatory Proposal, which is summarised in this Overview Paper, will provide better outcomes for our customers as we address the emerging challenges ahead.

Lance Balcombe
Chief Executive Officer

1. Snapshot of our revised Regulatory Proposal

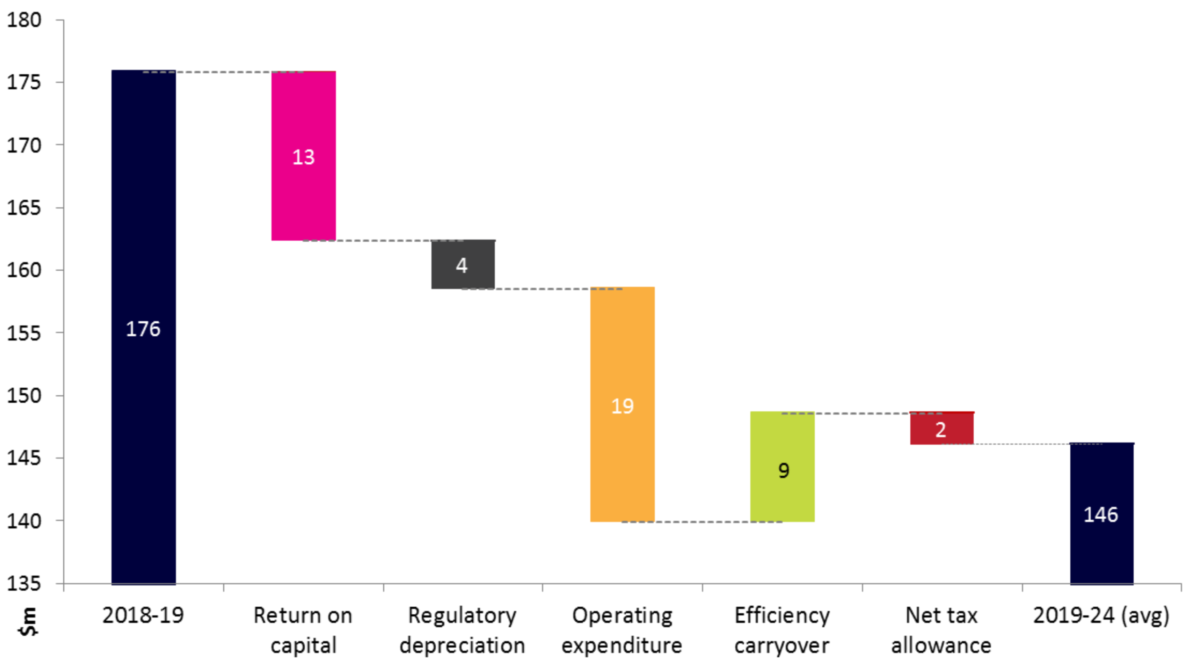
The table below shows how our revised five-year forecasts of revenue and expenditure compare with our actual revenue and expenditure for the previous five years.

Table 1: Changes in revenues and expenditure from the current period to the 2019-24 period (June 2019 $)

	% Change	Change ($ million)
Revenue Allowance - Transmission	-20%	-187
Revenue Allowance - Distribution	-11%	-150
Combined Revenue	**-15%**	**-337**
Capex	15%	125
Opex	-8%	-49

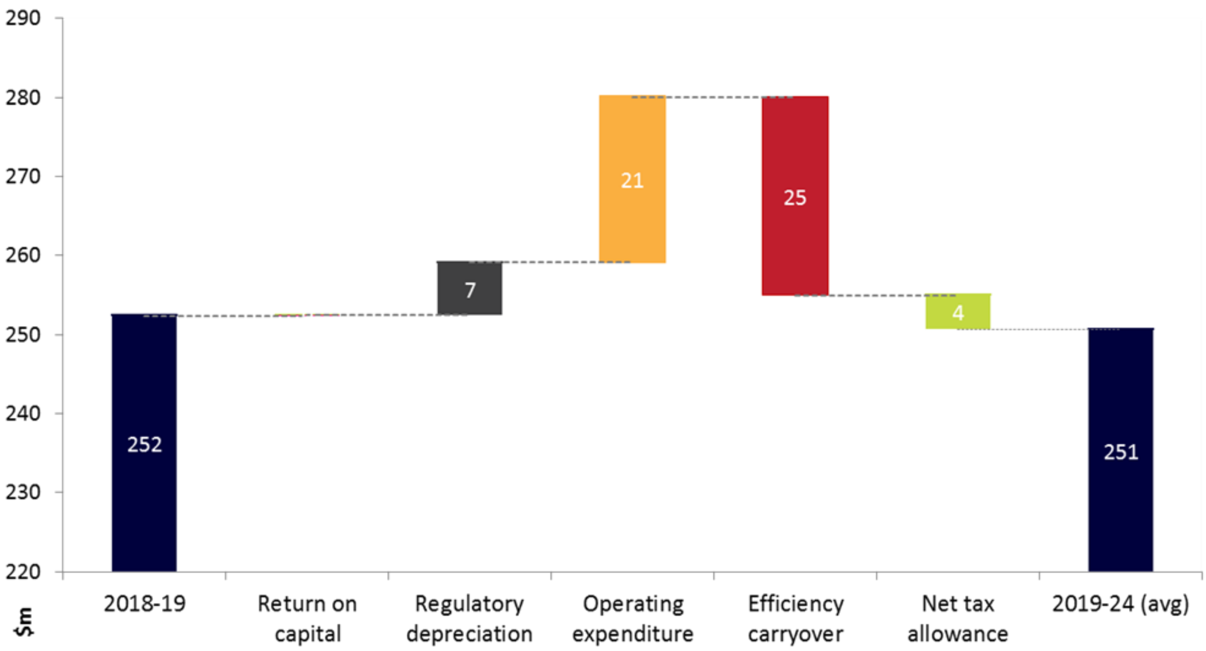
The figure below shows the change in our revised transmission revenue requirements from the final year of the current period, being 2018-19. It shows our proposed annual transmission revenue for the 2019-24 period (the right-hand blue bar) compared to our current revenue (the left-hand blue bar). The intermediate coloured bars show each of the drivers that lead to the lower average revenue in the 2019-24 period. We explain each of these drivers shortly.

Figure 1: Transmission revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



An equivalent figure is presented below in relation to our distribution revenue.

Figure 2: Distribution revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



The 5 drivers in the above figures are explained briefly in turn:

- **Return on capital**. This element comprises two components – our regulated rate of return and the value of our regulated asset base.
    - Our regulated rate of return is estimated with reference to recent financial market data and the regulator's Rate of Return Guideline.
    - The value of our regulated asset base is calculated in accordance with the National Electricity Rules, based on our historical and forecast investments.
- **Regulatory depreciation**. The regulatory depreciation or 'return of capital' reflects the decline in the value of our regulated asset base as our assets age.
- **Operating expenditure**. This element provides an allowance for maintaining our assets and running the business.
- **Efficiency carryover**. This element is a bonus or penalty payment, which provides an incentive to improve efficiency. The payment is calculated with reference to the regulator's expenditure allowances in the previous regulatory period.
- **Net tax allowance**. This element is an allowance to cover our tax obligations, which must be paid from our revenue.

The combined effect of our revised proposals is that our total transmission and distribution revenues over the 5 year regulatory period will increase by $36.7 million[1] or 1.75 per cent above the amount

[1] $36.7 million is the difference in total revenues over the 5 years, expressed in nominal terms.

proposed by the regulator in its draft decision. This is a relatively modest difference, given the complexity and uncertainty associated with planning expenditure over a 5 year period.

For the reasons explained in this Overview Paper, we consider that our revised expenditure plans and updated revenue proposals appropriately balance the challenges of maintaining safety and current performance levels; managing risks, including the risk of asset failure and cyber security; and keeping prices as low as possible.

2. Background

2.1 Purpose of this document

This document provides an overview of our revised Regulatory Proposal, which is being submitted to the regulator following the publication of its draft decision on our original Regulatory Proposal, which we lodged in January 2018.

The purpose of this Overview Paper is to provide customers with a 'plain English' summary of:

- our revised proposal and expenditure plans;
- our consumer engagement approach, including an explanation of how we have sought to respond to the feedback provided;
- the key risks and benefits of our revised Regulatory Proposal for our consumers; and
- our revised total revenue requirements and the price implications for our transmission and distribution customers.

Our revised Regulatory Proposal has been developed so that it delivers the best possible outcome for our transmission and distribution customers today and into the future. In addition to keeping costs low, this commitment means developing plans to meet our compliance obligations, including those relating to reliability, physical security, safety, environment, risk and other matters.

We have a strong track record in putting forward proposals that set challenging targets for our business – our revised Regulatory Proposal is no different. Further detailed information on our revised Regulatory Proposal is available on our website.[2]

In terms of the financial data presented in this Overview Paper, 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.

2.2 Our role in the Tasmanian electricity industry

As explained in our original Regulatory Proposal, TasNetworks provides both distribution network services (via the poles and wires) and transmission network services (via the large towers and lines) to customers in Tasmania. The business was created through the merging of Transend Networks and Aurora Energy Distribution in mid 2014, a process that has delivered a more optimised and efficient business, and allowed us to focus on managing 'one' Tasmanian network.

As the owner and operator of Tasmania's electricity transmission and distribution networks, our role is to deliver electricity safely and reliably to more than 285,000 households, businesses and

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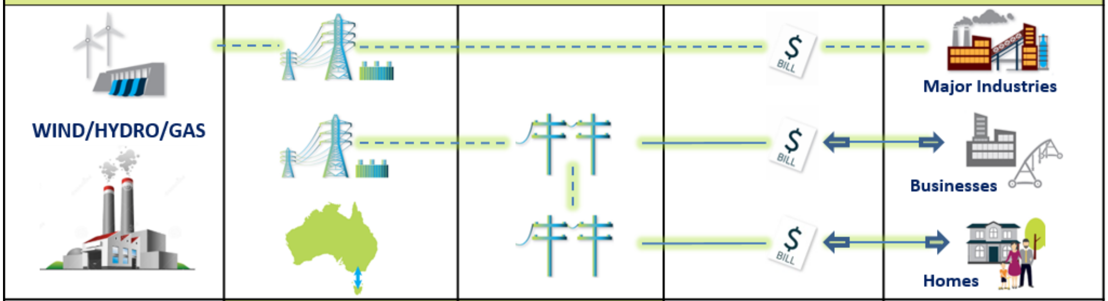
2 For further information please refer to the following link: https://www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals/revenue-reset-2019-2024/

organisations across Tasmania. Our role in the electricity supply chain and our customer service relationships is summarised below.

Figure 3: How your electricity gets to you and TasNetworks' role

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.

What it takes to deliver your power

TasNetworks is responsible for the design, construction, operation and maintenance of the network that supplies power from the generation source to Tasmanian homes and businesses.

The network is made up of:

Transmission

3,540 circut kilometres of transmission lines

7,742 transmission line support structures

11,183 hectares of easements

Distribution

16,566 kilometres of high voltage powerlines

4,973 kilometres of low voltage powerlines

2,524 kilometres of high and low voltage underground cables

230,129 poles

2.3 Our plans in a changing environment

Our revised Regulatory Proposal has been prepared during a period of unprecedented change and uncertainty in the National Electricity Market (**NEM**). The changes taking place in the electricity sector are being driven by customers as they embrace new technologies, take control of their energy use and support action on climate change. Increasingly, customers will play a much greater role in the electricity market as they exercise more control over their consumption and generation decisions, through solar PVs, battery storage and smart appliances.

While technological change is bringing significant benefits to customers, it also introduces new operational challenges for electricity networks. Electricity networks are transforming from simple 'one-way' transport systems that deliver generation to end-use customers, to more complex two-way networks in which generation is increasingly decentralised. If not managed proactively across the NEM, these operational issues may expose customers to an increased risk of supply interruptions. Our business faces a growing cyber security risk which has the potential to increase as we adopt new technology. We have allocated additional funds to identify and manage cyber security risks.

Our approach to addressing this significant transformation is to make prudent, incremental changes to our expenditure plans so that we are prepared for the challenges ahead, while keeping downward pressure on prices. Where appropriate, we will also take strategic initiatives to deliver value to our customers and the Tasmanian economy. For example, with the support of the Tasmanian Government, TasNetworks and ARENA have formed 'Project Marinus' to examine the case for enhancing the existing interconnection between Tasmania and the rest of the NEM.

Greater interconnection provides an opportunity for Tasmania to leverage its existing hydro capacity and to exploit its natural advantage by developing low cost, high value pumped storage for the benefit of the NEM. Interconnection will also facilitate increased renewable generation development in Tasmania, providing flow on benefits to the Tasmanian economy. It represents a strategic, long term response to address the challenges associated with the closure of base load coal plant on the mainland and the increasing reliance on intermittent renewable generation. The project, which involves a significant capital investment, will only proceed if it provides an overall net benefit to electricity customers.

The unprecedented changes in the electricity market are also driving numerous reviews and policy developments to ensure that the National Energy Rules (the **Rules**) and the regulatory framework continue to be 'fit for purpose'. These include:

- The proposed Retailer Reliability Obligation;
- AEMO's Integrated System Plan;
- The regulator's development of binding Rate of Return Guidelines;
- The regulator's review of the tax allowance for network companies; and
- ACCC's report on retail pricing.

While only some of these matters will have a direct impact on our revenue requirement in the forthcoming regulatory period, each creates particular challenges that must be addressed. Our approach, which is reflected in our revised Regulatory Proposal, is to ensure that we are appropriately equipped to address the challenges ahead, while continuing to provide the affordable, safe and reliable services that our customers expect.

3. Customer engagement

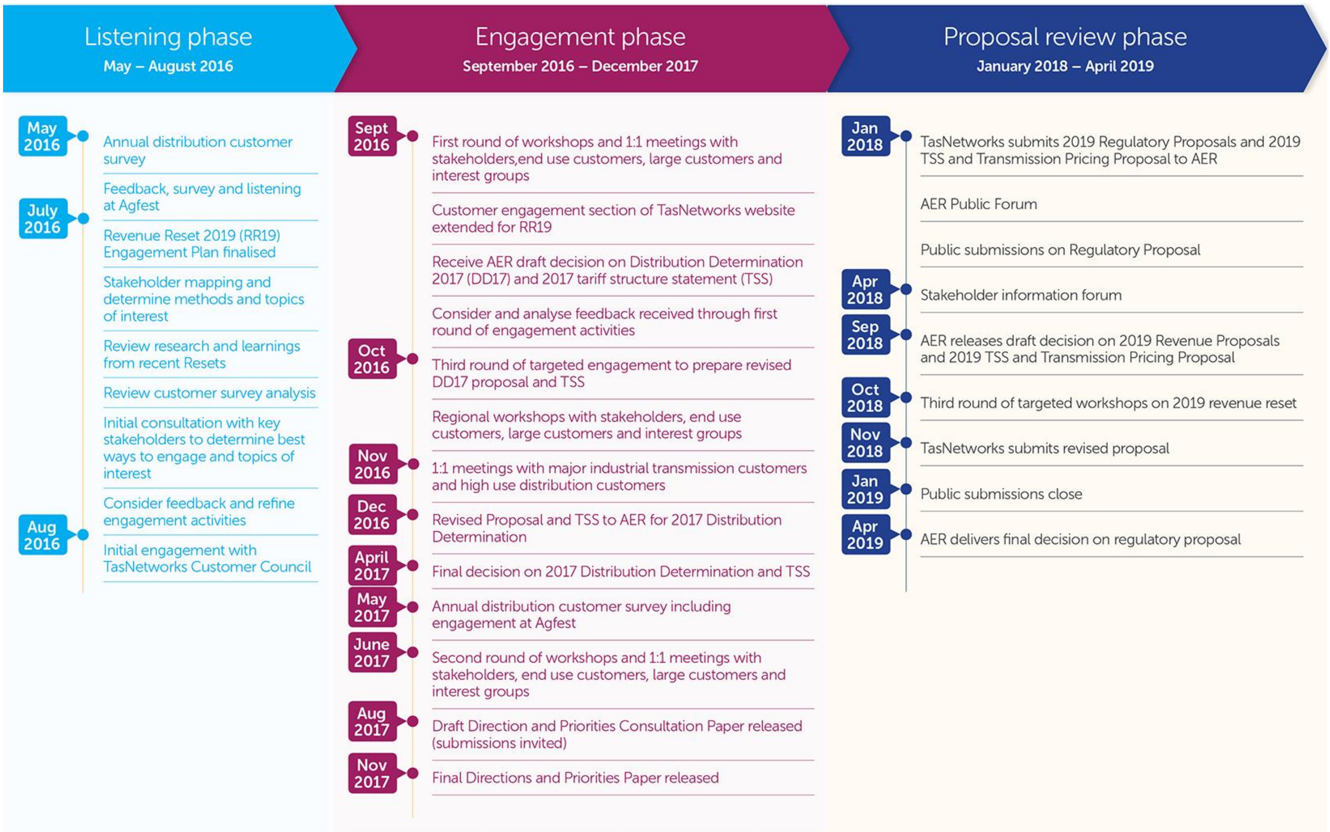
3.1 Initial engagement and feedback

In developing our original Regulatory Proposal, we implemented a three phase engagement process:

- A listening phase, from May to August 2016;
- An engagement phase, from September to December 2017; and
- A proposal review phase commencing in January 2018.

The figure below shows the extensive engagement program we undertook in relation to each of these phases.

Figure 4: Our on-going engagement program and activities



Our original Regulatory Proposal explained that we developed our expenditure plans in light of the feedback we received. We believe that our original Regulatory Proposal balanced the competing objectives raised by our customers and stakeholders, having regard to the condition of our assets and our overarching obligation to provide safe and reliable network services.

The engagement process enabled us to draw out the following themes that shaped our original Regulatory Proposal.

Table 2: Key themes from our original engagement process

Customer group	Key themes
Transmission customers	• 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 - reliability is still a key focus. • TasNetworks should demonstrate the benefits from investing in technology. • Engaging with customers before making investment decisions has been appreciated.
Distribution customers	• We are meeting most customers' needs from an overall reliability perspective. • While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices. • Continual improvement in the quality of our communication with customers is critical. • Customers recognise that technology is changing the electricity industry, particularly in relation to solar panels, battery storage and electric vehicles. • Customers are interested in distributed energy resources and using the network to trade energy. • The majority of our customers are concerned about affordability, but some customers are willing to pay more for new technologies and/or better outcomes.

We are pleased that the Consumer Challenge Panel[3] commended us for a "committed, well planned and well executed consumer engagement process". The Local Government Association of Tasmania also provided positive feedback on our consultation process, as did the Tasmanian Small Business Council (**TSBC**). However, we also acknowledge TSBC's comments that our approach to date is 'consultative' rather than 'collaborative'.

We are committed to continuing to improve our consumer and stakeholder engagement processes. As demonstrated by the positive feedback we have received, significant improvements have already been achieved by increasing the breadth and depth of our engagement. We will build on these improvements by continuing to use a wide range of communication channels to engage meaningfully with customers and stakeholders on issues that are important to them.

3.2 On-going engagement and updated feedback

Following the publication of our original Regulatory Proposal, we have continued to engage with our customers and stakeholders. In addition to meeting with industrial and business customers to discuss their specific issues, we have also held meetings with the following:

- AER Consumer Challenge Panel members
- AER Stakeholder Forum

[3] Consumer Challenge Panel, Sub-Panel no.13, Issues Paper – TasNetworks electricity network revenue proposal 2019-24, 16 May 2018, page 4.

- Anglicare Tasmania
- Aurora Energy
- Customer information sessions (Hobart and Launceston)
- Hydro Tasmania
- Local Government Association of Tasmania
- Office of the Tasmanian Energy Regulator
- Residential customers
- Stakeholder information sessions (Hobart and Launceston)
- TasCOSS
- Tasmanian Farmers and Graziers Associations
- Tasmanian Renewable Energy Alliance
- Tasmanian Small Business Council (TSBC)
- TasNetworks Customer Council
- TasNetworks Pricing Reform Working Group

In broad terms, the feedback we have received since the publication of our original Regulatory Proposal reinforces the key themes from our earlier engagement. In addition, however, the most recent customer feedback also identified a number of specific challenges that need to be addressed in our revised Regulatory Proposal, which we have captured in the summary statements below:

- Customers want us to increase our focus on affordability, which means that any change that leads to a price increase must be fully justified.
- Network reliability has never been so good, and therefore there should now be a greater focus on cost reduction.
- Our proposed capital expenditure needs better justification, particularly in relation to the proposed increases in replacement expenditure and IT.
- We need to provide a compelling case for including contingent projects, noting that these projects may lead to material increases in capital expenditure.
- We need to demonstrate that our proposed operating expenditure is consistent with delivering the lowest sustainable prices for customers.
- We need to balance the mixed views expressed in relation to tariff reforms. For example, the TSBC strongly prefers an accelerated implementation of cost reflective tariffs, while Aurora Energy questioned whether the case for change had been established.

In developing our revised Regulatory Proposal, we have sought to address these challenges. In addition, we have also considered the feedback received by the regulator through its own consultation process, which is discussed below.

4. How are we taking customers' further feedback into account?

Following the submission of our original Regulatory Proposal in January 2018, the AER published its Issues Paper[4]. The purpose of the AER's Issues Paper was to highlight some of the key elements of our original Regulatory Proposal, and explain how stakeholders can assist in the AER's review. As part of this process, the AER invited interested parties to a public forum in Hobart on 10 April 2018. The AER also invited written submissions on our original Regulatory Proposal by 16 May 2018. The AER has taken account of the submissions it received in developing its draft decision.

We welcome the written submissions in response to the AER's Issues Paper and our original Regulatory Proposal[5]. The table below shows how our customers' and stakeholders' views have been taken into account in our revised Regulatory Proposal.

Table 3: Feedback received and taken into account

What we heard	How we have addressed the feedback received
Our capital expenditure plans require further justification, as reliability performance is now better than ever.	We have provided further justification for our investment plans, and we have made reductions where this can be achieved without exposing the public and our people to unacceptable safety or performance risks.
The proposed contingent projects expose customers to large potential increases in capital expenditure.	We have removed two contingent projects from our revised Regulatory Proposal, provided detailed support for the remaining three contingent projects, and refined the triggers for these projects.
Our operating expenditure plans need to be consistent with our lowest sustainable costs.	The regulator's draft decision accepted our original forecasts. We have updated our forecasts to reflect the latest available information, but maintained our focus on delivering the lowest sustainable level of operating expenditure.
Our proposed IT expenditure needs to be fully justified.	We have provided further detailed justification of our proposed IT expenditure.
Our metering charges should not include accelerated depreciation.	We have accepted this position and we are no longer proposing to accelerate depreciation on our metering assets.
The proposed increase in public lighting charges is too high.	Our revised public lighting charges address the concerns raised regarding the proposed increases in charges.
There should be an increased focus on 'innovative projects', which demonstrate how we are moving towards our 2025 strategy.	We have now separately identified our distribution innovation capital expenditure and updated our plans to include additional specific initiatives linked to our 2025 strategy.

4 Australian Energy Regulator, Issues Paper - TasNetworks Distribution and Transmission Determination 2019 to 2024, March 2018.

5 The submissions are available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24-0/proposal#step-57113

5. Our capital expenditure proposals

Our original Regulatory Proposal explained that 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, we explained that we must increase our capital expenditure to renew those assets that are in poor condition, replace technology platforms at end of life, manage increased bushfire related risk and connect new customers.

We also recognised, however, that our customers' primary concern is affordability. With this focus in mind, our original Regulatory Proposal explained that we applied a top down discipline to our preliminary capital expenditure forecasts. As a result, we reduced our total capital expenditure forecasts by more than $42 million over the 5 year period. The optimisation of the distribution program in our original Regulatory Proposal reflected the benefits that we expected to flow from our planned investments in business transformation.

In its draft decision, the regulator imposed a reduction in our forecast total transmission capital expenditure of 14 per cent ($37.5 million) from $260.1 million to $222.6 million for the 5 year period[6], on the basis that:

- our forecasts reflect overly conservative assumptions about the risks and consequences of asset failures
- there is a lack of risk quantification in the underlying cost-benefit analysis.

In relation to our distribution capital expenditure, the regulator's draft decision raised similar concerns, and proposed a reduction of 25 per cent ($183.5 million) from $734.4 million[7] to $550.9 million. The reductions arose principally in two expenditure categories:

- Renewal capex was reduced by 34 per cent ($156.6 million) from $463.0 million to $306.4 million; and
- IT and communications capex was reduced by 24 per cent ($24.4 million) from $103.8 million to $79.4 million.

We have considered all of the matters raised by the regulator and revisited our transmission and distribution capital expenditure forecasts. To address the regulator's concerns, we undertook a comprehensive review of our cost benefit analysis and undertook a higher level of risk quantification, providing increased justification of our proposed renewal capex plans.

As a result of our review, we have identified some areas where the regulator's draft decision can be accommodated without compromising safety, service performance or effective risk management. We have therefore adopted those changes, using more up to date information – such as actual rather than forecast expenditure - where appropriate. Our updated transmission and distribution capital expenditure plans are summarised in the sections below.

6 Australian Energy Regulator, Draft Decision Overview- TasNetworks Distribution and Transmission Determination 2019 to 2024, September 2018, page 37.

7 The draft decision stated that our forecast distribution capital expenditure was $734.4 million, which is our original expenditure forecast of $738.8 million minus forecast disposals (of $4.4 million).

5.1 Transmission capital expenditure

As explained in our original Regulatory Proposal, our transmission investment in the 2019-24 period will be primarily focussed on:

- **Renewing assets in poor condition -** Our expenditure requirements are primarily driven by asset condition and risk in our aging protection and control systems, circuit breakers and power transformers.
- **Security of the system, supporting the clean energy transition -** This work is driven by voltage and ancillary services support, including an investment in excess of $15 million for 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.

The composition of our actual transmission capital expenditure for the current regulatory period, and our updated forecasts for the 2019-24 regulatory period are shown in the figure and table below.

Figure 5: Historic and forecast transmission capital expenditure by category (June 2019 $m)

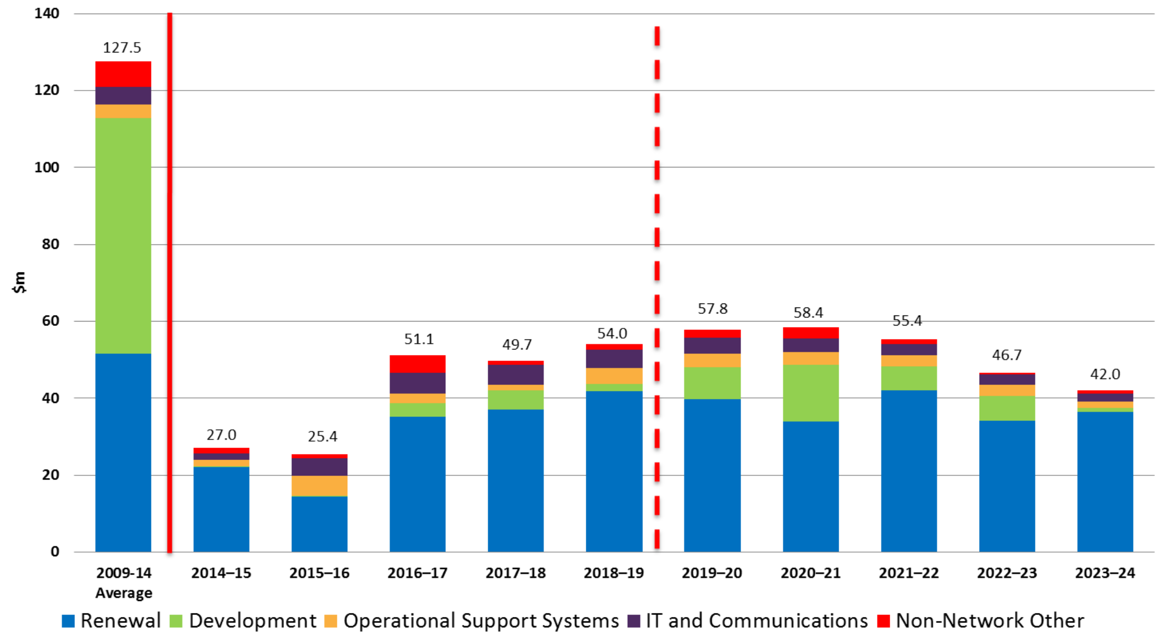


Table 4: Historic and forecast transmission capital expenditure by category (June 2019 $m)

Category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Development	0.2	0.3	3.5	4.8	1.9	8.2	14.9	6.1	6.4	1.0
Connection	0.0	0.0	0.2	0.9	0.1	0.1	1.5	2.2	6.4	1.0
Augmentation	0.2	0.3	3.3	4.0	1.8	8.2	13.3	3.9	-	-
Renewal	22.2	14.4	35.3	37.1	41.8	39.8	33.9	42.1	34.2	36.5
Reliability & Quality Maintained	22.2	14.4	30.8	35.1	41.8	39.8	33.9	42.1	34.2	36.5
Inventory and Spares	-	-	4.5	2.0	-	-	-	-	-	-
Operational Support Systems	1.5	5.0	2.4	1.5	4.1	3.6	3.2	2.9	2.8	1.6
Network Control	0.5	3.4	0.8	0.5	2.4	0.8	0.6	0.6	0.4	0.4
Asset Management Systems	1.1	1.6	1.6	0.9	1.7	2.8	2.6	2.3	2.4	1.2
IT and Communications	1.7	4.6	5.4	5.2	4.8	4.1	3.5	3.0	2.7	2.2
Non-Network Other	1.4	1.1	4.6	1.0	1.5	2.1	3.0	1.3	0.5	0.8
Total transmission capital expenditure	**27.0**	**25.5**	**51.2**	**49.7**	**54.0**	**57.8**	**58.4**	**55.4**	**46.7**	**42.0**

The key elements of our revised transmission capital expenditure proposal are summarised in the table below.

Table 5: Summary of our revised transmission capital expenditure proposal

Expenditure category	Our revised proposal
Development	Our original transmission development capital expenditure forecast was accepted by the regulator, so it is unchanged in our revised Regulatory Proposal.
Renewal	Our revised transmission renewal capital expenditure forecast addresses the issues raised by the regulator and its consultant, Arup. As already explained, we have re-analysed our renewal expenditure forecast using robust risk quantification techniques in accordance with practice guidance provided by the regulator. Our revised renewal capital expenditure forecast is $186.4 million for the forthcoming regulatory period. This is $18.1 million (8.9 per cent) lower than our original forecast.
Operational Support Systems	We have carefully reviewed our operational support systems capital expenditure, as the regulator's draft decision highlighted weaknesses in our asset management systems. As a result, we propose additional investment to lift our asset management capability to a level commensurate with our industry peers and good industry practice. We plan to increase our operational support system capital expenditure by a total of $15.2 million to cover increased investment in our asset management information system (AMIS). The increase in AMIS capital expenditure will see the application of condition-based risk management systems and practices extended to an additional 30 asset classes. Quantification of risk across these classes will greatly assist in ensuring that our capital expenditure is prudent and efficient, to the benefit of our customers. The transmission share of this additional expenditure is $4.1 million.

Expenditure category	Our revised proposal
IT and communications	Our forecast transmission capital expenditure for this category was accepted by the regulator's draft decision, so our revised forecast is unchanged.
Non-network Other	Our forecast non-network other capital expenditure was accepted by the regulator, so our revised forecast is unchanged.
Total	Our revised total transmission capital expenditure for the forthcoming regulatory period is $260.4 million, which is similar to our original forecast.

Our revised forecast transmission capital expenditure 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 revised forecast expenditure complies with the Rules requirements and should be accepted by the regulator.

5.2 Distribution capital expenditure

As explained in our original Regulatory Proposal, our key focus for the distribution network is to maintain and renew the 'poles and wires' that deliver energy to our 285,000 business and residential distribution customers, including increasing numbers of customers who have their own generation sources. As such, our distribution plans are targeted to deliver the following outcomes:

- increased investment to manage safety risks, including:
  - increase in pole renewal, including staked poles;
  - targeted bushfire mitigation programs;
  - service connection inspection and renewal due to safety issues associated with asset failure; and
  - improved network resilience in response to changing environmental factors.
- increases in the number of new distribution customer connections consistent with recent trends, with new connection standards to support network security and two way flows;
- an increase in technology-related expenditure to support two way flows in the distribution network;
- increased expenditure to manage network voltage levels as a result of the growth in embedded generation; and
- increased expenditure to support improved customer relationship management, SMS notifications, planned outage information, website portals, and network pricing reform.

The composition of our actual distribution capital expenditure to 2018-19 and our revised forecasts for the 2019-24 regulatory period is shown in the figure and table below.

Figure 6: Historic and forecast distribution net capital expenditure by category (June 2019 $m)

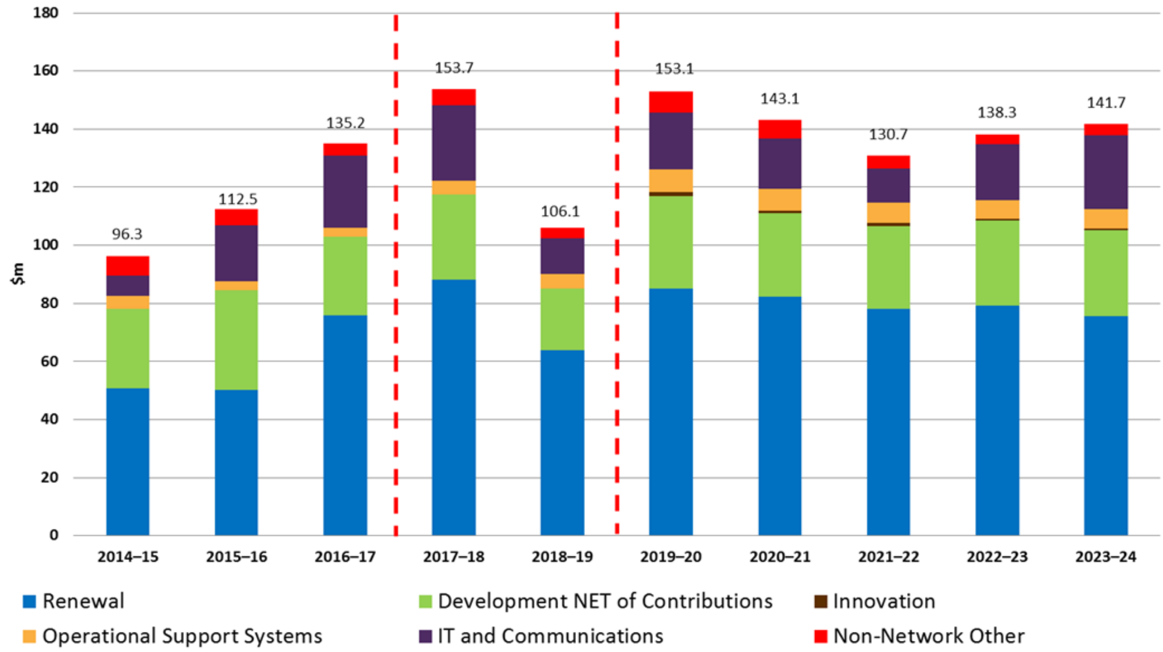


Table 6: Actual and forecast gross and net distribution capital expenditure for the current and forthcoming regulatory period (June 2019 $m)

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	38.9	40.4	40.8	45.0	38.7	39.2	32.9	41.2	39.2	38.9	40.1	40.4
Connection	29.8	27.5	31.3	31.6	32.4	32.3	26.4	28.9	32.2	32.4	33.6	34.2
Augmentation	9.1	12.9	9.4	13.3	6.4	6.9	6.5	12.3	7.1	6.5	6.4	6.2
Renewal	57.0	63.2	50.9	50.2	75.8	88.1	63.7	85.2	82.2	78.1	79.2	75.6
Operational Support Systems	2.8	4.2	4.4	3.2	3.1	4.7	4.9	7.8	7.3	7.0	6.4	6.8
Network Control	1.2	2.5	3.8	2.0	0.8	1.0	2.0	0.8	0.9	0.8	0.5	2.4
Asset Management Systems	1.6	1.7	0.7	1.3	2.3	3.7	2.9	7.0	6.5	6.2	5.8	4.4
Innovation			0.0	0.0	0.0	0.0	0.0	1.3	0.9	1.1	0.7	0.7
IT and Comms	18.0	23.8	7.0	19.3	24.7	26.0	12.2	19.6	17.4	11.7	19.2	25.2
Non-Network Other	6.4	7.3	6.7	5.5	4.3	5.4	3.8	7.4	6.3	4.4	3.6	3.9
Total gross distribution capex	**123.2**	**138.9**	**109.8**	**123.3**	**146.7**	**163.4**	**117.6**	**162.5**	**153.4**	**141.2**	**149.0**	**152.6**
Customer capital contributions	8.6	11.1	13.5	10.8	11.5	9.7	11.6	9.4	10.4	10.4	10.8	11.0
Total net distribution capex	**114.6**	**127.8**	**96.3**	**112.5**	**135.2**	**153.7**	**106.1**	**153.1**	**143.1**	**130.7**	**138.3**	**141.7**

In preparing our revised distribution capital expenditure forecasts, we have addressed the issues raised in the draft decision, and revisited our investment evaluations to ensure proper risk quantification in accordance with the regulator's preferred approach.

The key elements of our revised distribution capital expenditure proposal are summarised in the table below.

Table 7: Summary of our revised distribution capital expenditure proposal

Expenditure category	Our revised proposal
Development	Our original development capital expenditure forecast was accepted by the regulator. In our Revised Regulatory Proposal, our forecast distribution development capital expenditure is unchanged from our original Regulatory Proposal, with the following exceptions: • We have included an allowance of $1.3 million for the cost of an additional project to provide supply to Crotty Dam. The need for this additional project has been identified following the submission of our original Regulatory Proposal. • Our customer initiated capital expenditure forecast has been updated, as the original forecast inadvertently did not include overheads. • As indicated in the regulator's draft decision, we have amended our forecast capital contributions upwards in light of our latest information from 2017-18. The net effect of these changes is to increase our revised distribution development capital expenditure forecast by $44.4 million or 22.2 percent compared to our original forecast.
Renewal	We have comprehensively reviewed our distribution renewal capital expenditure forecast, and completed further detailed quantitative risk assessments, to ensure that our revised expenditure forecast is fully justified. Our revised distribution renewal capital expenditure forecast is $400.3 million. This is $62.7 million (13.5 per cent) lower than our original forecast.
Operational Support Systems	As explained above in relation to transmission, we have reviewed and increased our operational support systems expenditure forecast by a total of $15.2 million across transmission and distribution to cover increased investment in our asset management information system. The distribution share of this additional expenditure is $11.1 million.
IT and communications	The draft decision raised a number of concerns with our proposed meter data management system (MDMS) expenditure. Following further detailed engagement with vendors, we have reduced our forecast MDMS expenditure over the forthcoming period by $13.1 million. This saving is offset somewhat by a change in our forecast expenditure for cyber security, which has increased by $5 million from the $3 million originally proposed. Our revised distribution IT and communications capital expenditure forecast is $93.1 million. This is $10.7 million (or 10.3 per cent) lower than our original forecast of $103.8 million.
Non-Network Other	Our forecast of non-network other capital expenditure was accepted by the regulator, so our revised forecasts for this category are unchanged.

Expenditure category	Our revised proposal
Innovation	As already explained, in response to feedback from our customers we have included a new separate category for distribution innovation capital expenditure in our revised Regulatory Proposal. Four projects totalling $4.96 million over the forthcoming regulatory period are now included.
Total	Our revised total distribution capital expenditure forecast is $706.8 million, which is $32 million or 4.3 per cent lower than our original forecast (excluding forecast disposals).

Our revised distribution capital expenditure forecasts represent 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 revised forecast expenditure complies with the Rules requirements and should therefore be accepted by the regulator.

6. Our operating expenditure proposals

Our original Regulatory Proposal explained that we adopted the regulator's 'base-step-trend' forecasting method in preparing our transmission and distribution operating expenditure forecasts. This methodology uses our actual operating expenditure in a base year, being 2017–18 in this instance, as a starting point for estimating our future requirements. It is a simple method, which is effective in setting an efficient operating expenditure allowance.

In its draft decision, the regulator accepted our forecast operating expenditure, subject to a number of relatively minor differences in relation to labour escalation rates and an adjustment to account for growth. In response to the draft decision, we have updated our forecasts in accordance with the regulator's draft decision and the latest available information.

A significant update in our revised Regulatory Proposal relates to our transmission and distribution operating expenditure for the base year, 2017-18. In accordance with standard regulatory practice, our earlier estimates have been updated to reflect our actual audited expenditure. In total, our operating expenditure across the two business activities is closely aligned with our estimated total in our original Regulatory Proposal. Within this total operating expenditure, however, lower actual operating expenditure for transmission has been offset by an increase for distribution.

Our revised operating expenditure allowances for our transmission and distribution services continue to benchmark well against our peers. We have adopted challenging productivity targets and we have partially absorbed the cost of 'step changes', being additional activities that are required in the forthcoming regulatory period, and absorbing the cost impact of projected growth.

We are confident that our revised operating expenditure forecasts satisfy the Rules requirements and therefore should be approved by the regulator in its final decision. As with our original Regulatory Proposal, our revised operating expenditure forecasts deliver a very good outcome for our customers. Our updated transmission and distribution operating expenditure forecasts are presented below.

6.1 Transmission operating expenditure

The figure and table below show our updated transmission operating expenditure forecast alongside our actual and expected operating expenditure from 2012-13 to 2018-19.

Figure 7: Historic and forecast transmission operating expenditure by category (June 2019 $m)

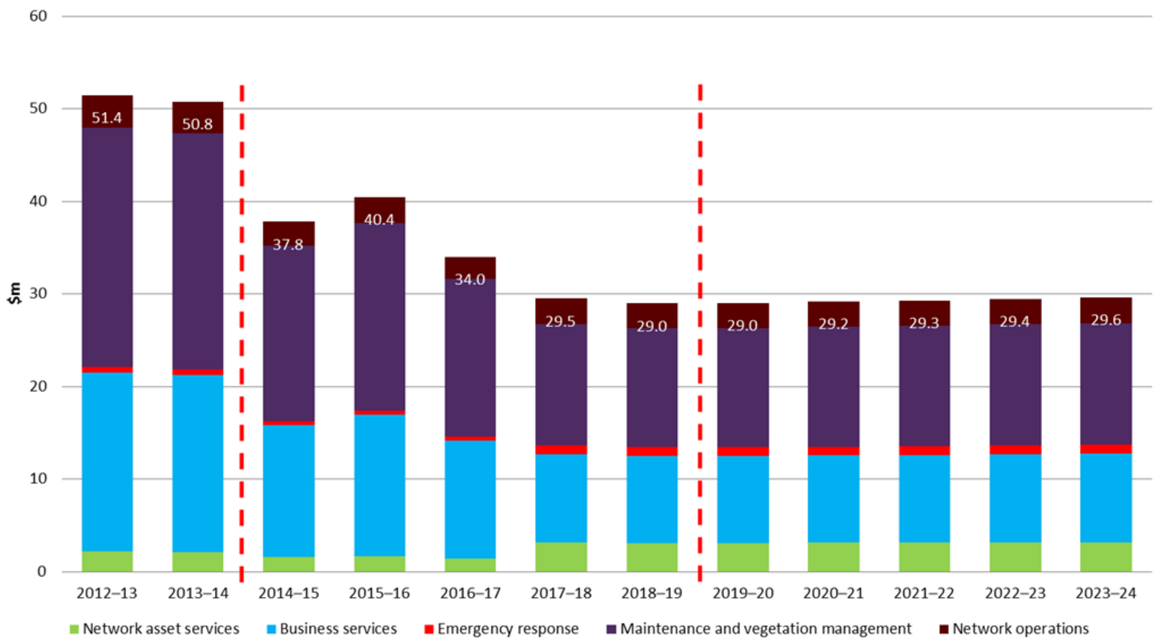


Table 8: Actual and forecast transmission operating expenditure by category (June 2019 $m)

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	0.6	0.6	0.4	0.5	0.4	0.9	0.9	0.9	0.9	0.9	0.9	1.0
Maintenance and Vegetation Management	25.8	25.5	19.0	20.3	17.1	13.1	12.8	12.9	12.9	13.0	13.1	13.1
Business Services	19.4	19.1	14.2	15.2	12.8	9.6	9.4	9.4	9.4	9.5	9.5	9.6
'Other' Operating Expenditure	5.7	5.6	4.2	4.5	3.7	5.9	5.8	5.8	5.8	5.9	5.9	5.9
Total transmission operating expenditure	**51.4**	**50.8**	**37.8**	**40.4**	**34.0**	**29.5**	**29.0**	**29.0**	**29.2**	**29.3**	**29.4**	**29.6**

As indicated in our original Regulatory Proposal, we have delivered substantial reductions in transmission operating expenditure in recent years. We believe that our forecast operating expenditure is at its lowest sustainable level, consistent with delivering affordable, safe and reliable transmission services to our customers.

6.2 Distribution operating expenditure

The figure and table below show our updated distribution operating expenditure forecasts alongside our actual and expected operating expenditure from 2012-13 to 2018-19. It shows that our proposed operating expenditure includes significant cost efficiencies over the forthcoming regulatory period.

Figure 8: Distribution Operating expenditure Actual/ Forecast– by expenditure category (June 2019 $m)

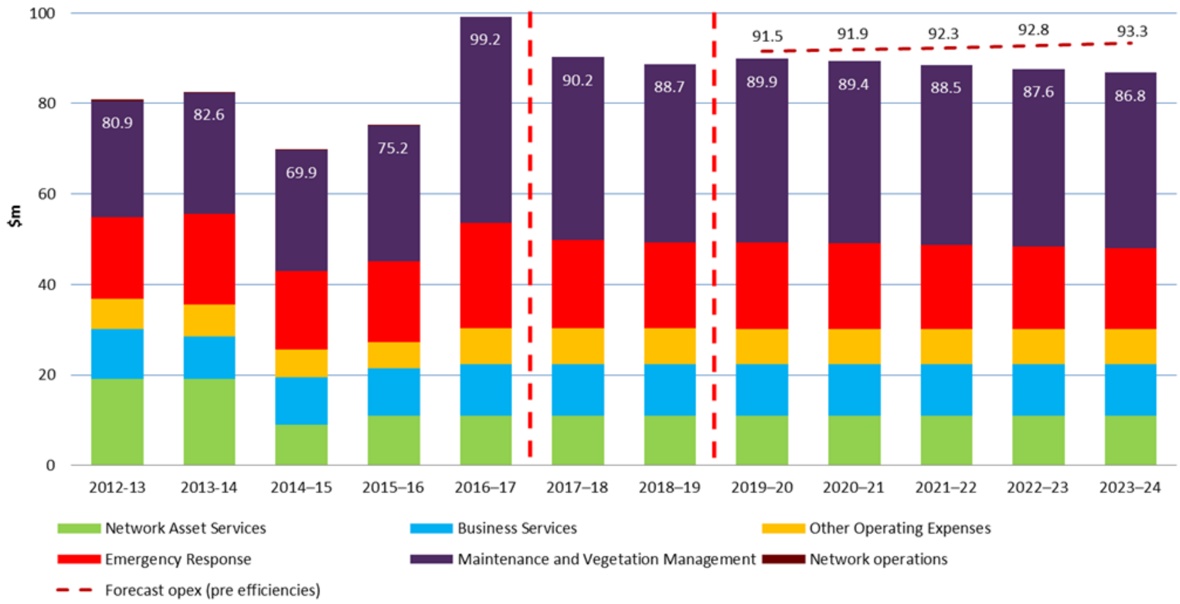


Table 9: Actual and forecast distribution operating expenditure by category (June 2019 $m)

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	19.5	19.0	19.2	19.0	18.6	18.2	17.8
Maintenance and Vegetation Management	25.5	26.7	26.7	30.0	45.6	40.4	39.4	40.5	40.3	39.8	39.3	38.8
Distribution Asset Services	19.1	19.1	9.1	11.0	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Business Services	11.1	9.4	10.3	10.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
'Other' Operating Expenditure	7.0	7.4	6.4	5.7	7.9	7.9	7.9	7.8	7.8	7.8	7.8	7.8
Total distribution operating expenditure	**80.9**	**82.6**	**69.9**	**75.2**	**99.2**	**90.2**	**88.7**	**89.9**	**89.4**	**88.5**	**87.6**	**86.8**

As we explained in our original Regulatory Proposal, we recognise that our recent distribution operating expenditure has increased from the very low levels obtained in 2014-15.

Our increased expenditure was 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, at the expense of the return to our shareholders rather than our customers.

We remain committed to bringing our distribution operating expenditure to lower levels following the necessary increases in recent years. We also recognise that it will take time to deliver these reductions, which will be sustainably achievable only if supported by improved processes, practices and business platforms to offset the range of new obligations and increased complexity in operating the distribution system. We are striving to deliver the required efficiency improvements over the remaining years of the current regulatory period and the forthcoming period.

As shown in the data presented above, we are projecting real reductions in distribution operating expenditure over the forthcoming period, even though we are connecting new customers and facing additional obligations or 'step changes' that will tend to push our costs higher. On this basis, and having addressed the issues raised in the draft decision, we consider that our updated distribution operating expenditure forecasts comply with the Rules requirements and should be accepted by the regulator.

7. Incentive mechanisms

We explained in our original Regulatory Proposal that the regulator applies a number of incentive mechanisms which affect our revenue allowance, and therefore the prices that our customers pay. The incentive schemes apply to both our transmission and distribution activities, although the design of some schemes differ slightly to reflect the particular characteristics of the services we provide.

The purpose of these incentive mechanisms is to make sure we focus on keeping costs as low as we sustainably can, while also striving to deliver better service. The incentive payments or penalties are summarised below:

- Capital and operating expenditure efficiency payments or penalties, based on our performance in the previous period.
- Annual allowances for demand management initiatives for our distribution services and for network capability improvements for our transmission services.
- Service incentives, so that we face financial rewards or penalties depending on whether our performance is better or worse than target. The maximum reward or penalty is five per cent of our allowable revenue for distribution and 1.25 per cent for transmission[8].

In addition to the above incentive schemes, we must also compensate individual distribution customers if they experience too many outages during the year, or outages that exceed a specified duration. This arrangement is called the Guaranteed Service Level or GSL Scheme, which is administered by the Tasmanian Economic Regulator.

Our transmission and distribution service performance has improved in recent years, which has delivered significant value for our customers.

In our original Regulatory Proposal, we asked the regulator to make the following adjustments to the future operation of the incentive schemes to:

- Make a technical change to our service targets for transmission, so that we continue to face strong incentives to maintain and improve performance.
- Allow us to report both transmission and distribution performance on a financial year basis, so that there is a clearer link between our transmission and distribution service performance and customer pricing outcomes.

The regulator's draft decision has not accepted our proposal to make these changes. While we are disappointed by the regulator's draft decision, we have decided to accept it.

The regulator's draft decision also rejected two projects we proposed to undertake to deliver improved network capacity. The regulator concluded that these projects will improve reliability and, therefore, did not meet the requirements of the incentive scheme. We accept the regulator's findings.

[8] The transmission service incentive applies only to network capability.

In our revised Regulatory Proposal, we have identified an alternative project that falls within the scheme's remit and should, therefore, be accepted by the regulator. Apart from this adjustment, we accept the regulator's draft decision on the application of the incentive schemes.

It should also be noted that, as a result of our increased distribution operating expenditure in 2017-18, we face an increased efficiency penalty compared to the amount calculated in the regulator's draft decision. This increased efficiency penalty has been factored into our updated revenue allowances in our revised Regulatory Proposal, which are presented in the next chapter.

8. Indicative annual revenues and prices

This section provides our updated forecast total revenue requirement for transmission and distribution alongside the regulated revenue allowance since 2012-13. It also provides an indication of outcomes in terms of total annual network charges for a sample of typical customers.

Our revised transmission revenue profile as shown in the figure and table below means that transmission prices on average (in real terms) will drop at the end of the current regulatory period and then remain relatively constant over the 2019-24 period in nominal terms, continuing to fall in real terms. Transmission revenue has decreased considerably over the last seven years and is projected to remain flat, a major achievement in a challenging environment.

Figure 9: Revenue allowance for prescribed transmission services (June 2019 $m)

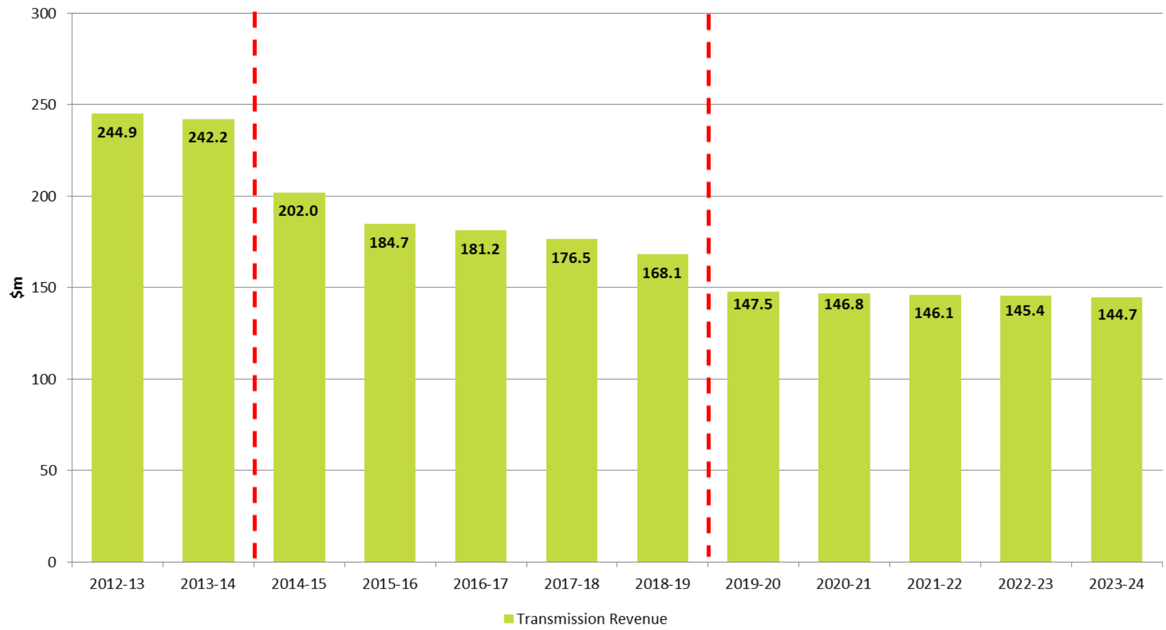
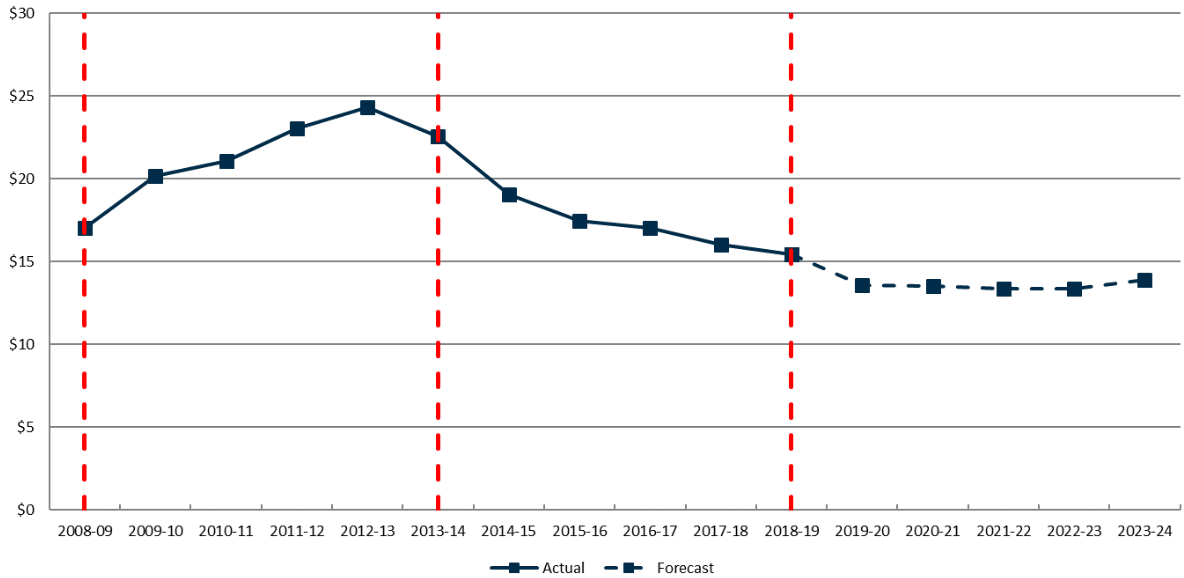


Table 10: Transmission Smoothed Revenue Requirement (June 2019 $m)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Revenue Requirement (smoothed)	168.1	147.5	146.8	146.1	145.4	144.7

Our revised proposed transmission revenue profile translates to an average price of $13.55 per MWh, which is 20 per cent lower in real terms than the average price over the previous five year period as shown in the figure below.

Figure 10: Indicative average transmission charges ($/MWh) (June 2019 $)



Our actual and revised proposed distribution revenue allowance for each year is shown in the figure and table below. Our distribution revenue is forecast in real terms to remain substantially lower than historical levels, as shown in the figure below.

Figure 11: Revenue allowance for standard control distribution services (June 2019 $m)

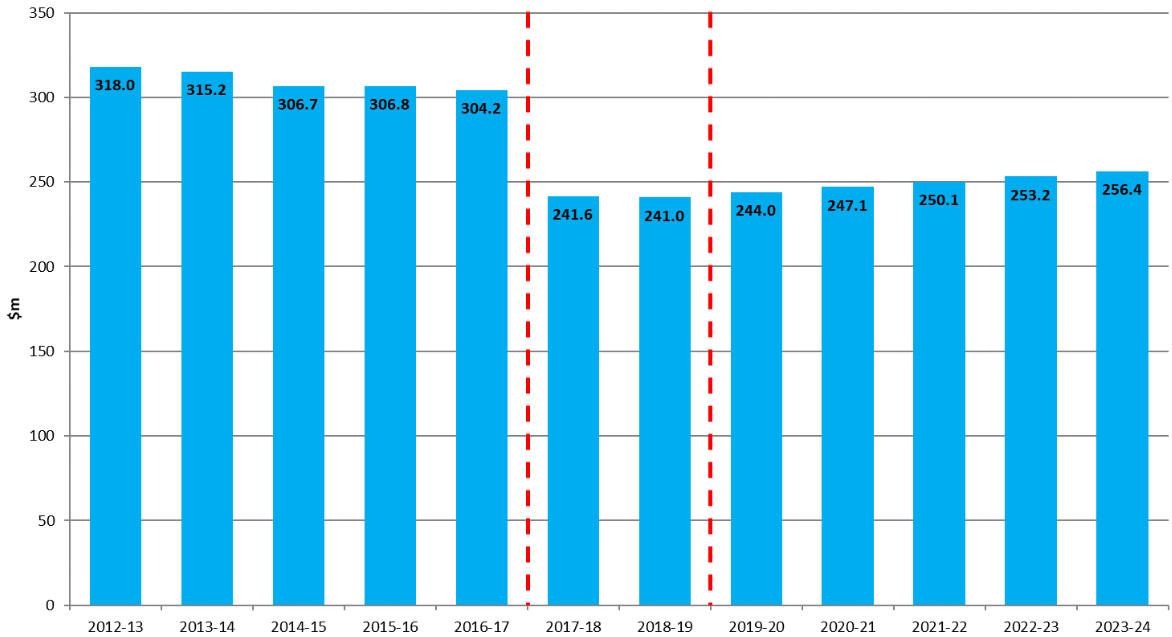
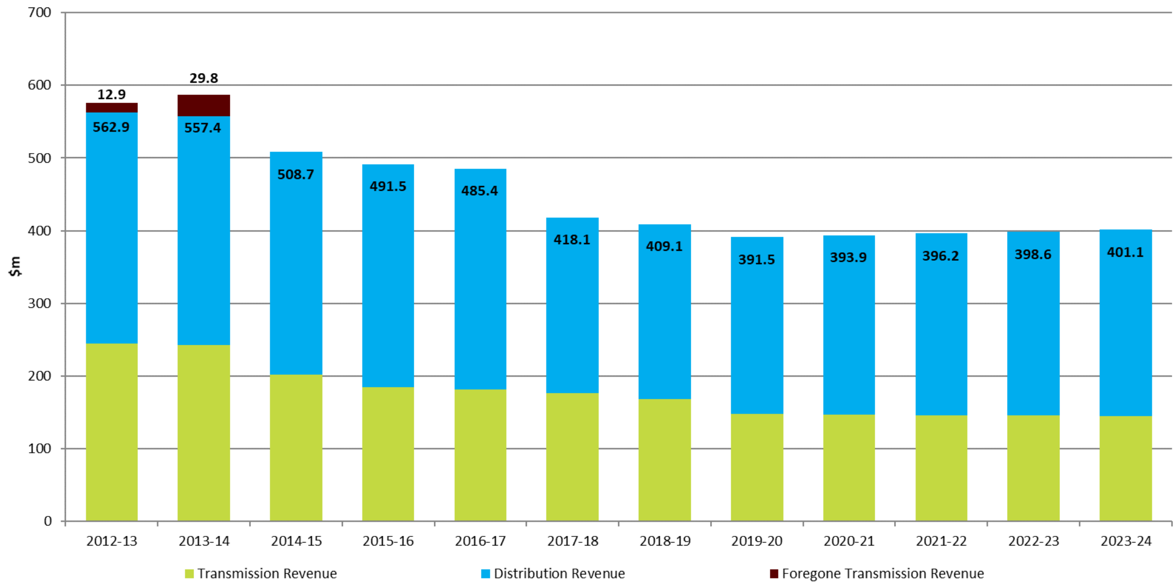


Table 11: Distribution Smoothed Revenue Requirement (June 2019 $m)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Revenue Requirement (smoothed)	241.0	244.0	247.1	250.1	253.2	256.4

The figure below shows our revised total smoothed revenue over the forthcoming regulatory period compared with historic levels. Our proposed combined transmission and distribution revenue is significantly lower than pre-merger levels.

Figure 12: Total Network Smoothed Revenue Requirement (June 2019 $m)



Our revised proposed distribution revenue allowance for each year together with the relevant share of the transmission network charges (around 55 per cent) as shown in the table below 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. The table below outlines our updated forecast revenue to be recovered from distribution customers.

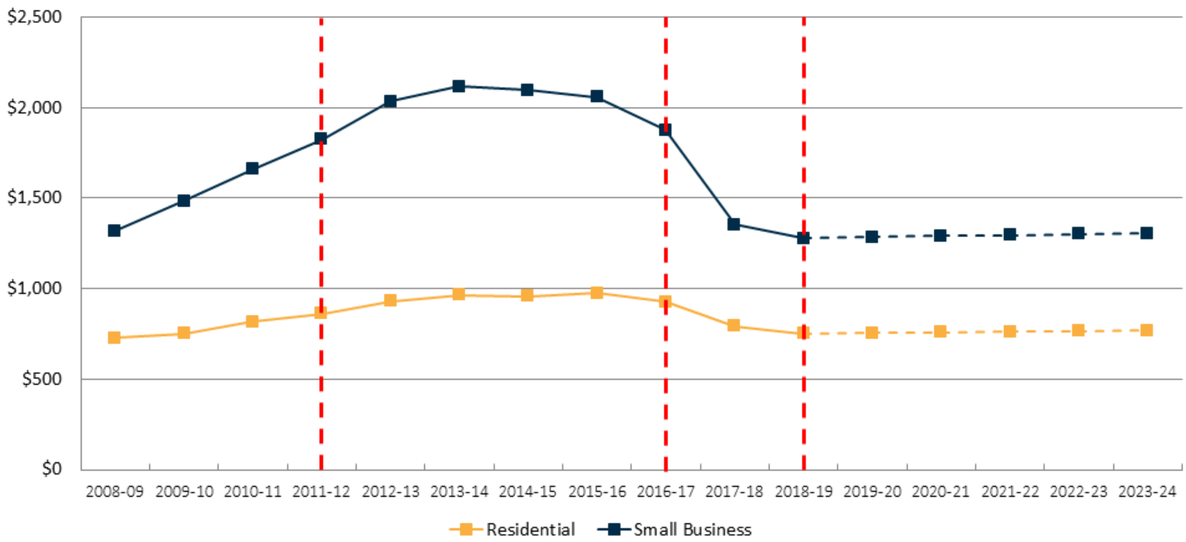
Table 12: Revenue to be recovered from distribution customers (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Transmission Revenue	79.5	78.6	78.1	77.7	77.3	76.8
Distribution Revenue	241.0	244.0	247.1	250.1	253.2	256.4
Total Revenue	**320.5**	**322.6**	**325.2**	**327.8**	**330.5**	**333.2**

TasNetworks charges each customer's retailer, based on the applicable network tariff. It is up to the retailer as to whether, and how, network tariffs are passed on to customers in the final retail bill. For many small customers, the Tasmanian Economic Regulator makes pricing decisions that affect how network charges are reflected in 'standing offer' customer bills.

Our revised 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 revised proposal results in most customers' network charges increasing only slightly above CPI and remaining well below pre-merger levels. The forecast network charge includes forecast transmission charges and distribution charges, and assumes no over- or under-recoveries or incentive adjustments.

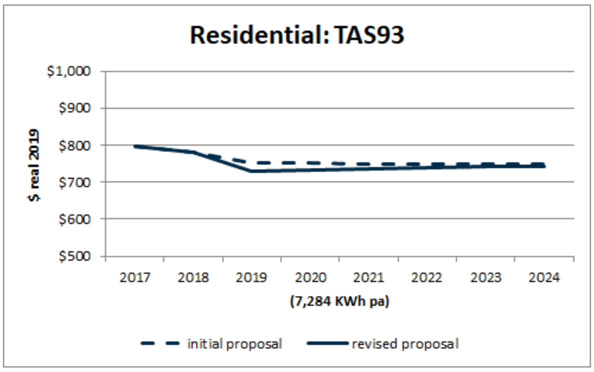
Figure 13: Indicative average annual network charge (June 2019 $m)



The figures below provide an indication of the outcomes under our proposals in terms of total annual network charges for typical customers on the following tariffs:

- Residential low voltage general (TAS31)
- Uncontrolled low voltage heating (TAS41)
- Business low voltage general (TAS22).

Figure 14: Indicative annual network charges for a sample of residential customers



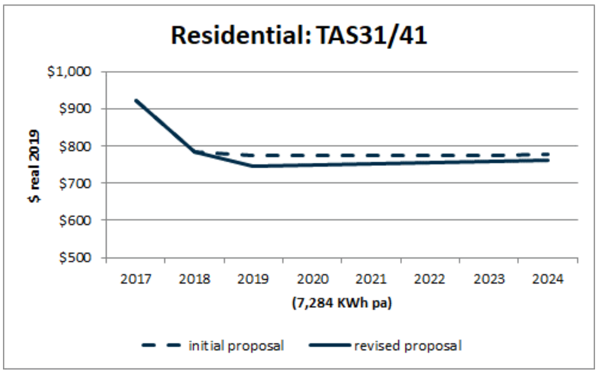
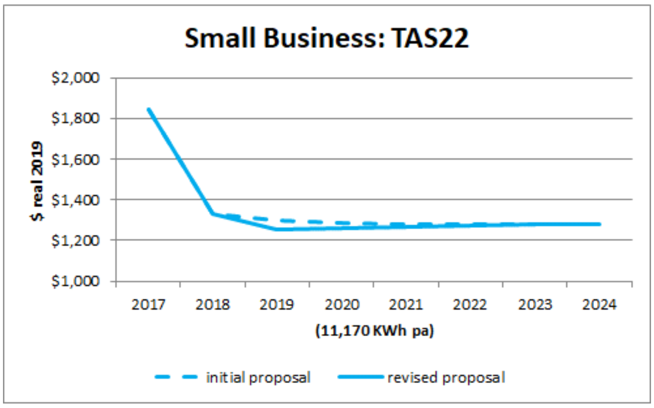


Figure 15: Indicative annual network charges for a typical small business customer



As shown in the above figures, our proposed charges compare very favourably with recent historical charges. For example, at the start of the next regulatory period, our proposed network charges for a typical residential customer will be 22 per cent lower in real terms compared to our charges in 2013 - 14. The reduction for a typical small business customer (TAS22) over the same period will be even greater at 39.6 per cent in real terms.

9. Sending better price signals

9.1 Our transmission pricing plan

Due to the confidential nature of individually calculated transmission prices, we engage directly with our transmission customers on transmission pricing issues.

As explained in our original Regulatory Proposal, we did not propose any changes to our current transmission pricing methodology, which has been accepted in the regulator’s draft decision. In our revised Regulatory Proposal, we have therefore maintained our current approach in accordance with our original Regulatory Proposal.

9.2 Our distribution pricing plan

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 regulator approved our first distribution Tariff Structure Statement for the 2017-19 period. This was an ‘establishment’ phase of our distribution customer pricing reforms that set a pathway for the future by:

- introducing the concept of reform to our stakeholders;
- introducing demand based tariffs for small customers and providing our customers with future investment and price signals; and
- progressing the slow (multi-period) process of unwinding inefficient legacy price levels and cross-subsidies.

9.3 Next phase distribution pricing reform

For the next phase of pricing reform, we are building on the ground work undertaken to date, considering other networks’ experiences, the regulator’s draft decision and further analysis we’ve undertaken.

For the 2019-24 period, we will continue pricing reform through the following measures:

- ongoing gradual tariff rebalancing to unwind legacy cross-subsidies between different customer types;
- introducing two new demand based network tariffs as an option for customers with distributed energy resources (**DER**) to provide new opportunities to control their electricity costs;
- offering ‘introductory’ discounts for our new demand based time of use tariffs for both residential and small business customers, to encourage customer take up of the new tariffs; and
- obtaining customer data through our emPOWERing You and Bruny Island Battery trials to inform our tariff design and pricing strategies.

As noted in our original Regulatory Proposal, we are not proposing to change the design of our existing tariffs for customers supplied at high voltages. These tariffs already feature combinations of cost reflective elements such as time of use and demand based charges.

An important change from our original Regulatory Proposal is that we are now proposing an ‘opt out’ rather than ‘opt-in’ arrangement in relation to our new small business and residential time of use network tariffs. This change - required by the AER - means that these new, cost reflective tariffs will apply to more customers, thereby delivering the associated benefits more quickly. We are introducing this change in response to the regulator’s draft decision, which did not support our proposed ‘opt out’ approach.

Given the change to an ‘opt out’ arrangement, we propose to increase our engagement with customers on network pricing, so that customers gain a good understanding of the new tariffs and the actions they can take to reduce their electricity costs. As explained in our original Regulatory Proposal, we believe that more cost reflective pricing will provide fairer and better outcomes for all our customers.

Further information on tariff reform is available on our website:

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

10. Benefits and risks to customers

The Rules require us to explain the benefits and risks to customers arising from our revised Regulatory Proposal and tariff proposals. We have updated the identified benefits and risks from those set out in our original Regulatory Proposal.

10.1 Benefits

The following points summarise the principal benefits to customers from our revised Regulatory Proposal:

- Affordability – We have reduced our expenditure and returns in response to the regulator's draft decision and our customers' and stakeholders' feedback, where these reductions can be achieved without compromising safety and reliability. Our updated forecast costs and revenue requirements reflect the lowest sustainable prices for our customers.
- Safety – Our capital and operating 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 working hard to deliver cost efficiencies without compromising safety or reliability. Our continuing investment in new systems and processes, will help drive these savings.
- Innovation – Our customers want us to embrace new technology where it is cost effective to do so. We have identified specific capital expenditure measures that are focused on innovation, without compromising our focus on affordability.
- Equity – Our new network tariffs are continuing to improve fairness and will deliver savings to customers that use the network more efficiently.
- Sustainability – We are working hard to ensure we only build, maintain and operate the network that our customers are prepared to use and pay for.

10.2 Risks

We have identified the following risks that customers should consider in reviewing our revised Regulatory Proposal:

- Pace of customer and technology-driven change – there is a risk of fundamental disruption in our sector, beyond the pace we anticipate. Our plans therefore reflect our present assessment of the services that will be required of our network over the years to 2024, and an efficient way to deliver these services.
- New obligations – given the unprecedented changes in the electricity sector, it is possible that new obligations will be imposed on us in the forthcoming regulatory period. If these obligations increase our costs materially, we may seek to increase our network charges accordingly. We will work hard to avoid any such increase, but it remains a possibility given the current level of uncertainty.
- Contingent projects – We have identified three large capital projects, including a second Bass Strait interconnector, that may be required if particular 'trigger events' occur. In light of the regulator's draft decision and further consultation, we have reduced the proposed number of

contingent projects and provided further information to explain why each project may be required. If one or more of these projects proceed, we are likely to seek additional funding, which would lead to higher network charges. However, a project will proceed only if it can be demonstrated that it is expected to provide an overall benefit to the electricity market and Tasmanian customers pay no more than their fair share of the project costs.

- Service performance risks – Our plans have been designed to maintain safety and reliability, connect new customers, and provide customer services, at a sustainable cost. There is always a risk that our revised forecast expenditure proves to be inadequate to maintain reliability across all our communities, or to meet our customers' service expectations. If our capital or operating expenditure is higher than forecast, for example to maintain safety, it may feed through to higher prices in future regulatory periods.
- Price impact from performance – We are subject to incentive schemes which adjust our annual network charges (up or down) depending on whether our service performance is better or worse than expected. The operation of the incentive schemes could therefore expose customers to unexpected price volatility – meaning that prices could be higher or lower than presented in our revised Regulatory Proposal.
- Price impact from lower consumption – As we are subject to a revenue cap, our network charges could increase if energy 'sales' are lower than expected. 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 – including customers in Victoria.
- Bushfire risks – Tasmanians know that we live in a state that is prone to bushfire. We have committed ongoing expenditure to manage this risk. We balance the cost of additional investment and safety measures against the benefit of reduced risk. It is important to get the balance right and we recognise the risk of bushfire cannot be eliminated entirely.
- Extreme weather events and climate change – The effects of extreme weather events including floods, storms and fires are increasing. These events have historically had a significant impact and cost on both TasNetworks and the Tasmanian community. We may need to respond to these types of events more in the future and this would have implications for network charges if these additional unforeseen costs are passed through to customers.

11. Alternative control services

The earlier chapters of this Overview Paper have focused on our revised expenditure proposals, revenue requirements and pricing for the network services that our customers use every day. In addition to these services, we also provide:

- metering services;
- public lighting services; and
- ancillary services.

Each are discussed in turn.

11.1 Metering services

All of our customers pay for metering services, which are subject to a separate revenue and pricing calculation to ensure that our charges are fair and reasonable.

The regulator's draft decision rejected our proposal to accelerate the depreciation of our metering assets. If our proposal had been accepted, it would have led to higher metering charges in the short term, but lower charges in the future. The regulator commented that we had not shown that our customers support our proposal.

Given our customers' concerns regarding affordability, we have decided to withdraw our proposal to accelerate the depreciation of our metering assets and accept the regulator's draft decision. However, we may revisit this matter in the future, once we have gained customer support for the proposal. We note that, in the absence of accelerated depreciation of these assets, there is the possibility that customers will pay for assets that no longer exist.

We have updated our proposed metering charges to reflect our acceptance of the regulator's draft decision on accelerated depreciation.

11.2 Public lighting services

Public lighting services are provided to councils across Tasmania. The emergence of new lighting technologies and alternative service providers are giving our customers increased choice. Our original Regulatory Proposal explained the basis for our public lighting charges.

In its draft decision, the regulator did not accept our proposed public lighting charges. The regulator commented that it accepted our labour rates and luminaire input costs, but did not accept our proposed overheads. Instead, the regulator concluded that our overheads should be capped at 25 per cent of direct costs.

We accept the regulator's proposed labour rates and luminaire input costs. However, we do not accept the regulator's benchmarking approach in setting an allowance for our overhead costs. In our revised Regulatory Proposal, we have provided further information to support our overhead costs and the resulting public lighting charges.

We have retained the ten year transition to cost reflectivity for our public lighting services to assist our customers. Furthermore, reductions in our costs mean that the ten year price path is now shallower with a lower final price point than our original proposal, which provides an additional customer benefit.

11.3 Ancillary services

Ancillary services are typically one-off services requested by a customer and charged directly to that customer. For example, a connection to the distribution network or a special meter read are ancillary services. Only the distributor can undertake the work associated with provision of ancillary services and for this reason the services are regulated.

Ancillary services are sub-divided into fee-based and quoted services.

- Fee based services apply to those services that are standardised, such as special meter reading, which means that they do not vary by customer. As such fee based services can be priced according to a tariff, which is updated annually for the duration of the regulatory period.
- Quoted services vary significantly depending on the scope of the customer's specific requirements. Accordingly, quoted services are priced based on the labour, materials and other direct costs required to meet the customer's service request.

In our original Regulatory Proposal, we submitted tariffs for each of our fee based services and our proposed labour rates and profit margin for quoted services. The regulator's draft decision queried our labour rates for administration services and the application of a margin and applied benchmarks for our overhead rates.

In our revised Regulatory Proposal, we have addressed the issues raised by the regulator and recalculated our proposed charges for ancillary services. We have also accepted the regulator's decision on our proposed margin, which essentially removes it as a separate charge but allows it to be recovered in the overhead allowance. We have also challenged the benchmarks to overheads rates that had been proposed for quoted services.

Further detailed information on our updated charges for ancillary services is provided in our revised Regulatory Proposal.

12. Next steps – Have your say

The regulator has published its draft decision in relation to our original Regulatory Proposal and invited submissions from customers and stakeholders. Our revised Regulatory Proposal will also be published on the regulator's website www.aer.gov.au. In addition to responding to the regulator, you can provide feedback to us, and we encourage you to raise any matter that is of interest or concern to you.

You can:

- Email your submission to: revenue.reset@tasnetworks.com.au
- Go on line at http://www.tasnetworks.com.au/customer-engagement
- Post your submission to:
  Program Leader Revenue Resets
  Po Box 606
  Moonah Tasmania 7009