Combined Proposal 2024-2029

Attachment 1
Customer and stakeholder engagement summary

Outline: This attachment summarises the engagement program and subsequent results that have helped shape the development of TasNetworks' Combined Proposal for the regulatory control period commencing on 1 July 2024 and ending on 30 June 2029.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	**Customer and stakeholder engagement summary**
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

1 Customer and stakeholder engagement summary

1 OVERVIEW

The engagement program and subsequent results outlined in this summary have helped inform the development of our Combined Proposal to the Australian Energy Regulator (**AER**) for the 2024-2029 regulatory control period. Our Combined Proposal details the funding we need to plan, build, maintain and operate our transmission and distribution networks to provide Tasmanians with safe, reliable and affordable electricity during the five year period.

1.1 Approach to engagement

As an organisation, we understand that placing our customers and stakeholders at the centre of our business planning – conducting genuine engagement with them on our plans and allowing them to shape them where possible – is key to ensuring those plans are in their long-term best interests.

This thinking builds on our previous reset engagement efforts, but is also being driven by the rapid transition occurring in Australia's energy industry and the National Electricity Market (**NEM**), which includes a conscious move towards more sustainable energy sources by customers, generators, retailers and network service providers (**NSPs**).

We developed an engagement program for the Combined Proposal that has sought to identify and understand what is important to our customers and stakeholders, and to build their knowledge and understanding of the energy sector and our business so they can participate in the program. We have used their subsequent insights to help shape a Proposal that is reflective of the feedback we have received. Read more about how we have sought to integrate their preferences in Section 1.3.

Capable of acceptance by the AER

In addition to developing a Combined Proposal that is reflective of the preferences of our customers and stakeholders, we have also endeavoured to create a proposal that is capable of acceptance by the AER, in-line with their key 2020-2025 Strategic Plan objective.

This work has been guided by the AER's Better Resets Handbook (**Handbook**). Published in December 2021, the Handbook sets out how the AER would like NSPs to complete their revenue proposals, placing greater emphasis on high quality engagement, as well as offering more clarity on what should be in a proposal to enable acceptance.

Although TasNetworks has not sought the early signal pathway outlined in the Handbook when developing our Proposal for the next regulatory control period, we have endeavoured to meet the guidelines and expectations outlined by the AER, recognising the broader benefits to our customers that may come as a result, including:

- Improved relationships and understanding between TasNetworks and our customers
- Greater faith from all parties in regulatory processes
- The generation of new ideas and regulatory approaches that benefit both customers and TasNetworks
- An increased probability that the regulatory proposal will be largely or wholly accepted at the draft decision stage, resulting in a more efficient reset process for all involved.

Specific details regarding how our Proposal seeks to meet the AER's expectations can be found in Appendix A.

1.2 Engagement summary

Spanning 18 months of concentrated effort between July 2021 and January 2023, the engagement program is the most comprehensive and diverse suite of engagement activities ever completed by TasNetworks. To date we have directly engaged with 567 individuals in 61 activities, covering 64 topics.

The program marks a distinct step-change in our engagement maturity as an organisation, built from the ground-up using direct input from our representative voices and key stakeholders during the early phases (see section 3.1 for details of the program's development). In addition to co-designing our engagement approach, we also released a Draft Plan for consultation, attracting submissions from multiple stakeholders.

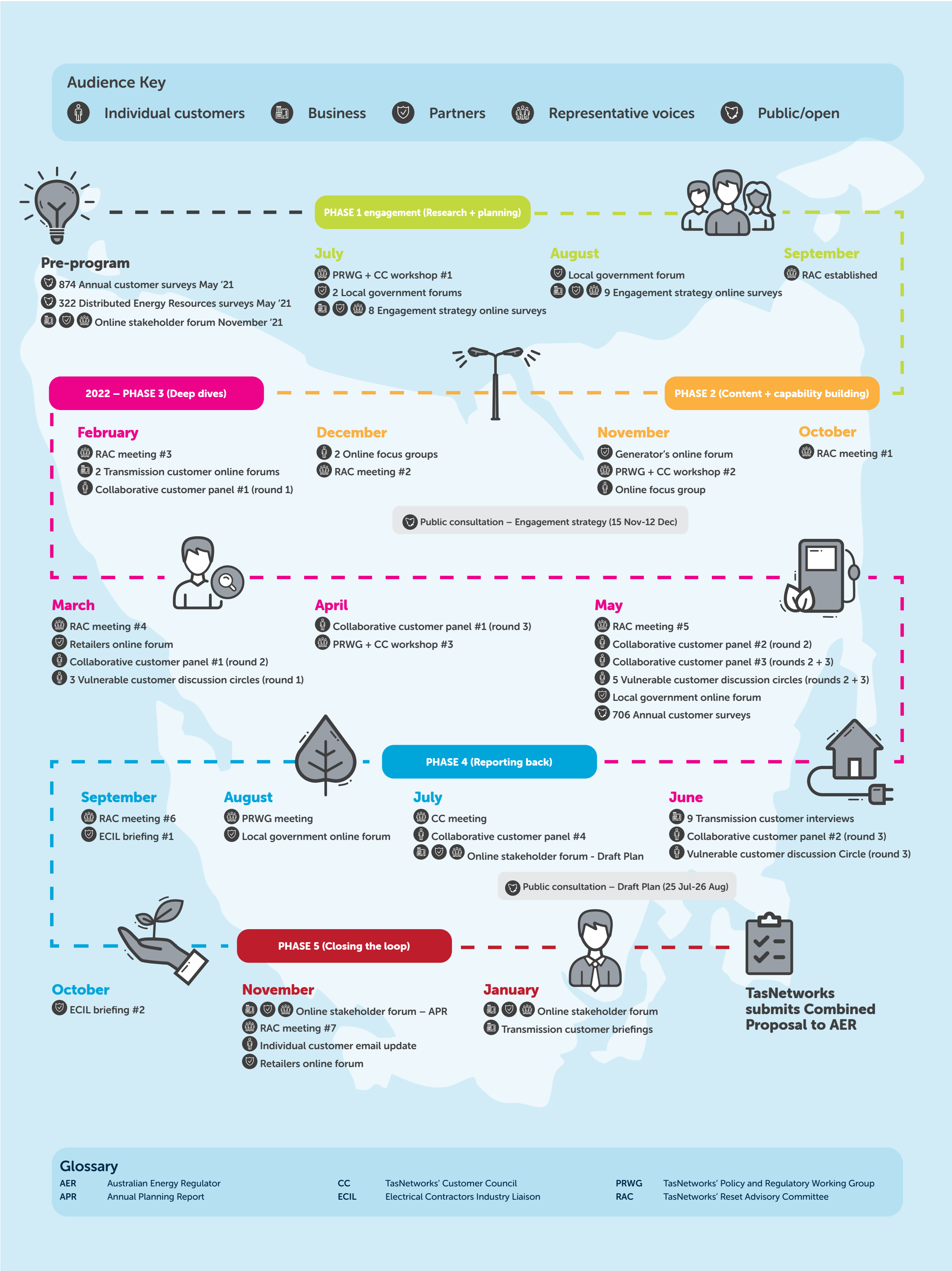
Each of these steps has helped create a more accessible, customer-focused program, evidenced by the fact that participant trust in TasNetworks has to act in the best interests of customers has risen from a benchmark of 66 per cent in the early stages of the engagement program to 89 per cent in latter stages.

Engagement activities have been structured and delivered in five distinct phases, resulting in the following -

Figure 1. Engagement by numbers

Figure 2 provides a visual glimpse of the engagement journey to date, inclusive of key audiences, activities, and the phases in which they occurred.

Figure 2. Engagement pathway



1.3 How engagement has shaped our proposal

During the delivery of our engagement program, four key themes clearly emerged as priorities for our customers and stakeholders. These themes remained largely consistent from Phase 1 research and planning in 2021, through to our last main feedback gathering period in Phase 3 deep dives, completed in July 2022. As shown in Figure 3, our customers and stakeholders were consistent in their advocacy for affordability, the need to cater for the renewable energy transition, network reliability, along with social responsibility and sustainability.

Figure 3. Key themes

Given the top concern for our customers was affordability, we have made trade-offs in our Combined Proposal that exert downward pressure on costs, without sacrificing reliability and safety or undermining the delivery of the other priorities of our customers and stakeholders.

Table 1 details changes made to our Combined Proposal as a result of customer and stakeholder feedback (see Appendix B for details of what topics we discussed with each of our key audiences, and where readers can find evidence of our response, either in our Proposal or other supporting documentation). Feedback that falls outside the four main themes but that helped shape our proposal is also outlined in Table 2 of this section.

Table 1. How engagement feedback has shaped our proposal

Key theme	What we've heard	How we've responded
Affordable for all	• Affordability is the most important factor for customers and stakeholders. • Bill shock is a real concern for many due to rising cost-of-living pressures, unemployment levels and low incomes. • TasNetworks could be more transparent about tariff and cost-saving options for individual customers. • Providing incentives for large industrial customers to save energy and lower power prices for all is also regarded as important.	• We are constraining our capital expenditure (**capex**), resulting in forecasts that are below the AER's approved allowances for the current regulatory control period. • We have selected 2020-21 as our base year for opex. This base year has been deemed as efficient for a network service provider (NSP) by the AER's economic benchmarking standards. • We are aiming to achieve opex productivity improvements of 3% in 2024-25, and 0.5% for each subsequent year. • We are developing initiatives that address cost of living pressures. • We are continuing to develop cost-reflective network tariffs to encourage less energy consumption during times of peak demand, placing long-term downward pressure on price for all customers while maintaining protections for vulnerable customers.
Reliable now, resilient for the future for the entire State	• Reliability of supply is considered very important to the wellbeing of Tasmanians, particularly beyond the greater Hobart area due to our climate and reliance on electric heating. Customers acknowledged there are barriers to achieving reliability in remote areas. • Customers expect TasNetworks to maintain current levels of reliability and improve poor performing areas without increasing prices. • Customers want the benefits offered by improved resilience but acknowledge the potential price increases to achieve these are challenging. • TasNetworks needs to demonstrate how investments will improve reliability and resilience in the longer term and optimise for investments that deliver both.	• We have rebalanced our reliability and resilience expenditure on our distribution network, resulting in an estimated cost reduction from \$121.8 million to \$115.3 million. This maximises value for our customers at the lowest sustainable cost, and mitigates, hardens and adapts our networks for the future. • We have rebalanced our forecasts to address reliability in ten poor-performing communities instead of the four previously proposed, increasing funds from \$7.37 million to \$10.8 million. • We are taking specific actions via our Network Resilience Strategy to build a more resilient network in a sustainable and affordable way for customers. Our climate change response can be found on our **website**.

Key theme	What we've heard	How we've responded
A transparent, socially responsible approach that ensures a sustainable solution for Tasmania	• Long-term, sustainable solutions are critical. Transparency and openness in our approach is key to ensuring our plans and investments are aligned with future customer expectations and needs. • Clearly communicating when, how and why investments are made will help customers have greater understanding and trust in our business decisions. • Environmental impacts, the interests of Tasmanian communities and the benefits to customers should always be taken into consideration regarding price rises. • The need to invest in Tasmanian communities, increase training opportunities, invest in future skills, and drive jobs growth were all important, particularly for young people. • TasNetworks should consider innovative alternatives to network augmentation, such as community batteries to improve reliability in remote areas.	• As a signatory to the Energy Charter since November 2021, we are embedding the Charter's frameworks and principles into our business to ensure customers are at the centre of our planning and decision-making. See how we are tracking in our **2021-22 Energy Charter Disclosure Report**. • In November 2022, TasNetworks committed to analysis of a Net Zero target, including a high level emissions reductions plan and assessment. • TasNetworks has adopted a Task Force on Climate-related Financial Disclosures (**TCFD**) recommendation to increase the transparency around our management of climate-related risk and opportunity. • Our priority areas for action against the United Nations Sustainable Development Goals are affordability, reliability, climate change and the transition to renewable energy. These were identified in 2021-22 as the most important issues to communities and our business, and we have attempted to balance our investments to reflect these preferences. • We are planning to conduct community battery pilots with stakeholders in the 2024-2029 regulatory control period as part of our Future Distribution System Vision and Roadmap project, with the aim of identifying non-network solutions to network challenges.

Key theme	What we've heard	How we've responded
Proactive, long-term investment in renewable energy that increases Tasmania's capability and unlocks associated community benefits	• It is critical to have government support to progress this priority due to the scope of the investment required. • Customers and stakeholders want to be informed about revenue and price outcomes for proposed contingent projects, particularly those linked to Renewable Energy Zones. TasNetworks needs to clearly communicate the benefits of future investments (who will access them and when they will be realised). • Customers and stakeholders feel that being open to embracing new technologies as alternatives to network augmentation (such as community batteries) could help reduce costs for customers and the network. • Customers and stakeholders are keen to understand how renewable energy investments will be planned and coordinated, including the planning assumptions used in forecasts. • System strength services are important, and customers want transparent information about the need, opportunities and costs of providing these services.	• We have revised our proposed investments to clearly state the anticipated customer benefits and associated timing, such as the Zeehan reliability improvement project. • We are proposing nine transmission contingent projects, outlining major augmentation to the transmission network to build Tasmania's renewable energy capabilities (Attachment 7 Contingent projects). • We have committed to continuing to engage on contingent projects in 2023, using the knowledge and capability of our representative voices to ensure customers' interests are represented. • TasNetworks' Annual Planning Report outlines the planning assumptions and forecasted investments on the transmission and distribution network for the next decade. • We have proposed steady and modest investment in enabling consumer energy resources (**CER**) through initiatives such as community battery trials and improving our visibility of the low voltage network.

In addition to the feedback and responses outlined in Table 1, we also engaged with customers and stakeholders on targeted topics. Table 2 outlines these topics, what we heard, and how our plans have changed as a result.

Table 2. Targeted topic feedback and our response

Topic/issue	What we've heard	How we've responded
Framework and approach **Service classification**	• Broad support for TasNetworks' proposed amendments to the framework and approach paper. • Concern about TasNetworks providing Stand Alone Power Systems (**SAPS**) to customers, as it might negatively impact the competitive market. • A lack of support for TasNetworks leasing the excess capacity from distributor owned community batteries. • Electrical industry representatives broadly support TasNetworks to include new private asset services, Provider of Last Resort and Rectification of Minor Private Asset Defects in the Combined Proposal, with further engagement on the proposed controls to help limit potential impacts to the competitive market.	• We are proposing to utilise regulated SAPS (not private), to replace existing distribution network assets where this is the least cost solution. No potential sites have been identified for upcoming regulatory control period at this stage. • We updated the proposed private asset service controls based on feedback received from stakeholders.

Topic/issue	What we've heard	How we've responded
Draft Plan public consultation	• Seven submissions were received during the consultation process. • There was broad support for key customer themes and priorities, but a request for TasNetworks to consider alternative approaches to affordability - such as working with customers to reduce energy costs through education and efficiency. • Request for greater transparency and clarity regarding how it intends to implement being a Provider of Last Resort and SAPS during the 2024-2029 regulatory control period. • Stakeholders identified an opportunity for greater innovation to be applied in the resolution network challenges. Stakeholders would like to understand what considerations have been made to ensure project delivery and the confirmation and realisation of customer benefits. • Concern regarding the potential price impact of contingent projects for Tasmanians, with a request for greater detail on project cost, timings and customer benefits.	• We continued to engage with stakeholders regarding Provider of Last Resort and SAPS – for our full response, with additional information available in Attachment 18 Alternative control services. No potential SAPS sites have been identified for the upcoming regulatory control period at this stage and we are still considering option for community batteries. • We are committed to seeking and implementing innovative options and seeking alternatives to traditional network solutions that provide the best customer outcome for the most efficient cost. Our expenditure forecasting process requires the consideration of non-network solutions as part of our options assessment, with the most economically beneficial option selected for progression. Further, all investments are retested prior to implementation to ensure any new options and innovations are considered and that the best outcome for customers is progressed.

Topic/issue	What we've heard	How we've responded
Customer Service Incentive Schemes	• Broad support from customers for TasNetworks to propose a Customer Service Incentive Scheme (**CSIS**) framework for the 2024-2029 regulatory control period using their prioritised list of customer service measures, in addition to the network reliability measures contained in the Service Target Performance Incentive Scheme (**STPIS**). • TasNetworks' Customer Council (**CC**) demonstrated support for the intent of the CSIS, number of service parameters and the approach to target setting. There was insufficient feedback from CC members to confirm TasNetworks' final proposed CSIS before submission of the Combined Proposal.	• TasNetworks is proposing to adopt the CSIS for upcoming regulatory control period, inclusive of the following performance parameters: o Customer satisfaction with complaints handling o Customer satisfaction with outage management (planned and unplanned) o Customer satisfaction with new connections. See Attachment 14 Customer service incentive scheme for detailed information on CSIS findings and the proposed approach.
Network tariffs	• TasNetworks' Policy and Regulatory Working Group (**PRWG**), helped shape the development of guiding pricing principles used to underpin the refinement and ongoing progression of our pricing strategy. **Cost reflectivity and tariff assignment** • Stakeholders acknowledged the benefits of cost reflective pricing are more clearly realised if accompanied by sufficient uptake of cost reflective network tariffs, but also recognised that electricity consumption is a low-involvement product for most customers, making differential pricing less impactful. • Stakeholders strongly emphasised the need for TasNetworks pricing strategy to include protections for customers experiencing vulnerability.	• TasNetworks adopted the pricing principles developed with the PRWG, and has used them to guide the development of pricing strategy and network tariffs. **Cost reflectivity and tariff assignment** • TasNetworks' existing default network tariffs will remain the default network tariff for all new residential and small business customers connecting to the network in the 2024-2029 regulatory control period. We are also proposing to make some 'flat rate' network tariffs obsolete. • We designed a tariff assignment policy reflective of stakeholder and customer feedback. The policy includes a data sampling period for customers placed onto a time of use network tariff thereby allowing vulnerable customers to opt-out of the default network tariff or choose an alternative that best suits their needs.
	Consumer energy resources • Stakeholders felt that the existing network tariff targeted towards customers with CER is not fit for purpose and required review to ensure the pricing offering was future-ready.	**Consumer energy resources** • We are proposing to amend the existing residential CER network tariff from a time of use demand, to a time of use consumption network tariff, inclusive of a super off-peak charging period.
	New network tariffs • Stakeholders recognised the need for consideration of equity and pricing arrangements for embedded networks.	**New network tariffs** • For new connecting customers we are proposing new embedded network tariffs for the low voltage and high voltage networks.

Topic/issue	What we've heard	How we've responded
	Tariff trials • Request for transparency of future plans in relation to the introduction of two-way pricing measures. Recognition of benefit in considering a trial prior to introduction of such pricing arrangements. • Stakeholders co-designed principles that could be applied to tariff trails that may be undertaken in the future: o being Tasmanian focused o beneficial to customers o clear in their intent and purpose o rewarding to customers o collaborative with industry partners.	**Tariff trials** • TasNetworks worked with our PRWG members on principles and considerations for potential future two-way pricing trials.
	Communicating network reform to customers • Customers may benefit from more information regarding which tariff options best suit their needs, and this information should be provided in simple, easy to understand language.	**Communicating network reform to customers** • We have developed a suite of fact sheets to explain the differences between network tariffs and how different network tariffs may be better suited to different customers. • TasNetworks continues to work with retailers to support consistency in messaging around pricing options for customers.
Rectification of minor private asset faults (Standard Control Service)	• Stakeholders broadly supported the introduction of a new rectification of minor private asset faults service for the 2024-2029 regulatory control period. • Stakeholders provided feedback that there should be a list of private asset repairs TasNetworks will complete, providing consistency state wide.	• We collaborated with stakeholders on the development of the controls to ensure limited impacts to the competitive market • We have also committed to continue engaging with industry to finalise the approved private asset repair list, which will inform stakeholders of the private assets TasNetworks will repair. • Once implemented, we have committed to providing regular reporting to industry regarding the number of faults being rectified.
Provider of last resort (Alternative Control Service)	• Stakeholders broadly supported the introduction of a new provider of last resort service for 2024-2029 regulatory control period. • Stakeholders wanted to ensure the service was only used in a last resort capacity and that TasNetworks provided assistance to customers in finding approved contractors.	• We collaborated with stakeholders on the development of the controls to ensure limited impacts to the competitive market. • TasNetworks has amended our external website to make it easier for customers to find power line contractors. • Once implemented, we have committed to providing regular reporting to industry regarding the number of services being completed.

Links to further information on customer and stakeholder feedback are provided in Appendix B.

2 OUR ENGAGEMENT FRAMEWORK

This section sets out the principles, objectives, key audiences, and best practice guidelines used in the development of our engagement program.

2.1 Co-design

In a first for TasNetworks, our engagement framework was built from the ground-up using direct input from our representative voices, individual customers and key stakeholders during the early phases of the engagement program. This work ultimately culminated in the development and release of our **2024-2029 Customer and Stakeholder Engagement Strategy** in January 2022.

Development timeline

July to August 2021 (co-design)
Workshops, forums and surveys with 63 representatives from our PRWG, CC, transmission customer base, and Tasmanian councils to identify our engagement principles, objectives, methods, barriers and success measures.

September 2021 (drafting)
TasNetworks' engagement team worked with our engagement consultancy, RPS Group, to shape the insights from the co-design activities into a Draft Customer and Stakeholder Engagement Strategy.

October to December 2021 (consultation)
Meetings, workshops, focus groups and public consultation with 89 representatives from our PRWG and CC, newly-established RAC, individual customers, and the general public to seek feedback on the Draft Customer and Stakeholder Engagement Strategy.

January 2022 (release)
First official iteration of the Customer and Stakeholder Engagement Strategy was publicly released on TasNetworks' website, engagement platform, and social media channels.

March 2022 (update)
Strategy received minor refinements based on feedback received during the public consultation, including realignment of delivery program timelines.

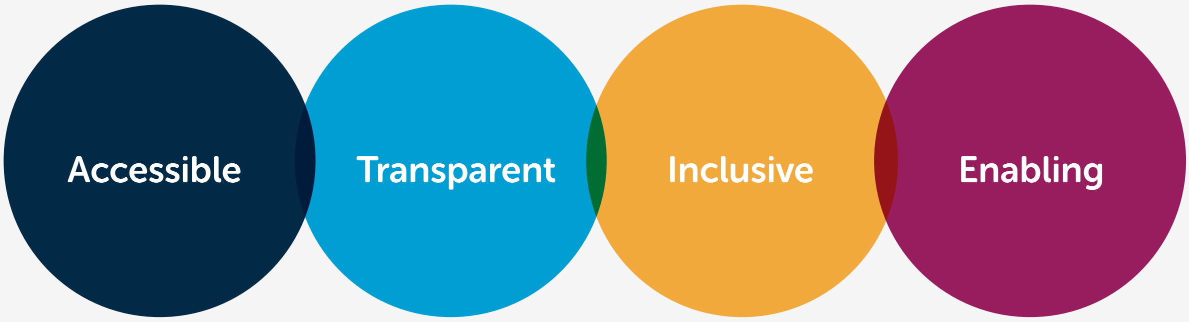
December 2022 (update)
Strategy received minor refinements, including the addition of an overarching purpose, and small amendments to the delivery program timelines.

This process is further detailed in our **Customer and Stakeholder Engagement Strategy,** while information on our delivery program can be found in Section 4.

2.2 Principles

Our engagement principles were shaped directly from feedback received during the workshops and forums we hosted in the co-design stage in July 2021. The principles were subsequently endorsed for inclusion in the Customer and Stakeholder Engagement Strategy by those who participated in the consultation stage.

Figure 4. Engagement principles



Ensuring engagement activities are convenient for participants, and that supporting materials are fully accessible.

This includes:

- hosting engagement activities at times/ locations that suit participants
- ensuring materials can be readily accessed (printed and digital), and easily understood.

Being as open as possible about the process and constraints, remaining accountable throughout.

This will include outlining what customers *can* and *cannot* influence in our Proposals from the outset of the engagement program.

Ensuring an equal opportunity to participate for all customers and stakeholders, with particular consideration for those experiencing disadvantage or with specific needs.

We will offer multiple opportunities to engage on each topic to cater for those with specific needs, or experiencing disadvantage.

We will enable participation.

This includes:

- being responsive to feedback and showing respect
- ensuring time provided for involvement and feedback is appropriate for the content
- providing capability-building opportunities and resource support so all those who want to participate can.

2.3 Objectives

Our engagement objectives were also shaped by the feedback we received during the co-design stage, and endorsed for inclusion in the Customer and Stakeholder Engagement Strategy by those who participated in the consultation stage.

Table 3. Engagement objectives

Objective	Description	Principle
Understand what is important to our customers and stakeholders	• Ensure we are listening to what our customers and stakeholders are saying, aspiring to hear perspectives that expand our current thinking and processes.	• Transparent
Build our customers' and stakeholders' understanding and knowledge of TasNetworks' operations, the energy sector and the Revenue Reset process	• All customers and stakeholders participating in the engagement program are exposed to a 'capability building' phase, where fundamental information regarding TasNetworks' operations, the broader energy sector and Revenue Reset process are introduced and explained in an accessible way.	• Enabling • Accessible
Identify those areas that customers and stakeholders can influence, and enable them to shape our Proposals	• The Engagement Strategy and our final Proposals to the Australian Energy Regulatory are reflective of what our customers and stakeholders told us. • The engagement program has been designed to capture and respond to both the breadth (diversity of audience and variety of methods) and depth (detail) of customer and stakeholder views.	• Transparent • Inclusive
Deepen customer and stakeholder trust in our Proposals	• Enable open dialogue which challenges TasNetworks' existing practices. • Customers and stakeholders have trust in the process and rationale behind decisions, even if positions are not always aligned. • Customers and stakeholders have confidence that TasNetworks has genuinely listened, and that investment decisions are in the long-term interests of customers.	• Transparent • Inclusive • Enabling
Drive internal cultural change	• Engagement is understood and accepted as an essential component of TasNetworks' activities and projects. • Maturing TasNetworks' engagement approach by embedding engagement into every-day functions. • Building TasNetworks' comfort regarding incorporating customer and stakeholder views into its key planning processes.	• Transparent • Inclusive • Enabling

2.4 Key audiences

We have sought to engage with a diverse range of customers and stakeholders, to build our knowledge of their needs and perspectives and ensure we develop a Combined Proposal that is reflective of those needs wherever possible. Figure 5 outlines our high-level audiences, while Table 4 details the key sub-groups for each of these audiences.

Figure 5. Audiences by segment

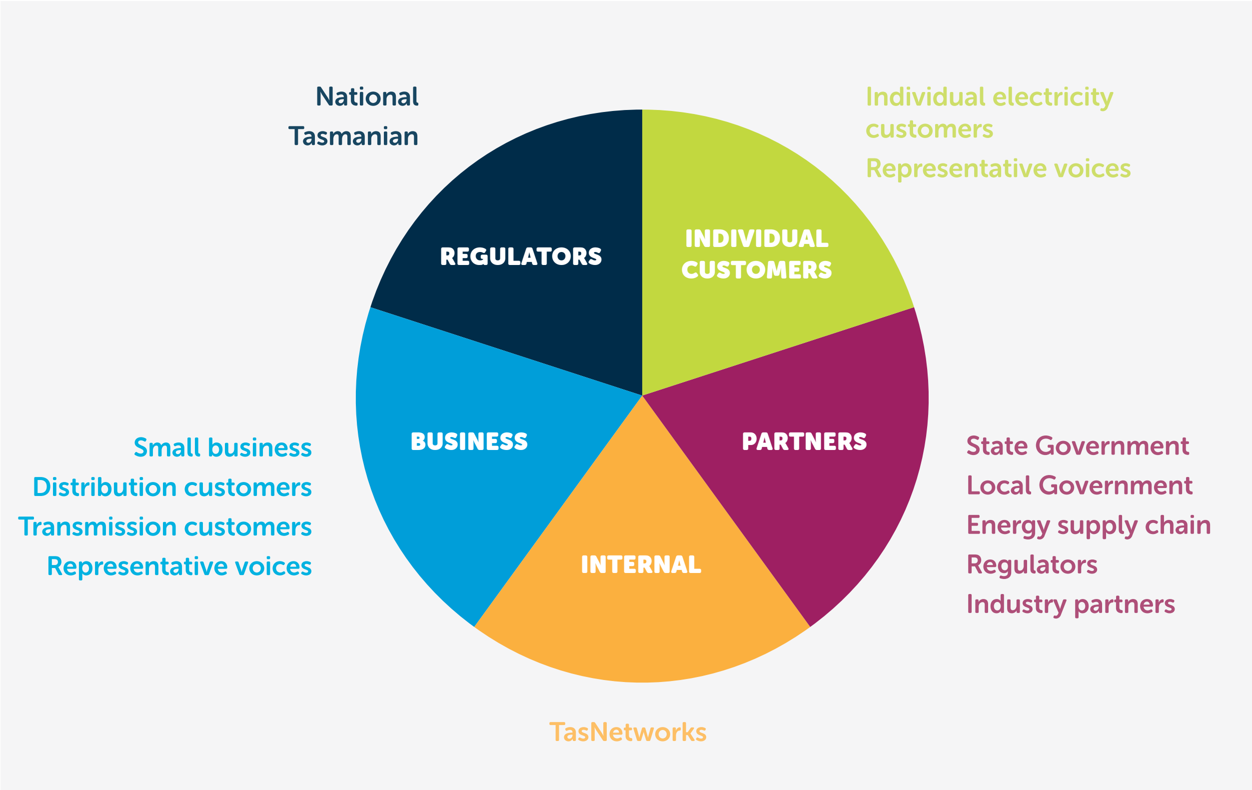


Table 4. Audience sub-groups

Segment	Group	Sub-group
Individual customers	**Individual grid consumers**	Residential Prosumers (smart devices, electric vehicles, solar, batteries) Customers experiencing vulnerability
	Representative voices	TasNetworks Reset Advisory Committee TasNetworks Customer Council TasNetworks Policy and Regulatory Working Group Australian Energy Regulator Consumer Challenge Panel Members Community Voices Program
Business	**Small business**	Owner occupier Customers experiencing vulnerability Rural and regional High consumption
	Distribution customers	Commercial (government agencies, councils, property managers, developers) Large embedded generators (solar, wind) Large distribution customers (factories, hospitals) Energy service providers Energy aggregators
	Transmission customers	Major industrials (Bell Bay Aluminium, Norske Skog, Nyrstar, MMG) Generators
	Representative voices	TasNetworks Reset Advisory Committee TasNetworks Council Forum TasNetworks Generators Forum Australian Energy Regulator Consumer Challenge Panel Members
Regulators	**National**	Australian Energy Regulator Australian Energy Market Operator Australian Energy Market Commission
	Tasmanian	Office of the Tasmanian Economic Regulator Energy Ombudsman Tasmania
Partners	**State Government**	Tasmanian Minister for Energy Tasmanian Minister for Local Government Tasmanian Department of Treasury and Finance
	Local Government	Local Government Association of Tasmania
	Energy supply chain	Generators Retailers Aggregators Solar installers Network service providers (distribution and transmission)
	Regulators	Australian Energy Regulator Australian Energy Market Operator Australian Energy Market Commission Office of the Tasmanian Economic Regulator Energy Ombudsman Tasmania
	Industry Partners	Electrical industry groups Electrical contractors Energy Networks Australia Property Developers Building industry groups (Master Builders Association)
Internal	**TasNetworks**	TasNetworks team members TasNetworks contractors

2.5 Ability to influence

We have used the IAP2 Public Participation Spectrum to guide the development of our engagement framework, and to ensure our delivery program is fit for purpose and in-line with industry best practice. Widely used in Australia and overseas, the spectrum enables organisations to identify the appropriate level of public involvement in any engagement process. Figure 6 is an approved adaptation of the official IAP2 model, representing TasNetworks' 2024-2029 revenue reset engagement program.

Figure 6. IAP2 Public Participation Spectrum (iap2.org.au/resources/spectrum).

	Inform	Consult	Involve	Collaborate	Empower
Public participation goal	To provide our customers and stakeholders with balanced and objective information to assist them in understanding our business, the revenue reset process and associated alternatives, opportunities and/or solutions.	To obtain feedback from our customers and stakeholders on analysis, alternatives and/or decisions relating to our Proposals.	To work directly with our customers and stakeholders throughout the development of our Proposals to ensure their concerns and aspirations are consistently understood and considered.	To partner with our customers and stakeholders at every stage of the drafting of our Proposals, including the development of alternatives and the identification of their preferred solutions.	To place final decision making regarding our Proposals in the hands of our customers and stakeholders.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge your concerns and aspirations, and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how your input influenced our Proposals.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into our Proposals to the maximum extent possible.	We will implement what you decide regarding our Proposals.

To support previous regulatory proposal processes, TasNetworks' engagement activities have tended towards the **'Inform'** to **'Consult'** end of the spectrum. However, for the development of the 2024-2029 Combined Proposal we have sought to mature our approach, developing a program with activities ranging from **'Inform'** through to **'Collaborate'**.

2.6 Topics and audiences

Table 5 details what topics were discussed with which groups, and during which phase these topics were introduced into the engagement program. Topics that have been engaged on across multiple phases are also noted.

Table 5. Topics and level of influence by audience

		Revenue reset overview (+ Phase 3)	AER engagement expectations	Engagement Strategy	TasNetworks / revenue reset overview (+ Phase 3)	AER Better Resets Handbook (+ Phase 3)	Draft Customer & Stakeholder Engagement Strategy	Topics for engagement	2019-24 overview and past performance	Expenditure forecasting, drivers of investment, rates of change	Regulated pricing overview	AEMO Integrated System Plan	Augmentation capital expenditure	Contingent projects / Marinus Link (+ Phase 5)	Preliminary expenditure forecasts / investment outlook (capex / opex / revenue for transmission & distribution)	Replacement capital expenditure	TasNetworks Transformation Program	Network reliability	Non-network capital expenditure (+ Phase 5)	Metering depreciation	Expenditure + revenue forecasting Process (+ Phase 5)
Individual Customers (inc. small business)							3	3		1	1			1	1						1
Individual Customers: Vulnerable		1			1			3										2			
Transmission Customers				3										1 1 1	1 1 1		1				1 1
RAC	REPRESENTATIVE VOICES				1	2 1 1	4		1 1	2	1	1	2	2 1 1	1 2	1	1	2	2 2 1	2	1
PRWG & CC	REPRESENTATIVE VOICES	1	1	4			3	3	1	2				3	2 3						
PRWG	REPRESENTATIVE VOICES																				
CC	REPRESENTATIVE VOICES																				
Local Government		1		3							1										
Retailers		1													1						
Industry Partners																					
Generators		1						3													
Interested Stakeholders															1						
General Public							3														

KEY

Phase 1	Nov '20- Sep '21	Phase 4	Jul-Oct '22
Phase 2	Oct-Dec '21	Phase 5	Nov '22 – Jan '23
Phase 3	Jan-Jul '22		

KEY: IAP2

Inform	1	Collaborate	4
Consult	2	Empower	5
Involve	3		

Transmission pricing changes / considerations	2024-29 program update	Indicative price outcomes (+ Phase 4 and 5)	Transmission Network Strategy	Customer Service Incentive Scheme	Network resilience	Future networks / DER overview	Revenue recovery + regulated pricing overview	Alternative Control Servicers (Quoted Services, Public Lighting)	Distribution Connection Pricing Policy	Customer connection / consumption forecasts	Draft Plan	Draft Plan feedback / responses	Embedded Network / DER Tariffs	ACS / Connections Policy	Service Classification (Provider of Last Resort / controls, Rectification of Private Assets Under Fault, Regulated SAPS)	Network Developments	Demand / supply + forecast scenarios	Tasmanian Renewable Energy Target / REZs	Network security performance	System strength	Network asset retirement / replacement	Network service performance	Distribution network tariffs	Customer impacts (transmission & distribution)	Engagement outcomes	Combined Proposal highlights
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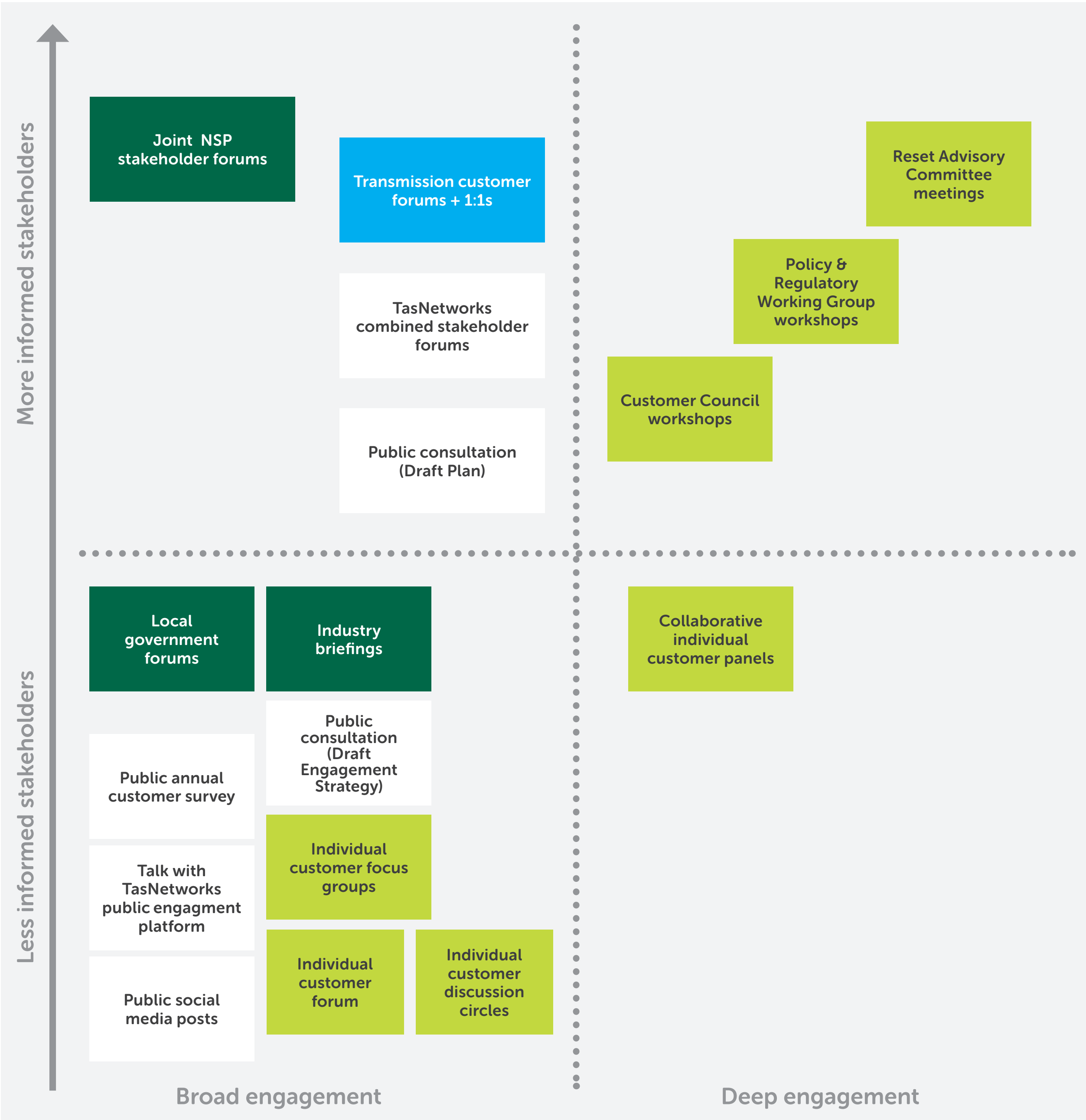
2.7 Breadth and depth

We greatly value all feedback received from our customers and stakeholders. However, in shaping the plans in our Combined Proposal, we have attributed more weight to the preferences and insights from stakeholders who have been able to contribute to our engagement activities in a more informed way through deliberative processes over a longer period.

This means that the often more detailed feedback gathered from deep and ongoing engagement with the RAC, PRWG, and CC has been prioritised in the development of our Combined Proposal.

Nonetheless, feedback from broader engagement methods, such as our annual customer survey, individual customer panels, discussion circles, focus groups and forums, has been used to confirm the direction provided by our more deliberative groups, to ensure their thinking is aligned with and representative of our broader customer base. Figure 7 illustrates the breadth and depth of our engagement activities with our key audiences.

Figure 7. Breadth and depth of engagement with key audiences/activities

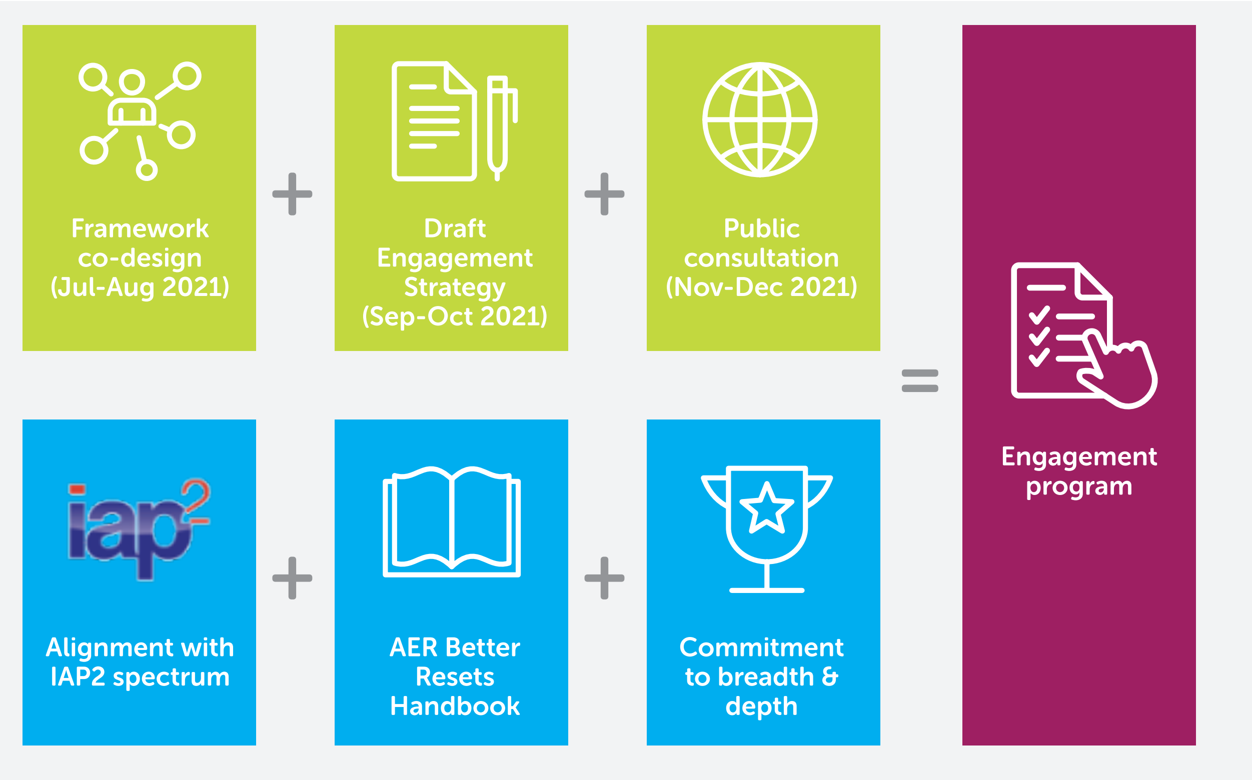


Individual customers = lime green
Business = bright blue
Partners = dark green
White = public

3 OUR ENGAGEMENT PROGRAM

Our engagement program utilises a variety of methods and channels to ensure we achieve a breadth and depth of insight from a diverse and representative cross-section of our customers and stakeholders. Figure 8 illustrates the evolution of the program's development.

Figure 8. Engagement program development



3.1 Program design

We designed a phased engagement approach to ensure our customers and stakeholders could participate in the engagement program to the greatest extent possible. This included introducing fundamental topics early, paving the way for deeper engagement on topics of interest as we moved along the engagement pathway, and in response to customers' and other stakeholders' needs and preferences (see section 2.6 to see the evolution of topics and audiences).

There have been five phases of engagement (see Table 6), each with a distinct focus and deliverables.
These have been informed by a significant period of research, analysis and internal engagement, subsequently built during the framework co-design stage using a combination of feedback gathered from our representative voices, customers and stakeholders.

Table 6. Engagement phases

Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Research + planning	**Context + capability building**	**Deep dives**	**Reporting back**	**Closing the loop**
Nov 2020-Sep 2021	**Oct-Dec 2021**	**Jan-Jul 2022**	**Jul-Oct 2022**	**Nov 2022-Jan 2023**
3 topics covered	**10 topics covered**	**33 topics covered**	**13 topics covered**	**18 topics covered**
Dedicated to uncovering customer and stakeholder needs and interests through research, and using these to directly shape our Draft Customer and Stakeholder Engagement Strategy.	Centred around activities that build the knowledge and understanding of our engagement participants, identifying topics for the following phases of engagement, and seeking feedback on the Draft Customer and Stakeholder Engagement Strategy.	Focused on conducting deep-dives into the topics and issues that customers and stakeholders have highlighted, gathering detailed feedback to help shape our Draft Plan and Combined Proposal.	Involved with seeking feedback on our Draft Plan with engaged stakeholders and customers, and using these insights to refine our Combined Proposal.	Concentrated on reporting back to our customers and stakeholders regarding how their feedback has helped shape our Proposal.

Adopting a phased approach has also allowed us to iteratively review our performance, enabling us to adapt activities, locations, methods and topics according to the changing needs of our customers and stakeholders as well as the external environment (e.g., COVID, rising inflation, rapid changes in the energy industry). In this way we have been able to make incremental improvements to our engagement approach, which has helped minimise barriers to participation.

Please refer to section 2.6 for a list of the topics covered in the program to date, along with details of the engagement phase in which each topic was introduced and with which audiences it was discussed. Section 3.2 provides detailed delivery programs for each of the completed phases, inclusive of audiences, topics and ability to influence.

3.1.1 Approach for individual customers

This audience includes individual energy customers and bill-payers like private households. It also includes customers experiencing vulnerability, such as those on low incomes or living with a disability. Our representative voices have also heavily advocated for the interests of this group. 134 customers were engaged during the five phases of engagement, covering over 20 topics in 20 activities.

Activities have included a mix of the following, focused on breadth rather than depth of engagement:

- Face-to-face (**F2F**) and online focus groups
- Discussion circles
- Collaborative customer panels
- Online forums
- Online surveys
- Email updates.

Understanding what our customers value and their concerns is fundamental to the successful development of our Proposal. As an essential service provider, it is also our responsibility to identify and reach people who might be missed by other engagement approaches, to ensure their perspectives are reflected. This commitment to inclusivity can be seen in the introduction of discussion circles into Phase 3 of the program, which saw us engage with 30 individual customers from across the State who were either experiencing vulnerability or living with a disability. Appendix B provides links to the findings of this engagement.

3.1.2 Approach for business

The business audience for our engagement program has included small and medium-sized businesses connected to our distribution network, as well as large commercial and industrial customers taking supply from the transmission network. The latter group consumes around 50 per cent of Tasmania's total energy production each year. The interests of this group are also represented by one or more of our representative voices groups.

Small/medium business customers

We have approximately 300,000 distribution customers, of which around 11.5 per cent are small to-medium businesses, encompassing everything from one-person operations through to farming ventures and government agencies. The interests of this audience are represented within our CC and PRWG by a number of peak bodies and their advocates, who are free to liaise with their respective member organisations and/or constituents.

These groups generally operate at a deeper level of engagement, covering more complex subject matter than most other groups, due to their advanced knowledge of the energy industry. Refer to section 2.6 to see which topics have been covered with these audiences.

Transmission customers

We have 15 transmission-connected customers across the State, operating in industries such as mining and manufacturing. Engagement activities with this cohort have included:

- Online forums (tailored for transmission customers)
- 1:1 meetings (both in-person and online)
- Mixed online stakeholder forums
- Online surveys
- Email updates.

When developing our Proposal we engaged with our transmission customers on nine topics across 13 engagement activities. Interactions with this group have generally been at a higher level of complexity, owing to their deep knowledge of the energy sector. With the exception of individual pricing information, the engagement has remained relatively broad in its scope. Refer to Appendix B for links to the engagement findings of these groups.

3.1.3 Approach for partners

This audience is broad, encompassing:

- those that shape the energy sector, such as federal, state and local government and regulators
- participants in the energy supply chain, such as generators and retailers
- industry partners, such as electrical contractors and building industry groups.

Given the diversity of these groups, various methods have been used to reach them, including:

- Online forums
- Industry briefings
- Online surveys
- Mixed online stakeholder forums
- Email updates.

Local government forums

Collectively, Tasmania's 29 local governments represent the largest component of the customer base for TasNetworks' public lighting services, and are also frequent users of TasNetworks' asset relocation services, to facilitate the widening or re-routing of roads. Commencing in 2021, the local government forums are designed to:

- provide an opportunity for TasNetworks and councils to better understand each other's needs
- provide information that enables councils to effectively plan their infrastructure and program of works
- offer an avenue to raise any issues or concerns as early as possible.

All local governments are invited to attend the forums, which have been held as both online and in-person activities across the State. To-date, eight topics have been covered in five forums.

Generators' forum

The Generators' forum enables TasNetworks to engage with existing and prospective Tasmanian generators as a group, and to consider appropriate strategies and plans in relation to the efficient development of the Tasmanian power system. This includes proposed transmission system planning considerations, strategic issues related to transmission system developments and related activities. While the forum is not a policy or decision-making body, feedback and outcomes from this group are used to help inform TasNetworks' decision-making. The forum last meet in November 2021, and discussed two topics.

Retailer's forum

Held on an as-needs basis, the retailers' forum is designed to:

- provide an opportunity for TasNetworks and retailers to better understand each other's needs
- provide information that enables retailers to plan their retail tariffs and services for customers
- offer an avenue to raise any issues or concerns as early as possible.

To date, this audience have met twice and discussed three topics.

3.1.4 Approach for representative voices

TasNetworks' representative voices include our:

- Customer Council
- Policy and Regulatory Working Group
- Reset Advisory Committee.

Activities completed with these groups have included:

- Workshops and meetings
- Online stakeholder forums and webinars
- Webinars
- Online surveys
- Email updates.

Customer Council

TasNetworks established the CC in 2015 to enable ongoing conversations about issues that matter to Tasmanian energy users. The key purpose of the Council is to:

- Evaluate current customer policies, procedures and services that are offered to customers
- Provide ongoing customer feedback on services, regulations, policies, and procedures
- Identify opportunities for new processes that would improve customer engagement.

CC membership includes a diverse range of stakeholder segments, including:

- **Individual customers –** who are recipients of our services and connected to our electricity and/or communications network
- **Business –** small, medium and large business customers who represent a group or individuals impacted by or with an interest in our operations. This also includes transmission customers
- **Regulators –** those responsible for shaping and monitoring the energy sector, focused on achieving the best outcomes for customers
- **Partners –** customers who we work with in a collaborative manner to meet our connected customers' needs and to achieve best possible outcomes for all involved.

The CC has met a total of four times during five phases of engagement in a series of online and F2F workshops to discuss 12 topics. The CC's topics of engagement can be found in section 2.6, while links to reports from their activities can be found in Appendix B.

Policy and Regulatory Working Group

Established in 2014, the PRWG provides guidance on customer needs and acts as an advisory group on the development of our Tariff Structure Statement (**TSS**).

The PRWG has broad representation from a variety of organisations with an interest in energy, including electricity retailers, energy advisors, customer advocates and representatives of the business community. This allows a diverse range of customer views to be represented, discussed and heard.

Since its inception, the group has focused on building capability by growing its understanding of the drivers that underpin network pricing. They have met a total of seven times during five phases of engagement and considered 12 topics in a series of online and F2F workshops. Their topics of engagement can be found in section 2.6, while links to reports from their activities can be found in Appendix B.

Reset Advisory Committee


Bill Harvey


Dr Eleni Taylor-Wood


John Pauley


Leigh Darcy


Richard Bevan


Dr Cynthia Townley

TasNetworks formed the RAC in September 2021 with the purpose of helping shape our Combined Proposal for the 2024-2029 regulatory period.

The key objective of the RAC is to support TasNetworks' development of a Combined Proposal.that balances the needs of our customers, owners and the AER.

Members of the public were invited to register their interest for the RAC via a public expression of interest process and were selected by a TasNetworks panel. The RAC is co-chaired by a TasNetworks representative and one of the six independent professional members from across Tasmania. Members have a blend of knowledge and experience in energy, utilities, social research, future technologies, economics, governance and policy, sustainability, and corporate strategy.

The RAC has met a total of seven times and discussed 17 topics during five phases of engagement, involving a combination of F2F and online meetings. Sessions have included workshops and presentations from internal and external subject matter experts, with a focus on informed discussion and analysis as part of their consideration of key aspects of our Draft Plan and subsequent Combined Proposal.

Out-of-session activities have also been scheduled to further the group's knowledge and capability, including site tours and deep dives with subject matter experts on items such as TasNetworks' network resilience strategy, capex investment optimisation tool, and to address outstanding questions from meetings. RAC members have also held independent conversations with the AER and members of the AER's Consumer Challenge Panel (**CCP**) regarding the engagement process and outcomes.

An overview of the RAC and all meeting materials is available on their dedicated Talk with TasNetworks page. Their topics of engagement can be found in section 2.6.

3.2 Program delivery

This section details each phase of our engagement, including the specific activities, topics, audiences and their level of influence according to the IAP2 Public Participation Spectrum. Table 7 provides a summary of the key metrics for each phase.

Table 7. Engagement metrics snapshot

Activity metrics	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Totals
Individuals *directly* engaged	63	112	195	145	52	567
Total activities completed	7/7	8/8	33/33	10/10	3	61
Time spent *directly* engaging	6hrs	15hrs	96hrs	15hrs	7hr	139
Total topics engaged (*new topic for phase)	3 (*3)	10 (*9)	33 (*30)	12 (*8)	18 (*tbc)	76 (*64)
Regions engaged	State-wide	State-wide	State-wide	State-wide	State-wide	State-wide

3.2.1 Phase 1 (Research and Planning)

Taking place between July and September 2021, Phase 1 was dedicated to uncovering customer and stakeholder needs and interest through research and then using the emergent insights to directly shape our Draft Customer and Stakeholder Engagement Strategy. A total of 63 individuals were directly engaged, covering three topics in seven activities across six hours of engagement.

Table 8. Phase 1 engagement program

Activity	Audience	Region	Type	Topics + IAP2 spectrum	Jul	Aug	Sep
PRWG & CC workshop #1	Members	State-wide	F2F	Revenue reset overview (***inform***), AER engagement expectations (***inform***), engagement strategy inputs (***collaborate***)	1		
Local government forum	Council representatives	State-wide	F2F	Revenue Reset overview (***inform***), engagement strategy inputs (***involve***)	20+29	19	
Online survey	Transmission customers, local government, PRWG & CC	State-wide	Online	Engagement strategy inputs (***involve***)	7 >	< 30	

3.2.2 Phase 2 (Context and capability building)

Phase 2 ran from October to December 2021. It focused on building the knowledge and understanding of participants, identifying topics for the following phases of engagement and seeking feedback on the Draft Customer and Stakeholder Engagement Strategy. Phase 2 included 10 topics covered in 15 hours of direct engagement across eight activities, attended by 112 individuals.

Table 9. Phase 2 engagement program

Activity	Audience	Region	Type	Topics + IAP2 spectrum	Oct	Nov	Dec
RAC meeting #1	RAC members	State-wide	Online	TasNetworks overview (***inform***), AER Draft Better Resets Handbook (***consult***), Draft Customer and Stakeholder Engagement Strategy (***collaborate***)	20		
Generators' forum	Generators	State-wide	Online	Revenue reset overview (***inform***), topics for engagement (***involve***)		15	
PRWG & CC workshop #2	Members	State-wide	Blend	2019-24 revenue reset lessons (***inform***), expenditure forecasting (***consult***), topics for engagement (involve), Draft Customer and Stakeholder Engagement Strategy (***involve***)		16	
Focus groups	Individual customers	South, north-west, north-east	Online	Revenue reset overview (***inform***), topics for engagement (***involve***), Draft Customer and Stakeholder Engagement Strategy (***involve***)		30	9 + 13
Public consultation	General public	State-wide	Online	Draft Customer and Stakeholder Engagement Strategy (***involve***)		15 >	< 13
RAC meeting #2	RAC members	State-wide	F2F	2019-24 revenue reset overview (***inform***), benchmarking methodology (***inform***), pricing overview (***inform***), drivers of investment and rates of change (***consult***)			2

3.2.3 Phase 3 (Key topic deep dives)

Phase 3 ran from January to July 2022. It included deep dives into the topics and issues that customers and stakeholders had highlighted in the first two phases. We gathered significant feedback in this phase, before feeding it back into the business to help shape our Draft Plan and Combined Proposal. 195 individuals were directly engaged across 33 activities in over 96 hours of activity, covering 33 topics.

Table 10. Phase 3 engagement program

Activity	Audience	Region	Type	Topics + IAP2 spectrum	Feb	Mar	Apr	May	Jun
Joint DNSP forum	Stakeholders	Nat	Online	Network resilience (***consult***)	8				
RAC meeting #3	RAC members	Tas	Online	AER Better Resets Handbook (***inform***), transmission augmentation expenditure (***consult***), AEMO Draft Integrated System Plan (***inform***), contingent projects (***consult***)	9				
RAC meeting #4		Tas	F2F	Preliminary capex forecasts (***inform***), repex expenditure (***inform***)		23			
RAC meeting #5		Tas	F2F	TasNetworks Transformation Program (***inform***), preliminary capex forecasts (***consult***), reliability (***consult***), non-network capex (***consult***), metering depreciation (***consult***)				27	
Online forums	Transmission customers	Tas	Online	Investment process (***inform***), contingent projects (***inform***), transmission pricing changes and considerations (***inform***)	16+17				
1:1 meetings (x10)			F2F	2024-29 revenue reset update, preliminary capex forecast, transmission capex forecast, transmission revenue forecast, transmission opex forecast, indicative pricing, contingent projects, Transmission Network Strategy, TasNetworks Transformation Program (***All inform***)					27 >
Retailer's forum	Retailers	Nat	Online	Revenue Reset overview (***inform***), pricing strategy overview (standard control services and alternative control services) (***consult***)		3			
Customer panel #1	Individual customers	Tas	Online	STPIS + CSIS (***collaborate***)	21	7	4		
Customer panel #2		SE-Tas	F2F	Risk and performance (***inform***), investment process (***inform***), contingent projects (***inform***), network resilience (***consult***) , network reliability (***consult***), pricing process (***inform***), future networks (***inform***)				7	4
Customer panel #3		N-Tas	F2F					1+29	
Discussion circle #1	Individual customers	NE-Tas	F2F	Revenue reset overview (***inform***), TasNetworks overview (***inform***), topics for engagement (***Involve***), network reliability (***consult***), network resilience (***consult***)		28		2+30	
Discussion circle #2		NW-Tas	F2F			29		3+31	
Discussion circle #3		S-Tas	F2F			31		5	2
PRWG & CC workshop #3	Customer representatives	Tas	F2F	PRWG & CC: 2024-29 revenue reset update (***inform***), preliminary investment outlook (***consult***), contingent projects – future engagement (***involve***), future network forecast (***involve***). Customer Council: revenue recovery and pricing overview (***inform***), CSIS (***collaborate***)			7		
Local government forum	Council representatives	TAS	Online	2024-29 revenue reset update (***inform***), quoted services (***inform***), distribution connection policy (***consult***), public lighting services (***consult***), preliminary investment outlook (***inform***), pricing overview (***inform***), customer connection and consumption forecasts (***inform***)				19	

3.2.4 Phase 4 (Reporting back)

Occurring between July and September 2022, this phase was concerned with seeking feedback on our Draft Plan with stakeholders and customers. We have used these insights to refine our plans ahead of submitting our initial Combined Proposal in January 2023. Engagement was conducted with 145 individuals on 12 topics, completed in 10 activities in a total of seven hours.

Table 11. Phase 4 engagement program

Activity	Audience	Region	Type	Topics + IAP2 spectrum	Jul	Aug	Sep	Oct
Customer Council meeting	Members	State-wide	Online	CSIS outcomes (***inform***)	13			
Individual customer forum	Individual customers	State-wide	Online	Draft Plan overview (***consult***), customer feedback and proposed responses (***inform***), price outcomes (***inform***)	21			
Draft Plan consultation period	Public	State-wide	Mixed	Draft Plan (***consult***)	25	26		
Joint stakeholder forum	Stakeholders	State-wide	Online	Draft Plan overview (***consult***), feedback/ proposed responses (***inform***)	27			
PRWG meeting	Members	State-wide	F2F	Embedded/CER tariffs, Alternative Control Services and connections policy (***all inform***)		16		
Local government forum	Council representatives	State-wide	Online	Draft Plan overview, Distribution Connections Policy, Quoted Services (***all inform***)		25		
RAC meeting #6	Members	State-wide	F2F	Draft Plan feedback/proposed responses (***inform***), Draft Plan support (***consult***), Capex program/customer feedback (***consult***), AER Better Resets Handbook (***inform***)			7	
Electrical Contractors Industry Liaison briefings	Contractors	State-wide	Online	Provider of last resort and controls (***consult***), rectification of private assets under fault and controls (***consult***), regulated SAPS (***inform***)			21	27

3.2.5 Phase 5 (Closing the loop)

The final engagement phase before submission of TasNetworks' Combined Proposal to the AER, Phase 5 took place between October 2022 and January 2023 and focussed on informing our customers and stakeholders about how their feedback had helped shape our Combined Proposal. At the time of publication a total of 52 individuals had been engaged on 24 topics in three activities.

Table 12. Phase 5 engagement program

Activity + audience	Region	Type	Topics + IAP2 spectrum	Nov	Dec	Jan
Annual Planning Report	State-wide	Online	Network developments, demand/supply and forecast scenarios, Marinus Link and NWTD, TRET and REZs, network security performance, system strength, network asset retirement/ replacement, network service performance (***all inform***)	4 Nov		
Retailer's forum	State-wide	Online	Network tariff strategy, embedded networks update, time of use tariffs (small business, CER and residential) (***all inform***)	17 Nov		
RAC meeting #7	State-wide	F2F	Expenditure forecast and preliminary revenue , information and communications technology (ICT), contingent projects (costs), Marinus Link update (***all inform***)	30 Nov		
Stakeholder forum	State-wide	Online	Customer impacts (transmission and distribution), engagement outcomes, Combined Proposal highlights (***all inform***)			23 Jan
Transmission customer 1:1s	State-wide	Blended	Individual indicative pricing based on final forecasts, contingent project costs (***all inform***)			Mid-month

4 EVALUATION OUTCOMES

Evaluating our activities and outcomes as we've progressed through the engagement program has helped ensure our engagement has remained fit-for-purpose, and greatly supported the development of a Combined Proposal that is reflective of the preferences and interests of our customers and stakeholders, as well as capable of acceptance by the AER.

4.1 Evaluation approach

We have consciously adopted an iterative approach to evaluating and reporting on our engagement program from the outset, based on a process of *planning, doing, reflecting* and *evolving*. We have endeavoured to focus on what we have heard from our engagement participants, and how we are doing in terms of the quality of our engagement, as well as meeting our overall engagement objectives.

Figure 9. Evaluation approach

Planning	Doing	Reflecting & evolving
Success measures and targets informed by the co-design phase and bench marking against other NSPs.	Capturing feedback at the end of an engagement activity or series of activities. **Key tool:** post engagement evaluation survey (see Appendix E)	Completing post-implementation reviews at the conclusion of each major engagement phase. Adjusting approach, methods, materials where necessary. **Key tool:** independently compiled phase reports (see Appendix D for links)

4.2 Measuring success

During our co-design phase, participants told us successful engagement would have the following markers for them:

- Their voices were heard and considered, even when their feedback was not positive for TasNetworks
- Their knowledge and understanding had increased in areas such as revenue resets, the energy sector, and TasNetworks' operations
- They received post-engagement feedback in a transparent and timely way.

To measure the success and quality of our engagement, we paired our overall objectives with our measurement methods. These methods and markers were informed by our co-design phase in 2021, along with benchmarking against other similarly placed NSPs. A detailed overview of our metrics and methods is available in our Customer and Stakeholder Engagement Strategy.

Overall, we aimed to achieve a minimum satisfaction rating of 70 per cent across all activities, phases and audiences. Table 13 shows that since measurement commenced in Phase 2, we have met and exceeded this target for all but one of our key metrics (*ability to influence was clear*).

Although the ability to influence metric is currently slightly below our desired average 70 per cent, there is clear improvement since the baseline measurement of 50 per cent was captured in Phase 2, having achieved 78 per cent in the most recently completed Phase 4.

Table 13. Evaluation metrics by phase

Evaluation metrics	Target	Phase 1 (n/a)	Phase 2 (n=44)	Phase 3 (n=103)	Phase 4 (n=27)	Average (n=174)
Trust TasNetworks to act in customers' best interests*	66%	n/a	66%	84%	89%	80%
Improved knowledge (TasNetworks' operations)+	70%	n/a	93%	96%	93%	94%
Improved knowledge (energy sector)+	70%	n/a	80%	91%	85%	85%
Improved knowledge (revenue reset)+	70%	n/a	82%	91%	93%	89%
Engagement activity objectives were clear^	70%	n/a	84%	94%	89%	89%
Ability to influence was clear#	70%	n/a	50%	65%	78%	64%
Felt TasNetworks had listened to/heard perspectives@	70%	n/a	84%	91%	96%	90%

Percentage of respondent who...

* ...agreed/strongly agreed TasNetworks would act in best interests of its customers

\+ ...agreed/strongly agreed the information provided improved their knowledge/understanding

^ ...agreed/strongly agreed the engagement session objectives were clear

\# ...agreed/strongly agreed they were clearly informed to what extent they were able to shape TasNetworks' proposals for given topics

@ ...agreed/strongly agreed they felt TasNetworks had listened to/heard their perspectives.

4.3 External scrutiny

In addition to the above metrics and methods, we have also deliberately and consistently exposed our engagement activities and program to ongoing scrutiny from several independent bodies to ensure we are:

- honestly and accurately appraising our efforts
- conducting best-practice engagement
- refining our approach, activities and materials when necessary.

RAC

Established specifically to provide input into the revenue reset's engagement program, the RAC provided initial direction into the evaluation approach during the co-design phase, and has since had a key role in reviewing and critiquing engagement efforts.

RAC members have been kept appraised of engagement activities and outcomes across the length of the engagement program via written updates during pre-reading for scheduled meetings, verbal updates received during scheduled meetings, and via push-notifications between meetings.

Additionally, RAC members have been surveyed after each of their seven meetings. On average, members indicated they were satisfied (*strongly agreed or agreed*) with the following measures:

- Meeting was at time that suited them (98 per cent)
- Meeting location suited them (95 per cent)
- Objectives were clear and easy to understand (100 per cent)
- Content was clear and easy to understand (100 per cent)
- Their knowledge and understanding of the following had improved as a result of the engagement:
    - TasNetworks' operations (93 per cent)
    - the energy sector (88 per cent)
    - the revenue reset process (88 per cent)

- Felt TasNetworks had heard their concerns and listened to them (93 per cent)
- Trust in TasNetworks to act in the best interests of customers (95 per cent).

Conversely, just 63 per cent of RAC participants stated they strongly agreed or agreed with the statement that it was clear if engagement topics could be influenced or not, with 36 per cent saying they *neither agreed nor disagreed.* This feedback is consistent with that of other audiences (see Table 13).

Rounding out this work, RAC members have also chosen to publicly critique their experience of the engagement program, culminating in the publication of an independent report (see Appendix D for the report link).

Australian Energy Regulator Consumer Challenge Panel (CCP)

CCP members assist the AER to make better regulatory determinations by providing input on issues of importance to consumers. TasNetworks was appointed three expert CCP members in December 2021 to oversee the engagement program:

- Ms Helen Bartley
- Ms Robyn Robinson
- Mr Mike Swanston.

TasNetworks representatives met with CCP members eight times between December 2021 and January 2023, covering:

- latest engagement activities
- topics of interest to consumers
- lessons learned
- issues raised by consumers, or by TasNetworks with consumers
- updates on the development of TasNetworks' Combined Proposal – topics and issues
- CCP member observations and reflections on engagement activities
- upcoming engagement activities (focus, topics, approach, audience)
- areas the CCP could assist TasNetworks.

Additionally, CCP members also attended a selection of TasNetworks' engagement activities, including:

- One collaborative customer panel
- Three Reset Advisory Committee meetings (F2F and online)
- One retailer forum (online)
- Two stakeholder forums (online).

Appendix A – AER engagement expectations

Table 14 outlines how TasNetworks has endeavoured to meet the AER's engagement expectations, as outlined in the Better Resets Handbook on the AER website.

Table 14. AER engagement principles and expectations

Principles	Engagement expectations + how our program seeks to satisfy
Nature of engagement	**1. Sincerity of engagement with consumers.** From the outset of the engagement program we have sought to foster an internal culture that is open to new ideas and accepting of change, and to engage sincerely with our customers and stakeholders. Within the business we set the engagement objective to drive internal cultural change, inclusive of building comfort with incorporating customer and stakeholder views into our key planning process. Another formative step included executive support to establish a dedicated, independent group to appraise our plans and engagement, resulting in the formation of the RAC in October 2021. This group has proved instrumental in critiquing our plans and activities (read more about them in sections 2.4, 3.1.4, and 4.3). Members of the executive have attended a number of RAC meetings and several of our individual customer engagement activities. We are committed to continuing to improve our engagement maturity, which has been identified as a strategic priority for TasNetworks, and we are confident we are taking the right steps to see improvement. For our customers and stakeholders, we developed an engagement program that focused first and foremost on identifying and understanding what was important to the various audiences, before progressing to deeper engagement on topics of interest. This approach has helped them set the engagement agenda, with the dual benefit of ensuring we are developing a proposal using their expressed needs and preferences, as well as improving their trust and confidence in TasNetworks. To date an average of 80% of participants have reported trusting TasNetworks to act in their best interests, while an average of 90% feel that we have listened to and heard their perspectives and concerns during their respective engagement activity (see evaluation metrics in section 4.2).
	2. Consumers as partners in forming proposals Section 1.3 provides a detailed overview of how feedback has helped shape our proposal. Historically, our reset engagement activities have tended towards the *Inform* to *Consult* end of the IAP2 Spectrum. However, for the 2024-2029 revenue reset we have endeavoured to build on our approach, developing a program with activities ranging from *Inform* through to *Collaborate*. Stand-out engagement processes include: • *Collaborating* on the Customer and Stakeholder engagement *strategy* • *Collaborating* on the choice between a CSIS and STPIS and associated performance indicators. Recognising the benefits of iterative engagement, we have been conducting annual customer surveys since 2014, capturing feedback from 800+ customers and members of the public each year. These insights help inform aspects of our regular business planning, but also provide an invaluable information base for our revenue reset engagement, both in the previous regulatory control period, and now in 2024-2029. Additionally, our CC (established 2015) and PRWG (established 2014), have been providing ongoing advocacy for our customers and stakeholders both within and without reset processes. We are equally keen to see our RAC (established 2021) permanently added to this collection of representative voices, to add another layer of expertise and diversity when engaging on complex projects and issues beyond revenue resets.

Principles	Engagement expectations + how our program seeks to satisfy
Nature of engagement	**3. Equipping consumers so they can effectively engage** To ensure our customers and stakeholders can effectively engage and provide informed feedback into our reset process, we have consciously developed an engagement program that builds their knowledge and understanding of the energy sector, our business and revenue resets. We have achieved this by: • introducing fundamental topics early in the program, paving the way for deeper engagement on topics of interest as we moved along the engagement pathway, and in response to their needs and preferences • focusing on providing accurate and objective information at each and every engagement touchpoint, including a disciplined approach to providing follow-up information for questions/issues that couldn't be answered during an engagement activity • providing early access to materials ahead of scheduled activities where appropriate, enabling participants additional time to prepare and to keep sessions focused on informed discussion • providing access to third-party training and information, such as the dedicated reset webinars offered by Energy Consumers Australia (offered to all our representative voices groups) • offering dedicated sessions with and access to our internal subject matter experts for members of our RAC to build their knowledge and understanding outside scheduled meetings • use of subject matter experts in our activities that are capable of speaking knowledgeably and simply about all aspects of our business, the revenue reset process, the energy sector, and customer pricing. These steps have enabled our customers and stakeholders to effectively participate in the program, ensure we are engaging on issues that matter most to them, and build their trust in us. An average of 94% of participants have so far reported improved knowledge/understanding of TasNetworks' operations, 85% improved knowledge/understanding of the energy sector, and 89% improved knowledge/understanding of revenue resets. In terms of independence, members of our representative voices groups are regularly prompted to provide any conflicts of interest, the RAC in particular has a set agenda item covering this issue. Individual customers consulted for research were recruited by an independent professional, and thoroughly vetted as part of that recruitment process, with any individuals with conflicts excluded from participation. Individual customers and members of TasNetworks' representative voices groups are offered financial remuneration for their participation. **4. Accountability, including transparency around reporting and the delivery of commitments.** We are currently working to mature our business-as-usual engagement to meet these commitments and expectations.

Principles	Engagement expectations + how our program seeks to satisfy
Breadth and depth	**1. Accessible, clear and transparent engagement** Fundamental to the development of our engagement program was the initial co-design of our framework with customers, representative voices and stakeholders. These audiences directly shaped our engagement principles, objectives, methods and success measures. Our principles of *accessible*, *transparent*, *inclusive* and *enabling* have successfully guided us from the initial formulation of the framework through five phases of engagement. We have also openly shared all engagement materials via our engagement platform – Talk with TasNetworks, as well as via targeted emails to engagement participants. We have been committed to clearly communicating the level of influence participants have over given topics and issues (see section 2.6 for individual topics and their level of influence by audience). While our metrics show this remains a growth point for us, we have improved dramatically over the course of the program, exceeding our target by 8% in our last completed phase. We also focused on tailoring our engagement approach for different audiences. For example, we discussed *future topics for engagement* with multiple audiences using different methods: • Individual customers experiencing vulnerability (series of three F2F discussion circles in accessible locations) • Individual customers (F2F focus group) • PRWG & CC (F2F workshop and online survey) • Generators' (online forum) • Transmission customers (online survey) Our *Draft Plan* was also discussed with multiple audiences using different methods: • Individual customers (F2F collaborative panel) • RAC (F2F meeting) • Local government (online meeting) • General public (online consultation process) and interested stakeholders (including our PRWG and CC members) • Interested stakeholders (online forum). **2. Consultation on desired outcomes and inputs** Two of our engagement objectives directly address the expectation of consulting on desired outcomes and inputs with our customers and stakeholders: • To understand what is important to our customers and stakeholders • To identify those areas that customers and stakeholders can influence, and enable them to shape our Proposal. As previously noted, we endeavoured to create an engagement program that focused first on identifying and understanding what was important to our various audiences before progressing to deeper engagement on topics of interest/individual components. So far we have engaged on 64 individual topics during the course of the program, which includes a mix of both short and long-term impacts and outcomes for customers.

Principles	Engagement expectations + how our program seeks to satisfy
Breadth and depth	**3. Multiple channels of engagement** As noted, we have deliberately employed a broad range of engagement methods to meet our audience's needs. Many of these methods were proposed by our customers and stakeholders during our co-design phase. Point 1 on page 36 provides examples when the same topic has been discussed with multiple audiences using a variety of methods. The detailed approach taken for each audience can be found in sections 3.1.1 to 3.1.4, while the detailed delivery programs are available in section 3.2. Where appropriate, engagement activities were also structured to identify divergent interests among the various audience segments. The most common example of this was splitting activities with individual customers by region (south, north-east, north-west Tasmania) in our collaborative panels. While we found several mild differences in feedback on topics such as reliability (those outside greater Hobart placed higher importance on reliability), feedback was generally otherwise consistent across the state for individual customers. Another example can be seen in our discussion circles, which focused on gaining insights from those experiencing vulnerability – including living with a disability and financial hardship. This cohort were also broken up by region, but their feedback subsequently cross-referenced with those from our collaborative panels. Again, feedback from the discussion circle participants largely aligned with that of other customer groups. **4. Consumers' influence on the proposal** As noted above under ***Nature of engagement***, our reset engagement has historically tended towards the *Inform* to *Consult* end of the IAP2 Spectrum. For the 2024-2029 revenue reset we have endeavoured to build on our approach, developing a program with activities ranging from *Inform* through to *Collaborate*. Detailed information on topics and their level of influence by audience is available in section 2.6. Recognising the importance of having customers feel informed enough to challenge the assumptions and information they've been presented with throughout the engagement program, we've prioritised opportunities to build their knowledge and understanding – which has also been covered under ***Nature of engagement***. An additional step in this space includes facilitating access to third-party resources to help fund independent analysis, such as the Consumer Empowerment Funding Program offered by Energy Consumers Australia for our RAC.
Clearly evidenced impact	**1. Proposals linked to consumer preferences** Tables 1 and 2 in section 1.3 outline what key feedback we received and how it has shaped our proposal, inclusive of how we have responded to submissions received on our Draft Plan. Additionally, links to reports covering individual topics can be found in Appendix B. **2. Independent consumer support for the proposal** Although TasNetworks has not pursued an early signal pathway for our 2024- 2029 revenue reset, our RAC has prepared an independent report for the AER's consideration (see Appendix D for the report link).

Appendix B – key evidence links

Table 15 provides a quick reference to information on specific topics in engagement reports, publicly available on Talk with TasNetworks.

Table 15. Key evidence links

Topics	AER Engagement Expectations	Engagement strategy	AER Better Reset Handbook (3)	Draft Customer + Stakeholder Engagement Strategy	Expenditure forecasting, drivers of investment and rates of change (+ Phase 5)	Augmentation capital expenditure	Contingent projects)+ Phase 5)	Replacement capital expenditure	Benchmarking methodology	Preliminary investment outlook	Network reliability	Non-network capital expenditure (+ Phase 5)	Metering depreciation	Expenditure forecasting (+ Phase 5)	Transmission pricing changes/ considerations	Indicative price outcomes (+ Phase 4)	Customer service incentive scheme	Network resilience	Future networks/DER overview (+ Phase 5)
Combined Proposal and Attachments	1	1	1	1	6	6	7	6	6 8	-	6	6	OV 18	6	23	OV 21 22	14	6	6
Engagement Phase Reports	Phase 1		Phase 2			Phase 3													
Engagement Summary Reports (by date)	01.07.21 16.08.22	01.07.21 19.08.21 30.08.21 15.11.21 16.11.21 13.12.21	20.10.21 09.02.22 07.09.22	30.08.21 20.10.21 16.11.21 13.12.21 21.07.22 27.07.22 07.09.22	02.12.21 07.04.22 30.11.22	09.02.22	09.02.22 17.02.22 07.04.22 04.06.22	23.03.22 30.11.22	02.12.21	07.04.22 19.05.22	01.07.21 27.05.22 04.06.22	27.05.22 30.11.22		16.11.21 23.03.22 30.11.22	17.02.22	01.07.21	07.04.22 13.07.22	02.06.22 04.06.22	07.04.22 17.11.22

Revenue recovery and regulated pricing overview	Alternative control servicers (quoted services, public lighting) (+ Phase 5)	Distribution connection pricing policy	Customer connection/consumption forecasts (+ Phase 4)	Embedded Network / DER tariffs (+ Phase 5)	Service classification (provider of last resort/controls, rectification of private assets under fault, regulated stand-alone power systems)	Network developments	Demand / supply + forecast scenarios	Tasmanian Renewable Energy Target / Renewable Energy Zones	Network security performance	System strength	Network asset retirement / replacement	Network service performance	Distribution network tariffs	Customer impacts (transmission & distribution)	Engagement outcomes	Combined Proposal Highlights
OV 2	18	20	20	22	15	6	6	OV 7	-	7	6	6	OV 21 22	OV 21 22	OV 1	OV
				Phase 4		Phase 5										
07.04.22	07.04.22 19.05.22 16.08.22 25.08.22 27.10.22	03.03.22 19.05.22 25.08.22 21.09.22	19.05.22 02.06.22 04.06.22	03.03.22 07.04.22 16.08.22 17.11.22	21.09.22 27.10.22	04.11.22	04.11.22	04.11.22	04.11.22	04.11.22	04.11.22	04.11.22	04.11.22 17.11.22	23.01.23	23.01.23	23.01.23

Appendix C – key engagement methods

Talk with TasNetworks (talkwithtasnetworks.com.au)

Type: digital
Access: open
Suits audiences: all those with an internet connection/ proficient with technology

Launched in 2020, Talk with TasNetworks is a dedicated engagement platform, designed to give our customers and stakeholders a central online space to their share thoughts and feedback and gain access to key information. As a digital resource, it is possible to view or participate via the platform at the participant's convenience. Examples of activities and content on Talk with TasNetworks includes surveys, polls, discussion papers, FAQs, news articles, Q&As, and event notices.

Collaborative customer panels

Type: F2F (or online if required)
Access: by invitation
Suits audiences: individual customers

Collaborative customer panels consist of approximately 15 statistically representative individuals, recruited randomly to provide qualitative feedback on chosen topics. Panels might meet multiple times for approximately 2.5 hours at a time, and can be used to understand customer perspectives based on their location, particular issues, or different customer cohort needs.

Discussion circles

Type: F2F
Access: by invitation
Suits audiences: individual customers, vulnerable customers

Study circles are designed to allow organisations to hear directly from customers experiencing disadvantage. The circle will usually consist of a small group of recruited individuals who meet in a familiar, safe place to have an informal conversation about energy issues relevant and important to them. A session may run from 1.5 to 2.5 hours, and the circle may meet up to three times to explore the nominated range of issues.

Focus groups

Type: F2F (or online if required)
Access: by invitation
Suits audiences: individual customers, partners, business, regulators, internal

Focus groups allow organisations to 'drill into' and understand specific customer interests or needs. Individuals are randomly recruited to reflect a specific community or demographic groups (such as people living with disabilities, or young people). The focus group may run for two hours and usually include a maximum of 12 participants who focus on one specific issue or option being considered.

Representative voices meetings

Type: F2F (or online if required)
Access: by invitation
Suits audiences: partners, business, regulators

TasNetworks hosts a number of reference group meetings on a regular basis for our CC and PRWG. A newly created group, the RAC, joined this category from October 2020. Sessions are typically hosted by subject matter experts from within TasNetworks, with set agendas. Individuals are appointed either as representatives of a particular demographic or organisation, or in the case of RAC members, based on their knowledge and experience.

Appendix D – source document links

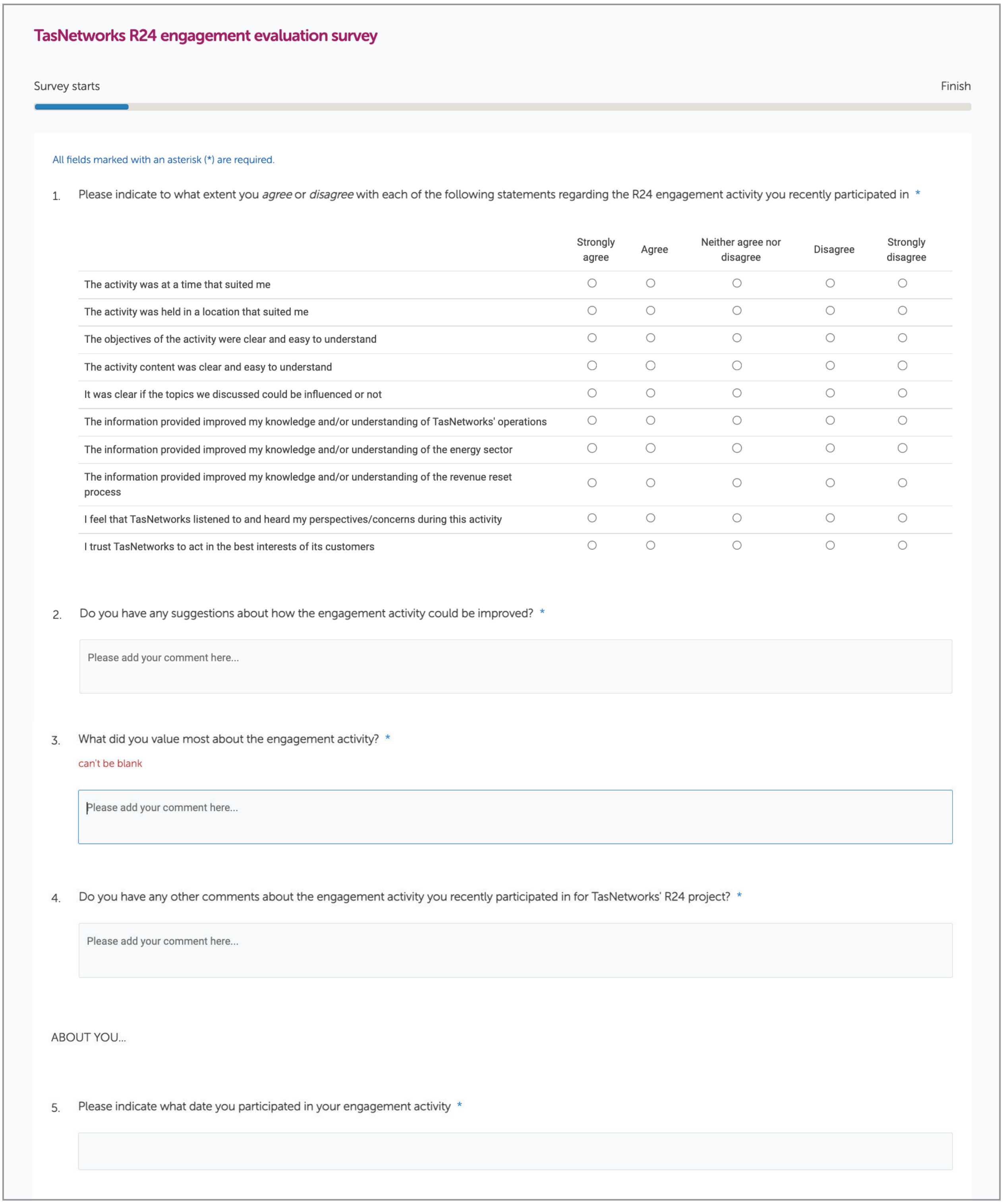
The following documents detail both the framework for our engagement program and the subsequent sources from which our Combined Proposal has been shaped. Each of these documents, and more, are available on our dedicated engagement platform, Talk with TasNetworks.

- Customer and Stakeholder Engagement Strategy
- Phase 1 Engagement Report
- Phase 2 Engagement Report
- Phase 3 Engagement Report
- Phase 4 Engagement Report
- Phase 5 Engagement Report
- Reset Advisory Committee Independent Report
- 2024-2029 revenue reset project on Talk with TasNetworks
- Individual engagement activity reports and materials
- Link to Draft Plan submissions

Appendix E – engagement evaluation survey

The following survey has been used throughout the engagement program to iteratively measure customer and stakeholder satisfaction and trust levels for engagement activities.

Figure 10. Engagement evaluation survey



TasNetworks R24 engagement evaluation survey

Survey starts Finish

All fields marked with an asterisk (*) are required.

1. Please indicate to what extent you *agree* or *disagree* with each of the following statements regarding the R24 engagement activity you recently participated in *

	Strongly agree	Agree	Neither agree nor disagree	Disagree	Strongly disagree
The activity was at a time that suited me	○	○	○	○	○
The activity was held in a location that suited me	○	○	○	○	○
The objectives of the activity were clear and easy to understand	○	○	○	○	○
The activity content was clear and easy to understand	○	○	○	○	○
It was clear if the topics we discussed could be influenced or not	○	○	○	○	○
The information provided improved my knowledge and/or understanding of TasNetworks' operations	○	○	○	○	○
The information provided improved my knowledge and/or understanding of the energy sector	○	○	○	○	○
The information provided improved my knowledge and/or understanding of the revenue reset process	○	○	○	○	○
I feel that TasNetworks listened to and heard my perspectives/concerns during this activity	○	○	○	○	○
I trust TasNetworks to act in the best interests of its customers	○	○	○	○	○

2. Do you have any suggestions about how the engagement activity could be improved? *

Please add your comment here...

3. What did you value most about the engagement activity? *

can't be blank

Please add your comment here...

4. Do you have any other comments about the engagement activity you recently participated in for TasNetworks' R24 project? *

Please add your comment here...

ABOUT YOU...

5. Please indicate what date you participated in your engagement activity *

6. Please indicate what type of engagement activity you participated in *

- ○ Online customer forum (21 July)
- ○ Reset Advisory Committee meeting
- ○ Policy and Regulatory Working group meeting
- ○ Customer Council meeting
- ○ Discussion circle (Launceston, Hobart or Ulverstone)
- ○ Customer panel (Launceston or Hobart)
- ○ Focus group
- ○ 1:1 meeting/interview
- ○ Council forum
- ○ Other (please specify)

7. Please select the option that best describes you *

- ○ I am a stakeholder of TasNetworks
- ○ I am a TasNetworks transmission customer
- ○ I am a residential TasNetworks customer
- ○ I am a small-medium business TasNetworks customer
- ○ I am a member of one of TasNetworks' advisory groups (RAC, PRWG, CC)
- ○ Other (please specify)

8. Please provide your first name and initial (for participation verification purposes only). For example, "Katie D". *

Please add your comment here...

0/255

Powering a
Bright Future

Combined Proposal 2024-2029

Attachment 2
Annual revenue requirement

Outline: This attachment to TasNetworks' Combined Proposal sets out how the annual revenue requirement provisions of the National Electricity Rules will apply during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	**Annual revenue requirement**
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

2 Annual revenue requirement

2.1 Overview

The forecast total revenue requirement for our transmission network for the 2024-2029 regulatory control period is $784.1 million ($2023-24). This is around 4.8 per cent lower than our total revenue requirement for the 2019-2024 regulatory control period. This total revenue reduction results in a forecast decrease in the average transmission price in the first year of the next regulatory control period of 1.0 per cent.

The forecast total revenue requirement for our distribution network for the 2024-2029 regulatory control period is $1,549.2 million ($2023-24). This is around 8.3 per cent higher than our total revenue requirement for the 2019-2024 regulatory control period resulting in an increase in the indicative distribution network charge in the first year of the next regulatory control period of around 5.9 per cent.[1]

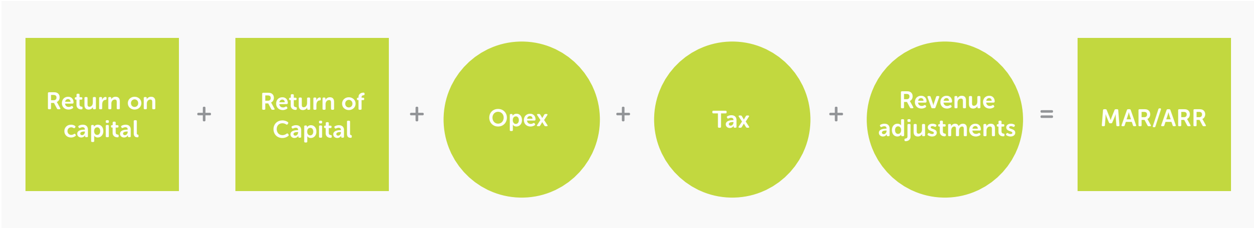
In accordance with the feedback we have received from our customers and stakeholders, we have taken a disciplined approach to our capital and operating expenditure by constraining the total revenue required to maintain safe, reliable and affordable network services.

2.2 Rule requirements

Our total revenue requirements for our transmission and distribution networks are based on the Australian Energy Regulator's (**AER's**) post-tax building block approach and comply with clauses 6.4.3 and 6A.5.4 of the National Electricity Rules (**NER**), the Post Tax Revenue Model (**PTRM**) and the Roll Forward Model (**RFM**). The revenue building block components are shown in Figure 1.

1 for a typical Residential customer

Figure 1. Revenue Building Blocks



TasNetworks' forecast total revenue requirement comprises unsmoothed annual revenue requirement (**ARR**) or maximum allowed revenue (**MAR**) for each year of the 2024-2029 regulatory control period, which are calculated as the sum of the above building block components for each of our networks. Clause 6A.6.8 of the NER requires that these unsmoothed revenue requirements must be smoothed with an X-factor, such that the smoothed ARR / MAR is equal to the net present value (**NPV**) of the annual unsmoothed ARR / MAR, while ensuring that the smoothed and unsmoothed ARR / MAR for the last regulatory year are as close as reasonably possible.

In addition to the above building blocks, clause 6A.7.2 of the NER requires that any changes in transmission network support costs that occur during a regulatory control period be subject to a pass-through application. The application will seek to vary the MAR for each year based on the difference between forecast and actual network support expenditure.

Furthermore, clauses 6A.7.3 and 6.6.1 of the NER allow the pass through of other approved transmission and distribution costs (refer to Attachment 17 Pass through events).

Finally, clause 6A.8 (transmission) and 6.6A (distribution) of the NER allows the AER to amend TasNetworks revenue allowance for costs associated with contingent projects that are triggered during a regulatory control period (refer to Attachment 7 Contingent projects).

2.3 Forecast revenue

Figure 2 shows a $39.4 million reduction in real terms and a flatter annual profile between TasNetworks' total annual revenue forecasts for our transmission network for the 2024-2029 regulatory control period compared to the 2019-2024 regulatory control period.

Figure 2. Forecast Transmission Revenue ($ million, 2023-24)

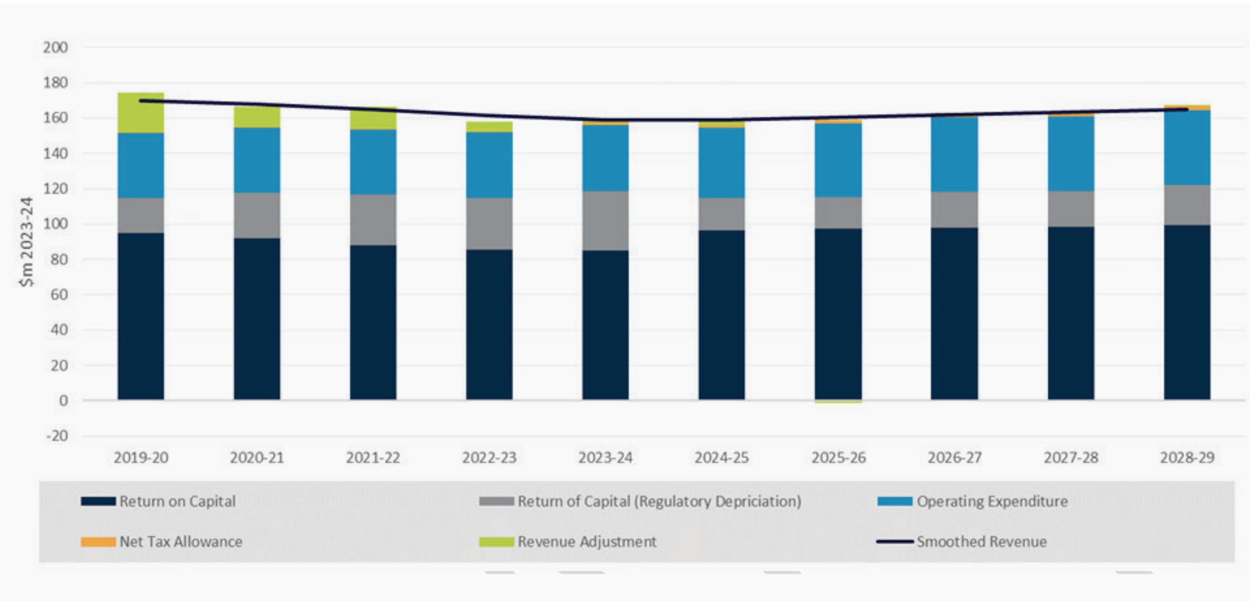
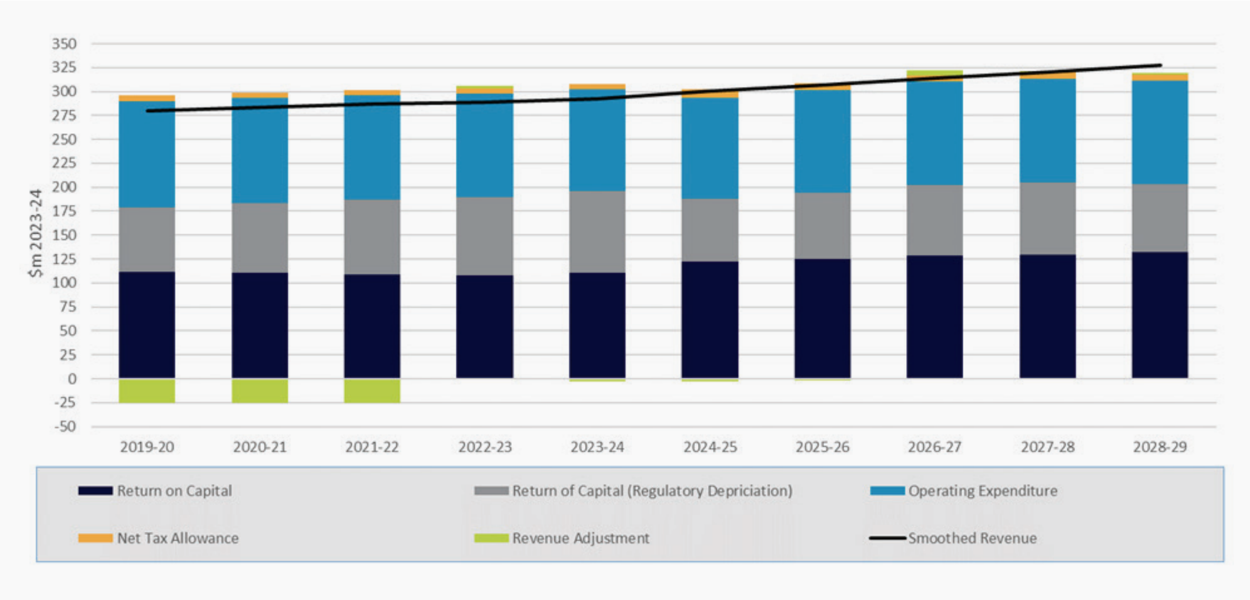


Figure 3 shows a $154.2 million increase in real terms between TasNetworks' total annual revenue forecasts for our distribution network for the 2024-29 regulatory control period compared to the 2019-2024 regulatory control period.

Figure 3. Forecast Distribution Revenue ($ million, 2023-24)



We summarise the various building block components in the following sections of this attachment. Further explanation and substantiation of these components is provided in subsequent attachments of this Combined Proposal.

2.3.1. Regulatory asset base

The value of our regulatory asset base (**RAB**) for each of our transmission and distribution networks determines our return on and return of capital allowances.

Our estimated opening RAB on 1 July 2024 for our transmission network is $1,758.7 million (nominal). Our estimated opening RAB on 1 July 2024 for our distribution network is $2,223.0 million (nominal). Our approach to calculating these opening RAB values is explained in Attachment 3 Regulatory asset base.

We have forecast a roll-forward of our RAB for each year of the 2024-2029 regulatory control period based on our forecasts for inflation (refer Attachment 4 Rate of return), regulatory depreciation (refer Attachment 5 Regulatory depreciation) and capital expenditure (refer Attachment 6 Captial expenditure). The RAB roll forward for each network is shown in Tables 1 and 2.

Table 1. Transmission Forecast RAB roll forward 2024-2029 regulatory control period ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	1,758.7	1,799.0	1,858.8	1,908.8	1,958.8
Capital expenditure, as incurred	54.4	73.3	65.6	66.6	61.6
Regulatory deprecation	(14.2)	(13.5)	(15.6)	(16.6)	(18.7)
Closing RAB	1,799.0	1,858.8	1,908.8	1,958.8	2,001.7

Table 2. Distribution Forecast RAB roll forward 2024-2029 regulatory control period ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	2,223.0	2,323.7	2,429.7	2,512.5	2,591.1
Capital expenditure, as incurred	162.6	173.6	158.5	158.1	160.5
Regulatory deprecation	(61.9)	(67.6)	(75.7)	(79.5)	(77.6)
Closing RAB	2,323.7	2,429.7	2,512.5	2,591.1	2,674.0

2.3.2 Return on capital

The return on capital is calculated by applying our rate of return (also referred to as the Weighted Average Cost of Capital or **WACC**) to the opening RAB in each year of the regulatory control period. Attachment 4 Rate of return further explains the calculation of our rate of return forecast.

Our return on capital forecast for each network is presented in Tables 3 and 4.

Table 3. Transmission Return on capital ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Opening RAB	1,758.7	1,799.0	1,858.8	1,908.8	1,958.8	
Rate of return	5.68%	5.80%	5.85%	5.93%	6.03%	
Return on capital	99.8	104.4	108.8	113.1	118.1	544.2

Table 4. Distribution Return on capital ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Opening RAB	2,223.0	2,323.7	2,429.7	2,512.5	2,591.1	
Rate of return	5.71%	5.78%	5.85%	5.93%	6.03%	
Return on capital	126.9	134.3	142.2	148.9	156.3	708.5

2.3.3 Regulatory depreciation

Regulatory depreciation (also referred to as the return of capital) is calculated by deducting the inflation adjustment made to the RAB from forecast depreciation. Attachment 5 Regulatory depreciation further explains the calculation of our regulatory depreciation forecast.

Our regulatory depreciation forecast for each network is presented in Tables 5 and 6.

Table 5. Transmission Return of capital ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Straight-line depreciation	73.0	73.7	77.8	80.5	84.3	389.4
Indexation on opening RAB	(58.9)	(60.2)	(62.2)	(63.9)	(65.6)	(310.9)
Return of capital	14.2	13.5	15.6	16.6	18.7	78.5

Table 6. Distribution Return of capital ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Straight-line depreciation	136.3	145.4	157.1	163.6	164.3	766.8
Indexation on opening RAB	(74.4)	(77.8)	(81.4)	(84.1)	(86.6)	(404.5)
Return of capital	61.9	67.6	75.7	79.5	77.6	362.3

2.3.4 Operating expenditure

Our operating expenditure forecast for each of our transmission and distribution networks is shown in Tables 7 and 8. Attachment 8 Operating expenditure further explains the calculation of our operating expenditure forecast.

Table 7. Transmission Operating expenditure ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Controllable operating expenditure	40.2	43.5	46.0	47.7	49.3	226.8
Debt raising costs	0.9	0.9	0.9	1.0	1.0	4.7
Total operating expenditure	41.1	44.4	46.9	48.7	50.3	231.4

Table 8. Distribution Operating expenditure ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Controllable operating expenditure	97.5	102.7	107.4	111.5	115.7	534.7
GSL	4.1	4.2	4.4	4.5	4.7	21.9
Electrical Safety Inspection Levy payments	5.3	5.4	5.6	5.8	6.0	28.1
NEM Levy payments	1.5	1.6	1.5	1.3	1.4	7.3
Debt raising costs	1.1	1.2	1.2	1.3	1.3	6.1
Total operating expenditure	109.5	115.1	120.1	124.4	129.0	598.2

2.3.5 Tax

We forecast the taxation building block for each of our transmission and distribution networks, by applying a statutory tax rate of 30% and value for imputation credits of 0.585 consistent with the AER's 2018 Rate of Return Instrument.2 This is presented in Tables 9 and 10.

Table 9. Transmission Corporate tax ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Corporate tax	2.5	4.1	3.6	4.2	6.1	20.6
Value of imputation credits	(1.5)	(2.4)	(2.1)	(2.5)	(3.6)	(12.0)
Taxation	1.0	1.7	1.5	1.7	2.5	8.5

Table 10. Distribution Corporate tax ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Corporate tax	20.7	16.4	15.1	16.8	16.3	85.3
Value of imputation credits	(12.1)	(9.6)	(8.8)	(9.8)	(9.5)	(49.9)
Taxation	8.6	6.8	6.2	7.0	6.8	35.4

2.3.6 Expenditure incentive schemes

Any capital and operating efficiency gains or losses arising from the Efficiency Benefit Sharing Scheme (**EBSS**) and Capital Expenditure Sharing Scheme (**CESS**) in the 2019-2024 regulatory control period are carried over as an adjustment to the ARR / MAR in the 2024-2029 regulatory control period.

Our EBSS and CESS carryover amounts for each network (refer Attachment 10 Efficiency benefit sharing scheme and Attachment 11 Capital expenditure sharing scheme) from the 2019-2024 regulatory control period are summarised in Tables 11 and 12.

2 AER, Rate of return instrument, Dec 2018

Table 11. Transmission EBSS and CESS carryover amounts ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
EBSS carryover	2.6	(2.2)	(0.2)	0.0	0.0	0.2
CESS carryover	0.7	0.7	0.7	0.7	0.7	3.5
Revenue Adjustments	3.2	(1.5)	0.5	0.7	0.7	3.7

Table 12. Distribution EBSS and CESS carryover amounts ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
EBSS carryover	(3.6)	(3.4)	4.2	0.0	0.0	(2.8)
CESS carryover	2.2	2.2	2.3	2.4	2.5	11.6
Revenue Adjustments	(1.5)	(1.2)	6.5	2.4	2.5	8.8

2.3.7 Shared asset decrements

Electricity network businesses may use assets to provide both regulated electricity services and other (unregulated) services. These assets are called 'shared assets'.

An example of a shared asset is a power pole, paid for by electricity consumers, which also supports a fibre optic cable for communications services. While the AER regulates electricity supply it does not regulate communications services. So, the power pole is a shared asset.

To manage this the AER has published a Shared Asset Guideline[3] which sets out its approach to sharing the benefits of the unregulated transaction with consumers of regulated services.

Importantly, when unregulated revenues from shared assets are more than one per cent of a Network Service Provider's total annual revenue the AER will reduce regulated revenues by around 10 percent of the value of unregulated revenues earned from the shared assets.

TasNetworks has forecast revenue from these shared assets for the 2024-2029 regulatory control period and only the distribution network has shared assets that meet the one per cent revenue threshold. Therefore, a shared asset decrement has been determined for the distribution revenue as shown in Table 13.

Table 13. Distribution Shared Asset Decrement ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Shared Asset Decrement	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(2.3)

2.3.8 X-factors and smoothed total revenue

X-factors are utilised in the PTRM as a method for ensuring that year on year differences in revenue are smoothed out for customers. The calculation of X-factors takes into account the NPV of the revenue stream and ensures that customers and networks are no better or worse off from any movements in the timing of revenue. X-factors are updated on a yearly basis to account for the annual update to the rolling cost of debt as part of the rate of return calculation. The AER will release an updated PTRM every year to account for this movement.

We have applied an X-factor to our unsmoothed ARR / MAR to reduce significant variations and/or smooth revenue in each year of the 2024-2029 regulatory control period. The smoothed annual revenue profile is used to set our transmission and distribution prices each year.

Our X-factors and smoothed ARR / MAR for the 2024-2029 regulatory control period are summarised in Tables 14 and 15.

Table 14. Transmission X-factors and smoothed MAR ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed revenue requirement	159.6	162.6	173.5	181.1	190.6	867.5
X-factors	1.63%	(0.78%)	(0.78%)	(0.78%)	(0.78%)	
Smoothed MAR	159.6	166.2	173.1	180.3	187.8	866.9

3 AER, Better Regulation Shared Asset Guideline, Nov 2013

Table 15. Distribution X-factors and smoothed ARR ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed revenue requirement	305.5	322.7	350.9	362.3	372.2	1,713.5
X-factors	(2.43%)	(2.36%)	(2.36%)	(2.36%)	(2.36%)	
Smoothed ARR	305.5	323.1	341.8	361.6	382.5	1,714.5

2.3.9 Possible additional revenue adjustments

During the 2024-2029 regulatory control period, our ARR / MAR will be updated each year to reflect:

- actual inflation
- changes to the annual return on debt
- any changes in network support costs subject to a pass-through application
- any cost pass-through events approved by the AER
- financial penalties or bonuses being subtracted from or added to our smoothed ARR / MAR due to our transmission and/or distribution network service performance in a year varying from the AER's approved targets (refer Attachment 12 Service target performance incentive scheme).

Our MAR for the transmission network may also change if any of our proposed contingent projects are triggered during the 2024-2029 regulatory control period and approved by the AER following an application from TasNetworks. No contingent projects have been identified for our distribution network in the 2024-2029 regulatory control period. (Refer to Attachment 7 Contingent projects).

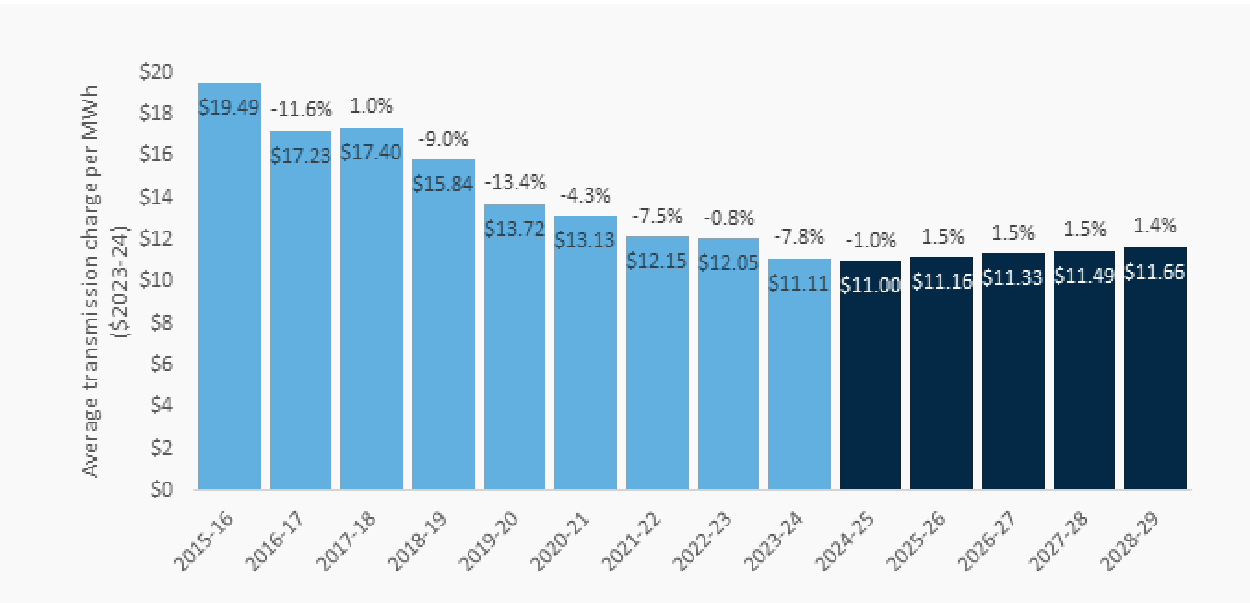
2.4 Indicative price impacts

TasNetworks calculates annual prescribed transmission prices consistent with our approved Pricing Methodology, which must comply with the requirements of the NER and the AER's Pricing Methodology Guidelines for transmission networks.

TasNetworks determines its transmission charges based on the approved smoothed MAR and the pricing principles in Clause 6A.23 of the NER. The average price path is illustrative and estimated using the AER's PTRM, whereby we divide our forecast annual smoothed MAR by forecast energy delivered in Tasmania in each year of the 2024-2029 regulatory control period. This is shown in Figure 4.

It is important to note that price movements for individual customers will vary depending on usage, location and the annual adjustments described above. As such, Figure 4 indicates the implications of our proposal for average transmission prices over the 2024-2029 regulatory control period.

Figure 4. Average charges for all transmission customers, average $/MWh ($real 2023-24)



The distribution revenue allowance for each year, together with approximately 55 per cent of transmission network charges, 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 electricity retailers.

Our proposed transmission and distribution smoothed ARR / MAR result in the indicative average annual network charges for residential and small business customers shown in Figures 5 and 6 respectively. Our proposal results in most customers' network charge movements being broadly aligned with forecast inflation. This is consistent with our key objective to balance ongoing affordability of our network services with the need to invest in services that meet Tasmanian electricity customers' long-term interests.

Figure 5. Indicative distribution network charges, residential customer ($real 2023-24)

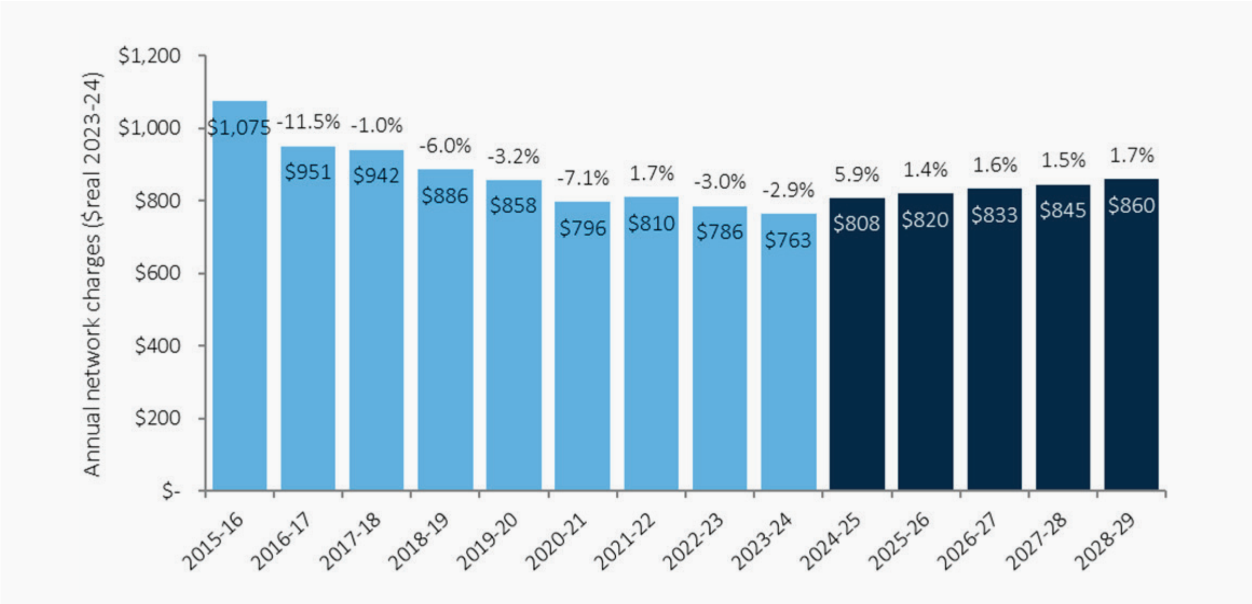
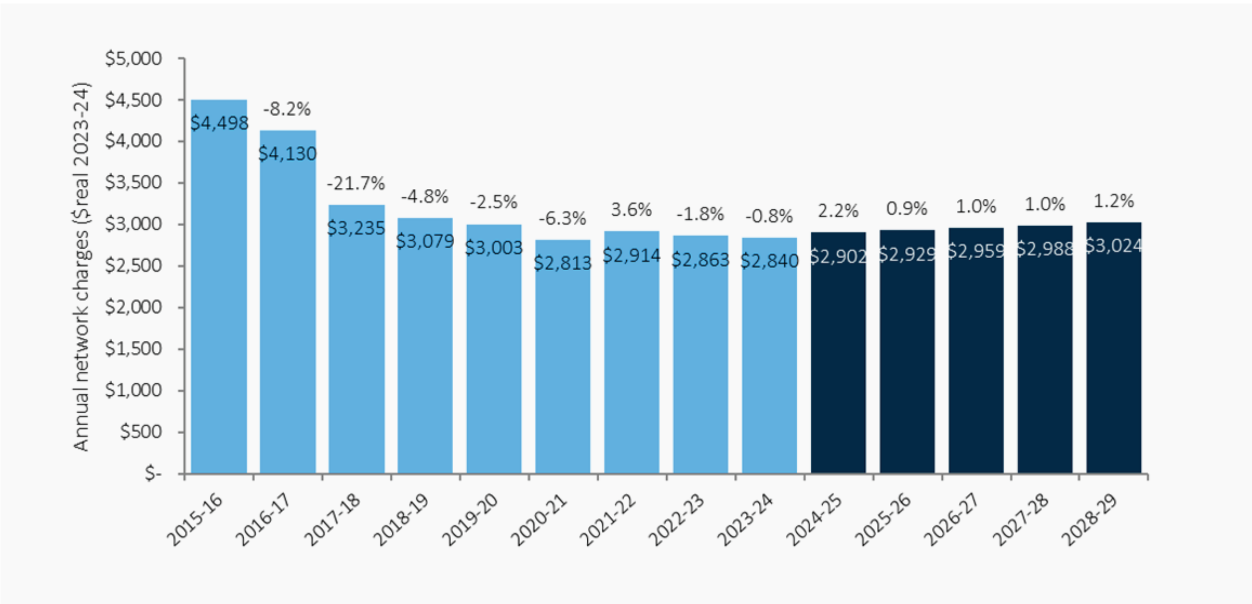


Figure 6. Indicative distribution network charges, small business customer ($real 2023-24)



Transmission and distribution network costs presently make up around 38 per cent of the average Tasmanian residential and small business customer electricity retail bill.

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Attachment 3
Regulatory asset base

Outline: This attachment to TasNetworks' Combined Proposal sets out forecasts for the roll forward of TasNetworks' regulatory asset base for Standard Control Services and regulatory asset base for the provision of Prescribed Transmission Services in the regulatory control period commencing on 1 July 2024 and ending on 30 June 2029.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	**Regulatory asset base**
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
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Tables in this attachment may not add due to rounding.

Contents

3 Regulatory asset base

3.1 Introduction

Electricity networks are asset-intensive businesses, requiring thousands of poles, wires and transformers to convey electricity from the point of generation to the point at which it is used, assets that involve significant capital outlays. Most of the assets TasNetworks invests in have operating lives measured in decades, and their cost is recovered from customers over time, rather than up-front or in the year they are built or installed.

TasNetworks is unusual within the National Electricity Market (**NEM**) in that it operates two regulated electricity networks: a shared transmission network that enables large generators, such as windfarms and hydro-electric power stations, to transmit the high voltage electrical energy they produce to population centres and major industrial users of electricity, and a shared distribution network, which delivers electricity to individual consumers at the lower voltages required by households and most businesses. Most of the network service providers within the NEM operate only one or the other.

Between them, the two networks connect a comparatively substantial number of renewable generators (around 30 hydro-electric power stations and wind farms) and provide energy to a geographically dispersed population, as well as a small number of large industrial users of electricity. Increasingly, the distribution network is also being asked to reticulate energy being exported by the growing number of households and small businesses that generate electricity using photo-voltaic solar panels.

The revenue TasNetworks is allowed to earn through its network charges is intended to recover the cost of building, maintaining and operating both the transmission and distribution networks, with the Australian Energy Regulator (**AER**) setting a separate annual revenue allowance for each network. The revenue allowances set by the AER include operational costs, like providing a call centre, clearing trees away from power lines and restoring power after storms. The revenue allowances set by the AER are also intended to provide TasNetworks with a fair return on its investment in the assets used to transmit and distribute electricity, and to enable TasNetworks to recover the cost of that investment over time (i.e., through a depreciation allowance).

The value of the regulatory asset base (**RAB**) therefore is the largest determinant of TasNetworks' revenue and the network charges paid by the end users of electricity in Tasmania. Together, TasNetworks' transmission and distribution networks comprise 3,500 circuit kilometres of transmission lines and underground cables, 49 transmission substations, 22,300km of distribution power lines and underground cables, over 230,000 power poles, 18 large distribution substations and 33,000 small distribution substations.

The annual revenue requirement (**ARR**) (see Attachment 2) allows TasNetworks to recover:

- the capital cost of the investments it has made in the RAB (depreciation)
- a fair return on that investment (the return on capital).

The RAB only comprises those assets used to provide regulated transmission and distribution network services (respectively Prescribed Transmission Services and Standard Control Services). The RAB generally excludes assets such as the high voltage connection assets that that are dedicated exclusively to individual generators or load customers. When assets are disposed of or customers make capital contributions towards the cost of shared assets, those contributions are removed from the overall RAB value. The value of the RAB is indexed each year for inflation to reflect the changing value of money over time.

The RAB calculation is summarised in Figure 1.

Figure 3.2 RAB calculation

3.2 RAB

With total assets of around $4 billion, TasNetworks is conscious of the relationship between RAB values and the delivered cost of energy for its customers. Since assuming responsibility for Tasmania's electricity grid in 2014, TasNetworks has focussed on ensuring that the investments it has made in the network are prudent and efficient, balancing the need for sustainable electricity prices over the long term with maintaining safe and reliable network services.

3.2.1 Rule requirements

Clause 6.4.3 of the National Electricity Rules (**NER**) provides that the annual revenue requirement for a distribution network service provider (**DNSP**) in each regulatory year of a relevant regulatory control period must be determined using a building block approach, which includes indexation of the RAB, a return on capital and depreciation. Clause 6A.5.4 of the NER sets out a similar provision for transmission network service providers (**TNSPs**).

Clause S6.1.3(7) of the NER requires the building block revenue proposal from each distribution network to include a calculation of its RAB for each year of the relevant regulatory control period, derived using the AER's roll forward model (**RFM**). The RAB values are to be accompanied by details of the amounts, values and other inputs used by the DNSP to calculate the value of its RAB, and an explanation of the calculation of the regulatory asset base's value in each regulatory year of the relevant regulatory control period. Clause S6A.1.3(5) of the NER places similar obligations TNSPs.

Clause S6.2.1 of the NER sets out how TasNetworks must establish the opening value of its distribution RAB for the 2024-2029 regulatory control period and calculate the forecast RAB values for the 2024-2029 regulatory period. This includes calculating the respective RAB values for each year of the current 2019-2024 regulatory control period using the AER's RFM and calculating the forecast RAB for the 2024-2029 regulatory period using the AER's post tax revenue model.

In calculating the forecast distribution RAB for the 2024-2029 regulatory period, the NER also requires TasNetworks to demonstrate that:

- indexation of the distribution RAB has been calculated in accordance with clause 6.5.1 and schedule 6.2, such that the building block revenue includes a negative adjustment equal to the amount referred to in clause S6.2.3(c)(4) for that year (to avoid the double counting of the change in the RAB value due to inflation)
- depreciation has been calculated in accordance with clause 6.5.5.

Clause S6A.1.3(5) of the NER places similar obligations on TasNetworks in relation to our transmission RAB.

3.3 Proposed RAB values

Based on the requirements of the NER, this attachment includes estimates of the closing values for both our transmission and distribution network RABs at the end of the 2019-2024 regulatory control period. It also includes the opening RAB values for each network on 1 July 2024 and forecast RAB values in each year of the 2024–2029 regulatory control period.

As part of these calculations:

- straight-line forecast depreciation, which is based on forecast capital expenditure as per the AER's final determination for the 2019-2024 regulatory control period, has been deducted from the initial value of the RAB at 1 July 2024
- actual capital expenditure has been rolled into the RAB to establish its initial value at 1 July 2024
- forecast capital expenditure for the 2024-2029 regulatory control period has been reduced for customer capital contributions made towards the asset and the disposal of assets, to determine net capital expenditure
- net capital expenditure includes a half year's weighted average cost of capital (**WACC**), to compensate for the six-month period before this expenditure is added to the RAB for revenue modelling
- the RAB has been adjusted for actual inflation to establish its initial value as at 1 July 2024 and adjusted to remove the effect of forecast inflation for the 2024-2029 regulatory period.

3.4 Distribution RAB

3.4.1 Distribution RAB roll-forward, 2019-2024

During the 2019-2024 regulatory control period, the value of TasNetworks' distribution network RAB is estimated to increase by 6.8 per cent in real terms (26.0 per cent in nominal terms). The roll forward of TasNetworks' distribution RAB for standard control services over the 2019–2024 regulatory control period is set out in Table 1. The (forecast) closing RAB as at 30 June 2024 is the estimated opening value at the start of the 2024-2029 regulatory control period.

Table 1. Distribution RAB roll-forward to 30 June 2024 (nominal, $ million)

	2019-20	2020-21	2021-22	2022-23 (forecast)	2023-24 (forecast)
Opening RAB	1,763.9	1,814.0	1,859.0	1,932.2	2,115.2
Actual/estimated capital expenditure, net of contributions and disposals	117.0	135.8	121.2	148.4	161.5
Indexation on opening RAB	32.5	15.6	65.1	154.6	99.4
Less: straight-line depreciation	99.4	106.4	113.0	120.0	133.2
Less: final year (2018-19) adjustments					19.98
Closing RAB	**1,814.0**	**1,859.0**	**1,932.2**	**2,115.2**	**2,223.0**

3.4.2 Distribution RAB roll-forward, 2024-2029

The roll forward of TasNetworks' distribution RAB over the 2024-2029 regulatory control period is set out in Table 2 and reflects forecasts for net capital expenditure, depreciation and indexation. The opening RAB at 1 July 2024 is based on the closing RAB value as at 30 June 2024 shown in Table 1.

Table 2. Distribution RAB roll-forward to 30 June 2029 (nominal, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	2,223.0	2,323.7	2,429.7	2,512.5	2,591.1
Actual/estimated capital expenditure, net of contributions and disposals	162.6	173.6	158.5	158.1	160.5
Indexation on opening RAB	74.4	77.8	81.4	84.1	86.8
Less: Straight-line depreciation	136.3	145.4	157.1	163.6	164.3
Closing RAB	**2,323.7**	**2,429.7**	**2,512.5**	**2,591.1**	**2,674.0**

TasNetworks' forecast capital expenditure in the 2024-2029 regulatory control period is discussed in Attachment 6 Capital expenditure.

TasNetworks proposes that the depreciation for establishing the closing RAB value of the distribution network at 30 June 2029 be based on forecast capex, consistent with the AER's Framework and Approach paper for TasNetworks in the 2024–2029 regulatory control period and clause S6.2.2B of the NER.

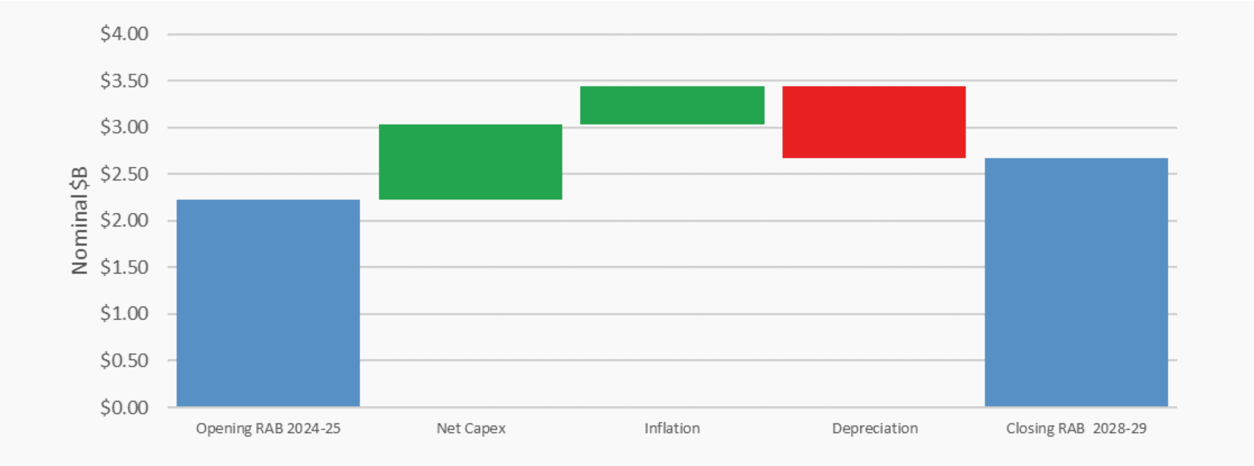
TasNetworks' forecasts of depreciation have been calculated on a straight-line basis using AER-approved standard asset lives and are discussed in Attachment 5 Regulatory depreciation.

Indexation of the RAB during the 2024-2029 regulatory control period has been calculated using a forecast inflation rate of 3.35 per cent, which is based on the AER's inflation forecasting methodology as discussed in Attachment 4 Rate of return. In calculating the return of capital allowance in the ARR (i.e., regulatory depreciation), the indexation amount is deducted from the value of straight-line depreciation.

The closing distribution network RAB at the end of the 2024–2029 regulatory control period is forecast to be 20.3 per cent higher in nominal dollar terms and 5.4 per cent higher in real dollar terms than the opening RAB at the start of that period.

Figure 2 shows the contributors to the forecast change in the value of TasNetworks' distribution network RAB over the course of the 2024-2029 regulatory control period.

Figure 2. Drivers of distribution RAB value, 2024-2029 (nominal, $ billion)



3.5 Transmission RAB

3.5.1 Transmission RAB roll-forward, 2019-2024

During the 2019-2024 regulatory control period, the value of TasNetworks' transmission network RAB is estimated to decrease marginally in real terms (18.9 per cent increase in nominal terms). The roll forward of TasNetworks' transmission RAB for the provision of prescribed transmission services during the 2019–2024 regulatory control period is set out in Table 3. The (forecast) closing RAB at 30 June 2024 is the estimated opening value of TasNetworks' transmission network RAB at the start of the 2024-2029 regulatory control period.

Table 3. Transmission RAB roll-forward to 30 June 2024 (nominal, $ million)

	2019-20	2020-21	2021-22	2022-23 (forecast)	2023-24 (forecast)
Opening RAB	1,479.1	1,506.7	1,513.1	1,560.5	1,695.0
Actual/estimated capital expenditure, net of contributions and disposals	51.6	45.6	47.1	64.1	56.6
Indexation on opening RAB	27.2	13.0	53.0	124.8	79.7
Less: straight-line depreciation	51.2	52.2	52.6	54.5	58.8
Less: final year (2018-19) adjustments					13.7
Closing RAB	**1,506.7**	**1,513.1**	**1,560.5**	**1,695.0**	**1,758.7**

3.5.2 Transmission RAB roll-forward, 2024-2029

The roll forward of TasNetworks' transmission RAB for prescribed transmission services over the 2024-2029 regulatory control period is set out in Table 4. TasNetworks has modelled the roll forward of its transmission network RAB in the 2024–2029 regulatory control period based on the closing RAB value on 30 June 2024, as shown in Table 3.

Table 4. Roll forward of Transmission network RAB, 2024–2029 (nominal, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	1,758.7	1,799.0	1,858.8	1,908.8	1,958.8
Actual/estimated capital expenditure, net of contributions and disposals	54.4	73.3	65.6	66.6	61.6
Indexation on opening RAB	58.9	60.2	62.2	63.9	65.6
Less: straight-line depreciation	73.0	73.7	77.8	80.5	84.3
Closing RAB	**1,799.0**	**1,858.8**	**1,908.8**	**1,958.8**	**2,001.7**

TasNetworks' forecast capital expenditure in the 2024-2029 regulatory control period is discussed in Attachment 6 Capital expenditure.

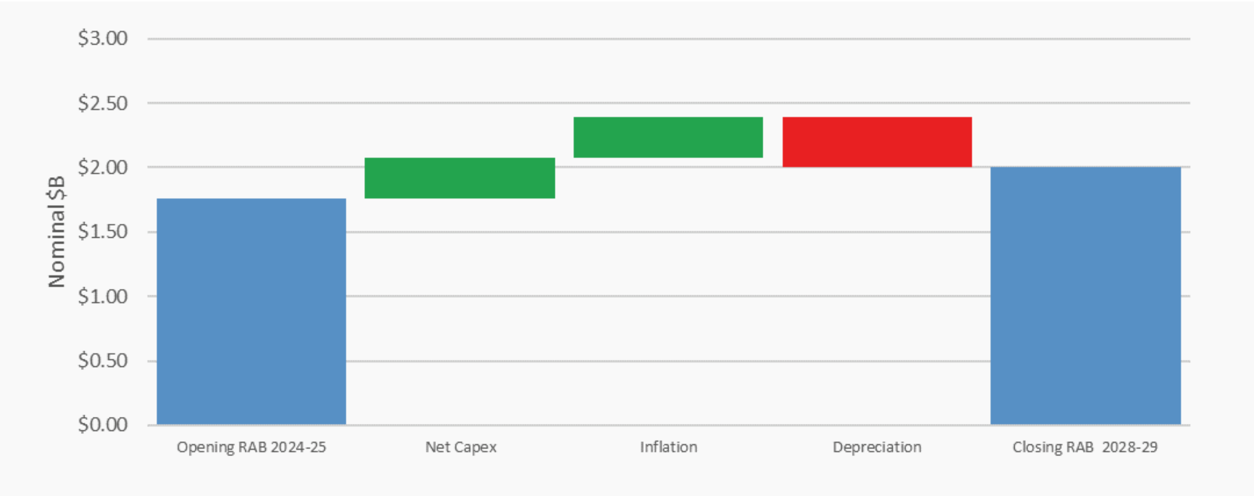
TasNetworks proposes that the depreciation for establishing the closing RAB value as at 30 June 2029 be based on forecast capex, consistent with the AER's Framework and Approach paper for TasNetworks in the 2024–2029 regulatory control period. TasNetworks' forecasts of depreciation have been calculated on a straight-line basis using AER-approved standard asset lives and are discussed in Attachment 5 Regulatory depreciation.

Indexation of the RAB has been calculated using a forecast inflation rate of 3.35 per cent, which is discussed in Attachment 4 Rate of return. In calculating the return of capital allowance in the ARR (i.e., regulatory depreciation), the indexation amount is deducted from the value of straight-line depreciation.

The closing transmission network RAB at the end of the 2024–2029 regulatory control period is forecast to be 13.8 per cent higher than the opening RAB at the start of that period, in nominal terms, and 0.2 per cent lower in real terms.

Figure 3 below shows the contributors to the forecast change in the value of TasNetworks' transmission network RAB over the course of the 2024-2029 regulatory control period.

Figure 3. Drivers of transmission RAB value, 2024-2029 (nominal, $ billion)



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Attachment 4
Rate of return

Outline: This attachment to TasNetworks' Combined Proposal sets out the proposed rates of return that will be applied to the value of TasNetworks' distribution and transmission networks, to determine the return on capital included in TasNetworks' regulated revenue allowance for the 2024-2029 regulatory control period.

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Note

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Tables in this attachment may not add due to rounding.

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4 Rate of return

4.1 Introduction

A key component of the revenue allowances set by the Australian Energy Regulator (**AER**) for network service providers (**NSPs**) such as TasNetworks is the return on capital that each business receives on its investment. The return on capital is intended to provide network businesses with the revenue they need to service the interest on the borrowings they use to finance network assets, as well as earn a fair return on equity for the investors in those businesses. This return on capital is set by applying a rate of return – calculated using the AER's Rate of Return Instrument (**RoR Instrument**) – to the value of each network's regulatory asset base (**RAB**). This Attachment explains how the rate of return is set to calculate the return on capital. It also forecasts an indicative rate of return, noting that the final rate of return will depend on economic conditions at the time the AER makes its Final Determination in April 2024.

Because the regulatory framework applied by the AER is incentive-based, the rate of return that is used to calculate the return on capital allowance is set with reference to an 'efficient benchmark' firm. This is intended to ensure that network businesses can only recover efficient costs. That is, the return on capital is not based on each network's actual cost of capital so NSPs are not compensated for inefficient funding arrangements or costs.

4.1.1 The AER's Rate of Return Instrument

The RoR Instrument is a guideline that specifies how the AER calculates the rate of return, comprising the return on debt and return on equity.

The AER is required to review and publish a new RoR Instrument every four years.[1] The RoR Instrument is binding for all revenue determinations made during the four-year period it applies. It is not retrospectively applied to revenue determinations already made by the AER.

The AER was due to publish a new RoR Instrument in December 2022, but this is now expected to be published in February 2023. As a result, TasNetworks is required to use the 2018 RoR Instrument for the purpose of this combined proposal. The AER Draft Decision, our revised proposal and the AER Final Determination will all use the 2022 RoR Instrument to calculate TasNetworks' return on capital and equity.

4.1.2 The impact of changes in financial market conditions

The RoR Instrument is highly prescriptive in terms of the methodologies and parameters used to estimate the rate of return. At the same time, it needs to reflect the impact of changing financial market conditions, which will drive the returns required by lenders (the return on debt) and equity investors (the return on equity). Noting that the timing of the regulatory control periods for each transmission and distribution network can differ, the rates of return that are set by the AER for each business need to have appropriate regard to the prevailing financial market conditions and outlook at the time of the revenue determination.

Under the 2018 RoR Instrument and the 2022 Draft RoR Instrument there are only two parameters whose values are allowed to vary over time in accordance with market conditions. These are:

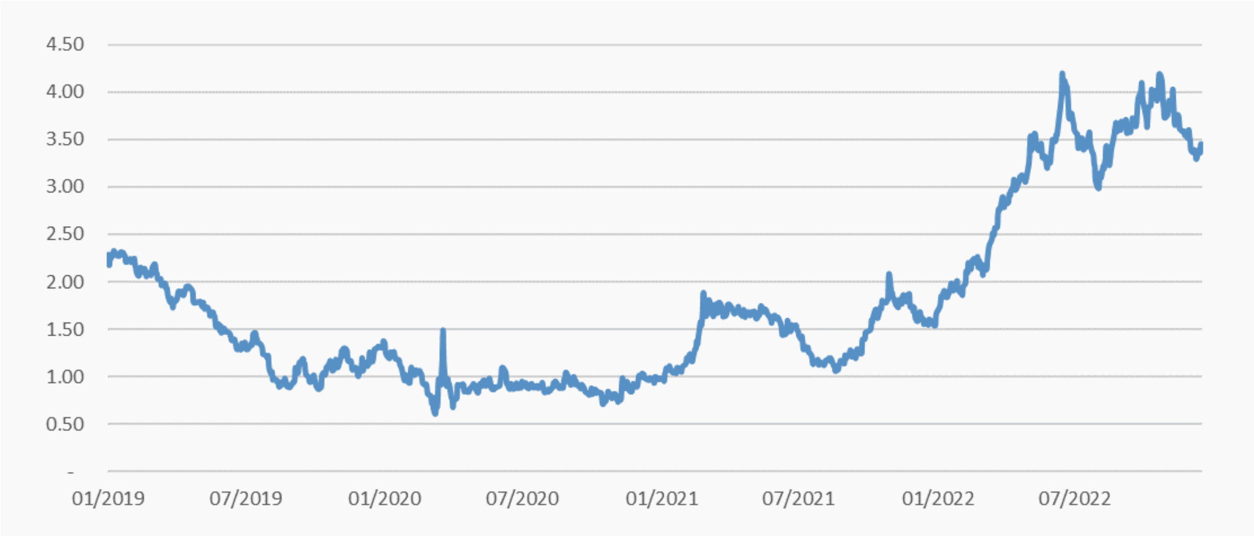
- The risk-free rate used to set the return on equity (refer section 4.3.1), which is based on the Australian Government bond yield. This is reset close to the commencement of each regulatory control period based on prevailing market rates. This value is then fixed for the duration of the regulatory control period
- The return on debt (refer section 4.3.2). This is updated annually to reflect changes in the benchmark cost of debt based on a detailed methodology prescribed in the RoR Instrument. This in turn reflects changes in the market interest rates for borrowing funds.

1 Section 18U of the National Electricity Law

Overall, the allowed rate of return that is set by the AER for the purpose of determining an NSP's allowed revenue (and hence prices) is beyond the control of TasNetworks. Apart from changes in the AER's RoR Instrument, the key driver of changes in the allowed rate of return is changes in market interest rates. This will be driven by changing conditions in financial markets.

At the commencement of TasNetworks' 2019-2024 regulatory control period, government bond yields remained at historical lows. This situation has now changed as domestic and global economies emerge from the COVID-19 pandemic and a number of factors, such as continued supply chain disruptions and the war in Ukraine, are placing significant pressure on inflation. The following chart shows the ten-year Australian Government bond yield (the risk-free rate under the 2018 RoR Instrument) from the start of TasNetworks' current regulatory control period on 1 July 2019 until the end of October 2022.

Figure 1. Ten-year Australian Government bond yield



Source: Reserve Bank of Australia, https://www.rba.gov.au/statistics/tables/#interest-rateshttps://www.rba.gov.au/statistics/tables/#interest-rates

The increases in the risk-free rate will be reflected in a higher rate of return estimate. However, as noted above, the final rate of return applying to TasNetworks' 2024-2029 regulatory control period will be based on the interest rate environment prevailing at the time of the AER's Final Determination. This could be quite different from the current environment and there remains significant uncertainty regarding future interest rates. Consequently, return on capital could be higher or lower than presented in this document when the AER makes its final determination in April 2024.

The key point is that the rate of return that is used to set TasNetworks' return on capital allowances for its transmission and distribution networks is outside our control; it is approved by the AER in accordance with its ROR Instrument. This in turn drives the most significant component of TasNetworks' building block revenue that is used to set prices.

4.2 Rule requirements

Clause 6.4.3 of the National Electricity Rules (**NER**) provides that the annual revenue requirement for a distribution network service provider (**DNSP**) in each regulatory year of a regulatory control period must be determined using a building block approach, and include a return on capital, calculated pursuant to clause 6.5.2 of the NER. Clause 6A.5.4 of the NER sets out a similar provision in relation to transmission network service providers (**TNSPs**).

Clause S6.1.3(9) of the NER requires that a revenue proposal from a DNSP must contain the DNSP's calculation of the allowed rate of return for each regulatory year of the relevant regulatory control period. For distribution networks, clause 6.5.2 of the NER states that the return on capital for a DNSP for a regulatory year (RC_t) is to be calculated using the following formula:

$RC_t = a_t \times v_t$

where:

a_t is the allowed rate of return for the DNSP for the regulatory year

v_t is the value, as at the beginning of the regulatory year, of the RAB for the distribution system owned, controlled or operated by the DNSP

Clause S6A.1.3(4A) and Clause 6A.6.2 provide the same requirements for a TNSP.

4.3 Forecast rate of return

The rates of return in the 2019-2024 regulatory control period were determined using the AER's 2018 RoR Instrument. The AER approved a nominal (vanilla) rate of return of 5.55 per cent for TasNetworks' Prescribed Transmission Services and 5.28 per cent for Standard Control Services for the first year of TasNetworks' 2019–2024 regulatory control period. A different rate of return has been applied in each subsequent regulatory year of the current regulatory control period because the return on debt is updated each year, in accordance with the 2018 RoR Instrument.

Table 1. Rate of return, 2019-20 – 2022-23

Regulatory year	2019-20	2020-21	2021-22	2022-23
Prescribed Transmission Services	5.55%	5.33%	5.11%	4.99%
Standard Control Services	5.28%	5.13%	4.97%	4.90%

Using the 2018 RoR Instrument, TasNetworks has estimated rates of return of 5.68 per cent for the transmission network and 5.71 per cent for the distribution network for 2024-25, the first year of the 2024-2029 regulatory control period. The estimated rates of return are based on financial market data up until the end of September 2022. The AER Draft Decision will utilise updated financial market data and the final 2022 RoR Instrument.

These are higher rates of return than the rates applying to TasNetworks in 2022-23 and higher than the rates of return that applied at the start of the 2019-2024 regulatory control period. As explained in section 4.1.2, this is primarily driven by changes in market interest rates.

The calculations for these rates of return have been based on the parameters set out in Table 2 which is followed by an explanation of the approaches used to estimate the rate of return parameters.

Table 2. Rate of return parameters

Parameter	Value (Transmission)	Value (Distribution)
Return on equity	7.44%	7.44%
Return on debt	4.50%	4.55%
Leverage / gearing ratio	60%	60%
Gamma	58.5%	58.5%
Nominal vanilla weighted average cost of capital (WACC)	**5.68%**	**5.71%**

4.3.1 Return on equity

Under the 2018 RoR Instrument, the return on equity must be calculated as the risk-free rate of return plus an equity beta multiplied by a market risk premium. The risk-free rate must be calculated as the ten-year yield to maturity on Australian Government Securities, measured over the risk-free rate averaging period approved by the AER.

We have calculated the return on equity using a placeholder risk free rate of 3.78 per cent, based on the placeholder averaging period of the last 20 business days in September 2022. The risk-free rate will be updated by the AER for its Draft Decision for TasNetworks. The risk-free rate will be updated again for the AER's Final Decision based on the approved averaging period (see section 4.4).

The equity beta and market risk premium is set by the RoR Instrument and is fixed for all determinations during the four year term of that instrument. As noted above the combined proposal is based on the 2018 RoR Instrument, but the final determination will be based on the 2022 RoR Instrument. In the 2018 RoR Instrument, the equity beta is set to a value of 0.6 and the market risk premium is set to an effective annual value of 6.1 per cent per annum and these values have been used to estimate the return on equity in the combined proposal.

4.3.2 Return on debt

The 2018 RoR Instrument requires the return on debt to be calculated as a ten-year trailing average, updated annually. TasNetworks has estimated the ten-year trailing average annual return on debt based on the placeholder averaging period of the last 20 business days in September 2022.

As with the risk-free rate in the return on equity, the return on debt will be updated by the AER for its Draft Decision. It will be updated again for the Final Decision based on the AER's approved averaging period (see section 4.4).

4.3.3 Leverage / gearing ratio

The gearing ratio refers to the proportion of debt in total financing. It is set by the RoR Instrument and is fixed for all determinations during the four-year term of that instrument. As noted above the combined proposal is based on the 2018 RoR Instrument, but the final determination will be based on the 2022 RoR Instrument. In the 2018 RoR Instrument, the gearing ratio is set at a value of 0.6.

4.3.4 Gamma

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. Gamma is the value of imputation credits calculated by the AER and set by the RoR Instrument. In the 2018 RoR Instrument gamma is set to 0.585.

The AER uses a post-tax framework with a rate of return that is after company tax but before personal tax. Under the post-tax framework, gamma is not a WACC parameter. Instead it is a direct input into the calculation of tax liability via the corporate tax component of the building block model. See Attachment 9 Corporate income tax for more information on TasNetworks' calculation of corporate income tax for the 2024-2029 regulatory control period.

4.4 Averaging periods

As described above, the risk-free rate and return on debt estimates that are finally used to set TasNetworks' revenue and prices at the commencement of the 2024-2029 regulatory control period will depend on the prevailing interest rate environment closer to that time.

Under the 2018 RoR Instrument, and taking into account the 2022 Draft RoR Instrument, TasNetworks has chosen to nominate averaging periods for the risk-free rate and return on debt in accordance with the terms of that instrument, for approval by the AER.[2]

2 For the return on debt, this same approved averaging period will be applied to the update of the return on debt in each year of the regulatory control period.

4.5 Forecast inflation

In setting TasNetworks' total revenue allowances at the start of each regulatory control period, the AER must apply a forecast of expected inflation. This forecast is used for a number of purposes, including indexation of TasNetworks' RAB. Adjusting the RAB for inflation is intended to preserve the value of investments made in that RAB.

Forecasting inflation for the five-year term of a regulatory control period is a challenging task. Under the NER, the AER is required to determine a method that is likely to result in the 'best' estimate of expected inflation.[3] In December 2020 the AER published its Final Position Paper following a review of the regulatory treatment of inflation[4] and this updated treatment has been reflected in updates to the post tax revenue model for transmission and distribution networks (the April 2021 amendments).[5]

The approach previously applied by the AER that was used to forecast inflation for TasNetworks' current regulatory control periods applied a ten-year average of:

- the Reserve Bank of Australia's (**RBA**) forecast of headline inflation for the first two years, then
- the mid-point of its target inflation band of 2 per cent to 3 per cent (i.e., 2.5 per cent) for the remaining eight years of that forecast.

The AER's recent inflation methodology review found that with the significant instability in the domestic and global economies and the persistently low inflation that has been experienced in recent years, its preferred methodology was not producing the 'best' estimate of expected inflation. It therefore concluded that adjustments to its methodology were required to improve the performance of its inflation forecast "in periods of economic instability or sustained periods of low or high inflation."[6] The main adjustments it has made are to:

- shorten the target horizon for forecasting inflation to match the term of the regulatory control period (which, in TasNetworks' case, is five years)
- apply a linear glide path from the RBA's forecasts of inflation in the first two years to the midpoint of the RBA's target band (2.5 per cent) in year five.

This is the approach that TasNetworks has applied in estimating its forecast of expected inflation for its transmission and distribution networks for the 2024-2029 regulatory control period.

Forecasting expected inflation in the current environment is particularly challenging. Although the environment leading up to the AER's recent inflation forecasting methodology review was characterised by persistently low inflation, the Australian economy, along with other world economies, is now experiencing significant inflationary pressures that are reflected in rising interest rates.

For example, in its November 2022 Statement on Monetary Policy, the RBA forecast headline inflation peaking at 8.0 per cent in December 2022, before gradually reducing to 3.2 per cent (just above the top end of the RBA's target band) in December 2024.[7] Consistent with the interest rate outlook, the future direction for inflation is highly uncertain.

Applying the AER's updated methodology, TasNetworks has applied a placeholder estimate of expected inflation of 3.35 per cent. This will be updated by the AER prior to its draft and final decisions for (the then) most recent RBA inflation forecasts.

3 Clause 6.4.2(b)(1) clause, 6A.5.3(b)(1).

4 Australian Energy Regulator, Final Position Paper: Regulatory Treatment of Inflation, December 2020

5 AER, Electricity transmission and distribution network service providers Post-tax revenue models (version 5), April 2021

6 AER, Final Position Paper: Regulatory Treatment of Inflation, December 2020, p.6.

7 Reserve Bank of Australia, Statement on Monetary Policy November 2022, accessed November 2022

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Combined Proposal 2024-2029

Attachment 5
Regulatory depreciation

Outline: This attachment to TasNetworks' Combined Proposal sets out TasNetworks' proposed approach to determining regulatory depreciation for the 2019-2024 and 2024-2029 regulatory control periods.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	**Regulatory depreciation**
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
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Contents

5 Regulatory depreciation

5.1 Introduction

Depreciation is the term used to describe the reduction in the value of assets that occurs over time due to factors such as wear and tear and obsolescence. The accumulated depreciation relating to a particular asset represents how much of the asset's value has been used. Depreciation allows for the return of capital to the owners of electricity networks over the life of the assets that make up a network service provider's regulatory asset base (**RAB**).

Clause 6.4.3 of the National Electricity Rules (**NER**) provides that the annual revenue requirement for a distribution network service provider (**DNSP**) in each regulatory year of a relevant regulatory control period must be determined using a building block approach, which includes a component for depreciation in that year, calculated pursuant to clause 6.5.5 of the Rules. Clause 6A.6.3 of the NER sets out a similar provision for transmission network service providers (**TNSPs**).

As explained in Attachment 3 Regulatory asset base, the RAB is indexed for inflation. A nominal Weighted Average Cost of Capital (**WACC**) is applied to the RAB to calculate the return on capital. This could lead to the double-counting of the change in the RAB value for inflation. To avoid this, the NER also requires the RAB indexation amount to be deducted from the annual revenue requirement.[1] In the AER's post-tax revenue model (**PTRM**) (for distribution and transmission), this indexation amount is deducted from depreciation. That net amount is termed 'regulatory depreciation'.

5.2 Rule requirements

Clause 6.5.5 sets out the requirements in calculating depreciation for DNSPs, which is based on the opening value of the RAB at the beginning of each regulatory year. This includes the requirements in relation to the depreciation schedule that is applied for each asset or category of assets, which is based on "a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets".[2]

Similar provisions apply for TNSPs, contained in clause 6A.6.3 of the NER. Clause 6A.6.3(c) further provides that to the extent that an asset (or group of assets) in the RAB is/are dedicated to one transmission network user (or a small group of users but not a DNSP), and where the indexed value of the asset/s at the start of the regulatory control period is greater than $20 million, then the asset/s must be depreciated on a straight-line basis. This is to occur over the life of the asset/s when first included in the RAB.

Clause S6.1.3(12) of the NER requires that a building block revenue proposal must include the depreciation schedules nominated by a DNSP for the purposes of Clause 6.5.5, and that those schedules must use a well-accepted approach to categorising assets (e.g., by asset class or category driver). Clause S6.1.3(12) also specifies that DNSPs need to provide details of the amounts, values and other inputs used to compile those depreciation schedules and demonstrate that schedules conform with the requirements of clause 6.5.5(b). Clause S6A.1.3(7) of the NER prescribes the same requirements for a TNSP's regulatory proposal.

1 NER, cl.6.4.3(b)(1)(ii); cl. 6A.5.4(b)(1)(ii).

2 NER, cl.6.5.5(b)(1).

Clause 6.8.1(b)(2)(ix) of the NER also requires that the AER's Final Framework and Approach[3] paper applying in respect of a distribution determination will set out, amongst other things, whether depreciation for establishing the RAB for a distribution system as at the commencement of the next regulatory control period is to be based on actual or forecast capital expenditure.[4] The same requirement applies to a transmission determination, pursuant to clause 6A.10.1A(b)(6).[5]

Consistent with its approach for TasNetworks' distribution network, the AER used forecast depreciation to set the opening RAB for TasNetworks' transmission network at the start of the 2019-2024 regulatory control period, as well as at the start of the forthcoming 2024-2029 regulatory control period.

The NER do not prescribe a method for calculating depreciation. However, the AER has set out its preferred methodology in the PTRM. Under the methodology, straight-line depreciation is applied using standard asset lives for each regulatory asset class. It is noted that straight-line depreciation is a well-established method used to reflect the decline in the service potential of an asset over its economic life.

TasNetworks has used the AER's current PTRM without amendment to calculate the depreciation component of regulatory depreciation. Regulatory depreciation for each of TasNetworks' distribution and transmission network RABs has been calculated by:

- determining nominal straight-line depreciation and then
- deducting the CPI indexation for each asset class in each RAB.

The calculation of each of these elements is set out below.

5.3 Depreciation methodology

5.3.1 Forecast straight-line depreciation – distribution network

New assets have been depreciated on a straight-line basis according to the AER-approved standard lives for each asset class. Existing assets have been depreciated over their remaining asset lives. The standard lives for each asset class are set out in section 5.5.

Opening asset values at 1 July 2024 have been calculated by applying the AER's current roll forward model (**RFM**). This was set out in section 3.4.2 of Attachment 3 Regulatory asset base. As noted in section 3.4.2 of Attachment 3, the opening RAB at 1 July 2024 is based on a forecast for the last two years of the current regulatory control period.

5.3.2 Forecast straight-line depreciation – transmission network

New assets have been depreciated on a straight-line basis according to the AER-approved standard lives for each asset class. Existing assets have been depreciated over their remaining asset lives. The standard lives for each asset class are set out in section 5.5.

Opening asset values at 1 July 2024 have been calculated by applying the AER's current RFM. This was set out in section 3.5.2 of Attachment 3. As noted in section 3.5.2 of Attachment 3, the opening RAB at 1 July 2024 is based on a forecast for the last two years of the current regulatory control period.

5.3.3 Application of forecast depreciation

As noted above, in its Final Framework and Approach paper the AER must nominate if it will use forecast or actual depreciation in establishing the RAB for each network at the commencement of the subsequent regulatory control period.

The AER used forecast deprecation to set the opening RAB for TasNetworks' transmission and distribution networks at the start of the 2019-2024 regulatory control period and has also determined that it will use this to establish the RAB at the start of the forthcoming 2024-2029 regulatory control period. In its Framework and Approach paper, the AER has also proposed using forecast depreciation to establish the RAB at the commencement of the subsequent 2029-2034 regulatory control period.

3 AER, *Final Framework and Approa*ch for TasNetworks for the 2024-29 regulatory control period, July 2022

4 This decision is to have regard to the requirements specified in clause S6.2.2.B.

5 The requirements for the AER's determination are contained in clause S6A.2.2B.

5.4 Year-by-year tracking

TasNetworks continues to use the year-by-year tracking method for depreciating existing transmission and distribution assets, which was approved by the AER for the 2019-2024 regulatory control period.[6] 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 remaining asset lives. These calculations are made in a separate depreciation model and the depreciation amounts are substituted directly into the PTRM. Both these models are supplied as supporting documents to this Combined Regulatory Proposal.

The use of the standard asset lives set out in the depreciation model gives rise to a depreciation schedule that reflects the economic lives of the relevant asset classes, consistent with the requirements of the NER.

5.5 Standard asset lives

TasNetworks has 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 transmission and distribution determinations for TasNetworks for the 2019-2024 regulatory control period.

5.5.1 Distribution asset lives

The table below sets out the standard asset lives for distribution assets by asset class.

Table 1. Standard distribution asset lives

Asset type	Standard asset life (years)
Overhead Sub-transmission Lines (Urban)	50
Underground Sub-transmission 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

6 Australian Energy Regulator, Final Decision, TasNetworks Distribution Determination 2019 to 2024 – Attachment 4 Regulatory Depreciation, April 2019; Final Decision, TasNetworks Transmission Determination 2019 to 2024 – Attachment 4 Regulatory Depreciation, April 2019

Asset type	Standard asset life (years)
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
Business Management Systems	10
Land	NA
Easements	NA

5.5.2 Transmission asset lives

The table below sets out the standard asset lives for transmission assets by asset class.

Table 2. Standard transmission asset lives

Asset type	Standard asset life (years)
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 – short life	4
Transmission operations – short life	10
Transmission operations – short life	4
Other – medium life	40
Other – short life	9
Other – short life	4
Land and Easements	NA
Communication assets – long life	45
Communication assets – medium life	10
Communication assets – short life	5

5.6 Forecast depreciation 2024–2029

Based on the depreciation methodology described in section 5.3, and applying the standard assets lives set out in section 5.5, forecast regulatory depreciation for TasNetworks' distribution and transmission networks is presented below.

Table 3. Forecast regulatory depreciation – distribution network (nominal, $ million)

Regulatory year	2024-25	2025-26	2026-27	2027-28	2028-29
Forecast straight-line depreciation	136.3	145.4	157.1	163.6	164.3
Less					
RAB indexation	74.4	77.8	81.4	84.1	86.8
Regulatory depreciation	**61.9**	**67.6**	**75.7**	**79.5**	**77.6**

Table 4. Forecast regulatory depreciation – transmission network (nominal, $ million)

Regulatory year	2024-25	2025-26	2026-27	2027-28	2028-29
Forecast straight-line depreciation	73.0	73.7	77.8	80.5	84.3
Less					
RAB indexation	58.9	60.2	62.2	63.9	65.6
Regulatory depreciation	**14.2**	**13.5**	**15.6**	**16.6**	**18.7**

5.7 Tax depreciation

For the purposes of calculating the estimated cost of corporate income tax pursuant to clauses 6.5.3 (distribution) and 6A.6.4 (transmission) of the NER, TasNetworks is required to calculate tax depreciation. Under Australian taxation law different asset lives apply for tax purposes than the asset lives used for the calculation of regulatory depreciation.

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Attachment 6
Capital expenditure

Outline: This attachment to TasNetworks' Combined Proposal sets out forecast capital expenditure for TasNetworks' transmission and distribution networks in the regulatory control period commencing on 1 July 2024 and ending on 30 June 2029.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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Figures and tables in this attachment may not add due to rounding.

Contents

6 Capital expenditure

6.1 Introduction

TasNetworks' capital expenditure (**capex**) forecasts cover the proposed capital investments for the provision of transmission prescribed services and distribution standard control services for the 2024-2029 regulatory control period.

This attachment outlines:

- the regulatory obligations relating to the capex forecast
- the current operating environment, including opportunities and challenges for TasNetworks in the forthcoming regulatory control period, and how this has influenced its capex forecast
- insights arising from TasNetworks' customer and stakeholder engagement process and the ways in which TasNetworks' has incorporated this feedback into its capex forecasts
- TasNetworks' performance under the Australian Energy Regulator's (**AER's**) cost benchmarking measures
- an overview of the process used by TasNetworks in developing its capex forecast
- TasNetworks' forecast transmission and distribution capex for the 2024-2029 regulatory control period
- an overview of TasNetworks' performance, highlighting specific categories where material changes in investment are proposed, and the drivers for these changes
- our delivery strategy for the capex forecast.

6.2 Capex proposal

TasNetworks has developed its transmission and distribution capex forecasts for the 2024-2029 regulatory control period with three key considerations in mind:

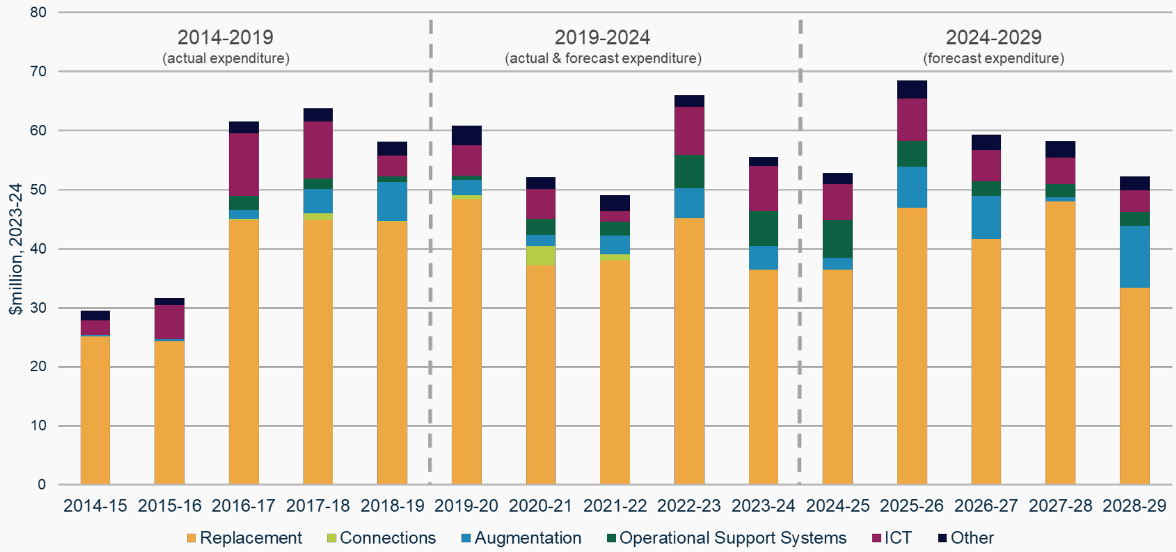
- Minimising upward pressure on customer pricing by keeping the level of forecast capex as low as sustainably possible – delivering affordability for our customers
- Maintaining reliability for customers – delivering services that our customers value
- Managing safety and risks associated with our operations – keeping our people and our customers safe.

Our capex forecasts reflect our efforts to continue delivering safe, clean, reliable and affordable electricity services to our customers while embracing the technological transition re-shaping our industry. They focus on improving community reliability and network resilience, supporting the renewable energy transition and the integration of consumer energy resources (**CER**), as well as managing an ageing asset fleet and addressing risks such as cyber security.

We have optimised our capex forecasts to reflect customer preferences and maximise customer value at the lowest sustainable levels of investment, resulting in transmission and distribution capex forecasts lower than those for the 2019-2024 regulatory control period. Figure 1 and Figure 2 outline our historical and proposed transmission capex and Figure 3 and Figure 4 outline our proposed historical and proposed distribution capex.

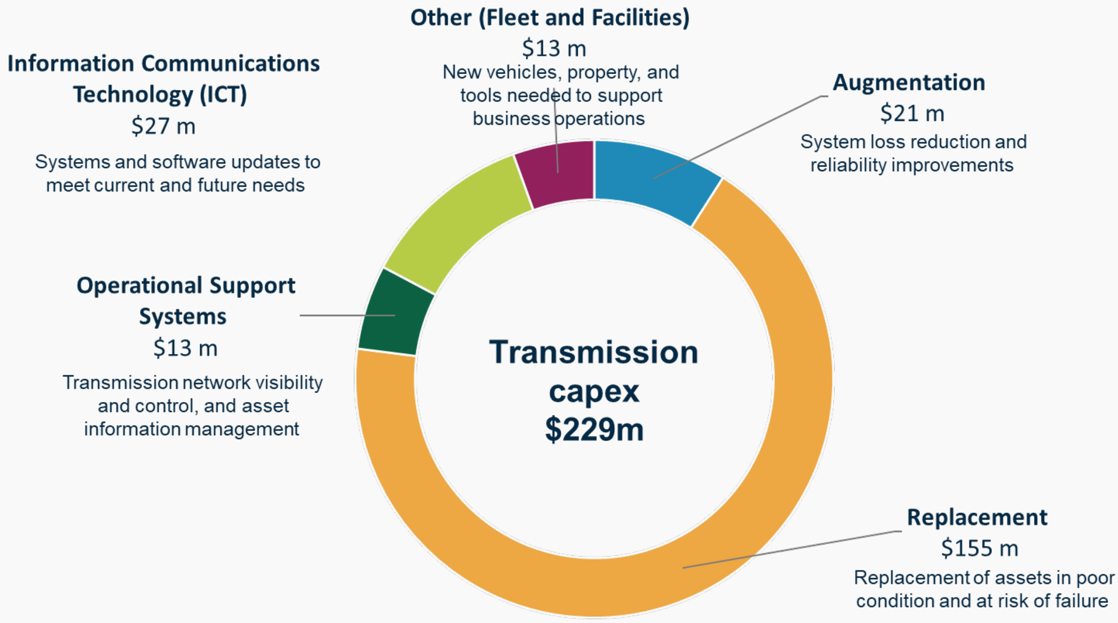
In addition to our base forecasts, seven contingent projects have been identified for our transmission network relating to possible major augmentations in the 2024-2029 regulatory control period. An additional two contingent projects have been included that relate to rule changes and an actionable project in the Australian Energy Market Operator's (**AEMO's**) Integrated System Plan (**ISP**). Attachment 7 Contingent Projects covers these projects in more detail.

Figure 1. Transmission capex - historic and forecast ($million, 2023-24)



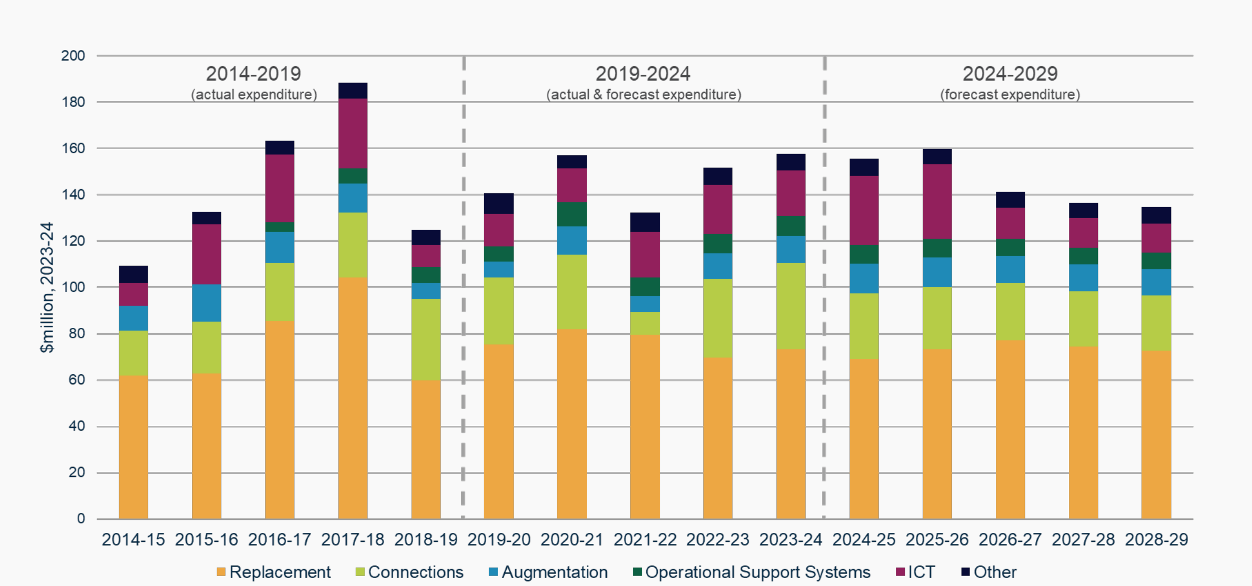
Note: Inclusive of capitalised overheads

Figure 2. Forecast 2024-2029 transmission network capital expenditure by category ($million, 2023-24)



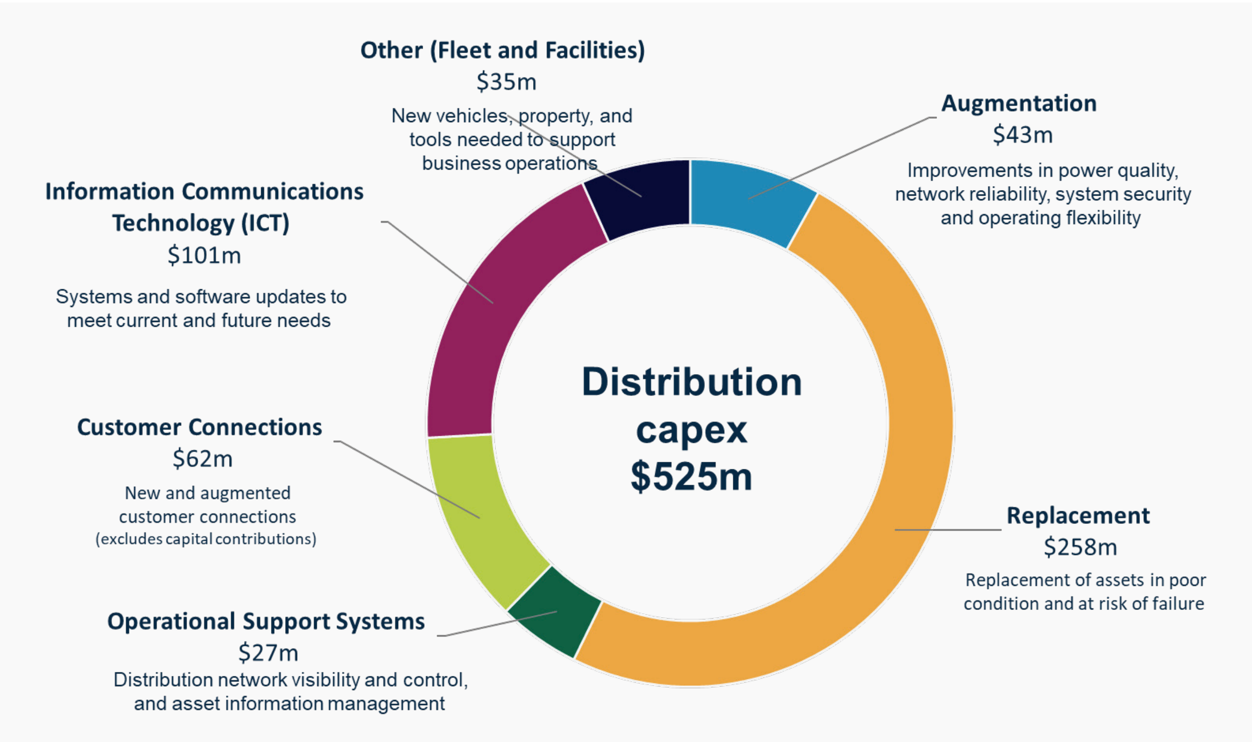
Note: Exclusive of capitalised overheads

Figure 3. Distribution capex - historic and forecast ($million, 2023-24)



Note: Inclusive of capitalised overheads and customer capital contributions

Figure 4. Forecast 2024-2029 distribution network capex by category ($million, 2023-24)



6.3 Rule requirements

For the 2024-2029 regulatory control period, the National Electricity Rules (**NER**)[1] require TasNetworks to prepare a total forecast of the capex that is needed to achieve the following capex objectives:

- meet or manage expected demand over the period
- comply with all applicable regulatory obligations or requirements
- maintain the quality, reliability and security of supply
- maintain the reliability and security of the transmission and distribution systems.

In assessing TasNetworks' Combined Proposal, the AER will have regard for several considerations including, but not limited to:

- the most recent annual benchmarking reports that have been published by the AER and the benchmark capital expenditure that would be incurred by an efficient network service provider (**NSP**) over the 2024-2029 regulatory control period
- the actual and expected capex of TasNetworks during any preceding regulatory control periods
- the extent to which the capex forecast includes expenditure to address the concerns of electricity end users identified through TasNetworks' engagement with customers and stakeholders during the preparation of this Combined Proposal
- the substitution possibilities between operational expenditure (**opex**) and capex
- whether the capex forecast is consistent with any incentive scheme or schemes that apply to TasNetworks
- AEMO's most recent ISP and any submissions made by AEMO, in accordance with the NER, on TasNetworks' forecast of required capex (transmission only)
- the extent to which TasNetworks has considered, and made provision for, efficient and prudent non-network options.

The capex forecasts presented here, and in supporting documentation, satisfy the requirements of the NER and provide the necessary information required by the AER to make its determination.

1 National Electricity Rules: Clauses 6.5.7 and 6A.6.7

6.4 Capex forecast drivers

6.4.1 Affordability

TasNetworks' capex forecasts for the 2024-2029 regulatory control period have been developed in challenging circumstances where inflation and cost of living pressures are weighing heavily on many Tasmanians. Balancing the need for investment in Tasmania's renewable energy future and the affordability of electricity for customers today is more complex and important than ever before.

To maintain affordability for our customers, we have constrained our capex to prudent and efficient levels, resulting in forecasts that are below the AER's approved allowances for the 2019-2024 regulatory control period. We achieved this through applying a top-down and bottom-up approach to developing our capex forecasts, ensuring they do not exceed the level of investment in the 2019-2024 regulatory control period, while also managing future reliability and risk and the preferences and priorities of our customers.

6.4.2 Maintaining safe, reliable and secure services

One of TasNetworks' key objectives is to ensure safe, reliable and secure services for our customers by maintaining and replacing our network infrastructure and investing in the network to support growth in consumption and demand. A measure of the reliability of our service is network service performance, and TasNetworks has adopted the following network service performance objective as noted in our Annual Planning Report:

"Network service performance will be maintained at current overall network service levels, while service to poor-performing reliability areas will be improved to meet regulatory requirements."

TasNetworks continually measures and monitors reliability at various levels of granularity, including state-wide, community, feeder/transmission line, and for individual assets. This analysis proactively identifies communities or assets that are trending towards unacceptable reliability levels as candidates for targeted investment – typically asset refurbishment or replacement - to reverse the trend and maintain acceptable reliability levels.

Ageing and potentially unreliable assets are managed as part of our overall asset management strategy. The focus of this strategy is to ensure that the replacement of assets is determined on the basis of condition and risk, rather than a reliance on age profile information. In developing strategies in relation to potentially unreliable assets we take a holistic approach to asset renewals, augmentations and decommissioning across the transmission and distribution networks. We also ensure that our asset management plans align with our development plans, driving the most efficient outcomes that balance cost, risk and performance.

Section 6.6 provides more information regarding the current reliability performance of our transmission and distribution networks.

6.4.3 Climate change

Electricity networks in Australia are particularly exposed to the effects of the changing climate, including increasingly frequent extreme climate-related phenomena such as storms, floods, heatwaves and bushfires, as well as more gradual but nonetheless significant underlying changes in the weather.

To ensure that climate impacts and network resilience are adequately considered in our strategic decision-making, TasNetworks has:

- identified priority impacts with potential to affect our transmission, distribution, and telecommunications networks; and
- assessed the risks associated with these impacts and determined the following key strategies to mitigate the risks:
  - installing non-burnable poles at selected high value pole locations in Tasmania's high bushfire loss consequence area (**HBLCA**)
  - installing fire-resistant wrap for selected poles in the HBLCA, and other high criticality/high fire danger locations outside the HBLCA
  - updating the HBLCA map to align with the harmonised Phoenix model developed by the ENA
  - encouraging legislative changes that allow vegetation management cost savings through installation of covered conductor on the network
  - increasing installation of lightning arrestors on overhead network transformers on the distribution network
  - updating our overhead distribution line design and construction manual to include the latest AS/NZS7000 design compliance requirements
  - increasing monitoring, analysis and modelling of extreme weather events such as bushfires and floods, through investment in digital technologies.

6.4.4 Demand forecast

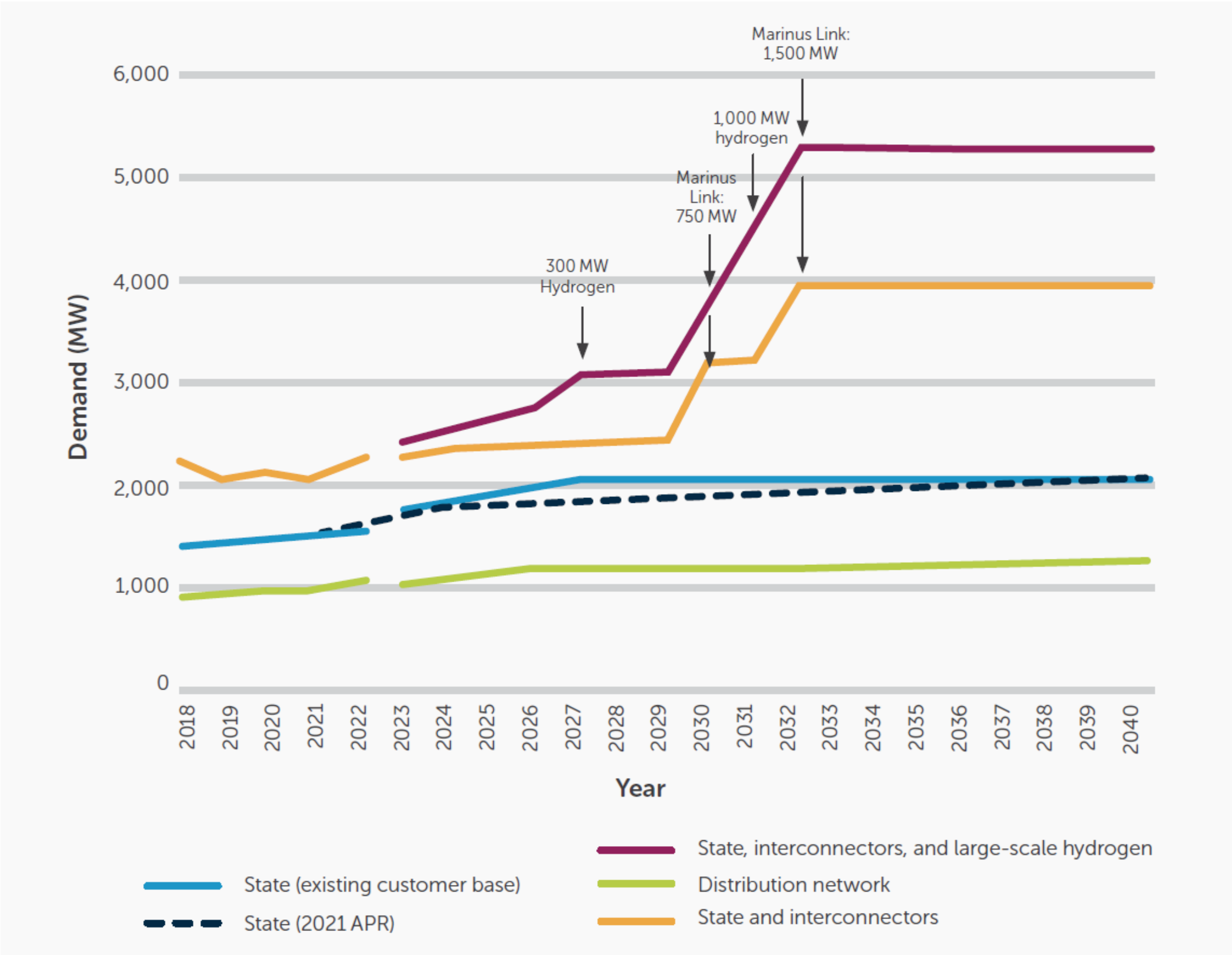
TasNetworks takes into consideration the AEMO state level forecast when producing its connection point and feeder level forecasts. As AEMO no longer publishes connection point forecasts for Tasmania, TasNetworks has made changes to the demand forecast production cycle. As a consequence, the demand forecast impacts seen at a state level are considered and analysed at a local level as part of the annual planning cycle.

Figure 5 presents the maximum demand forecast for Tasmania to 2042, including new loads on the transmission network that may emerge in the next 30 years. In the State (existing customer base) forecast, maximum demand is forecast to increase by approximately 0.9 per cent annually to exceed 2,000 MW by 2027. This is due to projected residential consumption and electric vehicle (**EV**) uptake. TasNetworks has forecasted modest investment in network augmentation in preparation for this scenario.

In the State and interconnectors forecast, the maximum demand on the transmission network is forecast to double over the next decade. In the State, interconnectors, and large-scale hydrogen forecast, maximum demand is forecast to exceed 5,000 MW by 2032 — more than twice the maximum demand on the existing network.

In Tasmania, rooftop solar photovoltaic (**PV**) output does not materially reduce the maximum electricity demand. This is because maximum demand occurs in either early morning or late afternoon/early evening during the winter months, when solar PV output is minimal.

Figure 5. Maximum demand forecast



6.4.5 Consumer energy resources

The push for clean energy, electrification and data accessibility is driving community-led change within our distribution system. New technologies are becoming an important enabler of efficient and sustainable distribution integration and customer services. As the costs of energy technologies decline, more customers are adopting CER technologies that interact with the distribution network, such as solar PV, battery storage and EVs. These technologies enable customers to participate in the energy market in different and greater ways, including by generating energy and storing or exporting it to the distribution network for use by other customers.

The distribution network was not designed for bi-directional power flows, a high penetration of CER or active energy management by consumers. As CER uptake continues to grow, understanding and managing power flows and voltage regulation becomes more challenging. Sections of the network can become overloaded and congested, resulting in consumers being unable to connect new CER or use their existing CER to full capacity. Uptake of EVs also may result in increased overall consumption and maximum demand on the network, and an increase in network complexity due to vehicle charging and related driver behaviour.

In Tasmania, the use of solar PV and household batteries is forecast to continue to grow, while the uptake of EVs is forecast to accelerate towards the end of this decade. Current modelling suggests that there will be insufficient uptake to cause widespread and material network constraints in the 2024-2029 regulatory control period for TasNetworks or our customers. Therefore, TasNetworks proposes a steady and modest level of investment to enable ongoing connection of CER and improved visibility of the low voltage network.

6.4.6 Cyber security

TasNetworks is facing an increasing ICT investment requirement because of growing risks to its cyber security. The most significant factor driving this change is the recent critical infrastructure reform under the (Commonwealth) *Security of Critical Infrastructure Act 2018*, which looks to uplift the security and resilience of critical infrastructure owned by electricity networks and other entities across Australia. The purpose of the reform is to address the growing global cyber threat, and the increased risk of cyber-attacks on Australian networks.

TasNetworks applies AEMO's recommended Australian Energy Sector Cyber Security Framework and we are uplifting our capability to align with the target state specified for NSPs (Security Profile 3). We will continue to implement initiatives to increase our vigilance, reduce the risk of cyber-attack and ensure the ongoing availability and reliability of our networks. The proposed level of investment in this area will ensure the ongoing resilience of our networks.

6.4.7 Distribution customer connections

In the current regulatory control period, TasNetworks has seen materially higher distribution customer connections compared to forecast levels. There have been several different factors behind this increase. TasNetworks has improved its forecasting approach for the 2024-2029 regulatory control period to align the forecast closer to our historic experience and, therefore, provide a more accurate forecast of connection volumes for the 2024-2029 regulatory control period.

6.5 Customer and stakeholder engagement

TasNetworks undertook a comprehensive customer and stakeholder engagement program over a period of 18 months when developing this Combined Proposal for the 2024-2029 regulatory control period. We sought a diverse range of customer and stakeholder views so that we could consider their preferences when developing our capex forecasts.

In implementing our customer and stakeholder engagement program, we engaged with more than 500 persons – presenting them with key components of our capex forecast. Our engagement approach varied in its breadth (the scope of engagement with customers and stakeholders) and depth (the level of detail at which we engaged). We engaged more broadly with our individual customers, and more deeply with our advisory groups (such as the Reset Advisory Committee and Customer Council) and transmission customers than ever before.

We received considerable feedback regarding customers' priorities and TasNetworks' targets for capital investment. The following themes reflect the position of most customers and stakeholders:

- **Affordable for all –** Keeping our capex forecasts as low as sustainably possible
- **Reliable now –** Seek ways to improve service performance for poor-performing communities
- **Resilient for the future –** Without losing sight of the need for affordability, make the necessary investments that will improve the resilience of our electrical networks in the long term.

The influence of these themes on our capex forecasts is presented in Table 1. More information on key themes can be found in Attachment 1 Customer and stakeholder engagement summary, including information for specific capex topics.

Table 1. Capex engagement themes and outcomes.

Key theme	What we've heard	How we're responding
Affordable for all	• Beyond all other considerations, affordability is the most important factor regarding electricity services for our customers and stakeholders. • TasNetworks should invest steadily and strategically in a proactive manner that sets Tasmania up for the long term.	• We have used both a top-down and bottom-up approach to develop our capex forecasts, ensuring they do not exceed the level of investment in the current regulatory control period, while also managing future reliability and risk. • We have ensured that our investment evaluation process considers all requirements required by the AER in its *Industry practice application note – Asset replacement planning*, including the consideration of numerous investment options to address customer needs, with subsequent NPV analysis being used to select the option representing the lowest whole-of-life cost. • We have optimised our capex programs at the portfolio level, ensuring we achieve the right mix of investments that manage risk and reliability outcomes at the lowest whole-of-life cost.
Reliable now	• Maintaining current levels of reliability is the expected minimum. • The reliability of poor-performing communities should be improved more quickly. The timeframes proposed in our early capex forecasts were too long. TasNetworks might not be quick enough to keep pace with population growth in some regional areas, and the new technologies being implemented by these customers such as solar PV, EVs, and batteries. • There were concerns that the cost of the reliability improvement activities proposed for Zeehan and the broader West Coast region may not be commensurate with the population that would benefit from this investment, and that other cheaper alternatives had not been sufficiently considered.	• Instead of waiting until the 2024-2029 regulatory control period, we have brought forward some community reliability investments into the 2019-2024 regulatory control period. • We have increased the number of communities targeted for reliability improvement in the 2024-2029 regulatory control period, from four up to ten, with no change in overall capex investment, through a rebalancing of the capex program. • We have reviewed the proposed solution for Zeehan within the context of broader regional reliability, identifying a multi-stage approach to improve reliability as early as possible and at lowest cost while also leaving opportunity for alternative non-network solutions to be identified.

Key theme	What we've heard	How we're responding
Resilient for the future	• Customers are concerned about climate change and the ability of electricity networks to maintain reliability within that changing environment, and they feel that action is needed now. • Customers valued the benefits of improved reliability and resilience, but noted the cost for some of the more wide-ranging options presented by TasNetworks were challenging to affordability. The consensus was that additional investment, compared to our initial capex program, was needed. • In developing its capex program, it is important that TasNetworks demonstrated how its investments will improve resilience and reliability, and withstand climate change over the long term.	• We have rebalanced our capex forecast to increase funding for network resilience by approximately $10 million, for activities such as installing composite poles, covered conductor and aerial bundled cable in bushfire risk areas. • We have increased our capex forecast to include additional investment of approximately $3 million ($6.3 million total) in CER compared with the 2019-2024 regulatory control period. • We have reviewed our initiatives and forecasts and can confirm that our broad portfolio of investments will continue to improve transmission and distribution resilience in the long term.

6.6 Our reliability performance

Reliability can be influenced in a variety of ways at many points in TasNetworks' business processes. The most cost-effective way TasNetworks achieves its long-term reliability objectives is by designing the right levels of reliability into its distribution and transmission networks when constructing new assets or replacing existing assets.

6.6.1 Transmission reliability

Two key measures used to assess TasNetworks' transmission network reliability are:

- Loss of Supply (**LOS**) events – reflecting the frequency and impact of fault and forced transmission outages resulting in a loss of downstream customer load
- Fault circuit outage rate – showing the percentage of transmission circuits that experience a fault outage each year, regardless of whether there was a loss of downstream load.

As shown in Figure 6 and Figure 7, very few fault and forced outage events on the transmission network result in loss of supply events for customers. This performance has been holding steady over time.

Figure 6. Transmission LOS events > 1.0 system minute

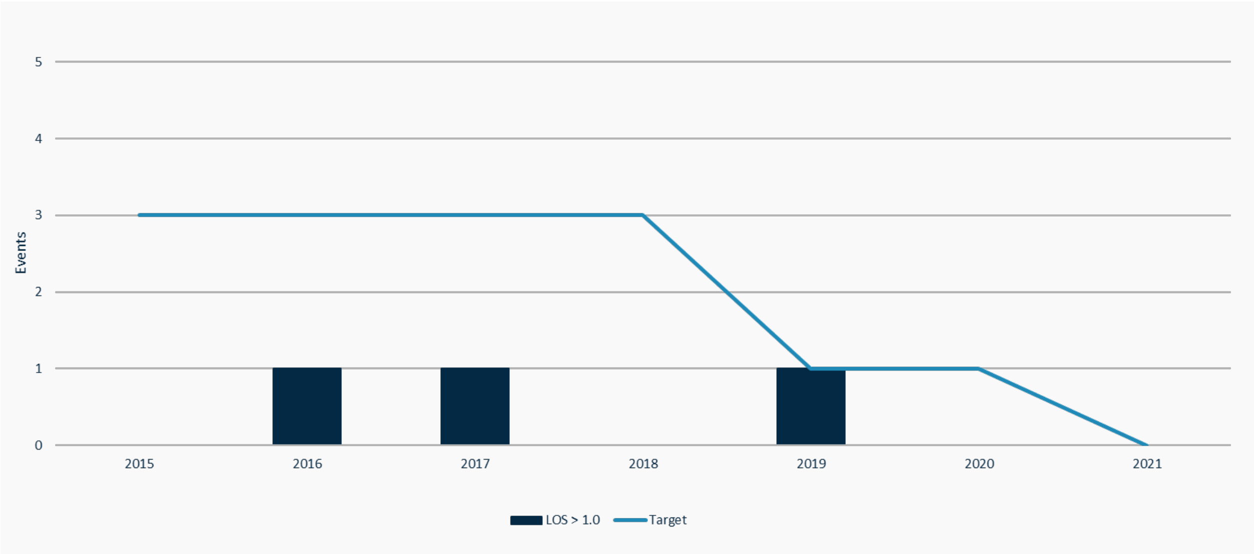
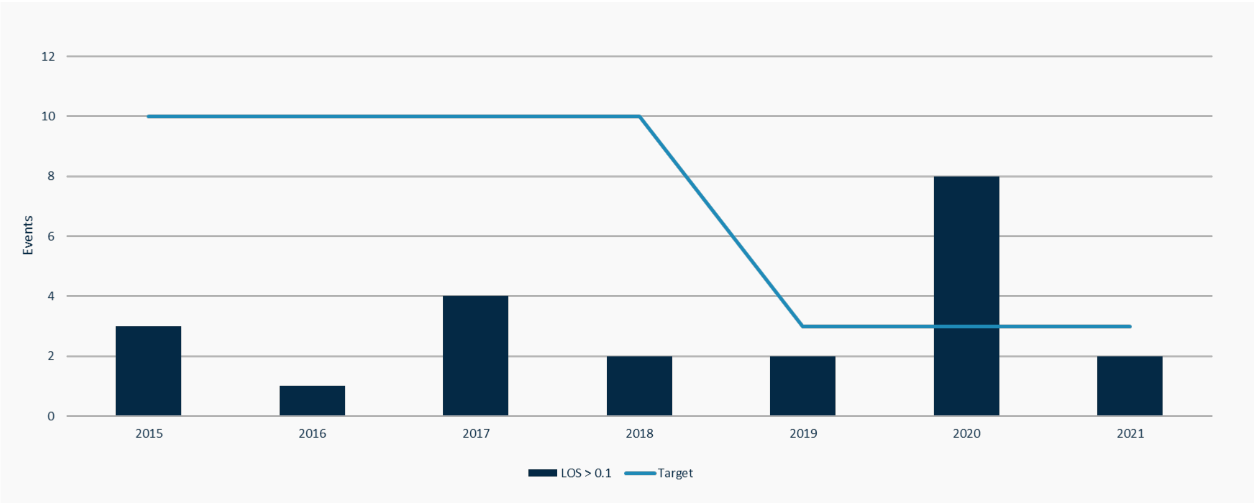


Figure 7. Transmission LOS events > 0.1 system minute



Similarly, as shown in Figure 8 and Figure 9, the underlying fault circuit outage rate for transmission lines has been holding steady while the fault circuit outage rate for transformer circuits has improved in recent years.

Figure 8. Transmission line fault circuit outage rate

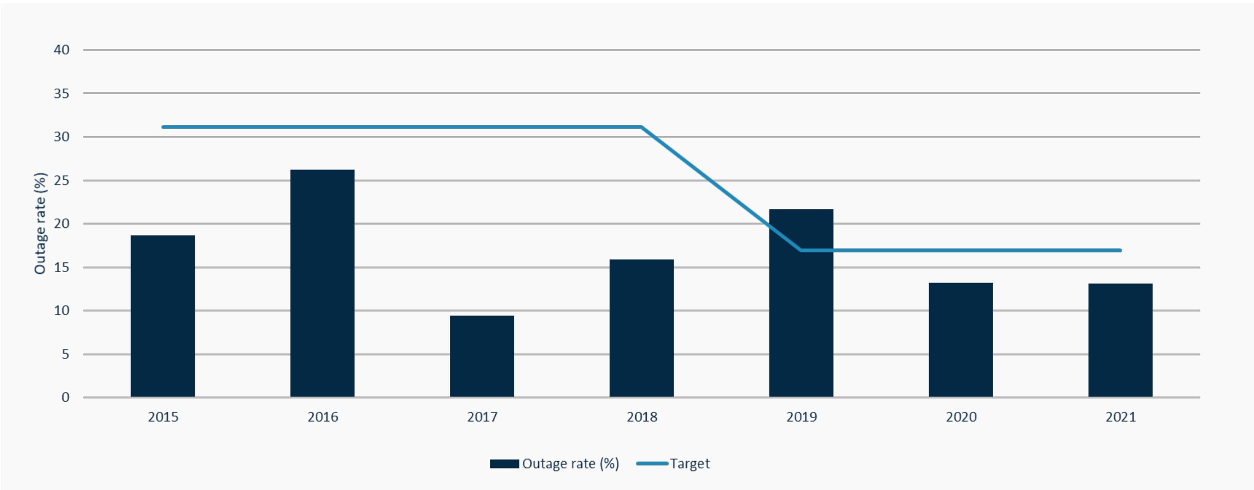
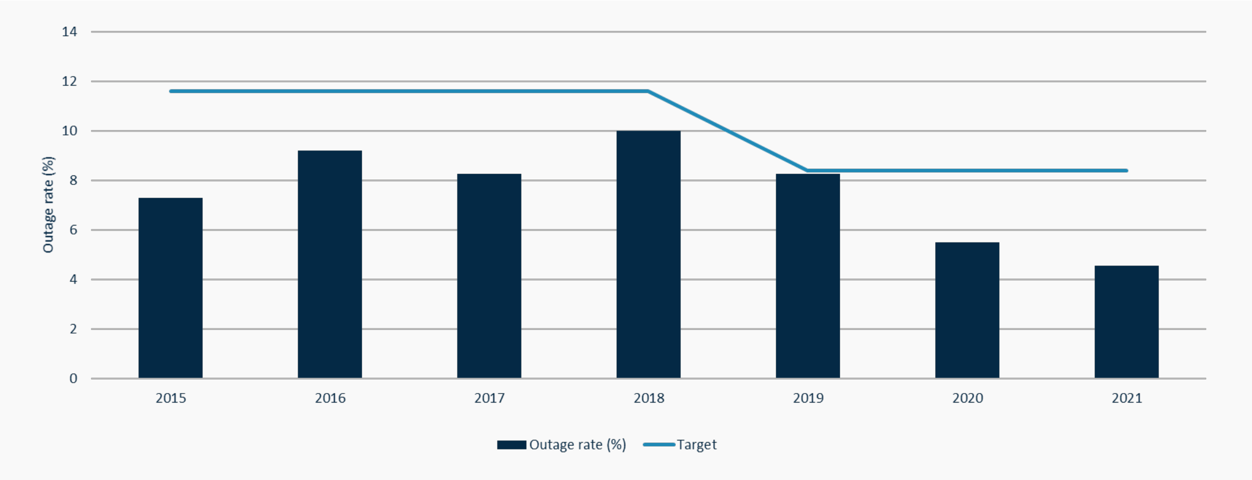


Figure 9. Transformer fault circuit outage rate



These performance outcomes are reflective of TasNetworks' current and previous capital investments to refurbish, replace and augment transmission network assets, reducing the frequency of unplanned outages that have the potential to impact on downstream customers. The outcomes also reflect effective operational responses to restore supply to customers as quickly as possible following any unplanned outages.

TasNetworks, therefore, does not propose specific capital investments in the 2024-2029 regulatory control period to improve transmission network reliability.

6.6.2 Distribution reliability

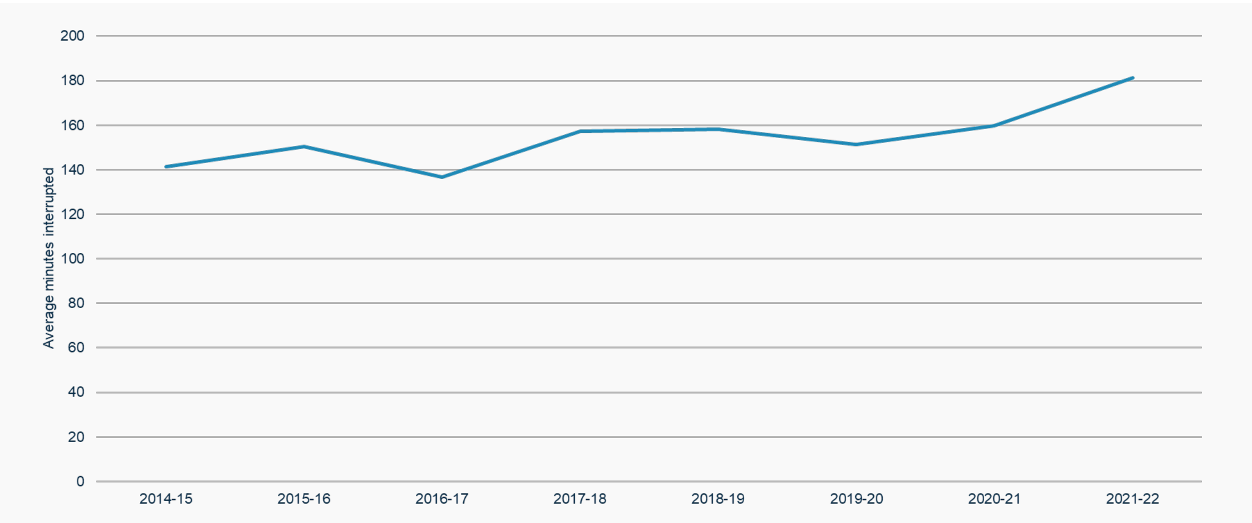
Two key measures used by the AER to assess TasNetworks' distribution network reliability, are:

- System average interruption duration index (**SAIDI**) – the average minutes per year that a customer will experience an unplanned LOS
- System average interruption frequency index (**SAIFI**) – the average number of unplanned LOS events a customer will experience per year.

Figure 10 and Figure 11 present historical overall SAIDI[2] and SAIFI[3] for the distribution network on an annual basis. Figure 11 shows on average the frequency of unplanned outages has been relatively stable in recent years. However, Figure 10 shows that the average minutes off supply per customer is starting to show a trend of deterioration.

By itself, the performance presented here is not sufficiently poor to justify significant Statewide capital investment for the improvement of reliability. However, and as discussed below, in conjunction with other more granular measures, targeted capital investment is needed.

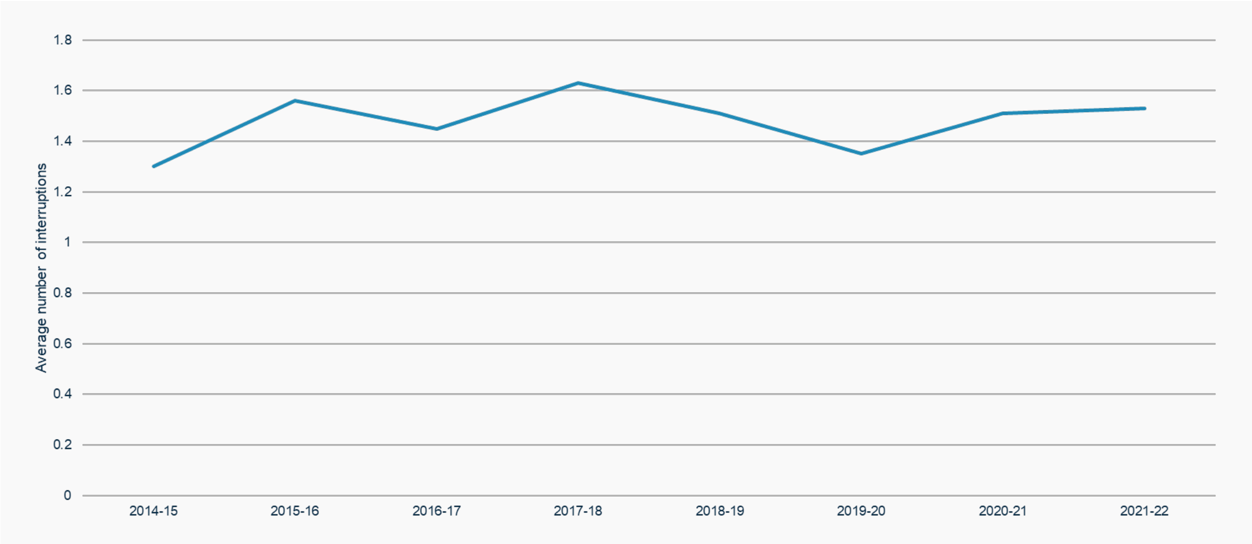
Figure 10. Distribution network system SAIDI



2 SAIDI data presented here excludes SAIDI due to Major Event Days and does not include 'excluded' unplanned outages, as defined by the STPIS

3 SAIFI data presented here excludes SAIFI due to Major Event Days and does not include 'excluded' unplanned outages, as defined by the STPIS

Figure 11. Distribution network system SAIFI

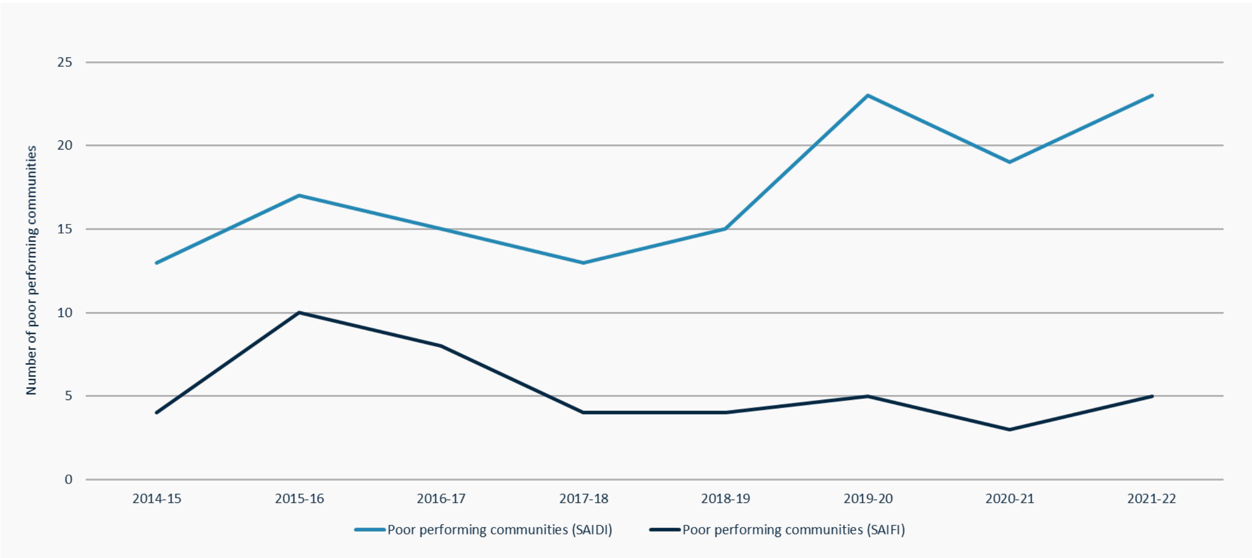


In addition to these two measures, the Tasmanian Electricity Code defines prescribed levels of reliability at a community level (of which there are 101 across Tasmania),[4] requiring TasNetworks to make reasonable endeavours to ensure that the average annual duration and frequency of interruptions in each community category does not exceed the relevant limit. The purpose of community level reliability is to provide reliability equity for customers living in regions with similar energy usage irrespective of their geographical location. For these reasons, TasNetworks also uses the following measures to assess distribution network reliability:

- Number of annual non-compliant communities (outage duration)
- Number of annual non-compliant communities (outage frequency).

Figure 12 presents the annual number of poor performing reliability communities, in terms of annual outage duration and annual outage frequency.

Figure 12. Distribution network annual poor performing communities



4 Office of the Tasmanian Economic Regulator, Distribution Network Performance Standards

TasNetworks' investments in asset and reliability management since 2014 have resulted in sustained annual improvements in terms of outage frequency (SAIFI) at the community level. However, in the last three years we have observed an increase in the number of communities experiencing poor performance in terms of outage duration (SAIDI).

TasNetworks' analysis found that while most communities only experience occasional poor performance, there are a small number of communities experiencing repeated poor reliability performance. There are many options available to TasNetworks to improve community reliability, from minor process improvements with minimal additional operational expenditure, to large-scale asset augmentation and significant capital investment.

Each poor performing community is subjected to an intensive review of underlying causes to identify remedial actions and the most cost-effective ways of bringing community reliability back within acceptable bounds. These communities are outlined in Table 2.

Table 2. Poor performing communities due to SAIDI

Area	Target	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Far North East Rural	720	560	793	650	416	520	902	916	910
Highlands	720	325	2342	459	1554	1390	1377	368	1285
North West	720	797	307	638	880	1032	776	1044	1551
Rosebery	240	177	158	32	167	283	514	272	219
Strahan	240	791	221	228	543	1059	359	690	607
Tamar South	240	164	153	284	207	528	256	229	301
Turners Beach	240	676	279	181	283	437	326	444	612
West Coast	720	565	746	625	923	1385	916	886	774
Zeehan	600	1280	28	304	983	1227	1956	1193	2022

This analysis identified that capital investment is required to achieve the desired reliability improvements. However, with customer affordability a critical consideration, TasNetworks initially constrained its reliability improvement investments to four of the communities identified as poor performing.

TasNetworks tested the importance of reliability and our proposed reliability investments with end use customers as part of of its engagement program. TasNetworks received strong and consistent feedback from communities around Tasmania highlighting reliability as a priority and showing a willingness to pay to improve reliability in more poor performing areas in a shorter timeframe. TasNetworks subsequently rebalanced its distribution capex investment program to align more closely with customer preferences, allocating additional funds to address the reliability of all poor performing communities without increasing the overall capex forecast.

6.7 Our benchmarked productivity

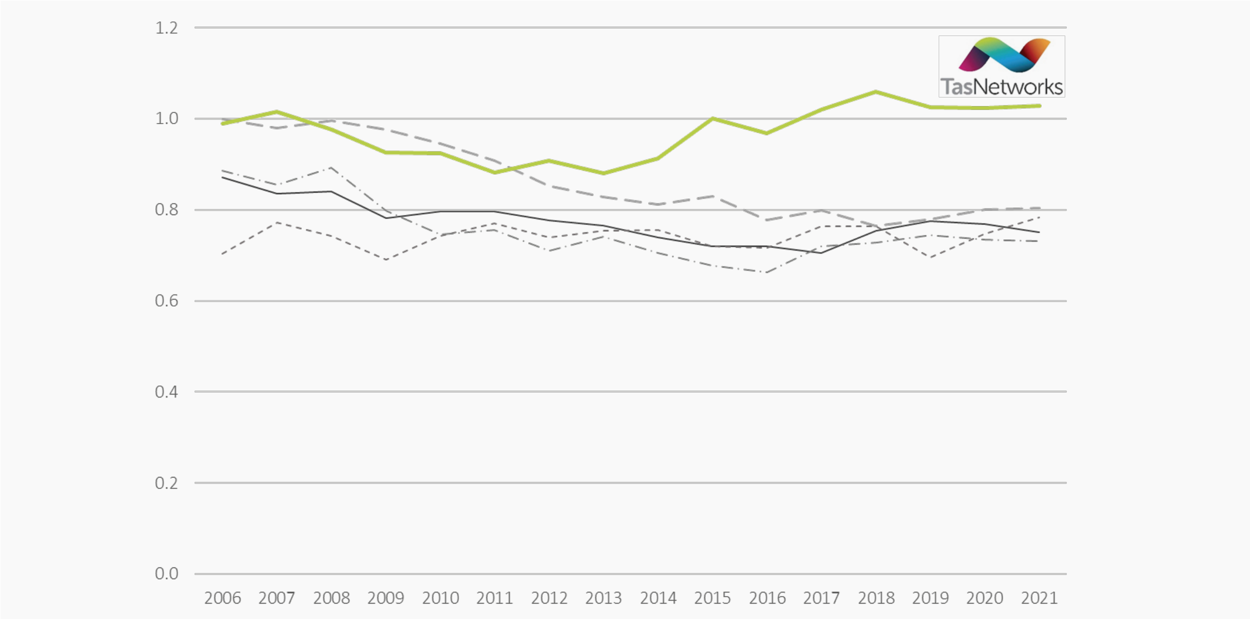
The AER uses industry benchmarking to measure and assess the efficiency and productivity of TasNetworks' transmission and distribution networks. Although the AER does not use results of benchmarking deterministically to set network revenue allowances, the results are used to identify elements of revenue and regulatory proposals where greater scrutiny may be required.

The AER's benchmarking models assess each network operated by TasNetworks independently. TasNetworks contends that it is a productive and efficient provider of transmission and distribution network services. TasNetworks' level of efficiency reflects the business' operating environment factors and the benefits of being the operator of two networks.

6.7.1 Transmission productivity

Figure 13 illustrates that, for the AER's Multilateral Total Factor Productivity (**MTFP**) benchmarking metric, TasNetworks is the most productive transmission network in the NEM. As noted by the AER's benchmarking consultants, TasNetworks' productivity *increased noticeably in 2014 and 2015 with the introduction of restructuring and reform initiatives*[5] and has remained high since.

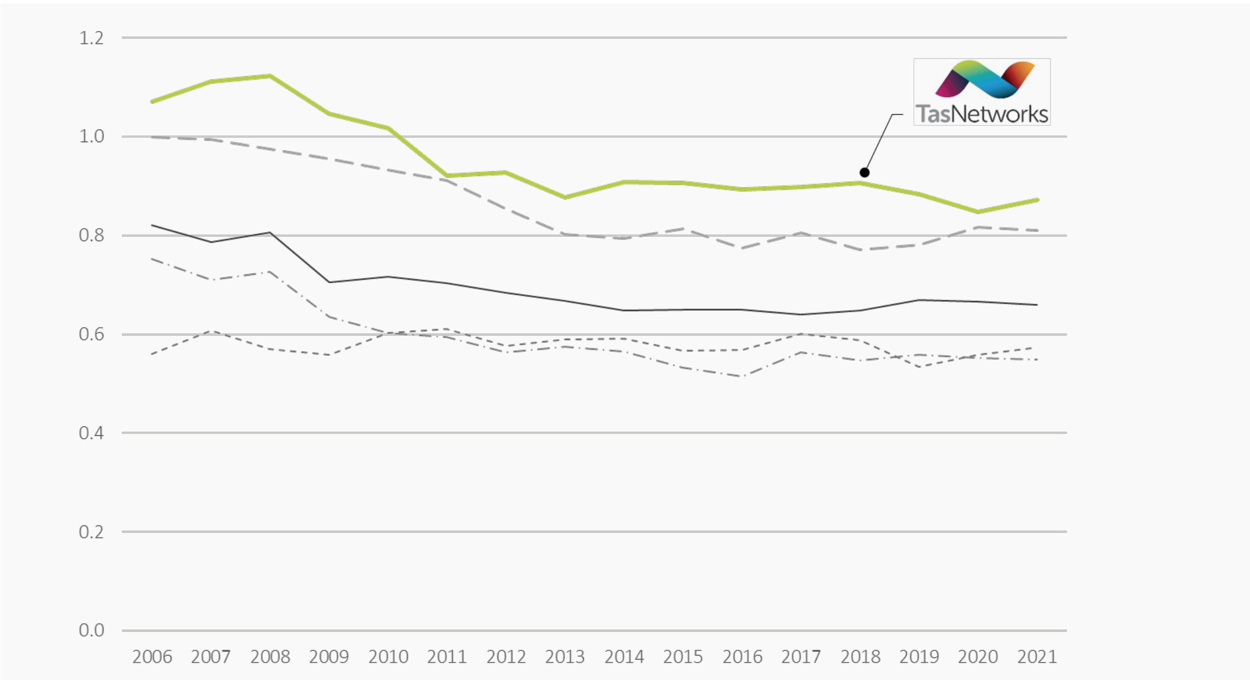
Figure 13. TNSP multilateral total factor productivity indexes, 2006–2021



Source: *Annual Benchmarking Report - Electricity transmission network service providers*, AER, November 2022

The AER's capital productivity performance indicator (**capital MPFP**) also places TasNetworks first of the five TNSPs in the NEM (see Figure 14).

Figure 14. TNSP multilateral capital partial factor productivity indexes, 2006–2021



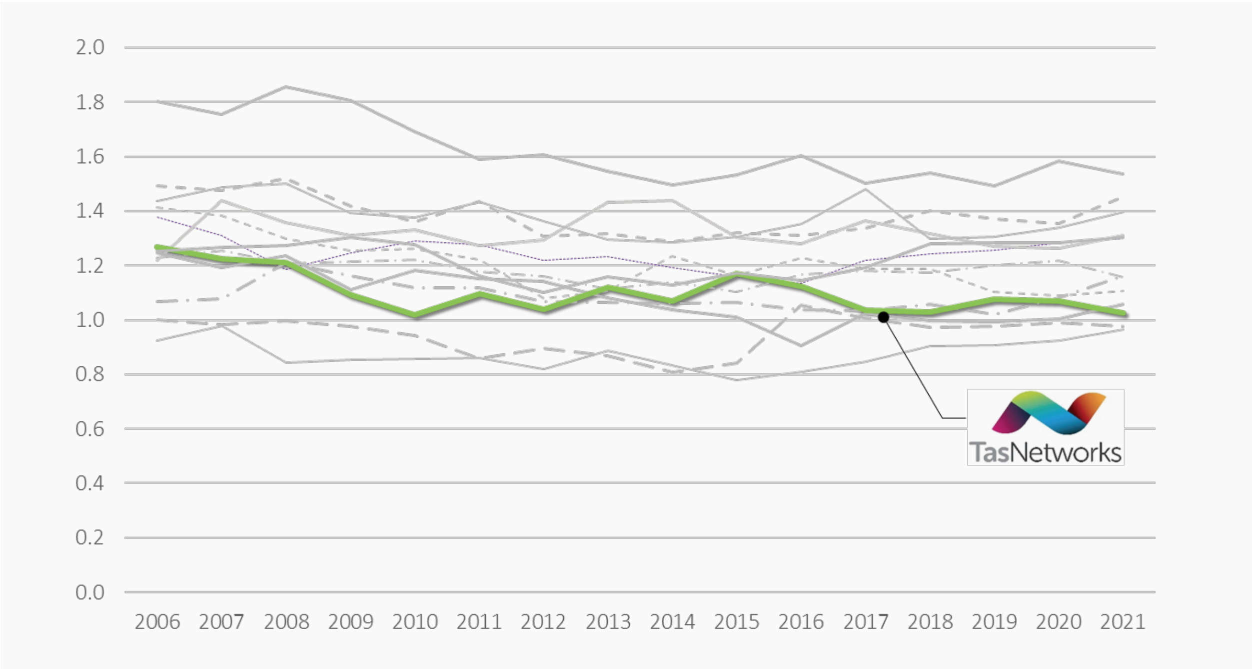
Source: AER, *Annual Benchmarking Report - Electricity transmission network service providers,* November 2022

5 Quantonomics Economics, *Economic Benchmarking Results for the Australian Energy Regulator's 2022 TNSP Annual Benchmarking Report*, Page 22, 3 November 2022

6.7.2 Distribution productivity

Figure 15 shows that the AER's MTFP benchmarking places TasNetworks at the lower end of Australian distribution networks. The AER's capital partial factor productivity performance indicator for distribution networks also places TasNetworks as having the lowest productivity in 2021 of the 13 DNSPs compared.

Figure 15. DNSP multilateral total factor productivity indexes, 2006–2021



Source: AER, *Annual Benchmarking Report - Electricity distribution network service providers,* November 2022

The AER has acknowledged that TasNetworks is something of an outlier in terms of system structure, as the transmission network boundary with the distribution network is by far the most 'downstream'. The benchmarking models used by the AER also do not represent TasNetworks' system structure well, favouring networks which utilise power lines rated at 33kV and above. TasNetworks operates a distribution network almost totally comprised of lines with a capacity of less than 33kV.

The effect of TasNetworks' network structure on its performance in the AER's MTFP benchmarking of distribution networks is considerable, and has prompted the AER's benchmarking consultants to recommend caution in interpreting TasNetworks' MTFP score. Analysis by TasNetworks has shown that were TasNetworks' distribution network structured similarly to other networks TasNetworks would be rated significantly higher in MTFP terms. The current specification of the MTFP model prevents TasNetworks obtaining an MTFP score that would place it among the leading DNSPs.

6.8 Capex forecasting

6.8.1 Methodology

TasNetworks' **2024-2029 Expenditure Forecasting Methodology** (**EFM**) outlines TasNetworks' capex forecasting methodology. Figure 16 presents the key steps in the process by which capex needs are identified, addressed and closed out.

Figure 16. Investment governance process

The development of a capex forecast for the purpose of a revenue determination requires NSPs to focus on the first two steps in this process, those being 'Needs analysis' and 'Investment evaluation'.

The 'Needs analysis' step comprises the recognition and response by TasNetworks to factors such as:

- customer connections and future demand
- historical performance, and forecast security, resilience, and reliability needs of customers
- challenges arising from the changing risk profile of ageing assets
- changing environmental conditions
- safety, security, digital, and environmental compliance obligations.

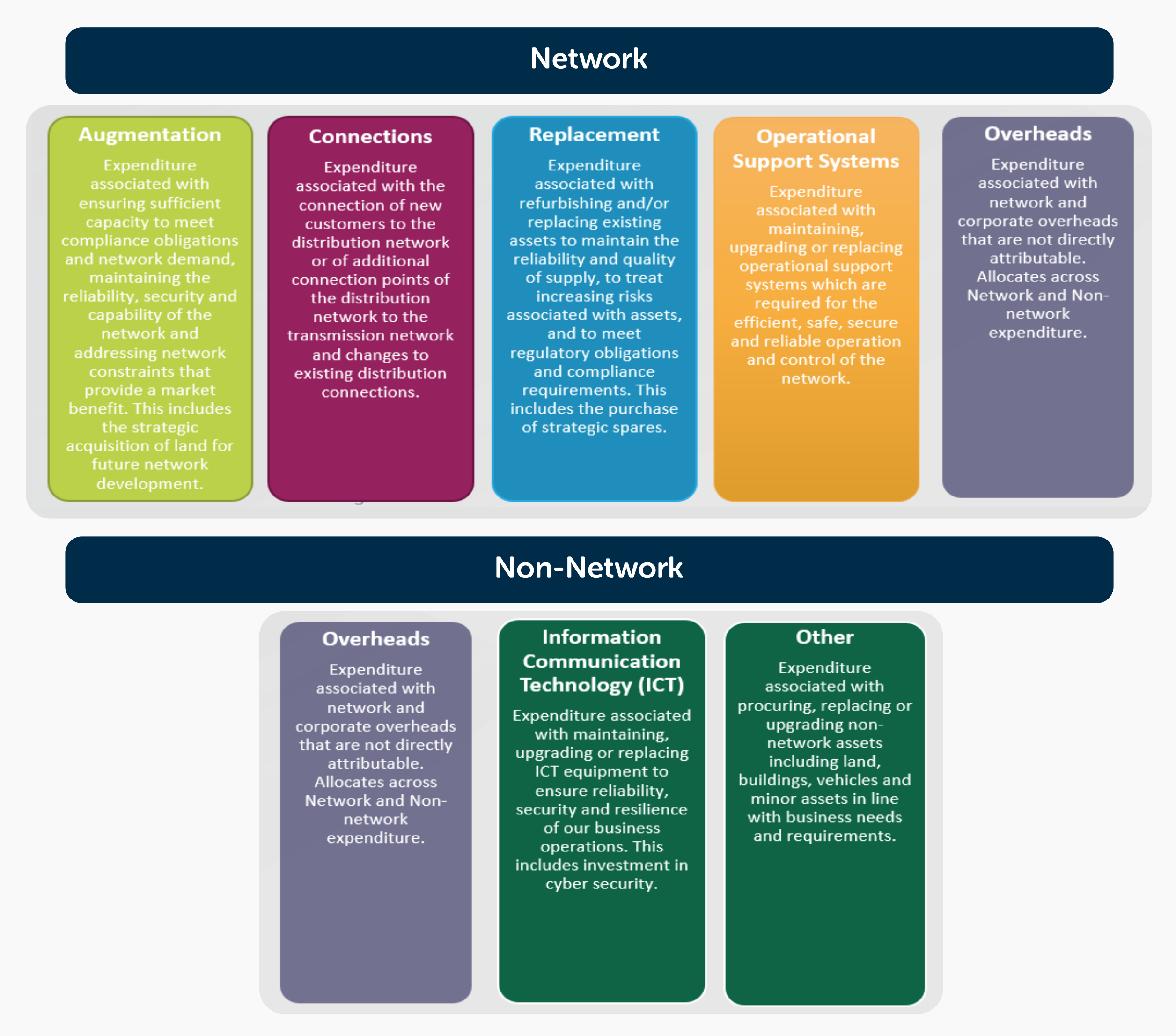
The 'Investment evaluation' step incorporates sub-processes that ensure TasNetworks meets the requirements of the AER's *Industry practice application note – Asset replacement planning*, while also managing long term risk outcomes at the lowest whole-of-life cost, without compromising on customer service performance outcomes. These include:

- options identification – demonstrating the broad range of options considered by TasNetworks that could meet the identified need(s)
- economic analysis (initiative level) – understanding the whole-of-life capital and operating costs needed to implement each option, balanced against the resulting risk cost mitigation outcomes
- economic analysis (portfolio level) – stepping away from the highly granular initiative level, and iteratively assessing combinations of options across categories of investment, asset fleets, and network sites, to identify more optimal risk, cost and service performance outcomes at the portfolio level than could be achieved when only examining individual investments
- preferred option selection – providing robust and quantitative reasoning for the selection of the preferred option, showing how it, and the broader portfolio of investments within which it resides, affordably achieves customer needs
- top down testing – comparing TasNetworks' total capex forecasts and capex category level forecasts against the actual spend over the current regulatory control period to ensure variations in expenditure between regulatory control periods are justified
- deliverability assessment – with consideration for TasNetworks' delivery strategy and resource mix, understanding the deliverability of the preferred options and making micro-adjustments to the forecast to increase efficiency in terms of both timing and resourcing.

6.8.2 Categories

TasNetworks applies a consistent forecasting framework for all transmission and distribution network capex, utilising well accepted categories of expenditure that align with the regulatory framework. Figure 17 shows how TasNetworks categorises capex, with these forecasting categories used consistently here, and throughout TasNetworks' Combined Proposal wherever capex is presented.

Figure 17. Capital expenditure forecasting categories



For most of TasNetworks' forecast capex program, costs can be attributed directly to either the transmission or distribution network. However, to realise the opportunities for efficiency that arise from TasNetworks' dual role as a TNSP and DNSP there are many support services where capex investments will benefit both the transmission and distribution networks, such as the upgrade of ICT assets (like server hardware) or the upgrade of vehicle fleet capabilities for emergency response.

The costs associated with these shared business services are defined as 'shared' and are allocated between the transmission and distribution networks based on the nature of the investment and expected use of the shared service by each network.

6.8.3 Assumptions

Our capex forecasts are underpinned by the key assumptions set out in Table 3.

Table 3. Capex key assumptions

The capex initiatives, including the investment evaluation summaries, project and program scopes and estimating practices, are soundly based and align with our strategic direction
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 and based on independent expert advice
Our cost of consequence values are aligned with TasNetworks risk management framework
There will be no changes to the ownership of private electricity network assets in Tasmania

As indicated in Table 3, a key assumption of TasNetworks' capex forecast is that 'there will be no changes to the ownership of private electricity network assets in Tasmania'. This assumption has recently been called into question. In November 2022, the Tasmanian parliament passed the *Electricity Safety Act 2022* which clarifies the boundary between TasNetworks owned 'electricity infrastructure' and privately owned 'electrical installations'. Section 32(2) of the Act states that *"The owner of an electrical installation must ensure that the operation, maintenance, repair and replacement of any electrical installation beyond the point of supply is such as to ensure the safe use of electricity."*

In addition, the management of private electricity infrastructure has been complicated by a decision in Western Australia (**WA**) known as the "Parkerville case". The case involved a failed private pole (which had a network owned service wire attached to it) which collapsed and started a fire, causing extensive damage to adjoining properties. The WA Court of Appeal (since upheld by the High Court) found Western Power 50 per cent liable in negligence by connecting its infrastructure to a defective private pole. The court held that a reasonable operator would have established a system for periodic inspection of the relevant poles, and either repair any defective poles themselves or require the customer to do so. The High Court found this is an on-going obligation and should be assessed based on the specific situation and the application of relevant local legislation.

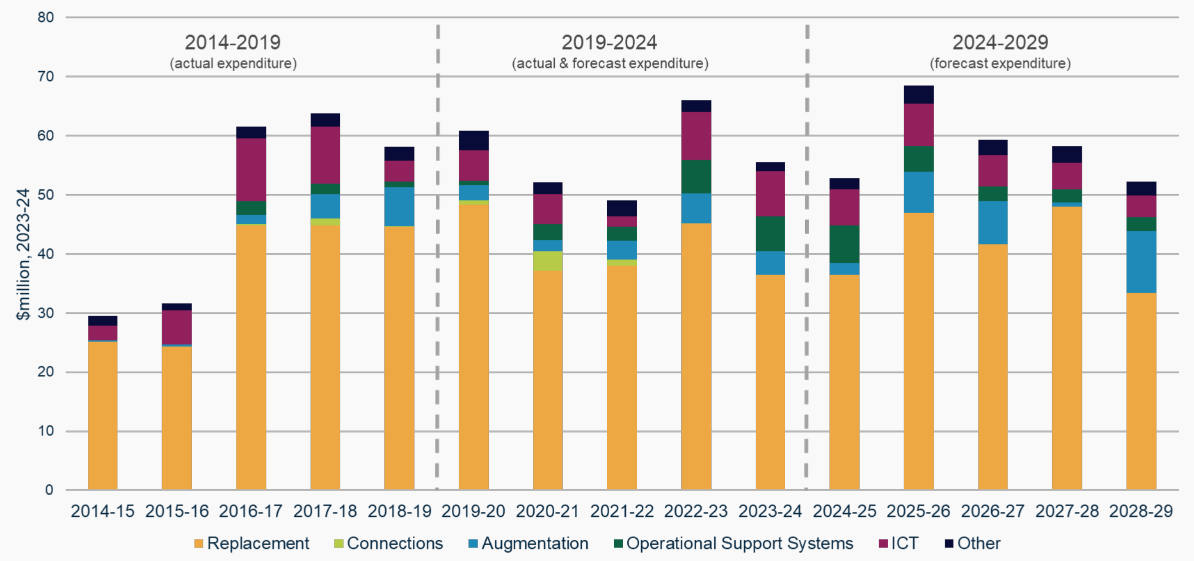
These recent changes to the legislative framework have required TasNetworks to reconsider its management of risk associated with providing network services to private assets. TasNetworks is considering several options on how to reduce its risk exposure, which may affect our future capex program.

6.9 Transmission capex forecast

The following sections outline our transmission capex forecasts, explaining the rationale behind any material step-changes, and compare our forecasts against historical levels of investment to assist the assessment of the prudency of TasNetworks' capex forecasts.

Figure 18 shows TasNetworks' transmission capex since 2014-15, including forecast capex for the remaining two years of the 2019-2024 regulatory control period and the 2024-2029 regulatory control period.

Figure 18. Transmission capex - historic and forecast ($million, 2023-24)

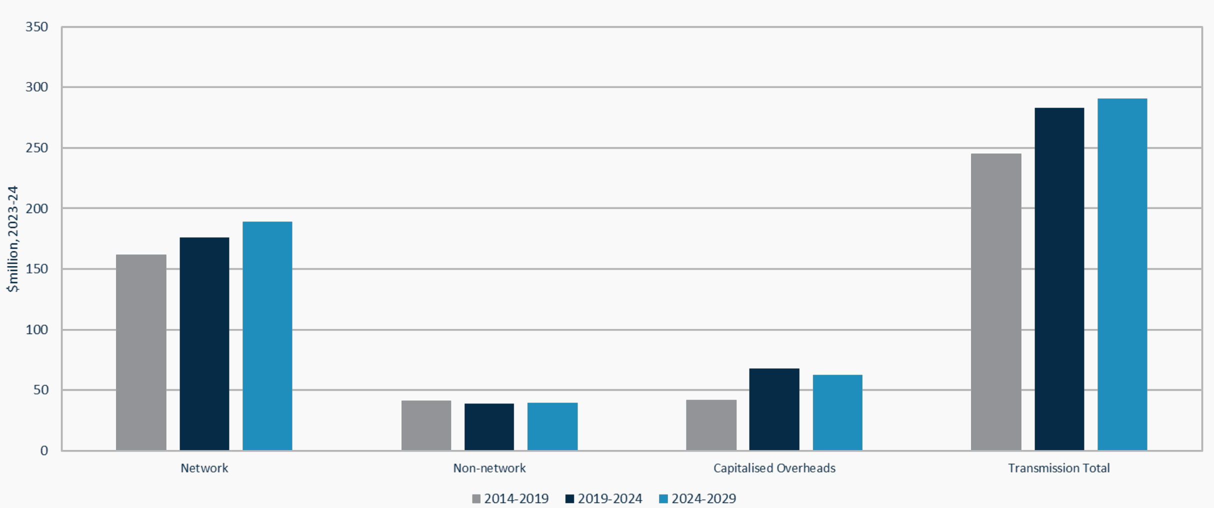


Note: Inclusive of capitalised overheads

Figure 19 presents TasNetworks' historical and future transmission capex showing:

- TasNetworks' total capex for the 2014-2019 regulatory control period
- TasNetworks' capex for the 2019-2024 regulatory control period, comprising three years of actual incurred capex and two years of forecast capex
- TasNetworks' total forecast capex for the 2024-2029 regulatory control period.

Figure 19. Historical and forecast transmission capex by category ($million, 2023-24)

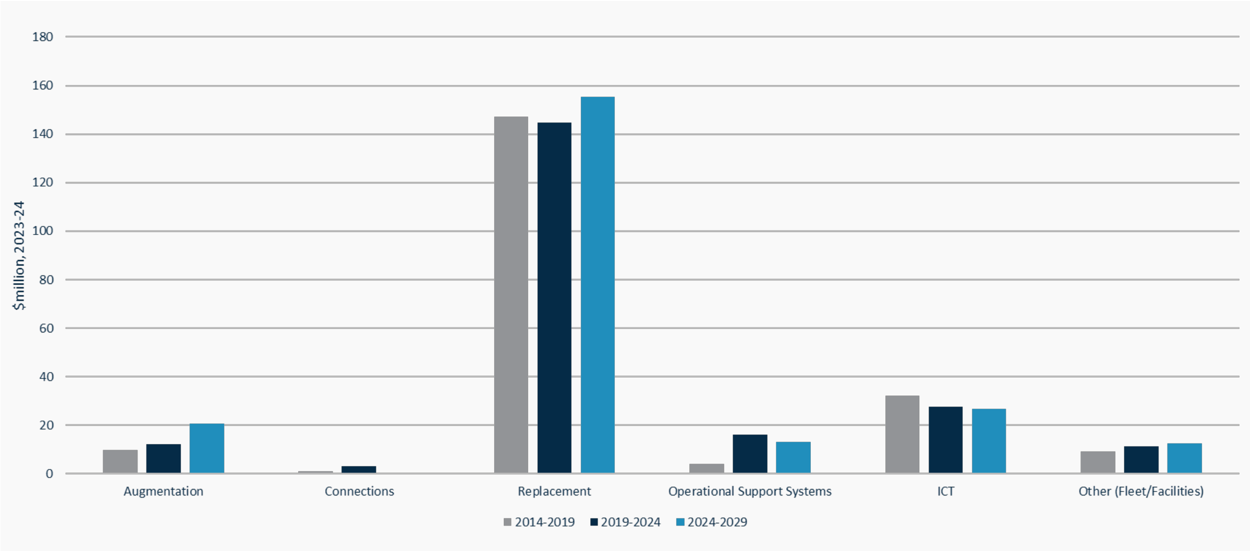


TasNetworks' total transmission capex forecast for the 2024-2029 regulatory control period is $290 million. This forecast is $4 million less than the allowance the AER determined for the 2019-2024 regulatory control period.

Network expenditure remains the largest component of our total transmission capex forecast, and is forecast to increase by $13m. The increase reflects the emergence of new network augmentation drivers and the deteriorating condition of assets in some categories where the risk of asset failure warrants increased investment in asset replacements.

Figure 20 shows how our transmission capex forecast is anticipated to change between regulatory control periods at the capex sub-category level. Analysis and commentary regarding material changes in capex is provided in the next sections.

Figure 20. Historical and forecast transmission capex by sub-category ($million, 2023-24)



6.9.1 Transmission connections

TasNetworks receives many connection enquiries from customers wanting to learn about the connections process, and the potential cost of connecting to the transmission network. Historically, many such enquiries do not proceed further.

To provide certainty in its revenue submission, TasNetworks includes a forecast comprising the capital investment needed for connection enquiries that have progressed to a formal connection application. TasNetworks has not received any connection applications from customers that would require investment on the shared transmission network in the 2024-2029 regulatory control period.

6.9.2 Transmission augmentation

TasNetworks forecasts the need for $21 million of capex to augment the transmission network, representing a $9 million increase compared to our forecast expenditure for the current regulatory control period. Consistent with our focus on affordability for customers and the delivery of services that our customers value, we have only proposed transmission augmentation investments that provide clear and material customer and market benefits.

Table 4 outlines our augmentation capex forecast for the 2024-2029 regulatory control period, comprising two transmission substation augmentation projects and several strategic land acquisitions to support development needs beyond 2029.

In addition, there are several high value capital projects classified as 'contingent' in the 2024-2029 regulatory control period which, if they were to proceed, would result in higher augmentation capex than forecast (see Attachment 7 Contingent projects for more information).

Table 4. Proposed transmission augmentation initiatives, 2024-2029 regulatory control period

Transmission Augmentation Investment	Capex ($m, $2023-24)	Problem / Opportunity	Proposed Solution
Loss Reduction in the Upper Derwent 110kV Network	10.9	Inefficiency in the 110kV Upper Derwent transmission network, is increasing costs for market participants and customers.	Conversion of the Upper Derwent transmission network from 110kV to 220kV, thereby reducing losses and maximising market benefits to participants and customers.
West Coast Reliability Improvement	7.1	Poor reliability is being experienced by customers in Zeehan, on Tasmania's west coast. We are also forecasting an increase in mining loads.	Construction of a new 22kV injection point for the network supplying Zeehan and the West Coast of Tasmania, thereby improving the long-term electrical security and reliability of the region.
Strategic Land Acquisitions	2.7	Land and easements are required for the construction or augmentation of transmission lines and substations. Delayed acquisition increases cost, timing and other project risks.	Acquisition of land and easements, where it can be demonstrated that overall projects costs and the risks of delay during implementation are reduced by early acquisition.

6.9.3 Transmission asset replacements

TasNetworks forecasts the need for $155 million of capex for transmission network asset replacements in the 2024-2029 regulatory control period, representing a $10 million increase in investment compared to forecast investment in the 2019-2024 regulatory control period.

Table 5 provides a breakdown of forecast expenditure by transmission asset categories for the 2024-2029 regulatory control period, including drivers underpinning material changes in the capex forecast.

Table 5. Proposed transmission asset replacement expenditure by asset class, 2024-2029 regulatory control period

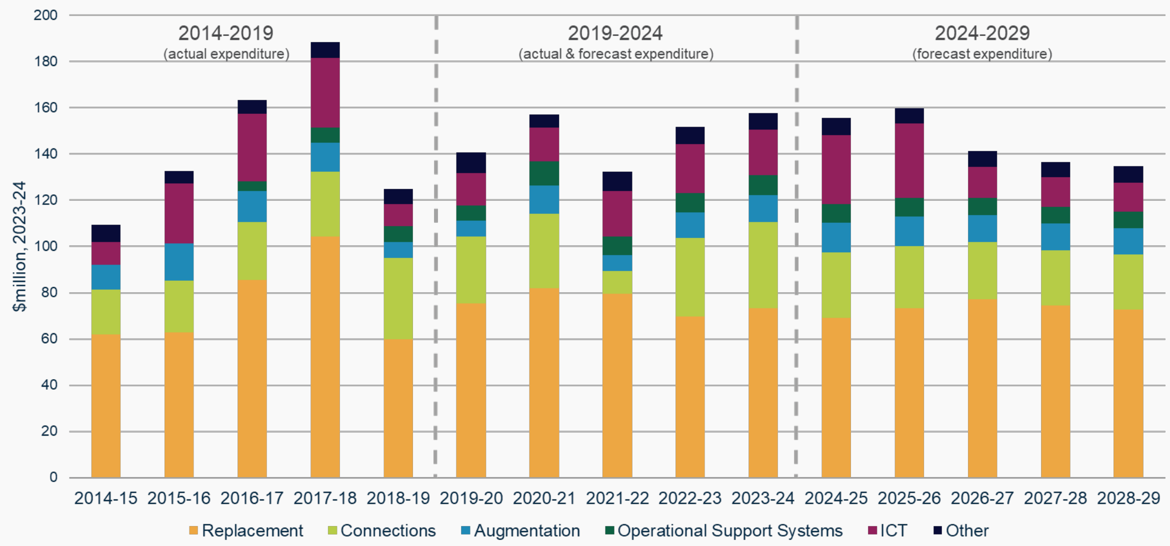
Transmission Asset Replacement Category	Total Capex ($m, $2023-24)	Drivers of change
Transformers	28.4	Increased investment needed due to deteriorating asset condition and risk of asset failure, and minimal investments in the current period.
Transmission line support structures and foundations	17.2	Asset audits have found that weather resistant steel (**WRS**) structures and assemblies are failing prematurely, with increased investment needed to mitigate this risk at critical locations.
Extra high voltage (EHV) switchgear	16.1	Increased investment needed due to deteriorating asset condition and risk of asset failure, and due to non-compliance with arc-flash standard requirements.
SCADA	15.7	In line with current investments.
EHV disconnectors and earth switches	13.9	Increased investment needed due to deteriorating asset condition and risk of asset failure, and minimal investments in the current period.
Telecommunications	11.9	Targeted multiplexor replacements in the current period reduce the need for investments in 2024-2029. Implementation of an improved asset spares management strategy that will make greater use of refurbished assets as spares in the future, significantly reducing the need for investment in new spares.
Transmission line conductor assemblies	10.7	Targeted replacement of galvanised iron (**GI**) conductors in the current period has been effective in mitigating risk, reducing the need for capital investment in 2024-2029.
Transmission line insulators	8.6	In line with current investments.
EHV circuit breakers	7.8	Targeted asset replacements made in the current period across many categories have been effective in mitigating risk, significantly reducing the need for capital investment in 2024-2029.
Transmission lines tracks and clearances	6.9	Increased investment for remediation of transmission spans identified as not meeting minimum clearance-to-ground standards.
Protection and control	5.9	Significant capex reduction resulting from the implementation of an optimised spares management strategy and a more targeted, risk focused approach to asset replacements.
Substation site – infrastructure and fire risk management	4.1	Targeted asset replacements made in the current period across many categories have been effective in mitigating risk, significantly reducing the need for capital investment in 2024-2029.
EHV current and voltage transformers	3.6	Increased investment needed due to deteriorating asset condition and risk of asset failure, and minimal investments in the current period.
Substation asset refurbishment	1.7	In line with current investments.
EHV cables	1.4	Increased investment due to deteriorating asset condition and risk of asset failure identified during dissolved gas analysis tests in the current period.
Substations AC systems	0.7	In line with current investments.
Transmission line rating monitoring	0.3	In line with current investments.
Substations spares management	0.1	In line with current investments.

6.10 Distribution capex forecast

The following sections outline our distribution capex forecasts, explaining the rationale behind any material step-changes, and comparing our forecasts against historical levels of investment to assist in the assessment of TasNetworks' capex forecasts.

Figure 21 shows how TasNetworks' capex has changed over time, including forecast capex for the remaining two years of the 2019-2024 regulatory control period and the 2024-2029 regulatory control period.

Figure 21. Historical and forecast distribution capex ($million, 2023-24)

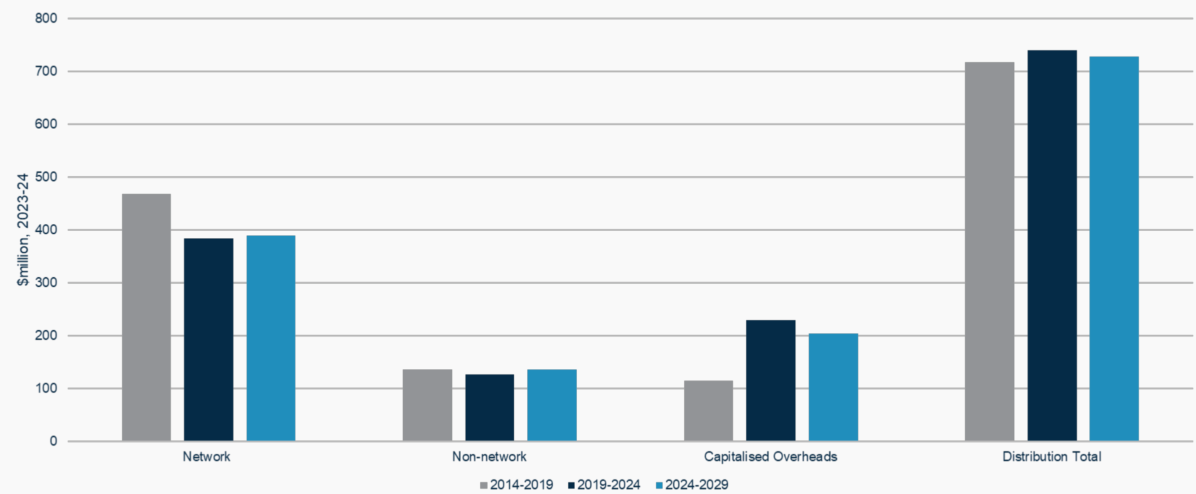


Note: Inclusive of capitalised overheads and customer capital contributions

Figure 22 presents TasNetworks' historical and future distribution capex showing:

- TasNetworks' total capex for the 2014-2019 regulatory control period
- TasNetworks' capex for the 2019-2024 regulatory control period, comprising three years of actual incurred capex and two years of forecast capex
- TasNetworks' total forecast capex for the 2024-2029 regulatory control period.

Figure 22. Historical and forecast distribution capex by category ($million, 2023-24)



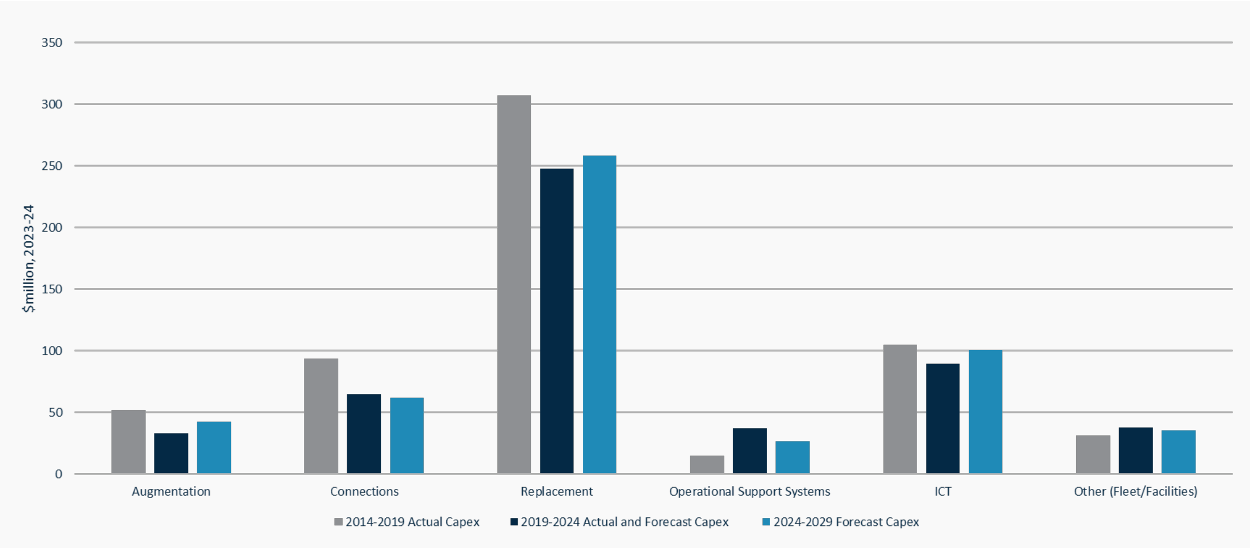
Supporting affordability for our customers, TasNetworks' total distribution capex forecast for the 2024-2029 regulatory control period is $729 million. This forecast is $11 million less than our expected distribution capex over the 2019-2024 regulatory control period. Further, the 2024-2029 forecast is $65 million less than TasNetworks' allowance for the 2019-2024 regulatory control period.

Network expenditure continues to be the largest component of our total distribution capex forecast, increasing by $5 million compared with network investments in the current period. This increase reflects the emergence of new network augmentation drivers, and a number of asset categories where condition deterioration and the risk of asset failure are sufficient to warrant an increase in investment for asset replacements.

We also propose an increase of $11 million in non-network ICT capex compared with similar investments in the current period. This increase is reflective of a number of critical systems approaching end of life and requiring replacement, and the need to uplift the cyber security and resilience of our critical infrastructure.

Figure 23 shows how our distribution network capex is anticipated to change between regulatory control periods, at the capex sub-category level. Analysis and commentary regarding material changes in capex is provided in the sections below.

Figure 23. Historical and forecast distribution capex by sub-category ($million, 2023-24)



6.10.1 Distribution augmentation

TasNetworks forecasts the need for $43 million of capex for distribution network augmentation in the 2024-2029 regulatory control period. This is a $9 million increase in investment compared with our forecast augmentation investments in the 2019-2024 regulatory control period.

The identified investments are outlined in Table 6.

Table 6. Proposed distribution augmentation initiatives, 2024-2029 regulatory control period

Distribution Augmentation Investment	Capex ($m, $2023-24)	Problem / Opportunity	Proposed Solution	Drivers of change
High and low voltage network reinforcement and upgrades due to capacity issues	15.6	Thermal overload, including fault levels, of high voltage conductors and cables imposing operational limitations during normal or contingency events.	Reinforcement or establishment of high voltage conductors and cables to manage thermal loading and fault levels and improve the transfer capability and operational flexibility on the high voltage network.	Improvements in the methodology and data used by TasNetworks to forecast network growth will reduce the level of investment for these assets. Increased customer connections, and the resulting capex needed to facilitate those connections, will also result in a corresponding reduction in the need for augmentation investment.
Future Distribution System Vision and CER enablement	9.7	Increased penetration, use and sophistication of CER is leading to increased bi-directional energy flows on the low voltage network and increased expectations from customers regarding the grid.	Improve visibility and control of the low voltage network, undertake trials to enable CER such as dynamic operating envelopes, network tariffs and community batteries.	Increased investment for the development and implementation of customer trials for community grid batteries, remote power systems, and building capability within the network to cater for increasing solar rooftop connections and EVs. Development of network asset models to leverage advanced meter data.
Distribution transformer upgrades due to supply quality issues	3.7	Poor quality of supply beyond legislated limits impacting customers on the high voltage and low voltage networks where the issue is identified at the transformer.	Replacement and upgrade of distribution transformers to address supply quality complaints from customers.	While solar PV and EV connections are forecast to continue to rise, actual demand in the current period has not reflected the forecasts used by TasNetworks in making its previous revenue submission, and this downward adjustment in investment for transformer voltage regulation is reflected in TasNetworks' forecast for the 2024-2029 regulatory control period.
High voltage network reinforcement and upgrades to address reliability issues	3.7	Poor reliability of supply, measured through the frequency and duration of outages, impacting customers.	Targeted reliability improvement initiatives to address poor performing sections of the distribution network.	Increased funding for reliability improvement for poor-performing communities.

Distribution Augmentation Investment	Capex ($m, $2023-24)	Problem / Opportunity	Proposed Solution	Drivers of change
Zone substation and sub-transmission circuit reinforcement and upgrades due to capacity issues	3.3	Thermal overload associated with zone substation transformers and sub-transmission circuits during normal or contingency events.	Upgrade and installation of new zone substation transformers (not required for the 2024-2029 regulatory control period) and relocation and renewal of sub-transmission circuits.	Reduced investment, due to improvements in the methodology and data used by TasNetworks to forecast network growth. Increased customer connections, and the resulting capex needed to facilitate those connections, will also result in a corresponding reduction in the need for augmentation investment.
High and low voltage network reinforcement and upgrades to address supply quality issues	3.0	Poor quality of supply beyond legislated limits impacting customers on the high voltage and low voltage networks.	Reinforcement and upgrade of the high voltage and low voltage networks to address supply quality complaints from customers.	Growth in solar PV and EV charging connections on the distribution network will drive an increase in capital requirement for improving power quality. Power quality investigations also reveal a need for increased investment in low voltage voltage feeder phase balancing.
Distribution transformer upgrades due to capacity issues	2.0	Capacity constraints on pole and ground mounted distribution transformers caused by excessive thermal loading and/or voltage and power quality issues associated with thermal loading.	Prioritised installation or augmentation of distribution substations to manage thermal loading constraints within the low voltage planning standards prior to failure.	In line with current investments.
Strategic Land Acquisitions	1.5	Land and easements are required for the construction or augmentation of the distribution network, in particular zone substations. Delayed acquisition increases cost, timing and other project risks.	Acquisition of land and easements, where it can be demonstrated that overall projects costs and the risks of delay during implementation are reduced by early acquisition.	In line with current investments.

6.10.2 Distribution customer connections

TasNetworks forecasts the need for $62 million of capex for customer connections in the 2024-2029 regulatory control period. This is $3 million less than our forecast expenditure for customer connections in the 2019-2024 regulatory control period.

TasNetworks has previously utilised several external economic forecasts to develop its distribution customer connections forecasts, including:

- new dwelling construction forecast information from the Housing Industry of Australia
- population growth data from the Department of Treasury and Finance
- unemployment rate data from the Department of Treasury and Finance
- Tasmanian Gross State Product from the Department of Treasury and Finance.

Current levels of investment for customer connections exceed the forecasts developed for TasNetworks' Combined Proposal for the 2019-2024 regulatory control period. Learning from this experience, TasNetworks has improved its forecasting approach by including additional new dwelling forecasts from the Master Builders Association and the Australian Construction Industry Forum. This information has been found to align more closely with TasNetworks' historic experience and is expected to provide a more accurate forecast of connection volumes for the 2024-2029 regulatory control period.

6.10.3 Distribution asset replacement

TasNetworks forecasts the need for $258 million of capex for distribution network asset replacements in the 2024-2029 regulatory control period. This is $10 million more expenditure than forecast for the 2019-2024 regulatory control period.

Table 7 provides a breakdown of forecast expenditure by distribution asset categories for the 2024-2029 regulatory control period, including asset-specific drivers underpinning material changes in the capex forecast.

TasNetworks also has undertaken an investment optimisation process for its 2024-2029 network program of work, using its asset health-based risk management tool to quantify, compare, and ultimately manage risks across the portfolio.

Table 7. Proposed distribution asset replacement expenditure by asset class, 2024-2029 regulatory control period

Distribution Asset Replacement Category	Total Capex ($m, $2023-24)	Drivers of Change
Poles and structures	103.7	Asset condition data, together with the age profile of TasNetworks' fleet of distribution wood poles, shows that failure rates are forecast to increase, and a corresponding increase in capex is needed. TasNetworks is also pursuing an improved asset management strategy, where wood poles are replaced with fibre-reinforced concrete poles that will provide improved bushfire resilience and service performance at a lower whole-of-life cost – both key priorities communicated to TasNetworks by its customers as part of the stakeholder consultation process.
High voltage conductors	41.3	Alternative technologies, including overhead covered conductor, are proposed for implementation at a lower cost per km compared to high voltage aerial bundled conductor (**ABC**) and undergrounding. This will enable funding to be reprioritised to other asset categories to achieve better cost, risk and service performance outcomes.
Ground mounted substations	16.6	TasNetworks' portfolio optimisation process has identified that there are other asset categories where capex investment will achieve better cost, risk and service performance outcomes. TasNetworks will continue to monitor the condition of the assets and failure rate to ascertain whether future investment practices need to adjust to ensure risk is managed within TasNetworks' risk appetite.

Distribution Asset Replacement Category	Total Capex ($m, $2023-24)	Drivers of Change
Service connection assets	15.6	Recent audits have identified an increase in the number of low voltage services and service fuses requiring replacement. Forecast increases are offset by removal of CablePI costs and a move to condition based replacement using advanced meter data to monitor for loss of neutral and other failing assets.
Pole mounted transformers	12.7	Forecast expenditure has been reduced in line with historical volumes.
Bushfire mitigation	8.3	In line with current investments.
Low voltage crossarms	7.9	TasNetworks' analysis shows that changing its asset management strategy for the replacement of low voltage cross-arms from a reactive approach to a pro-active condition-based approach is more cost-effective in the long-term, reducing capex without adversely impacting on risk and/or service performance.
Zone substation transformers	7.0	We propose to reduce capex for this asset category, as TasNetworks' portfolio optimisation process has identified that there are other asset categories where this capex will achieve better cost, risk and service performance outcomes.
Overhead high voltage switchgear	6.6	In line with current investments.
Ground mounted low voltage switchgear	5.5	In line with current investments.
Low voltage cables and connections	5.0	TasNetworks' analysis shows that changing its asset management strategy for CONSAC cables from proactive replacement to replacement on failure is more cost-effective, without adversely impacting on risk and/or service performance.
Ground mounted high voltage switchgear	5.0	We propose to reduce capex for this asset category, as TasNetworks' portfolio optimisation process has identified that there are other asset categories where this capex will achieve better cost, risk and service performance outcomes.
Bird mitigation	4.6	In line with current investments.
High voltage cables and connections	3.9	In line with current investments.
Regulators	3.8	In line with current investments.
Ground mounted transformers	3.2	In line with current investments.
Low voltage conductors	2.4	We propose to reduce capex for this asset category, as TasNetworks' portfolio optimisation process has identified that there are other asset categories where this capex will achieve better cost, risk and service performance outcomes. It is expected that improved spatial and asset data will enable improved prioritisation of works to manage risk more effectively.
SCADA and Network Control	2.6	In line with current investments.
Ground mounted substations site management	1.1	In line with current investments.
Protection and control	0.7	In line with current investments.
Telecommunications	0.4	In line with current investments.
Overhead low voltage switchgear	0.3	In line with current investments.
Oil containment	0.3	In line with current investments.
Submarine cables	0.1	In line with current investments.

6.11 Transmission and distribution capex forecast

The following sections outline our capex forecasts associated with shared business services, that are allocated between the transmission and distribution networks based on the nature of the investment and expected use of the shared service by each network. These include investments in the areas of operational support systems, ICT, fleet and facilities management.

6.11.1 Operational support systems

The Operational Support Systems (**OSS**) category includes investments needed to procure, develop and/or upgrade hardware and software associated with:

- Asset management information systems (**AMIS**) such as the Geographical Information System (**GIS**), health-based risk management (**HBRM**) system, and asset master data
- Network Operating and Control System (**NOCS**) and System Control and Data Acquisition (**SCADA**) systems that are needed for monitoring and controlling the transmission and distribution networks in real time.

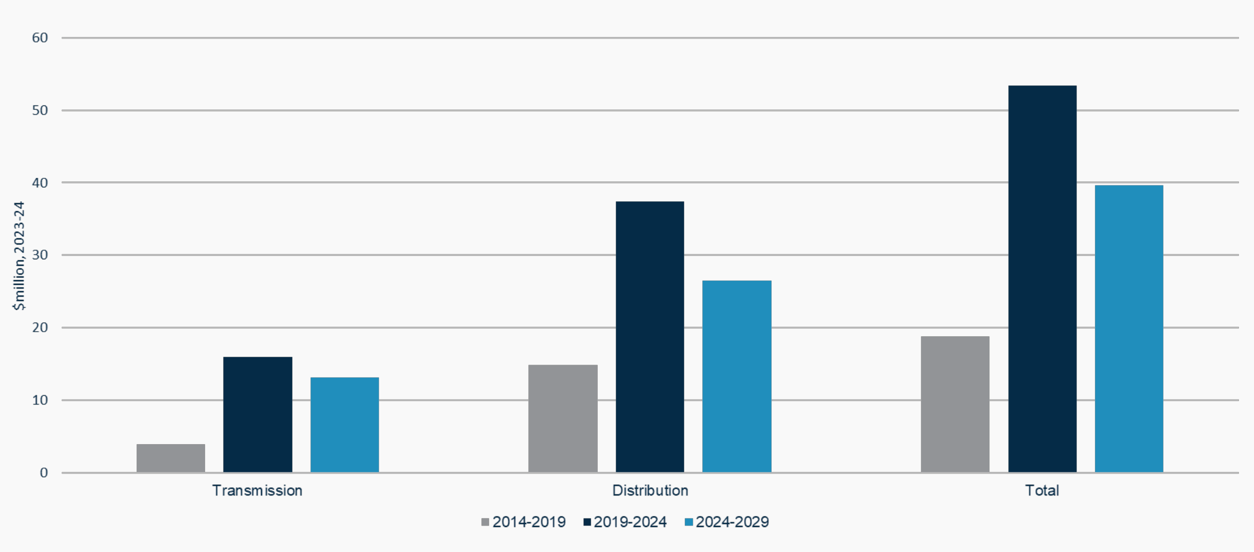
While TasNetworks categorises these investments as 'Network expenditure' (due to these investments strongly supporting the effective management of network assets), the nature of the investments is similar to those needed for ICT, as supported by the AER's definitions provided with annual transmission and distribution RINs.

For this reason, TasNetworks has used the AER's Guidance Note[6] of November 2019, to understand and assess the appropriateness of the mix of 'recurrent' and 'non-recurrent' capex investments required to meet customer and business needs.

Figure 24 presents TasNetworks' historic and forecast OSS expenditure for our transmission and distribution networks. TasNetworks forecasts the need for $40 million of capital investment for operational support systems in the 2024-2029 regulatory control period, comprising:

- $13 million for transmission network operational support systems, representing a $3 million reduction compared to forecast investment in the 2019-2024 regulatory control period
- $27 million for distribution network operational support systems, representing an $11 million reduction compared to forecast investment in the 2019-2024 regulatory control period.

Figure 24. Historical and forecast OSS capex by network ($million, 2023-24)

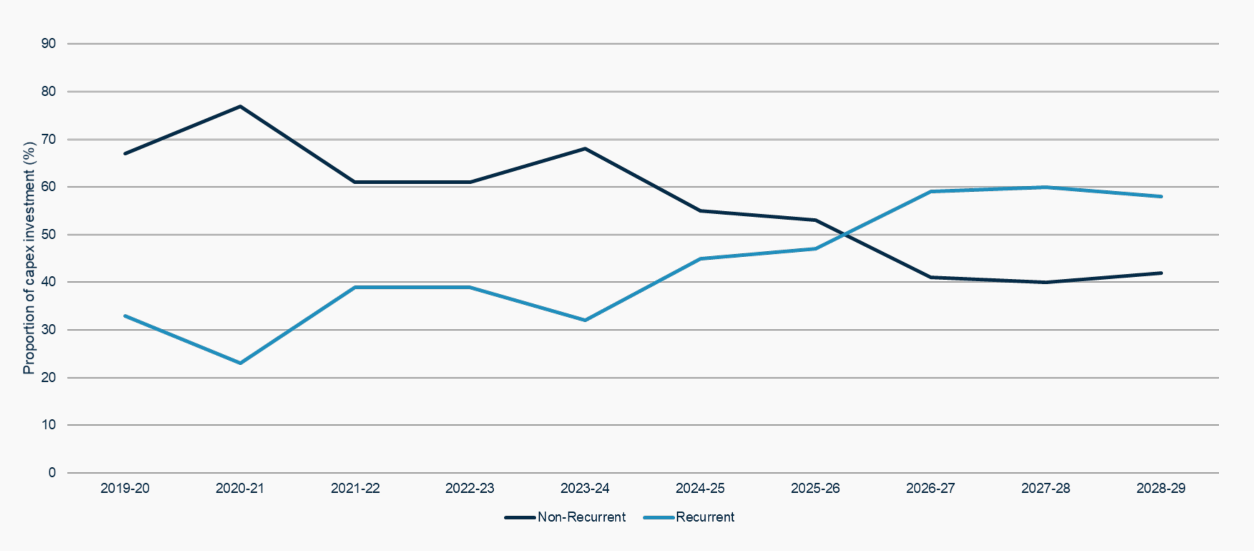


TasNetworks has made, and plans to make, significant non-recurrent investments in the 2019-2024 regulatory control period. By their nature, non-recurrent investments are infrequent and should result in a long term trend toward a greater proportion of recurrent investment (necessary for managing and maintaining the systems resulting from the non-recurrent investments).

6 Guidance note – Non-network ICT capex assessment approach (AER – November 2019)

Figure 25 presents TasNetworks' investments for OSS in terms of the annual proportion (%) identified as being either recurrent or non-recurrent. It shows non-recurrent investments reducing from a peak of 77 per cent early in the current regulatory 2019-2024 period, to around 40 per cent by the end of the 2024-2029 regulatory control period. Conversely, we see recurrent investments increase from 23 per cent up to around 60 per cent.

Figure 25. Recurrent and non-recurrent investment proportionality for operational support systems expenditure



Key non-recurrent investments proposed for the 2024-2029 regulatory control period include:

- AMIS:
  - HBRM system enhancements – acquisition and installation of additional modules for TasNetworks' HBRM system to improve data analytics and investment portfolio optimisation.
- NOCS/SCADA
  - Tasmanian Integrated System Protection Scheme – new control systems to manage transmission system security and maximise system capacity
  - Distribution System Operator (**DSO**) – investment in foundational information technology to support TasNetworks' transition to becoming a DSO
  - Phasor Measurement Unit (**PMU**) analytics – a one off implementation of a system to visualise transmission PMU data streams and automatically detect unusual power system operating conditions
  - Rotational load shedding – static, fixed, transmission load shedding systems (unlike the distribution network which requires annual changes based on feeder configuration and customer categorisation)
  - NOCS phasor measurement capability upgrade – one off upgrade of phasor measurement capability to improve data concentration, historian data storage, and data provision to AEMO
  - NOCS enhancement program – transmission control schemes and changes that are infrequent and that endure for a long period without the need for recurrent investment
  - NOCS infrastructure architecture change – step-change to transmission control systems undertaken for needs which are infrequent in nature, such as cyber security
  - AEMO Engineering Framework – delivery of elements of the new AEMO Engineering Framework and regulatory implementation roadmap necessary to manage new and increasingly dynamic network operating conditions.

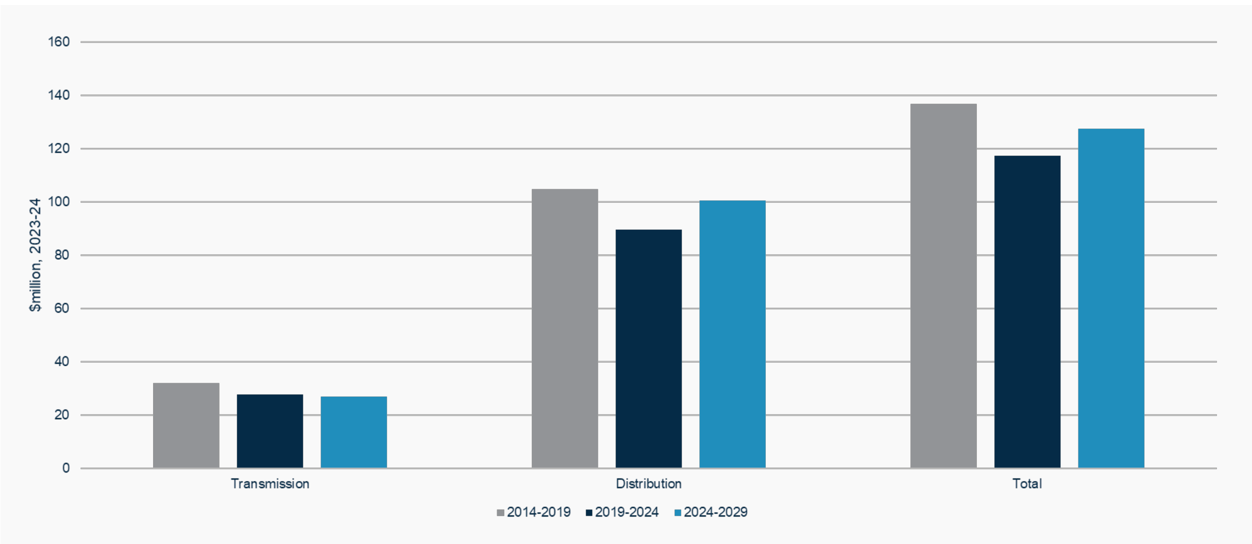
Key recurrent investments that will continue in the 2024-2029 regulatory control period include:

- AMIS:
  - Modelling capability – ongoing uplift in modelling capability for connectivity, forecasting, load and constraint management on the distribution network
  - Master data management – investing in tools and processes to continue to improve the quality of the asset master data and increasing the number of assets covered
  - Drawings management and capability – ongoing improvements to systems and processes
  - Data and analytics – periodic improvements to tools and systems facilitating data collation, interrogation and translation into actionable outputs.
- NOCS/SCADA
  - Advanced distribution management system (**ADMS**) – maintenance and periodic upgrades of software and hardware needed to support activities such as field mobility, visibility and management of network connectivity, and interfaces to CER
  - SCADA – tools and systems needed to maintain effective oversight of our distribution and transmission networks
  - Cyber security – ongoing, periodic improvements needed to cyber security controls to manage ongoing cyber security risks within a changing landscape, particularly considering increased future interconnection of TasNetworks' ADMS
  - Power quality and CER – continuous improvement in ensuring power quality data is being captured and effectively presented to the business, within an increasingly dynamic operating environment and with forecast increases in CER
  - Load management systems – ongoing, periodic upgrades in response to changing electrical networks, required for the rotational load shedding
  - System protection schemes utilising real-time software to calculate and apply transmission asset ratings, necessary for maintaining system capacity, security and reliability
  - Distribution network device lifecycle management, the integration of 'Internet of Things' (**IoT**) devices and associated software systems to support device lifecycle management and historian licensing.

6.11.2 Information communications technology

Figure 26 presents TasNetworks' historic and forecast ICT capex for our transmission and distribution networks.

Figure 26. Historical and forecast ICT capex by network ($million, 2023-24)



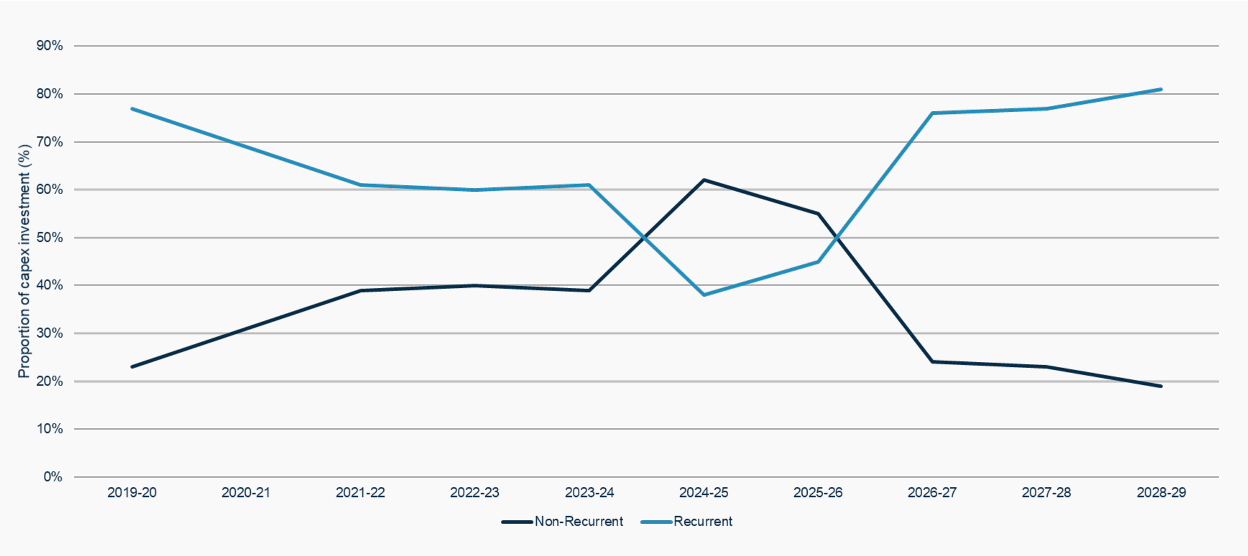
In the 2024-2029 regulatory control period we forecast an overall increase in ICT capex of $10 million.

The most significant drivers behind this increase include:

- Upgrade requirements for three systems comprising TasNetworks' Works Management Tool, as these systems are approaching end-of-life and do not integrate effectively with TasNetworks' enterprise resource planning (**ERP**) tool
- recent critical infrastructure reforms and updates to the (Commonwealth) *Security of Critical Infrastructure Act 2018*, requiring TasNetworks to improve the security and resilience of its critical infrastructure, with a focus on addressing the heightened cyber threat environment globally, and the increased risk of cyber-attacks on Australian networks.

In November 2019 the AER released a Guidance Note[7] explaining its approach to assessing non-network ICT capex forecasts and introducing the concept of 'recurrent' and 'non-recurrent' capex. Figure 27 presents the recurrent and non-recurrent components of TasNetworks' overall ICT capex, showing how they vary over time as a proportion of total capex.

Figure 27. Total ICT capex with recurrent and non-recurrent split



There are a number of non-recurrent investments proposed in the 2024-2029 regulatory control period. The level of investment is to rise in the first two years before reducing considerably in the last three years of the period. This is consistent with the transition to predominantly recurrent expenditure to manage the assets arising from the non-recurrent investments. Some investments comprise both a non-recurrent portion (typically needed for the development or purchase of a new system), and a recurrent portion to facilitate ongoing asset management and minor upgrades.

Key non-recurrent investments proposed for the 2024-2029 regulatory control period include:

- Market Data Management System (**MDMS**) replacement – replacing aging unsupported systems to maintain customer services and compliance
- MDMS upgrades – the non-recurrent component of adapting to regulatory changes, while ensuring we maintain market functions, customer service and compliance
- Works management tool upgrades – replacing and consolidating aging unsupported systems to maintain asset construction and maintenance functions, facilitating provision of good customer service
- Cyber security upgrades – to increase system resilience and to protect TasNetworks' systems and data
- ERP upgrades – the non-recurrent component of a program of upgrades and enhancements to the ERP suite to maintain software currency, optimise efficiency and maintain compliance
- Design and estimation completion – the continuation of investment from the 2019-2024 regulatory control period to replace and consolidate aging unsupported systems to improve efficiency and effectiveness of the design and works initiation processes.

7 Guidance note – Non-network ICT capex assessment approach (AER – November 2019)

Key recurrent investments in the 2024-2029 regulatory control period include:

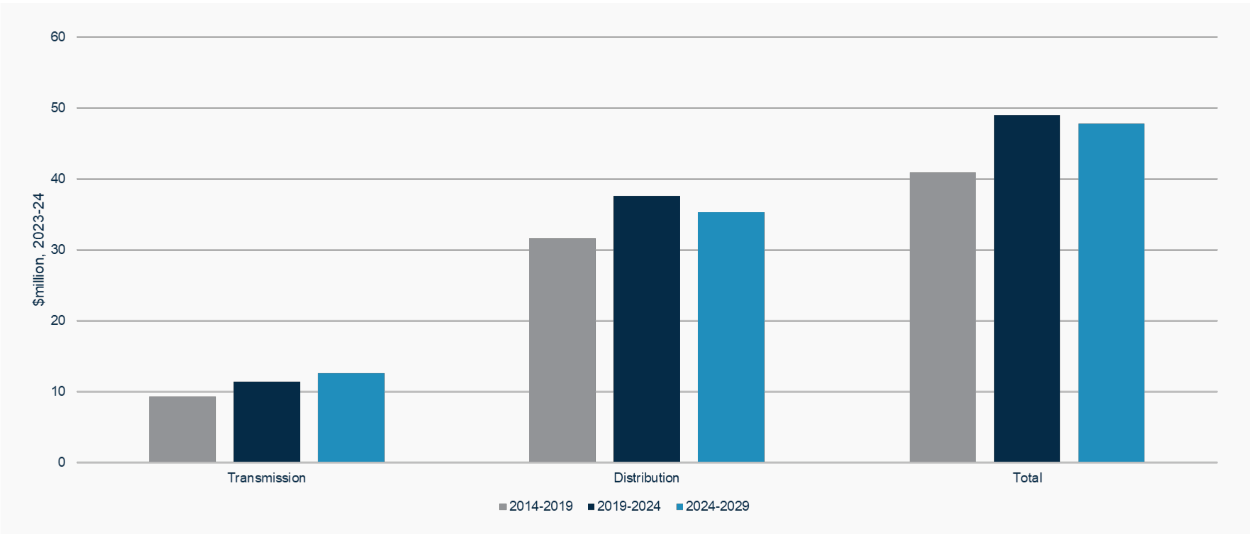
- MDMS maintenance – ensuring we maintain market functions, customer service and compliance
- Business systems maintenance – maintenance and minor upgrades of secondary tier applications that are integral to the successful operations of TasNetworks such as customer systems, collaboration and document management systems, engineering applications, training and licence management etc.
- Data analytics program – maintaining and developing TasNetworks' data warehousing, business intelligence and data analytics capability
- ERP upgrades – the recurrent component of a program of upgrades and enhancements to the ERP suite to maintain software currency, optimise efficiency and maintain compliance
- Digital infrastructure and end user computing – maintenance and replacements of digital infrastructure and hardware that are integral to the successful operations of TasNetworks such as network hardware and software, data storage and back up, desktop and laptop computers, mobile phones and supporting peripherals etc.

6.11.3 Other non-network capex

In line with the AER's standardised capex model, capex investments associated with fleet and facilities assets are reported under the category of 'Other'.

As shown in Figure 28, TasNetworks forecasts a $1 million reduction in capex investment for fleet and facilities in the 2024-2029 regulatory control period compared to the expected outcome for the 2019-2024 regulatory control period.

Figure 28. Historical and forecast non-network other capex by network ($million, $2023-24)



Key investments proposed under this category are presented Table 8.

Table 8. Proposed other non-network initiatives, 2024-2029 regulatory control period

Other Investments	Total Capex ($m, $2023-24)	Investment Need
Fleet replacements	32	Replacement of vehicles and other assets to meet safety and compliance requirements, while also ensuring the business can achieve its operational requirements in the field.
Facility upgrades and developments	16	Optimisation, upgrade, development, and other improvements to depots, offices and other facilities located across Tasmania.

6.12 Delivering our forecast capex program

The amount and composition of TasNetworks' forecast capex work program for the 2024-2029 regulatory control period is similar to that being delivered in the 2019-2024 regulatory control period. TasNetworks, therefore, has the resources and competencies available internally and externally to deliver the proposed works program for the 2024-2029 regulatory control period.

As at December 2022, TasNetworks employs around 1,100 full time equivalent (**FTE**) workers to deliver transmission and distribution services (including alternative control services). This includes field workers, professional and paraprofessional staff (e.g., engineers, technical officers etc.), corporate and support staff.

TasNetworks' strategy is to maintain a base level of in-house resources to deliver our prescribed transmission services and our alternative control and standard control distribution services, with workload peaks and troughs managed through supplementary external suppliers. Strategies are applied to ensure the availability of an optimum mix of skills and resources required to deliver the forecast capex program.

The internal field workforce required to operate, maintain and support the transmission and distribution networks is currently made up of approximately 510 FTEs, comprising Asset Inspectors, Distribution Operators, Dual-Trade Electricians/Lineworkers, Distribution Lineworkers, Live Line Workers, Meter Readers, Electricians, EHV Linesmen, Protection and Control officers, Vegetation Management officers, Project/Site Managers, Designers, Engineers and Schedulers.

TasNetworks also engages contractors to support the delivery of the program of work. Contractors currently provide the equivalent availability of 53 FTEs, which equates to approximately 73,000 hours of labour per annum, to assist with program delivery. The current pool of external service providers has access to crews based in mainland Australia, which can further supplement the external labour pool in Tasmania if required to meet the forecast work program schedule.

6.13 Appendix 1 Asset management framework

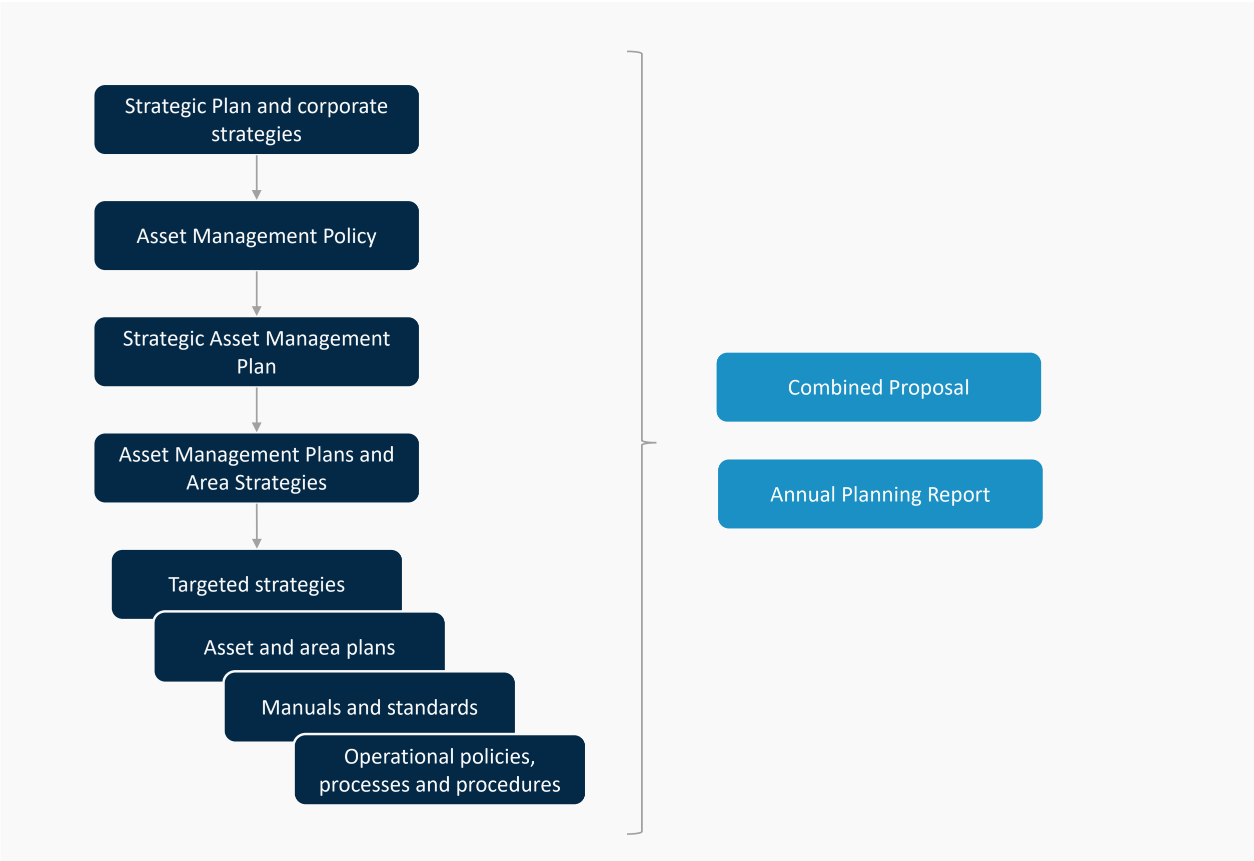
Several of TasNetworks' capex plans and strategies are related and collectively form part of the asset management framework used to manage existing transmission and distribution network assets and plan for new. This includes the preparation of the capex forecasts for our two networks for the 2024-2029 regulatory control period. We consider transmission and distribution planning as an integrated function and apply our asset management framework to one electricity network.

Key documents forming part of our asset management framework are as follows:

- Strategic Plan and other corporate strategies – these detail our strategic direction, key priorities and sets the overarching direction for TasNetworks
- Asset Management Policy – sets out the principles applied to our asset management activities
- Strategic Asset Management Plan – outlines the operating environment and the challenges faced by TasNetworks in delivering prescribed distribution and standard control distribution services now and into the future
- Asset Management Plan – details the levels of service delivered, the assets required to deliver these levels of service, the risks faced, asset life-cycle strategies, historical and forecast expenditure to deliver the levels of service and/or to address identified risks
- Annual Planning Report – informs stakeholders about the existing and forecast system limitations on our distribution and distribution networks, our network performance and proposed investments for the planning period. Preparation of this document is a regulatory requirement.
- Detailed strategies, plans, manuals, policies, processes and procedures – give detailed guidance for asset maintenance and day-to-day operational activities. These documents are available on request by the AER.

Documents from TasNetworks' asset management framework provided in support of this Combined Proposal are listed in Attachment 23 List of supporting documentation.

Figure 29. Asset management framework



TasNetworks

Powering a
Bright Future

Combined Proposal 2024-2029

Attachment 7
Contingent projects

Outline: This attachment to TasNetworks' regulatory combined proposal sets out how the contingent projects provisions of the National Electricity Rules will apply to TasNetworks during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
> **Attachment 7**	**Contingent projects**
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

7 Contingent projects

7.1 Introduction

Contingent projects are significant network augmentation projects that are reasonably likely to be required in the 2024-2029 regulatory control period but for which the timing and/or the associated costs are not sufficiently certain to warrant their inclusion in TasNetworks' capital expenditure (**capex**) forecasts. Consequently, expenditure for these projects does not form part of TasNetworks' total forecast capex in the 2024-2029 regulatory control period, but the costs of these projects may ultimately be recovered from customers if unique trigger events occur.

TasNetworks has identified seven contingent projects relating to major augmentations of our transmission network that may be required in the 2024-2029 regulatory control period. There are two additional contingent projects that are triggered automatically due to rule changes and being an actionable project in the Integrated System Plan (**ISP**). No contingent projects have been identified in relation to the distribution network for the 2024-2029 regulatory control period. The National Electricity Rules (**NER**) clauses referred to in this Attachment, therefore, relate to transmission services.

Table 1 summarises the seven contingent projects relating to major augmentations of the transmission network. The defined events that will trigger these projects are proposed in Section 7.5.2. One of the projects, the Palmerston to Sheffield Network Upgrade, also forms part of the Project Marinus Actionable ISP Project. It is also being proposed as a separate contingent project, as it may be required independently and in advance of Project Marinus. In developing this Combined Proposal, we have shared with customers and stakeholders the uncertainties associated with each of the nominated contingent projects and received their feedback.

Table 1: Summary of TasNetworks' proposed transmission network contingent projects

Contingent project	Project summary
George Town Reactive Support (Stage 1)	This project will provide dynamic reactive support to meet power system voltage and system stability requirements following new load connections in the George Town-Bell Bay area.
George Town Reactive Support (Stage 2)	Following new load connections in the George Town-Bell Bay area in excess of 300 MW, this project will provide further reactive support to meet power system voltage and system stability requirements.
George Town Substation Network Reinforcement	Following new load connections in the George Town-Bell Bay area, this project will rearrange the 220 kV connections at the existing George Town Substation and establish a new substation in the Bell Bay area to address TasNetworks' network security and performance standards obligations.
Palmerston to Sheffield Network Upgrade	This project will upgrade the transmission corridor between Palmerston and Sheffield to maintain network stability following connection of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Sheffield to George Town Network Upgrade	This project will upgrade the transmission corridor between Sheffield and George Town to maintain network stability following connection of over 300 MW of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Palmerston to George Town via Hadspen Network Upgrade	This project will upgrade the transmission corridor between Palmerston and George Town to address thermal capacity issues following connection of over 700 MW of new load in the George Town-Bell Bay area or connection of new generation in north west or central Tasmania.
Waddamana to Palmerston transfer capability upgrade	This project will upgrade the transmission corridor between Waddamana and Palmerston to maintain power flows within thermal and/or stability limits following connection of new generation in central or southern Tasmania.

All contingent projects relate to:

- additional renewable generation required to deliver the legislated Tasmanian Renewable Energy Target (**TRET**)[1]
- load associated with the production of green hydrogen envisioned in the State Government's Tasmanian Renewable Hydrogen Action Plan (**TRHAP**).[2]

The Tasmanian Government has set out a range of goals in its Tasmanian Renewable Energy Action Plan (**TREAP**).[3] It has also developed a Renewable Energy Coordination Framework,[4] which sets out the Government's plans to ensure that the projects needed to achieve the TRET, including development of Tasmania's Renewable Energy Zones (**REZ**), are delivered in an orderly, sustainable and integrated manner. The TRHAP sets out a vision for Tasmania to capitalise on its existing and expandable renewable energy resources to become a world-leader in large-scale renewable hydrogen production, for domestic use and export.

Together, it is these plans, as well as connection enquiries received by TasNetworks, which have informed the nomination of TasNetworks' 2024-2029 contingent projects.

7.2 Rules requirements

Most contingent projects must be identified in revenue determinations, along with indicative costing and proposed trigger event(s).[5]

Projects classified as actionable by the Australian Energy Market Operator (**AEMO**) in the ISP and projects to meet system strength requirements published by AEMO are not required to be identified in revenue determinations but are also contingent projects for the 2024-2029 regulatory control period under the NER.

1 In November 2020, the Tasmanian Parliament legislated the Tasmania Renewable Energy Target which is to increase Tasmania's renewable energy output equivalent to 150 per cent of 2022's renewable energy figures by 2030 and 200 per cent by 2040

2 Department of State Growth, Tasmanian Renewable Hydrogen Action Plan, March 2020, Tasmanian Government

3 Department of State Growth, Tasmanian Renewable Energy Action Plan, December 2020, Tasmanian Government

4 Renewables, Climate and Future Industries Tasmania, Renewable Energy Coordination Framework, April 2022, Tasmanian Government

5 NER Clause 6A.8

7.2.1 Criteria for inclusion

For a proposed contingent project to be accepted by the AER in TasNetworks' 2024-2029 revenue determination, the project must:[6]

- be reasonably required to be undertaken in order to achieve any of the capital expenditure objectives in the NER;[7]
- not otherwise be provided for in TasNetworks' total forecast capex for 2024-2029;
- reasonably reflect the capex criteria;[8]
- involve expenditure exceeding either $30 million or five per cent of TasNetworks' maximum allowable revenue for the first year of the 2024-2029 period, whichever is greater[9]; and
- have appropriate trigger events that are reasonably specific, capable of objective verification and consistent with the identified need for each project.

7.2.2 Trigger events

When nominating a project as a contingent project, TasNetworks is required to propose the specific event(s) that will trigger the requirement to undertake the contingent project. In determining whether a trigger event proposed in relation to a nominated transmission contingent project is appropriate, the AER must have regard to the need for the event:[10]

- to be reasonably specific and capable of objective verification
- to be a condition or event which, if it occurs, makes the investment in the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives
- to be 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
- to be described in such terms that it is all that is required for the revenue determination to be amended
- to be a condition or event, the occurrence of which is probable during the relevant regulatory control period but the inclusion of capex in relation to it is not appropriate because either:
    - o it is not sufficiently certain that the event or condition will occur during the period, or if it may occur after that period or not at all; or
    - o the costs associated with the event or condition are not sufficiently certain.

6 NER Clause 6A.8.1 (b)

7 Capex objectives are listed in clause 6A.6.7(a) of the NER

8 Capex criteria are listed in clause 6A.6.7(c)(1)-(3) of the NER

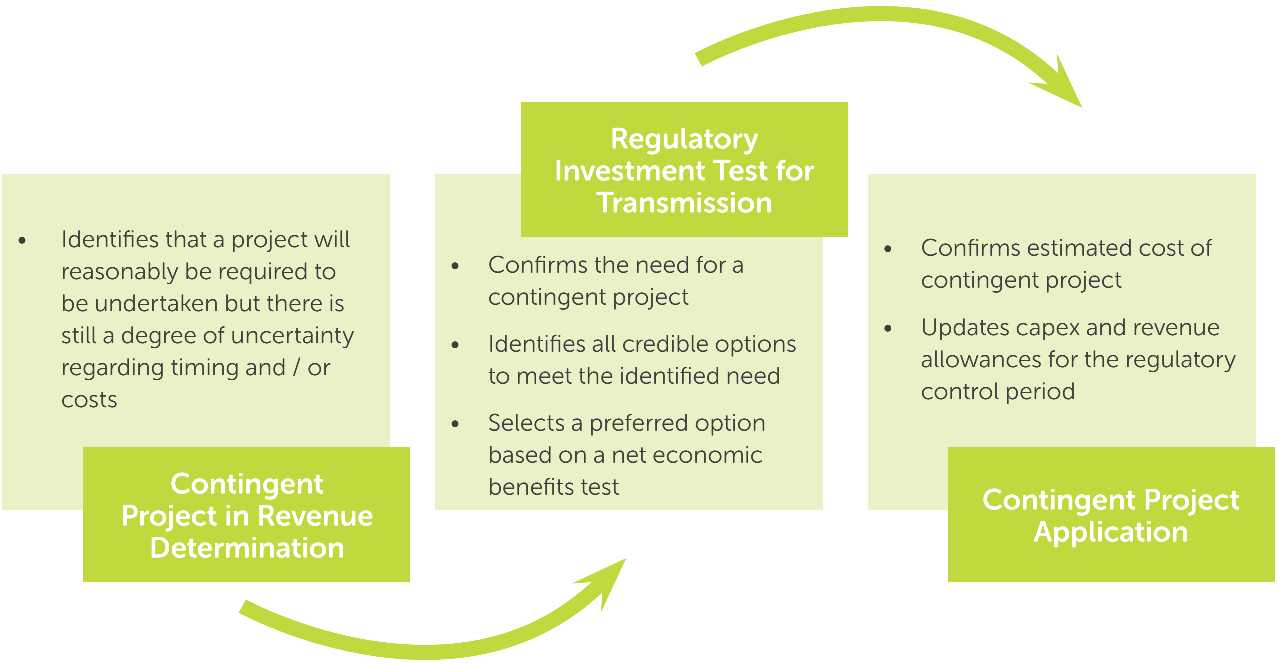
9 For TasNetworks, the contingent project threshold is $30 million

10 Clause 6A.8.1(c)

7.3 Contingent project regulatory and consultation stages

Nomination of a contingent project in a Revenue Proposal and acceptance by the AER in a Revenue Determination is the first regulatory step for major transmission projects (excluding ISP projects). Figure 1 shows the remaining regulatory steps where the project need, preferred solution and cost is further refined. Customer and other stakeholder feedback during these stages will help shape the project that will be delivered if trigger events occur during the 2024-2029 regulatory control period.

Figure 1: Contingent project regulatory and consultation stages



7.3.1 Regulatory Investment Test for Transmission

One trigger event common to all of TasNetworks' proposed transmission network contingent projects for the 2024-2029 regulatory control period is the successful completion of a Regulatory Investment Test for Transmission (**RIT-T**). The RIT-T is an economic analysis and assessment process that will identify the investment option that maximises net economic benefits in the National Electricity Market (**NEM**) while meeting the relevant service and technical standards set out in the NER or in Tasmanian jurisdictional instruments.

A key part of conducting a RIT-T is to consult with stakeholders on the economic cost benefit assessment and the ranking of investment options. Stakeholders will have opportunities as part of the RIT-T process to comment more specifically on a contingent project's need, costs, benefits and alternative solutions.

7.3.2 Contingent project application

If all triggers for a transmission network contingent project occur during the 2024-2029 regulatory control period, including successful completion of a RIT-T, TasNetworks can submit a Contingent Project Application (**CPA**) to the AER to amend its capex and operating expenditure (**opex**) allowances and annual revenue requirement for the remainder of the 2024-2029 regulatory control period.[11]
In making an application to the AER, TasNetworks must include certain details regarding the contingent project, including the forecast costs and project commencement and completion dates. The cost forecast in the CPA may differ from the estimate in this revenue proposal.

Prior to submitting a CPA to the AER, TasNetworks will engage with customers and stakeholders on project scope, costs and benefits. Customers and stakeholders will also be given an opportunity to ask questions and engage directly on the project. As noted above, stakeholders also will have the opportunity to discuss these projects as part of the RIT-T.

If the AER is satisfied that the trigger events for a specific contingent project have occurred and the forecast expenditure is prudent and efficient, it will amend TasNetworks' revenue determination for the remainder of the relevant regulatory control period.

7.4 Contingent project engagement

In developing TasNetworks' Combined Proposal, details of the nominated contingent projects have been shared with TasNetworks' Reset Advisory Committee (**RAC**), Policy and Regulatory Working Group (**PRWG**), Customer Council, Customer Panels and transmission customers during 1:1 meetings.

All groups were interested in future engagement on contingent projects with common themes being raised including:

- Project costs and benefits (all groups)
- Impacts on network charges (PRWG, Customer Council, Customer Panels and transmission customers)
- Project timeframes (PRWG, Customer Council, Customer Panels and transmission customers)
- Triggers (PRWG and Customer Council)
- Further information on the RIT-T and CPA processes (PRWG and Customer Council)
- Risks (Customer Panels).

All groups noted the need for clear and simple communication regarding contingent projects.

TasNetworks will continue to engage on contingent projects based on the feedback received so far.

7.5 Transmission network contingent projects

7.5.1 Contingent project drivers

All of the proposed contingent projects are triggered by new renewable generation and / or load. It is considered new renewable generation and load is likely to occur at large scale in Tasmania during the 2024-2029 regulatory control period, primarily driven by the TRET and the TRHAP.

This section provides further information on why it is expected that these projects will be required during the 2024-2029 regulatory control period. Further information on the implications for network capacity and costs from new generation and development of REZs in Tasmania can be found in Section 3.5 of TasNetworks' 2022 Annual Planning Report (**APR**). Section 3.6 of the APR provides further analysis on hydrogen and other load growth.

11 Clause 6A.8.2(a)

7.5.1.1 Generation growth

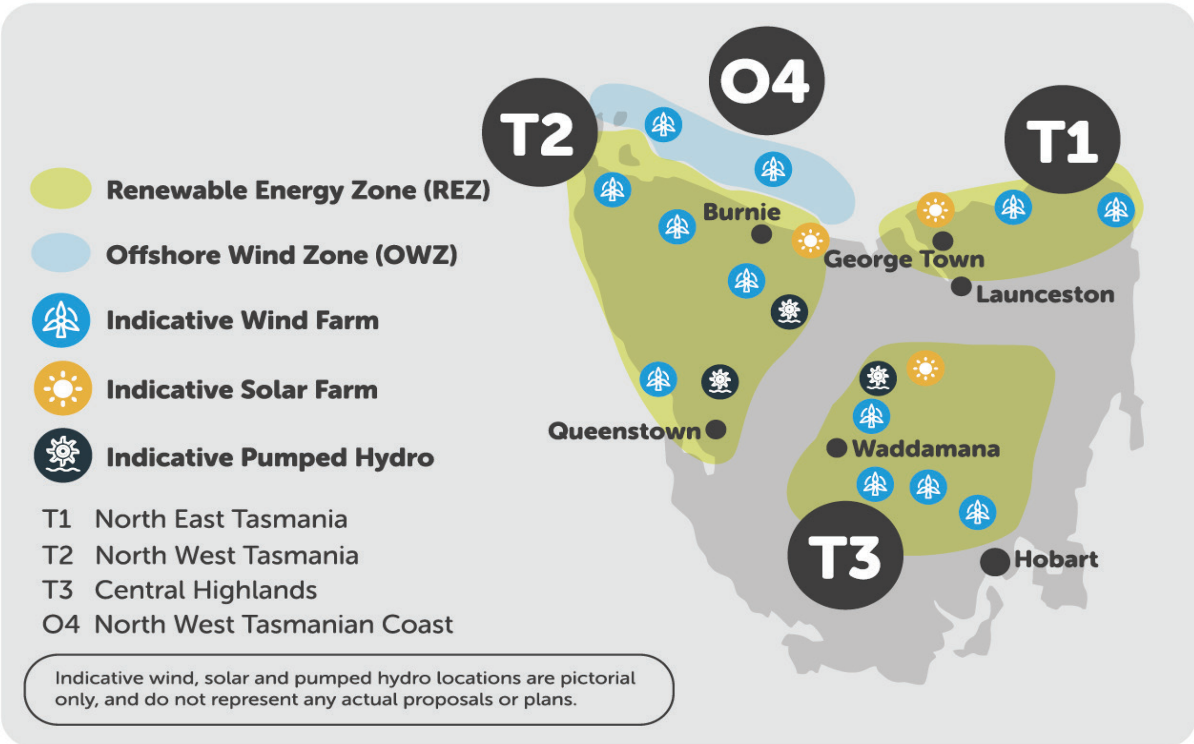
Up to four of the contingent projects are triggered by generator commitments to connect to the transmission network, noting three could also be triggered by new load in the George Town-Bell Bay area. It is expected many of these new connections will be driven by the TRET and the Renewable Energy Coordination Framework.

Under the TRET, an interim target of increasing renewable generation in Tasmania will see the output from renewable generation increase from 10,500 GWh in 2022 to 15,750 GWh in 2030. Tasmania's final legislated renewable energy target is to double renewable energy output, which will see Tasmania's renewable energy generation increase to 21,000 GWh by 2040.

The Renewable Energy Coordination Framework sets out the Tasmanian Government's plans to achieve the TRET, including development of Tasmania's REZs.

Figure 2 illustrates the location of each REZ in Tasmania as identified in the 2022 ISP.

Figure 2: Tasmanian Renewable Energy Zones[12]



The 2022 ISP forecasts 2.5 GW of new utility-scale wind generation in Tasmania by 2031-32 with 1,000 MW in the Central Highlands REZ by 2029-30 and 1,300 MW in the North West REZ by 2031-32. The contingent projects nominated in the Combined Proposal align with the ISP in that development of new generation during the 2024-2029 regulatory control period is expected in the Central Highlands and North West REZs.

A key trigger for contingent projects associated with new generation is generator commitment to connect to the transmission network. The point at which generation projects become 'committed' will be based on AEMO's five commitment criteria outlined in Table 2.

12 AEMO, Appendix 3 Renewable Energy Zones, 2022 Integrated System Plan, June 2022

Table 2: AEMO's commitment criteria for generation projects

Criteria Name	Description
Land	The project proponent has purchased / settled / acquired land for construction of the project.
Contracts	Contracts for the supply and construction of major plant or equipment components have been finalised and executed, including any provisions for cancellation payments.
Planning	The proponent has obtained all required planning consents, construction approvals, connection contracts (including approval of proposed negotiated Generator Performance Standards from AEMO under clause 5.3.4A of the NER), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Construction	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

7.5.1.2 Load growth

Up to six of the seven contingent projects are triggered by customer commitments of new load to connect to the transmission network in the George Town-Bell Bay area in Tasmania's north, noting that some contingent projects also could be driven by new generation in other regions of Tasmania. It is expected many of these new connections will be driven by the TRHAP.

The TRHAP contains the following goals:

1. By 2024 the production of renewable hydrogen will have commenced in Tasmania, with locally produced renewable hydrogen being used in Tasmania and projects to produce renewable hydrogen for export well advanced
2. By 2025 to 2027 Tasmania will have begun exporting renewable hydrogen
3. From 2030 locally produced renewable hydrogen will be a significant form of energy used in Tasmania and Tasmania will be a significant global producer and exporter of renewable hydrogen.

Both the *National Hydrogen Strategy*[13] and the TRHAP recognise the importance of developing hydrogen production hubs to leverage existing infrastructure and develop the industry. Tasmania has a number of locations that are well suited to large-scale hydrogen production, including the Bell Bay Advanced Manufacturing Zone (**BBAMZ**) in northern Tasmania.

The BBAMZ has been identified as the most suitable site for a potential hydrogen hub in Tasmania, due to its access to:

- certifiable renewable energy
- high-quality fresh water
- significant vacant industrial land near deep-water port facilities.

TasNetworks has seen significant interest from proponents looking to produce hydrogen in the BBAMZ. TasNetworks has received connection enquiries and pre-enquiries for hydrogen connections totalling over 2,500 MW and expects a number of these projects to become committed during the 2024-2029 regulatory control period. The interest from potential hydrogen proponents for transmission network connections exceeds the existing available network capacity supplying the Bell Bay area, and some level of network augmentation will be required.

Based on connection enquiries and aligning with the TRHAP, TasNetworks expects hydrogen production facilities to develop in the BBAMZ in three stages:

- Stage 1: 300 MW by 2026
- Stage 2: 700 MW by 2028
- Stage 3: 1,000 MW by 2030.

A key trigger for contingent projects associated with new load is load commitment to connect to the transmission network. A new load project will be considered 'committed' when there is a firm commitment between TasNetworks and the connection applicant regarding the connection.[14] Table 3 outlines the criteria used to determine the stage at which this has occurred.

13 Coalition of Australian Governments Energy Council, Australia's National Hydrogen Strategy, 2019, Commonwealth Government of Australia

14 TasNetworks Guide to Transmission Connections, Pg 14

Table 3: TasNetworks' commitment criteria for new load connections

Criteria	Description
Site	The applicant has firm rights to the land on which the project will be constructed.
Connection application	The applicant has submitted a complete connection application to TasNetworks.
Suppliers	The applicant has selected suppliers of major plant or equipment components, nominated primary plant, and provided associated models to TasNetworks.
Planning and approvals	The applicant has obtained all required planning and construction consents able to be obtained during this development period. This does not include consents and approvals required immediately prior to, or after, construction has begun. Performance standards for the facility (which ultimately require approval by TasNetworks and AEMO) have progressed to a stage where there are no material issues preventing connection, as determined by TasNetworks acting reasonably.
Commitment to proceed	The applicant and TasNetworks have each obtained Board approvals for the connection. TasNetworks and the applicant have signed an Asset Development Agreement and Connection Agreement. All applicant-controlled conditions precedent of the Asset Development Agreement have been satisfied within the nominated timeframe.
Finance	The applicant has achieved a positive investment decision, with written confirmation provided on behalf of the applicant and any financiers.

7.5.2 Proposed contingent projects

Table 4 outlines the drivers, trigger events and indicative costs of the proposed contingent projects. This is followed by a high-level overview of each proposed contingent project. Further background on the network locations relevant to TasNetworks' proposed contingent projects is provided in Attachment 23.

The cost estimates in Table 4 are based on the indicative project descriptions. The actual costs of fully scoped solutions are subject to the outcomes of the RIT-T and project tendering and procurement processes. When the specified trigger events for a contingent project occur during the 2024-2029 regulatory control period, detailed project scope and cost estimates will be provided during the CPA process. Customers and other stakeholders will have an opportunity to comment on the project scope and cost estimates during the development of the RIT-T and the CPA.

TasNetworks considers the proposed contingent projects meet the requirements of Clause 6A.8.1(b) of the NER and the associated trigger events to be appropriate for the purposes of Clause 6A.8.1(c).

Table 4: TasNetworks' proposed contingent projects, drivers, triggers and indicative costs

Project	Driver	Triggers	Indicative cost
George Town Reactive Support (Stage 1)	New load in the George Town-Bell Bay area	1. TasNetworks demonstrates customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under clause S5.1.8 of the NER. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$75m
George Town Reactive Support (Stage 2)	New load in the George Town-Bell Bay area	1. TasNetworks demonstrates that a second occurrence of load committed to connect to the transmission network in the George Town-Bell Bay area will result in TasNetworks being non-compliant with power system voltage and system stability requirements at George Town with respect to clause S5.1.8 of the NER. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, demonstrating a network investment is the most efficient option to meet reactive support requirements at George Town under clause S5.1.8 of the NER 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$80m
George Town Substation Network Reinforcement	New load in the George Town-Bell Bay area	1. TasNetworks demonstrates that customer commitment of additional load to connect to the transmission network in the George Town-Bell Bay area results in: • a material increase in the probability of cascading failure, following non-credible contingent events, as defined in clause S5.1.8 of the NER • breaches of minimum network performance requirements under regulation 5 of the *Electricity Supply Industry (Network Planning Requirements) Regulations.* 2. TasNetworks demonstrates that the solution required to meet the power system security obligations cannot be accommodated within the existing layout of George Town substation. 3. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates a network investment is the most efficient option to ensure TasNetworks meets its power system security obligations at George Town under: • clause S5.1.8 of the NER • The *Electricity Supply Industry (Network Planning Requirements) Regulations.* 4. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER	$50m

Project	Driver	Triggers	Indicative cost
Palmerston to Sheffield Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	1. One or both of the following: a. Commitment of additional load from one or more customers to connect to the transmission network in the George Town-Bell Bay area b. Commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Palmerston-Sheffield-George Town triangle and causes power flows through the Sheffield–Palmerston transmission corridor to be constrained to maintain network stability. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates augmenting power transfer capacity between Sheffield and Palmerston is the preferred option that provides net market benefits and / or addresses a reliability corrective action. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$212m
Sheffield to George Town Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	1. One or both of the following: a. Commitment of additional load from one or more customers with aggregated load above 300 MW to connect to the transmission network in the George Town-Bell Bay area b. commitment of new generation to connect in North West Tasmania or Central Highlands that results in higher power flows on the Sheffield-George Town-Palmerston triangle and causes power flows between Sheffield and George Town to be constrained to maintain flows within thermal and, or, stability limits. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity between Sheffield and George Town is the preferred option that provides positive net market benefits and, or, addresses a reliability corrective action. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$166m

Project	Driver	Triggers	Indicative cost
Palmerston to George Town via Hadspen Network Upgrade	New load in the George Town-Bell Bay area and / or New generation in North West or Central Highlands	1. One or both of the following: a. Commitment of additional load from one or more customers with aggregated load above 700 MW to connect to the transmission network in the George Town-Bell Bay area b. commitment of new generation to connect in North West Tasmania or the Central Highlands that results in higher power flows on the Palmerston-Sheffield-George Town triangle and causes power flows on the Palmerston to George Town via Hadspen 220kV transmission line to be constrained to maintain flows within thermal limits. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the capacity of the network between Palmerston and George Town via Hadspen is the preferred option that provides positive net market benefits and, or, addresses a reliability corrective action. 3. TasNetworks' Board commitment to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.	$209m
Waddamana to Palmerston transfer capability upgrade	New generation in the Central Highlands and / or southern transmission network	1. Commitment of new generation in the Central Highlands and / or the southern transmission network that results in power flow through the Waddamana–Palmerston transmission corridor to be constrained to maintain flows within thermal and, or, stability limits. 2. Successful completion of the RIT-T, including a comprehensive assessment of credible options, that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor is the option that maximises positive net market benefits. 3. TasNetworks' board commitment to proceed with the project subject, to the AER amending the revenue determination pursuant to the NER.	$113m

7.5.2.1 George Town area reactive support (Stage 1)

Background

Clause S5.1.8 of the NER requires TasNetworks to maintain an adequate reactive power margin at every connection point in the network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point.

The existing reactive support (capacitor banks) at George Town Substation is fully utilised to maintain voltage stability in the area. Any additional load in the area will need additional reactive support to maintain the transient voltage through the existing capacitor banks.

TasNetworks' analysis indicates that a significant amount of reactive support is needed to maintain the target voltage at George Town Substation and system stability under network contingencies.

Need

Additional dynamic reactive support is needed to facilitate future load growth and reduce the occurrence of Basslink export constraints. It is likely the reactive power margin will be breached following the addition of any new load connection in the George Town-Bell Bay area. Consistent with projected hydrogen growth, additional reactive support may be required before 2026.

Indicative solution

Although the quantity of voltage support required will be determined by the quantum of committed load, it will still need to be established in blocks that are both technically and economically efficient.

Initial studies indicate that the reactive power support requirement in the area is in the ratio of 1 MVAr to each 1 MW of load increase. Although, any additional load will trigger the need for reactive support, TasNetworks considers 300 MVAr is appropriate to align with the expectation of 300 MW of new hydrogen by 2026, while meeting TasNetworks' obligations under clause S5.1.8 of the NER. The installation of two $\pm$100 MVAr STATCOMs and two 50 MVAr capacitors at George Town are considered as an indicative solution to maintain steady state voltage and transient voltage stability in the area for an additional load of up to 300 MW.

Indicative cost

The indicative cost to install required dynamic reactive support and the capacitors needed to support an additional 300 MW of load is $75 million.

7.5.2.2 George Town area reactive support (Stage 2)

Background

Clause S5.1.8 of the NER requires TasNetworks to maintain an adequate reactive power margin at every connection point in the network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point.

New loads in the George Town-Bell Bay area beyond the first stage of hydrogen development will require installation of additional reactive support. As this is expected to occur several years after the installation of the initial reactive support, TasNetworks has proposed another contingent project to coincide with the second stage of hydrogen development.

Need

Following the installation of an initial 300 MVAr of reactive support, steady state and transient voltage at George Town may not be able to be maintained under some generation and load patterns with the proposed load developments in the George Town-Bell Bay area. Additional dynamic reactive support is needed to facilitate future load growth above 300 MW and reduce the occurrence of Basslink export constraints. It is likely the reactive power margin will be breached following the addition of any new load connection(s) involving more than 300 MW in the George Town-Bell Bay area. Consistent with Tasmanian Government objectives, additional reactive support could, therefore, be required before 2028.

Indicative solution

Initial studies indicate that the reactive power support requirement in the area is in the order of 1 MVAr to 1 MW of load. Although any additional load in the area will trigger the need for reactive support, TasNetworks considers 400 MVAr of additional reactive support would be sufficient to cater for the addition of 700 MW of new load associated with the production of green hydrogen by 2028, while still meeting TasNetworks' obligations under clause S5.1.8. The amount of reactive power required will become clearer following confirmation of other network and generation developments. An additional two $\pm$100 MVAr STATCOMs and four 50 MVAr capacitors at George Town are considered sufficient to maintain steady state voltage and transient voltage stability in the area for additional load of up to 700 MW.

Indicative cost

The cost to install the dynamic reactive support and the capacitors required to support an additional 400 MW of load in the George Town-Bell Bay area is estimated to be $80 million.

7.5.2.3 George Town Substation network reinforcement

Background

George Town Substation is the only substation supplying the Bell Bay area and is the largest single load point in Tasmania, having around 460 MW of relatively constant load. There are risks to the Tasmanian power system associated with having such a large share of the State's load at a single location.

Currently, the network connections and major industrial loads (as well as Basslink) are connected at opposite ends of the existing George Town Substation. This configuration raises network security risks under certain low probability conditions and the level of risk will increase as additional loads are connected.

There are currently insufficient available/spare bays at the existing substation to facilitate the three stages of hydrogen connections envisaged in the Tasmanian Government's TRHAP by 2030 and the required reactive support associated with that load. In addition, the surrounding infrastructure limits further expansion of the substation to accommodate additional bays.

Need

Under clause S5.1.8, TasNetworks must consider non-credible contingency events, such as busbar faults, which might result in the tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the power system. Furthermore, under regulation 5 of the *Tasmanian Electricity Supply Industry (Network Planning Requirements) Regulations 2018* (ESI regulations), in respect to an intact transmission system, load that is interrupted by a single asset failure is not to be capable of resulting in a black system.

It is expected that any additional load connection in the George Town-Bell Bay area would exacerbate the existing network security issues and require intervention to meet TasNetworks' regulatory obligations.

In general, two substation bays would be required to connect 300 MW of load and to maintain maximum contingency size in Tasmania. Given four additional bays will also be required for the first stage of reactive support, maintaining system security without augmentation is not feasible.

Indicative solution

TasNetworks preferred means of addressing the risks to the power system associated with the connection of additional industrial load in the George Town-Bell Bay area is currently to rearrange the 220 kV connections at the existing George Town Substation and establish a second substation in the Bell Bay area. The rearrangement of the existing substation will partially solve the problems associated with load growth driven by the industrialised production of hydrogen, but a new substation will be required to minimise the aforementioned network security issues and accommodate reactive support developments if the new connections envisaged in the TRHAP eventuate.

Indicative cost

The indicative cost of the proposed solution is $50 million.

7.5.2.4 Palmerston to Sheffield network upgrade

Background

The George Town-Bell Bay area is supplied from two 220 kV main corridors (Sheffield-George Town and Palmerston-Hadspen-George Town), which are interconnected through the Palmerston-Sheffield 220 kV line. This is known as the Palmerston-Sheffield-George Town triangle. The Palmerston–Sheffield 220 kV transmission line is single-circuit only and has a lower thermal capacity than the other circuits in the triangle. It also plays a major role in transient stability constraints, given that loss of this circuit dramatically increases the transmission distance between Sheffield and Palmerston. It will become a constraining element in a future network state when increased power flows are needed across the network.

The Palmerston to Sheffield line is a component of the transmission works required to support Project Marinus. As such, it is captured under the actionable ISP project framework and associated Project Marinus RIT-T. Because the Palmerston to Sheffield network upgrade may be required prior to the commissioning of Marinus Link to support additional generation and/or load, TasNetworks is also proposing it as a contingent project in the 2024-2029 regulatory control period, with its own unique triggers, independent of Project Marinus.

Need

The Palmerston to Sheffield Network Upgrade is required to support both new load growth in the George Town-Bell Bay area and, or, new wind developments in the North West.

As per the ISP, wind generation is most likely to develop in the Central Highlands REZ first and then the North West. If the additional load in the George Town-Bell Bay area is supplied from these two areas, flow in the Palmerston-Sheffield-George Town triangle will increase and eventually need to be constrained to maintain the network within either its stability or thermal limits. Upgrading the Palmerston to Sheffield line will relieve these constraints.

Additional connection of generation at the Sheffield Substation may lead to network flows in the Palmerston-Sheffield-George Town triangle being constrained to maintain power flows within thermal and/or stability limits. These limits change continuously and are dependent on load and generation dispatch, Basslink operation, and the status of reactive plant. The project will be triggered when the value of the generation constrained (calculated as the amount of generation multiplied by the cost at the time) exceeds the cost of the augmentation. The level of constraint may be sufficient to justify a transmission augmentation to increase the power transfer capability of the corridor at some time during the 2024-2029 regulatory control period and may be required in advance of Project Marinus. As at December 2022 there is 1,977 MW of publicly announced generation projects in the North West and TasNetworks expects significant new wind generation to connect by 2026.

Indicative solution

In order to alleviate the severity of network constraints in the triangle, augmentation of the existing Palmerston to Sheffield 220 kV corridor is proposed, consisting of a new double circuit 220 kV transmission line. This is consistent with the solution identified as part of the Project Marinus RIT-T, noting that a separate RIT-T will be required if the Palmerston to Sheffield upgrade occurs in advance of Project Marinus for a different identified need.

The proposed project will replace the existing single circuit Palmerston-Sheffield transmission line with a new high-capacity double circuit 220 kV line. The increased capacity of the double circuit will support higher power transfers from new generation, allow greater hosting capacity for new generation in the North West, and support new load commitments in the George Town-Bell Bay area.

Indicative cost

The indicative project cost is $212 million, which is consistent with the Palmerston to Sheffield component of Project Marinus' estimated cost in the ISP.

7.5.2.5 Sheffield to George Town network upgrade

Background

Following the Palmerston to Sheffield corridor, the next most constraining component of the Palmerston-Sheffiled-George Town triangle is the Sheffield-George Town 220 kV transmission corridor. The Sheffield to George Town line supplies load in George Town-Bell Bay from generation located in North West, West Coast and central Tasmania. Thermal issues in the Sheffield to George Town corridor are expected if more than 200 to 300 MW of load is connected in the George Town-Bell Bay area.

Need

Additional hydrogen load in excess of 300 MW at George Town-Bell Bay and/or generation development in North West or Central Tasmania will result higher power flows towards George Town through the Sheffield to George Town corridor of the triangle. This will introduce thermal issues on the Sheffield-George Town 220 kV line. With larger load and generation present in the network, contingent events such as loss of single or multiple circuits in the triangle will create stability issues on the Sheffield to George Town line. The TRHAP envisions 700 MW of new hydrogen load by 2028.

Indicative solution

TasNetworks expects the preferred solution would be to develop a second 220 kV double circuit line between Sheffield and George Town.

Indicative cost

The expected cost of the indicative solution is $166 million.

7.5.2.6 Palmerston to George Town via Hadspen network upgrade

Background

The Palmerston-Sheffield and Sheffield-George Town new double circuit transmission lines identified in the first and second hydrogen stages will provide a significant amount of thermal capacity along the Palmerston-Sheffield-George Town triangle. However, further hydrogen connections may require additional upgrades. The Palmerston-Hadspen-George Town line connects George Town-Bell Bay to the network not already supplied by the Sheffield-George Town line.

Need

Additional hydrogen load in excess of 700 MW and/or generation development in North West or Central Tasmania will result in thermal capacity issues on the Palmerston-Hadspen-George Town 220 kV line. The Tasmanian Government's TRHAP envisages the arrival of 1,000 MW of new hydrogen-related load in Tasmania by 2030. Based on this timeline, TasNetworks expects that over 700 MW of additional load will potentially require connection to the transmission network during the 2024-2029 regulatory control period.

Indicative solution

The indicative solution currently favoured by TasNetworks to address the thermal capacity issues associated with additional loads of more than 700 MW involves replacement of the existing Palmerston-Hadspen-George Town 220 kV line with a higher capacity line.

Indicative cost

It is estimated that replacement of the Palmerston-Hadspen-George Town 220 kV line with a higher capacity would cost $209 million.

7.5.2.7 Waddamana–Palmerston transfer capability upgrade

Background

The northern (from Palmerston Substation to north) and southern (from Waddamana Substation to south) sections of the Tasmanian transmission network are linked through a single transmission corridor, between the Waddamana and Palmerston substations. The Waddamana–Palmerston transmission corridor comprises a double-circuit 220 kV transmission line and single-circuit 110 kV transmission line.

New generation in the Central Highlands REZ area identified in the ISP is likely to make a significant contribution towards achieving the renewable generation targets legislated under the TRET. The ISP forecasts new wind generation in excess of 1,000 MW installed capacity in the Central Highlands REZ by 2030.

This forecast is considered credible, as there are currently 470 MW of publicly announced new wind generation projects in the Central Highlands REZ and southern transmission network. Further, TasNetworks is aware of other projects (in the order of hundreds of MW) undertaking preliminary feasibility work in the Central Highlands REZ area. Other projects may materialise, with progression of Marinus Link and the Bell Bay hydrogen hub.

Need

With the level of new generation forecast in the ISP, there will be very large power flows from Waddamana Substation to Palmerston Substation and the rest of the network. This will result in significant transmission constraints to maintain power flow within both thermal and stability limits of the Waddamana–Palmerston transmission corridor. These limits change continuously and are dependent on load and generation dispatch and the status of reactive plant. The Waddamana–Palmerston Transfer Capability Upgrade will be triggered when the value of the generation constrained (the amount of generation multiplied by the cost at the time) exceeds that of the augmentation. It is anticipated the level of constraint will be sufficient to justify a transmission augmentation to increase the power transfer capability of the corridor during the 2024-2029 regulatory control period.

Indicative solution

TasNetworks' indicative solution is the construction of an additional double-circuit Waddamana–Palmerston 220 kV transmission line to complement the existing double-circuit 220 kV and single-circuit 110 kV transmission lines.

Indicative cost

A second double-circuit Waddamana–Palmerston 220 kV transmission line is estimated to cost $113 million.

7.5.3 Other contingent projects

In addition to the seven contingent projects noted above, TasNetworks expects that two projects will be triggered as an actionable ISP project or as a system strength project, in accordance with clauses 5.16A.5 and 11.143.18 of the NER respectively. These projects are:

1. Transmission developments required to support Project Marinus in North-West Tasmania
2. Network development required to meet the new system strength framework.

Although these projects are triggered automatically and do not need to be included in TasNetworks' revenue proposal, information is provided in this section to give stakeholders full insight into all projects that may be required during the 2024-2029 regulatory control period.

Table 5 provides a brief overview of each of the above projects and the associated trigger events as defined in the NER.

Table 5: Other contingent projects

Project Name	Project Description	Triggers
North West Transmission Development	This project involves the construction of the following 220 kV transmission lines in North-West Tasmania to support the Marinus Link Interconnector. • Palmerston to Sheffield • Sheffield to Staverton • Staverton to Hampshire Hills • Hampshire Hills to Burnie • Burnie to Heybridge • Sheffield to Heybridge This project is considered an actionable ISP project in the 2022 ISP.	1. TasNetworks issues a project assessment conclusions report that meets the requirements of clause 5.16A.4 and which identifies a project as the preferred option (which may be a stage of an actionable ISP project if the actionable ISP project is a staged project) [**COMPLETE**] 2. TasNetworks obtains written confirmation from AEMO that: a. the preferred option addresses the relevant identified need specified in the most recent Integrated System Plan and aligns with the optimal development path referred to in the most recent Integrated System Plan b. the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path as updated in accordance with clause 5.22.15 where applicable. 3. no dispute notice has been given to the AER under rule 5.16B(c) or, if a dispute notice has been given, then in accordance with rule 5.16B(d), the dispute has been rejected or the project assessment conclusions report has been amended and identifies that project as the preferred option [**COMPLETE**] 4. the cost of the preferred option set out in the contingent project application must be no greater than the cost considered in AEMO's assessment in subparagraph (b).
Network development for System Strength rule change	This project will reflect the necessary investment needed for TasNetworks to meet the new system strength standard. At this stage, the scope of this investment including any network or non-network options are unknown. The costs are also unknown at this stage.	1. The Board of TasNetworks has committed to proceed with the system strength project subject to the AER amending TasNetworks' revenue determination in accordance with clause 6A.8.2. 2. TasNetworks has issued a project assessment conclusions report that meets the applicable requirements of new clause 5.16A.4 and which identifies the project as the preferred option. 3. the time period in rule 5.16B(c) for giving a dispute notice has elapsed and no dispute notice been given to the AER under rule 5.16B(c) or, if a dispute notice has been given, then in accordance with rule 5.16B(d), the dispute has been rejected or the project assessment conclusions report has been amended and identifies the system strength project as the preferred option.

7.5.3.1 North West Transmission Development

The North West Transmission Developments include the Tasmanian transmission developments to support new and existing renewable energy developments, including Marinus Link.

The developments formed part of the Project Marinus RIT-T. The new interconnector between Tasmania and Victoria is being progressed by Marinus Link Pty Ltd and, therefore, does not form part of TasNetworks' 2024-2029 Combined Proposal.

The preferred option identified through the Project Marinus RIT-T included the following on-island transmission developments:

- Construction of a new 220 kV switching station at Heybridge adjacent to the converter station
- Establishment of a new 220 kV switching station at Staverton
- Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie
- Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield
- Construction of a new double-circuit 220 kV transmission line from Heybridge to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor.

As part of the 2022 ISP, AEMO designated Project Marinus and the associated transmission developments as an actionable ISP project. As per the ISP, actionable projects should progress as urgently as possible. Under clause 6A.8.A1(b) of the NER, an actionable ISP project is considered a contingent project in relation to a revenue determination following the occurrence of the trigger events described in clause 5.16A.5. For Project Marinus, the only remaining trigger event is written confirmation from AEMO that the total project remains on the ISP optimal development path.

7.5.3.2 System strength

On 21 October 2021, the Australian Energy Market Commission (**AEMC**) made a final determination on the efficient management for system strength on the power system. This introduced a new system standard and transmission network standard for system strength under Schedule 5.1a and Schedule 5.1 of the NER, respectively. Under the rule, TasNetworks is required to use reasonable endeavours to plan, design, operate and maintain its transmission network to meet the system strength standard specified by AEMO.

The final rule included a new transitional rule that:

- deems a system strength project proposed to be undertaken by a System Strength Service Provider (**SSS Provider**) in its next regulatory control period to be a contingent project for the purposes of its revenue determination for that period
- sets out deemed 'trigger events' for that contingent project
- provides that the SSS Provider is not required to include the proposed contingent capital expenditure for this contingent project in its revenue proposal and the AER is not required to make a determination under clause 6A.8.1(b) in relation to this contingent project.

7.6 Distribution network contingent projects

No contingent projects have been identified for the distribution network in the 2024-2029 regulatory control period.

TasNetworks

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Combined Proposal 2024-2029

Attachment 8
Operating expenditure

Outline: This attachment to TasNetworks' Combined Proposal provides information about TasNetworks' past operating expenditure and forecast operating expenditure requirements, including an explanation of how TasNetworks' forecasts of operating expenditure for standard control services and prescribed transmission services have been developed for the 2024-2029 regulatory control period, and how we have incorporated customer and stakeholder feedback into those forecasts.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
> **Attachment 8**	**Operating expenditure**
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Tables in this attachment may not add due to rounding.

Contents

8 Operating expenditure

8.1 Introduction

Operating expenditure (**opex**) refers to operating, maintenance and other non-capital expenses.

Forecast opex is one of the building blocks used by the Australian Energy Regulator (**AER**) to determine the revenue allowances for regulated electricity network service providers (**NSP**). The AER is required to determine a separate opex allowance for each of TasNetworks' transmission and distribution networks for each five year regulatory control period. Overall, the AER is required to assess whether our forecast opex reasonably reflects the operating expenditure criteria. This attachment explains the forecasting methodology and why TasNetworks is satisfied the opex forecast reasonably reflects the operating expenditure criteria to prudently and efficiently achieve the operating expenditure objectives.[1]

8.2 Rule requirements

Clauses 6.5.6(a) and 6A.6.6 of the National Electricity Rules (**NER**) requires TasNetworks' Combined Proposal to include the total forecast operating expenditure (**opex**) for the 2024-2029 regulatory control period that TasNetworks considers is required to achieve the following opex objectives:

- meeting or managing the expected demand for standard control services or prescribed transmission services
- complying with the regulatory obligations or requirements associated with the provision of standard control services or prescribed transmission services
- maintaining the quality, reliability and security of supply of standard control services or prescribed transmission services
- maintaining the reliability and security of the distribution or transmission system
- maintaining the safety of the distribution or transmission system.

1 National Electricity Rules, clauses 6.5.6 and 6A.6.6

The AER is required to accept an NSP's forecast of total opex if it is satisfied that the opex proposed reasonably reflects:

- the efficient costs of achieving the opex objectives
- the costs that a prudent operator would require to achieve the opex objectives
- is based on realistic expectations of demand and the cost inputs required to achieve the opex objectives.

These assessment criteria are known as the opex criteria and are set out in clauses 6.5.6(c) and 6A.6.6(c) of the NER.

In deciding whether TasNetworks' forecasts of opex for the 2024-2029 regulatory control period reasonably reflect the opex criteria, clauses 6.5.6(e) and 6A.6.6(e) of the NER require the AER to have regard to factors including but not limited to:

- the most recent annual benchmarking report published and the benchmark opex that would be incurred by an efficient distribution network service provider (**DNSP**) or transmission network service provider (**TNSP**) over the 2024-2029 regulatory control period
- TasNetworks' actual opex during previous regulatory control periods (including the current 2019-2024 regulatory control period)
- the extent to which the opex forecast includes expenditure to address the concerns of electricity consumers identified by TasNetworks during its engagement with them
- the relative prices of operating and capital inputs
- the substitution possibilities between opex and capital expenditure (**capex**)
- whether the opex forecast is consistent with any incentive scheme(s) applying to TasNetworks, including the Efficiency Benefit Sharing Scheme (**EBSS**), Service Target Performance Incentive Scheme (**STPIS**), Demand Management Incentive Scheme (**DMIS**) and Demand Management Innovation Allowance Mechanism (**DMIAM**)
- whether the opex forecast includes amounts relating to projects that should more appropriately be treated as contingent projects under clauses 6.6A.1(b) or 6A.8.1(b) of the NER

- the most recent Integrated System Plan (**ISP**) and any submissions made by Australian Energy Market Operator (**AEMO**), in accordance with the NER, on the forecast of the TNSP's required operating expenditure
- the extent to which TasNetworks has considered, and made provision for, efficient and prudent non-network alternatives
- any relevant final project assessment report published as part of a regulatory investment test for distribution or transmission.

TasNetworks' forecasts of opex for its distribution and transmission networks have been prepared in accordance with the AER's Expenditure Forecast Assessment Guidelines.

8.3 Opex proposal

TasNetworks has adopted the 'base-step-trend' approach to forecast opex for the 2024-2029 regulatory control period, consistent with the AER's standard approach.

Table 1 sets out TasNetworks' transmission and distribution opex forecasts.

Table 1. TasNetworks' forecast opex ($ million, 2023-24)

	Transmission	Distribution
Base year opex (2021-22)	**36.6**	**104.3**
Base year adjustments	0.0	0.0
Remove category specific forecasts	0.0	(10.7)
2021-22 to 2023-24 increment	0.4	(2.1)
Base opex (2023-24)	**37.0**	**91.5**
Base opex (2024-2029)	185.0	457.7
Debt raising costs	4.2	5.5
Other category specific forecasts	0.0	51.9
Total base trend (2024-2029)	**189.2**	**515.1**
Output growth	0.1	3.7
Price growth	0.6	3.2
Productivity (efficiency) factor	(2.7)	(4.0)
Total rate of change (2024-2029)	**(2.0)**	**2.9**
Cybersecurity	15.4	3.9
Insurance	6.7	19.1
Total step changes (2024-2029)	**22.1**	**23.0**
Total (base trend + rate of change + step changes)	**209.3**	**541.0**

8.3.1 Base-step-trend approach

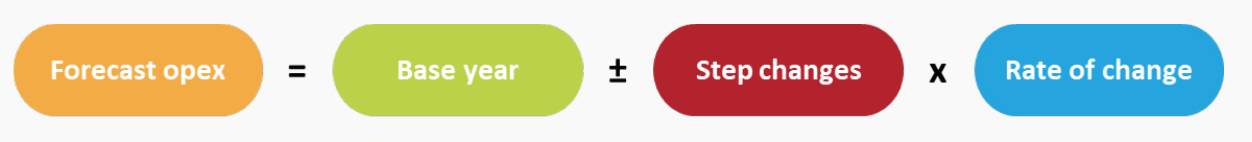
The opex forecasts have been developed in accordance with the AER's 'base-step-trend' method, consistent with the approach set out in the AER's Expenditure Forecast Assessment Guidelines and in our Expenditure Forecast Methodology previously submitted to the AER.[2] This involves forecasting opex at a total level based on revealed costs, rather than forecasts of individual opex projects. This approach is appropriate because opex is largely recurrent and stable at a total level.

The base-step-trend is a three-step process which involves:

- **Base:** using actual opex in a recent year as a starting point (revealed opex)
- **Step:** adjusting the base level of efficient opex for costs not compensated by base opex (e.g., costs associated with changes to regulatory obligations and forecast material increases in existing costs)
- **Trend:** forecasting a rate of change for growth in input prices, outputs and productivity.

2 TasNetworks, 2024-2029 Expenditure Forecasting Methodology, June 2022

Figure 1: The 'base-step-trend' methodology



In proposing the base-step-trend approach TasNetworks notes the operation of the EBSS in the 2019-2024 regulatory control period. The EBSS provides TasNetworks with incentives to reduce opex in every year of a regulatory control period, which means the actual level of opex in a year does provide a good estimate of the efficient costs required to operate a safe and reliable network and meet relevant regulatory obligations.

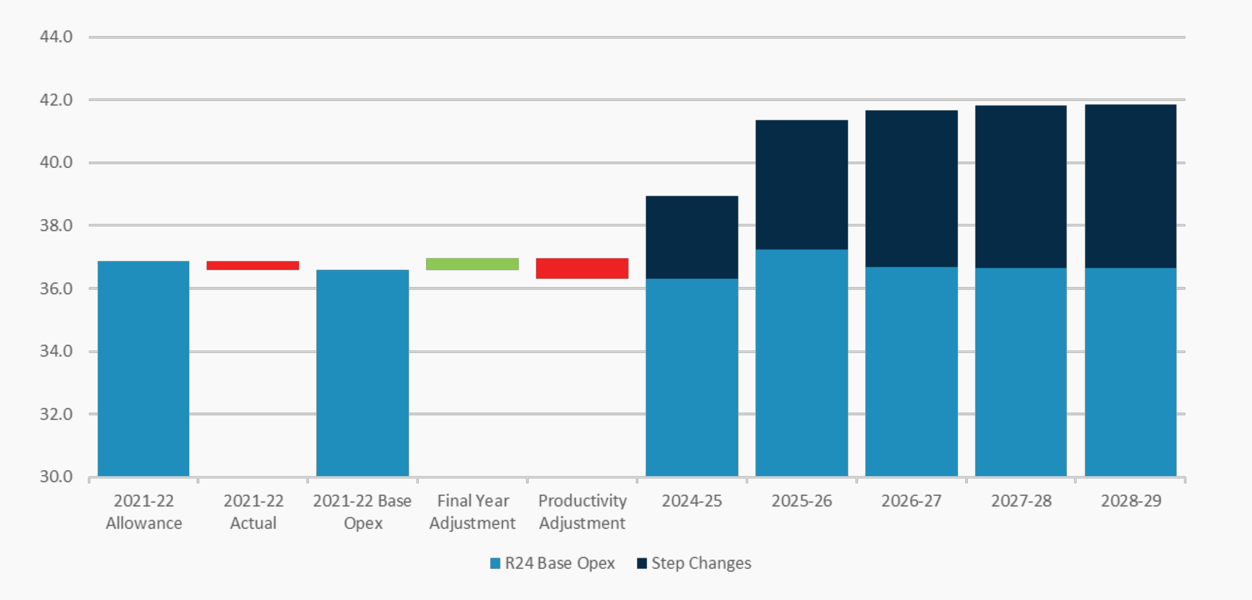
8.3.2 Transmission opex proposal

In applying the base-step-trend approach to forecast transmission opex for the 2024-2029 regulatory control period, TasNetworks' proposes:

- actual opex in 2021-22 as the base from which to forecast [$36.6 million ($2023-24)]
- adding $0.4 million to reflect the change in opex between 2021-22 and 2023-24
- applying a rate of change comprising of:
    - output growth ($0.1 million)
    - real price growth ($0.6 million)
    - productivity growth (-$2.7 million) or 3 per cent in 2024-25 and 0.5 per cent per annum from 2025-26 to 2028-29
- adding two step changes totalling $22.1 million ($2023-24) for:
    - increased insurance premiums ($6.7 million)
    - cyber security costs to comply with new critical infrastructure legislation ($15.4 million)
- adding $4.2 million of debt raising costs to arrive at total forecast opex of $209.3 million over the 2024-2029 regulatory control period ($2023-24).

The transmission base-step-trend outcomes for the 2024-2029 regulatory control period is summarised in Figure 2.

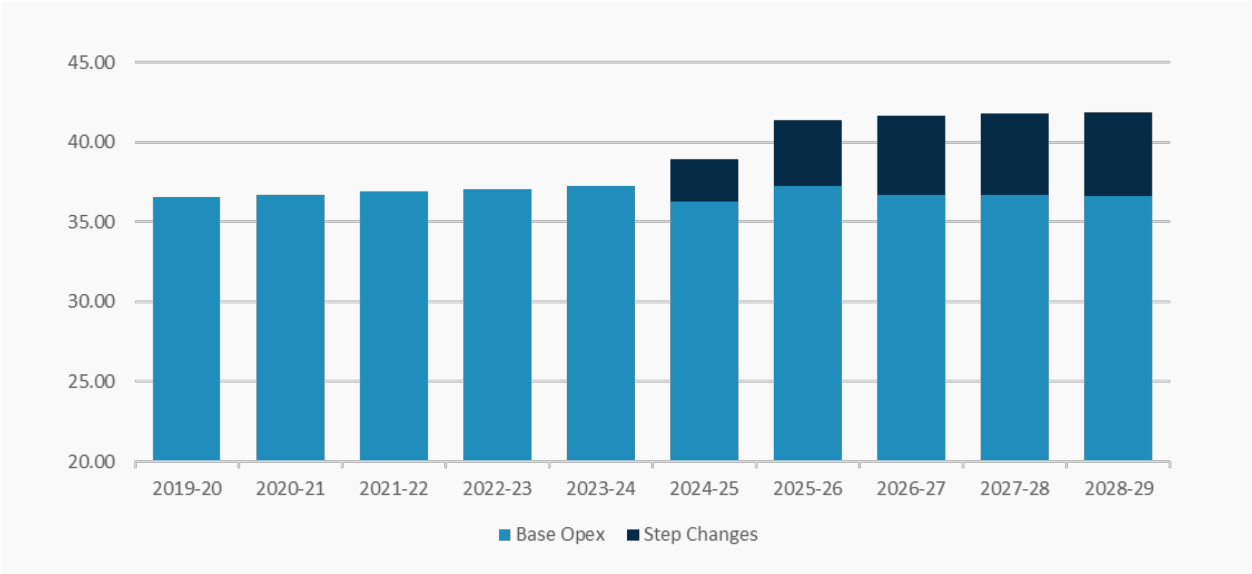
Figure 2. Transmission opex forecast ($ million, 2023-24)



The total transmission opex estimate for the 2024-2029 regulatory control period is $28.4 million ($2023-24) higher than estimated opex for the current 2019-2024 regulatory control period. The higher opex forecast is driven by opex to meet higher forecast cybersecurity and insurance costs (which are proposed as step changes, see section 8.5). These increases are partially offset by productivity savings associated with TasNetworks' transformation program.

Figure 3 compares TasNetworks' transmission opex forecast to previous opex allowances approved by the AER.

Figure 3. Transmission – historical and forecast opex ($ million, 2023-24)



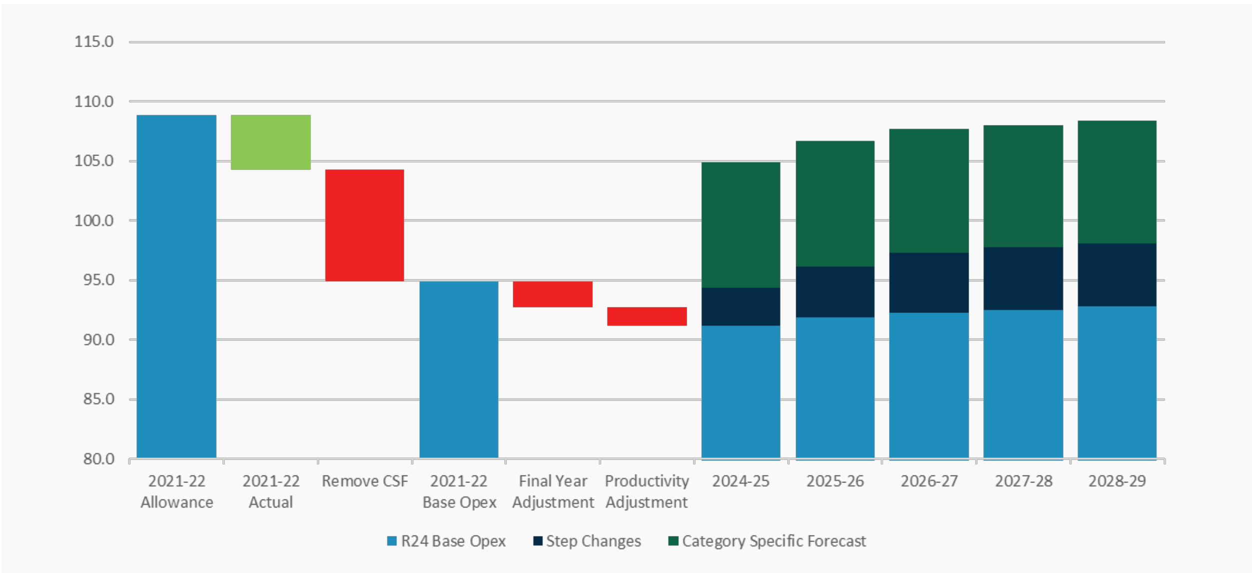
8.3.3 Distribution opex proposal

In applying the base-step-trend approach to forecast distribution opex for the 2024-2029 regulatory control period, TasNetworks' proposes:

- actual opex in 2021-22 as the base from which to forecast [$104.3 million ($2023-24)]
- removing $2.1 million to reflect the change in opex between 2021-22 and 2023-24
- applying a rate of change comprising of:
  - output growth ($3.7 million)
  - real price growth ($3.2 million)
  - productivity growth (-$4.0 million) or 3 per cent in 2024-25 and 0.5 per cent per annum from 2025-26 to 2028-29
- adding two step changes totalling $23.0 million ($2023-24) for:
  - increased insurance premiums ($19.1 million)
  - cyber security costs to comply with new critical infrastructure legislation ($3.9 million)
- adding $5.5 million of debt raising costs to arrive at total forecast opex of $541.0 million over the 2024-2029 regulatory control period ($2023-24).

The distribution base-step-trend outcomes for the 2024-2029 regulatory control period is summarised in Figure 4.

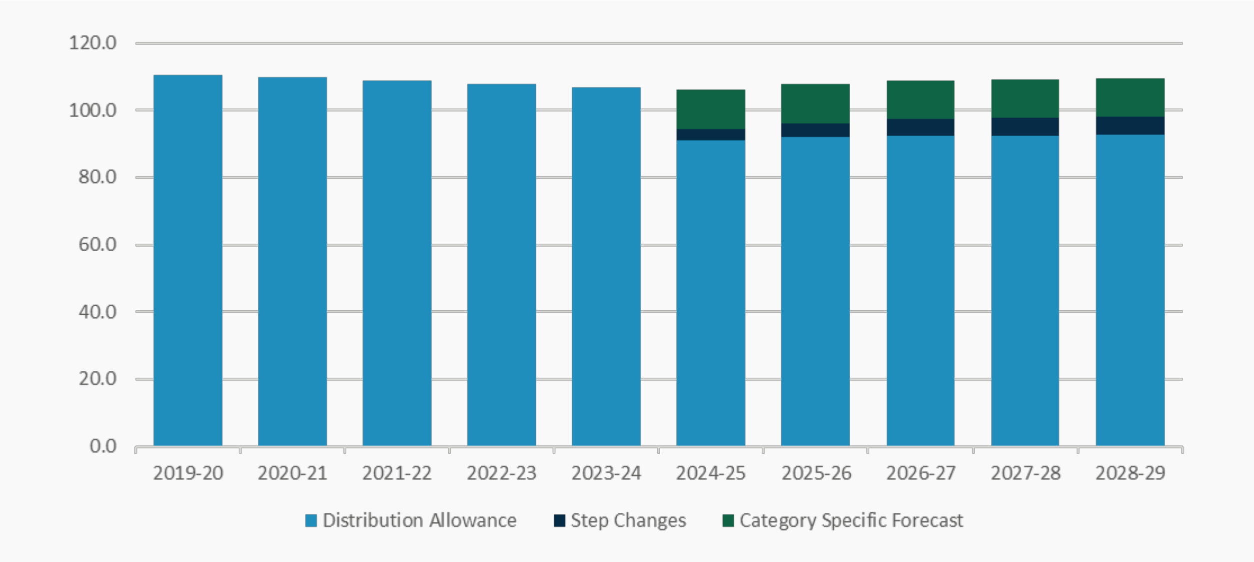
Figure 4. Distribution opex forecast ($ million, 2023-24)



The distribution opex estimate for the 2024-2029 regulatory control period is $26 million ($2023-24) change in than estimated opex in the 2019-2024 regulatory control period. The higher opex forecast is driven by opex to meet higher forecast cyber security and insurance costs (which are proposed as step changes, see section 8.5). These increases are offset by productivity savings associated with TasNetworks' transformation program.

Figure 5 compares the distribution opex forecast to previous opex allowances.

Figure 5. Distribution – historical and forecast opex ($ million, 2023-24)



8.4 Base opex

TasNetworks considers actual opex in 2021-22 to be an appropriate base for forecasting opex in the 2024-2029 regulatory control period as it:

- is the most recent completed financial year at the time of submitting the Combined Proposal
- represents a reasonable and efficient level of expenditure based on historic benchmarking outcomes
- is not impacted by one-off transformation costs expected to be incurred in 2022-23.

8.4.1 Efficiency of base year opex

TasNetworks considers the 2021-22 actual opex provides a good estimate of the efficient costs required to operate safe and reliable transmission and distribution networks and meet relevant regulatory obligations. In making this assessment TasNetworks notes:

- actual opex outcomes over time
- the results of the AER's benchmarking analysis
- the application of the EBSS in the 2019-2024 regulatory control period which is providing a continuous incentive to reduce opex, including an incentive to reduce opex in 2021-22.

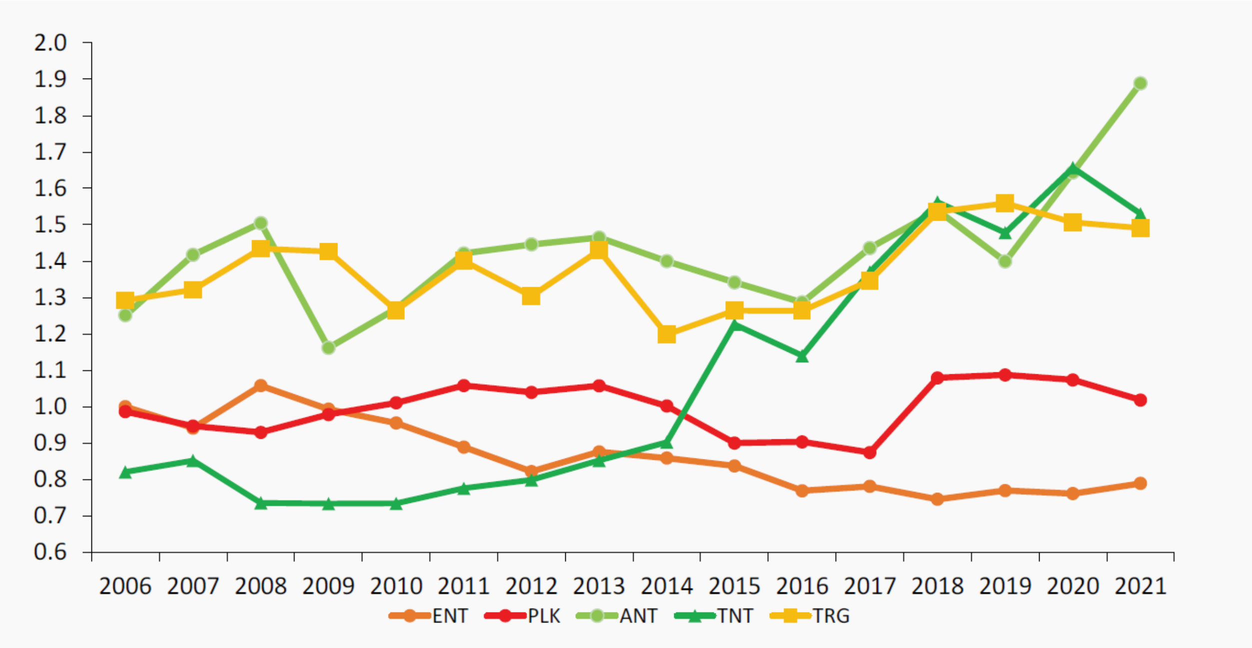
Stakeholders raised no concerns with the choice or efficiency of 2021-22 as the base year.

8.4.1.1 Transmission network – base year efficiency

As illustrated for the EBSS outcomes in Attachment 10 Efficiency Benefit Sharing Scheme, TasNetworks' transmission opex in the 2019-2024 regulatory control period has been consistent with the opex allowance set by the AER.

In terms of opex benchmarking, the primary technique relied on by the AER is multilateral partial factor productivity (**MPFP**), referred to as Opex MPFP. Figure 6, taken from the AER's 2022 annual benchmarking report for TNSPs, shows TasNetworks has been among the highest ranking TNSPs in terms of opex efficiency since 2015.

Figure 6. Electricity transmission opex MPFP index (2006 – 2021)



Source: AER, Annual Benchmarking Report – Electricity transmission network service providers, November 2022, p. 26.

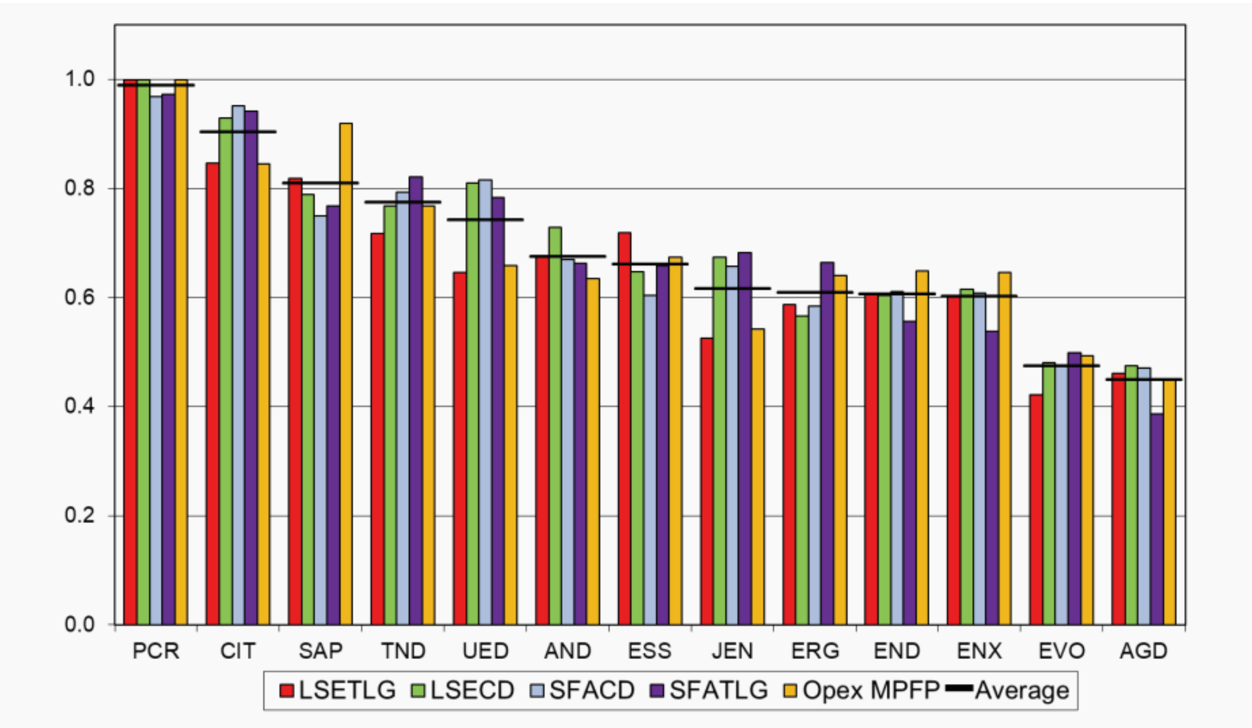
Given the above considerations and the application of the EBSS, TasNetworks has used 2021-22 transmission opex as the starting point for forecasting transmission opex in the 2024-2029 regulatory control period.

8.4.1.2 Distribution network base year efficiency

The AER's distribution benchmarking analysis can be more heavily relied upon to assess base year efficiency due to the larger sample size of distribution businesses in the National Electricity Market (**NEM**) compared to transmission businesses.

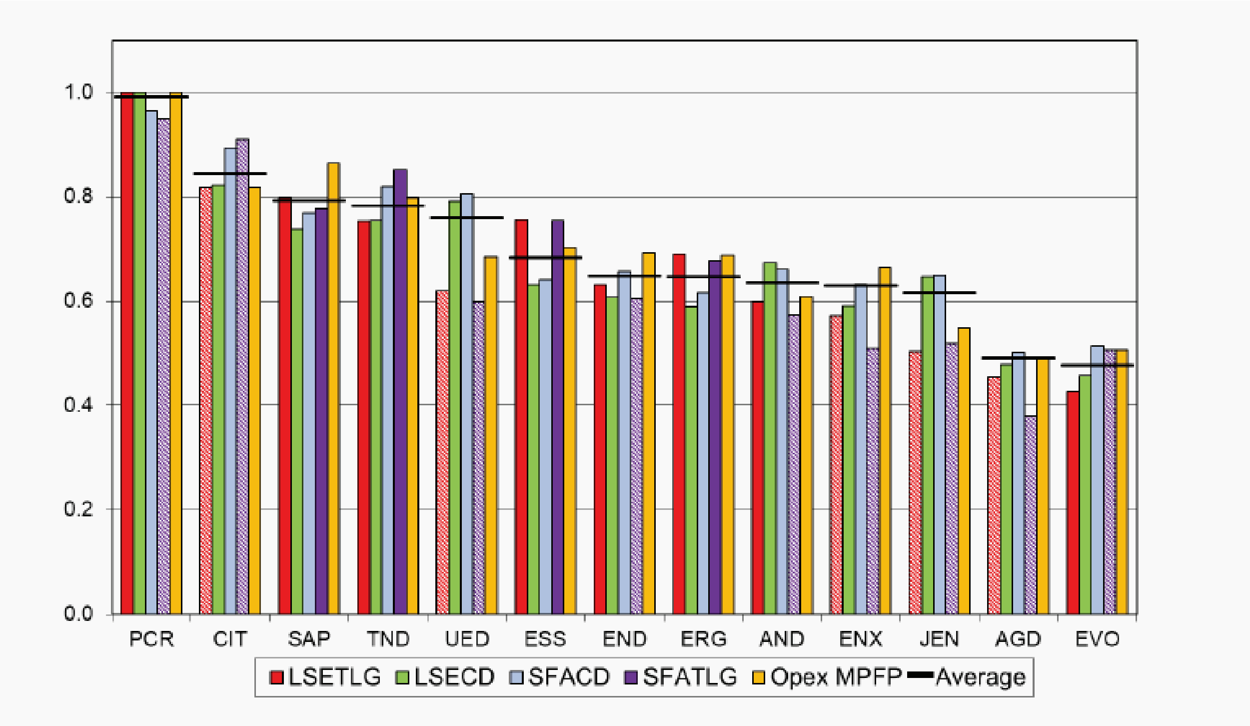
Figures 7 and 8, taken from the AER's 2022 Annual Benchmarking Report for DNSPs, show TasNetworks is ranked fourth in terms of efficiency among all regulated DNSPs when using the AER's four econometric models and opex MPFP over the period 2006-2021 and 2012-2021.

Figure 7. Opex efficiency scores and MPFP rankings (2006-2021)



Source: AER, Annual Benchmarking Report – Electricity distribution network service providers, November 2022, p. 34.

Figure 8. Opex efficiency scores and MPFP rankings (2012–2021)



Source: AER, Annual Benchmarking Report – Electricity distribution network service providers, November 2022, p. 35.

Given the AER benchmarking analysis and the application of the EBSS TasNetworks has used 2021-22 distribution opex as the starting point for forecasting distribution opex in the 2024-2029 regulatory control period.

8.4.2 Adjustments to base year opex

8.4.2.1 Adjustments to transmission base year opex

TasNetworks has not made any adjustments to the 2021-22 transmission base year opex for non-recurrent or one-off expenditure items.

Table 2. Transmission opex base year adjustments ($ million, 2023-24)

	2021-22
Transmission opex for 2021-22	36.6
Less	
Non-recurrent / one-off expenditures	0.0
Category specific forecasts	0.0
Other cost items	0.0
Proposed base year opex	**36.6**

8.4.2.2 Adjustments to distribution base year opex

Distribution base opex is adjusted by -$9.42 million ($2023-24) to reflect removal of:

- Guaranteed Service Level (**GSL**) payments – $3.52 million
- the Electrical Safety Inspection (**ESI**) levy – $5.09 million
- the NEM levy – $0.81 million.

The GSL allowance forms part of the service incentive arrangements for our distribution services. The ESI and NEM levy are Tasmanian Government charges passed through to distribution customers. TasNetworks is proposing to adjust annually the difference between forecast and actual levies as part of the standard control services revenue formula and pricing adjustments. This is consistent with the treatment of these costs in the 2019-2024 regulatory control period.

There were no non-recurrent or one off expenditure items in the 2021-22 base year that require a base year adjustment.

Table 3. Efficient base year distribution opex ($ million, 2023-24)

	2021-22
Distribution opex for 2021-22	104.3
Less	
Non-recurrent / one-off expenditures	0.0
Category specific forecasts	9.4
Other cost items	0.0
Proposed base year opex	**94.9**

8.5 Step changes

TasNetworks is proposing two transmission and two distribution step changes for the 2024-2029 regulatory control period representing:

- opex associated with meeting new cyber security / security of critical infrastructure obligations
- forecast increases of insurance premiums that are not captured in the base opex or the forecast rate of change.

Table 4 shows TasNetworks' transmission step changes and Table 5 distribution step changes.

Table 4. Forecast transmission opex step changes ($ million, 2023-24)

Step change	2024-25	2025-26	2026-27	2027-28	2028-29
Insurance	$0.97	$1.22	$1.43	$1.52	$1.53
Cyber security / security of critical infrastructure	$1.66	$2.93	$3.55	$3.64	$3.67
Total transmission step changes	**$2.63**	**$4.14**	**$4.98**	**$5.16**	**$5.20**

Table 5. Forecast distribution opex step changes ($ million, 2023-24)

Step change	2024-25	2025-26	2026-27	2027-28	2028-29
Insurance	$2.79	$3.49	$4.11	$4.34	$4.39
Cyber security / security of critical infrastructure	$0.42	$0.73	$0.89	$0.91	$0.92
Total distribution step changes	**$3.20**	**$4.22**	**$4.99**	**$5.25**	**$5.30**

The following sections set out the reasons for the step changes, including how the cost estimates have been developed.

8.5.1 Insurance

TasNetworks proposes a transmission step change of $6.7 million ($2023-24) and distribution step change of $19.1 million ($2023-24) for insurance. The proposed step changes are based on cost forecasts provided by Lockton Companies Australia Pty Limited (**Lockton**). The cost forecasts provided by Lockton relate to the full spectrum of TasNetworks' insurance program.

TasNetworks, like other NSPs, has experienced significant increases in insurance premiums in recent years due to continued extreme fire and flooding events and cyber security threats. Lockton expects this trend to continue in the 2024-2029 regulatory control period across all risk classes given the prevailing insurance market conditions. For example, due to the more frequent and more severe bushfires globally in recent years bushfire liability insurer capacity continues to shrink, insurer pricing continues to increase and the placement of insurance is more time consuming and complex to procure in the traditional insurance market.

Lockton's analysis for TasNetworks is confidential as it is based on sensitive information relating to TasNetworks' insurance coverage.

TasNetworks has calculated the step change as the difference between the cost forecasts prepared by Lockton and the insurance cost in the base year (2021-22).

8.5.2 Cyber security / security of critical infrastructure

TasNetworks proposes a transmission step change of $15.4 million ($2023-24) and distribution step change of $3.9 million ($2023-24).

The proposed step change will enable TasNetworks to uplift its cyber security maturity to implement the Australian Energy Sector Cyber Security Framework (**AESCSF**) to achieve Security Profile 3 (**SP3**) maturity within the 2024-2029 regulatory control period. This cyber security maturity uplift will allow TasNetworks to comply with the enhanced cyber security obligations stated in the *Security of Critical Infrastructure Act 2018*.

The AESCSF is a cyber security framework developed by AEMO in conjunction with industry and government stakeholders that enables energy sector participants to assess, evaluate, prioritise and improve cyber security capability and maturity. Given the elevated and increasing cyber threat landscape, TasNetworks considers it prudent as a TNSP and DNSP to uplift its cyber security and achieve SP3 maturity.

In developing this step change, TasNetworks engaged PwC to assist its analysis of the cyber security uplift requirement, including assessing the proposed expenditure against industry benchmarks and best practices. PwC's analysis is confidential as it is based on sensitive information relating to TasNetworks' cyber security maturity.

The allocation of expenditure between the transmission and distribution networks relates to where investments are required.

8.5.3 Metering data

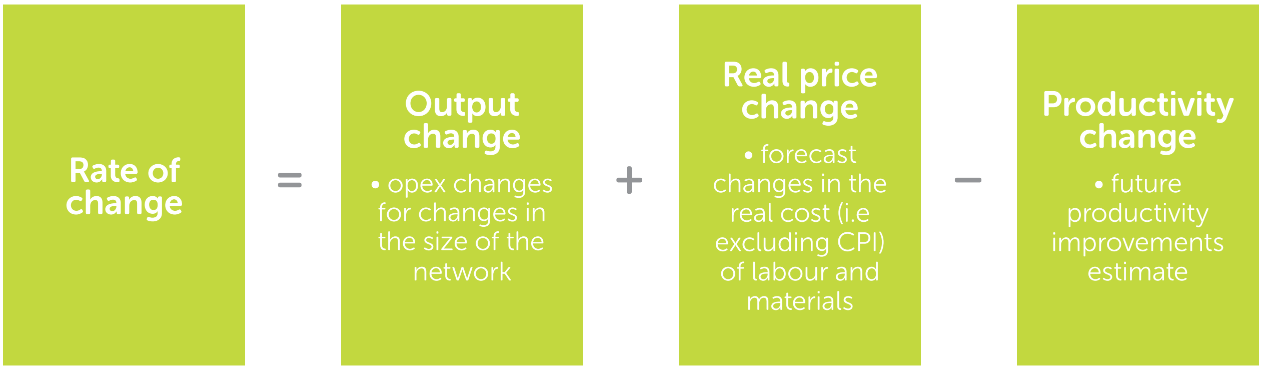
The Australian Energy Market Commission (**AEMC**) has initiated its Review of the Regulatory Framework for Metering Services that a number of industry reforms rely on consistent access to, and exchange of, power quality data from smart meters. The AEMC has indicated reforms are required since current arrangements for negotiating and utilising smart meter data are inefficient and are not in the long-term interests of customers. The detail of these reforms are still being developed but indications are that there will be a greater expectation that DNSPs will access, analyse and interpret advanced meter data. This will benefit customers in a number of ways, not least through improved safety outcomes through neutral integrity detection and resolution. The cost implication of these changes are uncertain and TasNetworks will continue to monitor and assess the implications for forecast opex and a potential step change as the review progresses.

8.6 Rate of change

The final step in the base-step-trend approach is to trend the efficient starting point, or base opex, forward to account for the forecast growth in prices, output and productivity. This is referred to as the rate of change.

TasNetworks proposes to apply the AER's standard approach to forecasting the rate of change in the 2024-2029 regulatory control period. The AER's standard approach is summarised in Figure 9.

Figure 9. Forecast rate of change method



TasNetworks proposes to adopt the AER's preferred forecasting approach to estimate each rate of change element.

Table 6 shows both TasNetworks' transmission and distribution rate of change estimates.

Table 6. Forecast rate of change, (per cent)

	2024-25	2025-26	2026-27	2027-28	2028-29
Transmission proposal					
Output growth	0.36	0.38	0.37	0.24	0.11
Price growth	0.93	0.86	0.42	0.20	0.36
Less productivity growth	3.00	0.50	0.50	0.50	0.50
Overall transmission proposal	**(1.75)**	**0.74**	**0.30**	**(0.06)**	**(0.04)**
Distribution proposal					
Output growth	0.57	0.57	0.56	0.56	0.55
Price growth	0.78	0.72	0.36	0.16	0.30
Less productivity growth	3.00	0.50	0.50	0.50	0.50
Overall distribution proposal	**(1.68)**	**0.79**	**0.42**	**0.22**	**0.35**

8.6.1 Output change

In its most recent determinations, the AER has applied econometric models to estimate the relationship between business growth and opex, noting that different models apply to transmission and distribution.

TasNetworks has forecast transmission output change by calculating the weighted average of output growth rates using the output weights from the AER's opex MPFP benchmarking model. The four outputs used in the AER's benchmarking model are:

- 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**)
- Customer numbers – the number of active connections
- Circuit length – total transmission line circuit length measured in kilometres (**km**).

Using this methodology TasNetworks forecasts transmission average annual output growth of 0.29 per cent. Table 7 shows the impact on transmission opex for the 2024-2029 regulatory control period.

Table 7. Transmission growth factor ($ million, 2023-24)

	2024-25	2025-26	2026-27	2027-28	2028-29
Transmission growth factor (%)	0.36	0.38	0.37	0.24	0.11
Impact ($ million)	0.03	0.04	0.04	0.02	0.01

For the distribution network, the growth factor is determined by ratcheted maximum demand; customer numbers and circuit length.

TasNetworks forecasts distribution average annual output growth of 0.56 per cent. Table 8 shows the impact on transmission opex for the 2024-2029 regulatory control period.

Table 8. Distribution growth factor ($ million, 2023-24)

	2024-25	2025-26	2026-27	2027-28	2028-29
Distribution growth factor (%)	0.57	0.57	0.56	0.56	0.55
Impact ($ million)	0.75	0.74	0.74	0.73	0.72

8.6.2 Real price change

TasNetworks forecasts average annual real price growth of 0.55 per cent for transmission and 0.46 per cent for distribution which increases our transmission opex by $0.6 million ($2023-24) and distribution opex forecast by $3.2 million ($2023-24).

The real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth.

To forecast labour price growth, TasNetworks commissioned BIS Oxford Economics and added legislated superannuation guarantee increases for 2024-25 and 2025-26. Tables 9 and 10 detail the forecast average annual change in labour costs for each year of the 2024–2029 regulatory control period.

Table 9. Transmission forecast real price growth – labour

	2024-25	2025-26	2026-27	2027-28	2028-29
Labour price growth forecast (%) **Source: BIS Oxford economics**	0.82	0.72	0.60	0.28	0.51
Superannuation guarantee charge (%)	0.50	0.50	0.00	0.00	0.00
Total weighted forecast labour price growth (%)	0.93	0.86	0.42	0.20	0.36

Table 10. Distribution forecast real price growth – labour

	2024-25	2025-26	2026-27	2027-28	2028-29
Labour price growth forecast (%) **Source: BIS Oxford economics**	0.82	0.72	0.60	0.28	0.51
Superannuation guarantee charge (%)	0.50	0.50	0.00	0.00	0.00
Total weighted forecast labour price growth (%)	0.78	0.72	0.36	0.16	0..30

TasNetworks has applied a forecast non-labour real price growth rate of zero percent to the opex forecasts. The weighted forecast labour growth for opex is based on input price weights of 70.4/29.6 per cent labour/non-labour for transmission and 59.2/40.8 per cent labour/non-labour for distribution.

8.6.3 Productivity change – transmission

TasNetworks has included forecast productivity growth of three per cent in 2024-25 and 0.5 per cent per year in each remaining year of the 2024-2029 regulatory control period.

The three per cent productivity in 2024-25 represents forecasted opex reductions from TasNetworks' transformation program being implemented across 2022-23 and 2023-24. The 0.5 per cent annual productivity growth rate reflects productivity improvements expected to be achieved in the 2024-2029 regulatory control period after the implementation of the transformation program.

This results in average annual productivity savings of one per cent. This is higher than the transmission industry average over the long term of 0.6 per cent.

Table 11 shows the forecast transmission productivity savings and Table 12 shows the forecast productivity savings for distribution.

Table 11. Transmission productivity improvements

	2024-25	2025-26	2026-27	2027-28	2028-29
Annual transmission cost savings (%)	3.00%	0.50%	0.50%	0.50%	0.50%

Table 12. Distribution productivity improvements

	2024-25	2025-26	2026-27	2027-28	2028-29
Annual distribution cost savings (%)	3.00%	0.50%	0.50%	0.50%	0.50%

8.7 Category specific forecasts

Category specific forecast items are subject to a separate forecast (i.e., not base-step-trend) on the grounds that base year expenditure does not reflect recurrent costs.

TasNetworks has included only one expenditure item in our transmission opex forecast outside of the base-step-trend approach: debt raising costs of $4.22 million ($2023-24).

Debt raising costs are costs incurred each time TasNetworks raises or refinances debt. These costs include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are forecast using a benchmarking approach rather than TasNetworks' actual costs in a single year to provide consistency with the forecast of cost of debt in the rate of return.

Table 13. Transmission category specific forecasts ($million, 2023-24)

Expenditure item	2024-25	2025-26	2026-27	2027-28	2028-29
Transmission debt raising costs	$0.85	$0.85	$0.85	$0.84	$0.83

In relation to distribution services, TasNetworks has developed separate forecasts for GSL, NEM levy, ESI levy and distribution debt raising costs.

The GSL allowance forms part of the service incentive arrangements for our distribution services. The ESI and NEM levy are Tasmanian Government charges passed through to distribution customers. TasNetworks is proposing to adjust annually the difference between forecast and actual levies as part of the standard control services revenue formula and pricing adjustments. This is consistent with the treatment of these costs in the 2019-2024 regulatory control period.

Table 14. Distribution category specific forecasts ($million, 2023-24)

Expenditure item	2024-25	2025-26	2026-27	2027-28	2028-29
GSL	$3.97	$3.97	$3.97	$3.97	$3.97
ESI Levy	$5.09	$5.09	$5.09	$5.09	$5.09
NEM Levy	$1.47	$1.47	$1.36	$1.17	$1.17
Distribution debt raising costs	$1.08	$1.09	$1.11	$1.11	$1.10
Total 'other' distribution operating expenditure	**$11.61**	**$11.62**	**$11.53**	**$11.33**	**$11.33**

TasNetworks

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Combined Proposal 2024-2029

Attachment 9
Corporate income tax

Outline: This attachment to TasNetworks' Combined Proposal sets out forecasts of the corporate tax allowances for TasNetworks' distribution and transmission networks in the regulatory control period commencing on 1 July 2024 and ending on 30 June 2029.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
> **Attachment 9**	**Corporate income tax**
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

9 Corporate income tax

9.1 Introduction

Under the post-tax revenue framework, a corporate income tax allowance is calculated for each Network Service Provider (**NSP**) using the Australian Energy Regulator's (**AER**) Post-Tax Revenue Model (**PTRM**). The NSP's estimate of the cost of corporate income tax for each regulatory year of the regulatory control period forms part of the NSP's building block proposal.

The building block for the estimated cost of corporate income tax takes into account the NSP's estimated taxable revenue and tax expenses (specifically depreciation, interest and operating expenditure), the statutory corporate income tax rate and the value of imputation credits. As with other aspects of the incentive regime applied by the AER, the forecast tax costs are based on a benchmark efficient entity operating the energy network, meaning the forecasts will differ from each NSP's actual tax liabilities.

In December 2018 the AER completed a review of its approach to calculating regulatory tax allowances. The purpose of the review was to investigate the nature of any differences between forecasts of NSPs' tax costs under the post-tax revenue framework and their actual tax payments.[1] The AER examined the drivers of these differences and considered whether changes to the regulatory tax approach were required.[2] In particular, the AER considered whether an alternative regulatory treatment would better measure efficient tax costs.[3]

In considering possible changes to the regulatory approach to assessing tax costs, the AER stated that its aim was not to reduce the tax difference (the AER noted that there may be valid and enduring reasons for the regulatory forecast of tax costs and actual tax payments to differ).[4] Rather, the AER focused on the promotion of the National Electricity Objective (**NEO**)[5] by seeking to identify the best method of determining NSPs' efficient tax costs.

The focus on the long-term interests of electricity consumers was also reflected in the AER's comments regarding inter-generational equity (i.e., ensuring that customers pay costs relevant only to the delivery of the services they receive), shorter effective regulatory asset lives for refurbishment capital expenditure (**capex**) and capitalisation policies and efficient capex/operating expenditure (**opex**) trade-offs.

9.1.1 Regulatory requirements

The estimated cost of corporate income tax is determined in accordance with clauses 6.5.3 and 6A.6.4 of the National Electricity Rules (**NER**). These clauses state that the estimated cost of corporate income tax for TasNetworks must be estimated for each regulatory year of the relevant regulatory control period in accordance with the following formula:

$ETC_t = (ETI_t \times r_t)\,(1 - y)$

where:

- ETI_t is an estimate of the taxable income for each regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services (**SCS**) if such an entity operated the TasNetworks' regulated network business, such an estimate being determined in accordance with the AER's PTRM
- r_t is the assumed statutory income tax rate for that regulatory year as determined by the AER
- y is the value of imputation credits.

9.2 Distribution opening tax asset base

TasNetworks has rolled forward the distribution tax asset base (**TAB**) to 30 June 2024 using the AER's Roll Forward Model (**RFM**). In accordance with TasNetworks' 2019-2024 distribution determination, the tax depreciation on the opening TAB at 1 July 2019 has been calculated using the year-by-year tracking approach. These calculations are made in a separate depreciation model (provided in Supporting Document TasNetworks - 5 - RAB Depreciation Model).

1 Australian Energy Regulator, *Final report – Review of regulatory tax approach*, 17 December 2018, p 2.

2 Ibid

3 Ibid

4 Ibid

5 Ibid

The depreciation amounts have been substituted directly into the RFM. This tax depreciation on the opening TAB at 1 July 2019 matches the calculation made in the 2019-2024 distribution determination, except for necessary changes arising from replacing the forecast capex for the 2018-19 regulatory year with actual capex for the 2018-19 regulatory year.

In doing this, TasNetworks determined the roll forward of the TAB value from 1 July 2019 to 30 June 2024 to be $1,756.52 million ($ nominal) for SCS. This TAB value is based on the forecast capex net of capital contributions and disposals for the 2022-23 and 2023-24 regulatory years. This value will be updated in TasNetworks' Revised Regulatory Proposal to reflect the latest available information concerning actual and estimated capex for those regulatory years.

The roll forward of TasNetworks' TAB over the 2019-2024 regulatory control period is set out in Table 1.

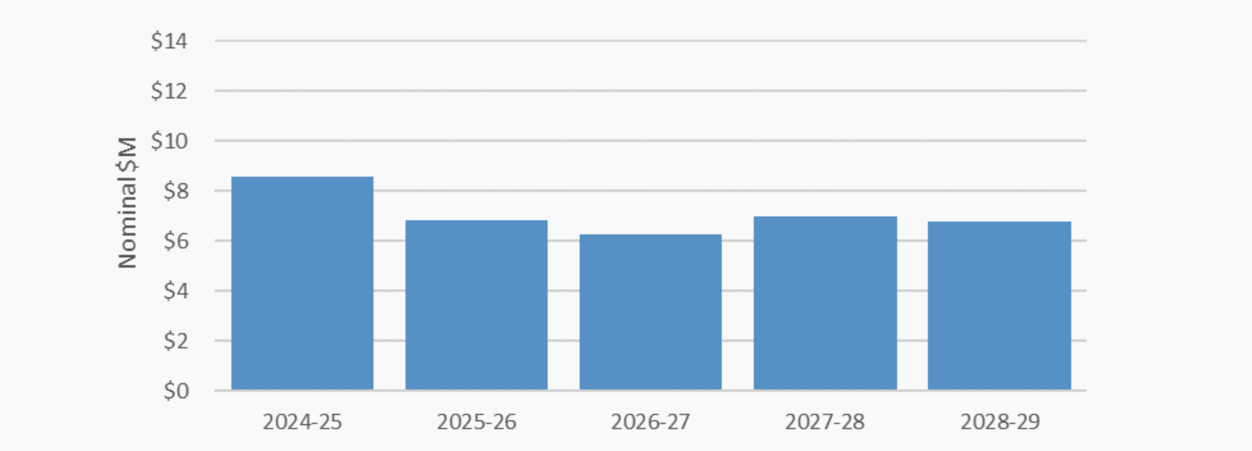
Table 1. Distribution: SCS TAB roll forward to 30 June 2024 (nominal, $million)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening TAB	1,364.94	1,435.98	1,522.09	1,594.98	1,668.75
Plus capex, net of contributions and disposals	130.95	152.13	146.55	155.62	169.57
Less straight line depreciation	59.91	66.01	73.66	81.85	81.80
Closing TAB	**1,435.98**	**1,522.09**	**1,594.98**	**1,668.75**	**1,756.52**

9.3 Estimated distribution corporate income tax costs: 2024-2029

TasNetworks estimates that the cost of corporate income tax, net of imputation credits, for the distribution network for the 2024-2029 regulatory control period will be $35.4 million ($ nominal), which is represented in Figure 1.

Figure 1. Distribution forecast tax allowance 2024-2029 (nominal, $ million)



As discussed in Attachment 4 – Rate of return, given the timing of the completion of the AER's review of the 2022 Rate of Return Instrument (**RoR Instrument**), for the purposes of this regulatory proposal TasNetworks has applied the AER's 2018 RoR Instrument. TasNetworks' value of imputation credits is based on a gamma value of 0.585 and a statutory tax rate of 30 per cent. TasNetworks' forecast tax allowance for the distribution network in the 2024-2029 regulatory control period is shown in Table 2 (below).

Table 2. Distribution forecast tax allowance 2024-2029 (nominal, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Tax payable	20.7	16.4	15.1	16.8	16.3	85.3
Less: value of imputation credits	12.1	9.6	8.8	9.8	9.5	49.9
Net corporate income tax allowance	**8.6**	**6.8**	**6.3**	**7.0**	**6.8**	**35.4**

Any changes arising from the finalisation of the AER's 2022 RoR Instrument will be reflected in TasNetworks' Revised Regulatory Proposal.

9.4 Transmission opening tax asset base

TasNetworks has rolled forward the transmission TAB to 30 June 2024 using the AER's RFM. In accordance with TasNetworks' 2019-2024 transmission determination, the tax depreciation on the opening TAB at 1 July 2019 has been calculated using the year-by-year tracking approach. These calculations are made in a separate depreciation model (provided in Supporting Document TasNetworks – 5 – RAB Depreciation Model).

The depreciation amounts have been substituted directly into the RFM. This tax depreciation on the opening TAB at 1 July 2019 matches the calculation made in the 2019-2024 transmission determination, except for necessary changes arising from the replacement of the forecast capex for the 2018-19 regulatory year with actual capex for the 2018-19 regulatory year.

In doing this, TasNetworks determined the roll forward of the TAB value for Prescribed Transmission Services from 1 July 2019 to 30 June 2024 to be $1,121.09 million ($ nominal).

This TAB value is based on the forecast/estimated capex for the 2022-23 and 2023-24 regulatory years. This value will be updated in our Revised Revenue Proposal to reflect the latest available information for our actual and estimated capex for those regulatory years.

Further details concerning the roll forward of TasNetworks' TAB over the 2019-2024 regulatory control period are set out in Table 3.

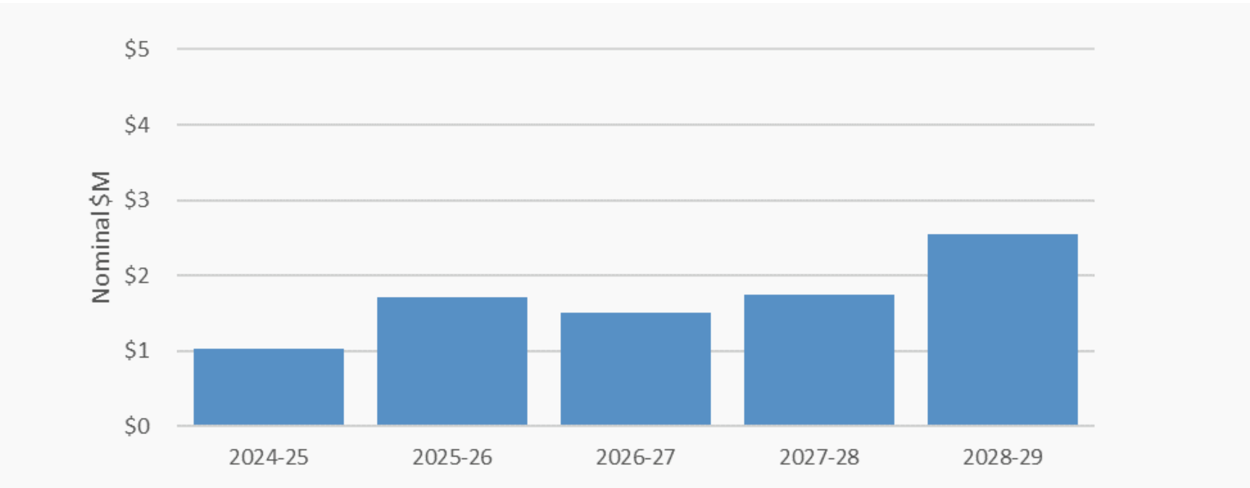
Table 3. Transmission: Prescribed TAB roll forward to 30 June 2024 (nominal, $million)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening TAB	1,108.07	1,122.18	1,113.40	1,110.70	1,108.17
Plus capex, net of contributions and disposals	57.62	37.41	43.50	45.55	60.89
Less straight line depreciation	43.50	46.20	46.20	48.08	47.96
Closing TAB	**1,122.18**	**1,113.40**	**1,110.70**	**1,108.17**	**1,121.09**

9.5 Estimated transmission corporate income tax costs: 2024-2029

TasNetworks estimates that the cost of corporate income tax, net of imputation credits, for the transmission network for the 2024-2029 regulatory control period will be $8.5 million ($ nominal), which is represented in Figure 2.

Figure 2. Transmission forecast tax allowance 2024-2029 (nominal, $ million)



As described above, consistent with the AER's 2018 RoR Instrument, TasNetworks' value of imputation credits is based on a gamma value of 0.585 and a statutory tax rate of 30 per cent. TasNetworks' forecast tax allowance for the transmission network in the 2024-2029 regulatory control period is shown in Table 4 (below).

Table 4. Transmission forecast tax allowance 2024-2029 (nominal, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Tax payable	2.5	4.1	3.6	4.2	6.1	20.6
Less: value of imputation credits	1.5	2.4	2.1	2.5	3.6	12.1
Net corporate income tax allowance	**1.0**	**1.7**	**1.5**	**1.7**	**2.5**	**8.5**

Any changes arising from the finalisation of the AER's 2022 RoR Instrument will be reflected in TasNetworks' Revised Regulatory Proposal.

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Combined Proposal 2024-2029

Attachment 10
Efficiency benefit sharing scheme

Outline: This attachment to TasNetworks' Combined Proposal sets out how the Efficiency Benefit Sharing Scheme will apply during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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Attachment 9	Corporate income tax
> **Attachment 10**	**Efficiency benefit sharing scheme**
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
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10 Efficiency benefit sharing scheme

10.1 Introduction

The Efficiency Benefit Sharing Scheme (**EBSS**) gives network service providers (**NSPs**) a continuous incentive to pursue operating expenditure (**opex**) efficiency improvements and provides for the sharing of any savings between NSPs and their customers. Under the scheme, NSPs retain the efficiency gains they achieve for a carry-over period (usually five years) and customers benefit from improved efficiencies through lower network prices in future regulatory control periods. Under this approach, reductions in an NSP's opex, relative to the opex allowances set by the Australian Energy Regulatory (**AER**), are shared approximately 30:70 between the NSP and its customers.

The AER determines separate EBSS rewards or penalties for TasNetworks' transmission and distribution networks for each five-year regulatory control period. National Electricity Rules (**NER**) clause 6A.6.5 and clause 6.5.8 establish an EBSS for transmission and distribution respectively. NER clause S6A.1.3(3) and clause S6.1.3(3) require NSPs to specify the EBSS values proposed to be applied in a regulatory control period and explain how those values comply with the EBSS' requirements.

TasNetworks' EBSS reward and penalty for the 2019-2024 regulatory control period have been calculated in accordance with version 2 of the EBSS, as applied by the AER.[1] TasNetworks' transmission network reward is forecast to be $0.2 million and the distribution network penalty is forecast to be $2.9 million ($2023-24). These outcomes will be applied as an additional building block adjustment to TasNetworks' revenue in the 2024-2029 regulatory control period.

The EBSS is inherently linked to the forecasting approach for opex. As noted in Attachment 8 Operating expenditure, the base-step-trend method has been applied to determine TasNetworks' opex forecast for the 2024-2029 regulatory control period and, as part of that methodology, it is contended that our base year expenditure is efficient. On that basis, TasNetworks proposes that version 2 of the EBSS should continue to be applied to both TasNetworks' distribution and transmission networks in the 2024-2029 regulatory control period. In addition, we propose adjustments to the transmission EBSS for the 2024-2029 regulatory control period, including two new exclusions:

- opex arising from actionable Integrated System Plan (**ISP**) projects
- opex arising from Renewable Energy Zone (**REZ**) developments.

10.2 Outcomes from the EBSS in the current regulatory control period

In Attachment 8 we outline the efforts we have made during the current regulatory control period to ensure that we are operating in an efficient and prudent manner.

Application of the EBSS can give rise to bonuses or penalties in each year of a regulatory control period, depending on whether TasNetworks has underspent or overspent the opex allowances determined by the AER. Under the scheme, TasNetworks retains any opex efficiency gains or losses for a five-year period, after which the gains or losses are passed onto customers.

1 AER, TasNetworks determination 2019-24, Attachment 8 – Efficiency benefit sharing scheme

TasNetworks' 2019-2024 regulatory determination excluded the following cost categories from the operation of the EBSS:

- debt raising costs (transmission and distribution)
- opex on network capability incentive projects under the Service Target Performance Incentive Scheme (transmission)
- Guaranteed Service Level (**GSL**) payments (distribution)
- Electrical Safety Inspection (**ESI**) levy payments (distribution)
- National Energy Market (**NEM**) levy payments (distribution)
- Network support costs (transmission).

In addition, when calculating the EBSS carryover amounts to be applied in the 2024-2029 regulatory control period, we propose that:

- TasNetworks' actual opex be adjusted to reverse any movements in provisions
- TasNetworks' forecast opex be adjusted to add (or subtract) any approved revenue increments (or decrements) made after the AER's initial regulatory determination, so that factors like approved pass-through events and contingent project expenditure are reflected in TasNetworks' EBSS outcomes
- TasNetworks' actual opex be adjusted by adding capitalised opex that has been excluded from TasNetworks' regulatory asset base
- categories of opex not forecast using a single year revealed cost approach for the regulatory control period beginning on 1 July 2024 be excluded, where doing so better achieves the requirements of clauses 6.5.8 and 6A.6.5 of the NER.

Tables 1 and 2 show TasNetworks' adjusted opex during the current regulatory control period for the transmission and distribution networks, compared to the opex allowances set by the AER. The data contained in both tables is used to calculate TasNetworks' efficiency gains to be carried over into the 2024-2029 regulatory control period. It is consistent with the information TasNetworks has applied in the EBSS models that accompany TasNetworks' combined proposal for the 2024-2029 regulatory control period.

Table 1. Transmission historical cost performance for EBSS carryover calculation (2023-24, $ million)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Forecast opex for EBSS purposes	55.7	55.0	35.5	35.6	35.8	36.0	36.2
Actual opex	36.2	38.2	33.2	36.8	36.6	38.3	N/A
Less							
Debt raising costs	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Self-Insurance	1.0	1.0	0.0	0.0	0.0	0.0	N/A
Network support costs	0.0	0.0	0.0	0.0	0.0	0.0	N/A
Other Adjustments	0.0	0.0	0.0	1.4	0.3	2.5	N/A
Adjustment for provisions	(0.4)	(0.6)	0.1	(0.1)	(0.6)	0.0	N/A
Adjusted actual opex	34.9	36.6	33.3	35.3	35.7	35.8	36.1

Table 2. Distribution historical cost performance for EBSS carryover calculation (2023-24, $ million)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Forecast opex for EBSS purposes	76.8	75.0	100.2	99.7	98.6	97.5	96.4
Actual opex	107.9	96.1	100.8	107.8	104.3	102.3	N/A
Less							
Debt raising costs	0.0	0.0	0.0	0.0	0.0	0.0	N/A
GSL payments	4.0	1.6	1.3	1.8	3.5	2.0	N/A
DMIA	0.0	0.0	0.0	0.2	0.0	0.0	N/A
ESI levy payments	4.8	4.8	5.3	5.3	5.1	5.1	N/A
NEM levy payments	0.8	0.8	0.9	0.8	0.8	1.4	N/A
Adjustment for provisions	(1.0)	(1.3)	0.0	0.0	0.0	0.0	N/A
Adjusted actual opex	99.3	90.3	93.3	99.7	94.8	93.7	92.7

TasNetworks' transmission opex in the 2019-2024 regulatory control period has been consistent with the opex allowance set by the AER, resulting in a projected EBSS reward of $0.2 million ($2023-24) carrying over into the 2024-2029 regulatory control period, as shown in Table 3.

Table 3. Transmission EBSS carryover amounts for the 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
EBSS carry over amount	2.5	(2.1)	(0.2)	0.0	0.0	0.2

As shown in Table 2, TasNetworks distribution network opex has been less than the opex allowance set by the AER in each year of the current regulatory control period. There is, however, a minor penalty to be applied from the reconciliation of the final year from the previous (two year) regulatory control period (2018-19). This results in a projected overall penalty of $2.9 million ($2023-24) carrying over into the 2024-2029 regulatory control period, as shown in Table 4.

Table 4. Distribution EBSS carryover amounts for the 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
EBSS carry over amount	(3.5)	(3.2)	3.8	0.0	0.0	(2.9)

10.3 EBSS applying from 1 July 2024

The AER's Final Framework and Approach paper[2] outlines an intent to apply the EBSS to TasNetworks in the 2024-2029 regulatory control period, if the AER can be satisfied that the scheme's application will result in efficiency gains and losses being shared fairly between TasNetworks and consumers. The AER notes that for this to happen, TasNetworks' operating expenditure forecast for the 2024-2029 regulatory control period will need to be based on TasNetworks' revealed costs in the current regulatory control period.

As discussed in Attachment 8, TasNetworks proposes a revealed cost forecasting approach for the 2024-2029 regulatory control period. Therefore, we propose that the EBSS version 2 should also apply.

Clause 1.4 of EBSS version 2 enables the AER to adjust an NSP's forecast or actual opex when calculating carryover amounts. Among other adjustments, these provisions within the EBSS enable:

- forecast opex to be adjusted to add any approved revenue increments or subtract any approved revenue decrements made after the initial regulatory determination, such as pass through amounts or opex for contingent projects; and
- the exclusion of categories of opex not forecast using a single year revealed cost approach for the regulatory control period, where doing so better achieves the requirements of clauses 6.5.8 and 6A.6.5 of the NER.

TasNetworks proposes that all the exclusions applying to TasNetworks in the 2019-2024 regulatory control period be applied to the EBSS in the 2024-2029 regulatory control period, as well as a number of additional categories of opex that are not able to be forecast for the coming regulatory control period using a single year revealed cost approach. On that basis, the categories of opex proposed by TasNetworks to be excluded from the EBSS for the 2024-2029 regulatory control period are:

- debt raising costs (transmission and distribution)
- opex on network capability incentive projects under the Service Target Performance Incentive Scheme (transmission)
- GSL payments (distribution)
- ESI levy payments (distribution)
- NEM levy payments (distribution)
- network support costs (transmission)
- opex for contingent projects (transmission)
- pass through amounts (transmission and distribution)
- opex arising from actionable ISP projects (transmission)
- opex arising from REZ developments (transmission).

All but two of the proposed exclusions are consistent with the application of the EBSS to TasNetworks during the current regulatory control period. The final two exclusions proposed in the above list have been nominated for the following reasons.

10.3.1 Opex arising from ISP projects

Transmission network service providers (**TNSPs**) are obligated to progress the early works related to actionable ISP projects identified by the Australian Energy Market Operator (**AEMO**). This introduces the possibility of significant costs being incurred by TNSPs during a regulatory control period that are over and above the recurrent costs associated with the delivery of prescribed transmission services and for which no allowance has been made as part of a revenue determination. If these projects do not proceed, for regulatory purposes the expenditure incurred is likely to be treated as opex.

Due to this uncertainty, any expenditure of this nature should be excluded from the EBSS, because of the potential for TasNetworks' opex to exceed its allowance, resulting in an EBSS penalty which is unrelated to TasNetworks' opex efficiency. The inclusion of opex arising from actionable ISP projects in the EBSS also creates a perverse incentive to proceed with projects which may only be of marginal economic viability in order to avoid penalty under the EBSS, or to at least factor in the avoidance of an EBSS penalty into any cost-benefit analysis.

10.3.2 Opex arising from REZ developments

TNSPs are obliged to prepare detailed REZ design reports if required by AEMO in an ISP. TasNetworks proposes to exclude REZ development costs from the EBSS as these costs will not be recognised within our approved opex allowance. As noted above in relation to the costs associated with actionable ISP projects, the incentive to proceed with REZ design reports is optimally preserved by EBSS exclusion.

10.3.3 EBSS opex forecasts

TasNetworks proposes that the opex forecasts presented in Table 5 and Table 6 be used to establish the controllable opex forecasts for the transmission and distribution networks applicable to EBSS calculation for the 2024-2029 regulatory control period.

2 AER, Final Framework and Approach for TasNetworks for the 2024-29 regulatory control period, July 2022, p. 50

Table 5 Transmission EBSS opex forecasts (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Forecast opex	39.80	41.57	42.51	42.66	42.68	209.22
Less						
Debt raising costs	0.85	0.85	0.85	0.84	0.83	4.22
Network support costs	0.00	0.00	0.00	0.00	0.00	0.00
Pass through amounts	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for provisions	0.00	0.00	0.00	0.00	0.00	0.00
Less actionable ISP project costs	0.00	0.00	0.00	0.00	0.00	0.00
Less REZ development costs	0.00	0.00	0.00	0.00	0.00	0.00
Forecast opex for EBSS purposes	38.94	40.72	41.67	41.82	41.85	205.00

Table 6 Distribution EBSS operating forecasts (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Forecast opex	105.99	107.74	108.80	109.07	109.45	541.04
Less						
debt raising costs	1.08	1.09	1.11	1.11	1.10	5.49
GSL payments	3.97	3.97	3.97	3.97	3.97	19.84
NEM levy payments	1.47	1.47	1.36	1.17	1.17	6.64
ESI levy payments	5.09	5.09	5.09	5.09	5.09	25.45
Adjustment for provisions	0.00	0.00	0.00	0.00	0.00	0.00
Forecast opex for EBSS purposes	94.38	96.12	97.27	97.74	98.11	483.62

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Attachment 11
Capital expenditure sharing scheme

Outline: This attachment to TasNetworks' Combined Proposal sets out how the Capital Expenditure Sharing Scheme will apply during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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11 Capital expenditure sharing scheme

11.1 Introduction

The Capital Expenditure Sharing Scheme (**CESS**) provides an incentive for network service providers (**NSPs**) to pursue efficiency improvements in capital works programs and provides for a fair sharing of efficiency gains between NSPs and customers.

The Australian Energy Regulator (**AER**) determines separate CESS rewards or penalties for TasNetworks' transmission and distribution networks. The AER applied its Capital Expenditure Incentive Guideline (**CESS Guideline**)[1] to TasNetworks' transmission and distribution networks in the 2019-2024 regulatory control period. Under the CESS Guideline, capital expenditure (**capex**) efficiencies are shared 70 per cent with customers and 30 per cent with the NSP.

TasNetworks' transmission network reward for the 2019-2024 regulatory control period is forecast to be $3.17 million and for the distribution network the reward is forecast to be $10.46 million ($2023-24). These rewards will be applied as an additional building block adjustment to TasNetworks' revenue in the 2024-2029 regulatory control period. In turn, customers benefit because efficiency gains results in a lower regulatory asset base (**RAB**) which is a key driver of the return of capital and return on capital building blocks.[2] These benefits will also flow through to customers in future regulatory control periods.

The AER's Final Framework and Approach paper stated an intention to continue to apply the CESS to both of TasNetworks' networks in the 2024-2029 regulatory control period.[3] TasNetworks supports the continued application of the CESS to its transmission and distribution networks. In combination with other incentive schemes, the CESS provides appropriate and balanced incentives for efficient expenditure while maintaining or improving service standards.

The Framework and Approach noted that the CESS is a focus of the AER's current Incentive Scheme Review and that any changes to the CESS would not apply retrospectively but to capex undertaken in the 2024-2029 regulatory control period to be applied as a reward or penalty in the 2029-2034 regulatory control period. Throughout the Incentive Scheme Review, TasNetworks has supported additional transparency regarding CESS outcomes.

11.2 Transmission network Reward / Penalty and CESS targets

TasNetworks has calculated capex efficiency rewards for our transmission network in the 2019-2024 regulatory control period and the target capex that will be used to assess capex efficiencies in the 2024-2029 regulatory control period.

11.2.1 Calculation of reward for the 2019-2024 regulatory control period

In accordance with the CESS Guideline, TasNetworks has calculated the transmission CESS outcome as follows:

- annual efficiency gains are calculated by subtracting actual capex from the capex allowance in each year of the 2019-2024 regulatory control period

1 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013

2 For more information on revenue building blocks refer to Attachment 2 of the Combined Proposal

3 AER, Final Framework and Approach for TasNetworks for the 2024-29 regulatory control period, July 2022, p. 50

- an estimate of capex based on current forecasts is used to calculate the impact for the final two regulatory years of the period as the Combined Proposal is made before those years have occurred
- the CESS sharing ratio of 30 per cent is applied to the adjusted efficiency gain to calculate TasNetworks' reward
- the financing benefit that has already accrued to TasNetworks in the 2019-2024 regulatory control period is calculated and subtracted from the annual efficiency gains.

Table 1 shows actual capex in the 2019-2024 regulatory control period compared to the capex allowance for the purposes of determining the CESS carryover amount. The CESS carryover for our transmission network arising from the 2019-2024 regulatory control period is shown in Table 2. The reward is included as a 'revenue adjustment' in our annual revenue requirement in each year of the 2024-2029 regulatory control period.

Table 1. Transmission historical cost performance for CESS carryover calculation (nominal, $ million)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Total capex allowance	58.04	56.20	54.57	49.70	46.14	**264.65**
Total actual capex	51.54	45.60	46.94	64.06	56.53	**264.68**
Less disposals	0.03	0.02	0.16	0.07	0.07	**0.34**
Less other capex	0.48	0.56	1.77	1.02	1.00	**4.84**
Net capex	51.03	45.01	45.01	62.98	55.46	**259.49**
(under) / over spend	(7.01)	(11.19)	(9.56)	13.27	9.33	**(5.16)**

Table 2. Transmission CESS carryover amounts for 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
CESS carry over amount	0.63	0.63	0.63	0.63	0.63	**3.17**

11.2.1.1 Reasons for transmission CESS reward

The reward of $3.17 million ($2023-24) is largely driven by a true-up of the CESS outcome in the final year of the 2014-2019 regulatory control period. Transmission capex allowance is forecast to be almost (98 per cent) fully expended in the 2019-2024 regulatory control period. The minor underspend primarily results from the impact of the COVID-19 pandemic and resultant challenges with resource availability in the first three years of the regulatory control period. It is forecast that most of the underspend in the first three years will be reversed by the end of the 2019-2024 regulatory control period.

11.2.1.2 Adjustment for capex deferrals

The CESS Guideline provides that an adjustment be made to the CESS outcome where there is deferral of capex from the current regulatory period to the next regulatory period.

The adjustment applies where TasNetworks has deferred capex in the 2019-2024 regulatory control period and:

- the amount of deferred capex is material
- the total capex underspend is material
- total approved forecast capex in the 2024-2029 regulatory control period is materially higher than it is likely to have been if the capex was not deferred in the 2019-2024 regulatory control period.

TasNetworks has not applied an adjustment to the transmission CESS outcome as there is no material forecast underspend of capex in the 2019-2024 regulatory control period.

11.2.2 CESS target to apply for the 2024-2029 regulatory control period

TasNetworks' total CESS target for the 2024-2029 regulatory period is $287.8 million ($2023-24) and is shown in Table 3.

Table 3. Transmission CESS capital expenditure forecasts for 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Net capital expenditure forecast	52.05	67.80	58.72	57.67	51.56	**287.80**
Adjustments	0.00	0.00	0.00	0.00	0.00	**0.00**
Movement in provisions	0.00	0.00	0.00	0.00	0.00	**0.00**
CESS target	52.05	67.80	58.72	57.67	51.56	**287.80**

Consistent with the CESS Guideline, adjustments may be made during the 2024-2029 regulatory control period for any capex approved by the AER for pass-throughs, reopening of capex or contingent projects that are triggered. Our proposed transmission network pass-through events are outlined in Attachment 17 Pass through events and proposed contingent projects are outlined in Attachment 7 Contingent projects. Also consistent with the CESS Guideline, TasNetworks' will exclude any capex incurred in delivering a priority project approved under the network capability component of the service target performance incentive scheme for transmission network service providers.

TasNetworks considers that the CESS should not apply to actionable Integrated System Plan projects, including the North West Transmission Developments (**NWTD**) associated with Project Marinus.

NWTD' estimated cost is approximately three times more than TasNetworks' total 2024-2029 capex forecast. Therefore, a small percentage under / over spend on NWTD will significantly impact TasNetworks' 2024-2029 incentive scheme outcomes, weakening incentives to find efficiencies in the underlying program of work. This is not consistent with the objective of the scheme and can be resolved by excluding NWTD capex from the CESS if the AER approves a NWTD contingent project application during the 2024-2029 regulatory control period.

11.3 Distribution network carryover amounts and CESS targets

TasNetworks has calculated capex efficiency rewards for our distribution network in the 2019-2024 regulatory control period and the target capex that will be used to assess capex efficiencies in the 2024-2029 regulatory control period.

11.3.1 Calculation of reward for the 2019-2024 regulatory control period

TasNetworks has calculated the carryover amount for this period for its distribution network using the same approach as for its transmission network explained in section 11.2.1 above.

Table 4 shows our capex in the 2019-2024 regulatory control period compared to approved capex allowance for the purposes of determining the CESS carryover amount. The capex reward for our distribution network arising from the 2019-2024 regulatory control period is shown in Table 5. The reward will be included as a 'revenue adjustment' in our annual revenue requirement in each year of the 2024-2029 regulatory control period.

Table 4. Distribution historical cost performance for CESS carryover calculation (nominal, $ million)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Total capex allowance	146.09	136.96	128.67	148.54	160.39	**720.64**
Total actual capex	135.12	154.93	151.43	164.55	176.60	**782.63**
Less customer contributions	16.95	18.94	29.77	15.28	14.12	**95.06**
Less disposals	1.14	0.14	0.50	0.88	0.93	**3.60**
Net actual capex	117.03	135.84	121.16	148.39	161.54	**683.96**
(Under) / overspend	(29.07)	(1.11)	(7.50)	(0.15)	1.15	**(36.68)**

Table 5. Distribution CESS carryover amounts for 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
CESS carry over amount	2.09	2.09	2.09	2.09	2.09	**10.46**

11.3.1.1 Reasons for distribution CESS reward

Distribution capex is forecast to be around 95 per cent of the capex allowance in 2019-2024 regulatory control period. The forecast underspend resulting in a reward of $10.46 million ($2023-24). The 2019-20 underspend is predominantly due to the impact of the COVID 19 pandemic and resultant challenges with resource availability. The impact of the COVID 19 pandemic underspend has been partially reversed in the remaining years of the regulatory control period, however this has been offset by underspends due to the deferral of the Market Data Management System (**MDMS**) replacement project. Further information on this project is found in Section 11.3.1.2.

11.3.1.2 Any adjustments for capex deferrals

The CESS Guideline provides that an adjustment be made to the CESS outcome where there is deferral of capex from the current regulatory period to the next regulatory period.

The adjustment applies where TasNetworks has deferred capex in the 2019-2024 regulatory control period and:

- the amount of the deferred capex is material
- the total capex underspend is material
- total approved forecast capex in the 2024-2029 regulatory control period is materially higher than it is likely to have been if the capex was not deferred in the 2019-2024 regulatory control period.

As noted in Section 11.3.1.1, the MDMS project has not commenced in the 2019-2024 regulatory control period. In TasNetworks' 2019-2024 Revenue Determination the MDMS replacement project was expected to be undertaken across the 2019-2024 and 2024-2029 regulatory control periods. In addition to the deferral, the MDMS replacement project forecast cost is now significantly lower. As a result, the deferral in the 2019-2024 regulatory control period does not materially impact the capex forecast in the 2024-2029 regulatory control period.

The deferral and significant reduction in forecast cost represent a significant efficiency gain that benefits TasNetworks' customers through a lower RAB in the 2024-2029 regulatory control period and beyond. An adjustment to the distribution CESS outcome has not been applied as the proposed capex in the 2024-2029 regulatory control period is not materially higher than it is likely to have been if the MDMS replacement project was not deferred in the 2019-2024 regulatory control period.

11.3.2 CESS target to apply for the 2024-2029 regulatory control period

TasNetworks' total CESS target for the 2024-2029 regulatory period is $729.4 million ($2023-24) and is shown in Table 6.

Table 6. Distribution CESS capital expenditure forecasts for 2024-2029 regulatory control period (2023-24, $ million)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Net capital expenditure forecast	155.55	160.68	141.86	136.91	134.38	**729.38**
Adjustments	0.00	0.00	0.00	0.00	0.00	**0.00**
Movement in provisions	0.00	0.00	0.00	0.00	0.00	**0.00**
CESS target	155.55	160.68	141.86	136.91	134.38	**729.38**

Consistent with the CESS Guideline, adjustments may be made during the 2024-2029 regulatory period for any capex approved by the AER for pass-throughs or reopening of capex. Our proposed distribution network pass-through events are outlined in Attachment 17 Pass through events.

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Combined Proposal 2024-2029

Attachment 12
Service target performance incentive scheme

Outline: This attachment to TasNetworks' Combined Proposal sets out the proposed application and components of the Service Target Performance Incentive Scheme (**STPIS**) that will apply to TasNetworks during the 2024-2029 regulatory control period and how we propose to set STPIS performance targets for this period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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	Combined Proposal overview
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Attachment 13	Demand management incentives and allowance
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12 Service target performance incentive scheme

12.1 Introduction

This attachment sets out TasNetworks proposed application of the Service Target Performance Incentive Scheme (**STPIS**) over the 2024-2029 regulatory control period. The STPIS plays a significant role in counter-balancing the incentives to minimise operating and capital expenditure that are provided by other aspects of the regulatory framework, including the Efficiency Benefit Sharing Scheme (**EBSS**) and Capital Expenditure Sharing Scheme (**CESS**). Unlike the EBSS and CESS, STPIS-based financial rewards or penalties over a regulatory control period are added to, or subtracted from, our annual revenue requirement within the same regulatory control period. In broad terms, the STPIS gives network service providers (**NSPs**) incentives to maintain and improve network reliability and performance.

TasNetworks operates under two STPISs. For transmission, this has been and will remain version 5, released in October 2015.[1] For distribution, TasNetworks is currently operating under version 1.2 but for the forthcoming regulatory control period will transition to version 2.0, released in November 2018.[2]

1 AER, Final Decision Electricity transmission network service providers, *Service Target Performance Incentive Scheme Version 5,* October 2015

2 AER, Electricity distribution network service providers, *Service target performance incentive scheme, Version 2.0*, November 2018

12.2 Rules requirements for distribution

The National Electricity Rules (**NER**) set out three relevant requirements in relation to the STPIS. They are:

- the building block proposal must contain a description of how the distribution network service provider (**DNSP**) proposes any STPIS specified in the Framework and Approach Paper should apply for the 2024-2029 regulatory control period[3]
- the building blocks used to calculate the annual revenue requirement for each regulatory year of the 2024-2029 regulatory control period must include (among other things) any revenue increments or decrements for the regulatory year arising from the application of the STPIS[4]
- the building block determination must specify how any applicable STPIS is to apply to a DNSP in the 2024-2029 regulatory control period.[5]

The STPIS to apply to TasNetworks in the 2024-2029 regulatory control period must be developed and implemented in accordance with clause 6.6.2 of the NER. In developing and implementing the STPIS, the AER must:

- consult with the authority responsible for the administration of relevant jurisdictional electricity legislation (i.e., the Office of the Tasmanian Economic Regulator (**OTTER**))
- ensure that service standards and service targets (including guaranteed service levels (**GSLs**)) set by STPIS do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including GSLs) as specified in jurisdictional electricity legislation
- consider specified matters, including the past performance of the distribution network

3 NER clause S6.1.3(4)

4 NER clause 6.4.3(a)(5)

5 NER clause 6.3.2(a)(3)

- have regard to the Distribution Reliability Measures Guidelines.

In the 2024-2029 Framework and Approach paper, the AER stated that it intends to apply version 2.0 of the national STPIS to TasNetworks for the 2024-2029 regulatory control period. The AER also set out the components of the STPIS that it proposes to apply to TasNetworks.

This is a change for TasNetworks, as for the 2019-2024 regulatory control period we have operated under version 1.2 of the STPIS published in November 2009.

Key changes in version 2.0 of the STPIS include:

- the change of sustained interruption threshold from greater than 1 minute to greater than 3 minutes
- adjusting the incentive rate weighting between System Average Interruption Duration Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**) from the current approximately 50:50 ratio to a 60:40 ratio.

In preparation for the changes in version 2.0 of the STPIS we have recorded the reliability of supply performance over the past five years incorporating the change in sustained interruption threshold to ensure that we have the data to calculate future targets that are consistent with version 2.0 of the STPIS.

12.3 Distribution STPIS to apply for the 2024–2029 regulatory control period

TasNetworks proposes that the AER apply the components of version 2.0 of the STPIS to TasNetworks for the 2024-2029 regulatory control period in a manner that is consistent with the AER's proposed approach as set out in the Framework and Approach with the clarifications as set out in Table 1.

Table 1. Summary of AER's STPIS position in the 2024-2029 Framework and Approach and TasNetworks' proposed approach

STPIS component	AER's Framework and Approach position	TasNetworks' proposed approach
Revenue at risk	± 5 per cent	Accept
Segment the network	Segment the network according to the Tasmanian Electricity Code's supply reliability categories (critical infrastructure, high density commercial, urban, high density rural and low density rural).	Accept
Performance parameters	Apply the SAIDI, SAIFI and customer service (telephone answering) parameters. However, if TasNetworks' proposed customer service incentive scheme (**CSIS**) includes a similar performance measure, the telephone answering parameter of the STPIS will not be applied.	Accept, and propose a CSIS to replace the customer service parameter. The CSIS is detailed in Attachment 14 Customer service incentive scheme.
Performance targets	Set performance targets based on TasNetworks' average performance over the past five regulatory years.	Accept
Exclusions	Apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets.	Accept
Incentive rates	Apply the latest published value of customer reliability (**VCR**) values by the AER to set the incentive rates for SAIDI and SAIFI.	Accept
Guaranteed Service Levels	Not apply the GSL component if TasNetworks remains subject to a jurisdictional GSL scheme (as set out in the Tasmanian Electricity Code).	Accept

Maintaining the revenue at risk at the current level of ± 5 per cent reflects our customers' feedback to maintain affordability and reliability of network services at current levels.

TasNetworks proposes to use data from 1 July 2017 to 30 June 2022 to set targets in this proposal and will update the targets using data from 1 July 2018 to 30 June 2023 in the Revised Proposal. TasNetworks proposes setting the major event day threshold using the methodology outlined in version 2.0 of the STPIS.

Table 2. Proposed STPIS distribution reliability performance targets and incentive rates for 2024-2029

Classification	SAIDI	Incentive rate	SAIFI	Incentive rate
Critical infrastructure	6.260	0.0027	0.078	0.1438
High Density Commercial	36.778	0.0032	0.365	0.2152
Urban	98.014	0.0351	1.080	2.1238
High Density Rural	241.273	0.0101	2.183	0.7425
Low Density Rural	375.790	0.0175	2.832	1.5485

Table 3. Proposed STPIS customer service targets and incentive rates for 2024-2029

Customer service parameter	Target	Incentive rate
Telephone answering	83.12%	-0.040

12.4 Rules requirements for transmission

The transmission STPIS is governed by NER clause 6A.7.4 and the arrangements established under that clause by the AER. It consists of three components:

1. a service component, which provides a reward or penalty of +/- 1.25 per cent of the maximum allowed revenue (**MAR**) for the relevant calendar year to improve network reliability by focussing on unplanned network outages and prompt restoration in the event of unplanned outages that cause supply interruptions. It is measured by four main parameters and various sub-parameters acting as key indicators
2. a market impact component (**MIC**), which provides a reward or penalty of up to +/- 1 per cent of the MAR for the relevant calendar year to minimise the impact of transmission outages that can impact the spot price and wholesale electricity market outcomes
3. a network capability component, which provides pro-rata incentive payment of up to 1.5 per cent of MAR for completion of operating expenditure (**opex**) or capital expenditure (**capex**) projects that improve network capability at times when it is most needed and provide value for money to customers.

In its Final Framework and Approach for TasNetworks, the AER concluded that STPIS version 5 will continue to apply for the 2024-2029 regulatory control period.[6] Therefore, in accordance with S6A.1.3(2) we are required to submit:

- proposed values for the service component parameters
- data for the market impact component for the preceding seven regulatory years and proposed parameter values for:
  - the performance target
  - the unplanned outage event limit
  - the dollar per dispatch interval incentive
- a Network Capability Incentive Parameter Action Plan (**NCIPAP**) containing proposed priority projects.

6 AER, *Final Framework and Approach for TasNetworks for the 2024-29 regulatory control period*, July 2022

12.5 Transmission STPIS to apply for the 2024–2029 regulatory control period

Our proposed performance targets, caps, collars, and weightings for the transmission STPIS 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 Framework and Approach for TasNetworks. We have:

- established reliability 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
- proposed caps and collars, which are set using a reasonable methodology as explained below.

We propose to use our performance data for the period 2018 to 2022 for target setting purposes. The current proposed targets, which are based on the latest available data, being 2017 to 2021, will be updated at the Revised Proposal stage once the 2022 data is available.

Clause 3.2(e) of the STPIS specifies that the proposed caps and collars must be calculated by reference to the proposed performance targets and using a sound methodology. These may result in symmetric or asymmetric incentives for the Transmission network service provider (**TNSP**).

The proposed collars and caps have been developed using the same methodology as that adopted by the AER in our current determination. For asymmetrical distributions, this outcome is achieved by setting collars and caps at the 5th and 95th percentile. These percentiles have been calculated using the distribution which best fits the 2017-2021 performance data.

Table 4 below shows the assumed probability distribution for each sub-parameter that has been used to set caps and collars to apply for the forthcoming regulatory control period, as well as the proposed targets, collars, and caps for each of the service component parameters, using the methodology described above.

Table 4. Proposed STPIS performance targets for transmission for 2024-2029

Service component	Distribution	Cap	Target	Collar	Weighting (% of MAR)
Average circuit outage rate					
Lines event rate –fault	Log Normal	8.99%	14.65%	22.14%	0.20%
Transformer event – fault	Uniform	3.83%	7.31%	10.79%	0.20%
Reactive plane outage rate – fault	Normal	4.06%	17.44%	30.81%	0.10%
Lines event rate – forced	Log Normal	6.88%	15.98%	30.16%	0.10%
Transformer outage rate – forced	Log Normal	2.31%	6.59%	13.79%	0.10%
Reactive plant outage rate – forced	Log Normal	8.63%	15.51%	25.23%	0.05%
Loss of supply (LOS) events					
LOS>0.1 system minutes	Poisson	1	4	7	0.15%
LOS>1 system minutes	Poisson	0	0	2	0.15%
Average outage duration (minutes)	Log Normal	15.71	170.67	643.39	0.20%
Proper operation of equipment					
Failure of protection system	Weibull	1	3	6	0.00%
Material failure of SCADA	Poisson	0	2	4	0.00%
Incorrect operational isolation	Exponential	0	3	8	0.00%

12.5.1 Market impact component

Under version 5 of the STPIS, TasNetworks is required to submit data for the MIC 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. This information is provided in Attachment 23.

TasNetworks considers the current design of the MIC is not suited to the current and future network operational conditions in Tasmania. The flow of energy over TasNetworks' transmission network is highly variable because of the operating behaviour of hydro-electric generation. This means it is inherently difficult to schedule planned outages at times of lower network constraints. TasNetworks collaborates with market participants and other stakeholders likely to be affected by a network outage to find the most convenient and efficient time for works. However, the nature of Tasmania's electricity system means it is difficult to forecast actual flows on the day of the outage making the use of predicted MIC impacts to influence the timing of planned outages a lottery.

Given these concerns, TasNetworks proposes that the MIC applied for the next regulatory control period be revised. A scheme similar to the MIC was historically used in the United Kingdom to incentivise the system operator to manage network outages. Following a review of incentives, a change was made in 2018 to base reward or penalty payments on a largely qualitative assessment of the outage management performance, measured against a forward plan. TasNetworks proposes that similar changes be made to the MIC. Under our proposed scheme, a TNSP would be able to avoid a MIC penalty in respect to an outage if it has consulted with affected market participants and delivers on an outage during the time agreed to.

The scheme would operate along the following lines:

- a secure page could be established on, for example the Australian Energy Market Operator's (**AEMO's**) website, access to which would be restricted to registered market participants
- each TNSP would place a notification of planned work in relation to a specified line and the timeframe required to complete the work
- the notification would be provided at least 13 months prior to a planned outage
- market participants would be given an automatic message when the page was updated
- market participants would have a month to provide feedback to the TNSP on their preferences for the timing of the outage
- the TNSP would weigh up the responses and determine the proposed timeframe for the outage
- if a market impact occurs as the result of the outage, the TNSP would provide the AER with the relevant information supporting the rationale for the timing of the proposed outage
- if it is demonstrable that the TNSP undertook the outage at the best time, no MIC penalty would apply.

To ensure symmetry in the scheme, the TNSP would initially be provided a bonus reflecting the cost of undertaking each consultation. A penalty would arise if the TNSP decides not to consult or is found to not have undertaken the outage at the appropriate time, with the current MIC count being used to calculate the size of the penalty.

TasNetworks recognises this is a departure from the current scheme but believes it will provide more targeted incentives that will encourage TNSPs to consult with affected parties leading to an improvement in the timing and notification of planned work. This should result in parties being more able to manage the impact on the market of those outages.

12.5.2 Network capability

A proposed NCIPAP has been developed in accordance with the requirements of version 5 of the STPIS. We have identified one low-cost priority project to improve network capability in the upcoming regulatory control period, summarised in the table below. The NCIPAP projects were identified based on analysis of project rankings to ensure that the selected projects delivered the best outcome for our customers.

Table 5 summarises the ranking of TasNetworks' proposed NCIPAP projects for the 2024-2029 regulatory control period. The scheme limits the value of NCIPAP projects to a combined expenditure limit of one percent of MAR; approximately $8 million for the 2024-2029 regulatory control period. Given the total project cost is below the expenditure limit, TasNetworks will continue to explore other projects to include in the NCIPAP over the 2024-2029 regulatory control period.

Table 4. TasNetworks' proposed 2024-2029 NCIPAP Projects

Tasnetworks project ranking	Project name	Scope of works	Payback period in years	Annual market benefits ($)	Project cost Level 1 estimate ($)	Project drivers and material benefit
1	Palmerston Substation terminal equipment upgrade	Upgrade terminal equipment at Palmerston Substation for Waddamana–Palmerston 220 kV transmission line	2.31	1,628,912	3,769,706	Upgrade terminal equipment limitation at Palmerston Substation on the Waddamana–Palmerston 220 kV transmission circuits, releasing available transmission capacity to support initial development of the Central Highlands Renewable Energy Zone. This increased rating would eliminate current congestion in the network allowing increased output of generation in the region.
Total project cost ($)					**$3,769,706**	

The STPIS guideline requires that TNSPs must consult with AEMO prior to submitting the NCIPAP[7] to assess and provide advice on the proposed projects to ensure the objectives of the scheme are achieved. The proposed NCIPAP for the 2024-2029 regulatory control period was shared with AEMO for review and endorsement in October 2022. Following its review of our proposed NCIPAP projects, AEMO agreed with the assessment of the proposed project needs, improvement targets, expected material benefits and ranking of proposed projects.

7 AER, Final Decision Electricity transmission network service providers, Service Target Performance Incentive Scheme Version 5, October 2015, page 13

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Combined Proposal 2024-2029

Attachment 13
Demand management incentives and allowance

Outline: This attachment to TasNetworks' regulatory proposal sets out how the Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism will apply during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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13 Demand management incentives and allowance

13.1 Overview

The Demand Management Incentive Scheme (**DMIS**) provides financial incentives for TasNetworks to undertake efficient demand management solutions in operating our distribution network.

The Demand Management Innovation Allowance Mechanism (**DMIAM**) provides a modest amount of funding for research and development in demand management projects that have the potential to reduce long term distribution and transmission network costs.[1]

The Australian Energy Regulator's (**AER's**) Framework and Approach Final Decision states an intention to apply the DMIS and DMIAM to TasNetworks distribution network and the DMIAM to the transmission network in the 2024–2029 regulatory control period.[2]
DMIS does not apply to transmission networks.

TasNetworks supports the continued application of DMIS and DMIAM to its distribution network and DMIAM to the transmission network noting:

- DMIS projects and financial incentives are proposed by TasNetworks and approved by the AER as part of an annual compliance and approval process, not through this determination process; and
- if DMIAM funding remains unspent at the end of the regulatory control period it will be returned to customers through a deduction to TasNetworks' revenue requirement in the second year of the next regulatory control period.

13.2 Proposed application of the DMIS in 2024-2029 regulatory control period

The DMIS will apply to TasNetworks' distribution network in the 2024-2029 regulatory control period.

To provide better outcomes for our customers during the 2024-2029 regulatory control period, TasNetworks will seek to identify and implement demand management projects that cost-effectively address network constraints as an alternative to more expensive capital expenditure projects. Cost-effective demand management projects will be annually reported to the AER that then will determine the DMIS financial incentive.

The DMIS operates separately to the Revenue Determination, via an application, reporting and approval process as set out in the documentation of the scheme.[3] There are no revenue adjustments to be determined as part of TasNetworks' Revenue Determination, with applications being required to be made during the 2024-2029 regulatory control period as potential projects arise.

1 Demand Management Innovation Allowance Objective – National Electricity Rules Clause 6.6.3A(b) and 6A.7.6(b)

2 AER, Framework and approach TasNetworks distribution and transmission (Tasmania) Regulatory control period commencing 1 July 2024, p 51.

3 AER, Demand management incentive scheme, Electricity distribution network service providers, December 2017.

13.3 Proposed application of the DMIAM in 2024-2029 regulatory control period

The DMIAM will apply to TasNetworks' distribution and transmission networks in the 2024-2029 regulatory control period. Projects which TasNetworks intends to undertake using the DMIAM do not need to be set out and approved in the Revenue Determination. The only matter to be decided in the Revenue Determination is the total amount of the available allowance.

Like DMIS projects, DMIAM projects and expenditure are assessed and approved annually by the AER. Transmission DMIAM may also be subject to independent assessments prior to AER approval. The following sections provide details of the forecast allowances and some projects that could potentially be funded by the distribution and transmission DMIAM in the 2024-2029 regulatory control period.

13.3.1 Distribution DMIAM

In accordance with the distribution DMIAM,[4] we propose the maximum DMIAM allowances for the 2024-2029 regulatory control period as shown in Table 1.

Table 1: Proposed Distribution DMIAM allowances for 2024-2029 regulatory control period (2023-24, $m)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
DMIAM	0.47	0.47	0.48	0.48	0.48	2.38

13.3.2 Transmission DMIAM

In accordance with the transmission DMIAM,[5] we propose the maximum DMIAM allowances for the 2024-2029 regulatory control period as shown in Table 2.

Table 2: Proposed Transmission DMIAM allowances for 2024-2029 regulatory control period (2023-24, $m)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
DMIAM	0.20	0.20	0.20	0.20	0.20	1.01

4 AER, Demand management innovation allowance mechanism, Electricity distribution network service providers, December 2017.

5 AER, Demand management innovation allowance mechanism, Electricity transmission network service providers, May 2021.

13.3.3 Potential DMIAM Projects

TasNetworks has identified two trials, an export tariff trial and a community battery trial, that may be funded through DMIAM. As DMIAM projects and expenditure are assessed ex-post by the AER, other projects may be identified and included during the 2024-2029 regulatory control period.

Given the relatively modest nature of TasNetworks' DMIAM allowance, we propose to identify opportunities to collaborate and pool funding with TasNetworks' distribution network and, or, other Transmission Network Service Providers. TasNetworks' transmission DMIAM will be used only to contribute to innovative trials or pilot projects that can, if successful, deliver benefits to the Tasmanian transmission network and Tasmanian electricity customers.

Export tariff trial

The use of export tariffs for distribution customers is a new concept in Australia and there are no data to determine the scale of the impact such tariffs will have on customer behaviour. However, an export tariff is expected to modify customer behaviour in relation to how rooftop solar photo voltaic (**PV**) output is utilised behind-the-meter.

TasNetworks expects that it would undertake relevant tariff trials prior to formally proposing export tariffs to the AER. Trials are a critical input as they can test customer responsiveness and sentiments on a smaller scale and enable feedback and refinements to be made before implementing tariffs for the entire customer base.

Community Battery Trial

Community batteries increase network hosting capacity and solve network constraints around dispatchability, reducing the pressure on the grid in both high and low demand events.

The results from a community battery trial are expected to include information on customer behaviour in relation to how rooftop solar PV output is utilised and how the network facing load-export profile (at the customer meter as well as upstream of the battery location) of customers will change.

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Combined Proposal 2024-2029

Attachment 14
Customer service incentive scheme

Outline: This attachment to TasNetworks' Combined Proposal sets out how the new Customer Service Incentive Scheme will apply during the 2024-2029 regulatory control period.

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Note

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14 Customer service incentive scheme

14.1 Introduction

The Customer Service Incentive Scheme (**CSIS**) is a new incentive scheme released by the Australian Energy Regulator (**AER**) in July 2020 that provides an incentive for distribution network service providers (**DNSPs**) to pursue service improvements identified by their customers. It is a flexible 'principles-based' scheme that allows TasNetworks to tailor the scheme to the specific preferences and priorities of customers.

Similar to the Service Target Performance Incentive Scheme (**STPIS**), DNSPs receive financial rewards for improving their customer service, or financial penalties if service deteriorates. Financial rewards (or penalties) are added to (or subtracted from) the annual revenue requirement as part of annual pricing processes.

Clause 3.3 of the *Final Customer Service Incentive Scheme*[1] lists the incentive design proposal requirements. The AER will not apply an incentive scheme design unless a distributor can demonstrate that its customers support the incentive design through genuine engagement.

TasNetworks proposes to adopt the CSIS for the 2024-2029 regulatory control period. This position is supported by customers and stakeholders and the proposed parameters and targets have been identified through engagement with customers and stakeholders. We will retest this with customers and stakeholders in 2023 when CSIS targets have been updated with additional performance data for the 2022-2023 financial year.

If adopted, the CSIS will replace the customer service component of the distribution STPIS.

14.2 Customer and stakeholder engagement

14.2.1 How we sought customers' views

The CSIS was developed over a twelve month period based directly on feedback from customers and stakeholders, captured using a variety of methods and different audiences:

- TasNetworks Annual Customer Survey: open to customers and the general public, the survey captures sentiment and satisfaction with TasNetworks' services and future plans
- TasNetworks Customer Panel: a deliberative panel of individual customers from across the state
- TasNetworks Customer Council: an existing customer representative group.

Engagement included empowering the Customer Panel and Customer Council to decide whether TasNetworks should propose the CSIS in the 2024-2029 regulatory control period. Following strong support received from customers and stakeholders to propose the CSIS, engagement focused on the detailed design of the CSIS with the Customer Council.

Table 1 outlines the engagement activities TasNetworks has undertaken with respect to CSIS.

1 AER, Final Customer Service Incentive Scheme, July 2020, p. 6

Table 1. CSIS engagement snapshot

Activity metrics	Phase 1 Research + planning Nov 2020-Sep 2021	Phase 2 Context + capability building Oct-Dec 2021	Phase 3 Deep dives Jan-Jul 2022	Phase 4 Reporting back Jul-Oct 2022	Phase 5 Closing the loop Nov 2022-Jan 2023	Totals
Individuals *directly* engaged	0	0	22	11	18	51
Total activities completed	0	0	4/4	1/1	1/1	6

Presentations and activity summaries for all engagement activities can be downloaded from Talk with TasNetworks.[2]

14.2.2 Customer Panel outcomes

An independent third party recruited 18 distribution customers from across Tasmania to participate in a series of three online engagement sessions dedicated specifically to CSIS. A total of 13 customers participated in all three sessions. Each session was facilitated by an independent engagement consultant, with the final activity also observed by members of the AER's Consumer Challenge Panel (**CCP**).

At the completion of session three, it was clear the majority of participants supported TasNetworks proposing the CSIS in the 2024-2029 regulatory control period, along with providing clear direction on the design principles that should underpin the CSIS. Participants ranked customer satisfaction with complaints handling, outage duration and outage communication as the top three parameters.

Table 2 summarises the topics and outcomes of each engagement activity, as well as the International Association for Public Participation (**IAP2**) level of audience influence.

Table 2. Customer Panel engagement summary

	Activity 1 21 February 22	Activity 2 7 March 22	Activity 3 4 April 22
Number of participants	18	14	13
Topics covered	• Inform on TasNetworks • Inform on STPIS • Collaborate on value of customer service • Inform on customer survey results	• Inform on Activity 1 • Inform on CSIS • Consult on design principles • Collaborate on potential customer service measures	• Inform on Activity 2 • Collaborate on prioritised customer service measures and targets, potential impacts and trade-offs • Empower panel to select STPIS or CSIS as preferred customer service incentive framework
Outcomes	• List of important aspects of customer service	• Prioritised customer service measures for further assessment	• Short list of prioritised customer service measures for CSIS • Support to proceed with CSIS framework and design

2 TasNetworks 2023, Engagement activity materials, Revenue Reset (R24)

14.2.3 Customer Council outcomes

TasNetworks established the Customer Council in 2015 to enable ongoing conversations about issues that matter to Tasmanian energy users. The key purpose of the Customer Council is to:

- evaluate current customer policies, procedures and services
- provide ongoing customer feedback on services, regulations, policies, and procedures
- identify opportunities for new processes that would improve customer engagement.

Customer Council membership includes a diverse range of stakeholder segments, including:

- individual customers – who are recipients of TasNetworks services and connected to the electricity and/or communications networks
- business – small, medium and large business customers who represent a group or individuals impacted by, or with an interest in, TasNetworks operations. This also includes transmission customers
- regulators – those responsible for shaping and monitoring the energy sector
- partners – customers who we work with in a collaborative manner to meet connected customers' needs and to achieve best possible outcomes for all involved.

TasNetworks held three activities with the Customer Council in which CSIS was discussed.

Activity 1 was an in-person workshop, facilitated by the same independent engagement consultant used for the Customer Panel. The Customer Council supported TasNetworks proposing the CSIS in the 2024-2029 regulatory control period and the design principles underpinning the CSIS. Participants ranked customer satisfaction with planned and unplanned outages, overall customer satisfaction and customer satisfaction with new connections as their top three parameters.

Activity 2 was an online workshop, facilitated by TasNetworks. Participants were presented with a number of potential options for the CSIS based on the prioritised customer service measures before gauging their level of support for the proposed CSIS models, measures and targets. The responses from this session were considered in the proposed CSIS for submission.

Activity 3 was conducted via email and online survey to consult on the proposed CSIS and confirm that CSIS remains the preferred customer service incentive framework. There was insufficient feedback from Customer Council members to confirm TasNetworks' approach before submission of the Combined Proposal. TasNetworks will engage with the Customer Council on the CSIS in detail in 2023 to confirm the approach prior to submission of the Revised Proposal.

Table 3 summarises the topics and outcomes of each engagement activity, as well as the IAP2 level of audience influence.

Table 3. Customer Council engagement summary

	Activity 1 7 April 22	Activity 2 13 July 22	Activity 3 November 22
Number of participants	9	11	18
Topics covered	• Inform on STPIS and CSIS • Collaborate on potential customer service measures • Inform on Customer Panel results	• Inform on Activity 1 • Consult on design principles • Consult on combined Customer Panel and Customer Council short listed customer service measures • Inform on historical performance of short listed customer service measures • Collaborate on number of customer service parameters, potential targets and weighting	• Inform on Activity 2 • Consult on design principles and proposed CSIS framework for submission • Confirmation of CSIS as preferred customer service incentive framework
Outcomes	• Short list of prioritised customer service measures for CSIS • Support to proceed with CSIS framework and design	• Confirmed design principles • Agreed number of customer service parameters and approach to target setting • Further assessment of incentive rates	• Insufficient feedback (one survey response)

14.3 Proposed application of the CSIS

With the support of customers and stakeholders, TasNetworks proposes to adopt the CSIS for the 2024-2029 regulatory control period. The following section summarises TasNetworks' proposed application of the CSIS and how it meets the incentive design requirements. A detailed assessment of the proposed CSIS against section 3 of the AER's Final Customer Service Incentive Scheme is provided at Appendix 1.[3]

14.3.1 Performance parameters

TasNetworks consulted with customers and stakeholders on a set of principles to underpin the design of TasNetworks' CSIS. These agreed principles are:

- the CSIS should be easy to understand and measure
- a maximum of four performance parameters to allow for meaningful focus
- the cost to implement and administer the CSIS should be proportional to the incentive
- service parameter targets will be based on historical performance
- at least one parameter reflects end use customer preferences identified in the engagement process.

Customers and stakeholders engaged in discussions around services they valued and TasNetworks shared current customer service parameters that are measurable and controllable by the business. Customers and stakeholders prioritised these customer service parameters in order of perceived value and expressed preferences for a three-parameter model for the 2024-2029 regulatory control period.

The proposed performance parameters are:

- customer satisfaction with complaints handling
- customer satisfaction with outage management (planned and unplanned)
- customer satisfaction with new connections.

There was discussion with the Customer Council regarding whether customer satisfaction with new connections should be included, as it is not reflective of the day-to-day services that the entire customer base experiences and values. A further consideration is that connection services are not all standard control services and TasNetworks' does not identify customers by forms of control as part of our monthly customer satisfaction surveys.

The Customer Council provided strong feedback regarding the value of connection services to customers, irrespective of the form of control. TasNetworks agrees with the Customer Council that new connections is an important interaction between networks and customers and proposes to include

3 AER, Final Customer Service Incentive Scheme, July 2020

customer satisfaction with new connections as a CSIS performance parameter. However, a lower incentive rate is proposed for the connections parameter compared to the other CSIS parameters to reflect the smaller customer base accessing this service.

Other prioritised measures were not selected as they were duplications of existing incentive schemes or parameters, such as outage duration and overall customer satisfaction, or TasNetworks does not currently have sufficient information on performance to ensure meaningful customer outcomes, such as outage communication.

Overall, TasNetworks considers that the three proposed performance parameters address the broad needs and preferences of customers than the current telephone answering parameter of the STPIS.

14.3.2 Measurement methodology

TasNetworks joined an energy benchmarking research program run by Customer Service Benchmarking Australia (**CSBA**) in 2020. The program tracks, measures and compares customer experiences across Tasmanian, South Australian and Victorian electricity distributors.

Contact details of customers that have experienced TasNetworks' services are made available to CSBA at the end of each month to conduct independent customer satisfaction surveys. Results are grouped by service type and are made available anonymously to TasNetworks via an online portal.

TasNetworks will continue to engage CSBA, or other appropriate equivalent entities, to conduct independent customer satisfaction surveys to allow for ongoing measurement of customer satisfaction performance against the proposed parameters.

14.3.3 Assessment approach

TasNetworks has adopted feedback from customers and stakeholders into the assessment approach and proposes that:

- baseline performance will be calculated as the average of the most recent three years of performance measurements available
- the performance target for each parameter will be determined using TasNetworks' average three year performance, or the CSBA industry benchmarked average three year performance, whichever average reflects a better customer outcome
- targets will be re-evaluated prior to submission of TasNetworks' Revised Proposal with the most recent data, to ensure any performance improvements are reflected in the final determination and include an additional year of performance for the outage management parameter
- financial rewards will be applied if TasNetworks outperforms against the performance target in a single year in the regulatory control period (customer satisfaction score greater than the target)
- financial penalties will be applied if TasNetworks underperforms against the performance target in a single year in the regulatory control period (customer satisfaction score lower than the target).

Table 4 details TasNetworks' historical performance and average three year performance, the average three year industry benchmark from CSBA and the proposed performance targets for each of the performance parameters. TasNetworks proposes to adopt the highest target of either the 3-year average of TasNetworks' historical performance or the 3-year industry average benchmark for each of the CSIS targets, whichever is more demanding.

Table 4. Historical performance and proposed targets

	TasNetworks performance					
Parameter	**2019-20**	**2020-21**	**2021-22**	**3 year average**	**3 year average industry benchmark**	**Proposed CSIS target**
Customer satisfaction rating of complaints handling	6.55	6.78	6.65	**6.66**	5.40	6.66
Customer satisfaction rating of planned and unplanned outages*	No data	No data	7.85	**7.85**	7.43	7.85
Customer satisfaction with new connections	7.34	7.27	7.95	7.52	**7.74**	7.74

*TasNetworks currently has only one year of data for this parameter and will update with two years for the Revised Proposal

14.3.4 Financial component

14.3.4.1 Revenue at risk

TasNetworks proposed to customers and stakeholders that, if adopted for the 2024-2029 regulatory control period, the CSIS will replace the customer service component of the existing STPIS, which in the current regulatory period has been measured by the number of calls to the fault service centre answered in less than 30 seconds. This position was not disputed by customers and stakeholders. Therefore, TasNetworks proposes that +/- 0.5 per cent (or around $1.5 million) annual revenue at risk be applied to the CSIS. This is the same revenue at risk under the existing customer service parameter in the STPIS and ensures customers are not exposed to greater variations in revenue than is the case in the current regulatory control period.

14.3.4.1 Incentive rate calculations

TasNetworks engaged with the Customer Council on the incentive rates to apply for the CSIS. Table 5 presents what we heard and TasNetworks' responses to the Customer Council's feedback, while Table 6 presents the proposed incentive rates.

Table 5. Feedback from Customer Council on incentive rates

What we heard	What we are doing
Good customer service should be part of standard operations and incentives/penalties should sit within the business, not with customers.	TasNetworks has a commitment to caring for customers and making their experience easier, irrespective of financial incentives/penalties available. Not proceeding with the CSIS means the call service component of the STPIS would remain in place and while the answering of calls to TasNetworks' fault service centre is important, this single performance parameter does not capture other services that customer's value and want improved.
The incentive/penalty framework provides poorer outcomes for customers because if TasNetworks underperforms, customers experience poorer service outcomes but if TasNetworks performs, customers pay for "better" service.	Incentive schemes are part of the AER's approach for regulating monopoly electricity and gas networks in Australia to incentivise Network Service Providers to run efficient businesses so that customers pay no more than necessary for the services that they value the most. TasNetworks operates to the best of its ability within this framework, to ensure customers receive the best service TasNetworks can deliver.
Members of the Customer Council were not certain that an incentive rate within the ± 0.5% of revenue at risk would be sufficient to encourage TasNetworks' to improve its performance.	Under the proposed CSIS, TasNetworks will only receive an incentive payment when it makes measurable improvements in service areas that customers have told us that they value. Further, TasNetworks is not seeking additional funding to meet the proposed new performance targets. Consequently, we consider that the incentive rates reasonably balance the interests of customers with TasNetworks' commitment to target improvements in performance in the designated service areas.

Table 6. Proposed CSIS incentive rates

Parameter	Proposed Incentive rate (%)	Estimated financial incentive*
Customer satisfaction rating of complaints handling	0.01	$30,963
Customer satisfaction rating of planned and unplanned outages	0.01	$30,963
Customer satisfaction with new connections	0.005	$15,481

*For 0.01 improvement in customers satisfaction

Appendix 1: CSIS requirements assessment

3. Incentive Design

3.1 Incentive Design Criteria	TasNetworks response
1) The incentive design criteria are: a) The incentive design must calculate any revenue adjustment using the method set out in Appendix A unless the AER is satisfied that another approach will better achieve the scheme objectives.	TasNetworks' does not propose to vary from the method set out in Appendix A.
b) The incentive design must set out each of the scheme elements, which are: i) *Performance Parameters*, consisting of the metrics of customer service performance subject to the incentive design ii) *Measurement Methodology*, consisting of a description of how performance against the performance parameters will be measured and the assurance arrangements that will apply to the measurement iii) *Assessment Approach*, consisting of a performance target and a method for evaluating measured performance against performance targets iv) *Financial Component*, consisting of an overall revenue at risk, an amount of revenue at risk for each performance parameter, and a means of setting the incentive rate for each performance parameter.	Each of the scheme elements of the incentive design has been set out in section 14.3 of this attachment.
c) Each of the scheme elements must satisfy the corresponding principles outlined in clause 3.2.	The following section outlines how TasNetworks has satisfied the principles in clause 3.2.
d) Customers of the DNSP strongly support the application of the incentive design.	Customers and stakeholders expressed a preference for the CSIS when presented the choice of the CSIS or the existing customer service component of the STPIS.
e) The incentive design must not continue beyond the end of the DNSP's next regulatory period. For clarity, the AER may, at a regulatory determination, make a decision to apply an identical incentive design for a second time to a DNSP.	The CSIS outlined in this attachment is proposed to apply for the 2024-2029 regulatory control period.
f) The incentive design must place a valid amount of revenue at risk. The revenue at risk will be valid if, by default, the maximum revenue increment or decrement (the revenue at risk) for each performance parameter in aggregate for each regulatory year within the regulatory control period is 0.5% of the DNSP's annual revenue requirement or less. That is, the sum of the H-factors associated with all performance parameters must lie between +0.5% (the upper limit) and −0.5% (the lower limit).	TasNetworks CSIS Model demonstrates the sum of the H-factors associated with all performance parameters are between +0.5% and −0.5%.

3.2 Scheme Element principles	TasNetworks response
1) The relevant principles for performance parameters are that each performance parameter must be an aspect of the customer experience component of the DNSP's standard control services.	The two key performance parameters (customer satisfaction related to complaints handling and customer satisfaction related to planned and unplanned outages) are aspects of a customer experience of TasNetworks' standard control services. Customer satisfaction with new connections includes standard control services and alternate control services.
2) that the customers of the DNSP particularly value and want improved, as evidenced by genuine engagement with, and support from, the DNSP's customers: a) that is substantially within the control of the DNSP b) for which the DNSP does not already have an incentive under another incentive scheme or jurisdictional arrangement.	Feedback from customers and stakeholder engagement supported that the selected performance parameters reflected services that customers value and are within TasNetworks' control. TasNetworks does not have an incentive under another incentive scheme of jurisdictional arrangement for the selected performance parameters.
3) The relevant principles for measurement methodology are that for each performance parameter, the proposed measurement: a) accurately measures the features of the performance parameter identified in clause 3.2(1)(a) b) is sufficiently independent, in that it is either conducted by an independent third party or based upon an independently developed methodology c) is compiled in an objective and reliable manner with data retained in a secure and logically indexed database d) produces results that could be audited by an independent third party.	TasNetworks engages an independent third party to conduct surveys with customers who have recently experienced TasNetworks' service. Customers are asked several questions, one of which is customer satisfaction - "how would you rate your satisfaction with the overall experience?" The results are compiled by the service provider and grouped by service type before being made anonymously available to TasNetworks via an online portal.
4) The relevant principles for assessment approaches are that for each performance parameter; the incentive design: a) Establishes a baseline or neutral level of performance, which in normal circumstances should be at least equal to the historical performance of the DNSP b) Sets a performance target for each performance parameter that: i) incentivises genuine improvement in line with the value of the identified service improvement to the DNSPs customers ii) makes reference to the baseline or neutral level of performance established in clause 3(4)(a). c) Expresses the result of the assessment of measured performance against each performance target as a single value d) Creates a clear relationship between: i) outperformance of the performance target resulting in a reward under the incentive design ii) underperformance of the performance target and receiving a penalty under the incentive design.	TasNetworks CSIS Model demonstrates how the incentive design of the CSIS meets the requirements of this clause.

5) The relevant principles for the financial component are that, the incentive design provides rewards or penalties that: a) will increase relative to the degree of outperformance or underperformance, commensurate with the identified value of the service improvement to customers of the DNSP b) are commensurate with the service improvements or degradations observed in respect of the DNSP's distribution system c) are not likely to exceed the value that customers attribute to the level of service improvement observed d) are not likely to, when considered in aggregate with all incentives applied to the DNSP for customer service, (including incentives external to the incentive design), result in the incentives available to the DNSP relating to customer service exceeding the value customers attribute to that component of service e) in satisfying the requirements of clause 3.2(4)(a) and (c), the value that customers attribute to service improvements or degradations is established using a reasonable process that identifies the value that customers attribute to the level of service improvement or degradation observed, in that the process: i) is transparent ii) involves genuine consultation with the DNSP's customers. f) Will exclude in circumstances agreed between the distributor and its customers, giving effect to principles 4)a) to 4)e) inclusive.	TasNetworks CSIS Model demonstrates how the incentive design provides rewards or penalties that will increase relative to the degree of outperformance or underperformance. The performance parameters selected were those that customers and stakeholders prioritised as most valuable during the engagement process. TasNetworks has undertaken a comparative value assessment of these performance parameters against the existing call service component of the STPIS and proposed incentives proportional to outcomes that may be expected under the STPIS. We consider that the value attributed to these parameters reasonably balance the interests of customers with TasNetworks' commitment to target improvements in performance in the designated service areas and will continue to engage with customers and stakeholders on these in 2023.

3.3 Incentive design proposal requirements	TasNetworks response
1) As stated in clause 2.1(c), where a DNSP proposes an incentive design, to be applied this proposal must meet the incentive design proposal requirements. The incentive design proposal requirements are that a proposal must:	
a) Include an incentive design satisfying the incentive design criteria	Prior sections outline how TasNetworks has satisfied the incentive design criteria.
b) Include a submission setting out: i) how, in the view of the DNSP, the incentive design satisfies the requirements of clause 2(1)(a) and (b) ii) how the DNSP consulted with its customers and other stakeholders, covering the perspectives of different parts of its customer base, and how it reconciled the different preferences of customers in developing the scheme iii) definitions of performance parameters to be applied iv) a template with which the DNSP will annually report on its performance in accordance with each of the performance parameters to the AER v) a description of the measurement methodology and associated assurance processes vi) proposed performance targets and the data used to calculate these proposed performance targets vii) proposed incentive rates and an outline of how these were calculated viii) any proposed circumstances where the penalties and rewards are not applied (exclusions) in accordance with clause 3.2.4)f).	This clause is met by this attachment and TasNetworks' CSIS Model.
c) Be submitted with the DNSP's regulatory proposal, unless the AER grants approval to submit at an alternative time.	This clause is met by TasNetworks Combined Proposal.

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Combined Proposal 2024-2029

Attachment 15
Classification of services

Outline: This attachment to TasNetworks' Combined Proposal sets out proposed classifications and descriptions for the regulated services that TasNetworks will provide to customers, in its capacity as Tasmania's distribution network service provider, during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
> **Attachment 15**	**Classification of services**
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

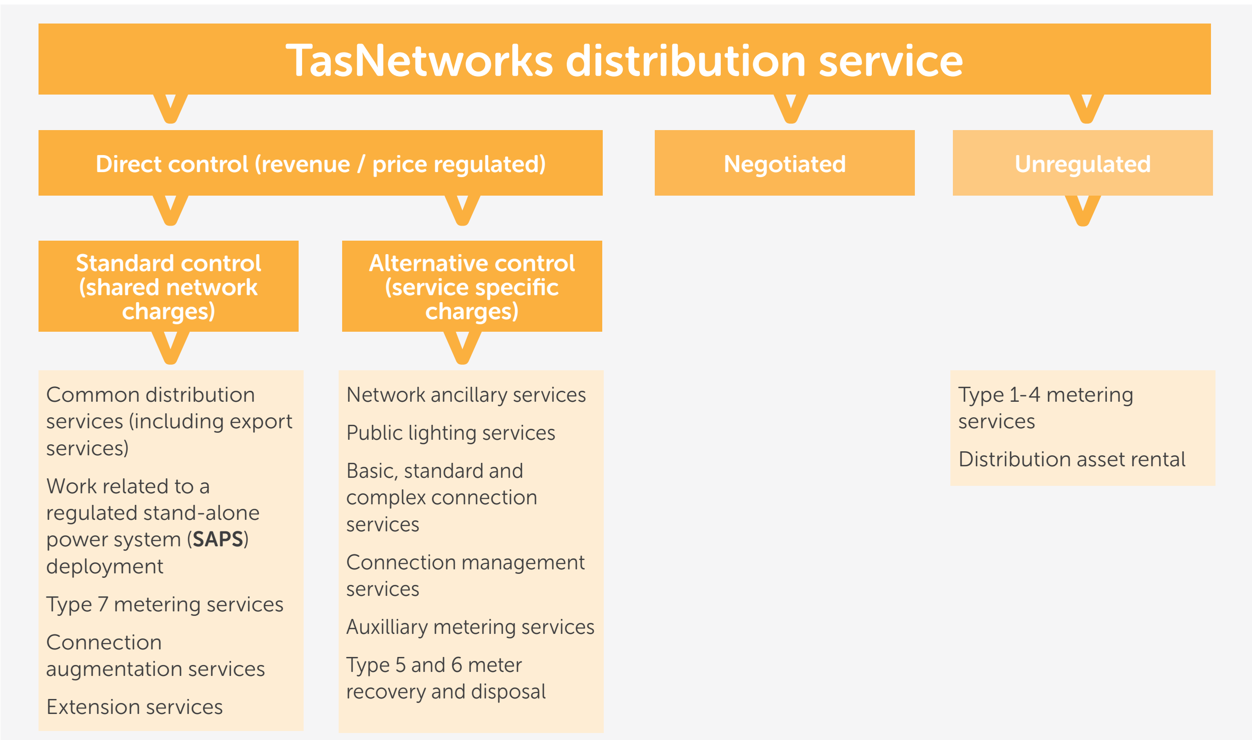
15 Classification of services

This attachment to TasNetworks' Combined Proposal sets out TasNetworks' proposed classifications and descriptions for the services that TasNetworks may provide to customers during the 2024-2029 regulatory control period. TasNetworks proposes to adopt the service classification as described in the Australian Energy Regulator's (**AER's**) Final Framework and Approach[1] with one exception.

The change TasNetworks proposes is to include an additional service, 'extensions', with the service a service classified as a standard control service. This is consistent with the service classification of extensions in TasNetworks' 2019-2024 regulatory control period. This departure from the Framework and Approach will provide clarity and continuity regarding the treatment of extension services for connection services and ensure consistency with TasNetworks' Distribution Connection Pricing Policy.

In developing its Combined Proposal for the 2024-2029 regulatory control period, TasNetworks has engaged with stakeholders under the assumption that extension services will continue to be classified as a standard control service. The change in classification proposed in the Framework and Approach will have detrimental customer impacts, as an alternative control service (**ACS**) classification does not allow an offset for the Incremental Revenue Rebate against the capital contributions made by customers towards the cost of an extension service. Therefore, connecting customers would be required to pay an amount greater than the incremental costs incurred by the remaining customer base. TasNetworks' proposal to continue classifying service extensions as standard control services will avoid this outcome.

Figure 1. Classification of distribution services in Tasmania, 2024-2029



Note: No current services have been classified as negotiated services for the 2024-2029 regulatory control period.
Source: *AER, Final Framework and Approach for TasNetworks for the 2024-29 regulatory control period,* July 2022, p. 6.
Details of the proposed classification are provided in Appendix 1.

1 *Framework and Approach, TasNetworks distribution and transmission (Tasmania), Regulatory control period commencing 1 July 2024,* Australian Energy Regulator, July 2022

In accordance with the Framework and Approach, TasNetworks proposes to group the distribution services provided as:

- common distribution services
- network ancillary services
- metering services
- connection services
- public lighting services
- unregulated distribution services.

Figure 1 summarises this approach and the forms of regulatory control to be applied to each service grouping.

Appendix 1:

Proposed classification of Tasmanian distribution services, 2024-2029[2]

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Common distribution services - use of the distribution network for the conveyance/flow of electricity (including services relating to network integrity)			
Common distribution services	The suite of activities that includes, but is not limited to, the following: • the planning, design, repair, maintenance, construction and operation of the distribution network • the relocation of assets that form part of the distribution network but not relocations requested by a third party (including a customer) • works to fix damage to the network[3] (including recoverable works caused by a customer or third party) • support for another network during an emergency event • procurement and provision of network demand management activities for distribution purposes • activities related to 'shared asset facilitation' of distributor assets[4] • emergency disconnections for safety reasons and work conducted to restore a failed component of the distribution system to an operational state upon investigating a customer outage • bulk supply point metering – activities relating to monitoring the flow of electricity through the distribution network • neutral integrity test – to identify the source of a fault following detection from a network issued device. Rectification work to render the network safe is limited to distribution network infrastructure.	Standard control	Standard control

2 The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and TasNetworks may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service

3 May include the provision of temporary stand-alone power systems to restore supply

4 Revenue for these services is charged to the relevant third party and is treated in accordance with the shared asset guideline. 'Shared asset facilitation' refers to administrative costs of providing the unregulated service

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029

Common distribution services	• rectification of simple customer faults relating to a life support customer or other critical health and safety issues the distributor is able to address
	• rectification of simple customer faults where:
	  - the need for rectification work is discovered in the course of the provision of distribution services
	  - the work performed is the minimum required to restore safe supply
	  - the work can be performed in less than thirty minutes and does not normally require a second visit
	• establishment and maintenance of National Metering Identifiers (**NMIs**) in market and/or network metering systems, and other market and regulatory obligations
	• inspection of private electrical works (not part of the shared network) required under legislation for safety reasons
	• private pole inspection as directed by the Tasmanian Government
	• supply abolishment of basic connections
	• work related to a regulated SAPS deployment, operation and maintenance (including fault and emergency repairs[5]), and customer conversion activities.
	Such services do not include a service that has been separately classified including any activity relating to that service.
		Standard control	Standard control

Network ancillary services – customer and third-party initiated services related to the common distribution service			
Design related services	Activities include: • provision of design information, design rechecking services in relation to connection and relocation works provided contestably • specialist services (which may involve design related activities and oversight/inspections of works), where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets • the provision of engineering consulting (related to the shared distribution network).	Alternative control	Alternative control

5 Includes simple customer fault rectification on generation service of regulated SAPS

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Access permits, oversight and facilitation	Activities include: • issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage • issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space • providing access to switch rooms, substations and other network equipment to a non-Local Network Service Provider party who is accompanied and supervised by a TasNetworks staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas • facilitation of generator connection and operation of the network • facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets.	Alternative control	Alternative control
Notices of arrangement and completion notices	Examples include: • Work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This includes: receiving and checking subdivision plans, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required and preparing notifications of arrangement • Provision of a completion notice (other than a notice of arrangement). This applies where the distributor is requested to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings.	Alternative control	Alternative control
Network related property services	Activities include: • Network related property services such as property tenure services relating to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with connection or relocation • Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer • Responding to inquiries from planning authorities to assess the works TasNetworks will need to undertake to give effect to the planning authority's planning applications.	Alternative control	Alternative control

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Network safety services	Examples include: • provision of traffic control and safety observer services by the distributor or third party where required • fitting of visual warning devices, such as tiger tails, and aerial markers • fitting of wildlife mitigation including possum guards and bird flappers • third party requests for de-energising wires for safe approach • high load escorts • customer requested network inspection undertaken to determine the cause of a customer outage where there may be a safety and/or reliability impact on the network or related component and associated works to rectify a customer caused impact on the network.[6]	Alternative control	Alternative control
Network tariff change requests	Activities including a retailer's customer or retailer requesting an alteration to an existing network tariff (for example, a change from a Block Tariff to a Time of Use tariff), requiring the distributor to conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. Where a distributor processes changes in its IT systems to reflect a tariff change request.	Alternative control	Alternative control
Services provided in relation to a Retailer of Last Resort (ROLR) event	The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For example: Preparing lists of affected sites and reconciling data with Australian Energy Market Operator (**AEMO**) listings, arranging estimate reads for the date of the ROLR event, preparing final invoices and miscellaneous charges for affected customers, extracting customer data, providing it to the ROLR and handling subsequent enquiries.	Alternative control	Alternative control
Customer requested network outage or rescheduling of a planned interruption	Examples include: • customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close or for safe approach) • where a customer requests the rescheduling of a planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours or at an alternative agreed time.	Alternative control	Alternative control
Attendance at customers' premises to perform a statutory right where access is prevented.	A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit.	Alternative control	Alternative control

6 An ACS charge is not applicable where it is determined the customer outage was caused by a fault on the network.

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Inspection and auditing services	Activities include: • inspection of and reinspection of gifted assets or assets that have been installed or relocated by a third party • investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship • auditing of a third party service provider's work practices in the field • re-test at a customer's installation, where the installation fails the initial test and cannot be connected • inspection of private electrical wiring work undertaken by an electrical contractor • inspection of privately owned low voltage or high voltage network infrastructure (i.e. privately owned distribution infrastructure located before the meter).	Alternative control	Alternative control
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network. Examples of training might include high voltage training, protection training or working near power lines training.	Alternative control	Alternative control
Authorisation and approval of third party service providers' design, work and materials	Activities include: • authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services) • acceptance of third party designs and works • assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor's approved materials list	N/A	Alternative control
Security lights	Provision, installation, operation and maintenance of equipment mounted on distribution equipment and used for security services, e.g. nightwatchman lights. Note: excludes connection services.	Alternative control	Alternative control
Customer initiated network asset relocations/re-arrangements	Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer).	N/A	Alternative control
Customer requested provision of electricity network data	Provision of data requested by customers or third parties, including requests for electricity network or consumption data outside of legislative obligations	N/A	Alternative control

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Third party funded network alterations or other improvements	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.	N/A	Alternative control
Metering services – activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters)			
Type 1 to 4 metering services	Type 1 to 4 metering installations[7] and supporting services are competitively available.	Not classified	Not classified
Type 5 and 6 meter maintenance, reading and data services (legacy meters)	Activities include: • Testing, inspecting, investigating, maintaining or altering existing type 5 or 6 metering installations or instrument transformers • Quarterly or other regular reading of metering installations including field visits and remotely read meters • Metering data services, including collection, processing, storage and delivery of metering data, the provision of metering data in accordance with regulatory obligations, remote or self-reading at difficult to access sites, and the management of related NMI Standing Data in accordance with the National Electricity Rules (**NER**).	Alternative control	Alternative control
Auxiliary metering services (Type 5 to 7 metering installations)	Activities include: • off-cycle meter reads for type 5 and 6 meters including move in and move out meter reading (type 5 and 6 meters) • type 5 meter final read on removed type 5 metering equipment • requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation • testing and maintenance of instrument transformers for type 5 and 6 metering purposes and type 5 to 7 non-standard metering services • works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site) • change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement • emergency maintenance of metering equipment not owned by the distributor (contestable meters).	Alternative control	Alternative control
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements.	Standard control	Standard control

7 Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Meter recovery and disposal – type 5 and 6 (legacy meters)	Activities include the removal and disposal of a type 5 or 6 metering installation.	N/A	Alternative control
Distributor arranged outage for purposes of replacing metering	At the request of a retailer or metering coordinator provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.	N/A	Alternative control
Connection services – services relating to the electrical or physical connection of a customer to the network[8]			
Basic connection services	Means a *connection service*[9] related to a *connection* (or a proposed connection) between a distribution system and a *retail customer's* premises (excluding a non-registered *embedded generator's* premises) in the following circumstances: (a) either: (1) the *retail customer* is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or (2) the *retail customer* is, or proposes to become, a *micro embedded generator* (b) the provision of the service involves minimal or no *augmentation*, or *extension*, of the *distribution network* (c) a *model standing* offer has been approved by the *AER* for providing that service as a *basic connection service*.	N/A	Alternative control
Standard connection services	Means a *connection service* related to a connection (or a proposed connection) between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances: (a) either: (1) the *retail customer* is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or (2) the retail customer is, or proposes to become, a *micro embedded generator*; and (b) the provision of the service involves extension of the *distribution* network but not *augmentation*; and (c) a *model standing offer* has been approved by the AER for providing that service as a *basic connection service*.	N/A	Alternative control

8 Applies to both NER chapter 5 and 5A connections

9 Italics denotes definitions in Chapter 5A of the NER

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Complex connection services	Means a *connection service* related to a connection (or a proposed connection) between a distribution system and a retail customer's premises in the following circumstances: (a) requires either an extension or augmentation and either: (1) the *retail customer* seeking the service requires the supply of electricity at high voltage or, if connected at low voltage, has maximum demand in excess of 70 kVA (or 25 kVA where a connection applicant's installation is supplied from the Single Wire Earth Return network); or (2) the *retail customer* is, or proposes to become, an embedded generator; or (3) the *retail customer* operates, or proposes to operate energy storage with the capacity to function as an *embedded generator* or community battery.	N/A	Alternative control
Connection augmentation services	Any shared network enlargement/enhancement undertaken by a distributor which is not an *extension*.	Standard control	Standard control
Extension	Extension is an enhancement required to connect a power line or facility outside the present boundaries of the distribution network owned or operated by a Network Service Provider	Standard control	Standard control
Negotiated connection services[10]	Means a *connection service* (other than a *basic connection service*) for which a DNSP provides a connection offer for a *negotiated connection contract*.	N/A	Alternative control
Enhanced connection services[11]	Other or enhanced connection services provided at the request of a customer or third party that include those that are: • provided with higher quality of reliability standards, or lower quality of reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance • in excess of levels of service or plant ratings required to be provided by the distributor.	N/A	Alternative control
Connection application and management services[12]	Works initiated by a customer or retailer which are specific to the connection point. This includes, but is not limited to: • connection application related services • connection point management services.	N/A	Alternative control

10 Applies to both NER chapter 5 and 5A connections

11 Applies to both NER chapter 5 and 5A connections and includes enhancements for both consumption and export services

12 Applies to both NER chapter 5 and 5A connection

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Connection administration services (formerly Site establishment services)	Activities include, but not limited to: • Connection establishment, including liaison with AEMO or market participants for the purpose of establishing NMIs in market systems, for new premises or for any existing premises for which AEMO requires a new NMI and for validation of and updating network load data. This includes processing and assessing requests for a permanently unmetered supply • Alteration, updating and maintenance of NMIs and their associated data in market systems • NMI extinction, processing requests by customers or their agents for permanent disconnection and the extinction of a NMI in market systems • Confirming or correcting metering or network billing information in market B2B or network billing systems, due to insufficient or incorrect information received from retailers or metering providers.	Alternative control	Alternative control
Construction/ augmentation of private assets as provider of last resort[13]	Specialist electrical contracting services provided under provider of last resort conditions. Activities include: • private pole installation • construction of private power lines • augmentation of existing private assets.[14]	N/A	Alternative control
Community network upgrades	Network enhancements requested by a collective of customers. Includes activities related to community requests to augment the network to enable higher PV exports, supply high levels of electric vehicle charging or underground existing overhead power lines for reasons of visual amenity.	N/A	Alternative control
Public lighting – lighting services provided in connection with a distribution network			
Public lighting	Includes the provision, construction and maintenance of public lighting and new/emerging public lighting technology.	Alternative control	Alternative control
Unregulated distribution services			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.).	Not classified	Not classified
Contestable metering support roles	Includes metering coordinator (except where the distributor is the initial metering coordinator), metering data provider and metering provider for meters installed or replaced after 1 December 2017.	Not classified	Not classified
Provision of training to third parties for non-network related issues	Training programs provided to third parties for non-network related issues.	Not classified	Not classified

13 Provision of these services is subject to the set of controls outlined on the TasNetworks website

14 Includes rectification of private asset defects

Service group/ activities included	Further description	Current classification 2019–2024	Proposed classification 2024–2029
Non-distribution services — Although this table relates to distribution services, we have included the below non-distribution services for clarity			
Operation and maintenance of isolated distribution networks not part of the NEM	The operation and maintenance of third party owned distribution networks not physically connected to the TasNetworks distribution network. e.g. Hydro Tasmania.	Non-distribution service	Non-distribution service

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Combined Proposal 2024-2029

Attachment 16
Control mechanisms

Outline: This attachment to TasNetworks' Combined Proposal sets out the proposed control mechanisms for TasNetworks' Standard Control Services and Alternative Control Services during the 2024-2029 regulatory control period, in TasNetworks' capacity as Tasmania's distribution network service provider.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	**Control mechanisms**
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

16 Control mechanisms

16.1 Introduction

The Australian Energy Regulator (**AER**) is responsible for regulating the revenues and/or prices of distribution network service providers (**DNSPs**) in the National Electricity Market (**NEM**). In its capacity as an economic regulator, the AER first classifies the distribution services that DNSPs provide, and then determines the control mechanisms for the revenue that DNSPs may earn and/or the prices they charge for each class of service.

Based on the AER's Final Framework and Approach Paper[1] this attachment sets out the control mechanisms that TasNetworks expects will apply to TasNetworks' regulated distribution services[2] in the 2024–2029 regulatory control period.

Under section 6.2.1 of the National Electricity Rules (**NER**) the AER may classify a distribution service provided by a DNSP as either a direct control service or a negotiated distribution service.[3]

16.1.1 Direct control services

Direct control services are those services for which the AER imposes controls over the prices or revenue recovered by DNSPs in relation to those services.

The control mechanisms available to the AER in relation to direct control services include price schedules, caps on the prices of individual services, revenue caps, weighted average price caps and combinations of the various mechanisms set out in the NER.[4] Clause 6.12.3(b) of the NER requires the form of control mechanisms applying to a DNSP's services to be set out by AER in a Framework and Approach paper.

16.1.2 Negotiated distribution services

TasNetworks does not currently provide any negotiated distribution services and is not proposing to do so in the 2024-2029 regulatory period.
Any emergent negotiations with Service Applicants regarding negotiated distribution services provided by TasNetworks will be undertaken in accordance with the negotiating framework provided at Attachment 19 of the Combined Proposal.

16.2 Standard control services

16.2.1 Revenue cap

Consistent with the AER's Framework and Approach, TasNetworks agrees that a revenue cap should continue to be the control mechanism for TasNetworks' standard control services in the 2024–2029 regulatory control period. The continued application of a revenue cap for standard control services promotes consistency between regulatory control periods for our customers.

Under a revenue cap form of control, the AER will set the total allowed revenue for TasNetworks' distribution network in each regulatory year of the 2024–2029 regulatory control period.

TasNetworks cannot recover more revenue in total from its customers in any given regulatory year than the annual revenue allowance set by the AER for that year. To comply with this requirement, TasNetworks will set its prices annually based on forecasts of variables such as customer numbers and their consumption of, and demand for, electricity, so that the expected revenue recovered in any given year will be equal to or less than the total revenue allowed for that year by the AER.

1 AER, *Final Framework and Approach for TasNetworks for the 2024-29 regulatory control period*, July 2022

2 This document does not address the control mechanism for TasNetworks' prescribed transmission services because the Rules (cl. 6A.3.1) require prescribed transmission services to be subject to a revenue cap

3 If the AER decides against classifying a distribution service, the service is not regulated under the NER

4 NER, cl. 6.2.5(b)

However, the differences between actual consumption and customer numbers in any given year, for example, and the forecasts that informed our price setting for that year can lead to an over or under recovery of TasNetworks' annual revenue allowance. Therefore, each year, TasNetworks reconciles the revenue recovered from customers for that year with our approved revenue allowance and adjusts prices in future years to account for any difference. In this way, any over or under recovery of revenue in relation to standard control services in any regulatory year will be either deducted from, or added to, TasNetworks' total revenue allowance in future regulatory years, and passed through to customers.

TasNetworks' annual revenue allowances also will be adjusted for the outcomes of the Service Target Performance Incentive Scheme (**STPIS**) and Customer Service Incentive Scheme (**CSIS**). The annual revenue allowance applying to TasNetworks' standard control services may also sometimes incorporate cost adjustments in recognition of the occurrence of 'pass through events' that are beyond our control, such as changes in regulated service standards, that result in a material increase or decrease in TasNetworks' costs.

For standard control services, NER section 6.2.6(a) requires that the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form.

The following formulae is the proposed control mechanism for TasNetworks' standard control services in the 2024-2029 regulatory control period.

Formula 1 - Revenue cap formula[5]

1	$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$	$i = 1, \ldots, n \text{ and } j = 1, \ldots, m \text{ and } t = 1,2,3,4,5$
2	$TAR_t = AAR_t + I_t + B_t + C_t$	$t = 1,2,3,4,5$
3	$AAR_t = AR_t$	$t = 1$
4	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$	$t = 2,3,4,5$

Where:

t	is the regulatory year with $t = 1$ being the 2024-2025 financial year.
TAR_t	is the total allowable revenue in year t.
p_t^{ij}	is the price of component 'j' of tariff 'i' for year t.
q_t^{ij}	is the forecast quantity of component 'j' of tariff 'i' for year t.
AR_t	is the annual smoothed revenue requirement in the Post Tax Revenue Model (**PTRM**) for year t.
AAR_t	is the adjusted annual smoothed revenue requirement for year t.
I_t	is the sum of incentive scheme adjustments for year t. To be decided in the distribution determination.
B_t	is the sum of annual adjustment factors to balance the unders and overs account for year t. To be decided in the distribution determination.
C_t	is the sum of approved cost pass-through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end-of-period adjustments for year t. To be decided in the distribution determination.
ΔCPI_t	is the annual percentage change in the Australian Bureau of Statistics (**ABS**) Consumer Price Index (**CPI**) All Groups, Weighted Average of Eight Capital Cities[6] from December in year $t - 2$ to December in year $t - 1$, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-1 divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t-2 minus one. For example, for the 2024-2025 year, t-2 is December 2022 and t-1 is December 2023.
X_t	is the X-factor in year , incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

5 All parameters are in nominal terms unless otherwise specified

6 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index

The B-factor (B_t) will include a true-up for:

- The net present value of under or over recovered revenue and will be calculated based upon the Distribution Use of System (**DUoS**) unders and overs account as specified in the AER's Annual Pricing Model which is issued to TasNetworks annually. This true-up will be calculated based upon the DUoS unders and overs account (Formula 2).
- The Electrical Safety Inspection Charge (Formula 3).
- The National Energy Market charge (Formula 4).

Under a revenue cap, TasNetworks' revenue in year t will be adjusted annually to true-up any under or over recovery of actual revenue collected through DUoS charges in year t-2 and any estimated under or over recovery of revenues in year t-1. In regulatory year 1, TasNetworks will base the level of this adjustment on the opening balance of the DUoS unders and overs account.

The true-up for any under or over recovery of actual revenue collected through DUoS charges are calculated using the following method.

Formula 2 – DUoS unders and overs true-up

$$DUoS\ unders\ and\ overs\ true-up_t = -(Opening\ balance_t)(1+WACC_t)^{0.5}$$

Where:

$DUoS\ unders\ and\ overs\ true-up_t$	Is the true-up for the balance of the DUoS unders and overs account in year t.
$Opening\ balance_t$	Is the opening balance of the DUoS unders and overs account in year t.
$WACC_t$	Is the approved weighted average cost of capital use in regulatory year t in the DUoS unders and overs account.

Formula 3 – True-up for the Electrical Safety Inspection Service charge

TasNetworks will continue to apply the true-up for the Electrical Safety Inspection Service Charge (**ESISC**). The formula for the ESIS charge is:

$$ESISC = (ESISCa_{t-1} - ESISCe_{t-1}) \times (1 + Nominal\ vanilla\ WACC)$$

Where:

$ESISCa_{t-1}$	Is the actual ESISC for year $t-1$.
$ESISCe_{t-1}$	Is the estimated ESISC for year $t-1$ as per the amount to be set in the final distribution determination.
$Nominal\ vanilla\ WACC$	is the approved nominal weighted average cost of capital (**WACC**) for the relevant regulatory year, calculated as follows: $Nominal\ vanilla\ WACC_t = ((1 + real\ vanilla\ WACC_t) \times (1 + \Delta CPI_t)) - 1$ Where the $real\ vanilla\ WACC_t$ is as set out in our final decision PTRM and updated annually.
ΔCPI_t	Is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[7] from the December quarter in year $t-2$ to the December quarter in year $t-1$, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t – 1 divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t – 2 Minus one For example, for the 2024-2025 year, t-2 is December 2022 and t-1 is December 2023

7 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index

Formula 4 – True-up for the National Electricity Market charge

TasNetworks will continue to apply the true-up for the National Electricity Market Charge (**NEMC**). The formula for the NEMC is:

$NEMC_t = (NEMCa_{t-1} - NEMCe_{t-1}) \times (1 + Nominal\ vanilla\ WACC_t)$

Where:

$NEMCa_{t-1}$	Is the actual NEMC for year .
$NEMCe_{t-1}$	Is the estimated NEMC for year as per the amount to be set in the final distribution determination.
$Nominal\ vanilla\ WACC_t$	is the approved nominal weighted average cost of capital (WACC) for the relevant regulatory year, calculated as follows: $Nominal\ vanilla\ WACC_t = ((1 + real\ vanilla\ WACC_t)\ x\ (1 + \Delta CPI_t)) - 1$ Where the $real\ vanilla\ WACC_t$ is as set out in our final decision PTRM and updated annually.
ΔCPI_t	Is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[8] from the December quarter in year to the December quarter in year, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year $t - 1$ divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year $t - 2$ Minus one For example, for the 2024-2025 year, t-2 is December 2022 and t-1 is December 2023.

16.2.2 Side constraints[9]

The below formula sets out the side constraints formula. For each regulatory year after the first year of a regulatory control period, side constraints apply to the weighted average revenue raised from each tariff class. In accordance with the NER, the permissible percentage increase is the greater of CPI-X plus 2 per cent or CPI plus 2 percent.[10] Recovery of certain revenues, such as those to accommodate pass throughs, is disregarded in deciding whether the permissible percentage has been exceeded.[11]

8 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index

9 All parameters are in nominal terms unless otherwise specified

10 NER, clause 6.18.6(c)

11 NER, clause 6.18.6(d)

Formula 5 – Side constraint formula

1.	$PP_t \geq \frac{SCR_t}{SCR_{t-1}}$
2.	$PP_t = \big((1 + \Delta CPI_t) \times (1 - X_t) \times (1 + 2\%) - 1\big) \times D_t + AA_t + Q_t + 1$
3.	$SCR_t = \sum_{i=1}^{m}\sum_{j=1}^{n} p_t^{ij} q_t^{ij}$
4.	$SCR_{t-1} = \sum_{i=1}^{m}\sum_{j=1}^{n} p_{t-1}^{ij} q_t^{ij}$
5.	$D_t = \frac{AAR_{t-1}}{SCR_{t-1}}$
6.	$AA_t = \frac{(I_t + C_t + B_t) - (I_{t-1} + C_{t-1} + B_{t-1})}{SCR_{t-1}}$
7.	$Q_t = \left(\frac{TAR_{t-1}}{SCR_{t-1}} - 1\right)$

Where each tariff class has "n" tariffs, with each up to "m" components, and where:

PP_t	Is the permissible percentage for year t, calculated as per formula 2 above.
SCR_t	Is the side constraint revenue for year t, calculated as the sum of the products of proposed prices and forecast quantities for year t, calculated as per formula 3 above.
SCR_{t-1}	Is the side constraint revenue for year $t - 1$, calculated as the sum of the products of prices charged for year and forecast quantities for year $t - 1$, calculated as per formula 4 above.
ΔCPI_t	Is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[12] from the December quarter in year to the December quarter in year $t - 2$, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t – 1 divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t – 2 Minus one For example, for the 2024-2025 year, t-2 is December 2022 and t-1 is December 2023
X_t	Is the X factor for each year of the regulatory control period as determined in the post-tax revenue model, and annually revised for the return of debt update. If $X > 0$, then X will be set equal to zero for the purposes of the side constraint formula.
2%	Is the additional threshold defined in the NER.
D_t	Is the adjustment made to the base threshold to create a common base, calculated as per formula 5 above.
AA_t	Is the annual percentage change in the sum of all annual adjustment factors (I, C, and B factors). This is calculated by dividing the total incremental revenues (the difference between the factors used in the total annual revenue formula for the regulatory year and) by the expected revenues for the year $t - 1$ (SCR_{t-1}). This calculation is provided at formula 6 above.
Q_t	Is the adjustment made each year to account for changes in quantities from the preceding year. The factor calculation is provided at formula 7 above.

12 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index

p_t^{ij}	Is the proposed price for component '*j*' of tariff '*t*' for year *t*.
q_t^{ij}	Is the forecast quantity for component '*j*' of tariff '*t*' for year *t*.
$p^i t\text{-}1^j$	Is the price charged for component '*j*' of tariff '*t*' for year *t – 1*.
AAR_{t-1}	Is the adjusted annual revenue requirement for year *t – 1* , as used in the revenue cap price control formulae in the preceding and current years.
I_{t-1}	Is the sum of incentive scheme adjustments in year *t* .
C_{t-1}	Is the sum of approved cost pass through amounts (positive or negative) in year *t*, as determined by the AER. It will also include any end-of-period adjustments to be made in year *t*.
B_{t-1}	Is the sum of annual adjustment factors for year *t*. It includes adjustments to balance the unders/overs account, relating to previous under/over-recoveries of revenue.
I_{t-1}	Is the sum of incentive scheme adjustments in year t-1. This is as per the approved *t – 1* pricing proposal.
C_{t-1}	Is the sum of approved cost pass through amounts (positive or negative) in year *t – 1*, as determined by the AER. This is as per the approved *t – 1* pricing proposal.
B_{t-1}	Is the sum of annual adjustment factors for year t. It includes adjustments to balance the unders/overs account, relating to previous under/over-recoveries of revenue. This is as per the approved *t – 1* pricing proposal. For the avoidance of doubt, the B factor for *t – 1* should be equal to that used to calculate *t – 1* revenue in the previous pricing proposal and should not be updated for movements in the unders/overs accounts in the year *t – 1* pricing proposal.
TAR_{t-1}	Is the total allowable revenue for year *t – 1*, calculated using the revenue cap control formula in the preceding year.
t	Is the forecast regulatory year.

16.3 Alternative control services

In its Framework and Approach Paper, the AER decided to apply a cap on the prices of individual services as the form of control mechanism for TasNetworks' alternative control services, which maintains the pricing approach applying to the current regulatory control period. TasNetworks accepts the AER's decision, as well as the formulas set out in the Framework and Approach paper that give effect to price caps for:

- type 5 and 6 metering services (legacy meters)
- public lighting services
- fee based ancillary services
- quoted ancillary services

Prices for quoted ancillary services will vary based on quantities of labour and the materials involved with provision of the relevant service. Therefore, our proposed price cap formula for quoted services differs to that proposed to apply to metering, public lighting and fee-based services. This is consistent with the approach TasNetworks has adopted in the current regulatory control period.

Following are TasNetworks' proposed control mechanisms for alternative control services in the 2024—2029 regulatory control period.

16.3.1 Price cap formula for legacy metering, public lighting and fee based ancillary services

$$\bar{p}_t^i \geq p_t^i \qquad i = 1,\ldots, n \text{ and } t = 1, 2, 3, 4, 5$$

$$\bar{p}_t^i = \bar{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i \qquad i = 1,\ldots, n \text{ and } t = 1, 2, 3, 4, 5$$

Where:

$\bar{p}_t^i$	is the cap on the price of service 'i' in year t.
p_t^i	is the price of service 'i' in year t. The initial value is to be decided in the distribution determination.
$\bar{p}_{t-1}^i$	is the cap on the price of service 'i' in year t–1.
t	is the regulatory year, with t = 1 being the 2024–2025 financial year.
ΔCPI_t	is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[13] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1 divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2 minus one. For example, for the 2024–2025 year, t–2 is December 2022 and t–1 is December 2023.
X_t^i	is the X factor for service 'i' in year t. The X factors are to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.
A_t^i	is the sum of any adjustments for service 'i' in year t. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

13 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index

16.3.2 Price cap formula to apply to TasNetworks' quoted services

TasNetworks is required to provide itemised quotes to customers prior to them consenting to the provision of a quoted ancillary service.

$$Price = Labour + Contractor\ Services + Materials + Margin + Tax$$

Where:

$Labour$	consists of all labour costs directly incurred in the provision of the service, which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1 + \Delta CPI_t)(1 - X_t^i)$
ΔCPI_t	is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[14] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method: The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1 divided by The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2 minus one. For example, for the 2024–2025 year, t–2 is December 2022 and t–1 is December 2023.
X_t^i	is the X factor for service i in year t. The X factor is to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.
$Contractor\ services$	reflects 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.
$Materials$	reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.
$Margin$	a regulated profit margin set by the AER and added to quoted service pricing to ensure that the prices paid by customers are reasonable and efficient, but not anti-competitive. A margin of 5.93 per cent – the average Weighted Average Cost of Capital forecast to apply to TasNetworks over the 2024–2029 regulatory control period – will be applied to the sum of Labour, Contractor Services and Materials costs, before the application of tax.
Tax	Tax is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, netting off the net present value of the reverse cash flow resulting from any income tax deduction (including depreciation) of the capital contribution.

14 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index

TasNetworks

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Combined Proposal 2024-2029

Attachment 17
Pass through events

Outline: This attachment to TasNetworks' Combined Proposal sets out the additional nominated pass through events proposed by TasNetworks for the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' regulatory proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	**Pass through events**
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

17 Pass through events

17.1 Introduction

The National Electricity Rules (**NER**) recognise that a network service provider (**NSP**) cannot reasonably be expected to forecast costs for major events beyond its control that could potentially occur during a regulatory control period.

The regulatory framework addresses this issue by including a cost pass through mechanism within Chapters 6 and 6A of the NER. Under the pass through mechanism, NSPs can seek the Australian Energy Regulator's (**AER's**) approval to recover the costs (or pass through the savings) in excess of a 'materiality' threshold, that are related to the occurrence of defined, unpredictable and high cost exogenous event(s) for which a determination does not provide a regulatory allowance.

To this end, the NER prescribes a number of pass through events that apply to all distribution determinations, as well as a range of pass through events applying to transmission determinations (see *Regulatory requirements*, below). These prescribed events ensure that NSPs do not face significant, irrecoverable costs arising from, among other things, occurrences such as unexpected regulatory changes or changes in the service standards applying to network services.

In addition to the pass through events specified in the NER, NSPs also can nominate additional pass through events through the revenue and regulatory proposals they submit to the AER. Most NSPs have used this provision within the NER to nominate incidents and occurrences such as acts of terrorism or natural disasters as pass through events, and the AER has accepted those nominations on the basis that NSPs cannot reasonably be expected to mitigate or avoid those events or insure against them.

Therefore, in addition to the pass through events specified in the NER, TasNetworks proposes the following additional pass through events for the 2024–2029 regulatory control period:

- insurance coverage event (transmission and distribution)
- terrorism event (transmission and distribution)
- natural disaster event (transmission and distribution)
- insurer credit risk event (transmission and distribution)
- Australian Energy Market Operator (**AEMO**) participant fee structure event (distribution)
- Renewable Energy Zone design report (transmission).

Each of the pass through events proposed by TasNetworks is consistent with the nominated pass through event considerations (defined in the NER) that the AER must consider when deciding whether to accept a pass through event proposed by an NSP.

The approval by the AER of the pass through events nominated by TasNetworks will not expose customers to additional costs through their network charges during the 2024-2029 regulatory control period, unless those events occur and the AER approves a cost pass through application from TasNetworks.

Each additional pass through event nominated by TasNetworks is discussed further in section 17.3.

17.2 Regulatory requirements

Clause 6.6.1 of the NER specifies that a pass through event for a distribution determination is any of the following:

- a 'regulatory change event'
- a 'service standard event'
- a 'tax change event'
- a 'retailer insolvency event'
- any other event specified in a distribution determination as a pass-through event for the determination.

Clause 6A.7.3 of the NER specifies that a pass through event for a transmission determination is any of the following:

- a 'regulatory change event'
- a 'service standard event'
- a 'tax change event'
- an 'insurance event'
- any other event specified in a transmission determination as a pass-through event for the determination
- an 'inertia shortfall event'
- a 'fault level shortfall event'.

Under the NER, TasNetworks can request in its regulatory proposal for the 2024–2029 regulatory control period, the inclusion of additional pass through events (see NER clauses 6.5.10(a), 6.6.1(a1)(5), 6A.6.9(a) and 6A.7.3(a1)(5)) in its determination having regard to the *nominated pass through event* considerations in Chapter 10.

The *nominated pass through event considerations* are defined in Chapter 10 of the NER as:

(a) whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to(4) (in the case of a distribution determination) or clause 6A.7.3(a1)(1) to(4) (in the case of a transmission determination)

(b) whether the nature or type of event can be clearly identified at the time the determination is made for the service provider

(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event

(d) whether the relevant service provider could insure against the event, having regard to:

  (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or

  (2) whether the event can be self-insured on the basis that:

    (i) it is possible to calculate the self-insurance premium

    (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services

(e) any other matter the AER considers relevant and which the AER has notified Network Service Providers is a nominated pass through event consideration.

17.3 Proposed additional pass through events

TasNetworks proposes the following additional pass-through events for the 2024-2029 regulatory control period:

- insurance coverage event
- terrorism event
- natural disaster event
- insurer credit risk event
- AEMO participant fee structure event
- Renewable Energy Zone design reports event.

Definitions for each nominated pass-through event and TasNetworks' reasons for proposing them are set out in the sections below.

17.3.1 Insurance coverage event

TasNetworks proposes a pass through event for an 'insurance coverage event' defined as follows:

An insurance coverage event occurs if:

1. TasNetworks:

(a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy (in whole or in part) or set of insurance policies; or

(b) would have been able to make a claim or claims under a relevant insurance policy (in whole or in part) or set of insurance policies but for changed circumstances;

2. TasNetworks incurs costs:

(a) both within and beyond the relevant policy limit or set of insurance policies; or

(b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and

3. The costs referred to in point 2 above materially increase the costs to TasNetworks in providing direct control or prescribed transmission services.

For this insurance coverage event:

- *'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of TasNetworks, where those movements mean that it is not possible for TasNetworks to take out an insurance policy (in whole or in part) or set of insurance policies at all, or on reasonable commercial terms, that include some or all of the costs referred to in paragraph 2 above, within the scope of that insurance policy or set of insurance policies.*
- *'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:*
  - *the claimable component up to the limit not been exhausted; or*
  - *those costs not been unrecoverable due to changed circumstances.*
- *a relevant insurance policy is an insurance policy (in whole or in part) or set of insurance policies held during the 2024–2029 regulatory control period or a previous regulatory control period in which TasNetworks was regulated.*
- *TasNetworks will be deemed to have made a claim on a relevant insurance policy (in whole or in part) or set of insurance policies if the claim is made by a related party of TasNetworks in relation to any aspect of TasNetworks' network or business.*

In assessing a cost pass through application for an insurance coverage event, the AER has said in recent determinations it will have regard to.:[1]

- the relevant insurance policy or set of insurance policies for the event
- the level of insurance that an efficient and prudent NSP would obtain, or would have sought to obtain, in respect of the event
- any information provided by TasNetworks to the AER about TasNetworks' actions and processes.

In support of this proposed pass through event, TasNetworks notes that:

- an insurance coverage event is not covered already by any of the categories of pass through events specified in the NER for distribution or transmission networks
- this type of event can be clearly identified
- TasNetworks cannot prevent this type of event from occurring (i.e., it is an outcome arising from conditions in the general insurance market and the requirement for TasNetworks to obtain a prudent level of insurance having regard to major network and business risk factors) and cannot substantially mitigate the cost impacts of this type of event (both prior to and after the occurrence of this type of event)
- TasNetworks cannot obtain appropriate insurance on reasonable commercial terms covering costs that exceed its policy limits
- the occurrence of a particular insurance coverage event has a low probability of occurrence but a high financial consequence or magnitude.

17.3.2 Terrorism event

TasNetworks proposes a pass through event for a 'terrorism event' defined as follows:

Terrorism event means 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*
- *materially increases the costs to TasNetworks in providing direct control services and/or, prescribed services.*

In assessing a pass through application for a terrorism event, the AER has said in recent determinations it will have regard to:[2]

- whether TasNetworks has insurance against the event
- the level of insurance that an efficient and prudent NSP would obtain in respect of the occurrence of the event.

In support of this proposed pass through event, TasNetworks notes that:

- a terrorism event is not already covered by any of the categories of pass through events specified in the NER
- this type of event can be clearly identified
- TasNetworks cannot prevent this type of event from occurring and cannot substantially mitigate the cost impacts of this type of event (both prior to and after the occurrence of the event)

1 AER, Powerlink Queensland Transmission Determination 2022 to 2027 (1 July 2022 to 30 June 2027), Final Decision, p 85

2 AER, AusNet Services Transmission Determination 2022 to 2027, Final Decision, Attachment 13 Pass through events, p 13-7

- TasNetworks cannot obtain appropriate insurance on reasonable commercial terms covering the full range of costs that could potentially be incurred as a result of the occurrence of this type of event
- the occurrence of a particular terrorism event has a low probability of occurrence but a high financial consequence or magnitude.

17.3.3 Natural disaster event

TasNetworks proposes a pass through event for a 'natural disaster event' defined as:

> *Natural disaster event means any natural disaster (including but not limited to cyclone, fire, flood or earthquake) that occurs during the 2024–2029 regulatory control period that increases the costs to TasNetworks of providing direct control and, or, prescribed services, provided the cyclone, fire, flood, earthquake or other event was:*
>
> - *a consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement or with an applicable regulatory instrument; or*
> - *not a consequence of the negligent acts or omissions of the service provider.*

In assessing a cost pass through application for a natural disaster event, the AER has said in recent determinations it will have regard to:[3]

- whether TasNetworks has insured against the event
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

In support of this proposed pass through event, TasNetworks notes that:

- a natural disaster event is not already covered by any of the categories of pass through events specified in the NER
- this type of event can be clearly identified
- TasNetworks cannot prevent this type of event from occurring and cannot substantially mitigate the cost impacts of this type of event (both prior to and after the occurrence of the event)
- TasNetworks cannot obtain appropriate insurances on reasonable commercial terms covering the full range of costs that could potentially be incurred as a result of the occurrence of this type of event
- the occurrence of a particular natural disaster event has a low probability of occurrence but a high consequence or magnitude.

17.3.4 Insurer credit risk event

TasNetworks proposes a pass through event for an 'insurer credit risk event'. This event is triggered where TasNetworks' insurer becomes insolvent and TasNetworks is subject to higher or lower costs, a higher or lower claims limit or a higher or lower deductible than those allowed under its insurance policy with that insurer. The proposed definition of an insurance credit risk event is:

> *An insurer credit risk event occurs if an insurer of TasNetworks becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, TasNetworks:*
>
> - *is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*
> - *incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*

In assessing a cost pass through application for an insurer credit risk event, the AER has said in recent determinations it will have regard to:[4]

- TasNetworks' attempts to mitigate and prevent the event from occurring, by reviewing and considering the insurer's track record, size, credit rating and reputation prior to taking out the relevant insurance policy
- if a claim would have been covered by the insolvent insurer's policy, whether TasNetworks had reasonable opportunity to insure the risk with a different provider.

In support of the acceptance of this proposed pass through event, TasNetworks notes that:

- an insurer credit risk event is not already covered by any of the categories of pass through events specified in the NER
- this type of event can be clearly identified
- TasNetworks cannot prevent this type of event from occurring and cannot substantially mitigate the cost impacts of this type of event (both prior to and after the occurrence of the event)
- TasNetworks cannot obtain appropriate insurance on reasonable commercial terms covering the occurrence of this type of event
- the occurrence of a particular insurer credit risk event has a low probability of occurrence but a high financial consequence or magnitude.

3 AER, Powerlink Queensland Transmission Determination 2022 to 2027 (1 July 2022 to 30 June 2027), Final Decision, pp 85-86

4 AER, Powerlink Queensland Transmission Determination 2022 to 2027 (1 July 2022 to 30 June 2027), Final Decision, p 86

TasNetworks submits that the occurrence of increased insurance premiums (or deductibles) from external insurers (where the original insurer becomes insolvent) is beyond its control. Higher insurance premiums also are beyond the control of TasNetworks in that they cannot be reasonably mitigated.

17.3.5 AEMO participant fee structure event

TasNetworks is proposing a pass through event for an 'AEMO participant fee structure event', which would be triggered by a change in AEMO's electricity market participant fee structure that leads to an allocation of AEMO's core NEM function costs to DNSPs.

AEMO recovers its budgeted revenue requirements from market participants within the NEM. Under the NER, AEMO has the power to recover market fees only from registered participants. The NER require AEMO to publish a structure setting out how its budgeted revenue is to be recovered through participant fees. AEMO determines the allocation of participant fees every five years, with the actual amounts charged determined on an annual basis, via the AEMO budgeting process.

As part of AEMO's most recent review of its electricity market participant fee structure, AEMO initially proposed[5] that it would introduce an allocation of its core NEM function costs to both transmission network service providers (**TNSPs**) and distribution network service providers (**DNSPs**). In its final determination[6] of the electricity fee structures to apply to participant fees from 1 July 2021, AEMO adopted the proposal from its Draft Report to recover costs from TNSPs. As AEMO had also proposed, the commencement of allocations to TNSPs was delayed by two years, and will commence from 1 July 2023, to provide time for TNSPs to seek the transitional arrangements needed to recover the fees.

It was determined that DNSPs would not be charged participant fees. However, not unlike the cost pass through arrangements applying to TNSPs and DNSPs, the NER allows for AEMO to determine a separate fee to recover the costs of specific projects (declared NEM projects) during the term of a participant fee structure determination. Accordingly, in the final determination of its electricity fee structure for the period from 1 July 2021 to 30 June 2026, AEMO indicated that DNSPs' involvement with AEMO's systems and processes would be monitored throughout the next fee period. Should there be a material increase in the level of that involvement, AEMO flagged that it will consider a declared NEM fee project consultation process to recover those costs from DNSPs.

The potential introduction of participant fee allocations for DNSPs mid-way through TasNetworks' next regulatory control period creates a step change risk for TasNetworks and its customers, should a direct pass-through mechanism not be allowed as part of the AER's regulatory determination for the 2024-2029 regulatory control period. TasNetworks therefore is proposing that an AEMO participant fee structure event be a nominated pass through event in TasNetworks' 2024-2029 regulatory control period. The proposed definition of an AEMO participant fee structure event is:

> *An AEMO participant fee structure event occurs if AEMO makes a determination in relation to its electricity market participant fee structure that requires DNSPs to contribute to the recovery of AEMO's core NEM function costs during the 2024–2029 regulatory control period, increasing the costs to TasNetworks of providing direct control services.*

In support of the acceptance of this proposed pass through event, TasNetworks notes that:

- TasNetworks' distribution annual revenue allowances for the 2024-2029 regulatory control period will not include the recovery of market fees paid to AEMO because no such obligation currently exists in relation to the provision of standard control services by DNSPs within the NEM
- a change in AEMO's participant fee structure is not already covered by the categories of pass through events specified in the NER
- this type of event can be clearly defined and identified
- TasNetworks cannot prevent this type of event from occurring and cannot substantially mitigate the cost impacts of this type of event (either prior to or after the occurrence of such an event)
- TasNetworks cannot obtain appropriate insurances on reasonable commercial terms covering the costs that could potentially be incurred as a result of the occurrence of this type of event.

5 Electricity Fee Structure Draft Report and Determination, AEMO, November 2020

6 Electricity Fee Structures Final Report and Determination, AEMO, March 2021

17.3.6 Renewable Energy Zone design report event

TasNetworks proposes a new pass through event for the 2024-2029 regulatory control period, to enable the costs incurred by TasNetworks in the preparation of Renewable Energy Zone (**REZ**) design reports to be recovered through the AER approved pricing methodology applying to TasNetworks' prescribed transmission services. The pass through event would be triggered by a request from AEMO for TasNetworks to prepare a design report for a REZ in Tasmania, made through the release of an Integrated System Plan (**ISP**) or updated ISP.

In 2021, the Energy Security Board (**ESB**) developed a set of changes[7] to the NER to support the design of REZs. The planning rules devised by the ESB built on previous changes to the NER designed to co-ordinate and optimise transmission and generation investment within the NEM, which had created the ISP framework and made them actionable.

As a result, REZs are subject to a special planning regime,[8] which includes the preparation of REZ design reports by Jurisdictional Planning Bodies. In most regions of the National Electricity Market the Jurisdictional Planning Body is also the local TNSP and TasNetworks is the Jurisdictional Planning Body for Tasmania. Under those arrangements, if an ISP requires a design report to be prepared for a REZ in Tasmania, TasNetworks must commence the preparation of the report as soon as practicable, or in accordance with the timeframes specified in the ISP.

AEMO has identified several potential REZs and offshore wind zones (**OWZ**) across the NEM. Three of those REZs and one OWZ are in Tasmania. As part of REZ development, under Clause 5.24.1 of the NER AEMO can require a jurisdictional planner to develop a REZ design report. A REZ design report is a significant planning exercise that considers the design, route and construction costs of the transmission infrastructure that would be required to connect new generation within a REZ to the power system.

If the requirement for the production of a REZ design report is known at the time of a revenue determination, the estimated costs of preparing that report can be included as part of a TNSP's operating expenditure in its revenue proposal. However, the requirement to produce a REZ design report during an upcoming regulatory control period and the timing of that work may not be known sufficiently in advance of a revenue determination for this to be possible.

ISPs are published by AEMO biennially. One ISP is due to be finalised in 2024, just before the start of TasNetworks' next regulatory control period, and two ISPs are due for release in 2026 and 2028 during TasNetworks' next regulatory control period. The obligation to prepare a REZ design report can also arise through the release of updated ISPs.

It is not expected that AEMO will require TasNetworks to commence preparation of a REZ design report prior to TasNetworks submitting its 2024-2029 revenue proposal. However, it is reasonably likely that TasNetworks will be required to produce one or more REZ design reports during the 2024-2029 regulatory control period, and that the obligation to do so will not be known in time for the costs of producing the report(s) to be factored in to TasNetworks' revenue allowance for that regulatory control period. Without the provision of a pass through mechanism, this would leave TasNetworks unable to recover the costs involved in the preparation of those reports.

The ESB recommended[9] that in the case of requirements to produce REZ design reports that are not known about at the time of a revenue determination, the cost pass through framework could be used by TNSPs to nominate unanticipated REZ design reports as a category of pass through event. Consistent with the ESB's recommendation, TasNetworks is nominating the preparation of a REZ design report event as a pass through event for the 2024-2029 regulatory control period.

Given that the requirement to undertake a REZ design report during the 2024-2029 regulatory control period is uncertain, including a 'REZ design report event' as a nominated pass through event will provide some protection for TasNetworks from the risk of unrecoverable expenditure, while at the same time ensuring that customers will only bear additional cost if AEMO requires a REZ design report to be produced. TasNetworks considers this approach to be more efficient and equitable than providing an upfront allowance in our building block costs for the preparation of REZ design reports that at the time of TasNetworks' next revenue determination are yet to be commissioned.

However, even with a nominated pass through event in place for REZ design reports that have not been funded through the revenue determination process, it is possible that TasNetworks could incur significant costs in preparing a report and still be unable to recover those costs, if the costs incurred in a given year are insufficient to qualify the report's preparation as a positive change event. This would particularly be the case if the preparation of a REZ design report and, therefore, its cost, is spread across more than one regulatory year.

7 Renewable Energy Zones planning final recommendations, Energy Security Board, February 2021

8 National Electricity Amendment (Renewable energy zone planning) Rule 2021, May 2021

9 Energy Security Board, Renewable Energy Zones Planning, Final Recommendations, February 2021

The risk of unfunded expenditure incurred in the preparation of REZ design reports not reaching a level that meets the materiality threshold in a particular regulatory year is exacerbated by the fact that some of the work involved with the preparation of REZ design reports is likely to have already been undertaken as part of TasNetworks' own transmission planning. If that is the case, while potentially still being substantial, the incremental costs associated with the preparation of REZ design reports are even less likely to meet the materiality threshold.

It would seem inconsistent that TNSPs with jurisdictional planning responsibilities should be able to recover even incremental costs associated with the preparation of a REZ design report by virtue of the request for the report being made in time to be included as part of a TNSP's operating expenditure in a revenue proposal, yet be unable to recover similar (or potentially greater) costs, simply because the timing of the request for a REZ design report falls outside of the revenue determination process.

The ESB has expressed the view that, while the materiality threshold should apply to REZ design reports as a pass through event, the costs associated with the preparation of multiple design reports within the one regulatory year should be able to be combined in order to meet the materiality threshold for a pass through event. From this, it is clear that the ESB has recognised the risk that TNSPs could be required to prepare REZ design reports and incur significant additional, unfunded costs, simply due to the request for the design report(s) being made at a point in the regulatory cycle where the costs of producing the report(s) are unable to be provided for as part of a TNSP's revenue determination.

TasNetworks considers this to be a genuine risk, which waiving the application of the materiality threshold would remove. However, TasNetworks accepts the position articulated by the AER in its draft decision on ElectraNet's transmission determination for the 2023-2028 regulatory control period that the NER's definition of a positive change event requires the application of the materiality threshold, and that this requirement may not be bypassed in the definition for a proposed nominated pass through event.

Nonetheless, TasNetworks considers it important that the risk of incurring unrecoverable costs in preparing REZ design reports needs to be addressed to the greatest extent possible under the NER. In addition to proposing the preparation of REZ design reports as a nominated pass through event for the 2024-2029 regulatory control period, TasNetworks also proposes that the costs associated with the preparation of multiple design reports within the same regulatory year should be able to be combined in order to meet the materiality threshold for a pass through event.

The ability to combine multiple REZ design reports as a means of meeting the materiality threshold will not eliminate the risk to TasNetworks of the costs incurred in preparing a particular REZ design report becoming an unfunded cost to the business. If TasNetworks is required to prepare only one unbudgeted REZ design report during the coming regulatory control period, or during a regulatory year within that control period, it remains a possibility that the costs of preparing that report will not be sufficient to meet the materiality threshold. This is particularly the case if preparation of the report spans multiple regulatory years.

Nonetheless, in the absence of a waiver from the materiality test, the ESB's recommended approach will at least offer more protection for TasNetworks in undertaking the planning work needed to facilitate investment in new generation and transmission infrastructure in Tasmania's REZs.

Under TasNetworks' proposal, a REZ design report event will occur if:

- AEMO requires TasNetworks to undertake the preparation of a REZ design report during the 2024-2029 regulatory control period
- TasNetworks will incur increased costs in preparing that REZ design report
- the costs of preparing that REZ design report were not incorporated into the revenue that may be earned by TasNetworks from the provision of prescribed transmission services during the 2024-2029 regulatory control period.

TasNetworks' proposed definition of a REZ design report event is:

A REZ design report event occurs if AEMO requires TasNetworks to prepare one or more REZ design report(s) during the 2024-2029 regulatory control period in accordance with clause 5.24.1(b) of the National Electricity Rules, giving rise to additional costs to TasNetworks, the recovery of which was not included in the maximum allowed revenue that TasNetworks may earn from the provision of prescribed transmission services during the 2024-2029 regulatory control period.

In support of this proposed pass through event, TasNetworks notes that:

- the event proposed is not an event covered by an existing pass through event
- this type of event can be clearly defined and identified
- the obligation to prepare a REZ design report is unavoidable, imposes significant additional costs on TasNetworks and arises from events beyond TasNetworks' control
- treating the obligation to prepare a REZ design report which was not anticipated as part of a revenue determination promotes an appropriate risk sharing arrangement which is in the long-term interests of TasNetworks' customers
- TasNetworks cannot obtain appropriate insurances on reasonable commercial terms covering the costs that could potentially be incurred as a result of the occurrence of this type of event.

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Combined Proposal 2024-2029

Attachment 18
Alternative control services

Outline: This attachment to TasNetworks' Combined Proposal outlines our plans for the delivery of Alternative Control Services during the 2024-2029 regulatory control period, including how we have developed our proposed prices for fee-based services and changes to the way we price quoted services.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

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Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
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18 Alternative control services

18.1 Introduction

In addition to standard control services (i.e., the distribution network services relied upon by all customers), TasNetworks also provides services to individual customers, such as new connections or connection alterations, where the costs – and the associated benefits – can be attributed directly to the customer that requests the service. Whereas the cost of providing the shared distribution network is recovered from the wider customer base through network charges, the cost of these customer-specific services is recovered only from the customer that receives the service. This ensures that the wider customer base does not share in the cost of services that benefit just the one customer.

These services are known as *alternative control services* (**ACS**). For ACS, the Australian Energy Regulator (**AER**) either caps the prices that can be charged or sets the input costs that can be used by TasNetworks to quote for jobs. This alternative control mechanism of capping prices for services to specific customers contrasts with the standard control mechanism of capping revenue for services that benefit all customers supplied through the shared network.

This attachment to TasNetworks' Combined Proposal sets out our plans and pricing methodologies for the provision of ACS in the 2024-2029 regulatory control period. For the purposes of our Combined Proposal, TasNetworks' ACS have been divided into four sub-categories, each of which are covered in separate sections in this attachment:

- metering services
- network ancillary service
- connection services
- public lighting.

Different services within an ACS sub-category may be delivered as fee-based services or provided as quoted services. New basic connections, for example, can be delivered as a fee-based service because the time and materials involved with delivering each connection are relatively consistent between customers. However, more complex new connections, which might require the preparation of a bespoke design and involve additional materials and on-site labour to construct, are delivered as quoted services.

18.2 AER's framework and approach

On 29 July 2022, the AER published the final Framework and Approach Paper[1] applying to TasNetworks for the 2024-2029 regulatory control period. Among other things, the Framework and Approach Paper sets out the services offered by TasNetworks that the AER will regulate in the next regulatory period and how those services will be regulated. TasNetworks accepts the AER's proposed classification of legacy metering services, various other metering-related services, connection services, network ancillary services and public lighting services as ACS and the application of a price cap form of control to those services.

Details of our proposed distribution service classification are set out in Attachment 15 to this Combined Proposal for the 2024-2029 regulatory control period.

1 AER, Final Framework and Approach for TasNetworks for the 2024-2029 regulatory control period, July 2022

18.3 Fee based services pricing

Fee-based services are homogeneous services provided on request (often from electricity retailers) for the benefit of a single customer, rather than a service supplied to customers collectively. The 2024-2029 Ancillary Services Guide[2] contains the full descriptions of all proposed fee-based services. Examples include the energisation/de-energisation of connections to the distribution network, special meter reading services, supply abolition, the provision of network-related property services and enacting network tariff change requests.

The AER has introduced standardised models for pricing many of the alternative control services that are delivered as fee-based services, including network ancillary services, metering and public lighting. TasNetworks has used these models to build the prices for fee-based network ancillary services, metering and basic connection services being proposed for the 2024-2029 regulatory control period.

Based on the labour rates, vehicle costs, overheads and the cost of materials that are expected to apply to the delivery of network ancillary services in the 2024-2029 regulatory control period, TasNetworks is proposing, on average, a slight increase in fee-based service prices when compared with the prices that will apply in the last year of the current regulatory control period (2023-24).

TasNetworks has recognised that while labour costs are higher in relation to work undertaken after-hours, the majority of TasNetworks' overheads are recovered from work delivered during standard business hours. While it is appropriate that some overheads are applied to the cost of fee-based services, TasNetworks has proposed a modification to the standardised model's formulas that will see a material reduction in the overheads allocated to the delivery of after-hours services. The proposed change in the calculation of the cost of fee-based services essentially halves the rate of overhead recovery applied to after-hours work.[3]

In the 2024-2029 regulatory control period TasNetworks will apply the price cap control formulae set out in the final Framework and Approach for TasNetworks' distribution network to legacy metering services, fee-based services, network ancillary services and public lighting. The formulae are the same as those used in the 2019-2024 regulatory control period and are as follows:

1. $\bar{p}_t^i \geq p_t^i$ where $i = 1, \ldots, n$ and $t = 1, 2, 3, 4, 5$

2. $\bar{p}_t^i = \bar{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i$ where $i = 1, \ldots, n$ and $t = 1, 2, 3, 4, 5$

Where:

Variable	Description
t	The regulatory year with t = 1 being the 2024–25 financial year.
$\bar{p}_t^i$	The cap on the price of service 'i' for year t.
p_t^i	The price of service 'i' in year t, with the initial value to be decided in the AER's distribution determination for TasNetworks.
$\bar{p}_{t-1}^i$	The cap on the price of service 'i' in year t–1.
ΔCPI_t	The annual percentage change in the Australian Bureau of Statistics' Consumer Price Index All Groups, Weighted Average of Eight Capital Cities[4] from December in year t–2 to December in year t–1. For example, for the 2024–25 year, t–2 is December 2022 and t–1 is December 2023.
X_t^i	The X factor for service 'i' in year t. The X factors are to be decided in the AER's distribution determination for TasNetworks.
A_t^i	The sum of any adjustments for service 'i' in year t. To be decided in the AER's distribution determination for TasNetworks.

2 Ancillary Services – Fee Based Services (2024-2029 Service Offering) document submitted in support of TasNetworks' regulatory proposal for the 2024-2029 regulatory control period

3 See the 'Calc|Fee Based' tab of the Standardised ANS model (cells AX10 to AY509 inclusive) submitted in support of TasNetworks' regulatory proposal for the 2024-2029 regulatory control period

4 If the ABS does not or ceases to publish the index, then CPI will be taken to mean an index which the AER considers is the best available alternative index

18.4 Introduction of traffic control service

The safety of TasNetworks' employees, contractors and members of the community is non-negotiable. For reasons of accessibility, much of TasNetworks' distribution network infrastructure is located on public land adjacent to roadways (known as road reserves). So, when working around public roadways TasNetworks is frequently required to utilise the services of appropriately credentialed external traffic control contractors.

The provision of traffic control services adds to the cost of building, maintaining and repairing the distribution network, and when TasNetworks is working on the shared network, for the benefit of the wider customer base, that cost is recovered through the network charges applied to all retail customers with a connection to the network. However, in the case of work on the network which is being undertaken as a fee-based service for the benefit of an individual or identifiable group of customers, the cost of that service – including traffic control – should be recovered from the customer(s) who requested the service.

TasNetworks is proposing to introduce a new traffic control fee based service in the 2024-2029 regulatory control period. This new service will ensure the costs of traffic control associated with the delivery of other, predominately connection related, fee based services are only recovered when traffic control is actually required and only recovered from the customer(s) that request the service.

18.5 Quoted services pricing

Quoted services are services provided by TasNetworks where the nature and scope of the job is specific to an individual customer's needs and can vary between customers. It is therefore not possible to set generic fixed fees in advance for these services. In the case of network ancillary services and connection services that are non-standard in nature and so are provided on a quoted basis, the prices charged to customers are based on an AER-approved methodology. This approach allows TasNetworks to recover the directly incurred costs for labour, contractors and materials involved in providing the service. The prices charged for providing quoted services are designed to recover the costs directly incurred in providing the service plus an AER-approved allowance for overheads and a margin.

TasNetworks is not proposing to change its methodology for pricing quoted services during the 2024-2029 regulatory control period. We do acknowledge, however, the addition of a tax component to the quoted services formula, as approved by the AER in our 2024-2029 Framework and Approach Paper. This component is to allow for the recovery of any income tax liability incurred by TasNetworks in relation to the provision of quoted services.

TasNetworks is required to provide itemised quotes to customers prior to them consenting to the provision of a quoted service. Having regard to the Framework and Approach Paper, it is proposed that TasNetworks will apply the following formula when pricing quoted services:

Price = Labour + Contractor Service + Materials + Margin + Tax

Where:

Variable	Description
Price	The price charged to the customer for providing the quoted service.
Labour	The labour costs directly incurred by TasNetworks in the provision of the service, which include labour on-costs and overheads. TasNetworks' proposed labour rates are set out in the Tariff Structure Statement (Attachment 21) that accompanies the Combined Proposal for the 2024-2029 regulatory control period. Labour rates will be escalated annually during the 2024-2029 regulatory control period by $(1 + \Delta CPIt) \times (1 - X_t^i)$ (see descriptions in rows below).
Contractor Services	The costs associated with the use of external labour including overheads and any direct costs incurred. Contracted services charges apply the rates charged to TasNetworks under existing contractual arrangements with service providers. Direct costs incurred are passed onto the customer.
Materials	The cost of materials directly incurred by TasNetworks in the provision of the service, including materials storage and logistic on-costs and overheads, as well as vehicle costs.

Margin	A regulated margin set by the AER and added to quoted services pricing to ensure that the prices paid by customers are reasonable and efficient, but not anti-competitive. Margin is an amount equal to 5.93 per cent of the total costs of labour, contractor services and materials, which is consistent with the Weighted Average Cost of Capital (**WACC**) forecast to apply to TasNetworks over the 2024–2029 regulatory control period.
Tax	Tax is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, netting off the net present value of the reverse cash flow resulting from any income tax deduction (including depreciation) of the capital contribution.
$\Delta CPIt$	The annual percentage change in the Australian Bureau of Statistics' Consumer Price Index All Groups, Weighted Average of Eight Capital Cities[5] from December in year t–2 to December in year t–1. For example, for the 2024–25 year, t–2 is December 2022 and t–1 is December 2023.
X_t^i	The X factor for service 'i' in year t. The X factors are to be decided in the AER's distribution determination for TasNetworks and will be based on the approach TasNetworks undertakes to develop its initial prices.

18.6 Rationalisation of quoted service labour rates

Although TasNetworks is not proposing to change the methodology for pricing quoted services, we have reviewed our quoted services labour rates to reduce complexity for our customers and TasNetworks' teams delivering quoted services. In the current regulatory control period TasNetworks uses 16 labour categories, including some which involve similar skill-sets but different charge-out rates, to calculate the cost to the customer of a quoted service. Several additional labour categories that include an allowance for the cost of a vehicle also are used. The similarities between some of the labour categories can make it difficult for customers to understand which tasks are completed by the different team members and may have contributed to inconsistencies in the build-up of prices charged to customers.

For the 2024-2029 regulatory control period, TasNetworks proposes to reduce the number of labour categories used to price the delivery of quoted services to eight. This approach removes skill-set duplication yet still allows labour rate diversity. TasNetworks has also proposed that vehicle costs will be recovered in the materials costs of a quoted service rather than in some labour rates.

The proposed labour categories are shown in Table 1.

Table 1. Quoted service labour categories

Proposed	Skillsets	Skill Set Description
Labourer	Field Construction Officer and Locations Officer	Field Workers not able to perform electrical work
Administration	Customer Service, Project Support Officer	Office-based staff not otherwise covered
Field Worker	Linesman, LV Cable Jointer, Electrical Technician, Dual-Trade Elec/Lineworker, Live Linesman	Field Workers able to perform electrical work
Designer	Designer	Worker who provides distribution network design services
Construction Coordinator	Site Manager, Scheduling, Field Coordinator, Team Leader, Project Manager Distribution	Worker who provides leadership services
Distribution Operator	Switching Operations, Distribution Operations	Field worker who operates the distribution network
Project Administration	Customer Experience, Land Access & Approvals [More specialised office-based staff]	Specialised office-based staff
Engineer	Engineer and Protection & Control Technical Officer	Worker who provides specialised engineering services

5 If the ABS does not or ceases to publish the index, then CPI will be taken to mean an index which the AER considers is the best available alternative index

TasNetworks has tested the proposal to reduce the number of labour categories for quoted services with a range of stakeholders, including State and local governments and TasNetworks' Policy and Regulatory Working Group (**PRWG**).

A clear majority of the local governments with which TasNetworks engaged supported a reduction in labour categories. PRWG members rated the proposal highly for its potential to deliver outcomes that will satisfy the PRWG's three pricing principles of fairness, simplicity and consistency.

18.7 Asset relocation services – removal of accumulated depreciation rebate

Providing a connection service sometimes requires the relocation of existing distribution assets, such as poles. The provision of an asset relocation service is a quoted service distinct from the connection service and attracts an additional charge to the connection applicant.

Asset relocation services also are requested commonly by parties other than connection applicants, such as road authorities or local councils, to facilitate the widening or re-routing of roads. Less often, TasNetworks receives requests from collectives of customers, and/or other third parties, to remove overhead distribution network infrastructure and replace it with underground reticulation to improve visual amenity.

TasNetworks' Distribution Connection Policy previously has provided guidance on the treatment of costs when a party requires the relocation of distribution network assets. Under the Policy, when calculating the customer contribution to a requested asset relocation, TasNetworks separates the work into:

- the works that are dedicated to particular customer(s) and provided as a quoted ACS
- works that are required on the shared network and undertaken as a standard control service.

Under the current policy, the customer contribution towards the cost of new distribution network assets is reduced by the value of the accumulated depreciation of the assets which are removed. This means that parties requesting the relocation or removal of old assets are charged less than parties requesting the relocation or removal of new assets. However, the age of assets has no bearing on the cost of their relocation, removal or replacement. As this component of the work is provided as a standard control service, the reduction in the contribution towards the cost of the work by the party which has requested the removal and replacement of the network assets is funded by the general distribution customer base.

TasNetworks considers that this reduction in the prices charged for asset relocations creates an equity issue by shifting costs from those customers who cause the expenditure to other customers who do not cause (or benefit from) it. This is inconsistent with the shift of network pricing in the National Electricity Market (**NEM**) to greater cost reflectivity.

TasNetworks therefore proposes removing the accumulated depreciation rebate on the basis that the reductions in the cost of asset relocations currently provided to the parties that request the service are being funded by the broader customer base.
The proposed change will ensure that more efficient pricing signals are provided to the parties that request asset relocations in the future.

The proposal to discontinue the discounting of asset relocation charges based on the age of any assets being removed was tested with a number of stakeholders, including representatives of customers and third parties that commission asset relocations. Members of TasNetworks' PRWG were fundamentally supportive of the proposal, recognising the improvement in customer equity the change would provide and the more cost-reflective, efficient price signals that the removal of the discount would send to parties that request asset relocations in the future. The representatives of local governments with whom TasNetworks consulted in relation to the proposed change to asset relocation pricing were similarly supportive of the change, even though discontinuation of the present discount would result in the cost to local governments of asset relocations involving older assets increasing in the future.

Some stakeholders noted that the change will increase the cost of asset relocations for the customers/third parties that request them, but that the change would result in those requesting asset relocations paying the full cost of removing and replacing assets. It was acknowledged that the overall cost to TasNetworks of removing assets and relocating network infrastructure will be unaffected and that TasNetworks does not stand to receive more income from the relocation of network assets because of the change.

18.8 Metering services

Metering plays an essential role in the electricity supply chain. Meters are used to measure and record electrical flows at every connection point within the distribution network, providing the data which informs billing by both networks and electricity retailers. Meters also capture the data on which payments to customers are made for services they provide to the network or other customers, such as feed-in tariffs.

In the past, only distribution networks – such as TasNetworks – provided metering services for electricity. Under national reforms that came into effect on 1 December 2017, electricity retailers assumed the responsibility for installing, reading and maintaining the advanced meters that are now a requirement for all new and replacement meters in the NEM.

TasNetworks still provides metering services to customers with accumulation meters installed before December 2017. The customers with these meters are typically residential and small business customers.

During the current regulatory control period, the accumulation meters previously been used in Tasmania, and the property of TasNetworks, have been replaced progressively with remotely read advanced metering technology by the State's largest electricity retailer. At the time of writing, TasNetworks still had approximately 270,700 meters in service around the State that require manual reading.

TasNetworks originally expected the rollout of the new meters to span several regulatory control periods. It now is expected to be largely completed by the end of 2027. TasNetworks' accumulation meters are highly likely to be retired completely before the end of the next regulatory period on 30 June 2029.

The likelihood that TasNetworks' legacy meters will be fully retired in the coming regulatory period was recognised by the Australian Energy Market Commission (**AEMC**) in a draft report published as part of its review of the regulatory framework for metering services in the NEM.[6] In that report, the AEMC proposed an accelerated programme of meter replacement under a legacy meter retirement plan in each jurisdiction of the NEM, with the aim of achieving a 100 per cent uptake of advanced meters by 2030. However, while this recommendation would, if adopted, apply to Tasmania, the AEMC acknowledged that Tasmania already has a programme in place to accelerate advanced meter deployment at a rate that would achieve the AEMC's objective.

Figure 1. Metering capital cost recovery ($ per annum)

Note: All costs $2023-24

6 Australian Energy Market Commission, Review of the regulatory framework for metering services, Draft report,, November 2022

To better align the recovery of its past investment in metering with the significantly reduced service life of its meters, TasNetworks intends to recover the remaining asset value of its superseded fleet of meters by the end of the 2024-2029 regulatory control period. Accelerating the recovery of the residual cost of the meters that are being phased out will have a minimal impact on customer prices as shown in Figure 1. It compares:

- the annual prices that TasNetworks would charge under the accelerated cost recovery plan for a low voltage single phase meter installed at a residential property with
- the prices that would apply if the cost of TasNetworks' legacy meters were to continue to be recovered in line with the current schedule.

TasNetworks' metering charges are made up of a capital component, which recoups the cost of the meter, and an operational charge, which recovers the cost of reading the meter and managing the metering data. As with our network charges, rather than bill customers directly, TasNetworks recovers its metering costs from electricity retailers, which factor in those metering charges when setting their retail tariffs.

Currently, all residential and small business customers, other than new installations that have connected to the network since 1 December 2017, contribute towards the capital cost of TasNetworks' legacy meter fleet, reflecting the unavoidable historical investment made by TasNetworks on behalf of all customers. However, the operational metering charges are only applied to premises where the legacy meters are still in service.

It should also be noted that these arrangements describe the charges TasNetworks levies on electricity retailers for the provision of metering services to their customers, rather than the metering costs which are factored into the retail electricity tariffs that determine individual residential and small business customers' power bills. Under the most recent determination of standing offer electricity prices made by the Tasmanian Economic Regulator,[7] residential and small business customers in Tasmania are charged the same retail tariffs by their electricity retailer, regardless of the type of meter installed at their premises. This means that the recovery of the costs associated with both advanced meters and legacy accumulation meters is averaged across the wider residential and small business customer bases, with customers on the same tariff making the same contribution to metering costs overall.

The Tasmanian Economic Regulator expects total metering costs in Tasmania to increase in coming years, due to the rollout of advanced meters. However, the standardisation of standing offer electricity prices means that customers who continue to have an accrual meter provided to them by TasNetworks, including vulnerable customers, will not be disadvantaged by any diseconomies of scale encountered by TasNetworks' in supporting its legacy metering fleet as it is retired from service in the coming regulatory control period.

The accelerated recovery time series in Figure 1 shows the impact that matching the recovery of the cost of TasNetworks' metering fleet with their shortened service life will have in the 2024-2029 regulatory control period. The capital metering charges applying to the type of single phase meter used for small business or residential customers will decrease from $13.55 per year from in 2023-24, the final year in the current regulatory control period, to just over $13 per year in 2028-29.[8] On a per meter basis, the accelerated recovery of the cost of TasNetworks' superseded fleet of meters will translate into a metering capital charge which is just under $3 per annum higher in 2028-29 than it might have been if the recovery of the residual value of the metering fleet was extended into the following regulatory control period, but still less per year than in 2023-24.

Under TasNetworks' proposal, customers will not pay more in present value terms for the redundant meters than they would if they continued paying capital charges at current rates, which are based on the expected service life of the meters. Further, by bringing forward the recovery of TasNetworks' investment in meters, there will be no capital charges applied to any accumulation meters that might remain in service beyond 30 June 2029.

The proposal to accelerate the recovery of the capital cost of TasNetworks' metering fleet has been tested with TasNetworks' PRWG. PRWG members were supportive of the idea of aligning the recovery of the metering fleet's capital cost with its reduced service life, noting that this could be accomplished while still ensuring savings for customers compared to the current level of metering charges in the 2019-2024 regulatory control period.[9]

Our operating expenditure forecasts for the 2024-2029 regulatory control period and, therefore, our proposed annual revenue requirements, factor in the reduction in costs associated with the faster than anticipated winding down of the metering services provided by TasNetworks.

7 Office of the Tasmanian Economic Regulator, 2022 Electricity Standing Offer Pricing Investigation – Final Report, April 2022

8 $2023-24

9 TasNetworks, Policy and Regulatory Working Group Meeting record, April 2022

There is not, however, a linear relationship between the reduction in the volume of legacy meters and TasNetworks' operational metering costs. This is because of declining economies of scale as the volume of legacy meters decreases to low levels, and the fact that some operational costs are unavoidable (e.g., meter reading). Analysis has shown, for example, that for every 10 per cent reduction in legacy meter numbers there is only a 5 per cent reduction in meter reading rounds.

To manage the cost to customers from the reduction of legacy meters, TasNetworks is proposing two operational expenditure step changes:

1. the funding of a targeted replacement program from 2026-2029, which will help electricity retailers to replace legacy meters where installation issues exist, such as a lack of an isolation point
2. the funding of meter reads as a fee-based network ancillary service rather than a base-step-trend forecast based on historical expenditure, removing the inefficiency of increasingly sparse meter reading rounds and allowing for the targeted reading of residual legacy meters.

Table 2. Metering operating expenditure step changes

($ million, 2023-24)	2024-25	2025-26	2026-27	2027-28	2028-29
Targeted meter replacements	0	0	0.50	0.50	0.50
Individual meter reads	0	1.75	1.24	0.50	0.20

18.8.1 Targeted meter replacement

TasNetworks owns the meter panels on which legacy meters are mounted. To support the shift to advanced meters, TasNetworks will make good any legacy metering installations that might have attributes that would prevent the installation of an advanced meter (such as an old meter panel containing asbestos). This will ensure that the transition to advanced meters for affected customers, who are unlikely to be aware of any issues that might hamper the installation of an advanced meter, will not be held-up by issues associated with a non-compliant legacy metering installation.

18.8.1 Individual meter reads

The installation of advanced meters over the 2024-2029 regulatory control period will mean increasing geographical distances between premises with legacy meters that require manual meter reads. The growing distances will rapidly reduce the efficiency of meter reading rounds. TasNetworks therefore intends to price the reading of legacy meters in line with the fee applied to site visits without an appointment (which is a fee-based service).

This will ensure the accurate recovery of the efficient costs of reading meters, without customers facing an increase in meter reading charges brought about by external diseconomies of scale that are beyond TasNetworks' control. When the number of legacy meters in service dips below the minimum level required to continue meter reading rounds undertaken by dedicated meter readers, meter reads will be performed by field workers when they carry out other duties in the same locale as meters requiring manual reads.

TasNetworks currently manages approximately 270,000 legacy meters, which are forecast to be replaced with advanced meters by the end of the 2024-2029 regulatory control period. As well as metering replacements initiated by electricity retailers or at the request of customers, TasNetworks' legacy meters will be replaced:

1. following meter failure
2. because of a 'family' of meters failing (in light of ongoing compliance testing by TasNetworks)
3. in response to connection alterations requiring a metering upgrade, such as the installation of photo-voltaic solar panels at a customer's premises.

Table 3 sets out TasNetworks' forecasts of the reduction in the number of legacy meters which is anticipated over the 2024-2029 regulatory control period. Forecast metering numbers are presented as at the end of each regulatory year. It should be noted that the population of legacy meters in service will have declined between the submission of this Combined Proposal and the start of the next regulatory control period on 1 July 2024.

Table 3. Forecast legacy meter volumes

	2024-25	2025-26	2026-27	2027-28	2028-29
Metering volumes	83,993	25,184	8,056	3,222	1,289

Note: Most residential and some small business customers have, in the past, been assigned to two retail tariffs and, therefore, two network tariffs. This means that they are likely to have two accumulation (Type 6) meters on their premises. On this basis, the number of small business and residential customers still with legacy meters at their premises will be considerably lower than the forecast volume of legacy meters shown in Table 3.

We have used the AER's Roll Forward Model (**RFM**) to roll forward the metering Regulatory Asset Base (**RAB**) in the current regulatory control period to derive the value of the opening metering RAB for type 6 metering services as at 1 July 2024 (i.e., the closing metering RAB as at 30 June 2024). No new capital expenditure is forecast for legacy metering services during the remainder of the current regulatory control period or the 2024-2029 regulatory control period.

Table 4 presents the metering RAB roll-forward for the 2024-2029 regulatory control period.

Table 4. Roll forward of metering regulated asset base in the 2024-2029 regulatory control period

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening metering RAB	28.01	22.63	17.57	12.15	6.35
Forecast capital expenditure	0.14	–	–	–	–
Depreciation (accelerated)	(6.46)	(5.81)	(6.01)	(6.21)	(6.42)
Inflation on opening RAB	0.94	0.76	0.59	0.41	0.21
Closing metering RAB	22.63	17.57	12.15	6.35	0.15

Note: All figures $million, nominal

TasNetworks' proposed revenue for the provision of regulated (legacy) metering services in the 2024-2029 regulatory control period is $37.73 million ($2023-24).

TasNetworks has utilised a 'building block' approach to develop its metering revenue forecast for the 2024-2029 regulatory control period. The proposed legacy meter service charges have been developed using the post-tax revenue model (**PTRM**) and RFM developed by the AER.

Our approach accounts for the reduction in operating expenditure associated with the decline in the number of meters remaining in service. This has necessitated discontinuing the base-step-trend approach usually used to forecast DNSPs' operating expenditure. The savings stemming from the lack of new investment in meters being added to TasNetworks' metering RAB since December 2017 and the accelerated recovery of the capital cost of TasNetworks' legacy metering fleet have also been taken into account.

Table 5 sets out TasNetworks' proposed building-block revenue for metering services in the 2024-2029 regulatory control period.

Table 5. Proposed metering services building block revenue, 2024-2029

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Return on capital	1.60	1.31	1.03	0.72	0.38	**5.04**
Return of capital (depreciation)	5.52	5.06	5.42	5.80	6.21	**28.01**
Operating expenditure	1.77	1.88	2.07	1.16	0.83	**7.70**
Revenue adjustments	–	–	–	–	–	**–**
Net tax allowance	0.38	0.78	0.81	0.84	0.87	**3.68**
Annual revenue (unsmoothed)	**9.27**	**9.02**	**9.32**	**8.52**	**8.29**	**44.42**

Note: All figures $million, nominal

A detailed explanation of our pricing approach for metering services and proposed prices for the 2024-2029 regulatory control period is provided in the *Tariff Structure Statement* (Attachment 21) and *Tariff Structure Explanatory Statement* (Attachment 22) that accompany this Combined Proposal.

18.8.3 Type 7 metering services

Type 7 metering services refer to unmetered connections with a predictable energy consumption pattern, such as public lighting or traffic lights. Electricity consumption is estimated for these connections. The metering charges associated with Type 7 metering services relate to the process of estimating electricity usage. With no scope for competition to develop in the provision of Type 7 metering services, these services continue to be classified by the AER as ACS and are provided by TasNetworks as a fee-based service.

18.8.4 Auxiliary metering services

TasNetworks provides a range of metering-related services to customers on request, such as meter testing and additional meter reads. These services are classified by the AER as ACS and grouped under the Network Ancillary Services sub-category, discussed in Section 6 below. (These services are additional to the reading of Type 6 legacy accumulation meters and the management of the metering data collected for these meters.)

18.8.5 Type 6 meter recovery and disposal

TasNetworks may from time to time be required to remove and/or dispose of legacy meters from a customer's premises. These services are classified by the AER as an ACS and grouped under the network ancillary services sub-category and are discussed further in 18.9 below. These services are distinct from the replacement of a legacy accumulation meter with an advanced meter, which is the responsibility of the customer's electricity retailer.

18.9 Network ancillary services

The term "network ancillary services" refers to services provided by TasNetworks that are associated with or incidental to the provision of the shared distribution network services on which all customers rely. The nature of the services is such that only TasNetworks can perform them (particularly when they involve work on, or in relation to, parts of the distribution network) yet not all customers require or request network ancillary services.

Network ancillary services captures a wide-range of activities, which are delivered as both fee-based and quoted services, including:

- auxiliary metering services (other than the metering services discussed in section 18.8)
- connection services (including new and modified connections to the distribution network, network extensions and augmentations)
- construction/augmentation of private assets as a provider of last resort
- network safety services (such as the fitting of aerial markers on power lines)
- processing network tariff change requests.

A detailed listing of the fee-based and quoted network ancillary services that TasNetworks proposes to offer during the 2024-2029 regulatory control period, including indicative prices, can be found in the *Tariff Structure Statement* (Attachment 21). More information about these services can also be found in the 2024-2029 Ancillary Services Guide, submitted in support of this Combined Proposal.

TasNetworks' proposed fee-based and quoted service charges have been developed in accordance with the price cap formulas set out in the AER's Framework and Approach Paper and detailed above in sections 18.3 and 18.5, respectively. Whether they are delivered as fee-based services or quoted services, TasNetworks recovers the full cost of providing network ancillary services from the customer or third-party that requests, initiates or triggers the service. This ensures that the customers or third parties that benefit from the service are not subsidised by the wider customer base.

18.9.1 Construction of private assets by TasNetworks (Provider of Last Resort)

Some customers, particularly in rural and regional Tasmania, have trouble procuring the services of specialist contractors to undertake the construction of private electrical infrastructure, such as private poles. To address this lack of market depth, in the 2024-2029 regulatory control period TasNetworks will undertake private asset construction and augmentation under Provider of Last Resort provisions. This new service has been approved by the AER as part of the Framework and Approach Paper applying to TasNetworks in the 2024-2029 regulatory control period. It will be provided as a quoted service.

The work undertaken by TasNetworks will be limited to the design, construction and/or augmentation of overhead and underground network extensions beyond a customer's point of supply that are necessitated by a new or augmented connection to TasNetworks' distribution network. This work may include the inspection, maintenance, testing and relocation, if necessary, of existing customer assets, and TasNetworks will undertake the design and construction of both low and high voltage assets.

The nature of the services able to be provided by TasNetworks will be aligned with the design and construction services TasNetworks provides as the State's distribution network service provider. This means that TasNetworks will not undertake the design or installation of switchboards, meters and consumer mains, or private assets beyond customers' metering points.

TasNetworks is mindful of the potential commercial sensitivities surrounding TasNetworks undertaking work on private assets. Accordingly, a *Provider of Last Resort* process will be put in place. The process will include a number of controls to ensure that when undertaking the construction or augmentation of private assets TasNetworks only ever acts in a provider of last resort capacity. Those controls will include requirements that, before a customer can submit a *contestable job request* for TasNetworks to undertake the construction of private assets:

- The customer must have previously contacted at least two third party service providers (i.e., appropriately credentialed electrical contractors) to request a quotation/proposal and been unsuccessful in obtaining a compliant quotation
- Customers who contact TasNetworks about constructing private power lines will be provided with a list of suitably credentialed contractors, based on the contractors registered for the provider of last resort web portal
- The customer must provide evidence/attest to their efforts to procure the services of an electrical contractor
- The customer will be required to submit to TasNetworks a description of the job (in a form and to a standard that would enable TasNetworks to design and construct the private assets in question), including its location, timing requirements, and the contractors they have sought quotes from.

TasNetworks will advertise proposed jobs on a secure page on its website. Contractors who have registered to have access to that website then will have two weeks to express their interest in undertaking the work and provide the customer with a quotation for the provision of the required services. All bidders will have access to the same information about a customer's job request for the same amount of time.

At the conclusion of the two week expression of interest period for each job, TasNetworks will liaise with the customer to ascertain the success or otherwise of the process in obtaining a compliant, competitive quote from a suitably credentialed contractor. Only if no compliant quotation is received for a job advertised on TasNetworks' website will TasNetworks agree to undertake the work.

Once the provider of last resort process has established that a compliant, competitive quotation has not been able to be obtained by the customer, that customer may submit a contestable job request to TasNetworks. In response to that request:

- TasNetworks will provide the customer with a quotation for the delivery of the requested services, using the same materials costs and professional charges applied to the design and construction of negotiated connections, including labour rates approved by the AER
- the customer will be required to accept TasNetworks' quotation for TasNetworks to proceed with the job.

TasNetworks' full costs in undertaking the construction or augmentation of private assets under the provider of last resort arrangements are to be recovered from the customer requesting the work.

TasNetworks has tested the concept for the provider of last resort service extensively with local representatives of several organisations representing the electrical contracting industry, and at forums involving electrical contractors, industry bodies and industry stakeholders, which were convened by TasNetworks as part of its ongoing interaction with the electrical contracting industry. The proposal to undertake the construction of private assets in limited circumstances also has been canvassed with TasNetworks' Customer Council and PRWG, as well as TasNetworks' shareholders (through the Tasmanian Department of State Growth and the Department of Treasury and Finance).

In general terms, it was recognised by many stakeholders, including some from within the electrical contracting industry, that there is a need for a provider of last resort scheme within Tasmania in relation to the construction and augmentation of private electrical assets. There was a generally accepted position that in some regions there is a demonstrated lack of depth in the contracting market and that this is affecting customers adversely. There also was acknowledgement that the proposed controls would help to ensure TasNetworks only undertakes private work in a last resort capacity.

Based on feedback received, TasNetworks strengthened the proposed controls around the provision of private asset construction and augmentation by TasNetworks in the capacity of a provider of last resort, with a view to improving consumer protection and confidence regarding the cost of any construction work.

18.9.2 Reserve feeder construction and maintenance

TasNetworks provides reserve feeders for a number of customers that require dedicated reserve network capacity, with the costs recovered under the terms of the customers' connection agreements. While the provision of reserve feeders is a monopoly service, it is used by a small number of identifiable customers on a discretionary basis and the costs can be directly attributed to those customers. On this basis, reserve feeder construction and maintenance services lend themselves to classification as an ACS.

The activity of reserve feeder construction and maintenance has been added to the Enhanced connection service grouping within the Framework and Approach service classification listing that will apply to TasNetworks in the 2024-2029 regulatory control period. The service has been classified as a direct control service and further as an ACS. The construction of reserve feeders will be treated as a quoted service, while their maintenance will be provided as a fee-based service (with charges set with reference to reserved feeder capacity).

TasNetworks' pricing method has been updated to set out the applicable charging parameters. TasNetworks' Tariff Structure Statement for the 2024-2029 regulatory control period sets out the charging parameters, fees, costs and/or labour rates applying to reserve feeder construction and maintenance.

18.10 Connection services

Customer connection services are customer-initiated services, or works, associated with the:

- establishment of a new connection between TasNetworks' distribution system and a retail customer's premises
- modification of an existing connection to TasNetworks' distribution network
- extension or augmentation of TasNetworks' distribution network in support of a new or modified connection.

TasNetworks is licensed to provide connection services in accordance with the provisions of various electricity laws. TasNetworks is the only party able to provide connection services in Tasmania because connection services frequently involve work on, or in relation to, parts of TasNetworks' distribution network.

Customers requesting a new connection to the shared distribution network, or the alteration of an existing connection, are required to contribute toward the cost of that new or altered connection. This is in addition to the ongoing network charges that the connection and the customer's use of electricity will attract once the connection is energised. Because TasNetworks is the only party able to provide connection services in Tasmania, the prices TasNetworks charges for connection services are regulated by the AER.

TasNetworks also is the sole provider of network augmentation and network extension services in Tasmania with one significant exception. Under the Connection Choice program, since January 2016 property developers can engage accredited service providers other than TasNetworks to design and construct network extensions (including public lighting) for new subdivisions/property developments involving underground electrical reticulation.

Network augmentation and extensions are priced by TasNetworks on a quoted basis, noting that under the connection charging principles in the should read National Electricity Rules[10] (NER) and TasNetworks' *Distribution Connection Pricing Policy (Attachment 20)*, customers requiring basic connections, or who have an anytime maximum demand of 70 kVA[11] or less, are not required to make a capital contribution towards the cost of any network augmentation needed to facilitate their connection.

In the 2019-2024 regulatory control period, TasNetworks offers only two types of connection service to customers wanting to connect to the distribution network: 'basic' and 'negotiated' connections. The AER treats both services as ACS.

10 Clause 5A.E.1 Connection charge principles, National Electricity Rules

11 25 kVA where a connection applicant's installation is supplied from the Single Wire Earth Return (SWER) network

Basic connections are standardised connections that are provided on a routine basis to retail customers who are typical of a significant class of retailer customer, such as residential customers, and which are generally provided at a fixed fee. In the 2019-2024 regulatory control period, TasNetworks has been offering 16 types of basic connection services, which distinguish between connection characteristics such as the number of phases, under-ground versus overhead connection and the requirement for crossover poles. Basic connections also are limited to customers whose loads do not exceed 100 amps per phase in circumstances where network changes or alterations are not required. Basic connections have been priced as a fee-based service, where the price (or fee) for each type of basic connection services is approved by the AER.

The term negotiated connection has been used in Tasmania to describe connections that are required when none of the basic connection types are suitable and, or, extension or augmentation of the network is required to provide a customer with a connection. Negotiated connection services are services that do not meet the definition of a basic connection service, such as those provided to commercial or industrial premises or a new property development. The prices paid by customers for negotiated connections have been determined on a quoted basis, based on the quantities of materials and labour involved.

In other jurisdictions within the NEM, however, the term 'negotiated connection' describes a connection for which the customer and distribution network service provider negotiate the terms of connection. Further highlighting the differences between the types of connections offered in Tasmania and those available elsewhere within the NEM, the service classification lists in recent Framework and Approaches for DNSPs in other jurisdictions have often referred to as many as four distinct categories of connection service types and distinguished between connection services that involve network extensions and augmentation.

To better align TasNetworks' connection services with the terminology used in Chapter 5A of the NER and in other NEM jurisdictions, the Framework and Approach that will apply to TasNetworks in the 2024-2029 regulatory control period sees TasNetworks offering four distinct categories of connection to the distribution network, as shown in Table 6.

Table 6. Connection types, 2024 – 2029 regulatory control period

Connection type	Description
Basic connection	Means a connection between the distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances: (a) either: a. the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or b. the retail customer is, or proposes to become, a micro embedded generator; and (b) the provision of the service involves minimal or no augmentation, or extension, of the distribution network; and (c) a model standing offer has been approved by the AER for providing that service as a basic connection service.
Standard connection	Means a connection between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances: (a) either: 1) the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or 2) the retail customer is, or proposes to become, a micro embedded generator; and (b) the provision of the service involves extension of the distribution network but not augmentation; and (c) a model standing offer has been approved by the AER for providing that service as a basic connection service.
Complex connection	Means a connection between a distribution system and a retail customer's premises in the following circumstances: (a) requires either an extension or augmentation and either: 1) the retail customer seeking the service requires the supply of electricity at high voltage or, if connected at low voltage, has maximum demand in excess of 70 kVA (or 25 kVA where a connection applicant's installation is supplied from the Single Wire Earth Return network); or 2) the retail customer is, or proposes to become, an embedded generator; or 3) the retail customer operates, or proposes to operate, energy storage with the capacity to function as an embedded generator or community battery.
Negotiated connection	Means a connection service (other than a basic connection service) for which TasNetworks provides a connection offer for a negotiated connection contract.

Basic connections are the low-voltage connections used by most residential and small business customers. These connections suit customers with demand not exceeding 100 amps per phase and for which standardised hardware is used for the connection. Basic connections also suit customers with micro-embedded generation (such as photo-voltaic solar panels) with output ratings of less than 10 kW (per phase). Basic connections do not involve network upgrades or extensions.

New connections that are more complicated, or differ markedly from a basic connection, are priced on a quoted basis. This reflects the often bespoke nature of the connection and its design and, or, the fact that an extension of the network or network upgrades also may be required to supply the customer's connection. These are the types of connection services that were previously referred to in Tasmania as 'negotiated' connection services, but which will be known as 'standard' and 'complex' connections in the 2024-2029 regulatory control period. Standard connections are generally basic connections plus a network extension service. Complex connections typically involve network augmentation and, potentially but not always, network extension.

Where customers are required to pay the direct costs associated with a network extension service the cost of network augmentation is based on the customer's expected maximum demand. TasNetworks is not proposing any change to the methodology used to develop augmentation rates or the augmentation threshold below which connection proponents are not required to pay augmentation costs.

TasNetworks has reviewed its current Distribution Connection Pricing Policy and is proposing minimal change for the 2024-2029 regulatory control period. The policy refers already to basic, standard and complex connection types, even though, to date, these terms have not been prevalent within either the electrical contracting industry or the wider community. TasNetworks proposes to continue applying the connection charge principles outlined in Chapter 5A of the NER, with the only substantive change in policy being to the treatment of costs associated with asset relocations (discussed in Section 18.7).

18.11 Public lighting

The public lighting services provided by TasNetworks include the provision, construction and maintenance of public lighting assets (public lighting service), as well as the maintenance of public lighting assets owned by customers (contract lighting services).

TasNetworks operates and maintains public lighting infrastructure in Tasmania on behalf of councils and other government road authorities. Around 75 per cent of public lighting is supported on distribution network poles and TasNetworks owns most of the luminaires. The remaining public lighting is mounted on dedicated poles, which in most cases are privately owned by local governments, State Government agencies and business enterprises, as well as contract clients.

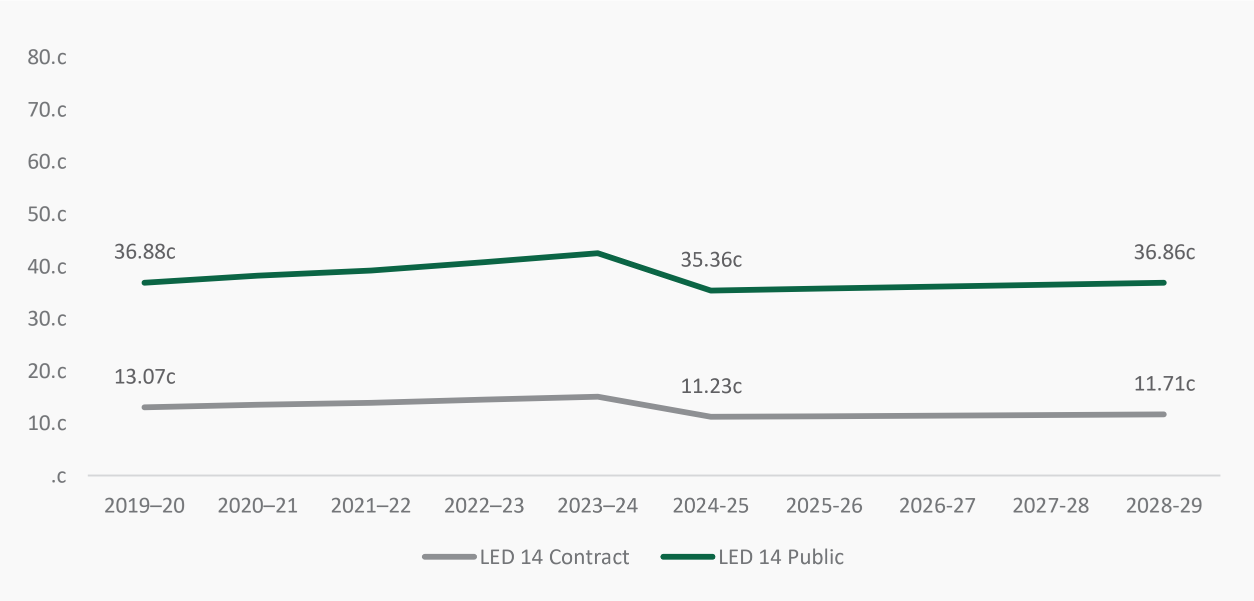
Public lighting tariffs do not include charges for the utilisation of TasNetworks' electricity network and contributions towards the costs of the electricity network are recovered from public lighting customers through separate network tariffs.

TasNetworks is proposing to continue the transition to light-emitting diode (**LED**) technology in the 2024-2029 regulatory control period by:

- using LED fittings for all new public and private contract light installations
- in response to legislative requirements, ending the like for like replacement of mercury and sodium vapour globes by installing LED fittings instead.

The transition to LED fittings will enable TasNetworks to realise savings in the maintenance of public lights. LED fittings do not require a replacement 'globe' over their twenty-year life, allowing TasNetworks to maintain light fittings on a ten instead of four yearly cycle.
The associated reduction in operational expenditure has resulted in proposed public light rates approximately 15 per cent lower for the 2024-2029 regulatory control period, as shown in Figure 2.

Figure 2. TasNetworks' public lighting charges, 2024-2029 (cents per day)



Note: All costs $2023-24

This proposal was explored in some depth with stakeholders, most notably representatives of the State's 29 local governments that jointly represent the largest component of the customer base for TasNetworks' public lighting services. Although questions were raised about technical attributes of LED lighting (such as the availability of LED replacements for large wattage lights, the expected service lives of LED light fittings and the colour temperature and brightness of new LEDs) over 90 per cent of local government attending stakeholders polled agreed with TasNetworks' proposed strategy to replace all legacy streetlights with LED fittings.

TasNetworks has applied a building block approach to determine the efficient costs of providing public lighting services under the price cap control mechanism the AER has set out in the Framework and Approach Paper. The price cap control formulae applied to TasNetworks' public lighting services is the same as the formulae applying to legacy metering and ancillary fee-based services, presented in Section 18.3.

A detailed listing of the public lighting services that TasNetworks proposes to offer during the 2024-2029 regulatory control period, including indicative prices, can be found in the Tariff Structure Statement (Attachment 21) that accompanies this Combined Proposal.

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Combined Proposal 2024-2029

Attachment 19
Negotiated service framework and criteria

Outline: This attachment to TasNetworks' Combined Proposal sets out the procedure to be followed during negotiations between TasNetworks and any person (Service Applicant) who wishes to receive a negotiated distribution service from TasNetworks, as to the terms and conditions of access for provision of the service during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	**Negotiated services framework and criteria**
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

19 Negotiated services framework and criteria

19.1 Introduction

The National Electricity Rules (**NER**) require each distribution network service provider (**DNSP**) to prepare a negotiating framework which sets out the procedure to be followed during negotiations with any person (**Service Applicant**) who wishes to receive a negotiated distribution service from that provider, as to the terms and conditions of access for provision of the service (NER clause 6.7.5(a)).

The negotiating framework must comply with and be consistent with:

(a) the applicable requirements of the relevant distribution determination applying to the DNSP (NER clause 6.7.5(b))

(b) the minimum requirements for a negotiating framework as set out in clause 6.7.5(c) of the NER.

This document sets out TasNetworks' negotiating framework and has been prepared by TasNetworks in accordance with its obligations under clause 6.7.5 of the NER. It replaces the previous Negotiation Framework 2019-2024.

It is not anticipated that TasNetworks will provide any negotiated distribution services during the 2024-2029 regulatory control period. However, any negotiations with Service Applicants regarding negotiated distribution services provided by TasNetworks will be undertaken in accordance with this negotiating framework.

19.2 Definitions

A reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision.

In this negotiating framework the words in italics have the meaning given to them in:

(a) this definitions section

(b) if not defined in this definitions section, the National Electricity Law (**NEL**)[1] and the NER.

19.2.1 Definition of a negotiated distribution service

According to the NER, a negotiated distribution service is a distribution service that is a negotiated network service within the meaning of section 2C of the NEL:

A negotiated network service is an electricity network service-

(a) that is not a direct control network service; and

(b) that-

(i) the Rules specify as a negotiated network service; or

(ii) if the Rules do not do so, the AER specifies as a negotiated network service in a distribution determination or transmission determination.

1 The National Electricity Law set out in the schedule to the National Electricity (South Australia) Act 1996 (SA) and applied in each participating jurisdiction, which includes Tasmania

19.2.2 Other definitions

The following definitions apply in this negotiating framework:

AEMO	Australian Energy Market Operator.
AER	Australian Energy Regulator.
Business day	A day other than a Saturday or Sunday or a state-wide public holiday appointed under the *Statutory Holidays Act 2000 (Tas)* and 27, 28, 29, 30 and 31 December.
Commercial information	Does not include Confidential Information provided to either party by another person, and will include, at a minimum, the following classes of information in relation to a Service Applicant, where applicable: • details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets • technical information relevant to the application for a negotiated distribution service • financial information relevant to the application for a negotiated distribution service • details of an application's compliance with the NER or any law, standard or guideline.
Confidential information	Information held by either party that is, by its nature confidential, is marked confidential or the receiving party knows or ought to know is confidential, and specifically includes: • information relating to or about the business affairs and operations of TasNetworks • Commercial Information and Requisite Information provided by TasNetworks to a Service Applicant pursuant to clause 19.6 of this negotiating framework • information provided to TasNetworks by the Service Applicant pursuant to section 19.7 of this negotiating framework • trade secrets, information, ideas, concepts, know-how, technology, processes and knowledge and the like provided to a party, or obtained by, the other party (including but not limited to in relation to a party, all information reports, accounts or data relating to that party's business affairs, finances, properties and methods of operations, regardless of the form in which it is recorded or communicated).
Disclosing party	Has the meaning provided in section 19.8 of this negotiating framework.
Distribution Network User	Distribution Customer or an Embedded Generator as defined by the NER.
NEL	National Electricity (Tasmania) Law pursuant to the *Electricity – National Scheme (Tasmania) Act 1999.*
Regulatory control period	A period for which TasNetworks is subject to a control mechanism imposed by a distribution determination, as defined by the NER.
Requisite Information	Has the meaning provided in section 19.6 of this negotiating framework.
NER	National Electricity Rules made under Part 7 of the NEL as amended from time to time in accordance with that Part 7.
Service Applicant	A person who asks TasNetworks for access to a negotiated distribution service, as defined by the NER.
TasNetworks	Tasmanian Networks Pty Ltd (ABN 24 167 357 299).
Terms and conditions of access	The terms and conditions described in clause 6.1.3 of the NER (for access to a distribution service), as defined by the NER.

19.2.3 References

This negotiating framework should be read in conjunction with the following documents:

- TasNetworks' Cost Allocation Methodology
- Chapters 5, 6, 10 and 11 of the NER.

19.3 Application of this Negotiating Framework

This negotiating framework applies to TasNetworks and a Service Applicant that has made an application in writing to TasNetworks for the provision of a negotiated distribution service. It sets out the procedure to be followed during negotiations as to the terms and conditions of access for the provision of that negotiated distribution service.

TasNetworks and any Service Applicant who requests to receive a negotiated distribution service from TasNetworks must comply with the requirements of this negotiating framework.

The requirements set out in this negotiating framework are in addition to any requirements or obligations contained in the NER or a relevant regulatory instrument of Tasmania. In the event of inconsistency between the NER or a relevant regulatory instrument of Tasmania and this negotiating framework, the NER or the relevant regulatory instrument will prevail.

Nothing in this negotiating framework or in the NER will be taken to impose an obligation on TasNetworks to provide any negotiated distribution service to the Service Applicant and TasNetworks has the sole discretion to determine if it will provide the negotiated distribution service to the Service Applicant at the conclusion of the negotiation process.

The Service Applicant acknowledges that TasNetworks is not liable for any loss or costs incurred or suffered by the Service Applicant (if any) as a result of TasNetworks not providing the negotiated distribution service at the conclusion of the negotiation process for such a service.

19.4 Request for negotiated distribution service

A Service Applicant who would like to receive a negotiated distribution service from TasNetworks must submit a written request to TasNetworks. A Service Applicant must nominate and provide contact details for a person that has authority to represent the Service Applicant in the negotiations. If the Service Applicant comprises more than one entity (for example, a partnership or joint venture) the nominated person must have authority to represent all the relevant entities.

TasNetworks will nominate and provide contact details for a person that has authority to represent TasNetworks in the negotiations.

19.5 Obligation to negotiate in good faith

TasNetworks and the Service Applicant must negotiate in good faith the terms and conditions of access to a negotiated distribution service sought by the Service Applicant.

19.6 Provision of Commercial Information to Service Applicant

The Service Applicant may request certain Commercial Information from TasNetworks that the Service Applicant reasonably requires to engage in effective negotiation with TasNetworks for the provision of the negotiated distribution service.

Subject to this section 19.6 of this negotiating framework, TasNetworks must provide all such Commercial Information a Service Applicant requests pursuant to this section 19.6 of this negotiating framework.

Subject to this section 19.6 of this negotiating framework, TasNetworks will use its reasonable endeavours to provide the Service Applicant with information requested under this section 19.6 of this negotiating framework within 10 business days of that request, or within such other time period as agreed by the parties.

TasNetworks reserves the right to withhold information requested by the Service Applicant pursuant to this section 19.6 of this negotiating framework if such information is legally privileged.

TasNetworks will identify and provide to the Service Applicant the following information, regardless of whether it has been requested by the Service Applicant (the Requisite Information):

(a) reasonable costs and/or increase or decrease in costs of providing the negotiated network distribution service

(b) a demonstration of how the charges for providing the negotiated distribution service reflect those costs and/or the cost increment or decrement

(c) an appropriate arrangement for assessment and review of the charges and the basis on which they are made.

TasNetworks agrees to provide the Requisite Information to the Service Applicant within a timeframe agreed by the parties, but in any case, prior to or in conjunction with the provision of the negotiated distribution service offer.

19.7 Provision of Commercial Information to TasNetworks

TasNetworks may request the Service Applicant to provide TasNetworks with Commercial Information held by the Service Applicant that TasNetworks reasonably requires to enable it to engage in effective negotiation with that applicant for the provision of the negotiated distribution service.

For the purposes of this section 19.7, Commercial Information does not include:

(a) Confidential Information provided to the Service Applicant by another person

(b) Information that the Service Applicant is prohibited, by law, from disclosing to TasNetworks.

The Service Applicant must provide TasNetworks with the Commercial Information requested under this section 19.7 of this negotiating framework within 10 business days of that request, or within such other time period as agreed by the parties.

TasNetworks may request the Service Applicant to provide TasNetworks with any additional information, or to clarify any information, provided to TasNetworks pursuant to this section 19.7 of this negotiating framework, that it reasonably requires to enable it to engage in effective negotiation with that applicant for the provision of the negotiated distribution service.

The Service Applicant must use its reasonable endeavours to provide TasNetworks the information requested by TasNetworks under this section 19.7 of this negotiating framework within 10 business days of the date of the request, or within such other period as agreed by the parties.

The Service Applicant must use its reasonable endeavours to provide the following information to TasNetworks within 10 business days of the written request for the negotiated distribution service (Step 2 of Table 1 in section 19.9 of this negotiating framework) being submitted to TasNetworks, regardless of whether it is requested by TasNetworks under this section 19.7 of this negotiating framework:

(a) technical information such as life cycle analysis, maintenance requirements, performance criteria, electrical specifications, or any other information relevant to the application for a negotiated distribution service

(b) financial information such as technology costs, maintenance costs, or any other information relevant to the application for a negotiated distribution service

(c) details of the compliance of the Service Applicant's application with any law, the NER, or applicable guidelines

(d) details of the compliance of the Service Applicant's application with AS/NZ 3000:2007, or AS 1158 or any other applicable standard.

19.8 Confidentiality

A party receiving information pursuant to section 19.6 or 19.7 of this negotiating framework may be required by the party disclosing such information (the Disclosing Party) to enter into a confidentiality agreement on terms reasonably acceptable to both parties, before the disclosure of the Confidential Information to that person.

Notwithstanding this section 19.8 of this negotiating framework, a party in receipt of Confidential Information under this negotiating framework shall:

(a) keep confidential the Confidential Information of the Disclosing Party

(b) take all reasonable steps to protect the confidentiality and security of the Confidential Information of the Disclosing Party

(c) without limiting the preceding paragraph, comply with the Disclosing Party's instructions regarding security of its Confidential Information

(d) not, directly or indirectly, divulge, use, disclose or publish the Confidential Information of the Disclosing Party to any person

(e) not make or allow to be made copies of, or extracts of, any part of the Confidential Information, except for the purpose of negotiating the terms and conditions of access to a negotiated distribution service sought by the Service Applicant.

Nothing in this section 19.8 of this negotiating framework restricts the disclosure of such information to the extent required by law.

Each party is liable for and indemnifies the other in respect of any claim, action, damage, loss, liability, cost, expenses or payment which the Disclosing Party suffers or incurs or is liable, as a result of a breach of this section 19.8.

19.9 Process and timeframes for progressing negotiations

The target timeframes for commencing, progressing and finalising negotiations for the supply of a negotiated distribution service are set out in Table 1 of this section 19.9.

TasNetworks and the Service Applicant must use reasonable endeavours to meet the timeframes set out in this section 19.9, subject to the Service Applicant providing the required information to TasNetworks pursuant to section 19.7 of this negotiating framework.

The timeframes set out in Table 1 of this negotiating framework may be varied by agreement between TasNetworks and the Service Applicant, and any such agreement must not be unreasonably withheld or delayed.

Table 1: Target timeframes

Step	Event	Target timeframe
1	Service Applicant makes written request to TasNetworks.	N/A
2	Service Applicant provides to TasNetworks the Commercial Information set out in section 19.7 of this negotiating framework.	No more than 10 business days after written request.
3	TasNetworks and the Service Applicant meet to discuss: • technical matters and the level of any technical evaluation required by TasNetworks • a preliminary project plan setting out a reasonable period of time for technical evaluation, including pilot studies, and the commencement, progression and finalisation of negotiations.	No more than 20 business days after written request.
4	TasNetworks and the Service Applicant finalise the preliminary project plan for commencing, progressing and finalising negotiations. The program may include, but is not limited to, milestones relating to: • the technical evaluation required by TasNetworks pursuant to step 3 of this Table 1 • the provision of information by TasNetworks pursuant to section 19.6 of this negotiating framework • the provision of information by the Service Applicant pursuant to section 19.7 of this negotiating framework • the notification and consultation with any affected Distribution Network Users in accordance with section 19.13 of this negotiating framework • the notification by TasNetworks of the reasonable direct expenses incurred in processing the application to provide the negotiated distribution service pursuant to section 19.12 of this negotiating framework.	No more than 30 business days after written request.
5	TasNetworks and the Service Applicant commence negotiations.	In accordance with negotiated timeframes.
6	TasNetworks provides to Service Applicant the Commercial Information set out in section 19.6 of this negotiating framework.	In accordance with negotiated timeframes.
7	TasNetworks completes its assessment of the Commercial Information, technical evaluations, and/or other relevant information.	In accordance with negotiated timeframes.
8	TasNetworks provides to Service Applicant the information set out in section 19.6 of this negotiating framework in accordance with section 19.6 of this negotiating framework.	In accordance with negotiated timeframes, but not subsequent to step 9 of this Table 1.
9	TasNetworks provides the Service Applicant with an offer to provide the negotiated distribution service.	In accordance with negotiated timeframes.
10	TasNetworks and the Service Applicant finalise negotiations.	In accordance with negotiated timeframes.

Any project plan finalised in accordance with step 4 of Table 1 of this section 19.9 may be modified from time to time by further agreement between TasNetworks and the Service Applicant, where such agreement must not be unreasonably withheld or delayed.

TasNetworks may request that the Service Applicant obtain technical and financial evaluation of any equipment associated with the negotiated distribution service that is proposed by the Service Applicant, and that the Service Applicant must provide this within the timeframes specified in Table 1.

Commencement of negotiations with a Service Applicant for the provision of the negotiated distribution service may be subject to the successful outcome of technical and financial evaluation pursuant to this section 19.9 of this negotiating framework.

19.10 Suspension timeframe for negotiation

The timeframes for negotiation of the provision of a negotiated distribution service set out in Table 1 of section 19.9 of this negotiating framework are suspended if any one of the following circumstances occur:

(a) a dispute in relation to the negotiated distribution service is notified to the Australian Energy Regulator (**AER**) under Part 10 of the NEL, from the date of the notification of that dispute to the AER until:

  (i) the withdrawal of the dispute under section 126 of the NEL

  (i) the termination of the dispute by the AER under section 131 or section 132 of the NEL

  (ii) a determination is made in respect of the dispute by the AER in accordance with section 128 of the NEL.

(b) after 15 business days of TasNetworks requesting additional information under section 19.7 of this negotiating framework, or, where an alternative timeframe for the provision of the Commercial Information has been agreed pursuant to section 19.7 of this negotiating framework, a further five business days has elapsed since and the Service Applicant has not provided the requested information.

(c) the Service Applicant fails to pay the reasonable direct expenses incurred in processing the application to provide the negotiated distribution service in accordance with section 19.12 of this negotiating framework, from the next business day after the amount is due until such time as the Service Applicant has paid the outstanding amount.

(d) where TasNetworks has been required to notify and consult with any affected Distribution Network Users in accordance with section 19.13 of this negotiating framework, from the date of the notification to the affected Distribution Network User until the end of the time limit specified by TasNetworks for any affected Distribution Network Users to provide to TasNetworks information regarding the impact of the provision of the negotiated distribution service, or the date on which TasNetworks receives such information from the affected Distribution Network Users, whichever is the later.

(e) where TasNetworks has been required to notify and consult with the Australian Energy Market Operator (**AEMO**), regarding the provision of the negotiated distribution service, from the date of the notification to AEMO until the date on which TasNetworks receives such information from AEMO.

Each party will notify the other party if it considers that the timeframe has been suspended, within five business days of the date that the party considers the suspension took effect.

19.11 Dispute resolution

All disputes with respect to the terms and conditions of access for the provision of negotiated distribution service are to be dealt with in accordance with either the relevant provisions of Part 10 of the NEL or Part L of Chapter 6 of the NER for dispute resolution.

A service applicant should initially raise a dispute in accordance with TasNetworks' Complaints Handling Policy.[2] If that proves unsatisfactory, then a complaint can be made to the Energy Ombudsman (which can be contacted on 1800 001 170 or as described on the Ombudsman's website).[3]

19.12 Payment arrangements

The Service Applicant may be required to pay TasNetworks' reasonable direct expenses which are incurred in processing the application to provide the negotiated distribution service.

From time to time, TasNetworks may give the Service Applicant a notice and tax invoice setting out the reasonable direct expenses incurred in processing the application to provide the negotiated distribution service.

The Service Applicant must, within 10 business days of the notice and tax invoice given pursuant to this section 19.12 of this negotiating framework, pay to TasNetworks the amount set out in the notice in the manner set out in the notice.

2 https://www.tasnetworks.com.au/config/getattachment/780d5b71-d9c1-49da-8896-252a8a93a331/complaint-handling-policy-29062022.pdf

3 https://www.energyombudsman.tas.gov.au/

19.13 Impact on other Distribution Network Users

TasNetworks must determine the potential impact on other Distribution Network Users of the provision of the negotiated distribution service.

TasNetworks must notify and consult with any affected Distribution Network Users and ensure that the provision of the negotiated distribution service does not result in noncompliance with obligations in relation to other Distribution Network Users under the NER or the Tasmanian Electricity Code.

If TasNetworks is required to consult the affected Distribution Network Users pursuant to this section 19.13 of this negotiating framework, the timeframes provided for in section 19.9 of this negotiating framework shall be suspended until the information required to assess the impact is received from the affected Distribution Network Users.

19.14 Results of negotiations

TasNetworks must publish the results of negotiations for access to a negotiated distribution service on its website.

TasNetworks

Powering a Bright Future

Combined Proposal 2024-2029

Attachment 20
Distribution connection pricing policy

Outline: This attachment to TasNetworks' Combined Proposal sets out the types of connection services provided by TasNetworks, the circumstances in which a customer may be required to pay a connection charge in relation to a new or altered connection, and how those charges are calculated during the 2024-2029 regulatory control period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
> **Attachment 20**	**Distribution connection pricing policy**
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

Distribution connection pricing policy

Distribution connection pricing policy

Customers requesting a new connection to the shared distribution network, or the alteration of an existing connection, may be required to make a contribution toward the cost of that new or altered connection. This is in addition to the ongoing network charges that the connection and the customer's use of electricity will attract once the connection is energised.

If the distribution network has to be extended or upgraded (known as augmentation) to facilitate a new or altered connection, the customer receiving the new or altered connection may be required to contribute to the cost of extending or upgrading the distribution network. In certain circumstances, customers requiring a new connection also may be required to share in the cost of a network extension or augmentation works that have previously been funded by another customer.

TasNetworks' charges for connection services are levied on either a fixed fee basis, in the case of standardised connection services, or on a quoted basis, in the case of more complex or tailor-made connections, where the connection charge is based on the materials, contractor and labour costs involved in providing the connection. In either case the fees and charges applied by TasNetworks are regulated by the Australian Energy Regulator (**AER**), with the AER approving the fixed fees applying to standardised connection services and the labour rates used to cost quoted connection services.

1 Purpose and scope

This Distribution Connection Pricing Policy (**policy**) sets out the types of connection services provided by TasNetworks, the circumstances in which a customer may be required to pay a connection charge in relation to a new or altered connection, and how those charges are calculated.

It applies to new and altered connections requested by or on behalf of a customer, real estate developer or embedded generator. It does not apply to connections for current or intending Registered Participants, as defined in the National Electricity Rules (**NER**), such as large generators that register with the Australian Energy Market Operator (**AEMO**) to participate in the National Electricity Market (**NEM**).

The policy applies from 1 July 2024 until 30 June 2029.

2 Connecting to the distribution network

Under the various rules and regulations governing the provision of distribution network services, TasNetworks is obligated to provide access to the distribution network to any party that requests a new connection, and to alter existing connections to the network to accommodate requests to meet the altered requirements of a connecting party. The services involved with providing a new connection to the distribution network or altering an existing connection are referred to as "connection services".

Connection services can include a number of different elements:

- establishment of a new connection
- alteration of an existing connection
- extension or augmentation of the distribution network required to supply a customer's new or altered connection
- removal or relocation of distribution network assets to accommodate a new or altered connection.

The provision of a connection service may involve one or more of these activities. This policy does not apply to work undertaken beyond the customer's point of supply. Further, connection services do not include the provision of metering services, which connection applicants are required to obtain through their electricity retailer.

In most instances, TasNetworks will be the provider of connection services. In a limited number of circumstances, such as the construction of underground electrical reticulation as part of a property development, the provision of connection services may be contestable; meaning that the connection service is able to be provided either by TasNetworks or, if the customer prefers, an Accredited Electrical Constructor (**AEC**) of their choice.

Connection services are a network-related service that TasNetworks provides on request, either from a customer or a third party acting on their behalf such as an electricity retailer. The costs of providing a new or altered connection – and the associated benefits – can be directly attributed to that customer and are, therefore, recovered from the customer receiving the service.

There are three types of connection services: Basic, Standard and Complex. Table 1 below summarises the service elements that each type of connection service potentially involves.

Table 1. Types of service connection

Connection type	Basic connection service	Consumer energy resources connection	Large/Complex connection service	Network extension service	Network augmentation service
Basic connection	✓	✓	✗	✗	✗
Standard connection	✓	✓	✗	✓ If applicable	✗
Complex connection	✗	✓	✓	✓ If applicable	✓ If applicable

2.1 Basic connections

The majority of residential and small business customers require what is referred to as a basic connection to the distribution network. Basic connections are for customers that require a connection with a capacity of no more than 100 amps per phase (or 70 kVA). The vast majority of micro embedded generation installations (that conform to Australian Standard AS 4777.1) will require only a basic connection.

A basic connection can comprise either of overhead service wire between the nearest TasNetworks power pole and the point of attachment on the customer's premises, or an underground cable from the nearest TasNetworks pole or fuse turret/cabinet to the point of supply on the customer's premises.

Sometimes, if the customer is located on the opposite side of the road from the overhead distribution network, a basic connection may also involve the installation of a crossover pole, along with an additional service wire from the crossover pole to the nearest TasNetworks pole. This is to maintain minimum ground clearance for the customer's service wire or ensure the length of the service wire does not exceed the maximum permissible length of a service conductor under TasNetworks' *Service and Installation Rules*.[1]

Basic connections involve minimal or no augmentation of the distribution network and for a new connection to be treated as a basic connection service; it must not involve an extension to the network. Basic connection service involve, therefore, either the provision of a new basic connection, or alterations to an existing basic connection (after which the connection will still be considered a basic connection).

1 TasNetworks, Service and Installation Rules, July 2022

2.2 Standard connections

In some circumstances, while a customer may require a basic connection, additional connection services will be required to connect the customer to the distribution network. For example, TasNetworks may be required to extend the network up to the customer's connection point. If the distribution network in the area where the customer requires a new connection is high voltage, the installation of a dedicated transformer may also be required in order to supply the customer at the required lower voltage. Some micro embedded generator connections may also require a standard connection service.

Even if the customer's connection with the network is technically a basic connection, connection works that involve extension to, or modification of, the distribution network are referred to as standard connections. The increased complexity and differences between standard connection projects means that the provision of a customer's connection, as well as any extension, will require assessments of the existing network capacity. This assessment enables the additional demands the customer is likely to place on the network to be understood and preparation of the detailed designs needed by TasNetworks of any network extension or modifications required to meet those demands.

The variations between standard connections mean that it is not possible to set a generic fixed fee in advance for these services, and the costs that the customer is required to pay will depend on the nature of their connection and be charged on a quoted services basis.

2.3 Complex connections

Large customers who take their supply of electricity from the distribution network generally require either connection to the network at high voltage or, if connected at low voltage, have maximum demand in excess of 100 amps per phase. This means that a basic or standard connection would be insufficient to cater for their needs and the demands that they place on the distribution network, and a tailor-made connection service is required. The connections for large customers are referred to as complex connections. This type of connection can also be used for 'small' customers that require complex solutions to meet their connection service requirements.

The design and specifications of complex connections varies significantly from customer to customer, meaning the cost of providing these services cannot be estimated without first understanding each customer's specific requirements. This means that it is not possible to set a standard fee for these services.

Connecting a large customer with a complex connection to the distribution network also may require extension or augmentation of the network. Customers that require larger, more complex connections also may require the relocation and/or removal of existing shared network assets.

The often-unique nature of a complex connections will require a detailed design of the customer's connection with the network to be prepared by TasNetworks, along with designs for any extension of, or modifications to, the existing distribution network. By their nature, the provision of electrical reticulation for property developments, such as a new subdivision, is treated by TasNetworks as a complex connection service. Large embedded generation connections are also treated as a complex customer project.

2.4 Export limits

When the connection to the distribution network includes the use of Consumer Energy Resources[2] (**CER**) technology TasNetworks will assess the networks capacity to accept the injection of energy, in order to determine its current export capacity.

On the basis of that assessment, TasNetworks may reduce the connection applicant's requested export limit. In limited circumstances, TasNetworks may apply a static zero export limit, in instances where:

- the injection of energy into the network by the customer has a high probability of causing voltage or power quality issues; and
- the cost of augmenting the distribution network to allow a reasonable export capacity exceeds the benefits arising from the additional export capacity.

In areas of the distribution network where the technology is available, TasNetworks will not apply static zero export limits to CER installations with the capacity to export energy where that CER has a dynamic response system that is able to respond to real-time changes in export limits from TasNetworks. This technology enables the injection of energy to be curtailed at times when the network is congested, while allowing the customer(s) to export energy the rest of the time.

2 Small scale energy resources, consumer assets such as rooftop solar, home batteries and electric vehicles connecting to the distribution network.

2.5 Real estate developments

A real estate development is a property development where:

Two or more property titles are created from one or more allotments; or multi-tenanted sites are constructed that contain three or more retail customers.

A developer requesting electricity reticulation for a new subdivision or development may require:

- the provision of connection services
- network extension services
- network augmentation services
- street lighting services.

Real estate developments generally involve the subdivision of large land holdings into smaller commercial or residential lots. A development is treated as a single customer for the purposes of calculating the customer connection charge. For example, TasNetworks will take into account the aggregate load and future network revenues attributable to the development as a whole. Where a real estate development proceeds in stages, each stage will be considered as a separate connection project, provided the connection of subsequent stages occur more than five years after the connection of the previous stage.

Where TasNetworks requires infrastructure (substations/transformers) to be installed to a greater capacity than that required for a specific development or stage of a development, the real estate developer will only be required to fund the infrastructure required for that development. This will typically occur where future development is likely beyond the boundaries of the current development or stage of the development and it is prudent to provide additional capacity within the distribution network for these future connections.

TasNetworks may require the real estate developer to fund the extension of the high voltage network through their subdivision to cater for subsequent developers. These assets will be classified as Developer Mains and in the future, the property developer may be entitled to a refund of some of the costs of network extension, should another developer or customer connect to these assets.

Where a real estate developer has elected for an AEC to provide connection services, including any network extension, the cost of that work is recovered from the customer by the AEC. Any connection related costs payable to TasNetworks will be limited to the cost of the works required to connect the new extension works undertaken by the AEC to the existing distribution network.

2.6 Temporary connections

The connection charge associated with a temporary installation should include costs associated with:

- installation of the connection assets required to connect the temporary installation
- removal of the connection assets associated with the temporary installation
- the return (in good order) of any reusable equipment provided free of charge by TasNetworks (to a nominated TasNetworks depot or location).

Typical temporary connections, for example building sites, are provided on a fixed fee basis. Larger construction projects requiring temporary connection to the distribution network will be charged on a quoted basis.

3 Connection cost recovery

A connection applicant requesting a new or altered connection to the distribution network is required to make a contribution towards the cost of that connection. The costs that each customer is required to pay will depend on the nature of their connection to the network, as well as a range of regulatory requirements. In all cases, there is a number of principles which guide the calculation of connection charges. Table 2 sets out the principles which guide the derivation of connection charges for all customers.

Table 2. Charging principles

Principle	Description
Cost reflectivity	Charges for connection services should be reasonable and provide a user pays price signal that takes into account the efficient costs of providing a new or altered connection, including the cost of extending and/or augmenting the distribution network. The cost to the customer of extension services is generally calculated on a full cost recovery basis. Charges for network augmentation are based on the average cost of augmentation in the distribution network for each unit of added capacity (in demand) multiplied by the demand estimate (kVA) of the connection applicant. The connection of a new customer, or modification of an existing connection to the distribution network to meet the changed requirements of a customer, should not impose undue costs upon other customers of the shared distribution network.
Least cost connections	The calculation of connection charges by TasNetworks will be based on the optimally sized assets (least cost and technically acceptable) required for the new or altered connection.
Above standard services	Customers may choose to have TasNetworks construct assets to a higher specification than the least cost technically acceptable solution proposed by TasNetworks. As this is an additional service to that being provided for connection, it is also an additional charge to the connection applicant.
Augmentation rates	The $/kVA unit rates utilised to recover augmentation costs above the threshold. Rates are provided in Appendix A.
Augmentation threshold	Customers requiring a basic connection are exempt from augmentation charges. For all other customers, TasNetworks is required to set an augmentation threshold such that connecting customers with an estimated demand below this threshold will be exempt from any augmentation charges. The augmentation threshold allowance is: a) 25 kVA where a connection applicant's premises are supplied from the Single Wire Earth Return (**SWER**) network; and b) 70 kVA for all other instances.
Incremental revenue	Where applicable, connection charges will take account of any incremental network revenue that may be generated by that connection in the future. Each connecting customer that will provide additional revenue, in the form of ongoing network charges, will receive a rebate, or a reduction, in their connection charges to reflect this future revenue stream. This is known as an incremental revenue rebate (**IRR**). Future operations and maintenance costs will not be included in any calculation of charges, or considered in the assessment of incremental revenues associated with the provision of connection services.
Developer mains	A customer that has previously paid connection charges towards the cost of a network extension provided solely in respect of their connection to the network may be eligible for a partial refund of that connection charge should another customer subsequently connect to that part of the network. Similarly, a customer may be required to contribute to cost of works previously funded by another customer.

In all instances where the provision of a connection service necessitates the relocation or removal of existing components of the distribution network, the relocation or removal of those assets is additional to the provision of the connection service, and the cost recovered from the customer through an additional charge to the customer. Parties other than connection applicants, such as a road authority, local council or collective of customers, may also request asset relocation services, for which they will be responsible for the cost.

The charge for the relocation or removal of existing distribution assets will include all costs associated with the removal and disposal of any assets, as well as the construction of the new installed assets. Where TasNetworks chooses to upgrade, or augment, the newly constructed assets, the additional costs of this upgrade will be borne by TasNetworks.

3.1 Basic connections

A customer requesting a basic connection is required to pay the direct costs associated with the provision of their connection.

Basic connections exhibit a high degree of similarity in terms of their specifications and the connection assets involved, which lends them to the use of a set fee to recover the cost of providing the connection. They can, however differ in terms of things like the number of phases involved, whether the connection is overhead or underground, and the need, or otherwise, for a crossover pole. To cater for these fundamental differences between basic connections TasNetworks offers a number of different basic connection services, each of which attracts a fixed connection charge that has been approved by the AER and reflects the typical cost of providing each type of connection.

Customers provided with a basic connection are not required to contribute to paying the cost of network extension or augmentation, or the cost of transformers required to facilitate their connection.

In cases where a customer seeking a basic connection to the overhead network requires a crossover pole, TasNetworks provides this service to the customer at no charge.

3.2 Standard connections

Customers requesting a standard connection are required to pay the direct costs associated with the provision of their connection, less any incremental revenue rebate.

Standard connection projects (including residential customers with standard connections) are exempt from augmentation charges, as they do not meet the augmentation threshold. However, customers with standard connections may be required to contribute to the cost of a Developer Mains Scheme, if applicable.

Connecting embedded generators are required to pay for any extension services. However, because there is no revenue associated with embedded generator connections (as TasNetworks does not currently apply use of network charges for export services), the incremental revenue rebate does not apply to these connections.

When the provision of extension services requires the installation of a transformer to service that connection, the charge is calculated in the following manner.

1. For low consumption installations[3] (excludes residential connections) – total extension costs are calculated and the customer's incremental revenue rebate is applied against the total extension costs, including the installed transformer costs.
2. For all other customers – the customer's incremental revenue rebate is firstly checked against the installed transformer costs. Any installed transformer costs that are in excess of the incremental revenue rebate are to be subtracted from the total extension services charges.

One exception to the approach outlined above is the costing of extension services for connections supplying the pumping of water for the purposes of irrigation. In line with guidance from the State Government, TasNetworks provides concessional arrangements for irrigation customers. Under those arrangements, where the provision of network extension services to supply an irrigation connection includes the installation of a dedicated transformer(s), the connection charge for extension services will not include the installed costs of the largest transformer.

An irrigator requesting a connection that requires a network extension service which does not involve the installation of a transformer, is required to pay the direct costs associated with the provision of those assets, less any incremental revenue rebate.

3 An installation for which the anticipated normal consumption is equal to or below 3,000 kWh per annum, but excluding a principal residential installation.

As with other customers, the other connection charges that apply to irrigation projects will depend on the size of the connection and whether the connection is a basic, standard or complex connection. An irrigator requiring the equivalent of a basic connection is required to pay the applicable regulated connection charge. Irrigation projects below the augmentation threshold are exempt from any augmentation charges. However, irrigation projects above the augmentation threshold are required to contribute towards any augmentation services based on their expected maximum demand.

3.3 Complex connections

A customer requesting a complex connection project is required to pay the direct costs associated with the provision of their connection, including any dedicated transformer assets and any extension and augmentation services, less any incremental revenue rebate.

Large customer connections are required to contribute to the augmentation charge based on their expected maximum demand. Customers requiring complex connections may be required to contribute to the cost of a Developer Mains Scheme, if applicable.

Large embedded generation connections are required to pay for any augmentation services. This is consistent with charging arrangements under the NER for other generation and, specifically, non-registered embedded generation. However, because there is no revenue associated with embedded generator connections (as TasNetworks does not currently apply use of network charges for export services), the incremental revenue rebate does not apply to these connections.

If the connection applicant is seeking a new load connection as well as the connection of a generator, the connection charge will be calculated based on the total cost of the works required to support both the generation (electricity output) and load components of the connection service, and there is no revenue rebate associated with the generation component.

A large embedded generator requesting an alteration to an existing connection is also required to pay for the direct costs associated with any alteration of connection assets required to accommodate that request and the direct costs associated with any augmentation services and extension services required to accommodate that request.

Embedded generators that are classified as registered participants, as defined in the NER, and embedded generation connections above five MW, will have their applications assessed in accordance with Chapter 5 of the NER.

4 Connection charge calculations

4.1 Steps in calculating customer charges

The approach to charging for customer project works depends on the nature of the service provided and a range of regulatory requirements.

Under the Connection Charge Guidelines, there is a number of requirements that can affect the cost of customer connection works. The charge that a connection applicant will pay to TasNetworks is also dependent on the classification of the required works and any rebates that may apply. Important parameters underlying the AER's methodology for calculating charges for connection and related services are briefly:

- Charges relating to the services where the assets are for a particular customer and regulated outside the revenue allowance set by the regulator are to be calculated separately. These are known as alternative control services (**ACS**)
- Charges relating to services that provide assets that are shared by all customers and are recovered through the revenue allowance, and ultimately network tariffs, are to be calculated separately. These are known as standard control services (**SCS**)
- Each connecting customer that will provide additional revenue, in the form of network tariff charges, will receive a rebate, or a reduction, in their standard control services connection charges, to reflect this new revenue stream. This is known as an incremental revenue rebate (**IRR**)
- There are also charges for the assets that have been previously funded by another customer as their dedicated connection assets. Because of a newly connecting customer, these assets will now form part of the shared distribution network. These are known as Developer Mains charges (**DM**).

The amount of each such charge is to be determined in accordance with the formula included in section 4.2 below.

4.2 Connection charge formula

In accordance with the Connection Charge Guidelines, the amount of any connection charge is to be determined in accordance with the following formula:

Connection Charge = ACS + SCS + DM

Where:

ACS — is the total charge payable to TasNetworks for all relevant alternative control connection services

SCS — is the total capital contribution (**CC**) payable to TasNetworks for all relevant standard control connection services.

DM — is the total charge payable to TasNetworks to account for any Developer Main Schemes applying to the assets to which the connection applicant connects.

and

CC = ICCS + ICSN – IRR (n=X)

Where:

CC = Capital Contribution for standard control services and CC $\geq$ 0

ICCS = Incremental Cost Customer Specific—the incremental costs incurred by TasNetworks for standard control connection services, which are used solely by the connection applicant. This typically includes any standard connection services, extension services or alterations to those connection services.

ICSN = Incremental Cost Shared Network—the costs incurred by TasNetworks for standard control connection services, which are not used solely by the connection applicant. This may include any augmentation (insofar as it involves more than an extension service) attributable to the new connection.

IRR(n=X) = Incremental revenue expected to be received from the new connection—the present value of an X year revenue stream directly attributable to the new connection (Incremental Revenue Rebate).

4.3 Connection charging summary

Table 3 summarises the charging approach to connections services.

Table 3. Connection charging summary

Charge	Component	Basic customer projects (residential, small business)	Standard customer projects (residential, small business, micro embedded generation)	Complex customer projects (large business, large embedded generation)	Complex customer projects (real estate developments)	Irrigation customer projects (irrigation)
+ ACS	Alternative control service charge	✓	✓	✗	✓	✓ If applicable
+ SCS	Extension services	✗	✓	✓	✓	✓
	Dedicated Transformation/ Substation	✗	* To level of revenue assessment	✓	✓	✗ ++
	Augmentation services (where in excess of augmentation threshold)	✗	✗	✓	✓	✓ +++
	Transformer/ substation upgrade	✗	✗	✓	✓	✗ ++
- IRR	IRR	✗	✓ ⊗	✓ ⊗	✓	✓
+ DM	**Developer Mains** Contribution towards any previous network development paid for by another customer	✗	✓	✓	✓	✓

* Low Consumption Installations pay for transformation because they do not contribute required revenues

++ Reflects State Government policy – treatment of irrigation connections

+++ Irrigation projects with demand below the augmentation threshold (equivalent of a basic or standard customer project) are not required to contribute to augmentation services

⊗ Embedded generation will have an incremental revenue rebate of zero

4.4 Application of overheads

Connection costs and charges include an allocation of overheads, determined by the application of TasNetworks' Cost Allocation Method (**CAM**). Amongst other things, the CAM assigns overhead costs to a range of different services. TasNetworks' CAM is approved by the AER.

5 Connection related services

5.1 Pre-connection services

Pre-connection services are the tasks associated with the administration of the connection application process and the preparation and finalisation of any asset construction design. While these costs are a precursor to establishing the final connection, they will form a component of the costs that should be borne by a connecting customer.

5.2 Application and design fees

Where a customer's application requires a formal design to determine specific requirements for extension and augmentation services, the customer will be charged fees to cover the reasonably incurred expenses in assessing the application, preparing a design and making the connection offer.

The fee applicable will depend on the size and complexity of the proposed connection and subsequent design work and engineering studies required.

The connection applicant will be liable to pay all reasonable costs incurred by TasNetworks, whether the final connection offer is agreed or not accepted.

5.3 Street lighting

5.3.1 Public lighting

The provision of public lighting in subdivisions, at the request of a developer (and in accordance with any council requirements) is additional to the provision of the connection service. These services are provided on a quoted basis and the cost will be separately itemised as part of the connection offer.

5.3.2 Private contract lighting

Customers may request the installation of private contract lighting near their premises, for example at the entrance of a driveway (and in accordance with any council requirements). TasNetworks will recover the cost of installing that lighting from the customer requesting the lighting.

5.4 Cost recovery for other connection related services

The provision of other connection related services is to be calculated in accordance with rates established in the AER's final distribution for TasNetworks. Where no specific rates are specified, all other charges will be determined on a cost recovery basis.

5.5 Asset replacement

The cost of replacing assets at the end of their useful life will be borne by TasNetworks. The replacement or removal of a customer's connection assets that are in serviceable condition at the request of that customer is treated as a request to alter that customer's existing connection and will be charged at full cost recovery.

5.6 Group applications for connection

Nothing in this policy prevents customers from equitably sharing the costs of connection works common to each prospective customer's development.

6 Payment terms and security fees

6.1 Payment terms

TasNetworks will require reasonable pre-payment of ancillary network service fees associated with connection offers. Pre-payment may be required to initiate the application and design work or the purchase of long lead-time materials.

Depending on the timeframe for construction of the project, a connection offer may require full or partial upfront payment and may include additional payments.

Generally, the timing of payments depends on whether the total amount of the connection charge is less than a threshold amount, which is $6,302 ($2022-23[4]). TasNetworks may, at its discretion, require the connection applicant to pay the connection charges on the connection applicant's acceptance of TasNetworks' offer to provide connection services.

Where the connection charge payable by a connection applicant exceeds the threshold amount. TasNetworks will include a payment schedule including due dates for payment.

The payment schedule will be based on:

- Full payment of the connection charge upon acceptance of the offer, if construction will commence within three months of acceptance and cannot be segmented logically into distinct stages of construction

4 The threshold will be indexed annually on 1 July for the movement in the CPI. The CPI used is the ABS' Consumer Price Index All Groups, Weighted Average of Eight Capital Cities, March to March Quarter, (ABS Catalogue 6401.0).

- For connection services requiring multiple distinct stages of construction, prior to each construction stage TasNetworks will require partial prepayment of the connection charge, one month prior to construction. Each prepayment will be reasonably reflective of the costs that will be incurred in each construction phase
- TasNetworks may negotiate alternative flexible payment arrangements with the connection applicant where appropriate.

In general, full payment must be received prior to final connection and energisation of the customer's premises, unless otherwise agreed by TasNetworks.

6.2 Security fees

TasNetworks may require the payment of security fee if it is considered that there is a high likelihood that the estimated incremental revenue calculated as part of a connection offer (for the purposes of the incremental revenue rebate) will not be collected. In practice, this is generally limited to large customer or developer connections where an incremental revenue rebate may fund substantial elements of the customer's extension, connection and/or augmentation services.

A security fee may take the form of either a prepayment, a financial guarantee (such as a bank guarantee), or a capital contribution.

If applicable, a security fee will be included as a condition of acceptance of the connection offer.

TasNetworks' requirements for a security fee will accord with the principles under part 10 of the Connection Charge Guideline. At a minimum:

- The amount of the security fee will not be greater than the amount of the incremental revenue rebate which TasNetworks assesses as having a high risk of not being recovered
- The security fee will not exceed the present value of the incremental costs TasNetworks will incur in undertaking any extension or augmentation services
- Where the security fee is provided as an upfront payment, TasNetworks will rebate the security fee via annual instalments, with the annual rebate being the:
    - o interest earned on the security, calculated at the cost of debt approved by the AER
    - o the lower of:
        - the actual incremental revenue received from the customer for the year
        - the security fee that was paid for that year.
- Where the security fee has been provided as an upfront payment, TasNetworks will pay interest on the security fee, commensurate with the cost of debt approved by the AER. Interest is not payable on security held in the form of a bank guarantee
- TasNetworks will not recover more from the security fee scheme than the total estimated incremental revenue. If the actual incremental revenue realised over the period of the security fee scheme exceeds the estimated incremental revenue, TasNetworks will refund the security fee in full
- The connection applicant will not be rebated an amount greater than the security fee deposit plus interest, over the security fee period.

7 Dispute resolution

The following process will be adopted for resolution of any customer dispute relating to the provision of connection services.

1. An attempt will be made to resolve the dispute in accordance with TasNetworks' internal dispute resolution policy.
2. If the matter is not resolved to the satisfaction of the customer, the matter will be referred to the Energy Ombudsman Tasmania for resolution.
3. If the matter remains unresolved, the matter will be referred to the AER for final resolution.

The customer is entitled to seek to have the AER determine a dispute with TasNetworks. Details of how the AER will determine the dispute or terminate proceedings are set out in Part G of Chapter 5A of the NER.

8 Compliance

This policy has been approved by the AER as part of its regulatory determination for TasNetworks during the 2024-2029 regulatory control period.

To the extent applicable, this policy is consistent with the connection charge principles set out in:

- Part E (Connection Charges) of Chapter 5A of the NER
- Part DA (Connection Policies) of Chapter 6 of the NER
- the AER's Connection Charge Guideline for electricity retail customers, published in accordance with clause 5A.E.3 of the NER
- any determination made by the AER in relation to the fees that TasNetworks can charge for the provision of connection services during a regulatory control period.

This policy should be read in conjunction with TasNetworks':

- Service and Installation Rules
- Credit Risk Management Policy
- Connection guidelines for specific connection types (e.g., micro generation).

Glossary

Unless a contrary interpretation appears, the following definitions will apply throughout this policy.

Accredited Electrical Constructor

An external service provider accredited by TasNetworks to undertake the construction of Contestable Works.

Accredited Electrical Designer

An external service provider accredited by TasNetworks to undertake the design of Contestable Works.

AER

Australian Energy Regulator

Asset relocation service

The removal and relocation of existing distribution network assets either requested by a customer or required to meet obligations.

Asset removal service

The removal of existing distribution network assets where requested by a customer or where required to meet obligations.

Augmentation service

Works to enlarge or increase the capacity of the existing distribution network (overhead and/or underground). This could include:

- A new or higher capacity transformer where the network is overhead
- A new or higher capacity substation where the network is underground
- Higher capacity poles and wires, which may include higher capacity conductor or an upgrade from single wire earth return line to a three phase line.

Basic connection services

The provision of new or altered connection assets for a home, business or other premises:

- that operate at low voltage
- that are rated at no greater than 100 amps per phase
- that do not require the completion of a formal design
- for which recovery of the cost of connection with a fixed connection fee is appropriate.

Complex connection service

The provision of a new or altered connection for a home, business or other premises to the existing distribution network, where that connection:

- is at either higher voltage or greater than 100 amps per phase or low voltage
- requires the completion of a formal design
- a standard fee cannot be charged.

Connect, Connection, Connected

To form a physical link to or through the distribution network so as to allow the supply of electricity between electrical systems.

Connection alteration

An alteration to an existing connection including an addition, upgrade, extension, expansion, augmentation or any other kind of alteration. For the avoidance of doubt a connection alteration is not the same as a network augmentation for the purposes of calculating connection charges.

Connection assets

Those components of the distribution system that are used to provide connection services solely for a single customer. That is, those assets forming the connection between the connection point and the point of supply.

Connection applicant

Means an applicant for a connection service for one of the following customer types:

- retail customer
- retailer or other person acting on behalf of a retail customer
- real estate developer.

Connection Charge Guidelines

The guidelines published by the AER in accordance with section 5A.E.3 of the NER.

Connection charges

Financial contributions by a customer or developer towards the costs associated with the creation of a new or altered connection to TasNetworks' distribution network or augmentation of the distribution network to support a new or altered connection.

Connection contract

Means a contract formed by the making and acceptance of a connection offer.

Connection offer

Means an offer by TasNetworks to enter into a connection contract with a:

- retail customer
- retailer or other person acting on behalf of a retail customer
- real estate developer.

Connection point

The point where the connection assets connect to either the existing distribution network or assets forming an extension service.

Connection services

Means either or both of the following:

- a service relating to a new connection between the existing distribution network and a premises
- a service relating to a connection alteration for a premises.

Connection works

The total works to connect a customer, including connection assets, network extensions and any network augmentation.

Consumer energy resources

Small scale energy resources, consumer assets such as rooftop solar, home batteries and electric vehicles connecting to the distribution network.

Customer

A person, including a developer, who requires customer project services.

Customer premises

Includes any building or part of a building, any structure or part of a structure, any land (whether built on or not) and any river, lake or other waters.

Developer, real estate developer

A person or entity who constructs subdivisions to allow the future provision of connection services to prospective customers.

Developer Mains Scheme

Includes any part of the distribution network:

- that necessitated an extension to the distribution network
- which was installed and has existed for less than seven years
- for which TasNetworks has required payment of a connection charge
- which was previously part of the connection assets of a single customer
- that requires payment of a connection charge greater than a threshold amount, which is $1,261 for 2022-23.[5]

Developer Mains Scheme register

The register held by TasNetworks listing the full details of all existing Developer Main Schemes.

Direct costs

Those costs attributable to the customer project services associated with the creation of a new connection or modification of an existing connection to TasNetworks' distribution network, but only to the extent that those costs refer to optimally-sized infrastructure to effect the connection.

Distribution network

The distribution network as defined in section 3A of the Electricity Supply Industry Act 1995 (Tas) (**ESI Act**) and owned and operated by TasNetworks under the terms of its licence issued by the Regulator under section 17 of the ESI Act.

Electricity laws

Includes the following, but not limited to:

- Electricity Supply Industry Act 1995 (Tas)
- National Electricity Law
- National Electricity Rules
- National Energy Retail Law
- National Energy Retail Regulations
- National Energy Retail Rules
- Tasmanian Electricity Code.

Embedded generator

A person who engages in the activity of owning, controlling, or operating a generating system that supplies electricity to, or who otherwise supplies electricity to, a distribution network and who holds or is deemed to hold a licence or has been exempted from the requirement to obtain a licence under a regulation of the ESI Act.

Extension service

The provision of network assets beyond the existing boundaries of the distribution network, and up to the connection point that are required to connect a customer.

This could include:

- New poles and wires between the existing distribution network and the connecting property (up to the connection point)
- A new transformer where the network is overhead
- A new substation where the network is underground.

High voltage

As defined in the ESI Act – Voltage greater than 1,000 Volts or above but less than 88,000 Volts.

5 The threshold will be indexed annually on 1 July for the movement in the CPI. The CPI used is the ABS' Consumer Price Index All Groups, Weighted Average of Eight Capital Cities, March to March Quarter, (ABS Catalogue 6401.0).

Irrigation customer

A customer in respect of an installation for which all or a significant part (> 90%) of the anticipated load is required for the purposes of pumping water:

- to irrigate crops or pasture
- that is subsequently used as part of an irrigation scheme to irrigate crops or pasture.

Large customer

A customer is a large customer in respect of an installation if that installation is not a residential installation and takes supply at:

- high voltage
- low voltage at greater than 100 amps per phase.

Large embedded generator

A generator that is not a micro embedded generator.

Load connection

A connection other than for a generator.

Low consumption installation

An installation for which the anticipated normal consumption is equal to or below 3,000 kWh per annum, but excluding a principal residential installation.

Low voltage

As defined in the ESI Act, Voltage less than 1,000 Volts.

Micro embedded generator

A generator of the type contemplated by Australian Standard AS 4777 "Grid Connection of Energy Systems via Inverters". Often a PV (solar) system classifies as a Micro generator.

National Electricity Law

The National Electricity Law contained in the Schedule (as amended from time to time) to the National Electricity (South Australia) Act 1996 (South Australia).

National Electricity Rules

Has the same meaning as in the National Electricity Law.

National Energy Retail Law

The National Energy Retail Law contained in the Schedule (as amended from time to time) to the National Energy Retail Law (South Australia) Act 2011 (South Australia).

National Energy Retail Regulations

The Regulations published by the parliament of South Australia in accordance under section 12 of the National Energy Retail Law and the National Energy Retail Law (South Australia) Act 2011 (South Australia).

National Energy Retail Rules

Has the same meaning as in the National Energy Retail Law.

NER

National Electricity Rules

Point of Supply

Has the same meaning as in the Tasmanian Electricity Code.

Prospective customer

A customer that is reasonably expected to connect an installation to the distribution network.

Prudential requirement

An arrangement to minimise the financial risks associated with a request for connection works.

Residential

An installation that is primarily used for residential purposes.

Retail Customer

Includes a non-registered embedded generator and a micro embedded generator.

Shared distribution network

The distribution network owned by TasNetworks that can provide services to a number of customers.

Standard Connection Contract

Has the same meaning as in the National Energy Retail Law.

Street lighting service

Provision of street lighting at the request of a customer, which may be to meet the requirements of a road authority (such as local council or State Growth).

Tasmanian Electricity Code

Has the same meaning as "Code" in the ESI Act, and as issued by the Tasmanian Economic Regulator.

Temporary installation

An installation that is intended to exist for a period of less than 12 months.

Appendix A – Augmentation charges

The unit rates used to determine augmentation charges are set out in the following tables. Where a connecting customer's estimated maximum demand exceeds the augmentation threshold, the customer's augmentation charge is calculated by multiplying the difference between the customer's estimated maximum demand and the augmentation threshold by the applicable augmentation rates from the tables below.

Table 4. Augmentation rates for residential and real estate developers (constructing residential subdivisions)

	2024-25	2025-26	2026-27	2027-28	2028-29
Network element	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)
Subtransmission	63	65	67	69	71
High voltage feeder	214	221	229	236	244
Distribution transformer	242	250	258	267	276
Low voltage mains	327	338	350	361	374
Zone substation	68	70	73	75	77

Table 5. Augmentation rates for non-residential (business) and real estate developers (constructing commercial subdivisions)

	2024-25	2025-26	2026-27	2027-28	2028-29
Network element	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)	Unit rate ($kVA)
Subtransmission	37	39	41	41	43
High voltage feeder	127	132	139	141	145
Distribution transformer	144	149	157	164	164
Low voltage mains	195	202	213	215	222
Zone substation	40	42	44	45	46

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Combined Proposal 2024-2029

Attachment 21
Tariff structure statement

Outline: For the 2024-2029 Regulatory Control Period this document outlines the tariff structures we will use to recover our allowable revenue for Standard Control Services from our customers; and the Alternative Control Services that TasNetworks will provide to our customers during the period.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing schemes
Attachment 11	Capital expenditure sharing schemes
Attachment 12	Service target performance incentive schemes
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
> **Attachment 21**	**Tariff structure statement**
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	Glossary

Contents

21 Tariff structure statement

OVERVIEW

21.1 Introduction

The purpose of this Tariff Structure Statement (**TSS**) is to explain to customers and stakeholders how TasNetworks' network tariffs have been developed to recover the revenue allowed by the Australian Energy Regulator (**AER**). This document is for the five-year regulatory control period 2024-2029, beginning 1 July 2024 and ending 30 June 2029. This document should be read together with Attachment 22, TasNetworks' Tariff Structure Explanatory Statement (**TSES**).[1]

21.1.1 Standard Control Services

Standard control services (**SCS**) refers to services that are relied on by most (if not all) customers and include the provision of complex connections to our distribution network. The revenue that TasNetworks generates from providing these services is capped by the AER for the five-year regulatory period.

The annual revenue is recovered through our general network charges (network tariffs), and enables the building, running and maintenance of the electricity distribution network. The amount of revenue that is recovered each financial year through our network tariffs is capped by the AER.

21.1.2 Alternative Control Services

Alternative control services (**ACS**) refers to those services that can be directly attributed to and/or are initiated by a particular customer. These services are subject to direct regulatory oversight where the AER caps the prices that can be charged or sets the input costs that can be used by TasNetworks to quote jobs. Services in this category include regulated metering services for small customers, network ancillary services and public lighting. Further information on our ACS can be found in Attachment 18, Ancillary Control Services.

1 The Tariff Structure Explanatory Statement is a more expansive document providing an explanation of our approach to setting and designing tariffs

Table 1. Structure of the TSS

Section		Purpose
Standard control services		
21.1	**Introduction**	Provides an introduction on the purpose of this document and outlines both Standard Control and Alternative Control Services.
21.2	**Tariff classes and allocations**	This section of our TSS describes the tariff classes in which retail customers for standard control services will be assigned for the 2024-2029 regulatory control period.
21.3	**Approach to setting network tariffs**	Explains how our tariffs comply with the pricing principles and the network pricing objective. This section also includes TasNetworks' approach to setting network tariffs for the 2024-2029 regulatory control period, including the stand-alone and avoidable costs, long run margin cost and side constraints. Additionally, customer impacts are addressed for residential and small business customers.
21.4	**Network tariff structures, charging parameters and classes**	Outlines the standard control services' tariff classes, network tariff structures and charging parameters used by TasNetworks.
21.5	**Tariff assignment procedures and policies**	Sets out the procedures and policies that TasNetworks applies when assigning customers to network tariffs and explains how network tariff choices for retailers/customers can be applied.
21.6	**Export tariff transition strategy**	Outlines the tariff transition strategy as it relates to pricing that TasNetworks seeks to undertake during 2024-2029.
Alternative control services		
21.7	**Alternative control services**	Outlines the tariff classes within the alternative control services suite, and the network tariff structures and charging parameters used by TasNetworks. Explains how we recover revenue from our customers and provides an overview of the pricing methodology for alternative control services.
Appendices		**Purpose**
A	**Indicative prices for 2024-2029 for Standard Control Services**	This section sets out indicative prices for SCS for the 2024-2029 regulatory control period.
B	**Indicative prices for 2024-2029 for Alternative Control Services**	This section sets out indicative prices for ACS for the 2024-2029 regulatory control period.

GLOSSARY

Term or Abbreviation	Description
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average incremental cost
Augmentation	Investment in new network assets to meet increased demand
Capacity	The amount of electrical power that a part of the network can carry
Capital contributed works	Works for which the customer(s) contribute towards the cost of supplying the services and/or assets. Typically resulting from the customers being the sole consumer of the services and/or asset
CBD	Central business district
Contestability	Customer choice of electricity or related service supplier
Controlled load	The DNSP controls the hours in which the supply of electricity is made available
Cost reflective pricing	Pricing which is indicative of the true cost of supplying or providing a service
DAPR	Distribution Annual Planning Report
Demand	Electricity consumption at a point in time
Demand Management	The ability for DNSPs to constrain customers demand at critical times and attempt to modify customer behaviour
CER (previously referred to as DER)	Customer energy resources, e.g., solar PVs, batteries, electric vehicles
Distribution network	The assets and services that carry the electricity conveyed from generators by the high voltage transmission system and deliver it to individual consumers at the lower voltages to operate lighting, heating, appliances, and industrial equipment.
DNSP	Distribution network service provider e.g., TasNetworks
DPPC	Designated Pricing Proposal Costs, also referred to a transmission use of service (**TUOS**)
DUoS	Distribution Use of System. The utilisation of the distribution network in the provision of electricity to distribution customers.
ESOO	Electricity Statement of Opportunities – prepared by AEMO
EV	Electric vehicle
FiT	Feed-in-tariff
GWh	Gigawatt hour
HV	High voltage
ITC	Individual Tariff Calculation. Refers to a network tariff class for a small number of large commercial and industrial customers whose circumstances are such that assignment to an averaged network tariff would not be cost reflective, giving rise to the application of individually calculated network tariffs
kV, kVA	Kilovolt, Kilovolt ampere
kW, kWh	Kilowatt, Kilowatt hour
LRMC	Long run marginal cost. The additional cost of providing one increment in service over the long run
LV	Low voltage
NEM	National Electricity Market
Network tariff	Network price components and conditions of supply for a tariff class
Network tariff class	A class of retail customers for one or more direct control services who are subject to a particular tariff or class of tariffs with similar electricity demand and usage
NER, or the Rules	National Electricity Rules

Term or Abbreviation	Description
NMI	National Meter Identifier This is the unique identifier for every connection between the customer and the distribution network
NMI	National Metering Identifier
NUoS	Network Use of System. Reflects the combination of DUoS and TUoS as the utilisation of the total electricity network in the provision of electricity to consumers
MVA	Megavolt-ampere
MW, MWh	Megawatt, Megawatt hour
PV	Photo Voltaic. Solar PV panels
Price signal	Information conveyed to end users of electricity via the prices charged for a network service, which provides a signal about the true cost of providing a service and/or the value to the customer of that service, which influences their decisions about the use of the service
PRWG	TasNetworks' Policy and Regulatory Working Group
Retailer	A business that buys electricity from generators, packages it with the network services (for transportation of the electricity) and sells it to consumers/end users
SCS	Standard control service
TEC	Total efficient cost
ToU	Time of use
Transmission network	The assets and services that enable large generators, e.g., windfarms, hydro-electric power stations, to transmit the high voltage electrical energy they produce to population centres and major industrial users of electricity
TSES	Tariff structure explanatory statement
TSS	Tariff structure statement
TUoS	Transmission Use of System. Charges for the utilisation of the transmission network, also referred to a Designated Pricing Proposal Costs (**DPPC**)
Unmetered supply	A connection to the distribution system which is not equipped with a meter and for which the consumption of electricity is estimated, e.g., public lights, traffic lights, phone boxes are not normally metered
VPP	Virtual power plant

STANDARD CONTROL SERVICES

21.2 Tariff classes and allocations

This section will demonstrate compliance with the following sections of the NER:		Section ref
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements: (1) the *tariff classes* into which *retail customers* for *direct control services* will be divided for the relevant *regulatory control period*.	21.2

For the 2024-2029 regulatory control period, TasNetworks proposes to streamline its tariff classes to address the rule requirements and pricing principles in a more efficient manner.

Table 2 summarises and compares the proposed tariff class structures against the tariff class structures used in the 2019-2024 regulatory control period. Clauses 6.18.3[2] and 6.18.4[3] of the NER provided the guiding principles for proposing the new tariff class structure (refer to section 21.4.2).

Table 2. Tariff class structure

2024-2029 regulatory control period Proposed tariff classes	2019-2024 regulatory control period Tariff classes
Low voltage residential	Residential low voltage Uncontrolled energy Controlled energy
Low voltage small business	Small business low voltage
Irrigation	Irrigation
Low voltage large business	Large business low voltage
High voltage large business	Large business high voltage Individual tariff calculation
Unmetered supplies	Unmetered supply Street lighting

The following assessment and review of the existing tariff classes have been undertaken to determine the appropriateness of refining our tariff classes.

2 Refer to section 21.4 of this TSS for compliance with Clause 6.18.3 of the NER

3 Refer to section 21.5 of this TSS for compliance with Clause 6.18.4 of the NER

Integration of the controlled and uncontrolled load tariff classes into the residential tariff class

The controlled low voltage tariff with afternoon boost (TAS61) is used by the majority of controlled load customers and has already been made obsolete. It is TasNetworks' intention to make the uncontrolled low voltage heating tariff (TAS41) obsolete for the next regulatory period.

The load profiles of the controlled and uncontrolled load customer groups closely resemble the profile of residential customers with a distinct morning and afternoon/evening peak.[4] Additionally, including the controlled and uncontrolled load tariffs in the residential tariff class better aligns with TasNetworks' modelling framework, Total Efficient Cost (**TEC**) allocations and cross-subsidies.

As we continue our transition towards cost reflectivity, the uncontrolled tariff will not be able to be used in conjunction with our cost-reflective tariffs however, our controlled night-time tariff (TAS63) is able to be used with our cost reflective tariffs.

Inclusion of the individual tariff calculation in the high voltage tariff class

There are currently 10 customers that are assigned to the Individual Tariff Calculation (ITC) tariff class. It is TasNetworks' strategy to align these customers' tariffs with the business high voltage kVA specified demand (>2 MVA) (TAS15) over time and to not offer new ITC arrangements where connection arrangements are consistent with other tariff class arrangements.

Current ITC customers were assigned to the ITC tariff based on their original connection arrangements, however they are mostly large industrials whose load characteristics closely resemble other high voltage business customers connected to the business HV kVA specified demand tariff (TASSDM) and the business high voltage kVA specified demand (>2 MVA) (TAS15) tariff.[5]

Combining the unmetered and street lighting tariff classes into unmetered supplies

Both the unmetered and the unmetered street lighting tariff classes currently comprise a single tariff each. Their unmetered connections are similar in nature and connected installations on both tariffs have relatively constant load profiles.[6]

4 NER Clauses 6.18.4(a)(1)(i),6.18.4(a)(2)

5 NER Clauses 6.18.4(a)(1)(i),6.18.4(a)(2)

6 NER Clauses 6.18.4(a)(1)(i),6.18.4(a)(2)

21.3 Approach to setting tariffs

This section will demonstrate TasNetworks' compliance with the following sections of the NER:		Section reference
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements: (5) a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each pricing proposal of the *Distribution Network Service Provider* during the relevant *regulatory* control period in accordance with clause 6.18.5.	21.3.1
6.18.1A(b)	A *tariff structure statement* must comply with the *pricing principles for direct control services*.	21.3.2
6.18.5(a)	The *network pricing objective* is that the tariff that *TasNetworks* charges in respect to its *direct control services* to a *retail customer* should reflect *TasNetworks'* efficient costs of providing the services to the retail customer.	21.3.2
6.18.5(b)	Subject to paragraph (c), a *Distribution Network Service Provider's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j):	21.3.3 to 21.3.8
6.18.5(e)	For each *tariff class*, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand along cost of serving the retail customers who belong to that class (2) a lower bound representing the avoidable cost of not serving those retail customers.	21.3.3
6.18.5(f)	Each tariff must be based on the *long run marginal* cost of providing the service to the *retail customers* assigned to that tariff.	21.3.4
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect *Distribution Network Service Provider's* total efficient costs of serving the retail customers assigned to that tariff (2) when summed, the revenue expected to be received from all other tariffs permit the *Distribution Network Service Provider* to recover the expected revenue for the relevant services with the applicable distribution determination for the *Distribution Network Service Provider* (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage of the relevant service that would result from tariffs that comply with the pricing principle set out in paragraph (f).	21.3.5
6.18.5(h)	A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*) (2) the extent to which *retail customers* can choose the tariff to which they are assigned (3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their decisions about usage of services.	21.3.7

This section will demonstrate TasNetworks' compliance with the following sections of the NER:		Section reference
6.18.5(i)	The structure of each tariff must be reasonably capable of: (1) being understood by *retail customers* that are or may be assigned to that tariff or (2) being directly or indirectly incorporated by *retailers* or *Market Small Generation Aggregators.* having regard to information available to the *Distribution Network Service Provider*, which may include: (3) the type and nature of those *retail customers* (4) the information provided to, and the consultation undertaken with, those *retail customers* (5) the information provided by, and consultation undertaken with, *retailers* and *Market Small Generation Aggregators.*	21.3.8
6.18.6	The side constraint on tariffs related to the provision of standard control services must not exceed the permissible percentage.	21.3.6
11.141.13(a)(1)	For each proposed export tariff, the basic export level or the manner in which the basic export level will be determined.	Not applicable[7]

21.3.1 Approach to setting network tariffs[8]

When setting tariffs, TasNetworks must comply with the pricing principles for direct control services set out in the National Electricity Rules (**NER**). The network pricing objective[9] requires that our network tariff charges should reflect our efficient costs[10] of providing these services to our customers.

To ensure we minimise price shocks for retail customers, TasNetworks is, over time, working towards recovering the efficient costs for customers on each of our tariffs – this involves removing existing cross-subsidies within the tariff suite in a manner that is sustainable, equitable, and fair to all customers.

Certain price relativities have been established between network tariffs within a tariff class. These relativities ensure that price changes over the 2024-2029 regulatory control period maintain the key pricing principles established with TasNetworks – fair, consistent and affordable (Table 3).

7 TasNetworks is not proposing export tariffs for the 2024-2029 regulatory control period.

8 NER, Clause 6.18.1A(a)(5)

9 NER, Clause 6.18.5(a)

10 NER, Clause 6.18.5(g)

Table 3. Tariff Component Ratios for time of use tariffs as a percentage of peak

	Shoulder	Off-peak	Super off-peak
Low voltage residential time of use consumption (TAS93)	-	21.0%[11]	
Low voltage residential time of use demand (TAS87)	-	33.3%	-
Low voltage residential time of use consumer energy resources (CER) (TAS97)	-	15.0%	0.5%
Low voltage small business time of use consumption (TAS94)	60.0%	15.0%	-
Low voltage small business time of use demand (TAS88)	-	33.3%	-
Low voltage small business time of use demand consumer energy resources (CER) (TAS98)	-	33.3%	-
Low voltage irrigation time of use consumption (TAS75)	60.0%	15.0%	-
Low voltage large business time of use demand (TAS89)	-	33.3%	
High voltage kVA specified demand (>2 MVA) (TAS15)	60.0%	15.0%	-
High voltage kVA specified demand (<2 MVA) (TASSDM)	60.0%	15.0%	-

In addition, energy charges on certain tariffs are aligned against other tariffs:

- The uncontrolled low voltage heating and hot water (TAS41) network tariff still provides discounted network charges for hard-wired space heating and hot water. TasNetworks started rebalancing this network tariff against the low voltage (**LV**) residential general light and power (TAS31) network tariff in 2017-18 in recognition of the demands that heating loads place on the network. TasNetworks continues to rebalance TAS41 for each year of the 2024-2029 regulatory control period, where at the end of the period TAS41 is forecast to be fully rebalanced against TAS31.
- The small business time of use demand distributed energy resources (**DER**) (TAS98) is aligned to the non-DER small business time of use demand tariffs (TAS88).

21.3.2 Compliance with the pricing principles and the network pricing objective[12]

The growing number of residential and small business customers with advanced meters, and the resulting increase in the availability of interval-based metering data, has provided TasNetworks with an opportunity to review and update its pricing models for the 2024-2029 regulatory control period. Our key objectives in revising our models was to:

- better capture where costs occur on our network
- increase our ability to fulfil TasNetworks' obligations in relation to network tariff reform
- respond to changes in energy use driven by the take-up of innovative technologies by customers.

Clause 6.18.1A(b) of the NER specifies that TasNetworks' TSS must comply with the pricing principles for direct control services. The objective of network pricing is that the charges applying to each retail customer should reflect TasNetworks' efficient cost of providing direct control services to that customer.[13]

Sections 21.3.3 to 21.3.8 of this TSS demonstrate how TasNetworks' network tariffs for the 2024-2029 regulatory control period comply with the network pricing principles and objectives in the NER.

11 The annual alignment for the LV residential time of use consumption tariff (TAS93) increases by 0.5% each year for the 2024-2029 regulatory control, resulting in the annual alignment to peak of 23.0% by 2028-2029

12 NER, Clause 6.18.1A(b), 6.18.5(a)

13 NER, Clause 6.18.5(a)

21.3.3 Stand-alone and avoidable costs[14]

Clause 6.18.5(e) requires TasNetworks' to recover revenue for each tariff class on or between the stand-alone and avoidable costs of serving retail customers within each tariff class. Therefore, the stand-alone and avoidable costs for a tariff class must be set between the costs necessary to supply only that tariff class (i.e., a standalone price) and the costs that could be avoided if that tariff class were not supplied at all (i.e., avoidable cost).

Setting revenue bounds based on this principle ensures economically efficient pricing. That is, it would be inefficient for networks to supply customers if they were charged less than the avoidable costs, and it would be economically beneficial for retail customer to bypass existing infrastructure to switch to other, less efficient supply options if they were charged above the stand-alone cost.

Table 4 shows that TasNetworks' stand-alone and avoidable costs comply with the requirements of clause 6.18.5(e) of the NER.

Table 4. Compliance of TasNetworks stand-alone and avoidable cost calculations

Tariff Class	Avoidable (lower bound) ($000s)	Revenue (lies between upper and lower bound) ($000s)	Stand-alone (upper bound) ($000s)	Compliance check
Residential	$48,458	$193,174	$281,294	OK
Small business (LV)	$11,706	$70,290	$241,094	OK
Irrigation	$4,469	$9,036	$139,616	OK
Large business (LV)	$1,297	$18,618	$129,478	OK
Large business (HV)	$435	$11,845	$86,154	OK
Unmetered supply	$11	$2,321	$155,790	OK

21.3.4 Long run marginal cost[15]

The application of the economic concept of long run marginal cost (**LRMC**) to network pricing is intended to ensure allocative efficiency: that is, customers consuming electricity up to the point where the marginal benefit to them of consuming an additional unit of energy (kWh, kW or kVA) equals the marginal cost of providing that extra unit of energy. When the price deviates from the marginal cost of supply, from an efficiency perspective the customer will consume either too much of the service, or not enough of the service. As such, the LRMC is a forward-looking concept in which changes in forecast expenditure are measured in response to changes in forecast demand.

The purpose of LRMC is to encourage optimal use of the existing network infrastructure, while providing a signal to the user of the cost of adding an additional unit of the service being provided. This ultimately ensures that customers obtain the maximum benefit from the network that has already been constructed.

Setting our network tariffs based on the LRMC provides customers with a cost reflective price signal that encourages efficient electricity use and reduces inefficient augmentation of the electricity network.

21.3.4.1 Inputs into the long run marginal cost

The development of LRMC is informed by the following:

- TasNetworks' ten-year program of work PoW forecasts, which includes projects that are related to:
  - augmentation of the network
  - the proportion of replacement expenditure[16] (repex) where it is established that proportion relates to increased demand on the network.
- ten-year demand forecasts at the distribution connection point level.

14 NER, Clause 6.18.5(e)

15 NER, Clause 6.18.5(f)

16 Refer to TasNetworks Distribution Pricing Methodology

21.3.4.2 Average incremental cost methodology

TasNetworks considered three different LRMC methodologies – the perturbation approach, the long run incremental cost (**LRIC**) approach, and the average incremental cost (**AIC**) methodology.

Consideration to the data and modelling requirements was given to all approaches and the average incremental cost methodology was selected using the following formula:

$$\text{LRMC} = \frac{\text{Present Value (new network capacity + marginal operating costs)}}{\text{Present Value (additional demand served)}}$$

Where:

- **New network capacity** is the forecast capital expenditure that has been categorised as being related to demand driven augmentation and replacements
- **Marginal operating costs** is the additional operating expenditure attributable to the incremental capital expenditure
- **Additional demand served** is the forecast incremental demand that can be served because of the above capital expenditure
- **The present value** has been determined for ten-year forecasts of incremental capital expenditure, operating expenditure and demand, using the regulated weighted average cost of capital as the discount rate.

21.3.4.3 Compliance with the Rules

In this TSS the calculations have been carried out at the high voltage and low voltage levels in the network. The LRMC of our distribution network is summarised in Table 5, consistent with the requirements under Clause 6.18.5(f) of the NER.

Table 5. Network level long run marginal cost

Network level	LRMC $/kVA per annum
High voltage	$56.09
Low voltage	$120.35

21.3.5 Total efficient costs[17]

TasNetworks has a revenue cap under which revenue is recovered, i.e., the maximum amount of revenue that can be recovered each year. Revenue is allocated across the tariff classes (and tariffs) according to the usage of retail customers of the distribution network levels (Table 6) involved. The total efficient cost model allocates our total annual revenue across our tariffs to reflect the cost of supplying the retail customers who are using each network tariff. This determines whether the costs generated from a customer's (or group of customers') use of the network is allocated efficiently.

Under the NER, the revenue that is expected to be recovered from each network tariff must reflect the total efficient costs of serving the retail customers assigned to that tariff and, when summed with the revenue expected from all tariffs, permit TasNetworks to recover the expected revenue for the services.

Table 6 shows the distribution network levels and their expenditure drivers relative to the nature of the different types of customer connections. A description of each distribution network level, and its respective drivers, follows:

- All customers use **sub-transmission lines** and **zone substations** and are, therefore, beneficiaries of these assets. Costs for these assets are typically driven by the demand requirements of the network and are, therefore, allocated on the basis of anytime maximum demand (**ATMD**)
- **High voltage lines** are also used by all customers. The cost of these assets is allocated to our tariff classes using a 70/30 split between ATMD and consumption (**kWh**)
- **Distribution transformers** and **low voltage lines** are used by customers on the low voltage distribution network only. Expenditure on these parts of the network is driven by a range of factors, including the number of customer connections and the uptake of consumer energy resources (**CER**), such as solar PV
- **Services** and **corporate costs** are used by all customers, and these costs are allocated to tariff classes based on the number of customer connections.

17 NER, Clause 6.18.5(g)

Table 6. Distribution network levels

Distribution network levels	Tariff class: Residential	Small business (LV)	Irrigation	Large business (LV)	Unmetered supply	Large business (HV)
Sub-transmission lines	100% ATMD					
Zone substations	100% ATMD					
High voltage lines	70% ATMD, 30% consumption					
Distribution transformers	5% NMI, 5% solar NMI, 5% embedded generation, 45% ATMD, 40% consumption					
Low voltage lines	15% NMI, 5% solar NMI, 5% embedded generation, 25% ATMD, 50% consumption					
Services, GSLs	100% NMI					
Corporate	100% NMI					

21.3.5.1 Residual costs

Distortions in energy price signals need to be minimised for efficient use of the service that result from tariffs being compliant with the LRMC[18]. Distribution use of service (**DUoS**) residual costs are allocated to network tariffs on the basis of the previous year's allocation and the current year's consumption volumes. This ensures the level of DUoS revenue expected to be recovered from each network tariff (and across all network tariffs) complies with Clauses 6.18.5(g)(1) and 6.18.5(h) of the NER.

21.3.6 Side constraints[19]

Under clause 6.18.6 of the NER, the annual movement for the recovery of revenue is limited due to side constraints. The side constraint applies only to the tariff class, not individual network tariffs or tariff elements.

For each regulatory year after the first year of a regulatory control period, the side constraint applies to the weighted average revenue raised from each tariff class, and in accordance with the NER[20], the permissible percentage increase is the greater of CPI-X plus 2 per cent ((1+CPI)(1-X)(1+2%)) or CPI plus 2 per cent ((1+CPI(1+2%)).

21.3.7 Customer impact[21]

In structuring our network charges, we have considered the impact on our customers throughout with the objective of sustainable pricing for our customers while maintaining a safe and reliable network, considering the pricing principles and objectives of the NER (as demonstrated above in sections 21.3.1 to 21.3.6) and TasNetworks' pricing principles of affordability, consistency, fairness, simplicity, innovation and providing customers with choice.

Managing customers' bill impact has been a significant aspect of TasNetworks' considerations as we transition to more cost reflectivity, recognising the future transformation of the network and our customers' use of the network.

A comprehensive analysis of customer impacts resulting from this proposal have been included throughout our TSES with specific analysis in sections 22.8 to 22.11. This section provides a summary of our analysis from the TSES.

18 NER, Clause 6.18.5(g)(3)

19 NER, Clause 6.18.6

20 NER, Clause 6.18.6(c)

21 NER, Clause 6.18.5(h)

Considerations of customer impact have included:

- Customers' future use of the network and network transformation
- Redesigning our residential CER tariff to make it more attractive to customers
- Updating our time of use windows for our small business customers
- Ensuring there is customer choice for our tariff classes, allowing customers to opt-out of the default tariff into a more suitable tariff.

Ensuring customer specific tariffs remain available to large, bespoke customers.

Measuring customer impact and ensuring allocative efficiency.

All aspects of our proposed tariff strategy have been discussed with our Policy and Regulatory Working Group (**PRWG**), ensuring different perspectives have been considered in the development of our tariffs. In addition, TasNetworks engaged directly with our customers through the DER Customer Survey to better understand our customers intent in investing in new technologies and the potential impact this investment will have on the network.

TasNetworks has analysed the effect of our proposed residential time of use consumption CER (TAS97) network tariff against our existing tariffs and how change customer behaviour could impact on customers' network charges. In addition, the proposed changes to our small business time of use consumption network tariff (TAS94) have been assessed against different types of businesses, e.g., hospitality, education, shops etc, to ensure that particular business types were not adversely affected by changing the time of use windows and the resultant rebalancing of the tariff.

Our TSES provides in depth analysis and explanations of customer impact analysis resulting from our network tariff proposal for the 2024-2029 regulatory control period. We contend our proposal strikes the right balance between improving price signals for customers, providing customer's network tariff choice, and fostering innovation, while ensuring efficient use of the network and taking into consideration the bill impact for our customers.

TasNetworks will continue to closely monitor how effective its tariffs are throughout the 2024-2029 regulatory control period, and in particular through the annual pricing process. It is important for tariffs to be cost-reflective and recover the appropriate level of revenue. This may be challenging to balance with the emergence of CER technologies over future regulatory control periods.

21.3.7.1 Residential customer behaviour analysis

TasNetworks undertook detailed scenario analysis to reflect changing customer behaviour resulting from customer investment in CER technology using the indicative 2024-25 prices (refer section 22.10.3 of the TSES).

The detailed analysis within the TSES demonstrates that household customers have significant potential to reduce network bills through technology. Technology can be used to effectively manage how electricity is consumed from the network, without requiring people to change how they live their day-to-day lives. In particular, a combination of household batteries and PV with time of use tariffs (especially the proposed CER tariff) can work hand-in-hand to reduce annual network costs. This analysis demonstrated that customers with solar PV and batteries (with network demand consumption of ~6,000 kWh) could save up to $218 per year (26 per cent) compared to a customer on a flat tariff and base consumption of ~7,600 kWh (the total household consumption would be the same for this example however, the consumption from the network is lower because of generation from the solar PV).

Even without an optimal customer response in terms of utilisation of the available technology (as indicated above), solar PV and batteries could reduce annual charges by $137 (16 per cent) compared to the base scenario.

TasNetworks' proposed CER tariff offers considerable opportunities for customers with PV and storage – and not just those that own an EV. TasNetworks expects that this tariff will be highly beneficial for many customers that have or are planning to invest in technology.

Importantly, TasNetworks' proposed time of use tariffs are generally well suited to customers experiencing vulnerability, as demonstrated in the TSES, and are not expected to further contribute to the challenges being faces by such customers. However, it is acknowledged that it may be more challenging for such customers to fully achieve cost savings because of the barrier to investing in technology that may be more accessible to other customer groups.

21.3.7.2 Small business time of use consumption network tariff rebalancing

TasNetworks has undertaken a more detailed analysis of the impact of rebalancing the small business time of use consumption (TAS94) network tariff using the indicative 2024-25 prices. As discussed in section 22.7.3 of the TSES, TasNetworks is proposing a change to the small business time of use consumption (TAS94) network tariff resulting from reviewing the time of use windows.

The analysis in the TSES shows that the proposed changes will benefit those customers using large proportions of their energy during the former peak windows, by shifting these former peak periods to shoulder and off-peak periods. The average bill impact is projected to reduce by $107 (2.7 per cent) for shops and reduce by up to $231 (3.7 per cent) for hospitality businesses. These changes are expected to benefit all main small industry types on average, as presented in section 22.11 of the TSES.

21.3.8 Network tariff components[22]

Network tariffs can be structured using a combination of different components. The components used by TasNetworks are outlined in Table 7 for each network tariff available to customers in the 2024-2029 regulatory control period.

Table 7. Network Tariff structures and their components[23]

Network tariff type	Status	Components	Unit
TAS93 – Low voltage residential time of use consumption	Default	Fixed (service charge)	c/day
		Peak consumption	c/kWh
		Off-peak consumption	c/kWh
TAS87 – Low voltage residential time of use demand	Opt-in	Fixed (service charge)	c/day
		Peak demand	c/kW/day
		Off-peak demand	c/kW/day
TAS97 – Low voltage residential time of use consumer energy resources (CER)	Opt-in	Fixed (service charge)	c/day
		Peak consumption	c/ kWh
		Off-peak consumption	c/ kWh
		Super off-peak consumption	c/ kWh
		Excess Demand	c/kW[24]
TAS31- Low voltage residential general light and power	Obsolete	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
TAS41 – Low voltage uncontrolled energy heating and hot water	Obsolete	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
TAS63 – Low voltage controlled energy off-peak [night only]	Opt-in secondary tariff	Fixed (service charge)	c/day
		Anytime consumption[25]	c/kWh
TAS61 – Low voltage controlled energy off-peak with afternoon boost	Obsolete	Fixed (service charge)	c/day
		Anytime consumption[26]	c/kWh
TAS94 – Low voltage small business time of use consumption	Default	Fixed (service charge)	c/day
		Peak consumption	c/kWh
		Shoulder consumption	c/kWh
		Off-peak consumption	c/kWh

22 NER, Clause 6.18.5(i)

23 This table does not include the network tariffs that are proposed to be abolished (TAS92 – low voltage residential PAYG time of use and TAS101 – low voltage residential PAYG)

24 This tariff component captures daily anytime maximum demands (ATMD) exceeding the 8.5kW demand threshold

25 Energy will only be available between 22:00 and 07:00

26 Energy will be available for a least nine hours between 20:00 and 07:00, and a further two hours between 13:00 and 16:30

Network tariff type	Status	Components	Unit
TAS88 – Low voltage small business time of use demand	Opt-in	Fixed (service charge)	c/day
		Peak demand	c/kW/day
		Off-peak demand	c/kW/day
TAS98 – Low voltage small business time of use demand consumer energy resources (CER)	Opt-in	Fixed (service charge)	c/day
		Peak demand	c/kW/day
		Off-peak demand	c/kW/day
TAS22 – Low voltage small business general light and power	Obsolete	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
TAS75 – Low voltage irrigation time of use consumption[27]	Opt-in	Fixed (service charge)	c/day
		Peak consumption	c/kWh
		Shoulder consumption	c/kWh
		Off-peak consumption	c/kWh
TAS89 – Low voltage large business time of use demand	Opt-in	Fixed (service charge)	c/day
		Peak demand	c/kVA/day
		Off-peak demand	c/kVA/day
TAS82 – Low voltage large business kVA	Opt-in	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
		Anytime maximum demand	c/kVA/day
TAS84T1, TAS84T2, TAS84T3, TAS84T4 – Low voltage embedded network (Tier 1 – Tier 4)	Default network tariff for embedded networks	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
		Peak demand[28]	c/kVA/day
TAS15 – High voltage kVA specified demand (>2MVA) and **TASSDM – High voltage kVA specified demand (<2MVA)**	Opt-in	Fixed (service charge)	c/day
		Peak consumption	c/kWh
		Shoulder consumption	c/kWh
		Off-peak consumption	c/kWh
		Specified daily demand	c/kVA/day
		Excess daily demand[29]	c/kVA
		Specified daily demand connection charge (TAS15 only)	c/kVA/day
		Excess daily demand connection charge (TAS15 only)	c/kVA
TAS14T1, TAS14T2 – High voltage embedded network (Tier 1 – Tier 2)	Default network tariff for embedded networks	Fixed (service charge)	c/day
		Anytime consumption	c/kWh
		Peak demand[30]	c/kVA/day
TASUMS – Unmetered supply general		Fixed (service charge)	c/day
		Anytime consumption	c/kWh
TASUMSSL – Unmetered supply public lighting		Anytime demand	c/lamp watt/day

27 Seasonality applies to this network tariff

28 The demand component of this network tariff applies as an excess demand charge when demand exceeds 8.5kW at anytime

29 High voltage commercial kVA specified demand (<2MVA) network tariff (TASSDM) applies a 20 per cent allowable excess demand above the specified demand

30 The demand component of this network tariff applies as an excess demand charge when demand exceeds 8.5 kW at anytime

21.4 Tariff structures, charging parameters and classes

This section will demonstrate TasNetworks' compliance with the following sections of the NER:		Section reference
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements: (3) the structures for each proposed tariff (4) the *charging parameters* for each proposed tariff	21.4.1
6.18.3(b)	Each *retail customer* for *direct control services* must be a member of 1 or more *tariff classes.*	21.4.2
6.18.3(c)	That separate *tariff classes* must be constituted for *retail customers* to whom standard control services are supplied.	21.4.2
6.18.3(d)	A *tariff class* must be constituted with regard to: (1) the need to group *retail customers* together on an economically efficient basis (2) the need to avoid unnecessary transaction costs	21.4.2

21.4.1 Tariff structures and charging parameters

Our network tariffs are based on target tariff parameters, forecast customer numbers, and consumption and demand forecasts related to each tariff. To determine the target network tariff parameters, we:

a) estimate the TEC for each tariff (section 21.3.5)

b) estimate the LRMC for each tariff (section 21.3.4)

c) calculate the required LRMC revenues for each network tariff (using the LRMC and consumption and demand forecasts)

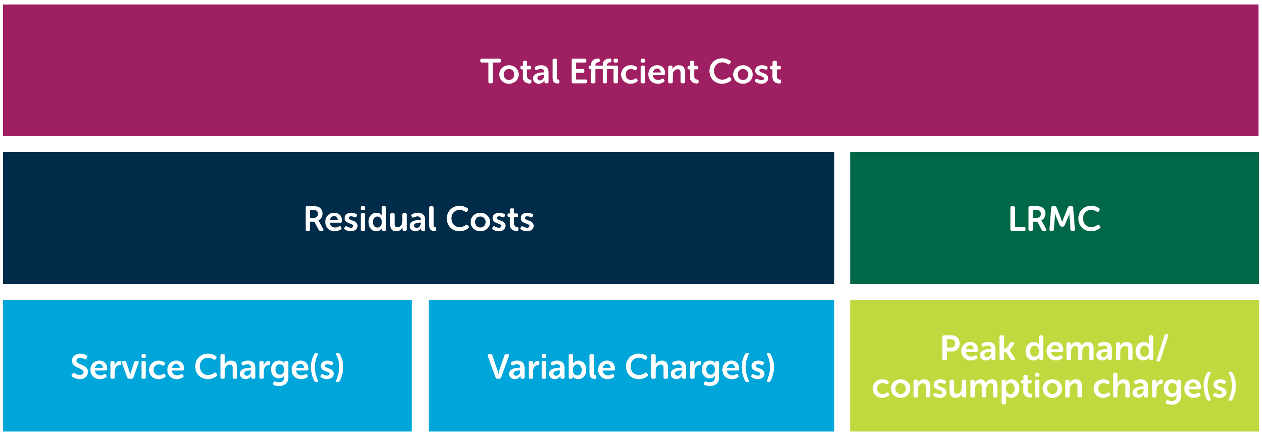
d) calculate the residual costs for each network tariff (which is the difference between the TEC and the LRMC revenues) and allocate these residual costs in a manner to reduce distortion to the LRMC price signals.

As noted in section 21.3.4, LRMC is an indicator of forward-looking costs and is used to calculate the peak demand and peak consumption component of each tariff. The residual costs – which represent the sunk costs on the network – are allocated between the service charge and the remaining variable charge(s) that make up each tariff, with the allocation being dependent on the characteristics of the tariff.

It is the overall aim of TasNetworks to offer network tariffs which are cost reflective while maintaining consistent, sustainable, and affordable prices for our customers. Therefore, to satisfy the NER requirements that our tariffs be based on the LRMC and TEC, and to ensure the pricing principles are observed, our transition towards cost reflectivity considers price impacts on customers.

Diagram 1 shows the relationship between the TEC, LRMC and residual costs for each network tariff.

Diagram 1. Relationship between our charging parameters



Our tariff structures described consist of some of the following charging parameters:

- Service / capacity charge – this is a daily charge providing access to the distribution network – it provides the ability for the retail customer to connect to the network
- Consumption/energy charge (c/kWh) – this is a volume charge in which retail customers are charged for the amount of energy they consume
- Demand charge (KVA) – this relates to the rate energy is used – it is directly linked to the maximum demand at a given point in time and is set to the long run marginal cost.

Table 8 to Table 13 shows the proposed tariff structures for the 2024-2029 regulatory control period. The *Network Tariff Application Guide 2024-2029* document that accompanies this proposal outlines how tariffs are applied to retail customers in accordance with their parameters and structures.

For the purposes of these tables, Australian Eastern Standard Time[31] is applicable for all time periods, and weekday refers to Monday through to Friday and weekend day refers to Saturday and Sunday.

31 Australian Eastern Standard Time is used due to the cost of reprogramming meters each time daylight savings begins or ends

Table 8. Proposed tariff structures for low voltage residential network tariffs[32]

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TAS93 – Low voltage residential time of use consumption **[default network tariff]**	Daily service charge c/day	Time of use consumption charge c/kWh	Weekdays 07:00 to 10:00 and 16:00 to 21:00	✖	All other times	✖
TAS87 – Low voltage residential time of use demand	Daily service charge c/day	Time of use demand charge c/kW/day	Weekdays[33] 07:00 to 10:00 and 16:00 to 21:00	✖	All other times	✖
TAS97 – Low voltage residential time of use consumer energy resources (CER)	Daily service charge c/day	Time of use consumption charge c/kWh	Demand threshold applies when demand exceeds 8.5kW anytime			
			Weekdays 07:00 to 10:00 and 16:00 to 22:00	✖	All other times	Weekdays and weekends Midnight to 04:00
TAS31 – Low voltage residential general light and power **[obsolete]**	Daily service charge c/day	Consumption charge c/kWh	Anytime			
TAS41 – Low voltage uncontrolled energy heating and hot water[34] **[obsolete]**	Daily service charge c/day	Consumption charge c/kWh	Anytime			
TAS63 – Low voltage controlled energy off-peak **[night only]**[34]	Daily service charge c/day	Consumption charge c/kWh	✖	✖	Weekdays and weekends Energy will be available between 22:00 and 07:00	✖
TAS61 – Low voltage controlled energy off-peak with afternoon boost[34] **[obsolete]**	Daily service charge c/day	Consumption charge c/kWh	✖	✖	Weekdays and weekends Energy will be available between 20:00 and 07:00 and between 13:00 and 16:30	✖

32 This table does not include the network tariffs that are proposed to be abolished (TAS92 – low voltage residential Pay As You Go (**PAYG**) time of use and TAS101 – low voltage residential PAYG)

33 The maximum demand figure applying to peak and off-peak periods during the monthly billing cycle is an average of the four highest peaks in demand recorded for the customer over the course of the month during the relevant peak and off-peak periods which apply to TAS87.

34 These tariffs are companion tariffs to other tariffs in the tariff suite and may have additional restrictions for the availability of energy. To determine whether a companion tariff applies, refer to the Network Tariff Application Guide 2024-2029 document that accompanies this proposal

Table 9. Proposed tariff parameters for low voltage small business network tariffs

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TAS94 – Low voltage small business time of use consumption **[default network tariff]**	Daily service charge c/day	Consumption charge c/kWh	Weekdays 07:00 to 10:00 and 16:00 to 21:00	Weekdays 10:00 to 16:00	All other times	✖
TAS88 – Low voltage small business time of use demand	Daily service charge c/day	Demand charge c/kW/day	Weekdays[35] 07:00 to 10:00 and 16:00 to 21:00	✖	All other times	✖
TAS98 – Low voltage small business consumer energy resources (CER)	Daily service charge c/day	Demand charge c/kW/day	Weekdays[35] 07:00 to 10:00 and 16:00 to 21:00	✖	All other times	✖
TAS22 – Low voltage small business general light and power **[obsolete]**	Daily service charge c/day	Consumption charge c/kWh	Anytime			

Table 10. Proposed tariff parameters for irrigation network tariffs

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TAS75 – Low voltage irrigation time of use consumption	Daily service charge c/day	Consumption charge c/kWh	**Summer (1 Oct – 31 Mar)**			
			✖	Weekdays 07:00 to 22:00	All other times	✖
			Winter (1 Apr – 30 Sep)			
			Weekdays 07:00 to 22:00	Weekends 07:00 to 22:00	All other times	✖

35 The maximum demand figure applying to peak and off-peak periods during the monthly billing cycle is an average of the four highest peaks in demand recorded for the customer over the course of the month during the relevant peak and off-peak periods which apply to these network tariffs

Table 11. Proposed tariff parameters for low voltage large business network tariffs

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TAS89 – Low voltage large business time of use demand	Daily service charge c/day	Demand charge c/kVA/day	Weekdays 07:00 to 10:00 and 16:00 to 21:00	✖	All other times	✖
TAS82 – Low voltage large business kVA	Daily service charge c/day	Demand charge c/kVA/day and Consumption charge c/kWh	Consumption – Anytime Demand – Anytime			
TAS84T1 – TAS84T4 Low voltage embedded networks (Tier 1 – Tier 4) **[default network tariff for low voltage business embedded networks]**	Daily service charge[36] c/day	Consumption charge c/kWh and Demand charge c/kVA/day[37]	**Consumption – Anytime**			
			Weekdays 07:00 to 10:00 and 16:00 to 21:00	✖	✖	✖

36 Based on connection capacity

37 The demand component of this network tariff applies as an excess demand charge when demand exceeds 8.5 kW at anytime

Table 12. Proposed tariff parameters for high voltage large business network tariffs

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TAS15 – High voltage kVA specified demand (>2 MVA)[38]	Daily service charge c/day	Consumption charge for peak, shoulder and off-peak c/kWh + Specified & Excess Demand charges[39] c/kVA/day	**Consumption Summer (1 Oct – 31 Mar)**			
			✖	Weekdays 07:00 to 22:00	All other times	✖
			Consumption Winter (1 Apr – 30 Sep)			
			Weekdays 07:00 to 22:00	Weekends 07:00 to 22:00	All other times	✖
TASSDM – High voltage kVA specified demand (<2 MVA)[38]	Daily service charge c/day	Consumption charge for peak, shoulder and off-peak c/kWh + Specified & Excess Demand charges[39] c/kVA/day	**Consumption Summer (1 Oct – 31 Mar)**			
			✖	Weekdays 07:00 to 22:00	All other times	✖
			Consumption Winter (1 Apr – 30 Sep)			
			Weekdays 07:00 to 22:00	Weekends 07:00 to 22:00	All other times	✖
TAS14T1 – TAS14T2 – High voltage embedded networks **[default network tariff for high voltage business embedded networks]**	Daily service charge[40] c/day	Consumption charge c/kWh and Demand charge c/kVA/day[41]	**Consumption – Anytime**			
			Weekdays 07:00 to 10:00 and 16:00 to 21:00	✖	✖	✖

ITC (**TASCUS**) network tariffs are included in the high voltage large business network tariff class and typically applies to customers with an electrical demand in excess of 2.0 MVA or where a customer's circumstances in a pricing zone identifies the average shared network charge to be meaningless or distorted. Individually calculated customer network charges are determined by modelling the connection point requirements as requested by the customer or their agents.

Most ITC prices are based on actual transmission use of system charges for the relevant transmission connection point (preserving the pricing signals within the transmission charges), plus charges associated with the actual shared distribution network utilised for the electricity supply, along with connection charges based on the actual connection assets employed. This provides the greatest cost reflectivity for this type of customer and is feasible since the number of such customers is relatively small.

Terms and conditions for these customers are contained within individually negotiated connection agreements.

38 No later than two months prior to the commencement of a financial year, customers on this network tariff are required to reach an agreement about the "Specified Demand" for their electrical installation. Excess demand charges will apply where demand exceeds the specified demand

39 Excess demand charges apply to any daily maximum demand exceeding the specified demand

40 Based on connection capacity

41 The demand component of this network tariff applies as an excess demand charge when demand exceeds 8.5kW at anytime

Table 13. Proposed tariff parameters for unmetered supplies

Network tariff	Network access	Charging parameters	Peak	Shoulder	Off-peak	Super off peak
TASUMS – Unmetered supply general	Daily service charge c/day	Consumption charge c/kWh			Anytime	
TASUMSSL – Unmetered supply public lighting	✖	Demand charge c/lamp watt/day			Anytime	

21.4.2 Tariff classes

Distribution revenue is allocated across the tariff classes according to usage of various groups of customers. All customers on standard control services have been assigned to the most applicable network tariff class which is determined based on a customer's current and future use of the network. This enables retail customers to be grouped together in an economically efficient basis and avoids unnecessary transaction costs.

The following outlines our proposed network tariff class structure as set out in section 21.2:

- Low voltage residential
- Low voltage small business
- Low voltage irrigation
- Low voltage large business
- High voltage large business
- Unmetered supplies.

The sections below outline the descriptions for customers who may be assigned to network tariffs within these tariff classes. TasNetworks' *Network Tariff Application Guide 2024-2029* provides further details on how our network tariffs are to be applied to customers.

21.4.2.1 Low voltage residential tariff class

Residential tariffs are for low voltage installations that are premises wholly or principally used as private residential dwellings.

21.4.2.2 Low voltage small business tariff class

Network tariffs within this class are for low voltage installations located on premises that are not used wholly or principally as private residential dwellings.

Small business customers are defined for those customers whose demand is equal to or less than 70kVA (i.e., less than or equal to 100 amps per phase).[42]

21.4.2.3 Low voltage irrigation tariff class

This low voltage network tariff class is for primary producers' business installations that are used solely for the irrigation of crops (including pasture) and classified as ANZSIC 01.

21.4.2.4 Low voltage large business tariff class

The network tariffs in this class are for low voltage multi-phase installations that are not used wholly or principally as private residential dwellings. There are no restrictions on the use of the supply (that is, the supply may be used for general power, heating, storage water heating etc.) on network tariffs in this class.

Large business customers are defined for those customers whose demand is greater than 70kVA (i.e., greater than 100 amps per phase).[44]

42 Existing tariff assignment will be grandfathered irrespective of the customer's current demand. However, if the customer chooses to change their connection or their tariff, the customer must select a tariff according to their demand

21.4.2.5 High voltage large business tariff class

Network tariffs in this class are for installations that take supply from the high voltage distribution network, with no assets owned by TasNetworks beyond the connection point. Customers must supply their own transformers and switchgear for installations within this network tariff class.

Metering of consumption (and demand) for an installation on this network tariff occurs at the high voltage connection point and requires a meter capable of recording interval data.

21.4.2.6 Unmetered supply tariff class

Network tariffs within this class are intended to be applied to small, low voltage, low demand installations with a relatively constant load profile.

These network tariffs are unmetered. For more information regarding the eligibility of an installation for this tariff and the calculation of network charges, see *TasNetworks' Service and Installation Rules*.

21.5 Tariff assignment procedures and policies

This section will demonstrate compliance with the following sections of the NER:		Section reference
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements: (2) the policies and procedures the *Distribution Network Service Provider* will apply for assigning retail customers to tariffs or reassigning retail customer from one tariff to another.	21.5.2
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of retail customers from one *tariff class* to another, the *AER* must have regard to the following principles: (1) retail customers should be assigned to tariff classes on the basis of one or more of the following factors: (i). the nature and extent of their usage or intended usage of distribution services (ii). the nature of their connection to the network (iii). whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement (2) *retail customer*s with a similar connection and *distribution service* usage profile should be treated on an equal basis (3) (4) a *Distribution Network Service Provider's* decision to assign a customer to a particular *tariff class*, or to re-assign a customer from one *tariff class* to another should be subject to an effective system of assessment and review.	21.5.3
6.18.4(b)	If the *charging parameters* for a particular tariff result in a basis of charge that varies according to the *distribution service* usage profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	21.5.3
11.141.13(a)(2)	relates to the eligibility conditions that are applicable to proposed export tariffs.	Not applicable[43]

43 TasNetworks is not proposing export tariffs for the 2024-2029 regulatory control period

21.5.1 Proposed network tariff assignment policy

Clause 6.18.1A(a)(2) of the NER requires that a TSS include the policies and procedures that the distribution network service provider (**DNSP**) will apply to assigning or re-assigning retail customers from one network tariff to another. TasNetworks is proposing the following network tariff assignment provisions.

Our network tariff assignment policy, is that from 1 July 2024:

1) The time of use consumption network tariffs for residential customers (TAS93) and small business customers (TAS94) will be the default network tariff.
2) The following flat rate network tariffs will be made obsolete:[44]
   - TAS31 – residential general light and power
   - TAS22 – small business general light and power
   - TAS41 – uncontrolled energy heating and hot water.
3) **All existing residential and small business customers** who, as at 30 June 2024, were assigned to an obsolete network tariff may continue to be assigned to those tariffs from 1 July 2024, until such time as they either opt to change their network tariff(s) to which they are assigned, or have an advanced meter installed on their premises (refer to point 5 below).
4) Residential and small business customers who **move into established premises** will be assigned to the same network tariff(s) as the previous occupants of those premises. This provision extends to any obsolete network tariffs, meaning that if the previous occupants of a property were assigned to a now obsolete network tariff the new occupant will be assigned to the same network tariff(s) – unless:
   a. they opt to change the network tariff(s) to which they are assigned. Customers who choose to opt-out of obsolete network tariff(s) on or after 1 July 2024 will not be permitted to revert to these obsolete network tariff(s) in the future; or
   b. have their meter upgraded or replaced with an advanced meter at their premises (refer to point 5 below).
5) Residential or small business customers who, on 1 July 2024, were assigned to the obsolete network tariffs (TAS31, TAS41, TAS22, TAS61) that have their **meter upgraded or replaced with an advanced meter** ('trigger event') at their premises will be assigned to the default time of use consumption network tariff applicable to their tariff class (TAS93 or TAS94) 12 months following the date of the trigger event. The intent of the delay is to enable customers to collect their time of use metering data to inform the customer's choice about the retail and, by association, network tariffs they want to be supplied under in the future. Affected customers may choose to either:
   a. exercise their choice of network tariff before the 12-month delay period ends and elect to **opt-out** of the default network tariff. This means that the automatic reassignment to the default time of use consumption network tariff would not be processed, and customers would remain on their existing network tariff(s); or
   b. **nominate an alternative** network tariff(s) for which they are eligible in accordance with TasNetworks' tariff assignment policy; or
   c. **accept the reassignment** to the default time of use consumption network tariff applying to their tariff class (TAS93 or TAS94).

   At the conclusion of the 12-month data collection period, residential and small business customers who have not chosen to either opt-out, nominate an alternative network tariff, or accept the reassignment will be assigned to the default time of use consumption network tariff for which they are eligible. Once assigned to the default network tariff, residential and small business customers are no longer able to revert to any obsolete network tariffs to which they may have previously been assigned.
6) **All new residential and small business connections** on or after 1 July 2024 will be assigned to the default time of use consumption network tariff applicable to their tariff class (TAS93 or TAS94). The customer may opt-out by requesting assignment to another network tariff in their tariff class that is not obsolete. New customers will not have the option of being assigned to the obsolete network tariffs (TAS31, TAS41, TAS22, TAS61).
7) A residential or small business customer who voluntarily **opts into a time of use consumption network tariff** on or after 1 July 2024 will be unable to revert to any of the obsolete network tariffs (TAS31, TAS41, TAS22, TAS61).
8) A residential or small business customer who installs an **electric vehicle fast charger**[45] at their premises will be assigned to TasNetworks' default time of use consumption network tariff. The customer may choose to opt into another cost-reflective network tariff but will be unable to choose or remain on any of the flat-rate network tariffs noted in point 2 above.

44 TasNetworks' low voltage controlled energy off-peak with afternoon boost (TAS61) was made obsolete on 1 July 2019. The assignment policy from point 3 of section 21.5.1 onwards applies to TAS61, unless specifically stated otherwise. Should a customer wish to retain this network tariff following a trigger event (but prior to the conclusion of the 12-month opt-out period), customers would need to request that the retailer reprogram their meter accordingly

45 TasNetworks' recognises the lack of visibility of EV charger installations and this assignment rule will be dependent on customers self-declaring an EV fast charger installation. An EV fast charger refers to a dedicated EV charger i.e., the EV is not charged from a regular household electricity outlet.

In discussion with our stakeholders, we have concluded that this is the best approach to progress the transition to cost reflectivity while providing protection to customers who are experiencing vulnerability. Table 15 summarises the circumstances in which the 12-month opt-out period will be applied.

Table 14. Our proposed default tariff assignment policy for residential and small business customers

Trigger events	Retain current network tariff	Default network tariff	Cost-reflective network tariff	12-month opt-out period
Advanced meter installation		✔		✔
New connection		✔		
Opt into alternative network tariff			✔	
Customer relocation	✔†			
EV fast charger installation		✔	✔	

† Refers to the network tariff(s) applying to the property the customer moves into, rather than the network tariffs applying to the customer's previous abode or business premises.

21.5.1.1 12-month opt-out period

The assignment to the relevant default network tariff is delayed by 12 months from the 'trigger' date e.g., meter installation i.e., the network tariffs applying to the customer's installation before the installation of an advanced meter will continue to apply for another 12 months after the change, at which pint TasNetworks will then reassign the customer's installation to the relevant default network tariff (unless the customer has opted-out of the reassignment). This proposed 12-month opt-out period provides customers (who have had an advanced meter installed) the opportunity to collect data throughout the year and determine whether they can take advantage of the change in network tariff to better manage their electricity costs. It also provides those customers who may be in vulnerable situations the opportunity to understand and respond to changing price signals.

At the end of the 12-month delay period applying to each installation that had their meter exchanged for an advanced meter, TasNetworks will commence charging the customer's retailer for the customer's use of the default network tariff, unless TasNetworks has received advice that the customers has opted-out. It will be up to the retailer to determine whether they choose to pass those time of use network pricing signals onto the customer via their retail billing process.

Any customer moving into a property part way through a 12-month delay before reassignment to a default network tariff will only remain on the network tariffs currently assigned to that installation for the balance of the 12-month delay period, unless they choose to opt-out of the default network tariff or opt-in to another network tariff(s) before the tariff reassignment is to take place.

Table 16 summarises our proposed network tariff assignment policy, where from 1 July 2024 all customers will remain on their existing tariffs. However, from 1 July 2024 new connections, and meter upgrades and replacements for residential and small business customers will result in the customer being assigned, by default, to the relevant time of use consumption tariff. However, these customers may choose to connect to any of the alternative tariffs upon request.

Table 15. Summary of our proposed tariff assignment and reassignment to primary network tariffs

Customers' network tariff on 1 July 2024	Assignment trigger	Network tariff choice options (upon request)
Residential customers		
TAS93 – Low voltage residential time of use consumption	Existing customers remain New connections Meter upgrades Meter replacements EV charger installation Customer choice	TAS87 – Low voltage residential time of use demand; or TAS97 – Low voltage residential time of use consumer energy resources (CER)
TAS87 – Low voltage residential time of use demand	Existing customers remain Customer choice	TAS93 – Low voltage residential time of use consumption; or TAS97 – Low voltage residential time of use consumer energy resources (CER)
TAS97 – Low voltage residential time of use consumer energy resources (CER)	Existing customers remain Customer choice	TAS93 – Low voltage residential time of use consumption; or TAS87 – Low voltage residential time of use demand
TAS31 – Low voltage residential general light and power [obsolete]	*Existing customers remain*	*TAS93 – Low voltage residential time of use consumption; or* *TAS87 – Low voltage residential time of use demand; or* *TAS97 – Low voltage residential time of use consumer energy resources (CER)*
Small business customers		
TAS94 – Low voltage small business time of use consumption	Existing customers remain New connections Meter upgrades Meter replacements EV charger installation Customer request	TAS88 – Low voltage small business time of use demand; or TAS98 – Low voltage small business time of use demand consumer energy resources (CER)
TAS88 – Low voltage small business time of use demand	Existing customers remain	TAS94 – Low voltage small business time of use consumption; or TAS98 – Low voltage small business time of use demand consumer energy resources (CER)
TAS98 – Low voltage small business time of use demand consumer energy resources (CER)	Existing customers remain	TAS94 – Low voltage small business time of use consumption; or TAS88 – Low voltage small business time of use demand
TAS22 – Low voltage small business general light and power [obsolete]	*Existing customers remain*	*TAS94 – Low voltage small business time of use consumption; or* *TAS88 – Low voltage small business time of use demand; or* *TAS98 – Low voltage small business time of use demand consumer energy resources (CER)*

Customers whose 'trigger event' occurred up to and including 30 June 2024 will have the 2019-2024 default network tariff assignment policy applied to them,[46] i.e., there will be a 12-month data collection period to allow customers to assess the impact of the network tariff change.

21.5.2 Tariff class assignment policies and procedures

Clause 6.18.4(a) of the NER requires that a TSS include the provisions governing the assignment or reassignment of retail customers to tariffs classes.

Assignment of existing retail customers to tariff classes at the commencement of the 2024-2029 regulatory control period

1. TasNetworks' retail customers will be assigned to the network tariff class to which they were assigned immediately prior to 1 July 2024 if:

    a) they were a retail customer prior to 1 July 2024

    b) they continue to be a retail customer as at 1 July 2024

    with the exception of retail customers in the following tariff classes – controlled energy, uncontrolled energy, ITC and street lighting. Customers who are in these tariff classes prior to the commencement of the 2024-2029 regulatory control period on 1 July 2024 will be re-assigned as follows:

    - Controlled and uncontrolled tariff classes will be reassigned to the residential network tariff class
    - ITC network tariff class will be reassigned to the large business high voltage network tariff class
    - Street lighting network tariff class will be reassigned to the unmetered supply network tariff class.

Assignment of new retail customers to a network tariff class during the 2024-2029 regulatory control period

2. If, after 1 July 2024, TasNetworks becomes aware that a person, business or organisation is to become a retail customer, then TasNetworks must determine the tariff class to which the new customer will be assigned.

3. In determining the tariff class that a new retail customer will be assigned or re-assigned to, TasNetworks must take into account one or more of the following factors:

    c) the nature and extent of a retail customer's usage[47]

    d) the nature of the retail customer's connection to the network[48]

    e) whether remotely read interval metering or other similar metering technology has or will be installed at the retail customer's premises.[49]

4. In addition to the above requirements, when assigning or re-assigning a retail customer to a tariff class, TasNetworks must ensure that:

    f) retail customers with similar connection and usage profiles are treated equally[50]

    g) retail customers who have micro-generation facilities are not treated less favourably than retail customers with similar load profiles without such facilities.[51]

Re-assignment of existing retail customers to another existing or new network tariff class during the regulatory control period

5. TasNetworks may reassign a retail customer to another network tariff class if the customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that retail customer to remain assigned to the network tariff class to which they are currently assigned. To determine the tariff class to which the retail customer is to be re-assigned, TasNetworks must comply with Clauses 6.18.4(1), 6.18.4(2) and 6.18.4(3) of the NER as well as points 3 and 4 above.

TasNetworks initiated network tariff class assignment

6. The assignment of customers to tariff classes and network tariffs is reviewed as part of the annual process of developing network tariffs for regulatory approval. We have set procedures and criteria to determine when it may be appropriate for a customer to be reassigned to a different network tariff class, or where the basis of a customer's demand charges should be amended. This change is usually the result of changes in the customer's energy consumption, expected maximum demand or connection characteristics. These procedures ensure the customer's underlying network tariff is appropriate for their assumed usage or load profile.

Reassignment triggered by the customer or the customer's retailer

7. Customers and the customer's retailer should monitor the suitability of the network charges applied. Where a customer or customer's retailer identifies that the network tariff to which the customer is assigned is not suitable, they must advise TasNetworks of the need for re-assignment.

46 Refer to TasNetworks' Revised Tariff Structure Statement 2019-2024

47 NER, Clause 6.18.4(a)(1)(i)

48 NER, Clause 6.18.4(a)(1)(ii)

49 NER, Clause 6.18.4(a)(1)(iii)

50 NER, Clause 6.18.4(a)(2)

51 NER, Clause 6.18.4(a)(3)

Obsolete tariffs

8. An obsolete network tariff is a network tariff that may apply to existing TasNetworks' customers but is not available to new customers. Customers who choose to transfer from an obsolete network tariff to another network tariff will lose all rights to all obsolete network tariffs, and the customer will be required to select a currently available network tariff. Customers may not go back to an obsolete network tariff once they have transferred from it.

9. Exceptions apply when customers are moved to a default time of use consumption tariff as a result of a change in their meter (see section 21.5.1). Refer to TasNetworks' Tariff Application Guide 2024-2029 which is available on https://www.tasnetworks.com.au/Poles-and-wires/Pricing/Our-prices for further details in relation to obsolete network charges.

Notifications

10. If TasNetworks has initiated the re-assignment of a retail customer to another network tariff, TasNetworks must notify the customer's retailer in writing of the network tariff to which the retail customer has been assigned or re-assigned, prior to the assignment or re-assignment occurring.

    a) In the event that a customer's retailer initiates the network tariff re-assignment, TasNetworks will notify the retailer in writing of the success or otherwise of the application. Where the application is not successful, or where TasNetworks has decided to assign a network tariff other than that proposed by the retailer, TasNetworks will advise the retailer of the reasons for that decision.

    b) The obligation to notify a customer's retailer of a tariff re-assignment does not apply if the customer has agreed with their retailer and TasNetworks that its network tariffs are to be billed by TasNetworks directly to the retail customer, in which case TasNetworks must notify the customer directly.

11. If TasNetworks receives a request for further information about a network tariff assignment or reassignment from a customer, then we will provide such information unless we consider the requested information is confidential. If the customer's retailer disagrees with any such confidentiality claim, the customer may have recourse to the dispute resolution procedures referred to be under 'Objections'.

12. The notification to the customer's retailer must include advice informing the customer's retailer that they may request further information from TasNetworks and that the retail customer may object to the proposed re-assignment. TasNetworks will encourage retailers to request further information or clarification of network tariff re-assignment decisions before lodging objections.

13. The customer's retailer is wholly responsible for conveying the correct information to TasNetworks and communicating any further requests and decisions made by TasNetworks to the customer.

14. The notice to the customer's retailer must:

    a) include a copy of TasNetworks' internal procedures for reviewing objections and a link to where they can find such information on our website

    b) inform the customer's retailer that if an objection is not resolved to their satisfaction then they are entitled to escalate the matter to the Energy Ombudsman Tasmania

    c) advise the customer's retailer that if their objection is not resolved to their satisfaction after escalating the matter to the Energy Ombudsman Tasmania, then they are entitled to seek a decision by the AER via the dispute resolution process available under Part 10 of the National Electricity Law.

Objections

15. The following steps will be applied as part of the objection process:

    a) Retailers must submit an objection in writing to regulation@tasnetworks.com.au. Retailers should make reference to their customer's load, connection and metering characteristics as part of the tariff re-assignment objection

    b) TasNetworks must review the objection, including any documentation provided. TasNetworks must assess if the original decision complies with this policy and regulatory obligations and must take into consideration any supporting evidence and documentation provided

    c) Within 20 business days of receiving the objection, TasNetworks must notify, in writing, the customer's retailer and, where appropriate, the customer, of the outcome of the review and any reasons for accepting or rejecting the objection. If TasNetworks believes the objection review process will exceed 20 business days, TasNetworks must advise the retailer, and where appropriate, the customer accordingly.

16. If a customer's retailer's objection to a tariff assignment or re-assignment is upheld:
    a) If the objection is received within 20 business days from the date the retailer was advised of the original network tariff assignment or re-assignment decision, TasNetworks must apply the changes from the last actual meter read date prior to the network tariff application.
    b) If the objection is received after 20 business days from the date the retailer was advised of the original network tariff assignment or re-assignment decision, TasNetworks must apply the changes from the last actual read date prior to the date the objection was received by TasNetworks.
    c) If TasNetworks requests further information from the retailer pertaining to the objection application, and such information is not provided within 20 business days from the date requested, TasNetworks must apply the changes following a subsequently successful objection from the last actual read date prior to the date the additional requested information is received.
17. Any adjustments to the network tariff charges billed to retailers, or directly to customers, because of an objection to an assignment or re-assignment being upheld, must be made by TasNetworks as part of the normal billing process.
18. If an objection to a tariff assignment or re-assignment made by a customer's retailer is upheld by the relevant body noted in points 14(b) and 14(c) above, then any adjustment which needs to be made to tariffs will be done by TasNetworks at the commencement of the next billing period for the customer or the originally notified date, whichever is the later.

21.5.3 Principles governing assignment or re-assignment of retail customers to tariff classes

Clause 6.18.4 for the NER sets out the principles governing the assignment or re-assignment of retail customers to tariff classes.

Assessments of the tariff class to which a retail customer is assigned are based on the:

- nature of the customer's usage, i.e., whether they are a residential or business customer
- customer's connection to the distribution network, i.e., whether they are connected to the LV or HV network
- usage profile for customers, for example, how customers consume energy.

The NER also require that retail customers with similar connection and distribution service usage profiles should be treated on an equal basis and that any network tariff assignment or re-assignment be subject to an effective system of assessment and review.

As noted in section 21.2, TasNetworks has reviewed its tariff classes for the 2024-2029 regulatory control period and has amended its network tariff class structure to better reflect the nature and usage of the distribution network by customers.

21.5.4 Impact of tariff assignment and reassignment on customers

The assignment or re-assignment of a retail customer to a particular network tariff does not necessarily translate to a change in the electricity retail tariff applying to that customer. This is because, rather than billing customers directly, TasNetworks charges electricity retailers for their customers' access to and use of the network.

The assignment or re-assignment of a retail customer to a network tariff determines what we charge retailers when we bill them for a customer's connection and the delivery of electricity. The charge retail customers see on their bills reflect how the retailer packages its costs for particular customers, including generation costs, network charges and the retailer's costs.

Re-assigning a customer to a different network tariff may not change the retail tariff applying to the customer, unless the retailer's tariff is underpinned by the network tariff.

21.6 Export tariff transition strategy

This section will demonstrate TasNetworks' compliance with the following sections of the NER:			Section reference
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements:		21.6
	(2A)	a description of the strategy or strategies the *Distribution Network Service Provider* has adopted, taking into account the pricing principle in clause 6.18.5(h), for the introduction of export tariffs including where relevant the period of transition (*export tariff transition strategy*)	

TasNetworks has incorporated the AER's *Export Tariff Guidelines* in preparing this export tariff transition strategy, particularly page 6 which sets out the AER's key expectations with respect to the transition strategy for those distributors that are proposing two-way pricing and those that are not proposing two-pricing for the upcoming regulatory control period.

Tasmania has a relatively low penetration of solar PV installations compared to other jurisdictions and TasNetworks has not yet experienced widespread issues relating to the export of solar PV generation to the network.

While solar PV capacity is expected to grow throughout the 2024-2029 regulatory control period and beyond, at this stage TasNetworks does not expect this to result in material issues (relating to the export of solar PV generation) that will drive network expenditure. This is because solar PV generation will in large part be absorbed by storage (for later use, such as in peak times) and increasingly by electric vehicles. Tasmania has a comparatively stable minimum (and base) demand, which is discussed further in section 22.6.4 of the TSES.

On this basis, TasNetworks is not proposing to introduce export tariffs in the 2024-2029 regulatory control period.

To inform whether TasNetworks will seek to propose and establish export tariffs in future regulatory control periods, beyond the 2024-2029 regulatory control period, TasNetworks will continue to assess the intrinsic hosting capacity throughout the network in the context of projections for CER installations – generation storage, and electric vehicles – all of which will influence how the hosting capacity is consumed. This will inform whether CER exports are expected to drive increased network costs in the future and therefore whether there is a strong rationale to incorporate export tariffs in the Tasmanian context. It is considered to be important to distinguish between localised and more general issues with respect to CER exports and network hosting capacity.

Should there be a rationale to incorporate export tariffs based on a limited intrinsic hosting capacity and projections, TasNetworks expects that it would undertake relevant tariff trials prior to formally proposing export tariffs to the AER. Trials are a critical input as they can test customer responsiveness and sentiments on a smaller scale, and enable feedback and refinements to be made before implementing tariffs for the entire customer base. TasNetworks will also review the findings from other distributors in their respective export tariff trials in the Tasmanian context. No export tariff trials are currently planned for the 2024-2029 regulatory control period but the need to undertake export tariff trials will continue to be assessed throughout the period.

Further, TasNetworks will incorporate customer and stakeholder feedback in any future design of export tariffs in the Tasmanian context, and will consider alternative ways of achieving desirable outcomes – such as through revised time of use tariffs. TasNetworks understands that there are many ways of signalling a more favourable utilisation of the network to customers and these levers need to be tested in the context of stakeholder support in planning our future strategy. TasNetworks will continue to work through the PRWG to engage with stakeholders in relation to two-way pricing in the future.

ALTERNATIVE CONTROL SERVICES

21.7 Alternative control services

The TSS provisions in the Rules apply to direct control services,[52] which comprise SCS and ACS. The purpose of this section of the TSS is to address the Rule requirements in relation to ACS.

ACS include regulated metering services for small customers,[53] public lighting and ancillary services (quoted services and fee-based services).

21.7.1 Tariff classes for alternative control services

This section addresses TasNetworks' compliance with the requirement in the NER for DNSPs to set out in their TSS the tariff classes applying to direct control services.

NER clause	TSS requirement	Section reference
6.18.1A(a)(1)	A tariff structure statement of a Distribution Network Service Provider must include the tariff classes into which retail customers for direct control services will be divided for the relevant regulatory control period.	21.7.1
6.18.3	Each retail customer for direct control services must be a member of one or more tariff classes and separate tariff classes must be established for retail customers who receive standard control services[54] and alternative control services. A tariff class must be constituted with regard to grouping retail customers together on an economically efficient basis and avoiding unnecessary transaction costs.	21.7.1

Our tariff classes for ACS reflect the nature of the services provided, with similar services being grouped together. This approach is economically efficient, in that the tariffs reflect the cost of the services and the characteristics of the customer using the service do not impact the cost of the service. Table 17 defines each of our tariff classes for ACS, which are consistent with those approved by the AER for the 2019-2024 regulatory control period.

Table 16. Tariff classes for alternative control services

Tariff class	Definition
Metering	Metering services are those services provided with respect to the provision, installation and maintenance of standard meters installed prior to December 2017 and the associated services provided to retail customers. This includes the metering services provided to small customers (using type 6 and type 7 meters) in our role as metering provider and meter data provider.
Public lighting	Public lighting services are those services provided with respect to: • the provision, construction, and maintenance of our public lighting assets • the maintenance of public lighting assets owned by customers (contract lighting). This includes the provision, construction, and maintenance of new and/or emerging public lighting technology services.
Ancillary services – Fee based services	Fee based services are provided for the benefit of a single customer rather than uniformly supplied to all customers. These services are provided at the request of a third party and are typically initiated by way of a service request received from a retailer. Fee based services include the provision of basic connections to the network.

52 NER, Clause 6.18.1

53 Type 6 and 7 meters

54 Refer to section 21.4 for tariff structures relating to standard control services

Tariff class	Definition
Ancillary services – Quoted services	Quoted (non-standard) services are those services where the nature and scope of the service is specific to individual customer needs and varies from customer to customer. Consequently, the cost of providing the services cannot be estimated without first knowing the customer's specific requirements. It is not possible therefore, to set generic fixed fees in advance for these services. Requests for quoted services may be received from a customer or from a retailer on behalf of a customer.

21.7.2 Approach to setting tariffs

This section sets out TasNetworks' compliance with the NER regarding TSS and the pricing of direct control services.

NER clause	TSS requirement	Section reference
6.18.1A(a)(5)	A tariff structure statement must include a description of the approach that TasNetworks will take in setting each tariff in each pricing proposal during the 2024-2029 regulatory control period.	21.7.2
6.18.1A(b)	A tariff structure statement must comply with the pricing principles for direct control services.	21.7.2
6.18.5(a)	The network pricing objective is that the tariffs that TasNetworks charges in respect of its provision of direct control services to a retail customer should reflect TasNetworks' efficient costs of providing those services to the retail customer.	21.7.2

21.7.2.1 Metering, public lighting and ancillary services (fee-based services)

Metering, public lighting, and ancillary services price caps are calculated for each year of a regulatory control period using a price control mechanism approved by the AER (see Attachment 16 Control mechanisms).

21.7.2.2 Ancillary services – quoted services

The cost to the customer of quoted services is built-up based on the cost of the inputs to the particular service, that is, labour time and rates, materials, contractors and other costs,[55] with overheads apportioned to the work. TasNetworks is also required to include the income tax liability incurred by TasNetworks in relation to the provision of electricity connection assets involving cash contributions and/or gifted assets from customers. This cost buildup reflects the steps required to set prices for the diverse range of activities provided as quoted services.

The labour rates used in determining quoted services pricing are set out in the Indicative Pricing Schedule in Appendix B.

55 Includes regulated margin and tax due in relation to customer contributions.

Appendix A – Indicative pricing schedule for standard control services

The following schedules can be found in in the attachment to this document – Attachment 21, Tariff Structure Statement (2024-2029 Regulatory Proposal) – Indicative Network Tariff Prices.

Appendix B – Indicative pricing schedule for alternative control services

Schedules for the following indicative prices can be found in Attachment 21, Tariff Structure Statement (2024-2029 Regulatory Proposal) – Indicative ACS Prices

- Indicative prices for metering services
- Indicative prices for public lighting services
- Indicative prices for contract lighting services
- Indicative prices for fee-based services
- Proposed labour rates for quoted services

TasNetworks | Powering a Bright Future

Combined Proposal 2024-2029

Attachment 22
Tariff structure explanatory statement

Outline: The Tariff Structure Explanatory Statement provides explanations of our approach to designing and setting those tariffs, our objectives in pursuing network tariff reform, our reasons for choosing the tariffs which appear in the Tariff Structure Statement and how they comply with the National Electricity Rules.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	**Tariff structure explanatory statement**
Attachment 23	List of supporting documents
Attachment 24	Glossary

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INTRODUCTION

22.1 Overview

TasNetworks' Tariff Structure Statement (**TSS**) has been prepared under the requirements of Chapter 6 of the National Electricity Rules (**NER** or **the Rules**). It provides details of our proposed approach to network tariffs over the period from 1 July 2024 to 30 June 2029.

This Tariff Structure Explanatory Statement (**TSES**) is a companion document to TasNetworks' TSS.

The TSES provides supporting explanations for the network tariffs, structures and assignment polices proposed in TasNetworks' TSS, including how we have incorporated feedback received from our customers and stakeholders. It also provides an opportunity for TasNetworks to comment on our network strategy and how this will shape future network use and pricing strategy. We recommend reading this together with TasNetworks' TSS.

22.1.1 Executive summary

Across Australia, customers are changing how they use and engage in the supply and distribution of electricity. Technologies such as household solar photovoltaics (**PV**), electric vehicles (**EVs**) and battery storage are driving this change and shifting customer expectations of their network service provider (**NSP**).

It is projected that in Tasmania the uptake of these technologies will continue to increase over the 2024-2029 period and beyond. EV take-up is expected to accelerate towards the end of this decade, driven by advancements in battery technology, reduction in capital cost, availability of a wider range of models and an increase in customer confidence with visibility of, and access to, public fast charging infrastructure.

As the distribution network service provider (**DNSP**) in Tasmania, we are preparing for this change. Many of the current pricing structures were introduced prior to the advent of this technology and established at a time when customers had different expectations of the network. Our customers and stakeholders have told us that TasNetworks needs to provide future-ready pricing structures for our customers. We heard both support for change as well as calls for moderation in terms of the pace of the change. Stakeholders also urged for the inclusion of protections for customers experiencing vulnerability.

When developing future-ready pricing structures, our aim is to better reflect the costs incurred by TasNetworks and provide network tariffs that promote efficient use of the network. This is achieved through pricing signals to incentivise customers to, for example, use the network at times of lower demand as opposed to times of peak demand. We aim to achieve this in a way that enables customers to readily understand and choose to use our cost reflective network tariffs, such that the network tariffs we set can ultimately be reflected in the retail tariffs set by retailers.

As well as providing new network tariffs, our pricing strategy also involves incentivising more customers to take up current cost reflective network options, such as time of use network tariffs. Over time, this may support reduced expenditure on expanding the network, meaning we can deliver more electricity without additional network investment to manage growing peaks in demand.

To achieve this, we are proposing to:

- amend our network tariff classes to produce a more streamlined structure
- make flat rate network tariffs obsolete[1] for residential and small business customers connecting to the network or upgrading their meter
- retain the current time of use consumption-based network tariffs as the default tariff option for residential and small business customers
- continue removing cross-subsidies between tariff classes and individual network tariffs
- revise the timing of peak periods for the time of use consumption-based network tariff for small business customers (TAS94)
- introduce new network tariffs designed specifically for embedded networks

1 Refer to section 22.7.2 for further discussion on making the flat rate tariffs obsolete

- provide pricing options for our residential customers who are more actively engaged with their energy needs (such as electric vehicle owners)
- design network tariff trials to understand the relationship between new technologies, pricing and network impacts.

22.1.2 Document Structure

TasNetworks' TSES consists of several parts – Talking with our customers, Standard control services, Export tariff transition strategy and Alternative control services. Table 1 outlines the structure of the TSES.

Table 1. TSES document structure

Section		Purpose
Introduction		
22.1	**Overview**	Provides an overview of the TSES and the executive summary of what the TSES contains.
22.2	**The tariff structure documents**	Introduces TasNetworks and the purpose of the TSS and TSES.
Talking with our customers		
22.3	**TasNetworks' engagement approach**	Summarises TasNetworks' approach to customer and stakeholder engagement.
22.4	**TasNetworks' customers and stakeholders**	Describes our customers and stakeholders and their relationship with the development of the Tariff Structure Statement and the Tariff Structure Explanatory Statement.
22.5	**Customer and stakeholder engagement**	Outlines key activities we have undertaken with our stakeholders over the last three years, which include workshops, forums, dedicated meetings, surveys and engagement with our agricultural customers.
Standard control services		
22.6	**Pricing strategy overview**	Provides an overview of our pricing strategy and our customers who use the network. This section discusses how our customers are changing their use on the network due to technology changes, the benefits of our pricing reform and what we are proposing for 2024-2029.
22.7	**2024-2029 pricing proposal**	This section provides detailed analysis of our pricing proposal, including amending our tariff classes, altering our tariff assignment rules, proposing new embedded network tariffs, reviewing our peak windows, updating our consumer energy resources tariff for residential customers, and developing complementary measures to our tariff design. In this section we also detail a potential tariff trial to support our agricultural customers to accommodate their investment in new technologies.
Customer impacts of this pricing proposal		
22.8	**Introduction**	Introduces this section and sets out its intent.
22.9	**Indicative price paths**	Analyses the indicative price paths of TasNetworks' network tariffs.
22.10	**Residential customer behaviour**	Undertakes scenario analysis of our residential customers to assess changes in customer behaviour resulting from their investment in new technology. Price impacts are analysed based using the existing network tariffs and the proposed new residential network tariff.
22.11	**Small business impact analysis**	Additional analysis of small business types is undertaken to assess the impact of the proposed changes to the small business time of use consumption (TAS94) network tariff.
Export Tariff Transition Strategy		
22.12	**Export tariff transition strategy**	This section provides an outline of TasNetworks' current situation on energy exports on our network and our future position on implementing export network tariffs.

Section		Purpose
Alternative control services		
22.13 to 22.18	Alternative control services tariff class	This section explains how TasNetworks' alternative control services are priced for the 2024-2029 regulatory control period.
Appendices		
A	Setting our tariffs	Outlines the process TasNetworks undertakes to ensure network tariffs are efficient and cost reflective. Also provides an outline of how transmission costs are included in the distribution network tariffs.
B	Engaging customers in our pricing plan and tariff designs	Summarises each of the Policy and Regulatory Work Group (**PRWG**) engagement workshops conducted in support of the development of TasNetworks' regulatory proposal for the 2024-2029 regulatory control period, as well as the issues raised by members.

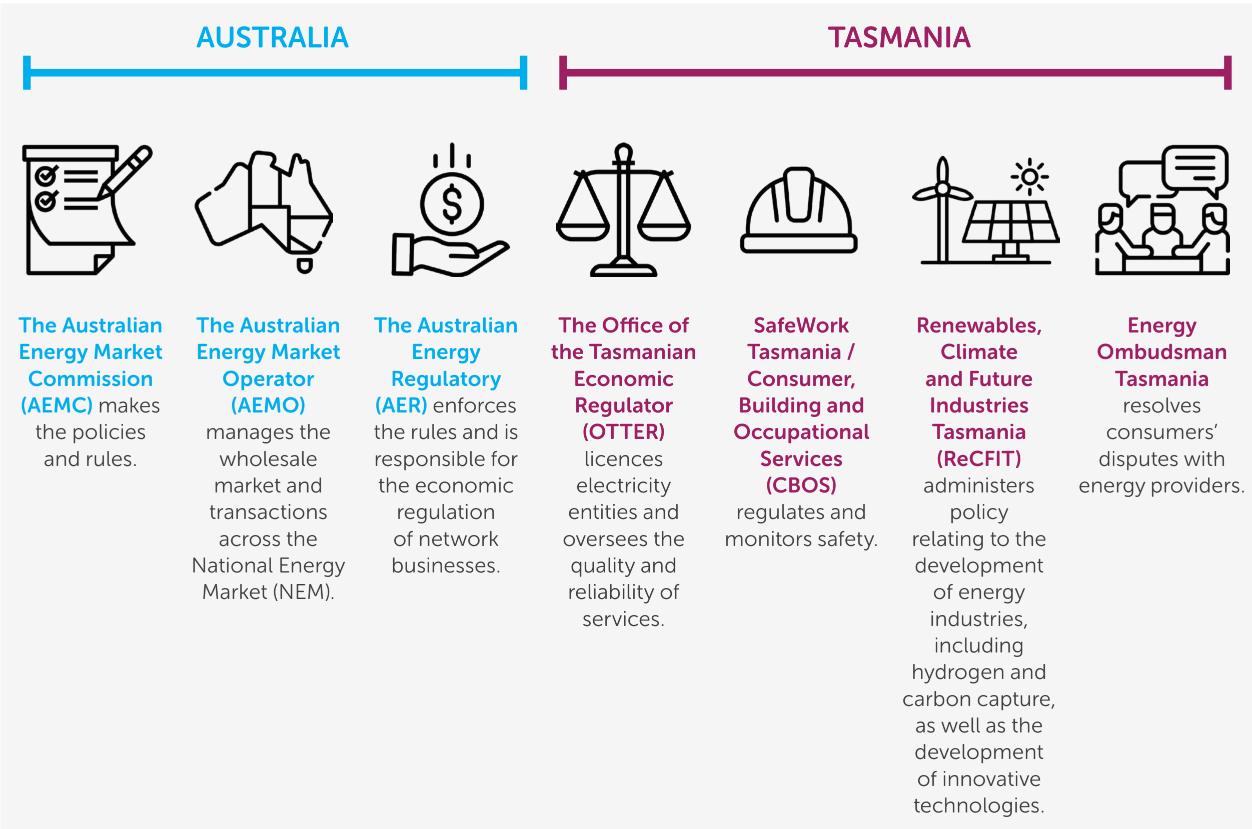
22.2 The tariff structure documents

This document outlines TasNetworks' strategy for recovering revenue as a DNSP.

22.2.1 The role of a network service provider

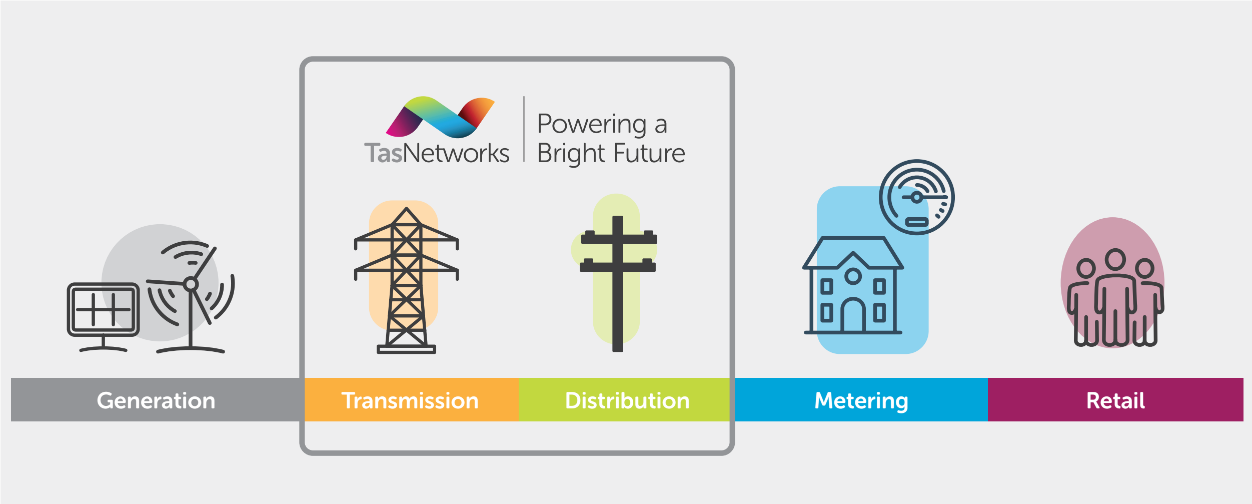
TasNetworks is a DNSP and Transmission Network Service Provider (**TNSP**) which operates within the National Electricity Market (**NEM**). We must adhere to a number rules and regulations at both the national and state level (Figure 1). These include rules applied by regulatory authorities like the Australian Energy Regulator (**AER**) and the Office of the Tasmanian Economic Regulator (**OTTER**).

Figure 1. TasNetworks' regulatory framework



The electricity supply chain consists of generation, transmission, distribution and retailers as shown in Figure 2. Unlike in other parts of the NEM, TasNetworks provides both electricity transmission and distribution services. The transmission network connects large scale generation to major energy consumers as well as the distribution network. The distribution network then provides network services to around 300,000 Tasmanian customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

Figure 2. TasNetworks' role in the energy supply chain



The AER regulates TasNetworks to ensure the provision of services delivered by TasNetworks are aligned to the National Electricity Objective (**NEO**) "to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity".

To ensure the NEO can be met, the AER sets the amount of revenue that we can recover from our customers for using our networks. The AER allows us to propose how we recover this revenue within constraints set out in the Rules. We do this by proposing network tariffs. Tariffs set the price for services that are provided by the electricity distribution network. The differences in tariffs reflect the varying ways customers use the network.

Our tariff strategy underpins the process undertaken for setting our tariffs and is outlined in the accompanying TSS. This document, the TSES, describes our approach to designing and setting tariffs, our objectives in pursuing network tariff reform, our reasons for choosing the tariffs which appear in the TSS and how they comply with the Rules. We have sought to explain the process by which we have set our network tariffs and how that process satisfies the principles established in the Rules. In doing so, it:

- outlines how we propose to move to pricing which is fairer for all our customers
- facilitates customer and stakeholder understanding of our pricing by providing an overview of network pricing and associated concepts
- sets out our proposed network tariff structures and charging parameters, as well as the approach for setting each tariff annually
- explains how we arrived at our proposed network tariffs and our future plans for tariffs in accordance with our strategy.

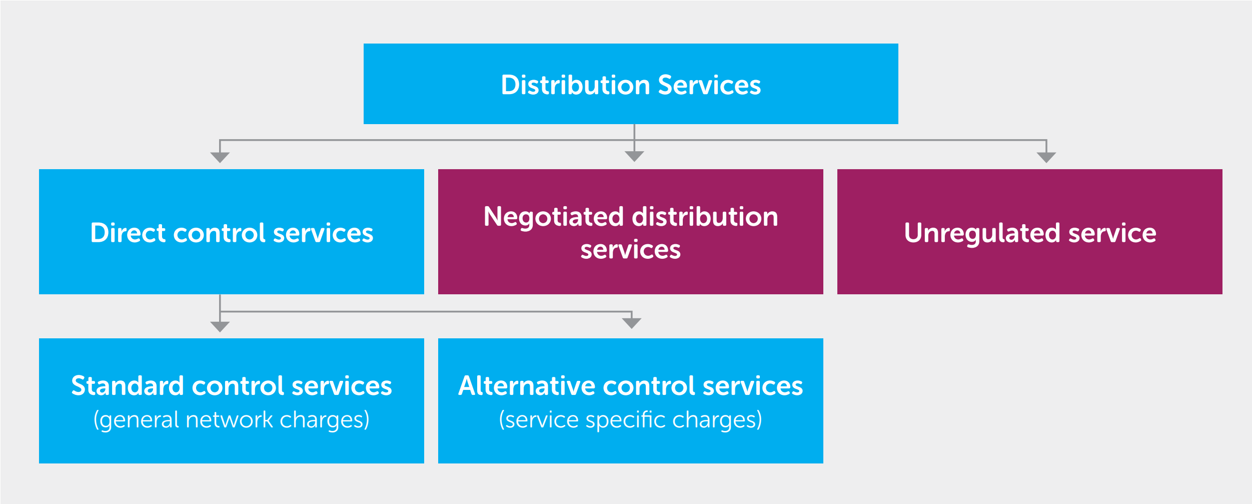
22.2.2 The services we provide

As part of the five yearly regulatory process the first step is the determination of which services will be regulated and how. This occurs through the Framework and Approach process. This delineation between services gives rise to a service classification. Services the AER determine need price regulation are termed direct control services. These are then further classified as standard or alternative control services.

Standard control services (**SCS**) refer to the regulation of network charges which involves the use of a cap on the amount of revenue that we are permitted to recover from our customers each year. General distribution network services which are relied on by most (if not all) customers, including the provision of complex connections to our distribution network, are known as 'standard control services'.

Alternative control services (**ACS**) refer to services where the costs – and the associated benefits from the service – can be directly attributed to a particular customer (for example, where a customer requests a service). For these services, instead of setting a revenue cap, the AER caps the prices that can be charged or sets the input costs that can be used by TasNetworks to quote jobs.

Figure 3. The services that TasNetworks' provide



22.2.3 Pricing strategy for direct control services

22.2.3.1 General network charges

The annual revenue allowance applying to our SCS is recovered through general network charges (network tariffs), and pay for the building, running and maintenance of the electricity distribution network. We apply a service charge to every connection to our network so that every household, business and organisation connected to the network makes a contribution towards the cost of the network service available to them.

22.2.3.2 Service specific charges

TasNetworks' ACS include regulated metering services for small customers, ancillary services (quoted services and fee-based services), and public lighting.

GLOSSARY

Term or Abbreviation	Description
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Capacity	The amount of electrical power that a part of the network can carry
Controlled load	The DNSP controls the hours in which the supply of electricity is made available
Cost reflective pricing	Pricing which is indicative of the true cost of supplying or providing a service
Demand	Electricity consumption at a point in time
Demand Management	The ability for DNSPs to constrain customers demand at critical times and attempt to modify customer behaviour
CER (previously referred to as DER)	Customer energy resources, e.g., solar PVs, batteries, electric vehicles
Distribution network	The assets and services that carry the electricity conveyed from generators by the high voltage transmission system and deliver it to individual consumers at the lower voltages to operate lighting, heating, appliances, and industrial equipment.
DNSP	Distribution network service provider e.g., TasNetworks
EV	Electric vehicle
FiT	Feed-in-tariff
GWh	Gigawatt hour
HV	High voltage
ITC	Individual Tariff Calculation. Refers to a network tariff class for a small number of large commercial and industrial customers whose circumstances are such that assignment to an averaged network tariff would not be cost reflective, giving rise to the application of individually calculated network tariffs.
kV, kVA	Kilovolt, Kilovolt ampere
kW, kWh	Kilowatt, Kilowatt hour
LRMC	Long run marginal cost. The additional cost of providing one increment in service over the long run
LV	Low voltage
NEM	National Electricity Market
Network tariff	Network price components and conditions of supply for a tariff class
Network tariff class	A class of retail customers for one or more direct control services who are subject to a particular tariff or class of tariffs with similar electricity demand and usage
NER, or the Rules	National Electricity Rules
MVA	Megavolt-ampere
MW, MWh	Megawatt, Megawatt hour
PV	Photo Voltaic. Solar PV panels
Price signal	Information conveyed to end users of electricity via the prices charged for a network service, which provides a signal about the true cost of providing a service and/or the value to the customer of that service, which influences their decisions about the use of the service
PRWG	TasNetworks' Policy and Regulatory Working Group
Retailer	A business that buys electricity from generators, packages it with the network services (for transportation of the electricity) and sells it to consumers/end users

Term or Abbreviation	Description
SCS	Standard control service
TEC	Total efficient cost
ToU	Time of use
Transmission network	The assets and services that enable large generators, e.g., windfarms, hydro-electric power stations, to transmit the high voltage electrical energy they produce to population centres and major industrial users of electricity
TSES	Tariff structure explanatory statement
TSS	Tariff structure statement
Unmetered supply	A connection to the distribution system which is not equipped with a meter and for which the consumption of electricity is estimated, e.g., public lights, traffic lights, phone boxes are not normally metered

TALKING WITH OUR CUSTOMERS AND STAKEHOLDERS

22.3 TasNetworks' engagement approach

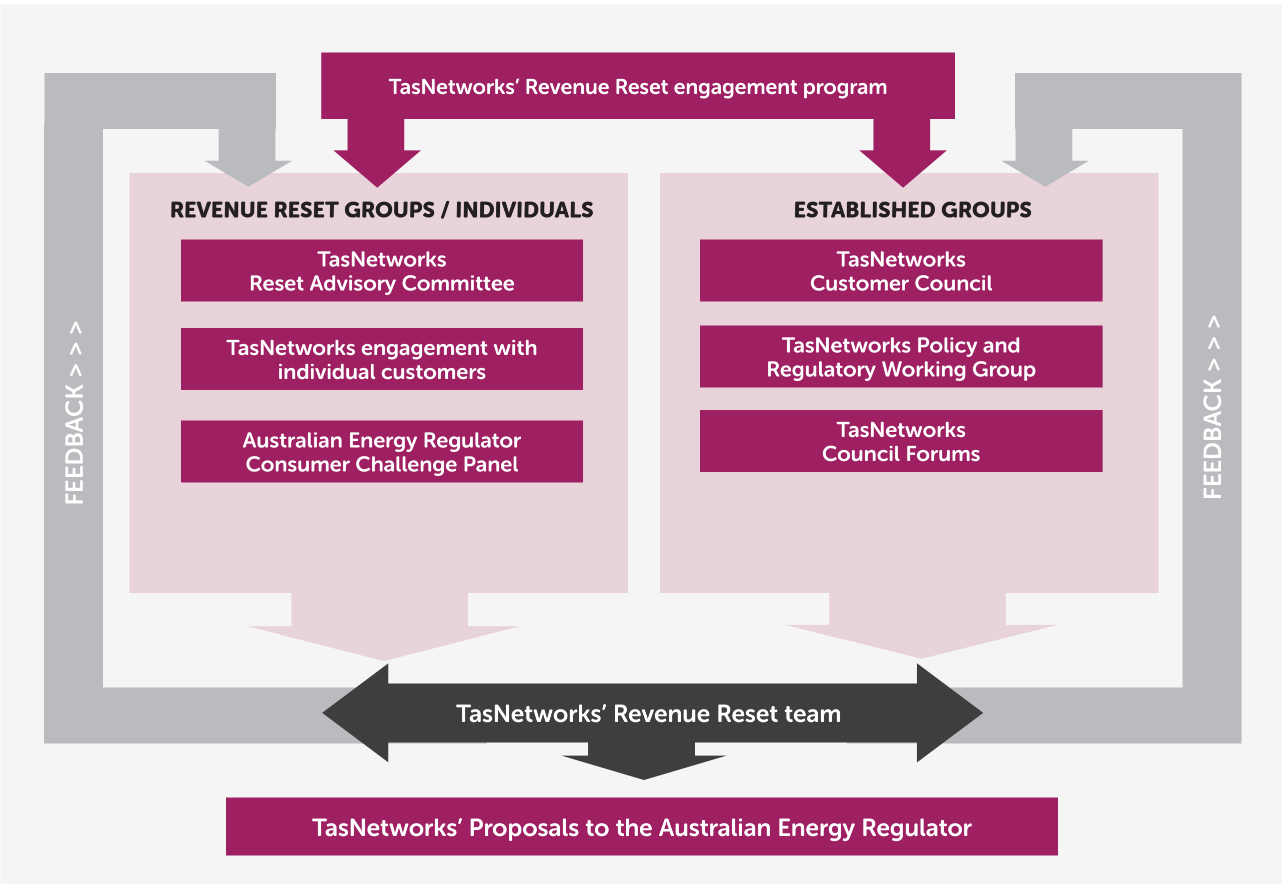
TasNetworks has engaged with its customers and stakeholders to develop its pricing strategy for the 2024-2029 regulatory control period. This section – "Talking with our customers and stakeholders" – summarises who TasNetworks' customers are, and how our engagement approach and activities led to the setting of tariffs for our standard control and alternative control services.

Our engagement approach builds on the feedback we received during the development of our first and second TSS, which applied in the 2017-2019 and 2019-2024 regulatory control periods. In response to the feedback, we conducted an extensive customer engagement process. This has involved engaging with end-use customers, retailers, and stakeholders to test their preferences and seek their input on all aspects of the TSS. The result is that the TSS has been strongly influenced by the views of customers and stakeholders.

We are continuing to reform our pricing strategy over multiple regulatory periods and have consulted on the additional new areas we are targeting for 2024-2029, including new and refined tariffs for emerging customer types. Our pricing strategy will continue to evolve in subsequent regulatory control periods, as further detailed in section 22.6.2.

Figure 4 summarises TasNetworks' customer and stakeholder engagement approach, as detailed in *Attachment 1 – Customer and stakeholder engagement summary.*

Figure 4. TasNetworks' customer and stakeholder engagement approach



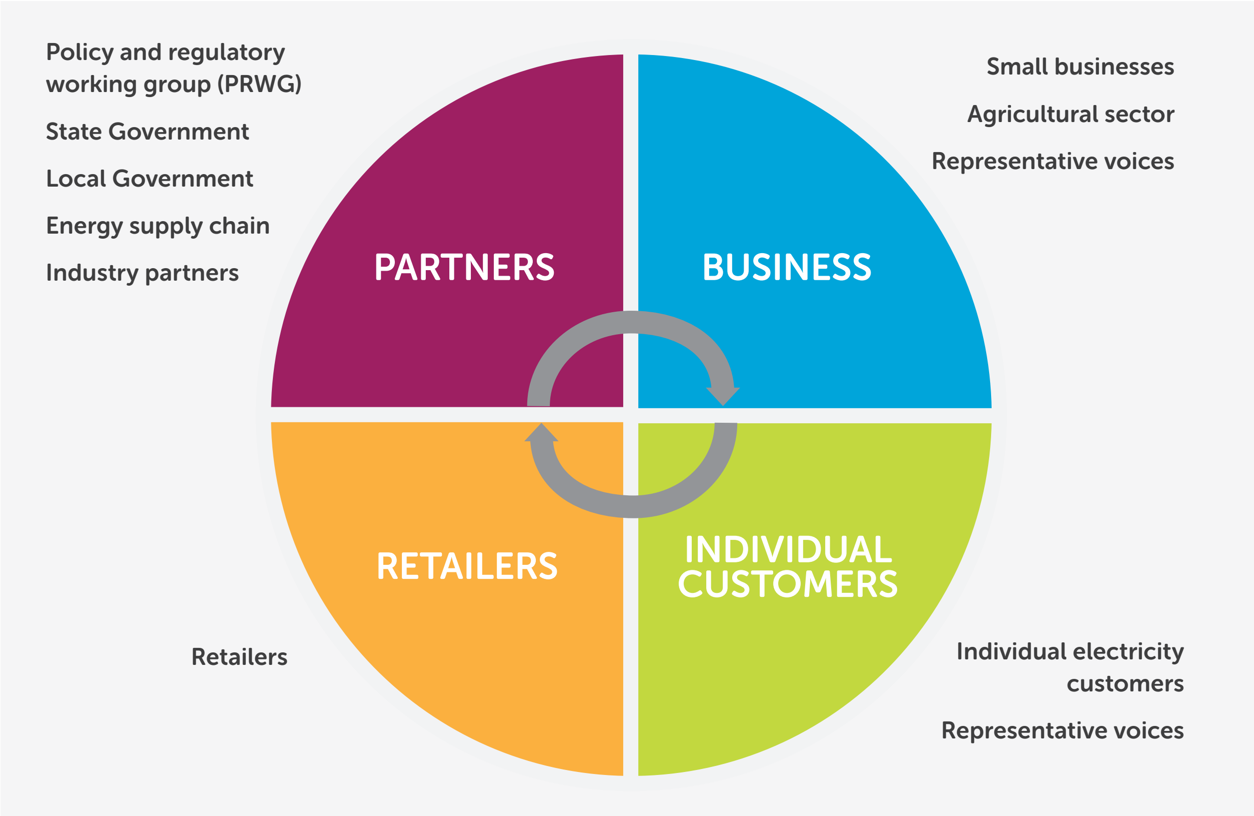
22.4 TasNetworks' customers and stakeholders

We do not limit the definition of a customer to only those who consume the energy delivered by our network. Our customer base includes electricity retailers as well as the wider Tasmanian community and their representatives, such as customer advocacy groups.

We have undertaken a range of engagement activities to gather feedback and understand the concerns of our end-use customers.

The information below, summarised in Figure 5, highlights the engagement undertaken specifically in relation to pricing and the feedback provided by our customers and stakeholders.

Figure 5. Who we engaged with to develop our pricing strategy



22.4.1 Partners

During the development of our regulatory proposal and TSS for the 2024-2029 regulatory control period we have been supported by a core group of highly engaged stakeholders in the form of our PRWG.

The PRWG, established in 2014, provides guidance on our customers' needs and acts as an advisory group on the development of our pricing's strategy. The broad representation within this group, which includes electricity retailers, energy advisors, customer advocates, renewable energy advocates and representatives of the business community, allows a diverse range of customer views to be represented, discussed and heard.

Since its inception, we have focused on building the capability of this group by growing their understanding of drivers underpinning network pricing. This allows our stakeholders to move beyond just providing feedback and instead partner with TasNetworks to build a pricing strategy.

We have collaborated with our stakeholders and sought their participation and input through hands-on activities related to a wide range of pricing matters, including the design of our pricing principles, tariff development, opportunities for tariff trials and the transition for tariff reform and tariff assignment.

22.4.2 Retailers

TasNetworks has sought to engage with all retailers that either currently operate in, or intend to enter, the Tasmanian electricity market, about network tariff reform throughout the development of our 2024-2029 tariff proposal. We have obtained feedback from retailers on our tariff assignment rules, revisions of existing network tariffs and the introduction of new network tariffs.

From this engagement our tariffs have been designed to maximise the probability of retailer pass-through of our pricing signals. This means a simple but effective tariff structure that can be communicated to customers and implemented in retailer billing systems.

22.4.3 Business

There are key stakeholders within the PRWG who represent Tasmania's business community, specifically the Tasmanian Small Business Council. In addition, the PRWG includes representation from organisations who specialise in providing energy services to businesses to optimise energy usage.

The Tasmanian Farmers and Graziers Association (**TFGA**) is included in the PRWG to represent agricultural industry in Tasmania. TasNetworks' also engages separately with the TFGA to address issues pertaining specifically to farmers and has engaged with them extensively on TasNetworks' em*POWER*ing Farms[2] trial and in relation to farmers' investment in Consumer Energy Resources (**CER**).

22.4.4 Individual customers

TasNetworks' recognises that capturing the lived experience of customers, in their own words, is the most powerful tool at our disposal to ensure our network pricing strategy continues to meet the needs of Tasmanians. Throughout the development of our 2024-2029 pricing strategy, we have sought feedback directly from end-use customers in a variety of ways.

The *DER Customer Survey* was able to quantify customer views and reached Tasmanians state-wide. The purpose and results of this survey are outlined further in section 22.5.4.

In May 2022, we engaged directly with customers via TasNetworks' People's Panel, providing information to enable our customers to engage with the pricing content.

Despite the challenges posed by COVID-19, we have been able to maintain a strong presence in the Tasmanian community. Our attendance at agricultural shows and science fairs provided us with the opportunity to speak with a diverse range of customers about our pricing strategy.

Each meeting and discussion, whether planned or not, was taken as genuine feedback and has been incorporated into our pricing strategy development.

22.5 Customer and stakeholder engagement

Over the past three years, TasNetworks has adopted a multifaceted engagement approach towards identifying the services that our customers wanted TasNetworks to deliver in the 2024-2029 regulatory control period.

In relation to standard control services, we have:

- facilitated pricing workshops with targeted stakeholders and customer groups
- hosted a TasNetworks' People's Panel pricing forum
- held two retailer information forums
- collated information from dedicated meetings with retailers, customers, and stakeholder representatives
- discussed with TasNetworks' Reset Advisory Committee (**RAC**) our pricing strategy for the 2024-2029 regulatory control period.

In relation to alternative control services, we have:

- considered, in conjunction with the PRWG, accelerating the recovery of the capital cost of TasNetworks' legacy meters
- consulted with the Local Government Association of Tasmania (**LGAT**) and some of its member councils regarding changes to the pricing of TasNetworks' asset relocation services (which are delivered as quoted services)
- worked with LGAT and a number of its members on revisions to TasNetworks' connections policy
- engaged with local governments in relation to TasNetworks' public lighting service offerings in the 2024-2029 regulatory control period
- discussed with representatives of the electrical contracting industry in Tasmania plans for TasNetworks to introduce a number of new services in the 2024-2029 regulatory control period which would see TasNetworks field crews undertaking work on private assets in a limited range of circumstances, specifically: the rectification of private asset defects under fault conditions, and the construction of private assets (e.g. private pole installation and power line construction) as a provider of last resort
- discussed with TasNetworks' RAC on the development of a metering strategy for the 2024-2029 regulatory control period.

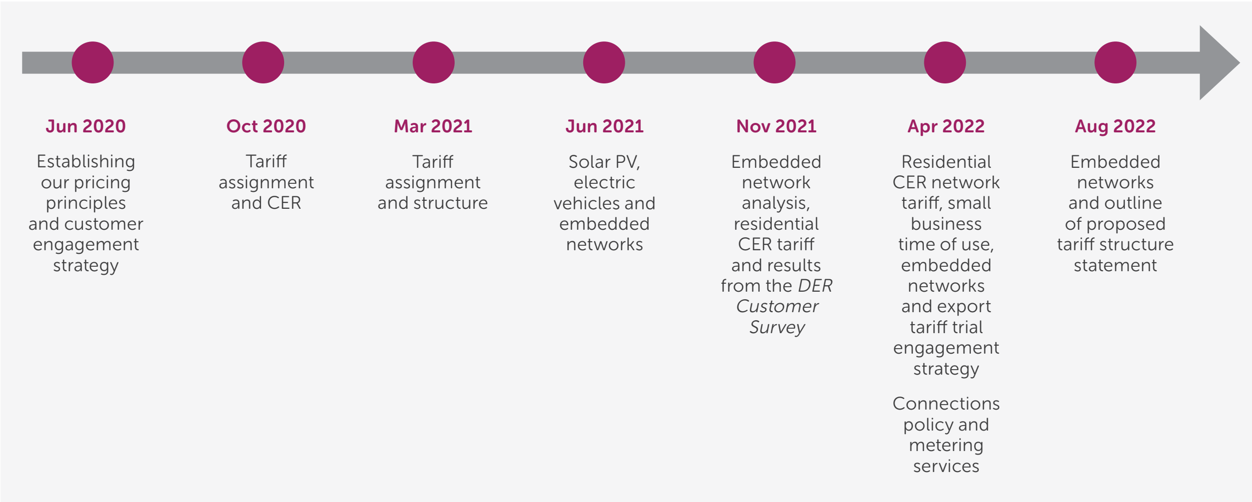
2 TasNetworks emPOWERing Farms

22.5.1 Pricing workshops

TasNetworks has facilitated workshops with the PRWG that were dedicated to the development of our 2024-2029 pricing strategy for both standard and alternative control services. These workshops provided a platform for two-way, transparent communication, with the aim of building effective relationships between TasNetworks, its stakeholders and customers.

Given the growing complexity of the electricity sector, a consultation paper[3] was provided by TasNetworks prior to each workshop to assist our stakeholders in engaging with us. These papers provided more detail on the topics we were looking to engage with our stakeholders on and included any recent analysis in relation to our network tariffs, any current or upcoming market changes, and the results of published customer surveys.

Figure 6. Engagement with our partners



22.5.1.1 Engagement to develop our pricing principles

Key outcomes: Design our pricing principles

Our initial engagement with the PRWG involved the development of our pricing principles. These principles have guided TasNetworks' development of our network tariffs and products, which has helped us refine our service offerings to ensure customer expectations are met (Figure 7).

3 All consultation papers, agendas, minutes and supplementary papers can be found on TasNetworks' website under the Policy and Regulatory Working Group section

Figure 7. TasNetworks' pricing principles for the 2024-2029 regulatory control period

Affordable

We offer an essential service and recognise that customers want affordability in the delivered cost of electricity. To support this, we will ensure sustainable network investment and that customers experiencing vulnerability will not be exposed to hardship as a result of our pricing or network tariff reforms.

Fair

We will provide transparent and cost reflective pricing signals so that all customers contribute to their portion of total network costs.

Consistent

We will avoid creating price shocks for customers and minimise upward pressure on the delivered cost of electricity.

Innovative

We will investigate innovative solutions that meet the changing needs of our customers and changes in technology.

Simple

Our network pricing will be both cost reflective and easy for our customers, retailers and stakeholders to understand.

Choice

We will not stand as a barrier for customers who invest in consumer energy resources, such as solar generation and battery storage. Our pricing will provide choice to our customers to best meet their energy needs, while not imposing on the needs of others or the network.

22.5.1.2 Cost reflectivity and tariff assignment engagement

Key outcomes: Review the default residential and small business network tariffs and determine the rebalancing approach for the small business time of use consumption tariff.

In 2020 we began discussions with stakeholders on the uptake of cost reflective network tariffs in relation to assignment policy changes. Stakeholders noted that time of use consumption tariffs are simple enough in structure to allow customers to appropriately understand and respond to the price signal. From this discussion, stakeholders, in conjunction with TasNetworks, concluded that the residential time of use consumption (TAS94) and small business time of use consumption network tariffs should remain the default network tariffs for all new residential and small business customers connecting to the network in 2024-2029.

TasNetworks provided insights into the current uptake of time of use consumption-based network tariffs and the forecast uptake for the remainder of the 2019-2024 regulatory period. This data and the discussions with our stakeholders suggested that TasNetworks' current network tariff assignment policy is not facilitating a significant take-up of cost reflective network tariffs and that additional levers should be considered. Our stakeholders encouraged us to do more to incentivise the uptake of cost-reflective network tariffs amongst residential and small business customers. In response to this recommendation, TasNetworks will work with the PRWG to consider complementary measures to encourage better uptake of cost-reflective tariffs.

Work in 2021 built on the feedback we obtained in the previous year. Together with our stakeholders we completed a deep dive, identifying barriers to network tariff reform. This included:

- understanding the impact of network charges on our customers
- determining whether there is a need to incentivise certain customer groups to take-up cost reflective network tariffs
- consider whether changes to TasNetworks' network tariff assignment policy could assist in increasing the uptake of cost reflective network tariffs.

It was acknowledged with the PRWG that engagement in electricity tariffs is low among customers, despite their awareness of retail electricity pricing as a cost-of-living issue. Because of this, the group reasoned that differential price levels may not be impactful, as many customers are unaware of alternate tariff offerings. However, stakeholders emphasised strongly that TasNetworks should include protections for our customers experiencing vulnerability. This would ensure we maintain the key pricing principles of fairness and equity in our pricing strategy.

From these discussions we designed, in collaboration with our stakeholders, TasNetworks' tariff assignment policy for 2024-2029, which includes providing a 'cooling off' period for customers placed onto a time of use network tariff as the result of an advanced meter installation. It was agreed that the proposed changes to our assignment rules will allow for a greater transition to cost reflective network tariffs, while providing our customers experiencing vulnerability with the opportunity to choose the best pricing option to suit their needs.

As a result of our engagement, our stakeholders helped refine our assignment policy – which is outlined in more detail in Section 22.7.2.

22.5.1.3 Time of use and rebalancing of the small business consumption tariff

Key outcomes: Review network time of use periods and determine the rebalancing approach adopted for the small business time of use consumption tariff.

During 2021, TasNetworks reviewed its time of use periods. The consumption on our current default residential time of use consumption network tariff (TAS93) was analysed and shared with PRWG members. In terms of the alignment of the tariff's time of use periods with peaks in demand for the network, the analysis demonstrated that the design of the current default residential network tariff (TAS93) continues to accurately reflect times of high network demand.

While this review of load data showed that the residential time of use periods align well with peak demand, it was found that the time of use periods applying to the consumption-based time of use tariff for businesses (TAS94) could be better aligned to reflect the collective load profile of the customers on that network tariff and times of high network utilisation. For example, small business consumption, unlike that of residential customers, declines on weekdays during the afternoon/evening peak period, and the contribution of the consumption of small businesses to maximum demand at a network level over the course of a weekend only fluctuates within a small range.

Our stakeholder's preference was to change the time of use periods for the low voltage small business time of use consumption tariff (TAS94) as outlined in section 22.7.3.

A change to the time of use periods required analysis on how to re-balance the tariff. At a subsequent workshop, TasNetworks presented to PRWG potential re-balancing scenarios for the small business time of use tariff. Three options were considered – an over-proportional increase in offpeak pricing, the application of even changes across the different time of use periods, and an over-proportional increase in peak period pricing. The PRWG voted in favour of applying evenly balanced time of use increases.

22.5.1.4 Redesign of existing CER residential tariff and development of new tariffs

Key outcomes: Identify changes to our residential CER tariff and develop the pricing components for a new embedded network tariff.

Our stakeholders told us that TasNetworks must provide future-ready pricing structures to ensure the best outcome for our customers. This includes providing choice to customers on how they meet their energy needs, but that customers without CER should not be disadvantaged in doing so.

As a result of this feedback, TasNetworks undertook a customer survey on CER intentions in 2021.[4]
We discussed the growth of CER, its impact on the Tasmanian distribution network, opportunities to realise benefits for the network from CER and deliver value for all customers, including those without CER. The survey demonstrated the responsiveness of customers who own CER technology to time of use tariffs. As a result, TasNetworks introduced to PRWG the potential to amend the existing residential CER network tariff to better accommodate the forecast increase in demands on the network from CER (a summary of the survey is provided in section 22.5.4).

4 TasNetworks' DER Customer Survey

TasNetworks highlighted concerns about the evening peak period as customers with CER technology shift their demand to utilise the overnight off-peak too early, i.e., prior to the evening utilisation declining enough to enable batteries and/or electric vehicles to be charged. The PRWG were provided with a number of options to consider, including extending the evening and or morning peaks, changing to a consumption-based tariff or providing longer average demand windows (instead of half hourly demand).

At the first workshop in 2022, we extended the discussion and presented three additional options for the PRWG to discuss and vote on, which proposed changing the existing tariff from a time of use demand tariff to a time of use consumption tariff with a demand threshold. TasNetworks undertook further analysis to determine that the optimum maximum demand threshold was 8.5 kW per household, which was presented at the final workshop. The changes to this network tariff are discussed in full in section 22.7.4.

In addition to amending the structure of an existing network tariff, it was suggested by a key stakeholder that TasNetworks investigate implementing embedded network tariffs.

TasNetworks presented the key distinguishing features of an embedded network and discussed the current differences between those customers within an embedded network and those customers directly connected to the distribution network. Many PRWG members provided support for TasNetworks to propose an embedded network tariff for the next regulatory period, with several members expressing concerns about perpetuating current inequities by allowing embedded networks to choose a less appropriate network tariff.

To progress the development of the proposed new embedded network tariff we clarified the assignment rules for embedded networks under this tariff. TasNetworks proposed that only new embedded networks will be assigned to the embedded network tariff from 1 July 2024.

A capacity charge was assessed by a number of stakeholders as being a good means of determining the daily service charge. After collating the feedback provided by stakeholders, TasNetworks put forward a network tariff structure and assignment policy to the PRWG in 2022.

The embedded network tariff structure and assignment rules are discussed further in section 22.7.5.

22.5.1.5 Tariff trials and co-designing complementary measures to communicate on tariff reform

Key outcomes: Determine the purpose of our two-way pricing trial and identify key topics for communicating to our customers on tariff reform.

Following the release of the determination to allow DNSPs to charge rooftop solar owners for exporting power to the grid, numerous conversations were held with our stakeholders and the PRWG.

At the April 2022 meeting of the PRWG, there was a comprehensive discussion regarding TasNetworks' position to not introduce export tariffs in the 2024-2029 regulatory control period. This decision was informed by the take-up levels of solar PV in Tasmania, which lag the solar PV take-up levels in jurisdictions where export-driven network issues are being experienced. TasNetworks did discuss whether to conduct a trial for two-way network pricing in the 2024-2029 regulatory control period. PRWG members observed that the negative publicity surrounding the rule change would require TasNetworks to provide clear messaging around its intention for two-way network pricing, i.e., to clearly communicate to stakeholders that two-way pricing will not be introduced in the 2024-2029 regulatory control period, and to articulate that a trial may be undertaken before implementing such a tariff.

While stakeholder engagement is an evolving process, TasNetworks presented a proposed process for undertaking a trial during the 2024-2029 regulatory control period for two-way pricing and the stakeholders it was envisioned would be involved with TasNetworks' engagement on this topic. In addition, the PRWG co-designed the principles that would apply to tariff trials that may be undertaken in the 2024-2029 regulatory control period, including a trial for two-way network pricing (refer to section 22.7.9).

It was identified in 2021 that complementary measures were required to update and inform customers on tariff reform, changes to tariffs and the changing energy market. At the August 2022 workshop, TasNetworks sought input from our stakeholders through various engagement activities to identify who we need to engage with, on what topics and through what communication medium.

At the August 2022 workshop, our stakeholders identified four key topics to communicate with customers:

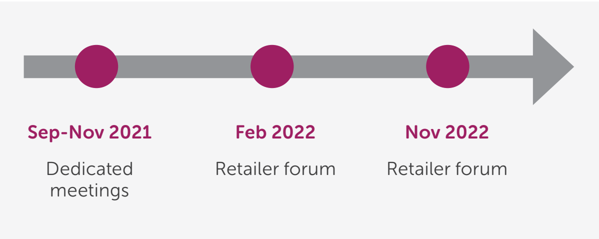
- pricing principles and how they assist in guiding tariff development
- rollout of advanced meters, and the impact this has for the energy sector
- time of use tariffs
- the progression of cost reflectivity and the need to make some legacy tariffs obsolete.

22.5.2 Retailer information forums

TasNetworks has sought to inform all Tasmanian retailers on our plans in respect to network tariff reform and alternative control services. TasNetworks held two information forums for all retailers that either currently operate in, or intend to enter, the Tasmanian electricity market.

Our forums included representatives from over five different retailers. At both forums, TasNetworks provided an overview of its pricing strategy for the 2024-2029 regulatory period, including the introduction of new network tariffs, changes to existing network tariffs and TasNetworks' tariff assignment rules. TasNetworks also shared its approach to alternative control services, in particular focussing on changes to our metering strategy for 2024-2029.

Figure 8. Retailer engagement



22.5.3 Dedicated meetings

Throughout our three-year engagement process for the development of our pricing strategy we have held dedicated meetings with a range of diverse stakeholders.

Throughout the course of our engagement, we met with:

- Government representatives
- Industry bodies
- Customer representatives
- Interested stakeholders
- Community groups
- Electric vehicle wholesalers
- Interstate network service providers.

22.5.4 Surveys

In 2021, TasNetworks issued a survey[5] to gain a better understanding our customers' views on CER, including how and when our customers use energy generation and storage technology, such as PV solar panels, batteries and electric vehicles. Of the 322 respondents to the survey:

- the majority were located in Hobart and owned their own home
- respondents tended to be in full-time employment and earn higher than average incomes
- had a diverse range of consumer energy resource technologies.

While some respondents owned multiple CER technologies, just over half (51 per cent) did not currently own either solar PVs, batteries or an electric vehicle.

TasNetworks' DER survey found that:

- generating electricity for self-consumption is the main driver of customers' investments in solar PV panels
- more than half of solar PV owners intend to install battery storage in the next ten years, to better utilise off peak rates and self-consume during peak times
- while EV owners prefer to charge their vehicle whenever it is convenient – which is mostly at home overnight or on weekends – they do change their charging times in response to time of use tariffs.

In addition, we completed analysis of existing consumption patterns of customers with CER. This analysis showed clear patterns of behaviour, depending on the type of CER technologies owned and the tariffs associated with the household (noting that some of the sample sizes are small).

The analysis of customers' load profiles and the customer survey helped form the initial view that a refined network tariff could meet the needs of more active prosumers. The survey provides evidence that we are seeing the rise of a growing prosumer group in Tasmania and that this group is expected to continue to grow in the 2024-2029 regulatory period.

5 TasNetworks' DER Customer Survey

22.5.5 Engagement with our agricultural customers

During the period 2019-2021, TasNetworks undertook the em*POWER*ing *Farms* trial to increase our understanding of our agricultural customers. A component of this trial included undertaking network tariff analysis on a range of farms, including crops, dairy, cattle and lambs. As well as our dedicated seasonal irrigation time of use consumption tariff (TAS75), we offer several network tariff options to our agricultural customers that are also available to our business customers more generally.

The trial included both qualitative and quantitative research to understand farmers' relationship with energy, their knowledge of the network and tariffs, energy retailers, and the composition of their bill. The quantitative research involved analysis of consumption data from interval meters across several farms. This information was used to explore the suitability of current network tariffs and the potential for other pricing options. The results of the quantitative and qualitative analysis are contained within the final project report.[6]

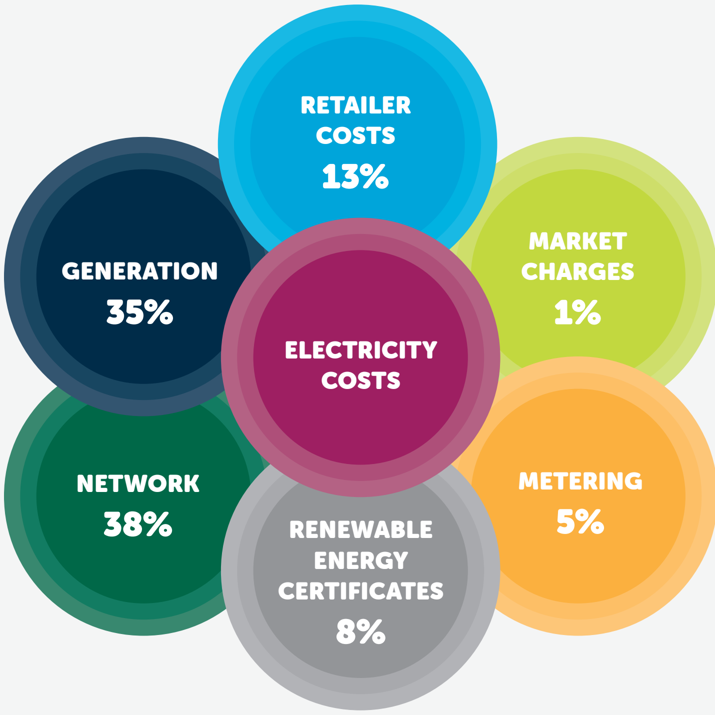
In addition to the em*POWER*ing *Farms* trial, we have also been engaging with farmers regarding the trialling of a tariff that supports the utilisation of CER across a number of connection points on an individual farm. Expressions of interest have been sought for this trial.

6 TasNetworks emPOWERing Farms

22.6 Pricing strategy overview

As the DNSP in Tasmania, TasNetworks sets the network tariffs used to recover revenue required to build, operate and maintain the poles and wires. This section of the TSES address the distribution costs of supplying energy – which is just one component of the total electricity bill that customers pay, refer Figure 9.

Figure 9. Indicative cost components of electricity costs for a typical residential or small business customer (2022-2023)[7]



TasNetworks' pricing strategy is to provide network tariff options that best meet the needs of our customers and reduce long term network expenditure. This involves adjusting the prices of our existing network tariffs by unwinding some long-standing cross subsidies and developing new network tariffs that incentivise customers to shift their energy usage outside of peak times.

These measures aim to encourage customers to use the network more efficiently and is referred to as 'cost reflective pricing'. The purpose of cost reflective pricing is to deliver a pricing signal to retailers and their customers during periods of peak demand. Reducing peak demand may reduce the need for future augmentation investment, thereby reducing costs for customers over the long term. Cost reflective pricing also provides better signalling of future costs for those customers wanting to use more electricity, particularly in peak times. The benefits of pricing reform are detailed further in subsequent sections.

7 Office of the Tasmanian Economic Regulator standing offer price determination 1 July 2022 - 30 June 2023

22.6.1 Our tariff reform strategy

This is the third TSS TasNetworks has developed which builds on the foundation of our previous work, including our customer and stakeholder feedback.

TasNetworks has developed a pricing strategy that spans multiple regulatory control periods, as shown in Figure 10. Each regulatory control period provides the opportunity to review our strategy progression and ensure we are keeping pace with changing customer needs and technology uptake.

The AER approved our first TSS for the 2017-2019 regulatory control period. This was the 'establishment' phase of our reforms that set a pathway for the subsequent periods by introducing the nature and objectives of our strategy to stakeholders and introducing new cost reflective network tariffs as a choice for customers, via their retailer.

In April 2019 the AER approved our second TSS for the 2019-2024 regulatory control period. This represented the continuation of TasNetworks' pricing reform by making the time of use consumption-based network tariffs as the default for newly connecting residential and small business customers.

For the upcoming 2024-2029 regulatory control period, we are proposing to:

- continue the gradual process of unwinding the discounts that exist in some of our network tariffs
- introduce new embedded network tariffs
- refine the existing residential CER network tariff and the small business time of use consumption tariff
- refine our tariff assignment rules to reflect our tariff strategy
- propose to undertake tariff trials to inform tariff settings for the next regulatory control period (2029-2034).

Figure 10. TasNetworks' tariff reform strategy

22.6.2 Our long-term vision for pricing

As shown in Figure 10, TasNetworks has a long-term strategy to deliver tariff reform. We recognise that by 2030, Australia's renewable energy transition will be well underway and that people and businesses will continue to invest in solar PV and batteries to generate and store their own electricity and use it to power their homes, businesses, and cars.

The uptake of electric vehicles is also expected to accelerate by 2030 and more so by 2050. AEMO[8] is forecasting that Tasmania will have approximately 62,000 electric vehicles by 2030 and significantly increasing by 2050 in the most likely step change scenario. In addition, AEMO is also forecasting 518 MW of solar PV by 2030 – a 93 per cent increase on 2022-23 levels.

This drives the need to ensure our tariffs are fit for purpose to facilitate the emergence of new technologies and increasing demand on the network through electrification. As part of this, it is important that our tariffs send appropriate, cost reflective, pricing signals to customers about how behaviour impacts the costs of providing and operating the network.

In developing our pricing strategy, we carefully considered these future scenarios, trends and customer preferences to ensure our plans are in the long-term interests of our customers. We have utilised the results of nation-wide surveys and research to inform our understanding of the uptake of new technologies, such as solar PV, battery storage and electric vehicles, to meet the energy needs of Australian customers. The *DER Customer Survey* that was conducted provided further local insights which inform our pricing strategies.

Future advances in technology, increasing number of models and public charging infrastructure will continue to evolve and provide a dynamic environment in which to operate.

8 AEMO's Inputs assumptions and scenarios workbook, 30 June 2022

Preparations are underway for this uptake and subsequent demand on the network. One of the ways we are preparing for electric vehicle growth is by ensuring we have appropriate network tariff options available for all customers, including those who wish to invest in CER such as electric vehicles.

TasNetworks is preparing for this future now by laying the foundations. We are enabling the move to a more sustainable electricity system and ensuring the delivery of safe, reliable, and affordable electricity for all consumers. Our enduring focus is to deliver value to electricity consumers through sustainable prices.

22.6.3 Customers on our network

The figure below provides a summary of the different customers that use our network.

Figure 11. Customers on TasNetworks' distribution network

Total connected customers 300,000

260,000 residential customers
35,540 business customers
3,500 irrigation customers

Advanced meters 150,000

51% of residential customers
35% of busness customers
53% of irrigation customers

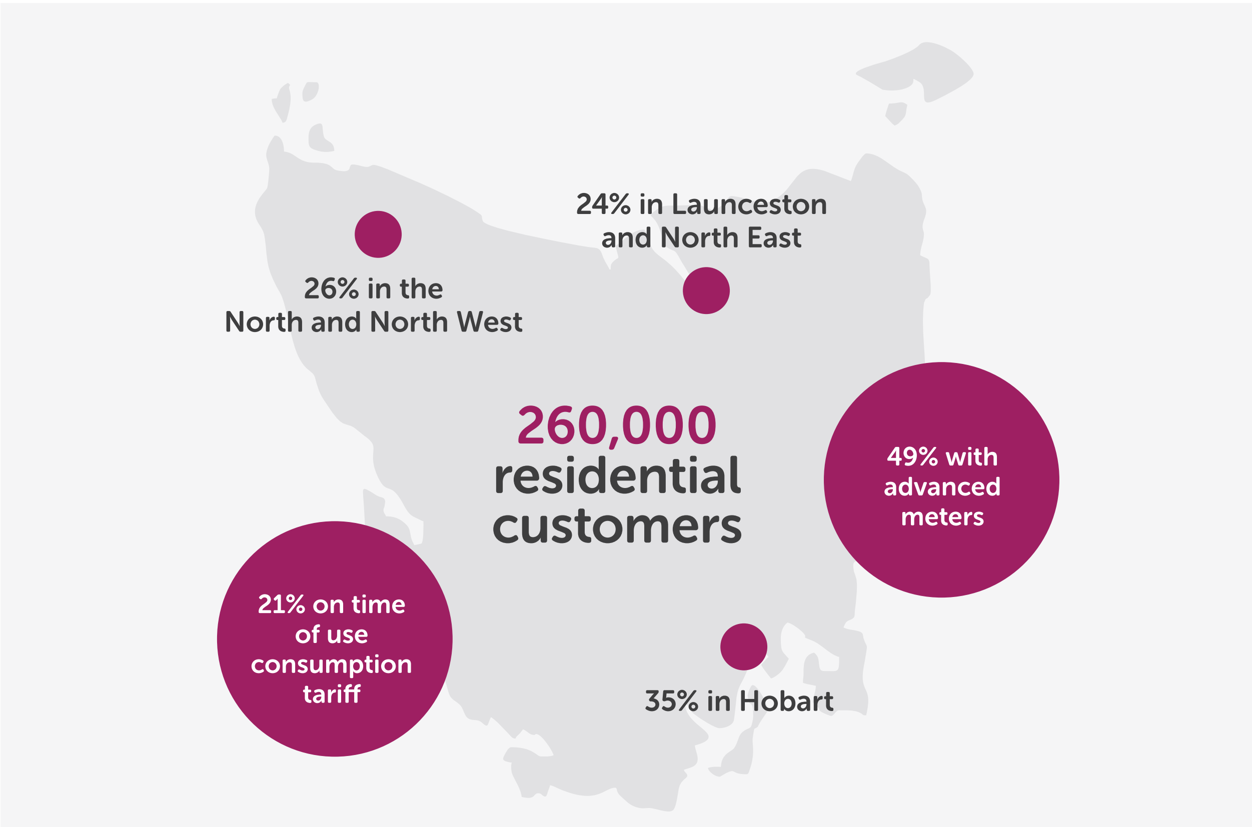
60,000 customers on cost reflective network tariffs

20% of residential customers
58% of business customers

22.6.3.1 Residential customers

The residential customers in our network area are diverse. They range in location, age, medical needs, financial means, household make-up and how they source energy (e.g., whether they have embedded generation such as solar PV).

Figure 12. Our residential customers



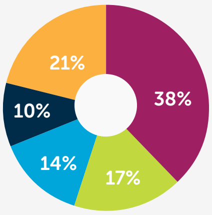
22.6.3.2 Our business customers

We have a diverse range of businesses connected to our network, including retail, real estate, construction, health, education, professional services, transport and industry. Tasmania also supports a large agricultural industry, which has long been a key part of Tasmania's economy.

We offer our business customers a range of network tariffs. The tariffs available include time of use consumption tariffs, demand only tariffs, tariffs for CER and a dedicated irrigation tariff for our agricultural industry.

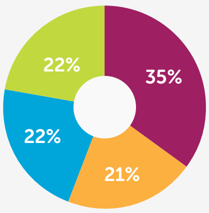
Figure 13. Our business customers

Proportion on number of customers by National Meter Identifier (NMI):



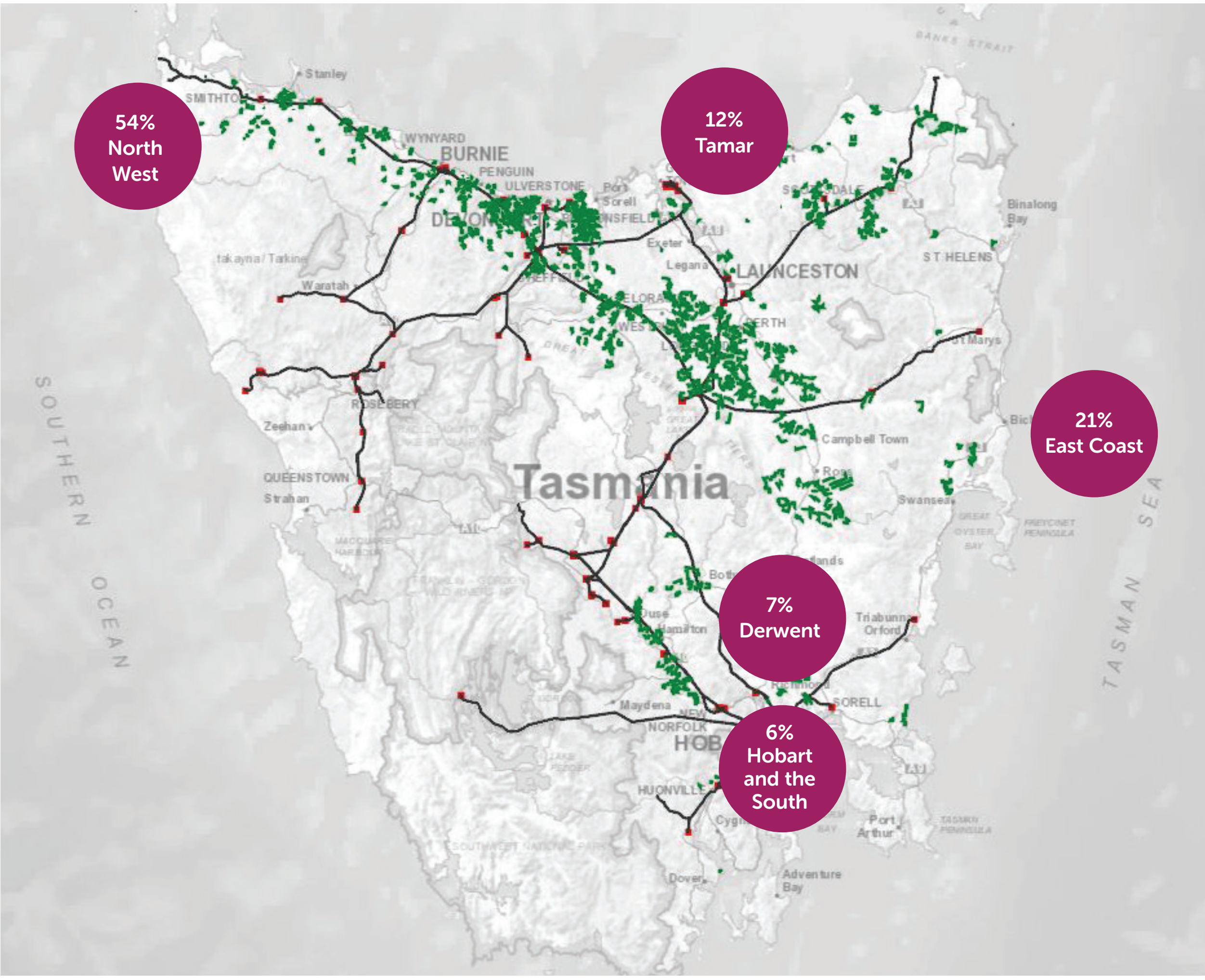
- **38% Shops/Buildings (offices)**
- **17% Factory/construction**
- **14% Hospitality, Education and Cultural Activities**
- **10% Primary industries**
- **21% Other, incl mining, sports facilities, medical and emergency.**

Proportion on size of kWh consumed:



- **35% Factories/construction**
- **21% Shops and Buildings**
- **22% Hospitality, Education and Cultural Activities**
- **22% Other.**

Figure 14. Our irrigation customers



22.6.4 The evolution of prosumers

Prosumer
The rise of the prosumer who seeks to actively trade energy as a source of revenue.

Electric Vehicles
Increased uptake of Electric Vehicles adding additional load and usage patterns on the grid, e.g. uncontrolled charge times / fast chargers.

DER (behind the meter)
Increased uptake of Distributed Energy Resources altering the dynamics/role of the traditional grid, e.g. update of rooftop solar.

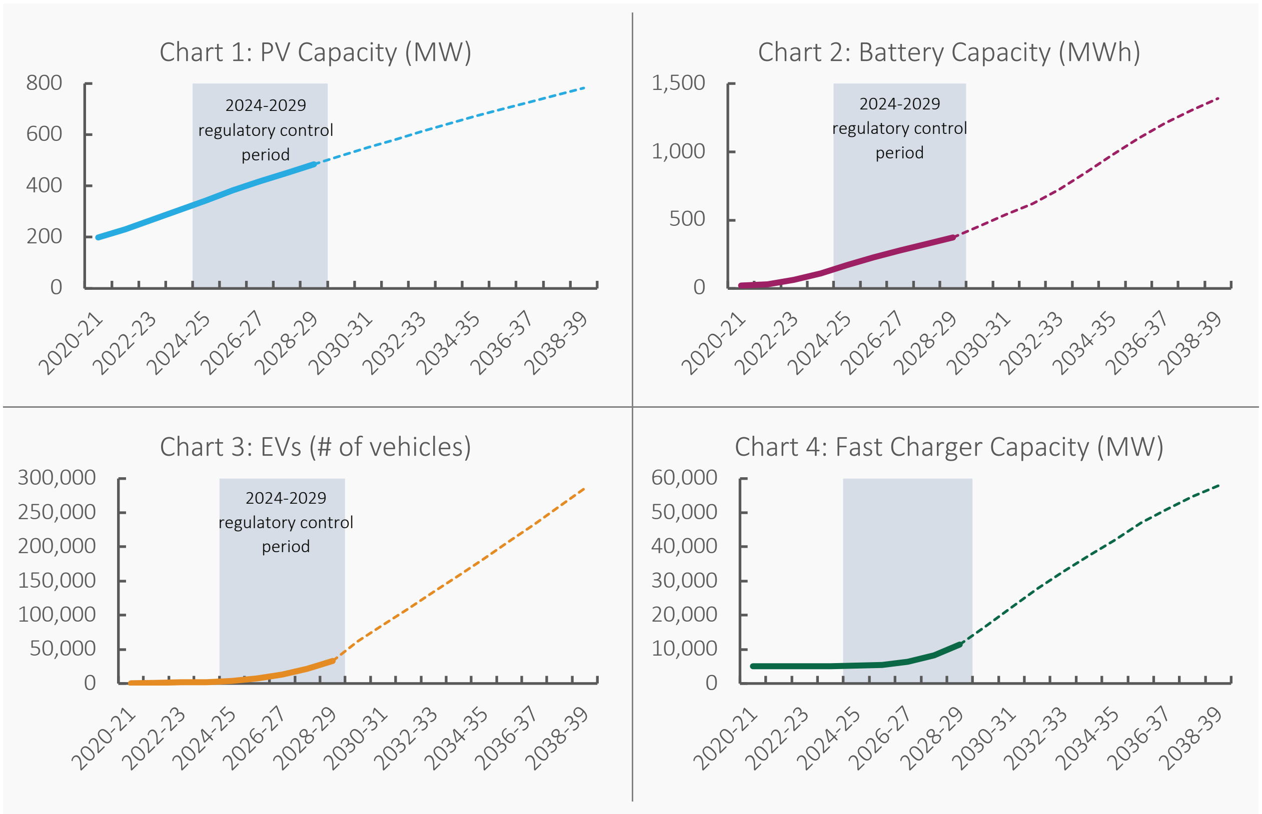
Batteries (Grid side)
Non-traditional infrastructure/technology providing alternative solutions to grid stability challenges.

The way our customers are using our distribution network is changing and our tariffs need to adapt accordingly.

Prosumers are more involved in the electricity industry than most, enabled by a growth in technology. They take an active role, at times enabled by technology, in meeting their energy needs and expect more varied ways to interact with and be part of the energy market. Tasmania has seen a steady growth of new CER technologies over the past decade, and we expect this to increase during 2024-2029 and beyond. Figure 15 shows forecasts for CER penetration based on AEMO's "step change" scenario from the 2022 ISP which indicates consistent growth in solar PV over the 2024-2029 regulatory control period and beyond, however for EVs, fast chargers and batteries, growth is more constrained over the 2024-2029 regulatory control period, after which growth is projected to accelerate.

The 2022 ISP provides forecasts out to 2050, which indicates that solar PV deployment is expected to be installed on most domestic properties[9]. Some of the increased solar PV generation could be stored either in household batteries, for use at a more beneficial time, or utilised to recharge EVs. Tasmania's battery capacity is estimated to increase substantially, and approximately 600,000 EVs are estimated to be on Tasmanian roads by 2050. The pace of EV uptake could result in significant additional load to the low voltage network.

Figure 15. TasNetworks forecasts for CER penetration[10]



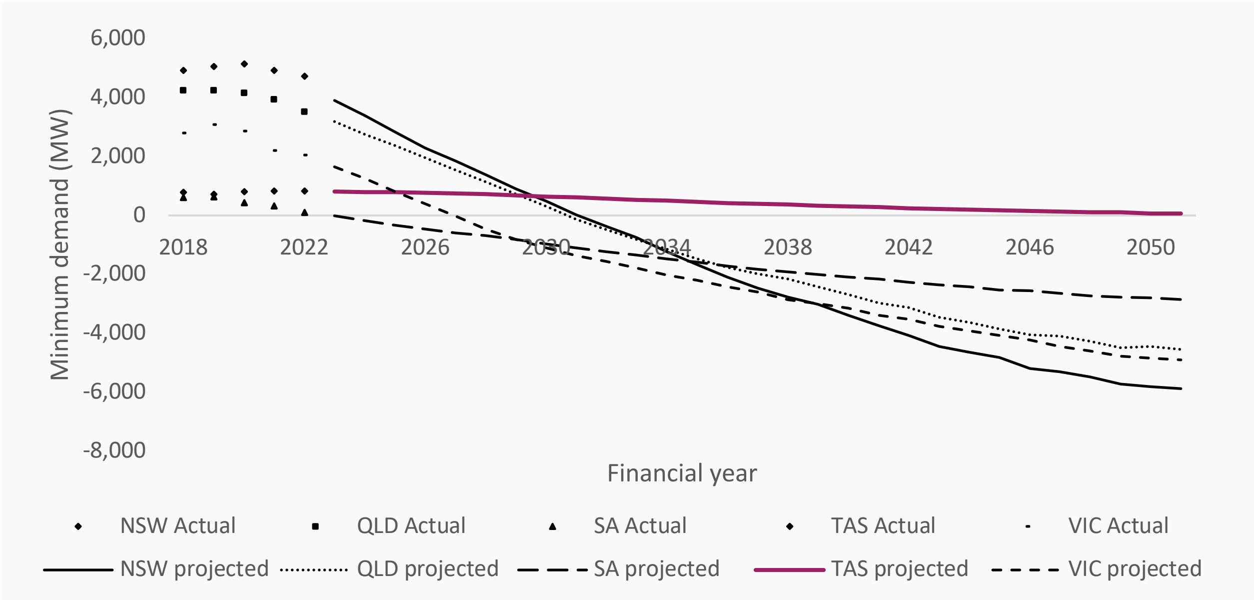
9 Total estimated PV capacity is 1,085 MW by 2050, AEMO's Integrated System Plan, 2022

10 Based on AEMO's Step Change scenario, 2021

TasNetworks has observed some impact of solar PV on the midday minimum demand on our distribution network in recent years (Figure 17) however, the current experience in Tasmania does not compare to the minimum demand issues occurring in other jurisdictions where solar PV penetration is higher.

As per AEMO's Electricity Statement of Opportunities (**ESOO**), as shown in Figure 16, Tasmania's minimum residential and business demand, which is expected to continue to occur in summer, is shown to be considerably more stable than other NEM regions. Tasmania is the only NEM region in which minimum demand is not expected to be negative (i.e., representative of net exports) by 2050. This is in large part due to Tasmania's relatively low levels of solar PV generation. At the aggregate level, this indicates that Tasmania is less likely to experience issues relating to solar PV exports (especially in the short to medium term) as the network as a whole will be demanding generation, even during minimum demand periods. Potential issues related to solar PV exports is considered further in TasNetworks' export tariff transition strategy (refer section 22.12).

Figure 16. Comparison of summer minimum residential and business demand by NEM region[11]

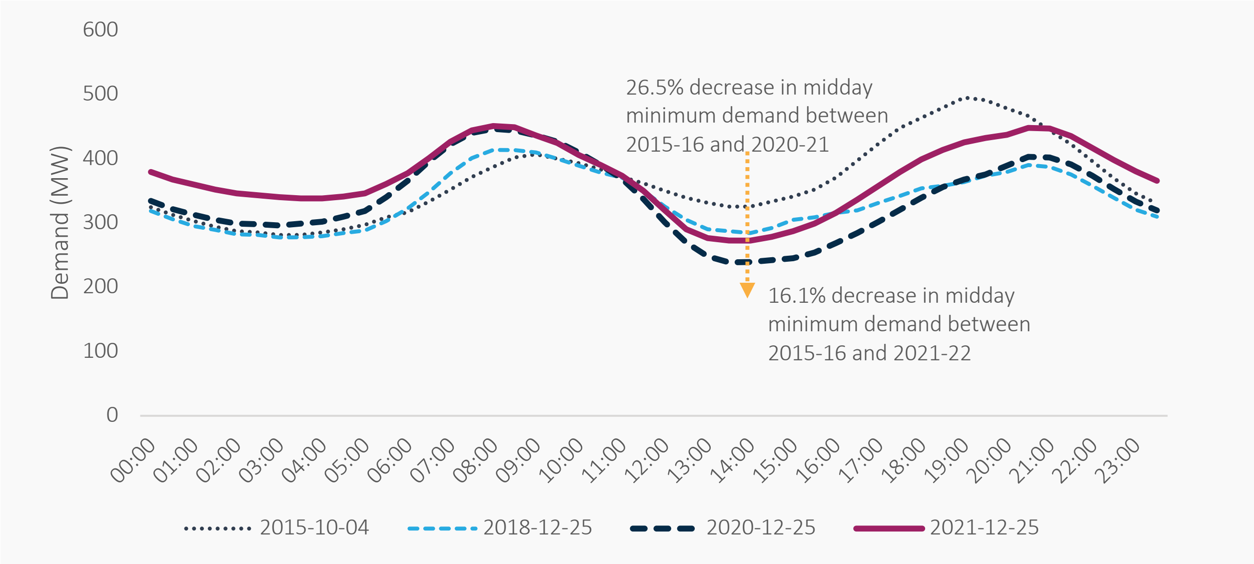


22.6.4.1 Tasmania's current minimum demand

Tasmania's midday minimum occurs during the summer months – mainly during the Christmas period, due to a lack of heating load on the distribution network. As investment in solar PV increases, midday minimum load is likely to decline further, especially if the solar PV capacity increases to the predicted levels as shown in Chart 1 in Figure 15. This is also aligned with Figure 16, above. TasNetworks has been monitoring its minimum demand (Figure 17) and while minimum demand has decreased since 2015, the declining trend seen in 2020-21 has somewhat reversed in 2021-22.

11 Sourced from AEMO's 2022 ESOO (Central Scenario), based on AEMO's 2022 ESOO (Central scenario), version as at 20/09/2022

Figure 17. Network minimum demand



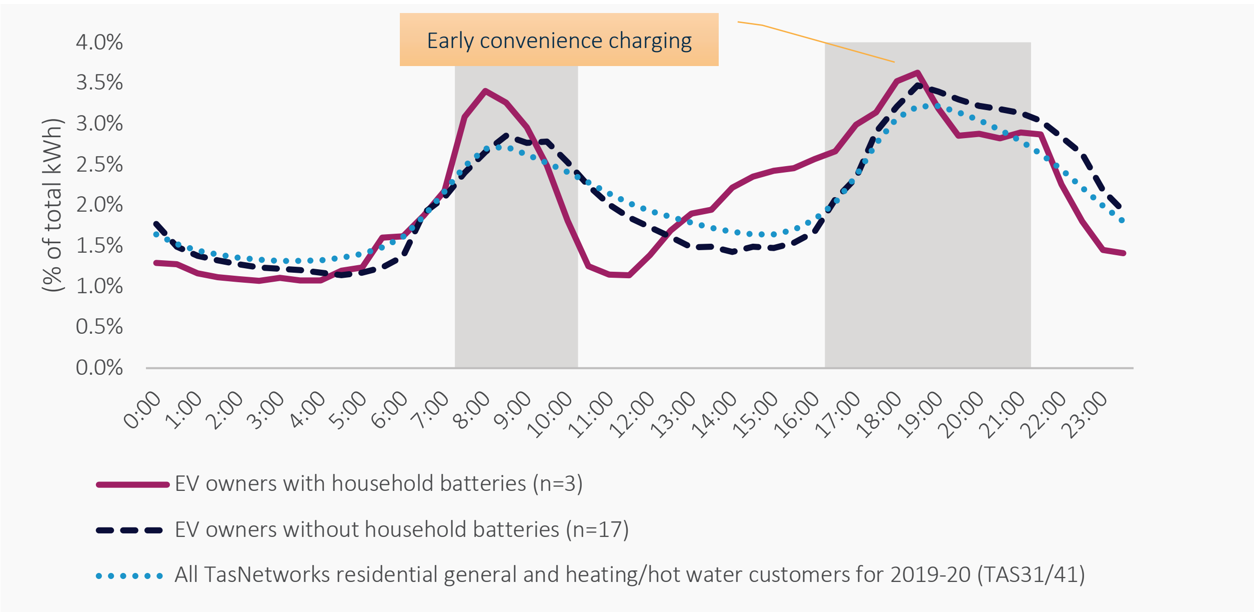
22.6.4.2 Forecast network impact from EVs

Chart 3, Figure 15 shows the forecast increase in the number of electric vehicles for Tasmania. For the purposes of our tariff redesign, we have utilised information from our *DER customer survey* to assess the residential EV charging impact on the network.

During the 2024-2029 regulatory control period we forecast the rate of EV uptake to increase, and further accelerate into the subsequent regulatory control periods with an estimated 286,000 EVs on Tasmania's roads by 2039.

TasNetworks' *DER customer survey* suggested a growing desire by Tasmanians to purchase an electric vehicle in the next regulatory control period. The data collected via the survey showed the charging behaviour of EV owners (Figure 18), providing an early indication of what may occur if widespread EV "convenience charging" occurs.

Figure 18. Electric vehicle user profiles for customers on the residential general and heating/hot water tariff (TAS31/41) in winter

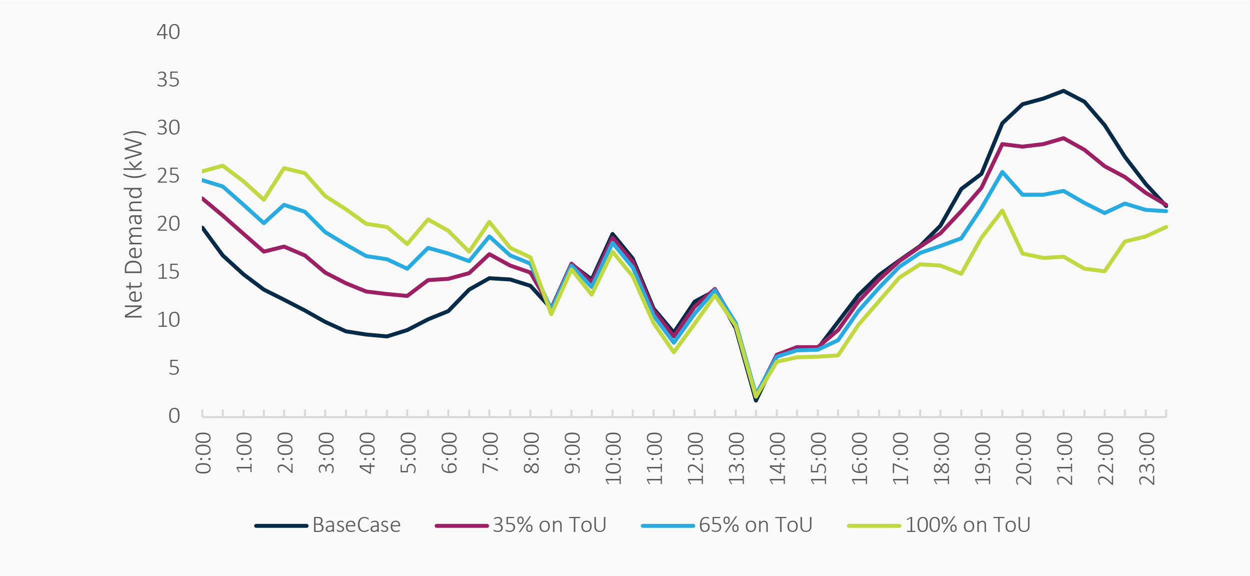


Feeder analysis[12] showed that future network constraints are primarily driven by the uptake of forecast EVs. Network demand on a winter weekday in 2050 would be significantly higher if all customers with EVs are on the residential time of use consumption tariff (TAS93). Network limits would be breached in the evening peak, however spare capacity would be retained in the early hours of the morning.

12 20 low voltage feeders were used in the analysis which included a representation of eight different network types, e.g., central business district (overhead and underground), urban residential (overhead and underground), mixed customer usage

Figure 19 shows that, if approximately 35 per cent of customers transition to a time of use tariff with incentives to charge vehicles in the early morning, the size of the evening peak reduced – but not sufficiently to alleviate some network constraints across some feeders. If, by 2050, approximately 65 per cent of customers take up a new time of use tariff that encourages early morning charging, the evening peak will further reduce and would result in no network investment being required. Moving 100 per cent of customers to a new time of use tariff with beneficial early morning charging rates would likely create another peak requiring network investment to facilitate EV charging during the early morning.

Figure 19. Effect of time of use profiles on the winter weekday demand profile



22.6.4.3 CER Future impacts

Modelling suggests that the uptake of solar PV, when considered with EV uptake, is insufficient to cause network constraints during the next regulatory control period[13]. Experience with our early adopters of EVs suggest that most customers will have access to charging their vehicles at home – this combines maximum customer convenience with minimum consumer cost.

However, there is uncertainty of the impact on demand from commercial fast chargers. It is assumed that these fast chargers are rarely used, and the impact to the network is likely to be localised. The uncertainty of the placement of fast charging stations on Tasmania's road network makes it difficult to determine the network impact, e.g., the placement of some chargers in rural areas or peak holiday regions will impact the network at different times or may have seasonal variation.

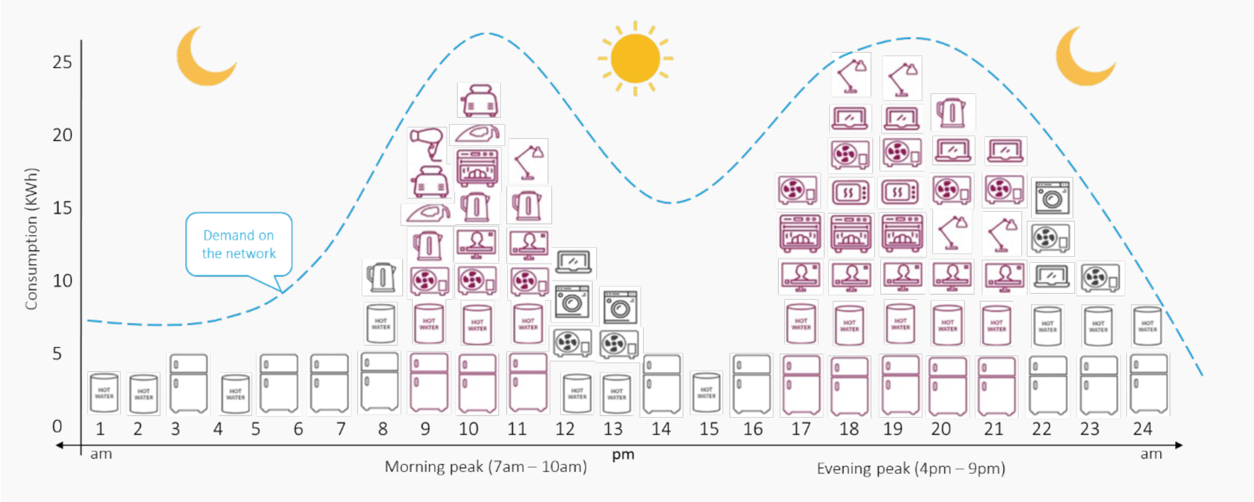
The electrification of transportation will continue to be monitored by TasNetworks throughout the next regulatory control period, particularly to establish whether the excess solar PV generation is soaked up through the charging of electric vehicles and whether commercial fast chargers are impacting on demand.

22.6.5 The benefits of pricing reform

When developing networks tariffs, our aim is to better reflect the costs incurred by TasNetworks that result from customer decisions to use electricity at specific times. Customers are gradually beginning to switch to time of use network tariffs – presently approximately 19 per cent of customers, as compared to three per cent at the beginning of the 2019-2024 regulatory control period. However, 82 per cent of residential and 72 per cent of business customers remain on the flat rate tariffs. The problem with this arrangement is that the pricing signal these customers receive does not appropriately reflect the costs associated with network provision. The cost of providing the network is not driven by the amount of electricity customers consume, but by the capacity needed to meet generally short peaks in usage – which typically occur on cold weekday mornings and evenings as shown in Figure 20.

13 Network modelling assumed the level of EV demand during the daytime was sufficient to mask the additional PV generation and avoid export limits being breached

Figure 20. How our everyday usage contributes to short peaks on the network



22.6.6 What is in our 2024-2029 distribution pricing strategy

Our pricing strategy for 2024-2029 builds on the foundations developed in previous periods, including retaining the current time of use consumption-based network tariffs as the default tariff option for residential and small business customers. We have been guided by our stakeholders, network impacts and customer expectations as we transition our tariffs to support the needs of our customers and future technological developments.
Our 2024-2029 distribution pricing strategy is summarised in Table 2.

Table 2. TasNetworks' distribution pricing strategy for the 2024-2029 regulatory control period

2024-2029 distribution pricing strategy	Resulting customer change
Amending our network tariff classes to produce a more streamlined structure	All customers
Altering our assignment rules to make the flat rate network tariffs obsolete for both residential and small business customers connecting to the network or upgrading their meter	Residential and small business customers
Retaining the current time of use consumption-based network tariffs as the default network tariff option for residential and small business customers	Residential and small business customers
Providing pricing options for our residential customers who are more actively engaged with their energy needs (such as electric vehicle owners)	Residential customers
Revising the peak windows for the time of use consumption-based network tariff for small business customers (TAS94)	Small business customers
Introducing new network tariffs designed specifically for embedded networks	All customers in embedded networks
Designing network tariff trials to understand the relationship between new technologies, pricing and network impacts	All customers
Continue removing cross-subsidies between tariff classes and network tariffs	All customers

22.7 2024-2029 pricing proposal

22.7.1 Amending our network tariff classes

We are proposing to amend our tariff classes and to implement a more streamlined structure which better meets the requirements of the Rules. This includes changes to our residential, business and unmetered tariff classes.

The development of our tariff classes for the 2024-2029 regulatory control period has been guided by the principles in the Rules, namely to:

- group retail customers together on an economically efficient basis[14]
- assign customers to tariff classes based on the nature and extent of their usage, their connection to the network and their metering technology[15]
- treat retail customers with similar connections and usage profiles on an equal basis.[16]

To enable alignment with the outlined criteria, we propose the following amendments to our existing tariff classes for the 2024-2029 regulatory control period:

- integrate the controlled and uncontrolled load tariff classes into the residential tariff class
- align the Individual Tariff Calculation (**ITC**) network tariff class with the business high voltage tariff class
- combine the unmetered and street lighting tariff classes into unmetered supplies
- include our new embedded network tariffs within our existing tariff classes.

Table 3 summarises our proposed tariff classes and provides a comparison to our current tariff class allocations.

Table 3. Proposed tariff classes for standard control services

2024-2029 regulatory control period Proposed tariff classes	2019-2024 regulatory control period Tariff classes	Typical customer characteristics
Low voltage residential	Residential low voltage *Uncontrolled energy* *Controlled energy*	Residential customers Low voltage connection
Low voltage small business	Small business low voltage	Small to Medium commercial customers Low voltage connection
Irrigation	Irrigation	Primary producers Low voltage connection
Low voltage large business	Large business low voltage	Medium to large industrial and commercial customers Low voltage connection
High voltage business	Large business high voltage *Individual tariff calculation*	Large industrial and commercial customers High voltage connection
Unmetered supplies	*Unmetered supply* *Street lighting*	Low demand installations with a relatively constant load profile Low voltage connection

14 NER 6.18.3

15 NER 6.18.4(a)(1)

16 NER 6.18.4(a)(2)

22.7.1.1 Integrate the controlled and uncontrolled load tariff classes into the residential tariff class

The controlled and uncontrolled load tariff classes both contain only a small number of tariffs, as shown in Table 4.

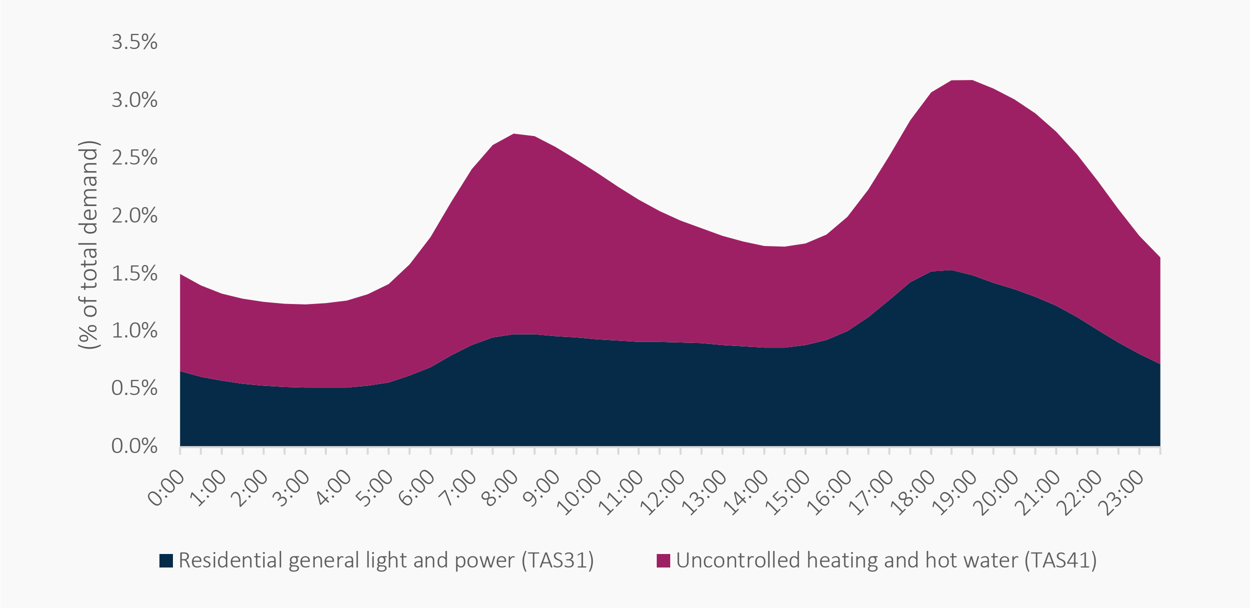
Table 4. Uncontrolled and controlled load tariff classes from the 2019-2024 regulatory control period

2019-2024 Tariff Class	Tariffs		Customer availability	Annual Consumption (FY 2021-22)
Uncontrolled Load	TAS41	Uncontrolled low voltage heating and hot water [proposed obsolete]	Residential customers Commercial customers	941 GWh (21% of total)
Controlled Load	TAS61	Controlled low voltage energy – off-peak with afternoon boost [obsolete]	Residential customers Commercial customers	35 GWh (0.8% of total)
	TAS63	Controlled low voltage energy – night period only	Residential customers Commercial customers	1.5 GWh (<0.05% of total)

All controlled and uncontrolled load tariffs are secondary tariffs, i.e., tariffs that can only be used in conjunction with other (primary) tariffs. Two of the three tariffs are either obsolete or proposed to be made obsolete in the 2024-2029 regulatory control period. It is therefore economically inefficient to retain separate controlled and uncontrolled load tariff classes. TasNetworks has analysed the affected tariffs in more detail and the following observations underpin our proposal to integrate both tariff classes into the residential tariff class:

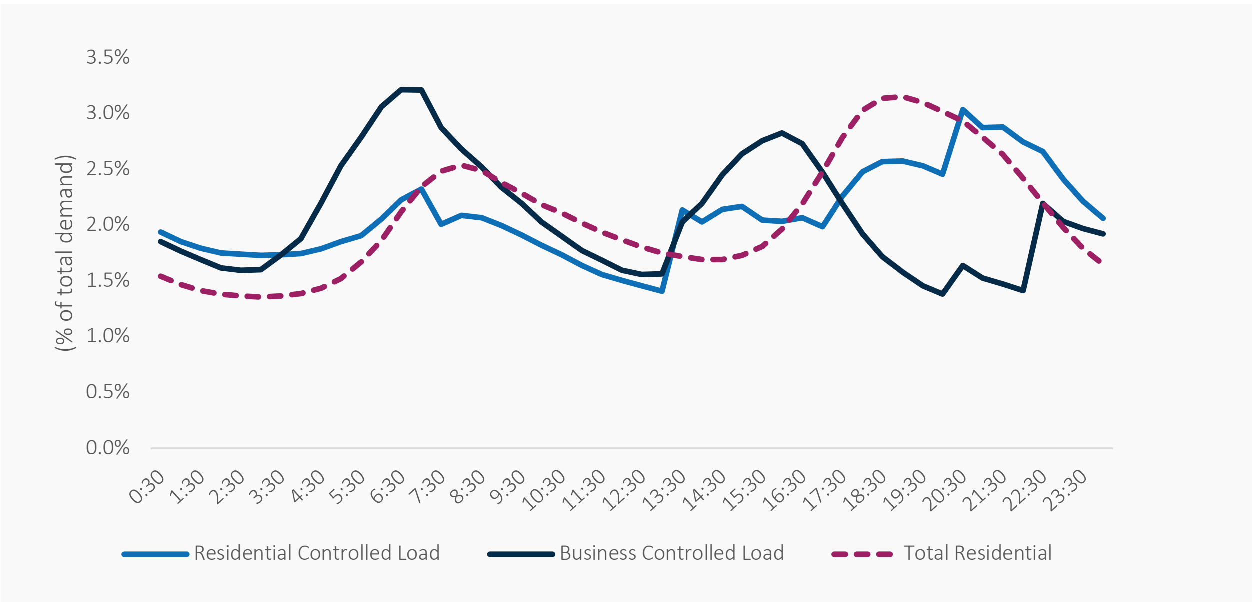
- Over 99 per cent of our uncontrolled load customers and over 96 per cent of our controlled load customers are residential. These proportions are unlikely to change, given both the majority of our controlled and uncontrolled load tariffs and the flat rate primary tariffs that are most commonly used in conjunction with these tariffs are either already obsolete or proposed to be made obsolete in the 2024-2029 regulatory control period (as outlined in section 22.7.2).
- The uncontrolled load heating and hot water tariff (TAS41) is used by the majority of our residential customers, in conjunction with the low voltage residential general light and power tariff (TAS31). The space heating and hot water loads associated with this tariff are a main driver of the distinct morning and evening peaks that characterise the overall residential load patterns (Figure 21). It is therefore closely intertwined with the residential tariff class, which is highlighted by the fact that one of TasNetworks' key strategic objectives is to remove the inherent discount of the heating and hot water tariff and to align it with the low voltage residential general light and power tariff, as outlined in section 22.6.6.

Figure 21. Residential Load Profile (TAS31/41)



- The controlled load tariff class accounts for less than one per cent of the Tasmanian total annual consumption. Around 92 per cent of this consumption is related to customers on the obsolete controlled load tariff with afternoon boost (TAS61), making it inefficient to retain the controlled load tariff class during the next regulatory control period. The controlled load tariffs are primarily used by residential customers, often in conjunction with the controlled load tariff. As a result, the demand profile of our residential controlled load customers closely resembles the overall residential demand profile. The same applies to our controlled load business customers who operate predominantly in the hospitality and dairy industries and whose load profiles display similar morning and evening peaks than the overall residential profile (Figure 22).

Figure 22. Controlled Load Customer Profiles

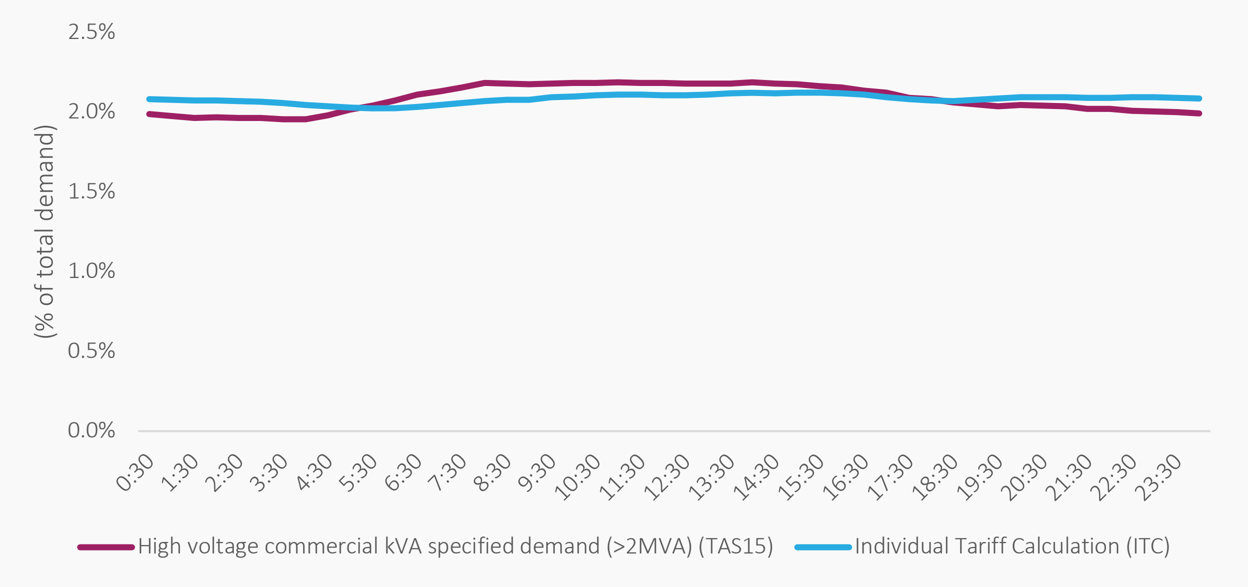


22.7.1.2 Include Individual Tariff Calculation in the high voltage tariff class

There are currently 10 high voltage customers that are assigned to the ITC tariff class which comprises a single tariff. It is TasNetworks' strategy to align these customers' charges with the business high voltage kVA specified demand >2 MVA tariff (TAS15) over time and to not offer new ITC arrangements where connection arrangements are consistent with other tariff class arrangements.

Current ITC customers were assigned to this tariff class based on their original connection arrangements. These customers are mostly large industrials whose load characteristics closely resemble other high voltage business customers, particularly those connected to the TAS15 business high voltage kVA specified demand >2 MVA tariff (Figure 23). TasNetworks therefore proposes to integrate the ITC tariff class into the existing high voltage tariff class.

Figure 23. High Voltage Business Load Profiles



22.7.1.3 Combine the unmetered and street lighting tariff classes into unmetered supplies

Both the unmetered supply and the unmetered street lighting tariff classes currently comprise a single tariff each. These unmetered connections are similar in nature and connected installations on both tariffs have relatively constant load profiles during times of operation. It is therefore proposed to combine these tariff classes in the next regulatory control period.

22.7.2 Altering our tariff assignment rules

The benefits of cost reflective pricing are more clearly realised if accompanied by sufficient uptake of cost reflective network tariffs. However, TasNetworks is mindful of the impact of pricing reform on customers when making changes to our network tariff assignment policy.

During the 2024–2029 regulatory control period we propose to transition an increasing number of customers to more cost reflective network tariffs by modifying our network tariff assignment rules.

22.7.2.1 The transition to cost reflectivity

As the transition to cost reflective tariffs continues across the NEM, mandatory assignment policies are becoming more prevalent, with customers being unable to opt out of a cost reflective network tariff.

We discussed options with our stakeholders to continue and accelerate the take-up of our cost reflective network tariffs. The discussion centred around electricity being a low involvement product, resulting in many customers being unaware of incentives that may be on offer via alternate tariff offerings. This suggests that differential pricing would be less impactful, resulting in our stakeholder's preference to transition our customers to cost reflective tariffs by revising our network tariff assignment rules.

We therefore propose that for the 2024–2029 regulatory control period our tariff assignment rules be changed to make the residential general light and power (TAS31), heating and hot water (TAS41) and the business general light and power (TAS22) network tariffs obsolete.[17] These three tariffs are referred to as flat rate network tariffs.

22.7.2.2 Background to TasNetworks' network tariff assignment policy

TasNetworks' network tariff assignment policy for the 2019-2024 regulatory control period specified that from 1 July 2019 the residential consumption-based time of use network tariff (TAS93) and the small business time of use consumption network tariff (TAS94) would be the default network tariffs for these customer classes. Customers are assigned, on an opt-out basis, to the relevant time of use consumption network tariff by default, in response to several 'trigger events':

- moved into newly connected premises from 1 July 2019; or
- upgraded their connection to the distribution network from 1 July 2019 (e.g., by changing from a single phase to multi-phase power supply); or
- modified their connection to the distribution network from 1 July 2019 (e.g., through the installation of solar panels); or
- have their existing accumulation meter replaced with an advanced[18] meter (e.g., when the existing meter reaches the end of its service life or fails).

This default network tariff assignment was not immediately applied but was delayed by 12 months from the trigger event date.[19] The 12-month data sampling period was implemented to provide customers with an opportunity to better understand their electricity usage, including variations over the year,[20] before choosing the network tariff that they wished to be assigned to in the future.

17 This is in addition to TasNetworks' low voltage controlled energy off-peak with afternoon boost (TAS61), which was made obsolete on 1 July 2019

18 An advanced meter refers to an electricity meter capable of measuring electricity usage in specific time intervals, enabling the application of network (and retail) tariffs that can vary by time of day

19 One trigger event will be applied per residential or small business installation as it is recorded at the national metering identifier level (NMI)

20 Note: Some customers may have access to less than 12 months of data (e.g., if a customer moves into a property during the data sampling period)

Figure 24. Total network uptake of cost reflective tariffs[21]

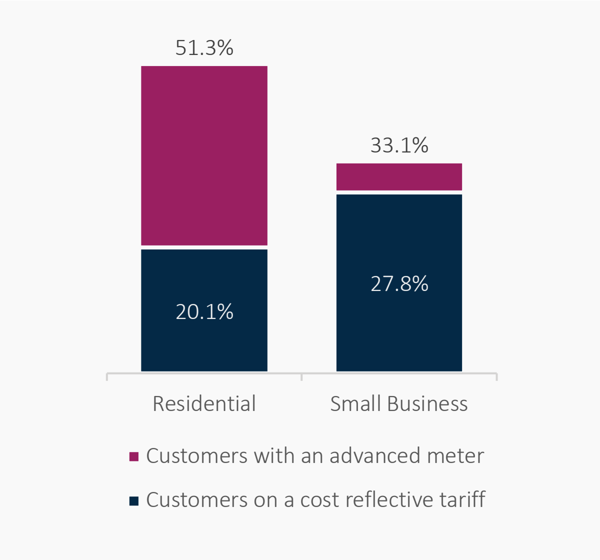
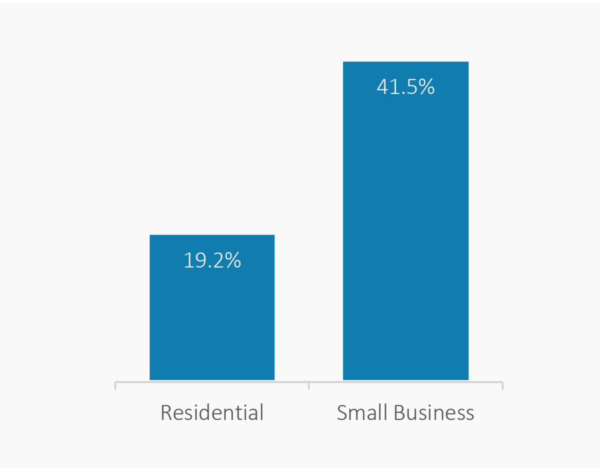


Figure 24 shows that just over 20 per cent residential customers are on cost reflective tariffs (despite over 50 per cent of these customers having an advanced meter). However, for small business customers, nearly 30 per cent are on the default time of use network tariff, even though only 35 per cent of small business customers have an advanced meter.

Figure 25. Uptake of cost reflective tariffs for new connections since 1 July 2019[21]



In addition, it has been observed that since 1 July 2019, approximately 20 per cent of new residential customers and 42 per cent of new small business customers have been assigned to the default time of use consumption tariffs (see Figure 25).

This relatively low rate of assignment of newly connected customers to our default time of use network tariffs has contributed to the low overall uptake of our cost reflective tariffs, especially for residential customers.

21 Figures are prepared as at 30 November 2022

22.7.2.3 Advanced meter rollout in Tasmania

The Tasmanian Government has committed to accelerating the rollout of advanced meters across the State, with the aim of reaching full deployment during TasNetworks' next regulatory control period.[22]

The current pace of the advanced meter rollout should result in approximately 33 per cent of customers still needing an advanced meter upgrade at the beginning of the 2024-2029 regulatory control period. This will see approximately 25-30 per cent of residential customers being potentially impacted by the proposed changes in the assignment rules and potentially needing a mechanism to opt-out.

22.7.2.4 Customer impact of tariff assignment policy

Residential customers

In Tasmania, many residential customers choose to be connected to the residential flat rate tariffs due to their reliance on electricity to provide home heating and hot water in a way not seen anywhere else in Australia. The uncontrolled low voltage heating network tariff (TAS41) currently provides customers with discounted network charges for hard-wired space heating and hot water systems.

During the 2024-2029 regulatory control period, TasNetworks will seek to continue the alignment of the price points of the heating and hot water tariff (TAS41) with the network tariff applying to residential customers for general power and light (TAS31) to remove the existing cross-subsidy. This means that the price of the TAS41 network tariff will continue to be slowly increased during the 2024-2029 regulatory control period, with parity with TAS31 expected to be achieved by June 2029.

Figure 26 shows the forecast change in network charges for customers[23] if they were moved from the current combination of the residential general light and power and heating and hot water network tariffs (TAS31/41) used by most residential customers to the time of use consumption tariff (TAS93) that is now the default residential network tariff. Our network charge comparisons indicate that at the beginning of the 2024-2029 regulatory control period, approximately 65 per cent of customers would benefit from switching to the cost reflective network tariff (TAS93) without making any changes to their use of electricity, with average annual network charge savings of approximately \$21[24]. By the end of the 2024-2029 regulatory control period, around 66 per cent of customers are anticipated to benefit from a switch to the time of use consumption tariffs, with average annual network charge savings estimated to increase to around \$25.

22 Tasmanian Liberals, Securing Tasmania's Future by delivering affordable, reliable clean energy

23 Calculations were undertaken for customers with an advanced meter throughout the entire 2021-22 financial year

24 Noting that the typical residential customer's savings are approximately \$9 per annum

Figure 26. Annual network charge comparison for customers on the combined low voltage residential general light and power, with heating and hot water network tariff (TAS31/41)[25]

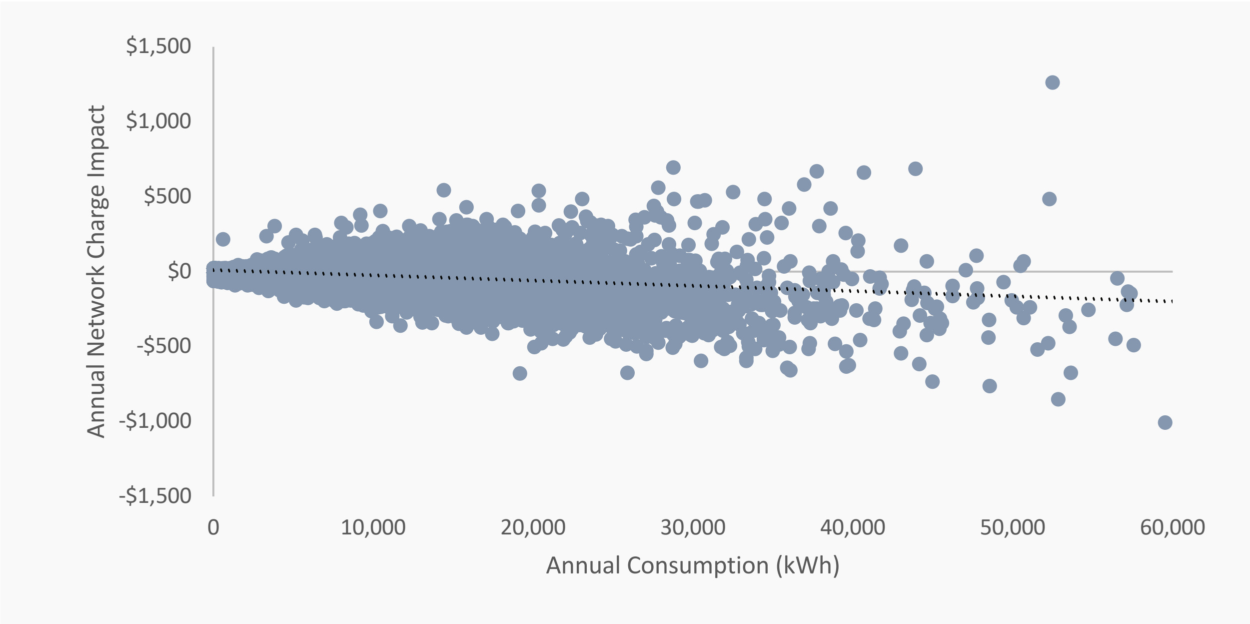
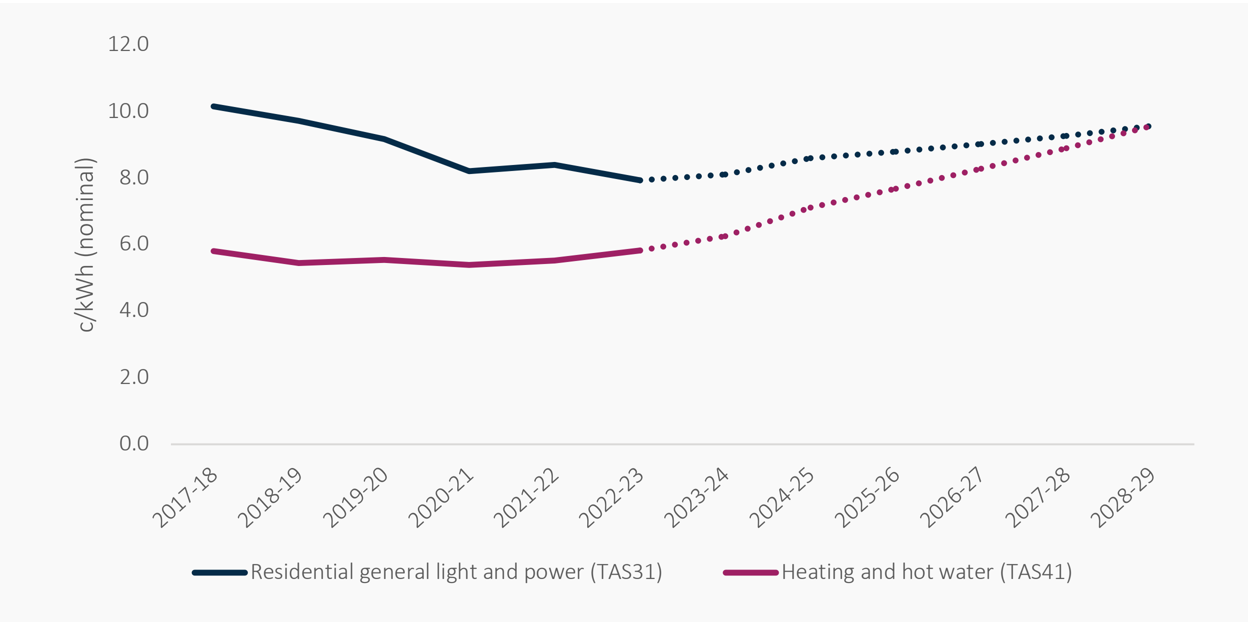


Figure 27 shows our current plans of fully aligning the energy charges of the TAS31 and TAS41 network tariffs by the end of 2028-29.

Figure 27. Projected alignment of the residential general light and power (TAS31) and the heating and hot water (TAS41) energy charges



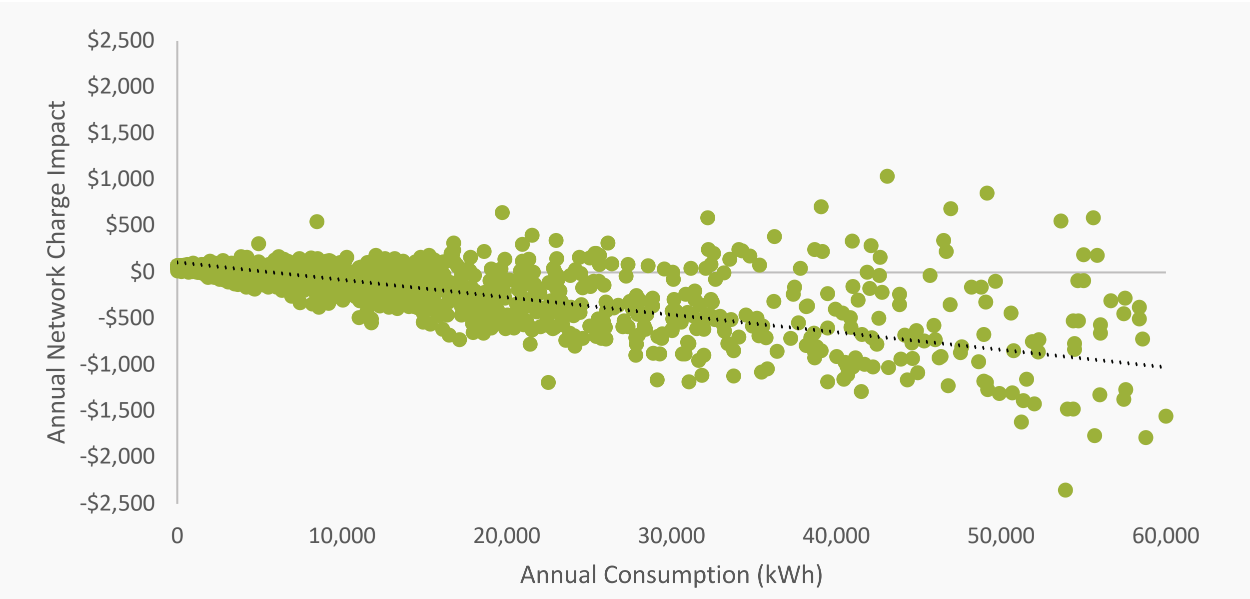
Small business customers

The proportion of small business customers taking up the cost reflective tariff when there has been a change of circumstance (e.g., advanced meter installation) is significantly higher as a proportion of the advanced meters that have been rolled out than for residential customers. Since the introduction of cost reflective time of use tariffs approximately 8,600 small businesses have moved onto the default time of use consumption tariff (TAS94).

25 Prepared using the indicative prices for 2024-25

Figure 28 shows the forecast change in network charges for customers on the small business low voltage general light and power network tariff (TAS22)[26] if they were to switch to the TAS94 time of use consumption tariff at the beginning of the 2024-2029 regulatory control period. Our network charge comparisons indicate that these customers have the potential to make significant savings on the small business time of use network tariff TAS94 as compared against the general network tariff (TAS22), and that TAS94 is likely to remain the more lucrative tariff options for the majority of our small business customers throughout the regulatory control period.

Figure 28. Annual network charge comparison for customers on the business low voltage general light and power network tariff (TAS22)27



22.7.2.5 Engagement and consideration of customer protections

The above information was provided to our stakeholders over multiple workshops. While our analysis shows that many residential and small business customers will benefit from changing to the default time of use consumption network tariff, stakeholders were cautious about making our flat rate network tariffs obsolete. During our engagement we heard multiple stakeholders clearly state that as we progress to greater cost reflectivity in our network pricing, customer protections need to be in place to protect those customers in vulnerable situations.

The stakeholder group identified 'trigger events' that are proposed to initiate a network tariff change that would cause concern if applied to customer in vulnerable situation. These were:

- advanced meter installation
- customers relocating to existing premises, e.g., moving house
- premises being connected to the distribution network for the first time
- opting-in to a time of use consumption tariff.

Some stakeholders called for a cooling off period to apply to all trigger events, so that any customer could move back onto a flat rate network tariff within a specified time. However, this would greatly delay our customers' ability to realise and receive the benefits identified in the earlier analysis associated with a move to cost reflective pricing.

Other stakeholders questioned whether we could identify specific customers experiencing vulnerability and exclude them from our assignment policy. However, excluding a specific group of customers from tariff reform would remove the ability for these customers to benefit from cost reflective pricing, and identification of such a group of customers would not be possible without additional data.

A compromise approach was reached where stakeholders supported continued network tariff reform with some limitations, specifically an opt-out period, to protect, to protect customers in vulnerable situations. This approach aligns strongly with our pricing principles, to provide fair and equitable pricing that provides a choice in pricing for all customers.

26 Calculations were only done for customers with an advanced meter throughout the entire 2021-22 financial year

27 Prepared using the indicative prices for 2024-25 and the tariff structure for the small business time of use consumption (TAS94) network tariff proposed in section of this paper

The proposal to make our flat rate tariffs obsolete was accepted by most of our stakeholders on the condition it was also accompanied with in-built customer protections, such as an opt-out period to allow for the metering data to be collected and analysed, and a more targeted transition to cost-reflectivity.

22.7.2.6 Network tariffs for abolishment

During the 2019-2024 regulatory control period, the following two network tariffs had been declared obsolete:

- TAS92 – Low voltage residential pay as you go (PAYG) time of use
- TAS101 – Low voltage residential pay as you go (PAYG).

As at 31 October 2022, there is one installation on the TAS92 network tariff, and 14 installations on the TAS101 network tariff (of which four installations have recorded zero consumption over the last 12 months). All installations are currently connected through an accumulation meter.

During the 2023-24 financial year (the final year of the 2019-2024 regulatory control period), TasNetworks will have aligned the network prices of TAS92 to the low voltage residential time of use consumption (TAS93) network tariff, and TAS101 to the low voltage residential general light and power network tariff (TAS31). Once the network tariffs have been aligned, customers will be reassigned to the relevant available network tariff prior to 30 June 2024 resulting in no customers remaining on these obsolete network tariffs. TasNetworks propose that TAS92 and TAS101 are abolished from 1 July 2024.

22.7.2.7 Summary of our proposed network tariff assignment policy

TasNetworks is proposing the following network tariff assignment policy:

- From 1 July 2024, the time of use consumption network tariffs for residential customers (TAS93) and small business customers (TAS94) will be the default network tariff. The residential general light and power (TAS31), small business general light and power (TAS22) and heating and hot water (TAS41) network tariffs will be made obsolete.[28]
- All existing residential and small business customers who, as at 30 June 2024, were assigned to an obsolete network tariff may continue to use those tariffs from 1 July 2024, until such time as there is a trigger event.
- Residential or small business customers that have their **meter upgraded or replaced with an advanced meter** on or after 1 July 2024, will be assigned to the default time of use consumption network tariff 12 months following the date of their meter being exchanged ('trigger date'). Prior to the conclusion of the 12-month period, customers may choose to opt-out of the default network tariff, nominate an alternative cost reflective network tariff or accept the reassignment to the new default network tariff.
- All **new residential and small business connections** on or after 1 July 2024 will be assigned to the default time of use consumption network tariff.
- A residential or small business customer who **voluntarily opt into a time of use consumption network tariff** on or after 1 July 2024 will be unable to revert to any of the obsolete network tariffs.
- Residential and small business **customers who move into established premises** will be assigned to the same network tariff(s) as the previous occupants of those premises. If the previous occupants of the property were assigned to a now obsolete network tariff, the new occupant will be assigned the same network tariff(s) unless they opt to change their network tariff, or have their meter upgraded.
- A residential or small business customers who installs an **electric vehicle fast charger**[29] at their premises will be assigned to TasNetworks' default time of use consumption network tariff.

Table 5 summarises the circumstances in which the 12-month opt-out period will be applied.

28 TasNetworks' low voltage controlled energy off-peak with afternoon boost (TAS61) was made obsolete on 1 July 2019. This network tariff assignment policy will apply to TAS61

29 TasNetworks' recognises the lack of visibility of EV charger installations and this assignment rule will be dependent on customers self-declaring an EV fast charger installation. An EV fast charger refers to a dedicated EV charger i.e., the EV is not charged from a regular household electricity outlet

Table 5. Our proposed default tariff assignment policy for residential and small business customers

Trigger events	Retain current network tariff	Default network tariff	Cost-reflective network tariff	12 month opt-out period
Advanced meter installation		✔		✔
New connection		✔		
Opt into alternative network tariff			✔	
Customer relocation	✔†			
EV fast charger installation		✔	✔	

† Refers to the network tariff(s) applying to the property the customer moves into, rather than the network tariffs applying to the customer's previous abode or business premises.

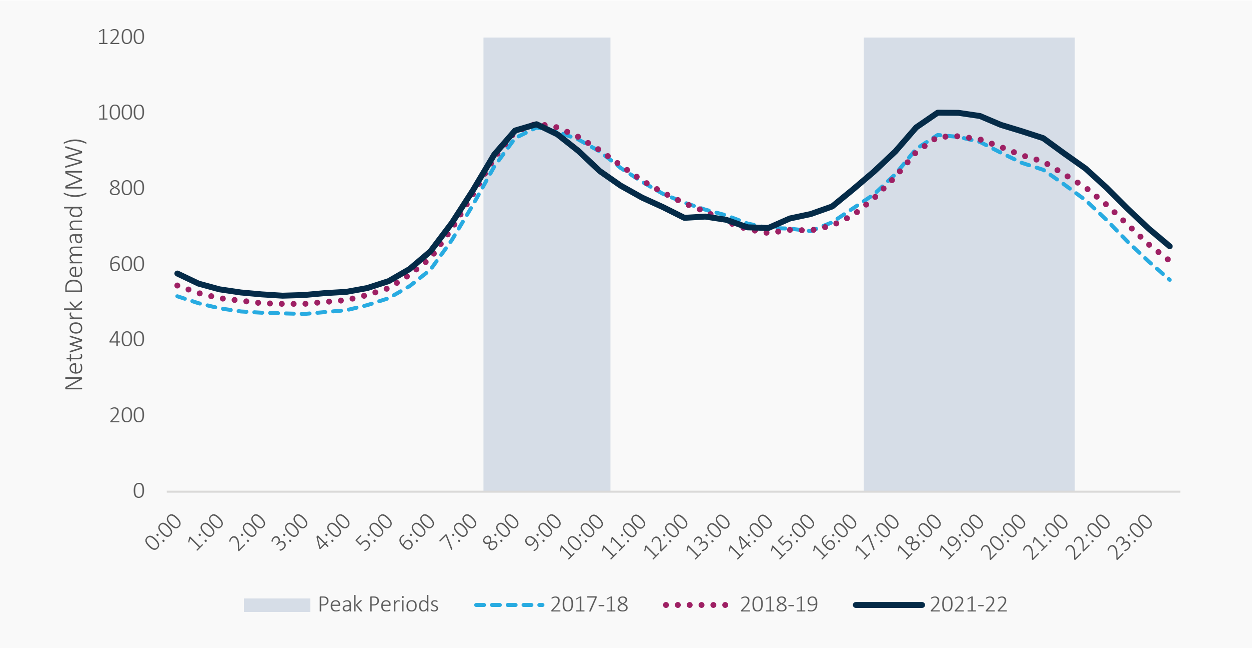
22.7.3 Peak window review

22.7.3.1 Monitoring our peak time of use windows

The main driver of TasNetworks' network peak is residential demand, with businesses also contributing. Historically the network peak usually correlated with cold winter mornings, yet we observe that the network peak became an evening peak for the first time during 2021-22 and exceeded 1,000 MW. This increasing evening peak is most likely a result of the large number of new residential connections – approximately 88 per cent of new connections since 1 July 2019 have been residential connections.

TasNetworks continues to monitor its peak time of use windows to ensure they align with times of local demand and network peaks. Figure 29 shows that the network peaks have not substantially moved between 2018-19 and 2021-22 and our time of use tariffs continue to be well aligned to times of high network utilisation.

Figure 29. Network peak day comparison



TasNetworks assessed the time of use periods for each tariff to ensure they were reflective of the collective load profile of the customers of that network tariff and overall network utilisation.

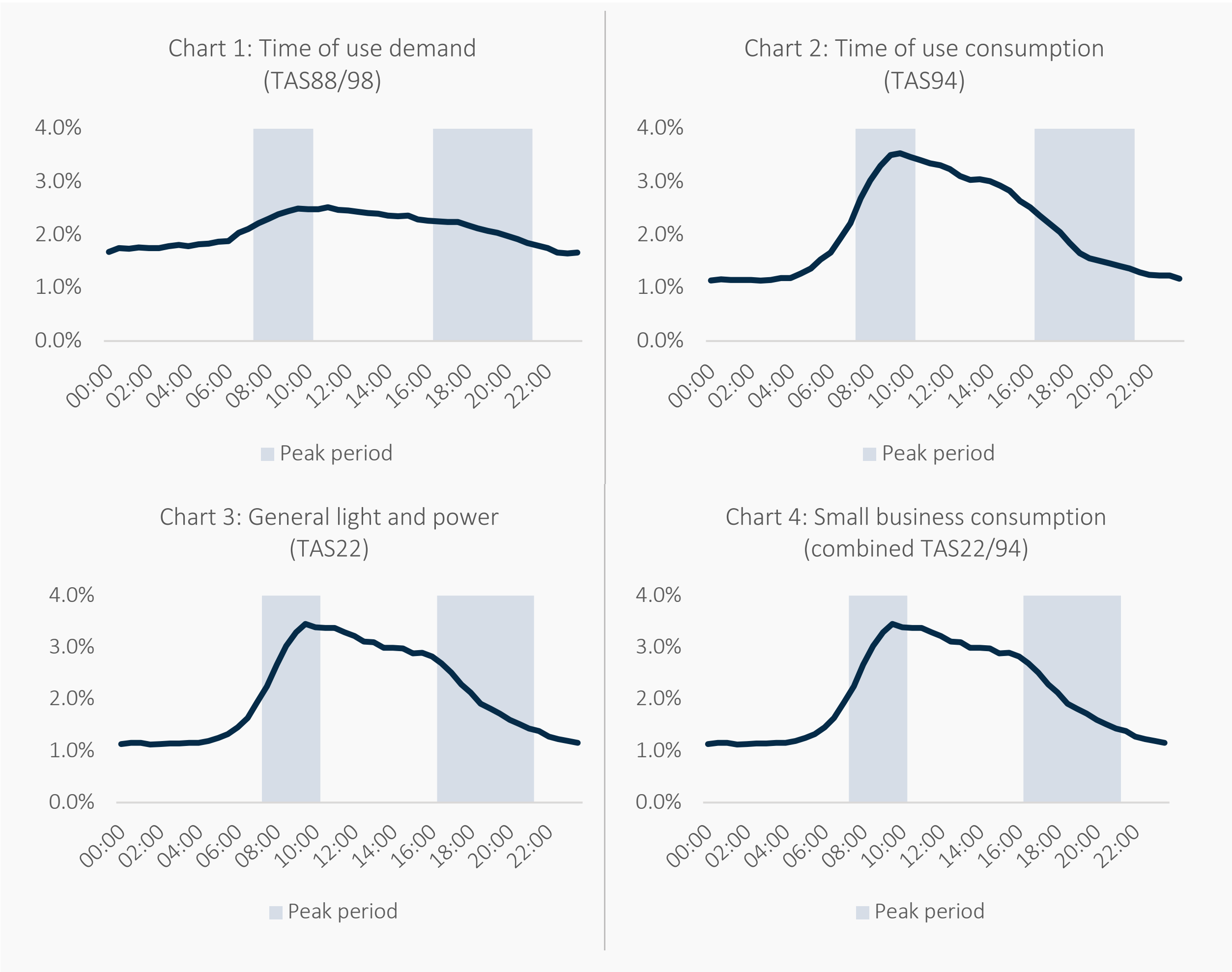
Figure 30 profiles small business customers on the low voltage network. Customers on the time of use demand (TAS88/98) network tariffs have a much flatter profile than the customers on the time of use consumption (TAS94) and the general light and power (TAS22) network tariffs. TasNetworks has also considered the profile of customers on the time of use consumption (TAS94) and the general light and power (TAS22) network tariffs.[30]

30 Analysis has shown that of customers who, during the 2019-2024 regulatory control period, moved from the general light and power network tariff (TAS22), approximately 85 per cent changed to the time of use consumption network tariff (TAS94)

Charts 2-4 in Figure 30 show the profile of customers on the time of use consumption tariff (TAS94) and the general light and power (TAS22) network tariff. The profiles of customers within these tariffs are similar, i.e., they tend to have higher consumption earlier in the day, which starts to decline from 10:00 onwards (the end of the morning peak period).

In collaboration with our stakeholders and given the combined profile of customers (Figure 29) a review of the time of use windows of the small business time of use consumption (TAS94) network tariff was undertaken to determine if it could be better aligned to reflect small business load patterns and times of high network utilisation.

Figure 30. Network utilisation and peak weekday time of use periods for business tariffs



22.7.3.2 Small business time of use peak charging review

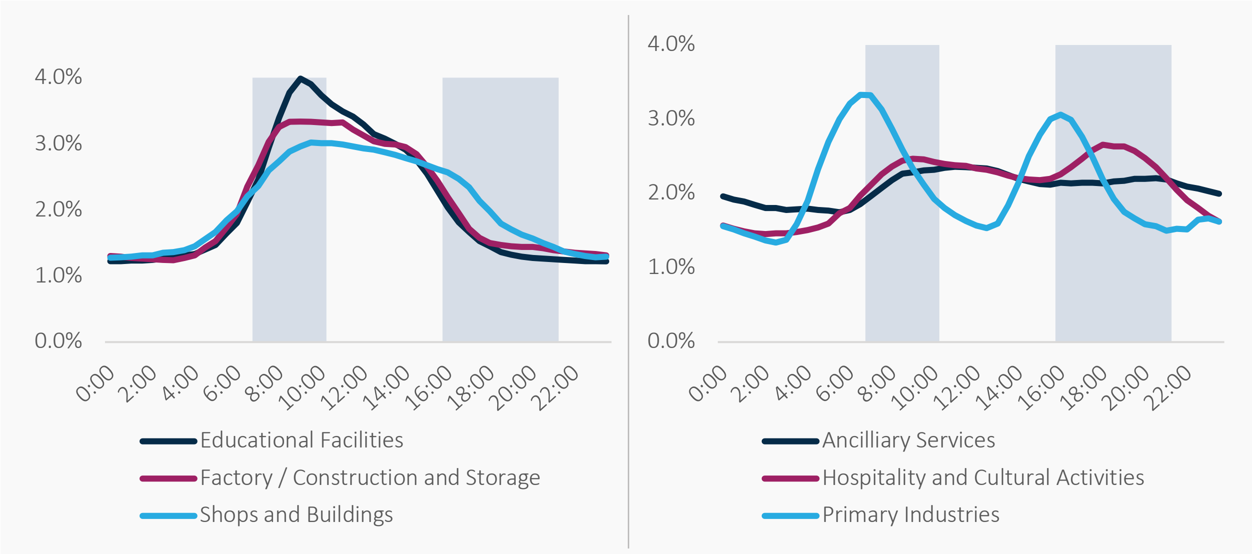
Our network has traditionally seen lower utilisation during the middle of the day, and with increasing solar PV being deployed across the network the opportunity presents to encourage increased day time network utilisation.

Figure 31 shows the load profiles of subsets of customers within the small business time of use consumption (TAS94) and general light and power (TAS22) network tariffs. Educational facilities, factories/construction and storage, and shops and buildings tend to have an early morning peak during the network peak period of 07:00-10:00, however, consumption declines during the middle of the day, with only shops and buildings maintaining close to the peak level of consumption during the late afternoon/early evening.

Conversely, hospitality and cultural activities, and primary industries have either a flatter profile, or have two distinct peaks in demand. Primary industries'[31] peak occurs at the beginning of the network peak. As would be expected, hospitality has higher consumption during the evening peak period, however consumption remains relatively flat from early morning until after lunch.

31 Note: Primary industries in this discussion does not include the irrigation (TAS75) network tariff. Dairy farmers and fish farms are the largest subgroup in primary industries in terms of annual consumption

Figure 31. Low voltage small business profiles



22.7.3.3 Proposed peak periods for the low voltage small business time of use consumption network tariff

In consultation with our stakeholders, it was agreed that the low voltage small business time of use consumption network tariff (TAS94) could be better aligned to the network peaks to further encourage usage during the middle of the day.

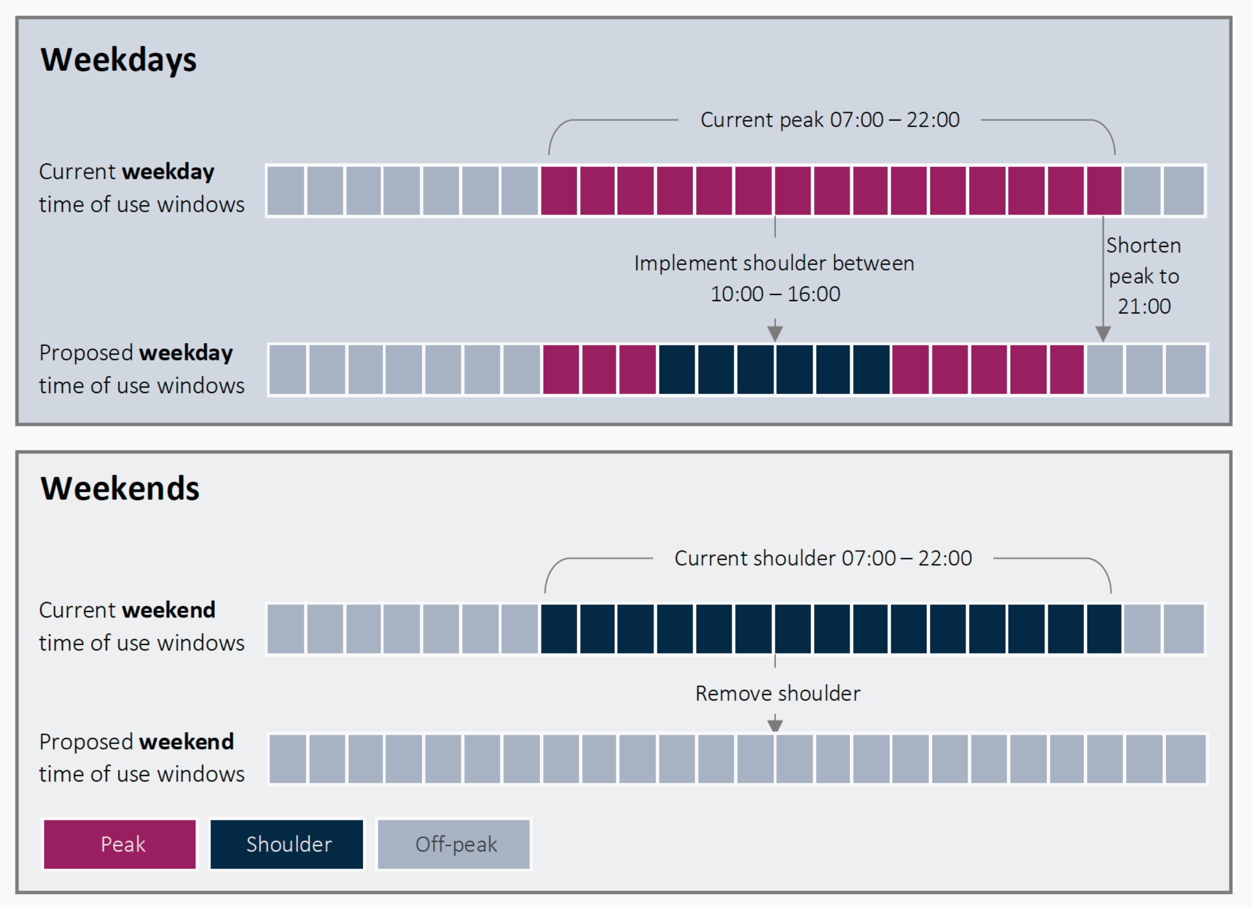
While small businesses contribute to peak demand during the network peak periods on weekdays, over the weekend, overall network utilisation for small businesses is lower than during the week and tends to fluctuate within a small range.

We propose to change the time of use charging windows for the small business time of use consumption network tariff (TAS94) as follows:

- During the weekdays we propose to introduce:
  - a shoulder period between 10:00 and 16:00
  - ensure the peak period reflects the network peaks between 07:00 to 10:00 and 16:00 to 21:00 (note the end of the evening period is earlier, changing from 22:00 to 21:00)
  - all other periods will be off-peak.
- It is proposed that the current shoulder period on the weekends (07:00 to 22:00) be removed. This results in the entire weekend (Saturday and Sunday only) being off-peak.

These proposed time of use periods are intended to provide an incentive to move discretionary loads (including electric vehicle fleet charging) into times of lower network utilisation, while reducing the likelihood of localised midday peaks in areas with a higher proportion of small businesses.

Figure 32. Proposed changes to the low voltage small business time of use consumption network tariff (TAS94)



22.7.3.4 Pricing for the revised small business time of use consumption structure

The revenue to be recovered from the low voltage time of use consumption network tariff (TAS94) needs to reflect the efficient costs of providing this service. Since this tariff is currently recovering (and is forecast to recover) close to 100 per cent of its total efficient cost (**TEC**), the tariff price has been set so that the total revenue recovered under the proposed structure closely aligns to the same revenue under the existing structure.

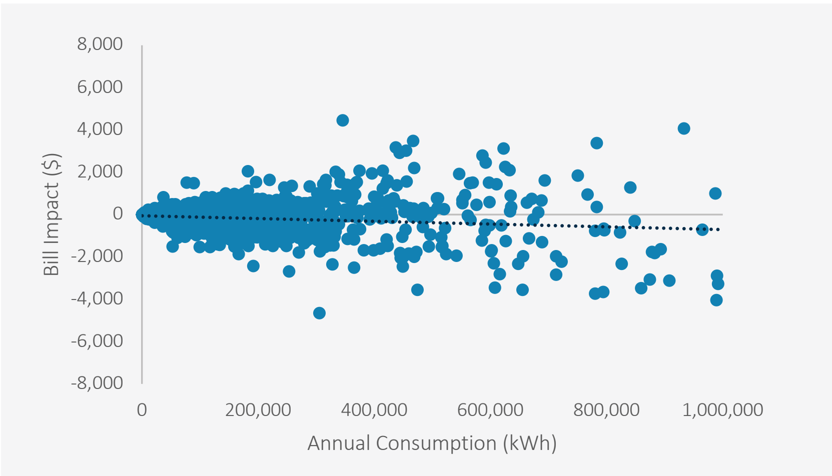
Figure 33 shows the customer impacts from switching the low voltage time of use consumption network tariff to the proposed time of use structure and charges in the 2024-2029 regulatory control period. The proposed charges represent an even increase of the current peak, shoulder and off-peak charges and are likely to reduce the network charges for approx. 76 per cent of our current TAS94 customers.

Figure 33. Customer impact to rebalancing[32]

Even time of use changes

Approximately 76% of current customers' network charges are expected to decrease under the proposed tariff structure in 2024-25 – on average by $108 pa.

Approximately 78% of customers are expected to experience a ±5% variation in their network charges – the majority of these customers is likely to experience a decrease.



32 Prepared using the indicative prices for 2024-25

22.7.4 Residential CER tariff review

22.7.4.1 Tasmania's prosumers and prosumer network tariffs

TasNetworks recognises the "pro" in prosumer as two-fold:

- either relating to production, i.e., a customer has become a producer of energy due to their investment in generation technology such as solar PV
- the proactive participation in the consumption and/or storage of energy through investing in batteries and/or electric vehicles.

In preparation for the anticipated growth in prosumers we are proposing to adjust the current residential CER network tariff to better target the behaviours and needs of our emerging prosumer, and to accommodate the increasing EV charging loads at residential properties in a way that benefits owners and sends a price signal to encourage efficient network utilisation.

During our stakeholder engagement, we discussed the opportunities and impact of increased CER connections to our distribution network. PRWG members considered a range of varying network challenges associated with the increased penetration of these technologies (solar PV, batteries and EVs) recognising that different technology has different challenges associated with it.

Our stakeholders also discussed how TasNetworks can develop a network tariff structure to prepare for the increased take-up of these technologies. As part of this discussion, we sought feedback on the inclusion of additional components to revise the existing CER demand-based network tariff, specifically by changing the tariff to a consumption-based tariff with a demand threshold and altering the time of use windows.

These proposed revisions are to promote the efficient use of the network by better targeting the behaviours and needs of our emerging prosumer customer and in turn, assist to minimise the cost of future investments.

22.7.4.2 Background to the CER network tariff

During the 2019-2024 regulatory control period, we offered a CER network tariff for residential customers (TAS97), which is a time of use demand-based tariff. However, we have learnt, through consistent stakeholder and customer feedback that residential customers have difficultly effectively using demand-based tariffs within a household context. This has resulted in a lack of an associated retail offering and no customers being assigned to the CER network tariff.

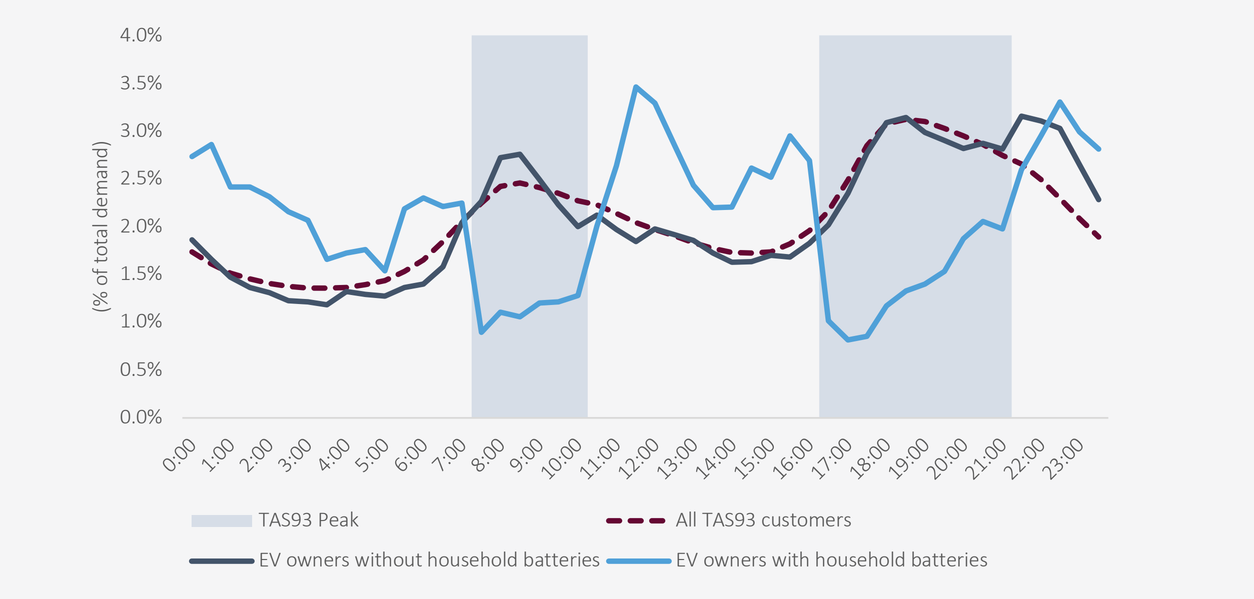
To provide an innovative additional tariff choice for customers, we sought to understand our customers' use of CER technologies, and whether these technologies have changed how customers use the network.

As described in 22.5.4 we undertook a survey to gain a better understanding our customers' views on CER.

The survey provided some important insights into the charging behaviours of EV owners. Whilst most customers stated that they preferred to charge their vehicle when it was convenient, we observed different behaviours from customers depending on their household tariff, for example:

- Customers who were on the combined flat rate tariff (TAS31/41), tended to charge their vehicles in the early evening. This indicates that customers were plugging in their vehicles to charge when they arrived home.
- This compared to customers on the time of use consumption tariff (TAS93), who were able to respond to price signals, and therefore tended to charge during off peak times (Figure 34). We also observed the following:
    - Customers with household batteries were even more responsive to price and demonstrated the ability to significantly reduce their consumption from the network during peak times
    - Customers tended to start charging immediately following the end of the peak period – potentially before peak consumption has significantly declined. Therefore, continuing this behaviour could lead to the evening peak being extended, or hitting a higher peak between 21:00-22:00.

Figure 34. EV charging profiles for customers with and without household batteries on the time of use consumption network tariff (TAS93)



22.7.4.3 Electric Vehicle Trials

To better understand the specific characteristics of CER owners and prosumers, numerous trials are currently conducted across Australia. A large proportion of these trials focusses on EVs, which are projected to add significant loads and pose new challenges to electricity networks in the near to medium future. TasNetworks is closely monitoring the outcomes and findings of these trials, and currently participates in the EV Grid trial to interact more closely with EV owners in Tasmania and to gain additional insights into this emerging customer group. The EV Grid trial is undertaken collectively by DNSPs in Victoria, ACT and Tasmania, and it aims to explore ways in which networks can effectively manage increased EV loads with minimal infrastructure upgrades.[33]

22.7.4.4 Our proposed amended CER tariff

We are proposing an innovative additional choice of network tariff for residential customers, involving revisions to an existing network tariff which have been developed with the growing number of prosumers in mind. The proposed network tariff represents a cost reflective alternative to the default consumption-based time of use network tariff (TAS93) to be made available through retailers, on an opt-in basis.

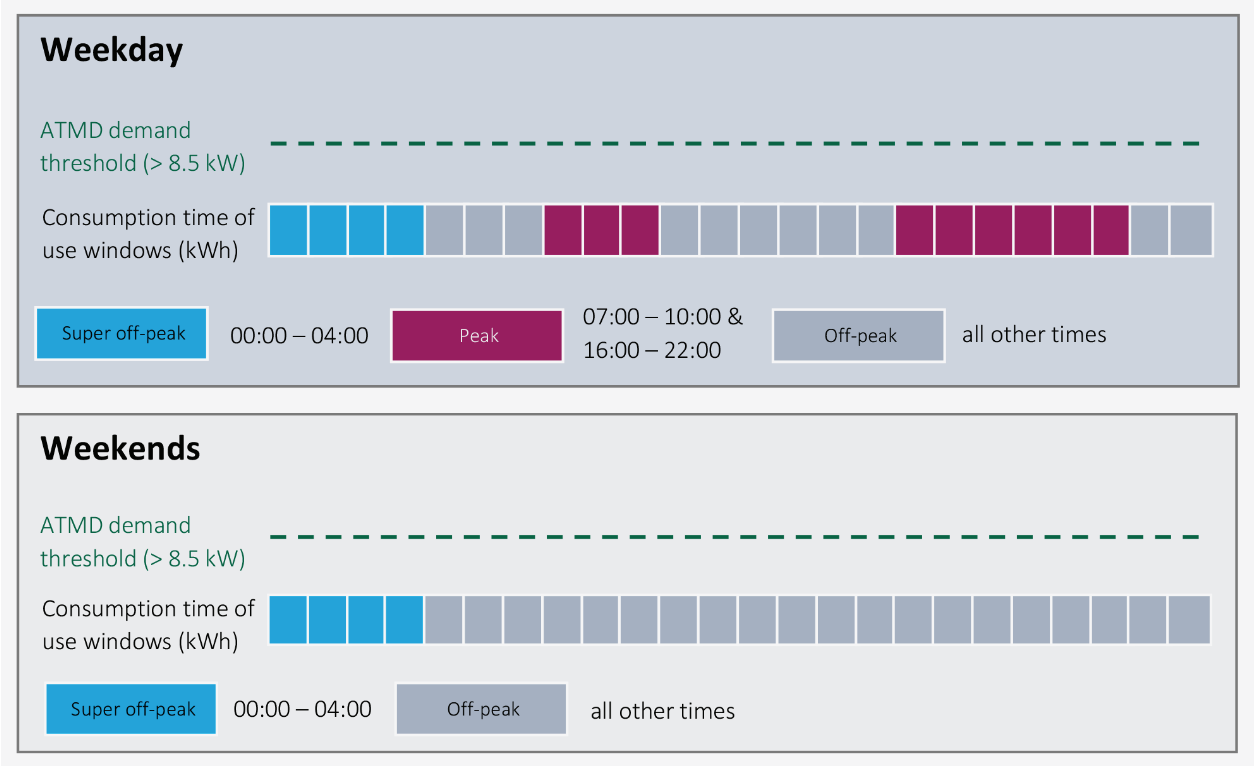
This proposed tariff is primarily a time of use consumption tariff which, from 1 July 2024, will include a new super off-peak period between midnight and 04:00, as well as a demand threshold that rewards customers who are able to keep their peak demand below an anytime maximum demand (**ATMD**) threshold. There are several key components to the proposed tariff:

- a super off-peak period between midnight and 04:00 on both weekends and weekdays
- a morning peak period between 07:00 and 10:00, with an extended evening peak period between 16:00 and 22:00 on weekdays.
- a demand threshold on any day (weekdays and weekends):
    - for any day on which the customer's daily ATMD remains below the demand threshold (i.e., ≤8.5 kW), no demand related charges would be applied
    - for any day on which the customer's daily ATMD exceeds the demand threshold (i.e., >8.5 kW), an excess demand charge would be applied to the difference between the ATMD on that day and the demand threshold.

Figure 35 illustrates the time of use periods applying to the revised network tariff.

33 Electric Vehicle Trial | EV Grid | Australia

Figure 35. Proposed structure of the residential time of use DER tariff (TAS97)



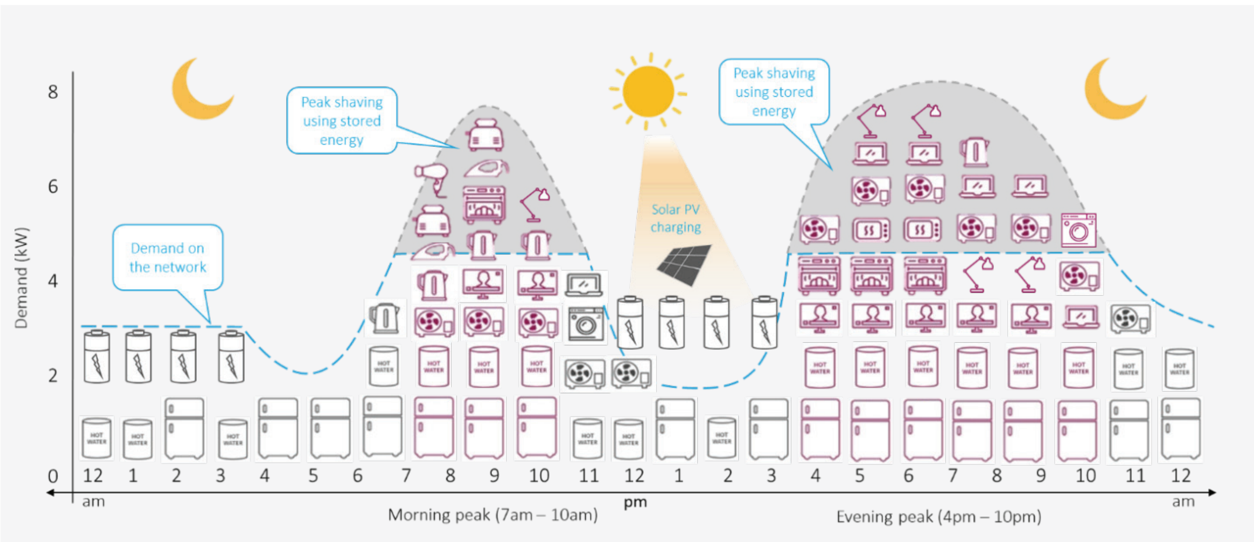
22.7.4.5 Peak shaving and stored energy

One of the purposes of the structure of this tariff is to encourage customers with storage devices to use their stored energy during peak periods, often referred to as "peak shaving", i.e., to reduce the amount of energy purchased from the network during the peak periods.

Customers who take advantage of the off-peak and super off-peak periods will potentially benefit from lower network charges. The reduction in peak demand on the network, or at least the lessening of growth in peak demand, made possible using battery storage with the support of time of use network pricing, means that, in the longer term the overall distribution customer base will benefit from reduced augmentation of the network.

Figure 36 illustrates the potential for customers with battery storage to use stored energy at peak times of the day when the delivered cost of energy on a time of use basis is at its highest, maximising the value of their batteries. The practice of peak shaving has the added benefit of potentially keeping a customer's peak demand below the residential CER network tariff's demand threshold of 8.5 kW.

Figure 36. Peak shaving using stored energy



22.7.4.6 Anytime maximum demand threshold

The ATMD threshold for the residential CER tariff has been set at such a level so as to not penalise the typical utilisation of household appliances, such as heating and hot water requirements even during winter.

Figure 37 shows that around 94 per cent of households' current maximum demand during peak periods is less than or equal to the 8.5 kW demand threshold being proposed as part of the residential CER tariff. This means that for the vast majority of residential customers, if they were to opt-in to the residential CER network tariff, they would not need to modify their current use of electricity in any way to avoid incurring charges for exceeding the demand threshold. Of the small percentage (around 6 per cent) of residential customers that do exceed a maximum demand of 8.5 kW during peak periods, 70 per cent have a maximum demand of no more than 10.5 kW, meaning that that they would incur demand charges based on a difference of 2 kW or less between their metered demand and the residential CER tariff's demand threshold.

Figure 37. Household maximum demand during peak periods

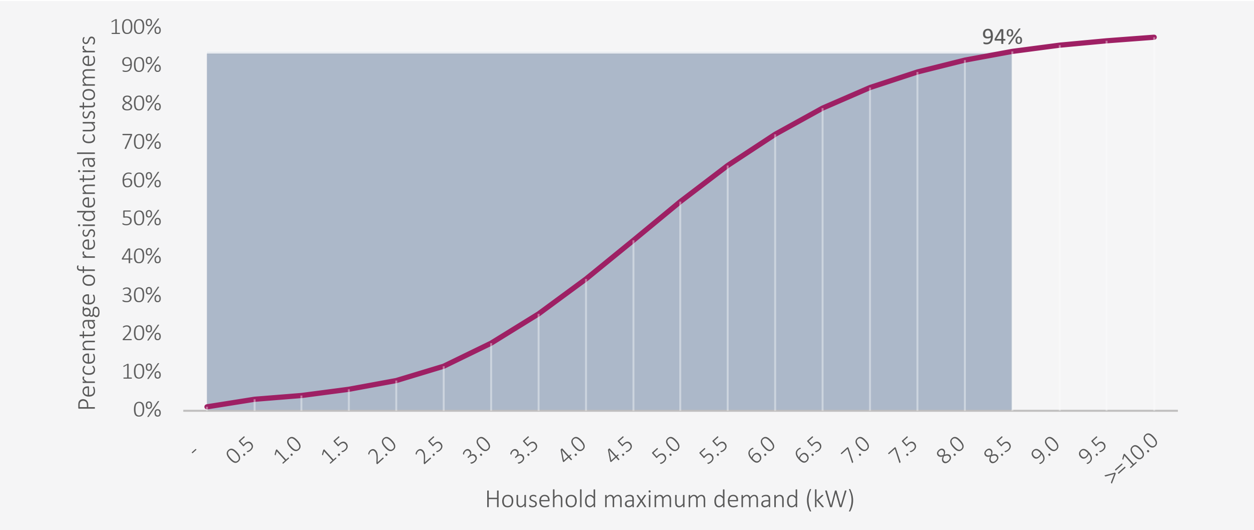
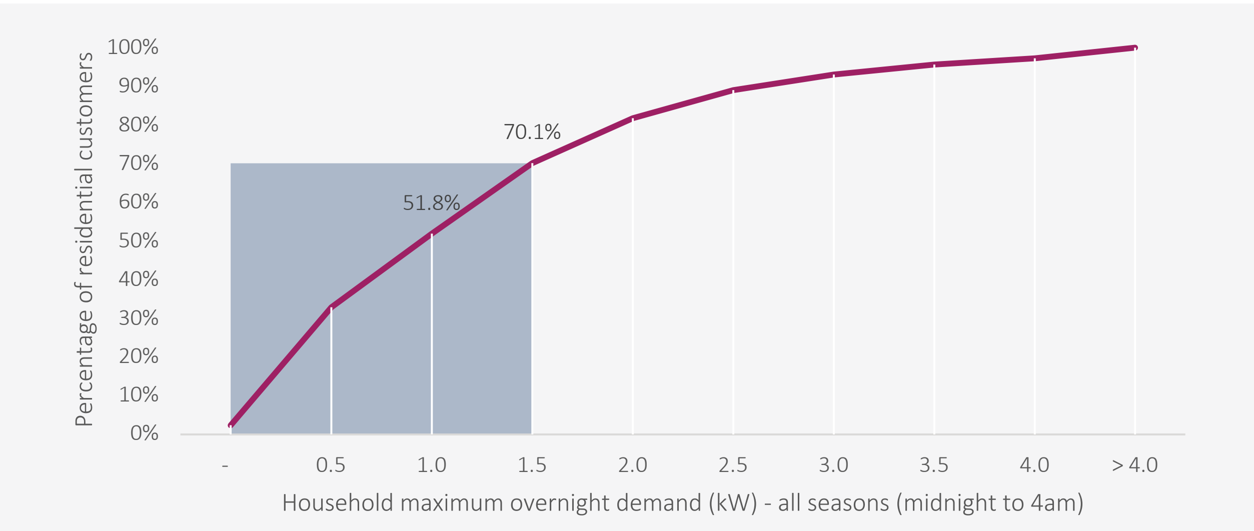


Figure 38 illustrates maximum demand amongst residential customers from midnight to 04:00, which aligns with the proposed super off-peak period timeframe for the residential CER network tariff. The graph shows that just over 50 per cent of households have a maximum demand of 1.0 kW or less between the hours of midnight and 04:00, while approximately 70 per cent of households have a maximum demand of 1.5 kW or less during the same period. This suggests that most residential customers could charge an EV using a 7.2 kW Level 2 charger during the proposed super off-peak period without exceeding the residential CER tariff's demand threshold or having to modify their use of electricity to keep demand under the threshold.

Figure 38. Overnight maximum household demand (kW)



The 8.5 kW ATMD threshold should provide sufficient 'headroom' overnight, when household energy use is usually at its lowest, to charge an EV during off-peak and super off-peak periods using a 7.0 – 7.5 kW charging station without exceeding the threshold. At that rate, four hours of charging during the super off-peak period alone should provide sufficient charge to cater for most customers' regular weekday usage. Plus, a further five hours of off-peak period charging is available between 22:00 and 07:00 the next day to add additional charge if greater range is going to be required in coming days, all without charging the EV during the more expensive peak periods.

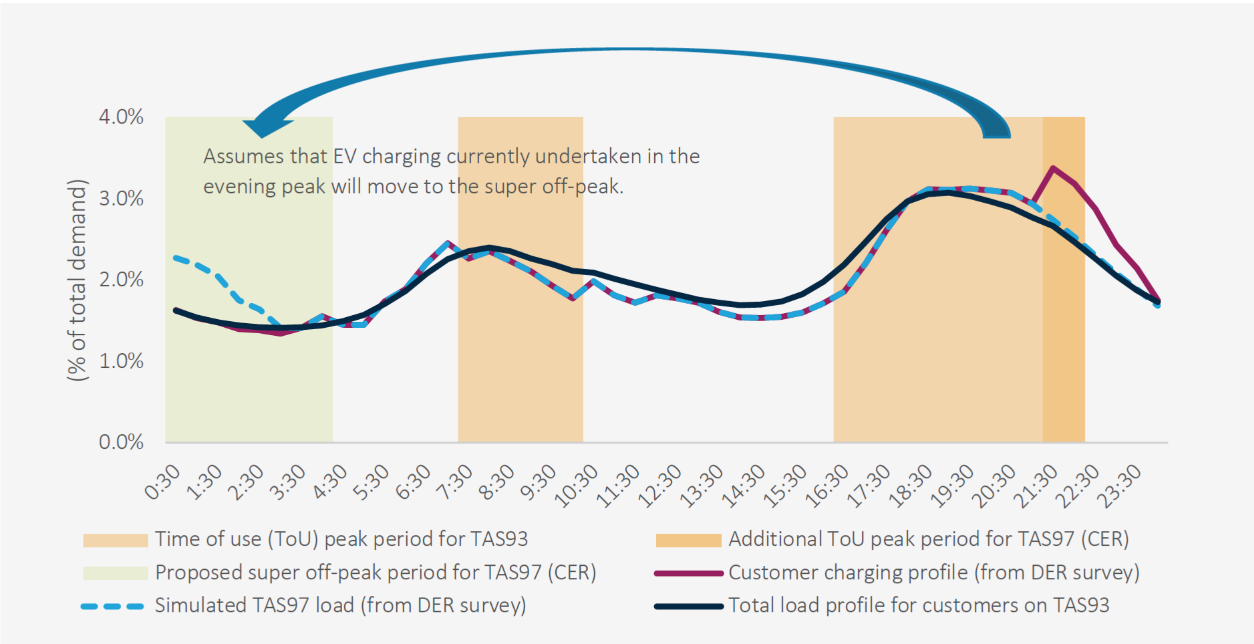
It is important to note that if the ATMD threshold is exceeded, the demand charges that are applied to the difference between the customer's actual maximum demand and the threshold (the excess demand) are not intended to be punitive. As is the case with the higher network charges applied to energy consumed during peak periods on the network, the pricing applied to a customer's excess demand is merely intended to provide a cost reflective pricing signal to customers, that their usage of electricity is imposing greater demands and, therefore, additional costs on the network

22.7.4.7 Customer Impacts

EV ownership information is not captured by TasNetworks. Our customer impact analysis of the proposed CER tariff is based on information where EV owners have been identified through specific trials or surveys, including the DER survey mentioned in section 22.5.4, the *ARENA EV Grid Trial*[34] in which TasNetworks is a participant (as outlined in section 22.7.4.3), and by reviewing the experiences of the impact of EV load in the UK.

Our customer impact analysis uses the load profile from customers on the residential time of use consumption network tariff (TAS93) and assumes that customers who take up the proposed CER tariff will respond to the price signals by shifting their EV loads from the evening peak period into the midnight to 4am super off-peak window (Figure 39).[35]

Figure 39. Electric Vehicle Owner Load Patterns (TAS93)



Additional EV charging scenarios were considered to ensure a wider range of potential customer impacts, were considered (Figure 40):

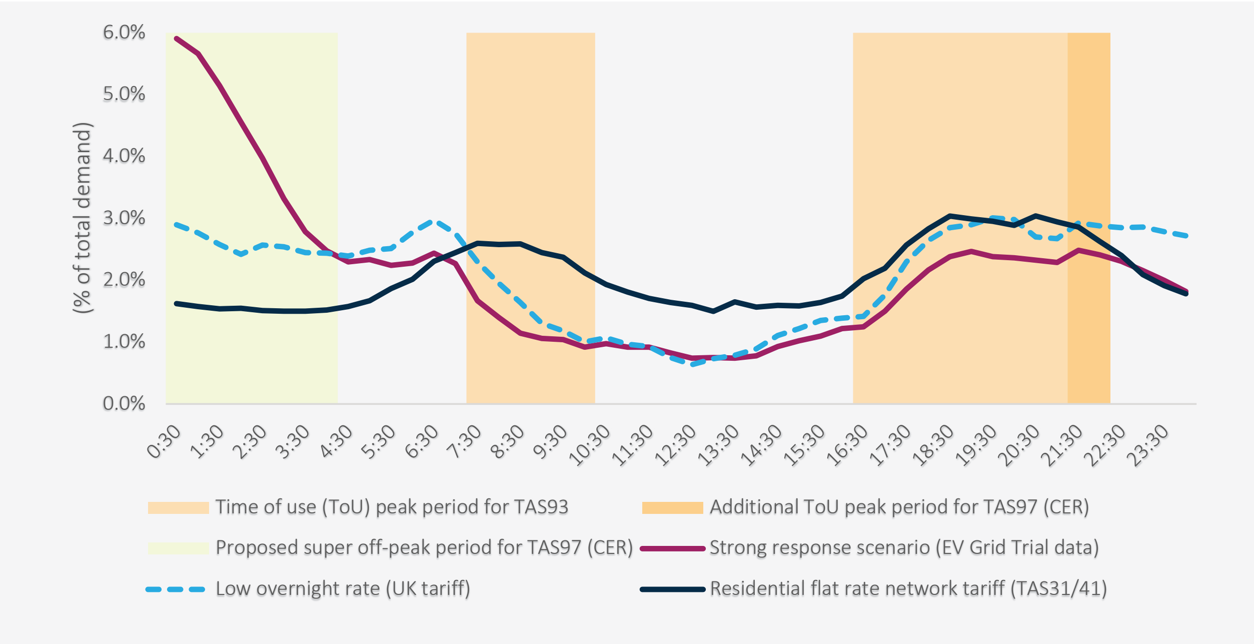
- Tasmanian customers participating in the A*RENA EV Grid Trial* has provided new insights into customers' charging usage. This data was used to develop a **strong response scenario**, where all EV charging is moved to the proposed super off-peak window (between midnight and 4am), i.e., this assumes that almost the entire EV charging load is moved into the proposed super off-peak period

34 Jemena Dynamic Electric Vehicle Charging Trial – Australian Renewable Energy Agency (ARENA)

35 This modelling assumes that only the excess consumption in the peak period moves to the super off-peak period

- TasNetworks has used the profiles of EV owners who participated in an **EV charging trial in the UK**. This scenario was selected due to similarly low overnight rates being offered.[36] It was interesting to observe that the overnight charging peak as a proportion of total demand was not as significant as TasNetworks' model for the strong response
- It is expected that the load profile for EV owners assigned to the **residential flat rate tariffs** (TAS31/41) are unlikely to see significant changes to when they use energy. It is expected that we will see 'convenience charging' of EVs to continue during the evening peak (as discussed in section 22.6.4.2).

Figure 40. Additional Electric Vehicle Owner Profiles



Initial customer impact analysis indicates that customers who switch from either the flat rate network tariff (TAS31/41) or the residential time of use consumption network tariff (TAS93) could make savings by:

- switching to the time of use CER network tariff (TAS97)
- changing their usage patterns by predominantly charging their EV between midnight and 4am.

A strong tariff response i.e., only charging your EV between midnight and 4am, could yield potential savings of up to 15%. Savings of up to 7 per cent could be made by customers on the residential time of use consumption network tariff (TAS93) and flat rate network tariffs (TAS31/41).

22.7.4.8 Use cases

Electric vehicles

Respondents to our DER Customer Survey[37], both EV owners and non-EV owners, stated that they would predominantly charge electric vehicles at home – mostly overnight. This is consistent with the EV ownership experience which is emerging in other parts of Australia and overseas. However, it is noted that new EV owners tend to 'top-up' their battery more frequently than more experienced EV customers, possibly due to higher levels of range anxiety.

The rate at which an EV can be charged in a residential setting, and the level of demand that charging a vehicle will place on the network, is determined by a combination of factors, including the customer's connection characteristics (single or three phase), the plugs and chargers installed in their home, the size of the vehicle's battery and state of charge, as well as the maximum charge rates of the vehicle and the charger. Ambient temperatures also play a part in determining how much charge and, therefore, range, can be added to an EV over a given period. Table 6 provides an indicative guide to the time it might take to add 60 kWh of energy to an EV's battery pack using a variety of charging technologies which are available for use in residential settings, ranging from a 230 volt general power outlet to a 22 kW Level 2 charger.

36 The utilised tariff structure offered low overnight rates between 10pm and 6am, but had a higher super off-peak to peak ratio than the proposed TAS97 tariff structure: Electric Nation Trial – UK

37 TasNetworks DER Customer Survey

Table 6. Types and levels of EV charging[38,39]

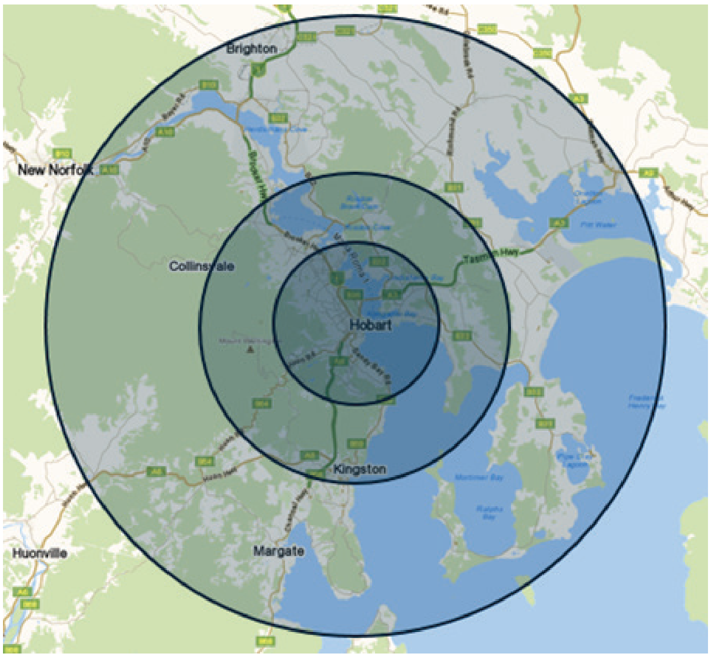
Type of EV chargers	Level 1 "Regular electricity outlet"		Level 2 "Dedicated home EV charging point"		
EV charging plugs (AC only)	230-volt AC up to 10A 2.3kW (single phase)	230-volt AC up to 15A 3.5kW (single phase)	230-volt AC up to 32A 7.2kW (single phase)	400-volt AC up to 16A 11kW (3 phase)	400-volt AC up to 32A 22kW (3 phase)
Time to charge 60 kWh battery	26-34 hours	16 hours	8 hours	6 hours	3 hours

The distance an EV can travel on any given charge depends on a range of factors. As a result, the distance an EV might be able to travel using the charge illustrated in the above table might vary from approximately 230 km for an EV that uses 26 kWh per 100 km to 375 km for an EV that uses 16 kWh per 100 km.

While much is made of range anxiety and the maximum range of different EV models, the reality for many people is that they infrequently travel distances approaching their vehicle's maximum range. Regular travel by private vehicle is likely to be limited to commuting and some incidental journeys.

Amongst Australian states and territories, Tasmania has a relatively disaggregated population and travel distances vary across the state. However, the majority of the population (approximately 70 per cent[40]) reside in urban areas. The following maps show examples of population centres in Tasmania and illustrate the sort of distances that commuters might travel in a day.

Hobart and surrounds



The inner suburbs of Hobart (represented by the inner circle) involve commutes of up to 10 km each way into central Hobart, and encompass suburbs like Glenorchy, Mt. Nelson and Lindisfarne.

The outer suburbs involve commutes of up to 15 km, one-way, into central Hobart, a distance which takes in areas like Austins Ferry, Kingston, Cambridge and the Hobart Airport.

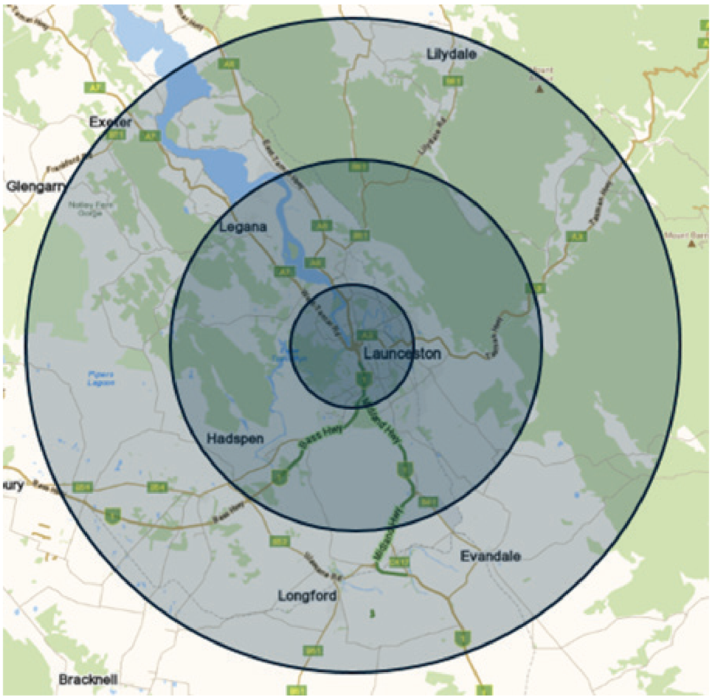
A number of 'dormitory' suburbs and towns in the greater Hobart area involve commutes of between 25-35 km, one-way, to reach central Hobart. This includes towns like Sorell, New Norfolk and Brighton.

38 EGen Electrical EV charging guide

39 Electric Vehicle Council

40 ABS Population Estimates (2017)

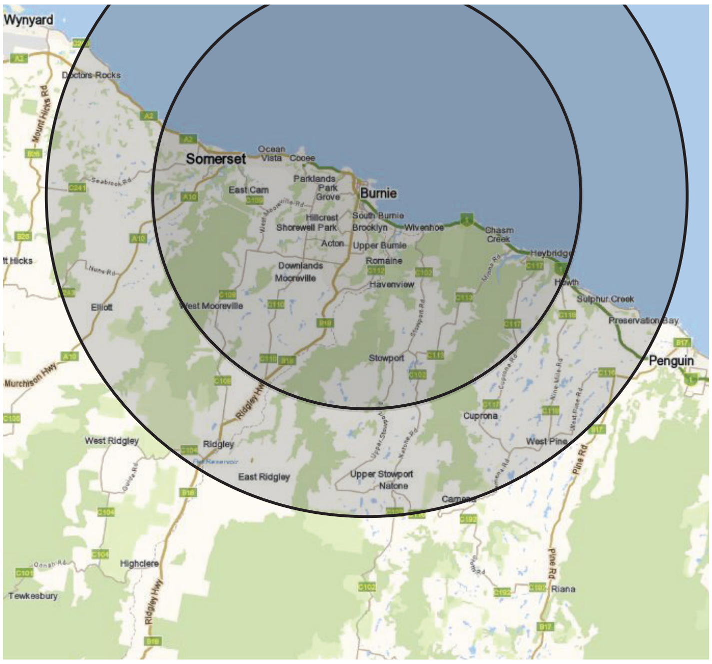
Launceston and surrounds



Launceston's inner suburbs (the inner circle) within 10-15 km of the city centre include the suburbs of Prospect Vale, Kings Meadows, Rocherlea and Riverside.

Launceston's surrounds, including the towns of Legana and Hadspen, are less than 25 km from the Launceston centre, with larger commutes of between 25 and 35 km including locations suchs as Evandale, Longford and Exeter.

Burnie and surrounds



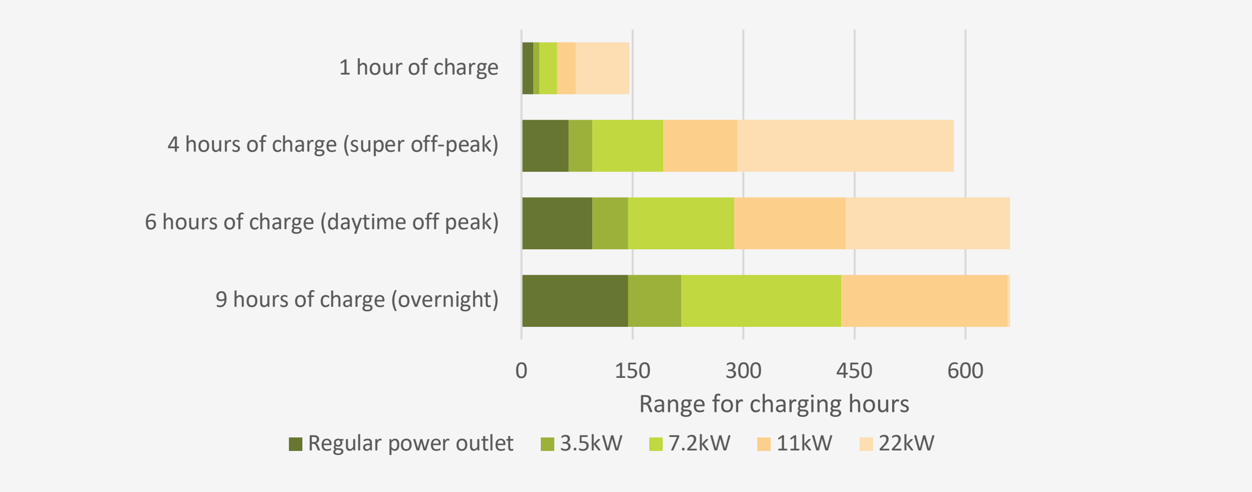
The City of Burnie occupies an area that can be described within a 10 km arc of the city's central business district. The communities of Cooee, Somerset, Stowport and Heybridge all fall within a 10 km radius of Burnie's centre.

Commutes of up to 15 km, one-way, would add the townships of Ridgley and Natone, with Penguin and Wynyard falling just outside a 15 km zone from Burnie's centre.

Devonport, the other city on the North West Coast is around 40 km from Burnie. For an EV which uses 18 kWh per 100 km, without making allowances for terrain etc., a round trip of 80 km between the two cities would consume in the order of 14-15 kWh, or about the amount of energy that a 7 kW Level 2 home charging station could add to an EV battery in about two hours.

It is acknowledged that some commuters will travel greater distances, in some instances over 100 km (return) a day.[41] Figure 41 shows that over four hours of charging at home using a 7 kW charger, a typical EV can add sufficient charge to its batteries to travel approximately 180 km (or approximately 45 km of range per hour of charging). On this basis, the four hour super off-peak period which is to be a feature of the revised residential CER network tariff should afford the vast majority of EV owners with sufficient access to a lower delivered cost of energy to charge their vehicles enough to cater for everyday use and even, with some planning, journeys that require the battery to be fully charged.

Figure 41. Estimated EV range for weekday off-peak or super off-peak charging[42]



Household batteries

Aside from encouraging customers with EVs to charge their vehicles overnight during the off-peak and super off-peak periods the residential CER network tariff has also been designed to maximise the financial benefits for prosumers who invest in battery storage and solar panels.

The time of use windows that apply to the residential CER network tariff help make it possible for prosumers to charge and discharge (or 'cycle') their batteries at least twice a day. If a prosumer with battery storage only does solar charging, their battery will cycle at most only once per day. Cycling a battery more than once a day by also drawing on the network for recharging can potentially reduce a customer's energy bills and shorten the payback period for their batteries, while at the same time reducing load on the network at peak times.

Prosumers assigned to the residential CER network tariff with appropriately sized solar panels and batteries will be able to:

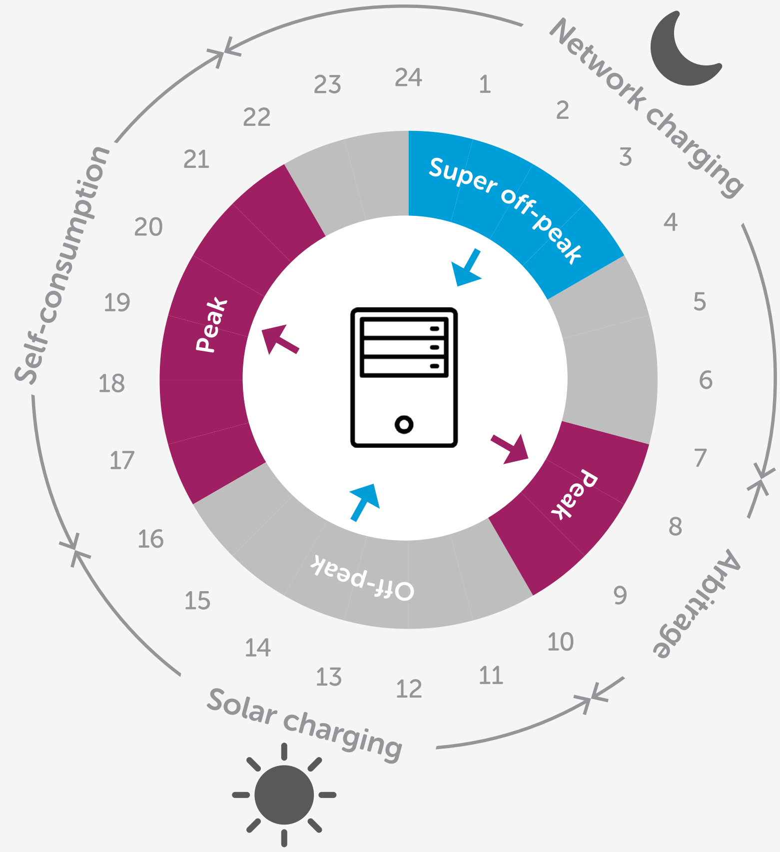
- charge their battery overnight during the super off-peak period (and the off-peak periods on either side of the super off-peak period, if necessary)
- discharge energy from the battery during the morning peak period
- recharge the battery using power generated by their solar panels during the day; and then
- discharge the battery again during the evening peak period, before repeating the same cycle the next day.

The following diagram (Figure 42) illustrates the interaction between the residential CER network tariff and the use of battery storage (and solar panels) to maximise the savings available to customers from time of use network pricing.

41 Examples of commutes greater than 100km per day include Deloraine to Launceston or Bushy Park to Hobart

42 How much will it cost to install an EV charger at home? Note: These times are estimates only and are not manufacturer endorsed. They assume a 15kWh/100km efficiency

Figure 42. Cycling battery storage using the residential time of use CER network tariff (TAS97)



Using the battery, solar panels and network in this way potentially delivers value for the customer by:

- **Maximising the value of the energy generated during the day**

  The energy produced using a customer's solar panels during the daytime off peak period can be stored for self-consumption during the subsequent afternoon/evening peak, when electricity prices are at their highest – and significantly higher than the feed-in tariff that could be earned by the customer if they exported the energy they produce for use by others.

- **Minimising the cost of energy taken from the grid to charge the battery**

  By recharging the battery overnight, when the delivered cost of energy is at its lowest, the customer can effectively buy electricity at off-peak rates, store it in a battery and then consume that energy during the subsequent peak period, saving themselves the difference between the peak and off-peak retail electricity prices.

Taking advantage of the differences in electricity prices that occur at different times of the day in this manner is a form of 'arbitrage'. For a residential customer on a time of use retail tariff, assuming a differential between peak and off-peak periods of around 13 cents per kWh,[43] if a customer with a 10 kWh battery were to fully charge their battery during the overnight off-peak period and discharge the battery completely during the subsequent morning peak period, without allowing for any efficiency losses, they would theoretically save $1.30 each day, or potentially around $474.50 a year.

If that same storage capacity were able to be recharged using solar panels during the course of the day, and the stored energy used during the subsequent evening peak, based on current peak retail pricing, the customer could conceivably save a further $3.46 each day, or just over $1,262 during the course of a year.[44] Using the common rule of thumb that one kW of solar panels will produce around four kilowatt hours of electricity per day, in theory an array of only 3 kW in capacity might be sufficient to charge a 10 kWh battery.

43 As per indicative 2024-25 pricing

44 As per indicative 2024-25 pricing

While in practice the actual results achieved may be something less than the above estimates, the use of the network to charge storage devices, rather than solely relying on solar panels, has the potential to unlock greater value from customers' investment in CER.

Energy can also potentially be discharged from the battery to keep a customer's demand below the 8.5 kW threshold applying to the residential CER network tariff, above which the customer would incur demand charges – or at least minimise any above-threshold demand if the customer is using an energy intensive appliance such as a level 2 home charger for an EV that draws more than 8.5 kW.

Why not a time of use demand tariff?

TasNetworks introduced time of use demand tariffs on an opt-in basis for both residential and small business customers in 2017, but to date neither tariff has been incorporated by retailers into their retail tariffs. Those demand-based network tariffs will continue to be available in the 2024-2029 regulatory period. However, our expectation is that the primarily consumption-based CER tariff for residential customers being proposed for the 2024-2029 regulatory control period will offer benefits for customers with CER that will make the tariff more appealing to retailers and customers alike than current demand tariffs.

The economic case for introducing demand charges in residential network tariffs is well documented. Well-designed demand tariffs are considered by many economists and experts involved in the economic regulation of electricity networks to better reflect the demands that individual customers place on networks, and to allocate costs more equitably between customers than consumption tariffs. However, the concept of demand is arguably a more difficult concept for most residential customers to understand than consumption.

Time of use demand tariffs are a concept that many residential customers have difficulty understanding – even those that might be more engaged with managing their energy usage and generation. Concluding in mid-2019, our *emPOWERing You* trial tested residential customer's responsiveness to a time of use demand-based network tariff and showed that participants found it easier to reduce consumption than to implement measures specifically aimed at reducing demand.

On an interval (time of use) basis there is also a direct link between consumption and demand, meaning that the pricing signals provided by a time of use consumption tariff are a good proxy for demand-based time of use pricing. Amongst *emPOWERing You* participants there was a strong correlation between consumption and demand. For example, for the majority (73 per cent) of participants the direction of the change in their maximum demand recorded during winter aligned with changes in their consumption.

In practice, network tariffs are required to strike a balance between cost-reflectivity and a range of competing tensions, such as equity, simplicity and technological neutrality. This can mean some design elements that might increase cost reflectivity may not be practical or be supported by customers.

The correlation between changes in consumption and demand suggests that if customers are willing and have the capacity to respond to time of use pricing signals, rather than relying on demand-based time of use tariff, changes in network peak demand could be achieved using a consumption-based time of use tariff, which has the advantage of being better understood by customers.

Why not a controlled load tariff?

Many Tasmanians are familiar with the concept of a controlled load tariff – if not the terminology – through their exposure to the off-peak tariffs which have been available to Tasmanians for many decades. The defining characteristics of controlled load tariffs are that electricity is only supplied for a specific end-use (e.g., hot-water heating and (storage) space heating) and for a limited number of hours each day, usually at a lower price than electricity supplied at other times of the day. Controlling load typically requires dedicated circuits in the customer's premises that are separately metered.

Traditionally, electricity distributors have been responsible for electing which hours electricity is supplied under controlled load arrangements as a means of limiting peak demand on the network. In the past, time clocks were used to control load on a set and forget basis, although other techniques exist and advanced meters now potentially make dynamic control of load possible.

In theory, a controlled load network tariff could be used to allow EV owners to connect a charging station in their home's garage to their meter box, via a dedicated circuit, giving access to a lower delivered cost of electricity for charging EVs at times that don't add to peak demand on the network. TasNetworks does not, however, consider that a controlled load tariff for EV charging represents a better solution than uncontrolled time of use network tariffs.

The use of controlled load arrangements and their reliance on separate circuits and metering may result in additional costs for the customer, including increased charger installation costs and additional supply charges and metering costs.

Controlled load tariffs also prevent customers from using energy at certain times of the day. This means customers may not be able to charge their EVs at times that suit them more than the charging periods offered under a controlled load arrangement or to charge their vehicle for unplanned or urgent trips.

Smart charging technology is increasingly putting load control into the hands of the customer, making it easier to respond to time of use pricing. Some EVs also feature on-board charging timers, which can be set to charge (or not) at various times, with those settings even able to be made location specific.

Lastly, because the time of use network tariff for residential customers with CER will apply to all the electricity a household consumes, rather than just the electricity supplied to a particular circuit and end use, customers will be able to take advantage of features such as the super off-peak period to do things other than charge an EV, like charge stationary batteries or power energy intensive appliances.

22.7.5 Embedded network tariff

22.7.5.1 Background

TasNetworks proposed two embedded network tariffs for the previous regulatory control period (2019-2024). The AER did not accept our proposal at the time, but provided critical guidance regarding how the case for these tariffs can be made by:[45]

- clarifying how any proposed embedded network tariff must be more cost-reflective than existing network pricing arrangements and lead to a more equitable contribution towards the cost of the distribution network
- explaining how the price levels for the embedded network tariffs are quantified as well as information on existing embedded networks currently operating on the network
- explaining the relative costs for embedded networks to provide network services with regard to density of consumption and diversified use when compared to the average customer for which embedded network customers are currently referenced to
- showing that differences in network pricing across tariff classes are incentivising the creation of embedded networks
- substantiating how the existence of any such incentive is not in the long-term interests of consumers.

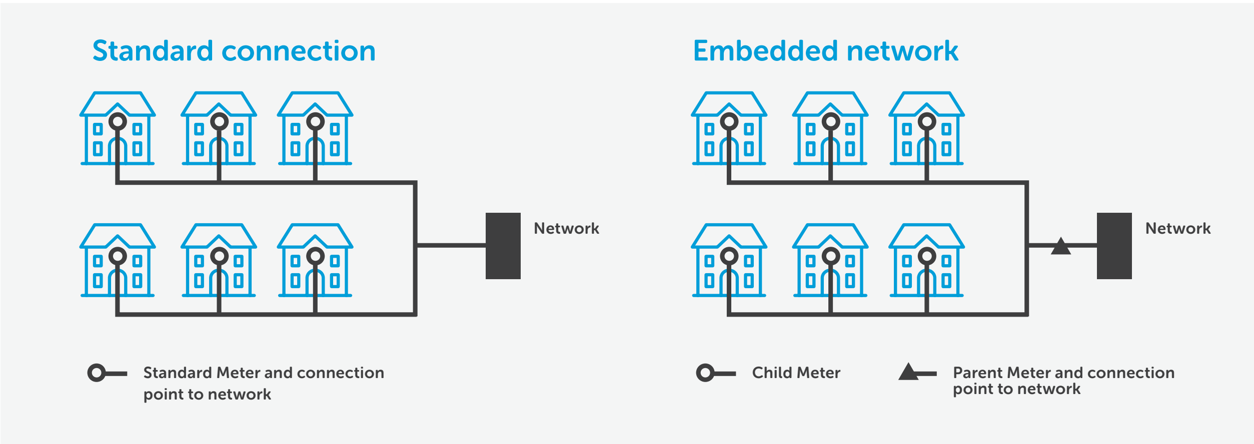
22.7.5.2 What is an embedded network?

Embedded networks are private networks that serve multiple premises located on the same property connected to the distribution network through a single connection point. The electricity that flows through this point is purchased by the embedded network operator and on-sold to its customers.

Common examples of embedded networks include shopping centres, retirement villages, apartment complexes and caravan parks. In the case of a shopping centre set up as an embedded network, the shopping centre owner or managing agent might be the embedded network operator and the individual shops within the shopping centre the members (or customers) of the embedded network. The customers of an embedded network are not customers of TasNetworks and neither their metering data nor any information relating to their metering identifiers is visible to TasNetworks.

Figure 43 shows how embedded networks differ from standard customer connections.

Figure 43. Comparison of an embedded network connection and a standard network connection



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The key differences are:

- an embedded network is supplied through a single connection "parent meter"
- TasNetworks does not know the connection arrangements beyond the parent meter
- all electricity that flows through the parent meter is purchased by the embedded network operator and on-sold to its customers within the embedded network.

Whilst embedded networks may be less common in Tasmania than interstate, in recent years TasNetworks has observed an increase in the level of interest from property owners and property developers in the use of embedded networks. Many of those enquiries have been from businesses in other states that specialise in embedded network management.

TasNetworks has identified the risk that, without a specifically designed network tariff, the operators of embedded networks (and, indirectly, the members of their embedded networks) may avoid making an equitable contribution towards the cost of the distribution network, resulting in these costs being borne by other customers. Dedicated embedded network tariffs could be used to ensure that equity outcomes are protected for all customers, while still offering embedded network owners and their customers the scope to reduce their network charges overall, by virtue of sharing a connection with the distribution network.

22.7.5.3 Rule requirements for embedded networks

Under the National Energy Law (**NEL**), the on-selling of electricity within an embedded network requires both an authorised retailer and network manager. For many smaller embedded networks, the full requirements of being an authorised retailer and network manager would be too onerous. Thus the AER has established a simplified authorisation process, with some owners of embedded networks having deemed exemptions from the need to register as a retailer or NSP. Gaining such an exemption does not release the embedded network manager/operator from all obligations with some customer protections remaining.

Managers of larger embedded networks must be accredited and registered with the AEMO and need to comply with a range of regulatory obligations and standards.

Since December 2017, customers within embedded networks in the NEM have been able to choose their electricity retailer in the same way as a customer connected to the grid.

However, in Tasmania the changes were not enacted meaning embedded network managers were not required to allow all its customers a choice in retailer. This has resulted in a different situation to that on the mainland such that in Tasmania embedded network managers of, for example, caravan parks and office blocks have no obligation to gain retailer authorisation and customers within these embedded networks have no choice in their retailer. The requirements to register as a network service provider or gain an exemption from the AER were enacted in Tasmania.

The fact that the changes to the NEM were not enacted does not prevent embedded network managers from registering and allowing its customers to choose their own retailer; it is just optional in Tasmania.

This has resulted in very few embedded networks being officially recorded on the AER register due to the different approach to retailer and network management. However, TasNetworks is aware there are a number of embedded networks operating within Tasmania and a number of configurations whose physical connection resemble an embedded network.

As a result, there have been limited opportunities to obtain data on known embedded networks. However, we were able to use a proposed commercial embedded network for a shopping centre, plus create synthesised embedded networks based on the likelihood of certain embedded network structures, such as, retirement villages, shopping centres, and apartment buildings to investigate the options for an embedded network tariff.

22.7.5.4 Achieving equitable pricing outcomes

Central to our engagement with stakeholders, was a discussion on whether an embedded network was equitable under our current tariff suite.

The pricing principles for distribution networks are outlined in the Rules, which would require an embedded network to:

- allow TasNetworks to fully recover the efficient costs it determines are associated with providing the standard control service to the embedded network
- ensure that standard control service revenue recovered from other customers is lower than would be otherwise be the case due to the introduction of the embedded network tariff
- minimise potential adverse bill impacts on customers within new embedded networks that are subject to the embedded network tariff, primarily by ensuring that customers with similar consumption profiles within and outside the embedded network are paying similar distribution charges
- incentivise the embedded network to consume electricity in a manner that minimises future network costs.

In addition to the pricing principles in the Rules, TasNetworks needs to ensure that embedded networks align to TasNetworks' pricing principles (section 22.5.1.1).

Figure 44 and Figure 45 summarise the tariff comparisons we undertook for potential embedded network connections, using the data sources described in section 22.7.5.3. The undertaken analysis highlights that our current network tariff suite creates considerable incentives for embedded networks to be formed from groups of geographically close individual network users to decrease the distribution network charge to the embedded network operator.[46] These incentives arise from the embedded network operator's opportunity to abate both the variable costs and the daily fixed charges that are usually paid by every metered customer by reducing the number of metered customers to one.

Figure 44. Abated costs for existing network users when mixed residential embedded networks are formed

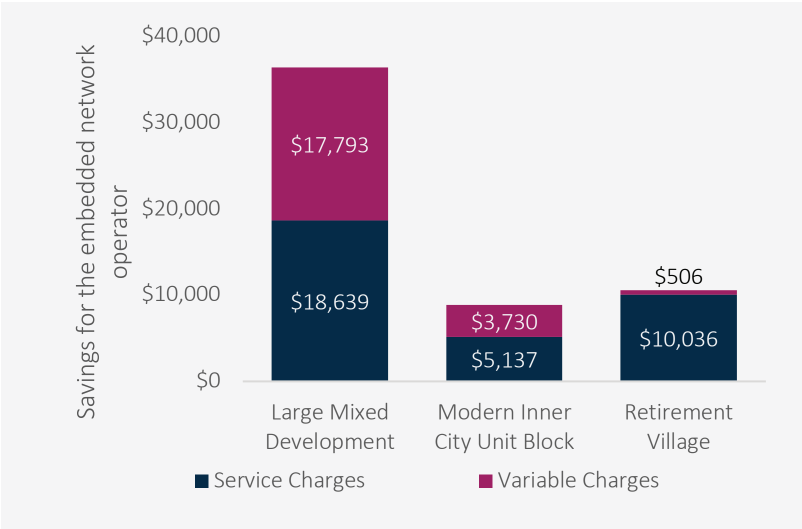
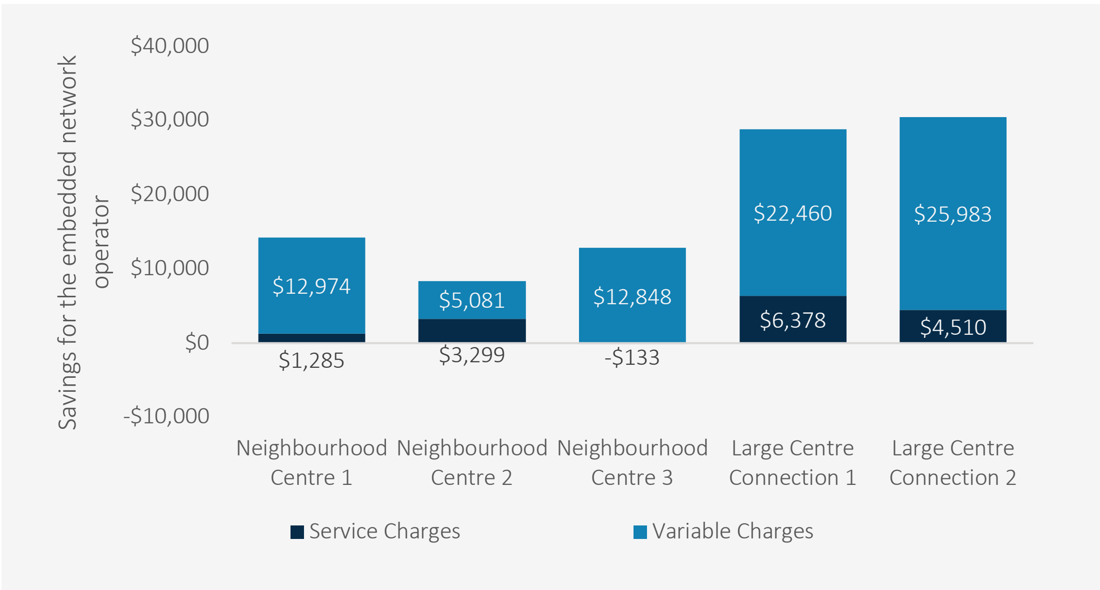


Figure 45. Abated costs for existing network users when low voltage commercial embedded networks are formed



This current inherent incentive gives embedded network operators the opportunity to decrease their costs by seeking a network tariff that provides them with the highest benefit. This is problematic as it means that part of the efficient costs attributable to the embedded network are being recovered from other network customers, resulting in both an efficiency and equity issue.

A purpose-designed embedded network tariff allows for pricing arrangements that will protect the equity outcomes for all our customers, while offering embedded network owners a charge that reflects their use on the network. An embedded network tariff would provide an opportunity for customers who can flatten their demand through embedded generation and/or storage capacity to be rewarded for doing so.

46 Based on embedded networks modelling undertaken during 2022. The potential savings of the modelled connections amount to 30-40 per cent of their current combined charges

22.7.5.5 Structures for our proposed embedded network tariff

Given the diversity of existing and prospective embedded network sites, our stakeholders have indicated a preference for any network tariff designed specifically for embedded networks to incorporate a capacity-based charge, rather than the fixed daily service charges that form part of the network tariffs applied to more homogenous customer groupings. The PRWG has previously identified that a single fixed connection charge would not be flexible enough to support the range of embedded networks that might exist.

Charging embedded network operators for the network capacity required to service the aggregate demand of their customers is a way of ensuring embedded networks make cost reflective contributions towards the cost of the network. A network tariff specific to embedded network operators is also a means of ensuring that embedded networks also benefit from the costs TasNetworks avoids by supplying an embedded network through a single connection point, rather than each customer within the embedded network having their own connection. This approach, and the need to ensure embedded networks contribute towards the cost of the network that reflects the characteristics of their load and their connection to the network, has been informed by our engagement with the PRWG.

To ensure the proposed tariffs recover the revenue allocated to the tariff in the most efficient way possible, it is proposed that the embedded network tariffs will have three components (see Figure 46):

- **Service charge –** a tiered daily charge based on the network capacity[47] of an embedded network at the embedded network's connection point to the distribution network
- **Demand charge –** based on the maximum demand an embedded network places on the distribution network during peak times (measured in half-hourly intervals)
- **Consumption charge –** a volumetric charge based on the energy consumed by an embedded network as a whole (and delivered to the embedded network via the distribution network).

Figure 46. Embedded network tariff charging components

The tiered service charge will recognise that embedded network owners are a diverse group of customers, with significant differences in the connection capacity and network capability required to support each embedded network (with expected maximum demand being the principal driver of that capacity).

The tiered arrangement is intended to provide more flexibility and greater cost-reflectivity than a fixed daily charge. Table 7 (below) sets out the proposed tiers associated with the service charges that will be applied to embedded networks connected at both low and high voltages. Customers assigned to the low voltage network tariff for embedded networks will be catered for by a range of four capacity tiers, whilst the network tariff for embedded networks connecting at high voltage will feature two capacity tiers.

Table 7. Proposed capacity tiers for embedded networks

	Capacity allowance	
Tier	**Low voltage**	**High voltage**
Tier 1	0-100 kVA [0-140 Amps]	0-750 kVA [0-1,000 Amps]
Tier 2	100-300 kVA [140-400 Amps]	750+ kVA [1,000+ Amps]
Tier 3	300-750 kVA [400-1,000 Amps]	n/a
Tier 4	750+ kVA [1,000+ Amps]	n/a

Embedded network operators will determine the required connection capacities in their contracts and the equipment is set up accordingly when the network connection is installed. We are proposing a maximum and minimum level of energy for each tier. There will be some overlap between low voltage and high voltage connection levels depending on where customers will ultimately connect – this will be determined by individual customer circumstances, preferences, and location.[48]

47 TasNetworks will undertake a review of the demand for embedded networks each year to ensure customers are assigned to the correct service charge tier. This will ensure that the service charge reflects changes in the load or connection characteristics of an embedded network that might arise, for example, as a result of growth within the embedded network or changes in the embedded networks' reliance on the distribution network due to the deployment of CER within the embedded network

48 Customer circumstances and preferences may include the willingness and/or ability to own and maintain high voltage equipment

It is possible that larger connections, such as shopping centres, may use multiple low voltage connections. This will involve multiple connection applications and the capacity charge of the embedded network tariff will apply to every connection individually.

The demand charges will be set based on the long run marginal cost (**LRMC**), ensuring that embedded network customers receive cost-reflective price signals regarding the demand they place on the network during times of network peak utilisation. To simplify the tariff design, only peak demand charges will be applied within the proposed tariff structures.

The volumetric and capacity charges' role is to recover the residual network costs. The ratio of the tiered capacity charge to the volumetric charge is a key tariff design decision as it will determine the proportion of residual cost recovery and the associated price signals being sent to customers via the two charging components.

The tiered capacity charge guides this charging component ratio, with the levels being a function of:

- the estimated cost of each tier of capacity
- the size of the embedded tariff capacity charge relative to daily services charges on the tariffs that potential embedded customers are currently assigned to
- the targeted amount of revenue to be recovered under each of the new tariffs applying the total efficient costs.

22.7.5.6 Proposed embedded network tariff assignment policy

The new embedded network tariffs will be assigned to all new embedded networks connecting to the distribution network on or after 1 July 2024.

TasNetworks' tariff assignment rules will not make it mandatory for existing embedded networks to move to the new embedded network tariff. Existing embedded networks will be permitted to remain on the network tariff they are assigned to as at 30 June 2024. However, if existing embedded network customers choose to change network tariffs after 30 June 2024, their only option will be to opt-in to the embedded network tariff which is most suited to their network connection, and once assigned to an embedded network tariff, an embedded network may not revert to a non-embedded network tariff.

While most embedded networks are served by a single connection to the distribution network, some larger sites, such as a large shopping centre, may potentially have multiple connections to the distribution network. Under these circumstances, each connection will need to be assigned to an embedded network tariff, meaning that the capacity charge, as well as the volumetric and demand-based charges, will apply to the multiple connections.

As discussed in section 22.7.5.3, there are Tasmanian specific differences to how embedded networks are regulated. This provides limited visibility of existing embedded networks. A decision to apply the retailer authorisation requirements in Tasmania may provide an opportunity for TasNetworks to review its tariff assignment policy in future regulatory control periods should existing embedded networks become visible to TasNetworks. However, before making a change to our assignment policy, analysis would be undertaken to understand the impact to the network and ensure alignment to our pricing principles.

22.7.5.7 Tariff class assignment

Considering the Rule requirements regarding tariff classes (as outlined in section 22.7.1), TasNetworks deemed it most appropriate to place embedded networks within existing tariff classes. The main reasons for doing this are:

- The proposed tariff assignment rules will not make it mandatory for existing embedded networks to move to the new embedded network tariff. The new tariff will only apply to new embedded networks. As a result, there will be new embedded networks assigned to the new tariffs while incumbent embedded networks can choose to remain assigned to their existing tariff under existing tariff classes (unless the incumbent embedded network operators choose to change tariffs). Therefore, not introducing a new tariff class will ensure that customers with similar characteristics will remain grouped together.
- The synthesised embedded networks' usage profiles and the nature and extent of their usage or intended usage of the distribution services are similar to those customers within the existing tariff classes that could embed (Figure 47 and Figure 48). This includes the two distinct load profiles that were identified within the group of commercial connections, i.e., shopping centres.

We may consider, in a future regulatory control period, to create a dedicated embedded network tariff class if there is sufficient evidence and uptake to warrant a new tariff class.

Figure 47. Load profiles of mixed residential embedded networks against typical customer usage profiles

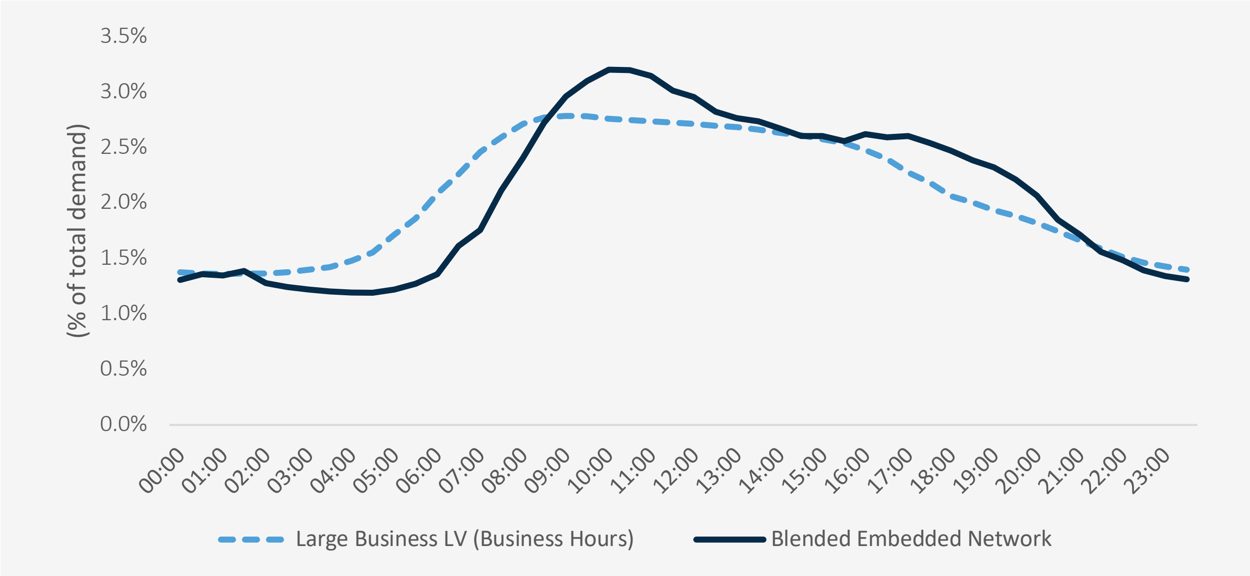
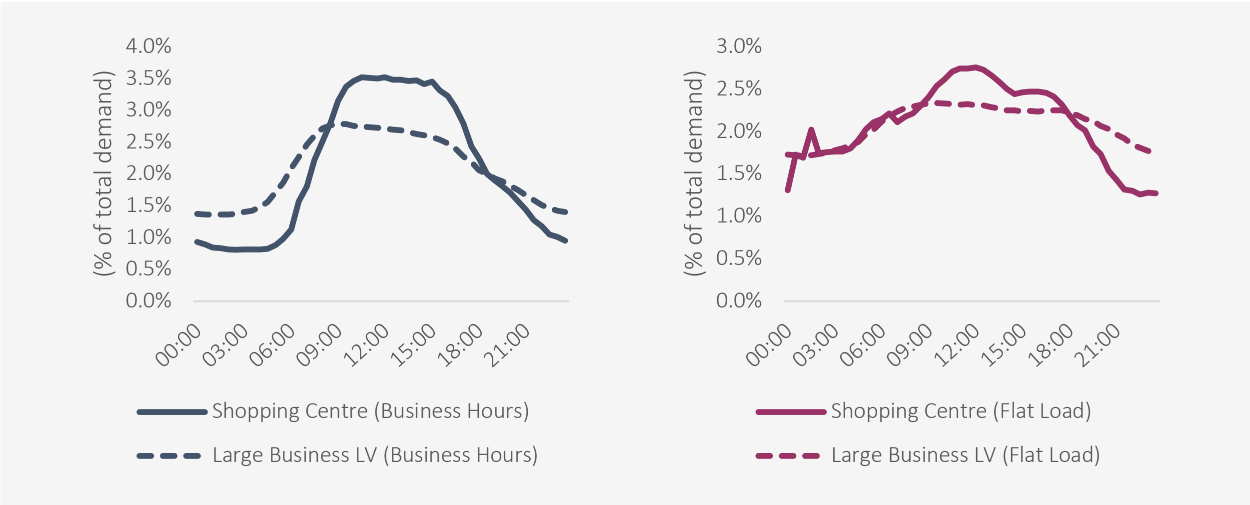


Figure 48. Load profiles of low voltage commercial embedded networks against typical customer usage profiles



22.7.5.8 Embedded network proposal for the 2024-2029 regulatory control period

For the 2024-2029 regulatory control period, TasNetworks is proposing embedded network tariffs for both the high voltage and low voltage distribution network. We propose to place our new embedded network tariffs within the existing commercial tariff classes (Table 8).

Table 8. Assignment of our proposed new embedded network tariffs to tariff classes

Embedded network tariff	Proposed tariff class
LV business embedded network (4 tiers)	Low voltage large business
HV business embedded network (2 tiers)	High voltage large business

The pricing of these tariffs aims to recover most of the revenue TasNetworks would earn from the embedded network members if they connected individually, while recognising that TasNetworks will realise some operational cost savings resulting from of embedded networks being formed. These savings mostly relate to reduced network liability and life support obligations as embedded networks are treated as single network connection points.

22.7.6 Complementary measures to tariff design

TasNetworks would like to help customers make more informed decisions about the network tariffs to which they are assigned and their use of electricity. Our stakeholders have told us that network tariff reform needs to be accompanied by clear communication and education programmes for customers.

To that end, a range of measures will be employed during the in 2024-2029 regulatory control period to complement the proposed tariff changes outlined in our TSS. The aim of these measures will be to facilitate more informed decision making by customers in relation to their use of electricity, their investments in electrical appliances and CER, and their choice of network tariff. TasNetworks wants to help customers understand how they can respond to changes in network pricing structures, such as network charges that reflect time of use.

Our complementary measures for 2024-2029 will include:

- the provision of up-to-date information which is easy for customers to access
- partnering with third parties who are trusted by customers as sources of information and advice about energy.

Updated and easy to access information

Our stakeholders have told us that network tariff reform needs to be accompanied by a strong communication and education programme for customers. They also consider it essential that TasNetworks works closely with retailers to ensure consistent messaging. Stakeholders have told us that customers 'want to be told once, by one party', rather than face potentially conflicting and confusing messaging from multiple sources.

The level of interest and engagement in a particular energy related topic for even an individual customer can also vary over time according to the circumstances in which they find themselves. For example, connection services and tariff selection for a new connection are likely to be of most interest to customers who are building a new home or business premises, rather than established homeowners. And in the coming regulatory control period, those customers are going to need to know that some of the tariffs that they have been used to may no longer be available to them for their new property. But with a range of issues to talk about with our customers and a large number of customers to reach, TasNetworks does not have the capacity to reach out to customers constantly in the hope that they'll receive our messaging.

Therefore, a key part of TasNetworks' communication strategy in relation to network tariffs and the pricing of alternative control services will be to ensure that customers have access to information from TasNetworks, whether directly or indirectly, during the information gathering phase of their decision-making process, neither too far in advance of their decision – possibly before they've identified the need for a particular service or product – nor after they've made their decision.

During TasNetworks' engagement with the PRWG, a consistent theme emerged: the need to ensure customers are well informed when choosing the network tariffs to which they are assigned and when making decisions about their use of electricity.
Our PRWG members suggested a number of topics relating to network tariff reform that will be of particular importance to residential and small business customers in the 2024-2029 regulatory control period.
Those topics were:

- Advanced meters
- Time of use tariffs
- Pricing principles
- Obsolete network tariffs.

There are approximately 300,000 households, businesses and institutions in Tasmania that take their supply of electricity from the network of poles, wires and underground cables which make up the electricity distribution network. Those customers exhibit varying degrees of interest, understanding and engagement in relation to the management of their use of electricity, ranging from sophisticated prosumers, innovators, and early adopters of new technologies to customers that prefer to 'set and forget', as well as customers experiencing vulnerability.

In the 2024-2029 regulatory control period, TasNetworks will employ communications strategies and messaging that will address, amongst other things, the issues of importance highlighted by the PRWG, in ways that are appropriate for the varying degrees of engagement and energy literacy across the wider customer base.

Partnering with third parties

Customers and stakeholders have told us that they first seek information on their energy needs, particularly about CER technology, through parties other than TasNetworks. In relation to EVs, for example, after family and friends, respondents to a *DER Customer Survey* conducted by TasNetworks cited the internet as a major source of information on EVs, along with car retailers and motoring associations like the Royal Automobile Club of Tasmania (**RACT**). Some respondents also mentioned websites such as the Australian Electric Vehicle Association (**AEVA**) website and EV manufacturers' sites.

The results of the *DER Customer Survey* also suggested that only a small proportion of residential and small business customers (6 per cent amongst respondents) consider TasNetworks and electricity retailers (3 per cent of respondents) as potential sources of information and advice in relation to their energy use.

On this basis, in addition to TasNetworks' own communications, a successful communication plan in relation to network tariff reform and pricing will require cross-industry cooperation and is likely to involve third parties acting in partnership with TasNetworks or as intermediaries.

During the 2019-2024 regulatory control period we partnered with an independent foundation to run a series of webinars relating to managing household energy needs. That series of webinars covered topics such as reducing hot water costs, understanding CER technology and efficient heating options. The response to those webinars was extremely positive, with the webinars being well attended and generating additional visits to TasNetworks' website.

In 2024-2029, we are looking to continue and expand our partnering with the third parties that our customers rely on for information about their household or business' energy needs so that we can provide the information customers need at the right point in their energy journey.

22.7.7 Tariff classes and tariffs for 2024-2029

Our proposed tariff classes and network tariffs for 2024-2029 are outlined in Table 9.

Table 9. Proposed tariff classes for standard control services

Proposed tariff class	Network tariff	Network tariff code	Type
Low voltage residential	Low voltage residential time of use consumption	TAS93	Published tariff – default
	Low voltage residential time of use demand	TAS87	Published tariff
	Low voltage residential time of use CER	TAS97	Published tariff
	Low voltage residential general light and power	*TAS31*	*Published obsolete tariff*
	Low voltage uncontrolled energy heating and hot water	*TAS41*	*Published obsolete tariff*
	Low voltage controlled energy off-peak [night only]	TAS63	Published tariff
	Low voltage controlled energy off-peak with afternoon boost	*TAS61*	*Published obsolete tariff*
	Low voltage residential PAYG time of use[49]	*TAS92*	*Abolished*
	Low voltage residential PAYG[50]	*TAS101*	*Abolished*
Low voltage small business	Low voltage small business time of use consumption	TAS94	Published tariff – default
	Low voltage small business time of use demand	TAS88	Published tariff
	Low voltage small business time of use demand CER	TAS98	Published tariff
	Low voltage small business general light and power	*TAS22*	*Published obsolete tariff*
Irrigation	Low voltage irrigation time of use consumption	TAS75	Published tariff
Low voltage large business	Low voltage large business time of use demand	TAS89	Published tariff
	Low voltage large business kVA	TAS82	Published tariff
	Low voltage embedded network Tier 1	TAS84T1	Published tariff
	Low voltage embedded network Tier 2	TAS84T2	Published tariff
	Low voltage embedded network Tier 3	TAS84T3	Published tariff
	Low voltage embedded network Tier 4	TAS84T4	Published tariff
High voltage business	High voltage kVA specified demand (>2 MVA)	TAS15	Published tariff
	High voltage kVA specified demand (<2MVA)	TASSDM	Published tariff
	Individual tariff calculation	TASCUS	Published tariff
	High voltage embedded network Tier 1	TAS14T1	Published tariff
	High voltage embedded network Tier 2	TAS14T2	Published tariff
Unmetered supplies	Low voltage unmetered supply general	TASUMS	Published tariff
	Low voltage unmetered supply public lighting	TASUMSSL	Published tariff

22.7.8 Proposed tariff structures

Table 10 shows the proposed network tariffs and network tariff structures for the 2024-2029 regulatory control period, including the proposed changes discussed above.

49 TasNetworks is proposing to abolish this network tariff for the 2024-2029 regulatory control period

Table 10. Proposed tariff parameters

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
Low voltage residential network tariffs													
TAS93	Low voltage residential time of use consumption	Default network tariff	Primary network tariff, may be used with TAS63	Daily service charge c/day	c/kWh	✖	✖	✖	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	All other times
TAS87	Low voltage residential time of use demand	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	✖	✖	c/kW/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	All other times
TAS97	Low voltage residential time of use consumer energy resources (CER)	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	c/kWh	✖	✖	✖	c/kW[50]	Weekdays 07:00-10:00 16:00-22:00	✖	Anyday Midnight – 04:00	All other times
TAS31	Low voltage residential light general light and power	Obsolete[51]	Primary network tariff, may be used with TAS41, TAS63, TAS61	Daily service charge c/day	✖	c/kWh	✖	✖	✖	✖	✖	✖	✖

50 This network tariff has a demand threshold, where if demand exceeds 8.5kW at any time, an excess demand charge is charged

51 Obsolete tariffs are no longer available for new installations. Existing installations on other network tariffs are also unable to be reassigned to obsolete tariffs. Customer installations that were, as at 1 July 2024, assigned to an obsolete tariff are able to remain assigned to that network tariff and will continue to apply to customers who move into those premises after that date according to the assignment rules outlined in the TSS, section 21.5.

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
TAS41	Low voltage uncontrolled energy heating and hot water	Obsolete[52]	Secondary network tariff, may be used with TAS31, TAS22	Daily service charge c/day	✖	c/kWh	✖	✖	✖	✖	✖	✖	✖
TAS63	Low voltage controlled energy off-peak [night only]	Opt-in	Secondary network tariff, may be used with TAS31, TAS93, TAS22, TAS94	Daily service charge c/day	✖	✖	c/kWh	✖	✖	✖	✖	✖	Energy will be available during certain times [52]
TAS61	Low voltage controlled energy off-peak with afternoon boost	Obsolete[52]	Secondary network tariff may be used with TAS31, TAS22	Daily service charge c/day	✖	✖	c/kWh	✖	✖	✖	✖	✖	Energy will be available during certain times[53]

52 Energy will only be available between 22:00 and 07:00

53 Energy will be available for a least nine hours between 20:00 and 07:00, and a further two hours between 13:00 and 16:30

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
Low voltage small business network tariffs													
TAS94	Low voltage small business time of use consumption	Default network tariff	Primary network tariff, may be used with TAS63	Daily service charge c/day	c/kWh	✗	✗	✗	✗	Weekdays 07:00-10:00 16:00-21:00	Weekdays 10:00-16:00	✗	All other times
TAS88	Low voltage small business time of use demand	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	✗	✗	✗	c/kW/day	✗	Weekdays 07:00-10:00 16:00-21:00	✗	✗	All other times
TAS98	Low voltage small business time of use demand consumer energy resources (CER)	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	✗	✗	✗	c/kW/day	✗	Weekdays 07:00-10:00 16:00-21:00	✗	✗	All other times
TAS22	Low voltage small business general light and power	Obsolete[52]	Primary network tariff, may be used with TAS41, TAS63, TAS61	Daily service charge c/day	✗	c/kWh	✗	✗	✗	✗	✗	✗	✗

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
Low voltage irrigation network tariff													
TAS75	Low voltage irrigation time of use consumption	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	c/kWh	✖	✖	✖	✖	Winter (1 April – 30 September)			
										Weekdays 07:00-22:00	Weekends 07:00-22:00	✖	All other times
										Summer (1 October – 31 March)			
										✖	Weekdays 07:00-22:00	✖	All other times
Low voltage large business network tariffs													
TAS89	Low voltage large business time of use demand	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	✖	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	All other times
TAS82	Low voltage large business kVA	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	✖	c/kVA/day	✖	✖	✖	✖
TAS84T1	Low voltage embedded network Tier 1	Opt-in[54]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖

54 From 1 July 2024, all new connecting embedded networks on the low voltage network must select an embedded network tariff i.e., they are not eligible for other low voltage business network tariffs, however they may select the Tier that is most suitable for their embedded network

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption: Time of use	Consumption: Flat rate	Consumption: Controlled load	Demand: Time of use	Demand: Flat rate	Time of use periods in (AEST): Peak	Shoulder	Super off-peak	Off-peak
TAS84T2	Low voltage embedded network Tier 2	Opt-in[55]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖
TAS84T3	Low voltage embedded network Tier 3	Opt-in[55]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖
TAS84T4	Low voltage embedded network Tier 4	Opt-in[55]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖
High voltage business network tariffs[55]													
TAS15	High voltage kVA specified demand (>2 MVA)	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	c/kWh	✖	✖	✖	c/kVA/day	Winter (1 April – 30 September)			
										Weekdays 07:00-22:00	Weekends 07:00-22:00	✖	All other times
										Summer (1 October – 31 March)			
										✖	Weekdays 07:00-22:00	✖	All other times

55 Excluding Individual Tariff Calculations (TASCUS), which have customer-specific charging structures

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
TASSDM	High voltage kVA specified demand (<2 MVA)	Opt-in	Primary network tariff, no secondary tariff available	Daily service charge c/day	c/kWh	✖	✖	✖	c/kVA/day	**Winter (1 April – 30 September)** Weekdays 07:00-22:00 **Summer (1 October – 31 March)** ✖	Weekends 07:00-22:00 Weekdays 07:00-22:00	✖ ✖	All other times All other times
TAS14T1	High voltage embedded network Tier 1	Opt-in[56]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖
TAS14T2	High voltage embedded network Tier 2	Opt-in[57]	Primary network tariff, no secondary tariff available	Daily service charge c/day	✖	c/kWh	✖	c/kVA/day	✖	Weekdays 07:00-10:00 16:00-21:00	✖	✖	✖

56 From 1 July 2024, all new connecting embedded networks on the low voltage network must select an embedded network tariff i.e., they are not eligible for other high voltage business network tariffs, however they may select the Tier that is most suitable for their embedded network

Network tariff		Status	Primary or secondary tariff	Fixed charge	Consumption			Demand		Time of use periods in (AEST)			
					Time of use	Flat rate	Controlled load	Time of use	Flat rate	Peak	Shoulder	Super off-peak	Off-peak
Unmetered supplies													
TASUMS	Unmetered supply general			Daily service charge c/day	✖	c/kWh	✖	✖	✖	✖	✖	✖	✖
TASUMSSL	Unmetered supply public lighting			✖	✖	✖	✖	✖	c/lamp watt/day	✖	✖	✖	✖

22.7.9 Tariff trials

As TasNetworks continues to implement its tariff reform pricing strategy, we will need to continue to develop tariffs that support changing technologies, and our customer's needs. As CER technology becomes an increasingly important part of Tasmania's energy mix, TasNetworks will continue to monitor the impact of CER on the network. In addition to addressing our customer's needs, the regulatory environment continues to adapt to the changing role of the electricity grid.

Network tariff trials develop our understanding of how TasNetworks can provide customers with appropriate levels of services and price offerings. It allows us to learn more about how specific customers respond to change – particularly where there are new technologies – and allow us to test innovative pricing solutions within a controlled environment.

In July 2021, TasNetworks consulted with our stakeholders to discuss options for tariff trials during the 2024-2029 regulatory control period, and the principles that will guide the development and implementation of trials. There was a wide-ranging conversation regarding the selection of potential trials, however the overarching theme demonstrated strong support in community-based programs to increase reliability, and to specifically target more vulnerable communities or those with lower network reliability. Key trials that were identified include:

- two-way pricing trial to provide better optionality with CER e.g., electric vehicles, vehicle to grid and export charging and incentives
- battery trials such as community batteries or reliability batteries
- business trials to provide more choice to businesses, including options to support electric vehicle charging for commercial providers
- on farm power sharing to support investment in CER in the agricultural sector.

22.7.9.1 Tariff trial principles

In July 2021, PRWG members identified five key principles to guide the development of our tariff trials for the next regulatory control period (Figure 49).

Figure 49. Tariff trial principles

22.7.9.2 Proposed tariff trials

In response to the increasingly important role of CER technologies in Tasmania's energy mix we propose to explore the following trials with our customers:

- two-way pricing trial
- on farm power sharing trial
- community battery trial.

The implementation and success of our proposed trial will be reflective of the community's ability to engage and participate in the proposed trials. TasNetworks will also consider the network issues that need remediating and the effectiveness of tariffs in altering customer behaviour that may contribute to lowering costs.

Two-way pricing trial

The regulatory environment is adapting to recognise the changing role of the electricity grid – from the traditional service of transporting electricity to customers, to using the network as a trading platform. That is, electricity networks are increasingly required to support an increase in the two-way flow of energy. This allows TasNetworks to seek an innovative tariff to provide customers choice in how they utilise the network more efficiently while recognising customer diversity – both in their use of the networks and how they value 'export services'.

TasNetworks may design and undertake an export tariff trial in the 2024-2029 regulatory control period, however it is expected that this would require evidence that CER exports were projected to drive network expenditure. This is set out more fully in our export tariff transition strategy.

Virtual NMI trial

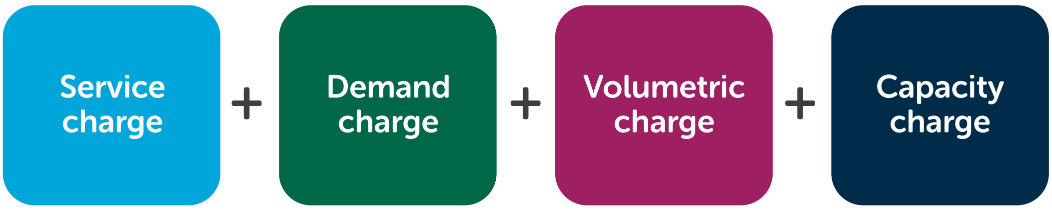
TasNetworks undertook consultation with the agricultural sector as an outcome of the emPOWERing Farms project. This consultation has resulted in a proposed trial to allow on-farm power sharing (referred to as the Virtual NMI Trial) under certain conditions. The premise of this trial is to improve investment outcomes for agricultural customers who innovate and invest in new energy technologies, such as wind farms and solar PV.

The purpose of developing this trial is to overcome the issues of agricultural businesses having multiple connections to the distribution networks across their property. Under current arrangements some properties that have invested in CER have been unable to offset their energy consumption at one connection against the generation of energy at another connection. Therefore, rather than using the surplus energy across multiple connections on the same property, owners must sell their surplus generated energy and then purchase the electricity back at a higher price.

This is primarily an issue encountered by customers who have a number of connections over a large geographical area within the same property. In 2021, TasNetworks proposed the parameters for a trial tariff (Figure 50) and released an expression of interest for the Virtual NMI trial targeting large agricultural customers:

- with advanced meters throughout their property;
- who hold multiple adjacent NMIs
- who are connected to the same high voltage feeder
- have greater that 30KW
- have a large amount of embedded generation installed on their property.

Figure 50. Proposed tariff components for a virtual NMI tariff trial



TasNetworks remains interested in recruiting agricultural customers for this trial for the 2024-2029 regulatory control period.

Community battery trials

PRWG showed great interest in implementing a community battery trial which provides a focus on the services being provided to communities where there is potentially network reliability issues or vulnerable communities.

During the 2019-2024 regulatory control period, TasNetworks undertook a community battery trial at a remote location – Derwent Bridge. This location was chosen due to reliability and power quality issues in the area.

TasNetworks will take the learnings from this trial to assess and evaluate the performance of community batteries and identify further trials and trial locations during the 2024-2029 regulatory control period. The outcome of these learning will inform how tariffs can support the storage and usage of energy through community batteries.

CUSTOMER IMPACTS OF THIS PRICING PROPOSAL

22.8 Introduction

This pricing proposal provides customers choice of network tariffs to best suit their situation. TasNetworks has been developing tariffs to minimise price impacts to customers and seeks to provide affordable options for all customers, while ensuring that customers contribute fairly to their portion of network costs.

Throughout this TSES, customer impact analysis has been provided to reflect the changes that are proposed to our network tariffs. This section will provide the indicative price paths of our network tariffs, and scenario analysis to reflect changing customer behaviours because of the uptake of new technologies, specifically solar PV, household batteries and EVs.

22.9 Indicative price paths

Our indicative price path reviews consider different sized households and small businesses to assess the impact of our prices on different customers. The following sections provide high level price path analysis by network tariff class.

22.9.1 Residential customers

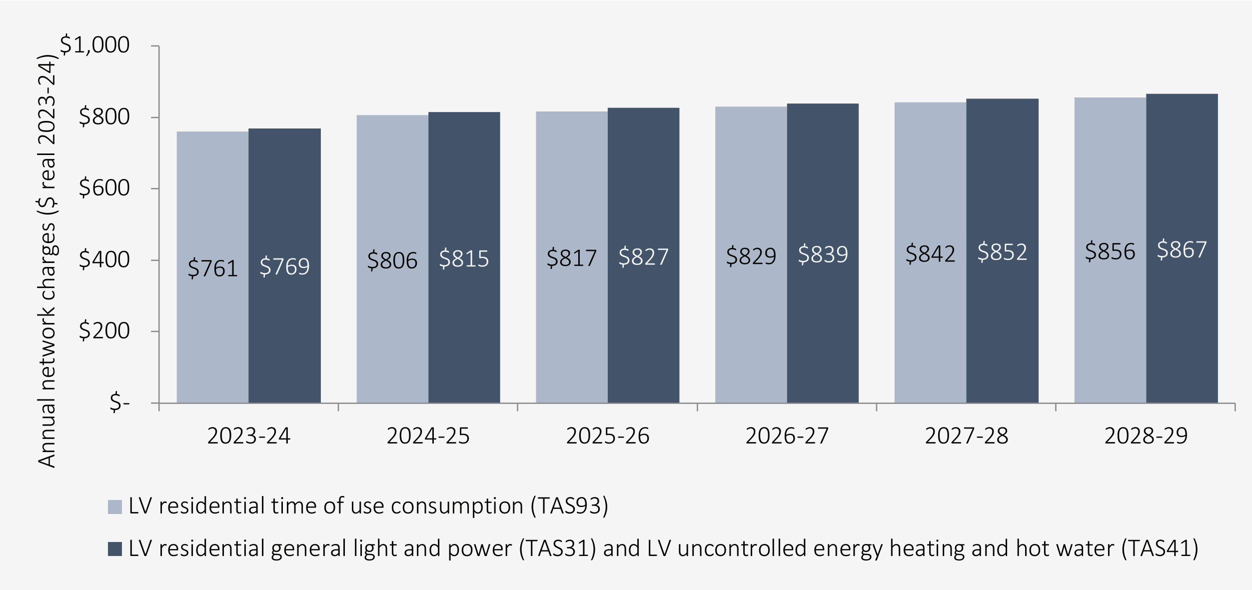
Approximately 80 per cent of residential customers use the flat rate network tariffs, of those approximately 94 per cent use the combined general light and power (TAS31) and uncontrolled heating and hot water (TAS41) network tariffs. The remaining customers are connected using the default network tariff – time of use consumption (TAS93).

Figure 51 provides a summary of the customer impact analysis for the 2024-2029 regulatory control period using an average consumption of 7,566 kWh per annum for residential customers on general light and power (TAS31) and uncontrolled energy heating and hot water (TAS41). The projections are built on indicative prices for the daily service charge and the per unit consumption charge (kWh). The different network tariffs have used the following specific underlying assumptions.

- Time of use consumption network tariff (TAS93), the peak and off-peak period are based on the following proportions – 33 per cent peak usage and 67 per cent off-peak usage, consistent with the average customer profile on this network tariff.
- General light and power with the heating and hot water (TAS31/41) network tariffs assumes that approximately 44 per cent of household usage is for general light and power, with the remaining 56 per cent for heating and hot water.

The annual movements between these two network tariffs are closely aligned. For customers using more or less energy, energy at different time of the day, or have different ratios for peak/off-peak or light and power/heating and hot water, the annual network charges may differ from that provided below. However, the direction is likely to be similar.

Figure 51. Annual network charge price path for a typical residential customer



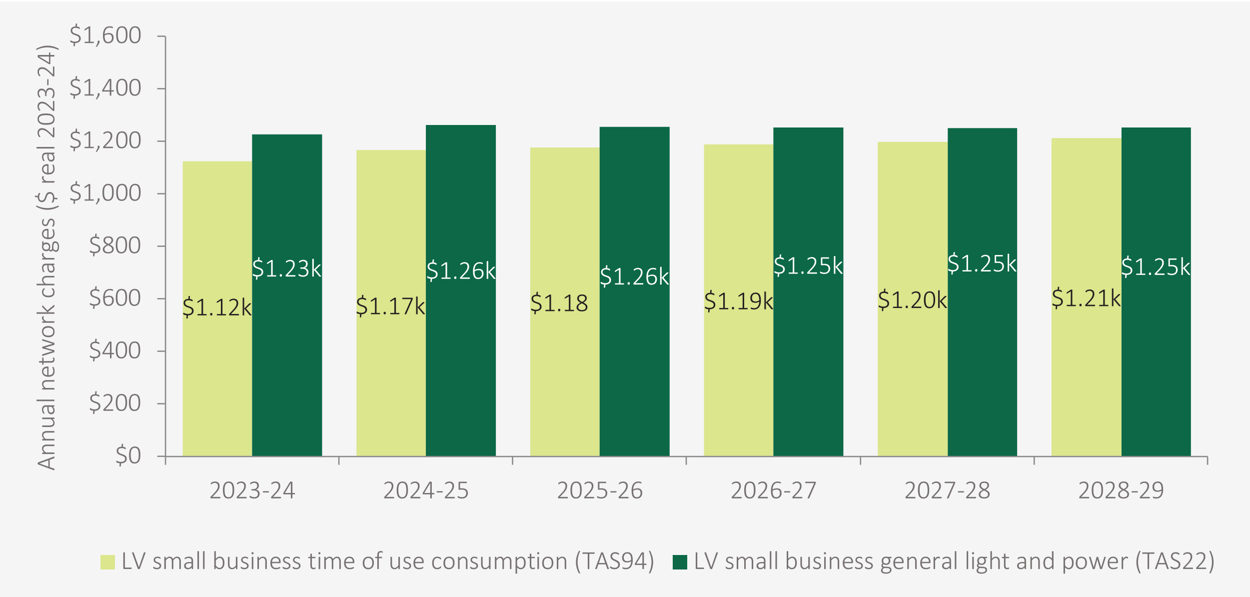
22.9.2 Small business customers

For the 2024-2029 regulatory control period, it is proposed that the time of use consumption network tariff (TAS94) time of use periods be changed. These changes are reflected in the indicative network charges in Figure 52. Based on interval metering data for small business customers, it has been assumed that small businesses use approximately 28 per cent of their energy during the proposed peak periods, 25 per cent during the proposed shoulder periods, and 44 per cent during the proposed off-peak periods. For customers with different load profiles, the outcomes differ.

Figure 52 provides the indicative price path using indicative prices for the daily service charge and the per unit consumption charge (kWh) for small business customers on TAS22 and TAS94 network tariffs and assumes average energy consumption is 10,711 kWh per annum. Network charges for these customers are expected to increase by around 0.9 per cent to 1.1 per cent in each year during the 2024-2029 regulatory control period (in real terms).

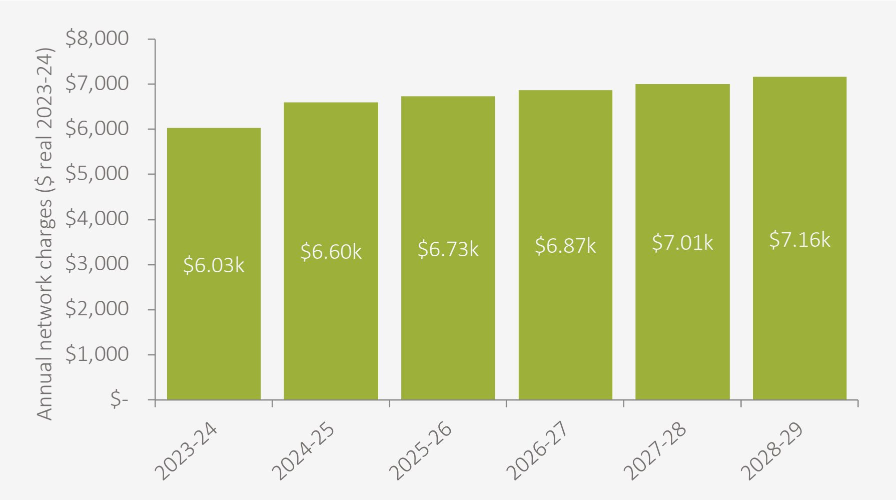
The small business general light and power (TAS22) network tariff is assigned to approximately 70 per cent of small business customers. However, over the 2019-2024 regulatory control period, uptake of the default time of use network tariff (TAS94) increased from 17 per cent.

Figure 52. Annual network charge price path for a typical small business customer on consumption tariffs



The low voltage time of use demand tariff (TAS88) has been taken up by a sub-group of our small business customer base who consume more energy than those on the consumption-based network tariffs. To analyse the typical customer outcomes for this tariff, an average monthly maximum demand of approximately 20 kW has been assumed for both peak and off-peak periods. This corresponds to an annual consumption of approximately 101 MWh (Figure 53). Network charges for these customers are expected to increase by around 1.9 per cent to 2.2 per cent in each year during the 2024-2029 regulatory control period (in real terms).

Figure 53. Annual network charge price path for a typical small business customer on the time of use demand (TAS88) network tariff



22.9.3 Irrigation customers

TasNetworks has provided a dedicated network tariff for irrigators across Tasmania, which is a time of use consumption-based network tariff (TAS75). The energy used varies depending on the time of day, which are defined differently in summer and winter (see Table 10 in section 22.7.8 of this document).

Using information gathered through our *emPOWERing Farms* project, our irrigators also have other low voltage business network tariffs available to them, these include:

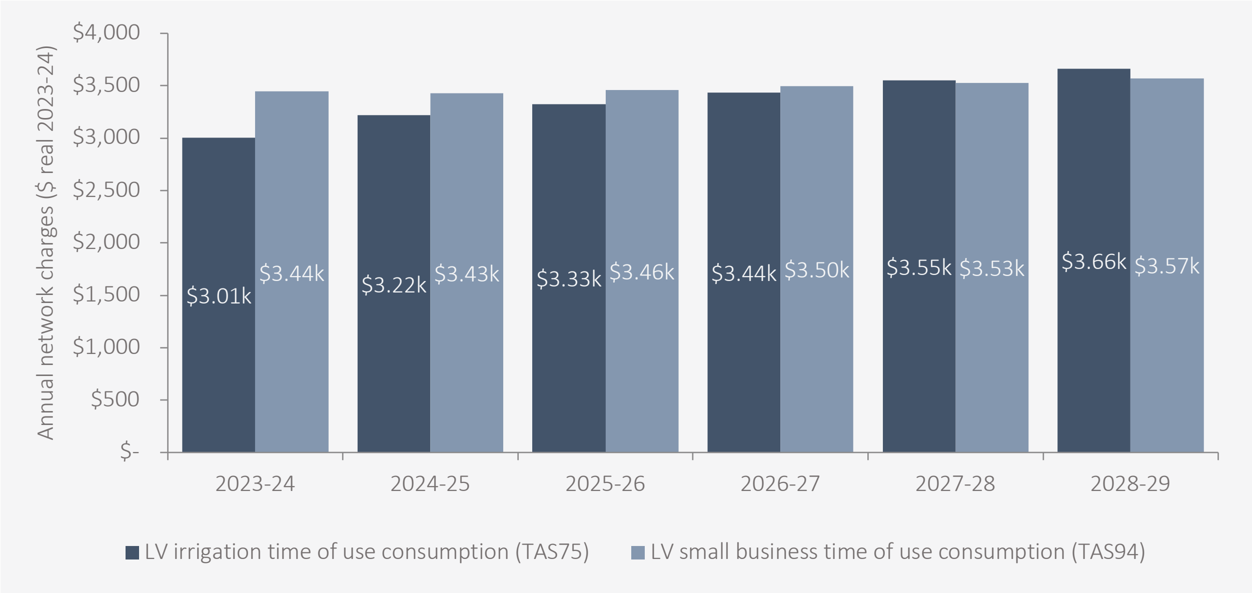
- Low voltage small business time of use consumption (TAS94)
- Low voltage small business time of use demand (TAS88)
- Low voltage small business time of use demand consumer energy resources (CER) (TAS98)
- Low voltage small business general light and power (TAS22).[57]

Figure 54 shows the price path for irrigators with an annual consumption of approximately 50,137 kWh per annum across a selection of network tariffs. It has been assumed that the average irrigator consumes 6 per cent of their energy during peak, 36 per cent during shoulder and 58 per cent during off-peak periods under the current TAS75 structure. It is noted that peak usage has been historically low as irrigators have tended to respond to the pricing signals. This chart shows that the low voltage irrigation network tariff (TAS75) remains an attractive option for primary produces required to irrigate. However, consistent with the advice provided through our *emPOWERing Farms* trial, we note that primary producers should evaluate their individual usage patterns and consider alternative network tariffs as applicable.

It is anticipated that annual network charges for irrigators will reach parity between the low voltage small business time of use consumption (TAS94) and the low voltage irrigation (TAS75) network tariffs during the 2024-2029 regulatory control period (assuming the consumption patterns noted above). Network charges for current TAS75 customers are expected to increase by around 3.2 per cent in each year during the 2024-2029 regulatory control period (in real terms).

57 Refer to the assignment rules in section 22.7.2 of this document

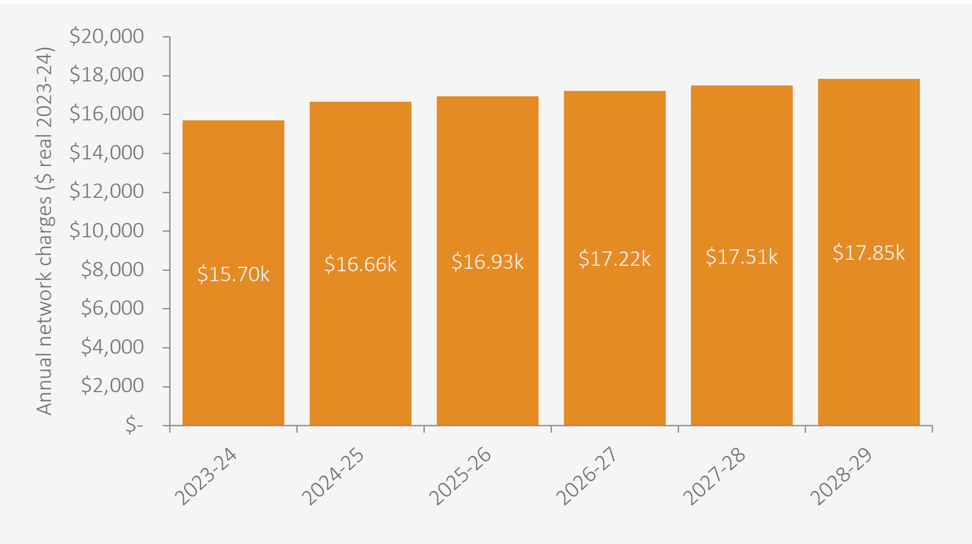
Figure 54. Annual network charge price path for a typical irrigation customer on low voltage consumption-based network tariffs



22.9.4 Large business customers (low voltage network)

Figure 55 shows a summary of the indicative annual network charges under the low voltage large business kVA demand network tariff (TAS82). This example of a typical large business customer assumes annual consumption of approximately 229 MWh per annum and an anytime maximum demand of 67 kVA, putting this customer into the mid-range of our large business customer base. Network charges for these customers are expected to increase by around 1.6 per cent to 1.9 per cent in each year during the 2024-2029 regulatory control period (in real terms).

Figure 55. Annual network charge price path for a typical large business customer on the low voltage kVA demand (TAS82) network tariff

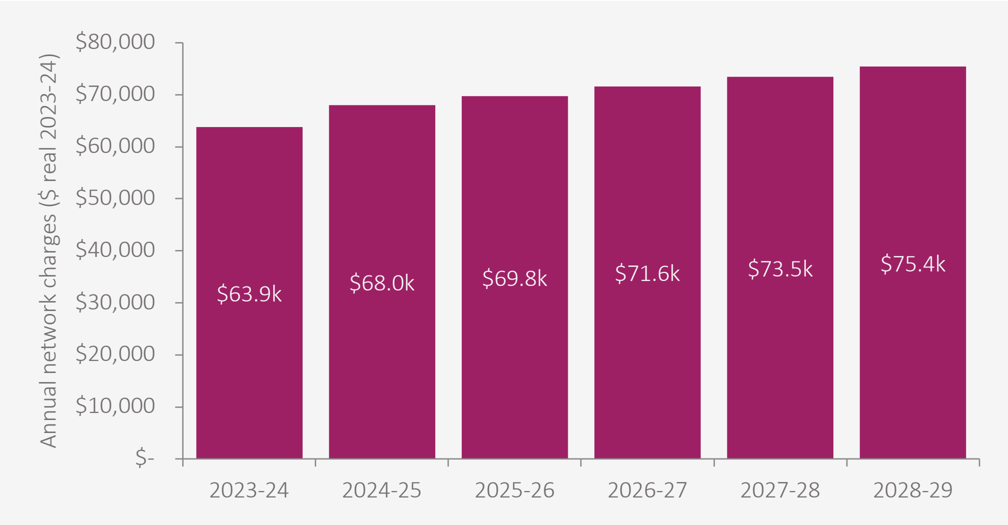


22.9.5 Large business customers (high voltage network)

Indicative network charges using the TASSDM – HV commercial kVA specified demand (<2MVA) have been used to calculate the indicative network charges for our large commercial customers (Figure 56). This price path uses approximately 2,058 MWh per annum with a specified demand of approximately 633 MVA. It is assumed that high voltage business customers use approximately 30 per cent of the energy they consume during peak periods, 32 per cent during shoulder periods and 38 per cent in off-peak times. Network charges for customers on this network tariff are expected to increase by around 2.6 per cent in each year during the 2024-2029 regulatory control period (in real terms).

Customers connected to the high voltage network also have the option of using the TAS15 network tariff (HV commercial kVA specified demand (>2MVA)). However, this network tariff only applies to a very small cohort of customers and incorporates site specific Transmission Use of System (**TUoS**) charges that depend on the characteristics of the connection, meaning that there isn't really an indicative customer that can be used as a basis for comparing network charges over time.

Figure 56. Annual network charge price path for a typical commercial customer on the high voltage commercial kVA specified demand (<2MVA) network tariff (TASSDM)



22.10 Residential customer behaviour analysis

Over the past five years, TasNetworks has undertaken the emPOWERing You trial and the DER Customer Survey with our residential customers. Insights from these key investigations have been used to form scenarios that reflect changes in customer behaviour under certain circumstances, related to uptake of technology and the impact of our network tariffs on customers experiencing vulnerability and disadvantage. TasNetworks recognises that there may be limited capacity for customers to physically change how they use electricity. However, customers can effectively reflect changes in network demand through technology (e.g., battery storage), which could strongly contribute to lowering network costs through tariffs and without changing how customers live their day to day lives.

This section analyses the customer impact for customers experiencing vulnerability and disadvantage, and examines several scenarios reflecting how a customers' potential energy consumption may change resulting from their investment in technology.

22.10.1 Studies and trials

22.10.1.1 emPOWERing You

The *emPOWERing You*[58] trial included the deployment of 600 off-market advanced meters to residential customers located in the municipality of Brighton in southern Tasmania which enabled the collection of usage data over a 12-month period. Extensive focus-groups, interviews and surveys were undertaken with participants to help us understand and communicate to customers the changing tariff offerings and the impact of these offerings.

Overall, the trial resulted in an observable reduction in participants' maximum demand, as well as their consumption, indicating some behavioural change, however participants' response was muted most likely a reflection on lifestyle.

Customers who were most likely able to respond strongly to cost reflective network tariffs were those who consume significantly more energy than the average, have larger households than the trial average, were most likely in paid employment and had above average household income amongst the trial participants.

TasNetworks continues to use the insights from this trial to continue developing and supporting our pricing strategy. The demographic data provided through the emPOWERing You trial, we have been able to identify customers who may be at a disadvantage or experiencing vulnerability.

58 emPOWERing You trial, Final report summary, August 2019

22.10.1.2 DER customer survey

The *DER customer survey*[59] was undertaken during 2021 and provided valuable insights into the purchasing intentions of our customers for DER technology. The majority of respondents were from wider Hobart in southern Tasmania, however there were some respondents from the north and north-west of Tasmania.

A number of respondents already owned some form of DER technology, however it was those respondents who owned household batteries or EVs that demonstrated the greatest ability to change their consumption habits.

Those customers who responded to the survey and had household batteries tended to shift their peak consumption into the off-peak periods of our time of use consumption (TAS93) network tariffs. It also demonstrated that customers with EVs on the time of use consumption tariff (TAS93) tended to have an additional evening peak between 9pm and 10pm – following the conclusion of the network tariffs peak period.

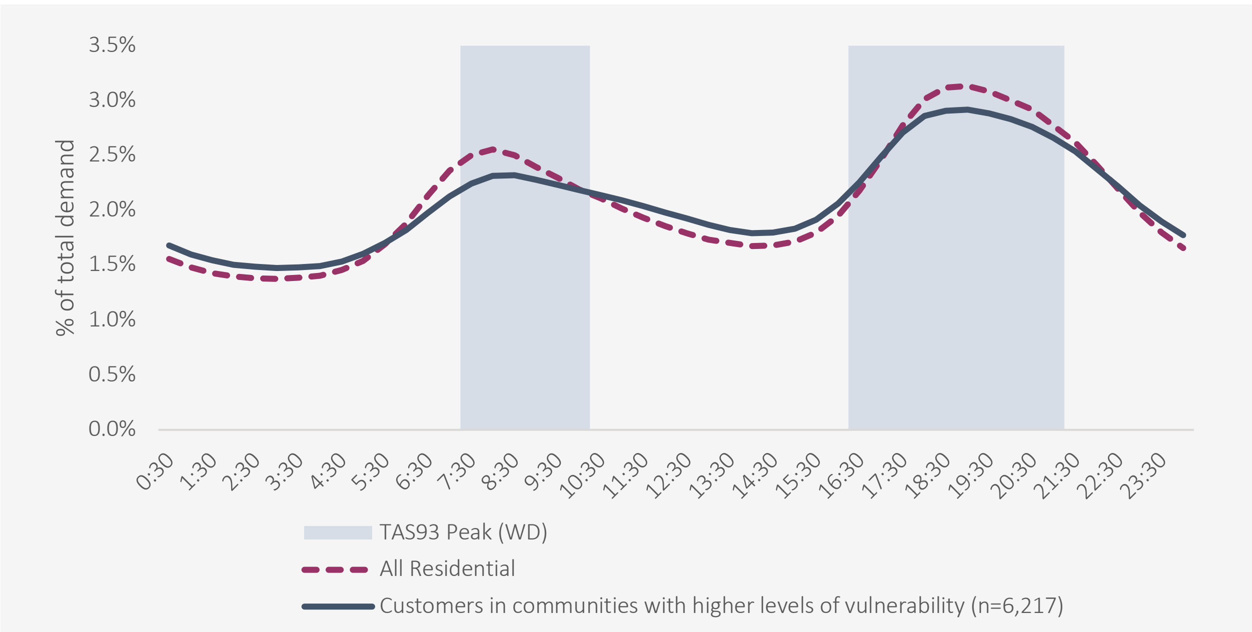
22.10.2 Customers experiencing disadvantage or vulnerability

TasNetworks combined information from the *emPOWERing You* trial and external sources such as the *Tasmania – Dropping off the Edge*[60] report to identify customers who experience higher-than-average levels of vulnerability or disadvantage. Data from around 6,200 households was used to better understand electricity consumption patterns within this customer cohort and to inform tariff comparisons between our general light and power (TAS31) and time of use consumption (TAS93) network tariffs. This data showed that customers with higher levels of vulnerability tend to have:

- relatively low levels of solar penetration – 11 per cent compared to the residential average of 16 per cent
- high levels of advanced metering (approximately 67 per cent compared with the residential average of 50 per cent)
- high levels of uptake of the time of use consumption network tariff (TAS93) (approximately 35 per cent compared with the residential average of 20 per cent). This is primarily a result of replacing the PAYG meters as part of the abolishment of the low voltage residential PAYG network tariff (TAS101).

Customers experiencing vulnerability and disadvantage tend to have lower than average consumption during the morning and evening peak periods and higher than average consumption during the middle of the day and overnight (Figure 57). Their average annual consumption is approximately 9,300 kWh (approximately 10 per cent higher than the residential average).

Figure 57. Load profiles of customers experiencing vulnerability or disadvantage



The identified consumption patterns result in relatively low proportions of peak consumption amongst customers experiencing disadvantage or vulnerability, which suggests that this group of customers are more likely to benefit more from time-of-use network tariffs than the average household.

59 TasNetworks' DER Customer Survey

60 Tasmania - Dropping off the Edge

Based on the indicative 2024-25 network prices, further analysis found that customers who experience vulnerability and currently use the residential general light and power network tariff (TAS31), 79 per cent of the 2,400 customers analysed would likely benefit from moving to the residential time of use consumption network tariff (TAS93), with average savings of around $42 per annum (Figure 58). This exceeds the proportion of all customers on the residential general light and power network tariff (TAS31) where 65 per cent are likely to benefit from switching to the residential time of use consumption network tariff (TAS93) with potential average network savings of approximately $21.

Figure 58. Annual network charge impact for customers experiencing vulnerability or disadvantage on the general light and power network tariff (TAS31)[61]

Compared to other demographics, these customers may not be as readily able to invest in technologies that could further lower their annual network bills. The next section investigates how an average customers' network charges may be influenced by changing consumption behaviour resulting from investing in CER technology.

22.10.3 Customer behaviour analysis with and without investment in technology

TasNetworks has approached the following scenario analysis by investigating two distinctly different groups of customers:

- Customers who do not respond to price signals – these customers may have invested in new technology, but have not fully optimised their utilisation of the technologies
- Customers who do respond to price signals and fully implement the advantages of new technologies.

Illustrative examples of customer profiles are provided (Table 11),[62] and the same "Base" profile was used in each scenario to measure the difference in energy usage of customers. Depending on the level of CER investment the illustrative customer profile has been provided to indicate the potential customer response, presented against:

- the time of use windows for the residential time of use consumption (TAS93) network tariff (for customers who do not respond to price signals)
- the proposed time of use windows for the residential time of use CER (TAS97) network tariff (for customers who do respond to the price signals).

The customer profiles have been identified through the data collected from TasNetworks' *DER customer survey.*

Where appropriate, an average customers' network charges have been calculated for the proposed residential time of use CER network tariff (TAS97) to demonstrate the appropriateness of this network tariff when household investment in CER technologies is high.

61 Prepared using the indicative prices for 2024-25

62 Illustrative examples provide an indication of the likely response, however may differ for individual circumstances depending on the customer's choice of network tariff and individual consumption requirements

22.10.3.1 Customers who do not respond to price signals

Throughout our cost reflective tariff discussions with stakeholders, we receive feedback in relation to customers that have a lifestyle that has them "locked into" a typical consumption profile i.e., customers use more energy during between 7am and 10am, and 4pm and 9pm on weekdays, therefore contributing to the network.

Three scenarios were developed for this group of customers:

- **Base scenario** where the average residential household consumption was approximately 7,600 kWh per annum and the customer profile reflects the average customer profile for our network.
- **Base scenario plus solar PV** accommodates those households that have invested in solar only. It is assumed that the annual consumption is reduced by approximately seven per cent to 7,100 kWh, resulting from using solar PV generation during the middle of the day. Note: the calculated network charges do not include savings made through the feed-in-tariff (**FiT**).
- The final scenario for this cohort includes the addition of **household batteries** to supplement the **solar PV installation**. It is assumed that any solar energy that is not consumed by the household is primarily used to charge the household battery, until the battery reaches its capacity. Any additional solar generation is then exported into the network. This scenario assumes a 5 kWh battery, which reduces the total annual consumption to around 6,000 kWh (i.e., a further 15 per cent compared to the previous scenario). It is further assumed that the customer does not calibrate the battery to respond to time of use price signals.

The analysis in Table 11 indicates that customers who have no CER technologies i.e., the "Base" scenario are better off using TasNetworks' time of use consumption (TAS93) network tariff when compared against the combined flat rate network tariffs (TAS31/41) – this is consistent with analysis conducted for our wider customer base, and for customers experiencing vulnerability and disadvantage. If the same customer invests in CER technology, the inherent savings resulting from reduced consumption are apparent, however the differential in network costs are marginal. Additional optimisation of storage would be required to further increase cost savings however, to maximise the value of their investment, these customers would need to respond to network pricing signals.

22.10.3.2 Customers who do respond to price signals

These scenarios reflect changing customer behaviours resulting from the investment in CER technologies. It is assumed that these customers are using time of use tariffs and aim to maximise their return on investment by responding to the charging windows of these tariffs. TasNetworks examined four CER uptake scenarios, and different responses to the residential time of use consumption (TAS93) and the residential time of use consumption CER (TAS97) network tariffs are modelled in each scenario. Under both tariff structures, customers are assumed to minimise their consumption during the respective peak hours. The modelled residential time of use consumption CER network tariff (TAS97) responses consider the extended evening peak window and assume an additional consumption shift into the midnight to 4am super off-peak period as well as a significant reduction of any excess demand above the 8.5 kW threshold. All scenarios use the "Base" customer profile established in section 22.10.3.1.:

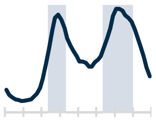
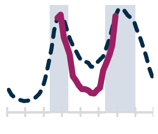
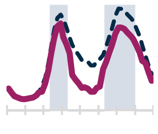
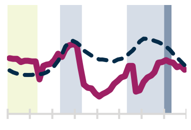
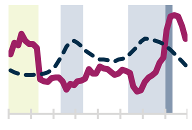
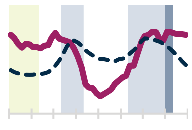
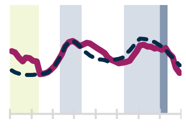
- Customers who have **household batteries installed with their solar PV** are assumed to have the same total annual consumption as the non-responder group (approx. 6,000 kWh pa). However, this group uses their batteries to lower their network charges by shifting consumption in response to time of use price signals.
- Those customers with **solar PV with household batteries** and have also invested in an EV are assumed to use any solar generation that is not consumed by the household or the battery to charge their EV. The EV charging is assumed to occur in the overnight period between midnight and 7 am. It is estimated that these customers will see an increase in consumption of approximately 21 per cent compared to non-EV owners with solar and batteries (from around 6,000 kWh to 7,300 kWh per annum).
- Customers who only have **solar PV and an EV**, but who have chosen not to invest in a household battery are assumed to use any solar generation that is not consumed by the household to charge their EV. Total annual consumption for this group is estimated to increase by around 13 per cent compared to non-EV owners with solar PV (from around 7,100 kWh to 8,000 kWh per annum).
- Customers who own an **EV** but have not invested in any additional CER technology are assumed to fully charge their EV through the network. This increases total annual consumption for this group to approximately 9,700 kWh, an increase of 29 per cent compared to non-EV owners without CER technologies.

In all scenarios, a moderate response to the proposed residential time of use CER network tariff (TAS97) has been assumed.

Table 11 summarises the findings of the undertaken analysis. The proposed residential time of use CER network tariff (TAS97) offers the best customer outcomes in all CER uptake scenarios, with estimated network savings ranging between eight and 22 per cent compared to the combined flat rate network tariffs (TAS31/41), and between 1.5 and 8.0 per cent compared to the time of use consumption (TAS93) network tariff.

Households who own the full range of CER technologies have the highest level of influence over how they consume energy. This group has the highest ability to shift consumption out of peak periods and therefore the strongest potential to realise network charge savings. While households without batteries can achieve some savings by moving to cost reflective network tariffs, they are less able to reduce their consumption during peak periods when compared to customers who have household batteries.

Table 11. Typical residential customer outcomes with different technology and network tariff combinations ($ 2024-25 nominal)

Scenario	Customers who do not respond to price signals and implement new technologies			Customers who respond to price signals and implement new technologies[∫] The charts below provide an indicative customer profile where the customer responds to the relevant residential time of use consumption network tariff compared to the base.			
	Base ~7,600 kWh pa	Base + Solar PV[□] ~7,100 kWh pa	Base + Solar PV + batteries[§] ~6,000 kWh pa	Base + Solar PV + batteries ~6,000 kWh pa	Base + Solar PV + batteries + EV ~7,300 kWh pa	**Base + Solar PV +EV** **~8,000 kWh pa**	Base + EV ~9,700 kWh pa
Key for charts: Peak (7am-10am, 4pm-9pm) Proposed super off-peak (midnight-4am)							
Residential general light and power plus heating and hot water (TAS31/41)	$843 ■	$800 ◆	$712 ◆	$712 ■	$821 ■	$881 ■	$1,028 ■
Residential time of use consumption (TAS93)	$830 ◆	$800 ◆	$706 ◆	$652 ◆	$696 ◆	$805 ◆	$971 ◆
Residential time of use consumption CER (TAS97) (assumes an additional response to the network tariff structure)	Not applicable	$801 ◆	$706 ◆	$625 ■	$640 ■	$795 ■	$947 ■

□ It is assumed that customers who only install solar PV do not substantially change their consumption profiles or behaviour. However, these customers do reduce their annual consumption, mostly through offsetting consumption during the midday off-peak, with any excess energy being exported to the network.

§ It is assumed that customers in this group install solar and batteries, but do not substantially change their behaviour.

Key for scenario outcomes (i.e., network pricing outcome depending on customer response and technology):

■ Worse customer outcome

◆ Neutral customer outcome

■ Better customer outcome

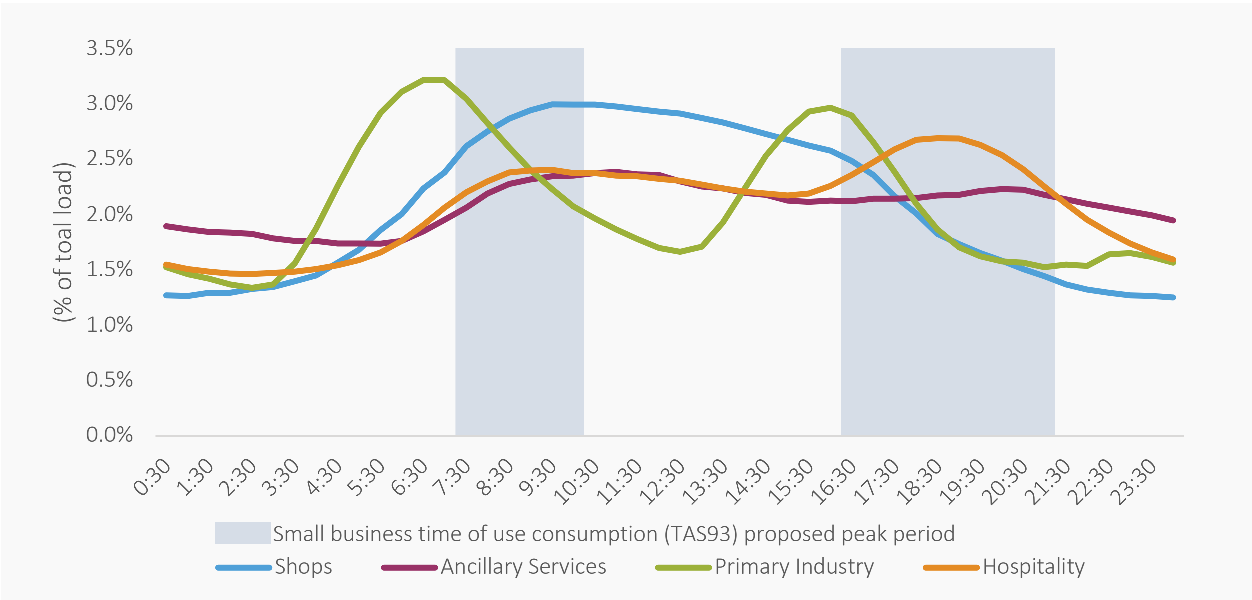
22.11 Small business impact analysis

TasNetworks is proposing to change the time of use periods for the small businesses time of use consumption (TAS94) network tariff in the 2024-2029 regulatory control period to:

- introduce a shoulder period during the middle of the day (10am – 4pm) on weekdays
- reduce the weekday evening peak period from 10pm to 9pm
- change the weekend shoulder period to off-peak all weekend.

TasNetworks' small business customers are diverse and include, but are not limited to, small industry, shops, hospitality, primary industries, educational facilities, and sports facilities. The load profiles of the most common industry types in Tasmania are shown in Figure 59 illustrating this diversity however, despite this, most businesses tend to have relatively consistent load profiles during their respective operating hours, and a common feature is the comparably high energy consumption through the middle of the day. For example, shops tend to operate between 8:30am and 5pm, the hospitality sector consumes energy all day with an increase in consumption during the evening, and our primary industry sector have a profile that reflect the early morning and early afternoon work patterns which predominantly occur prior to the network peak periods.

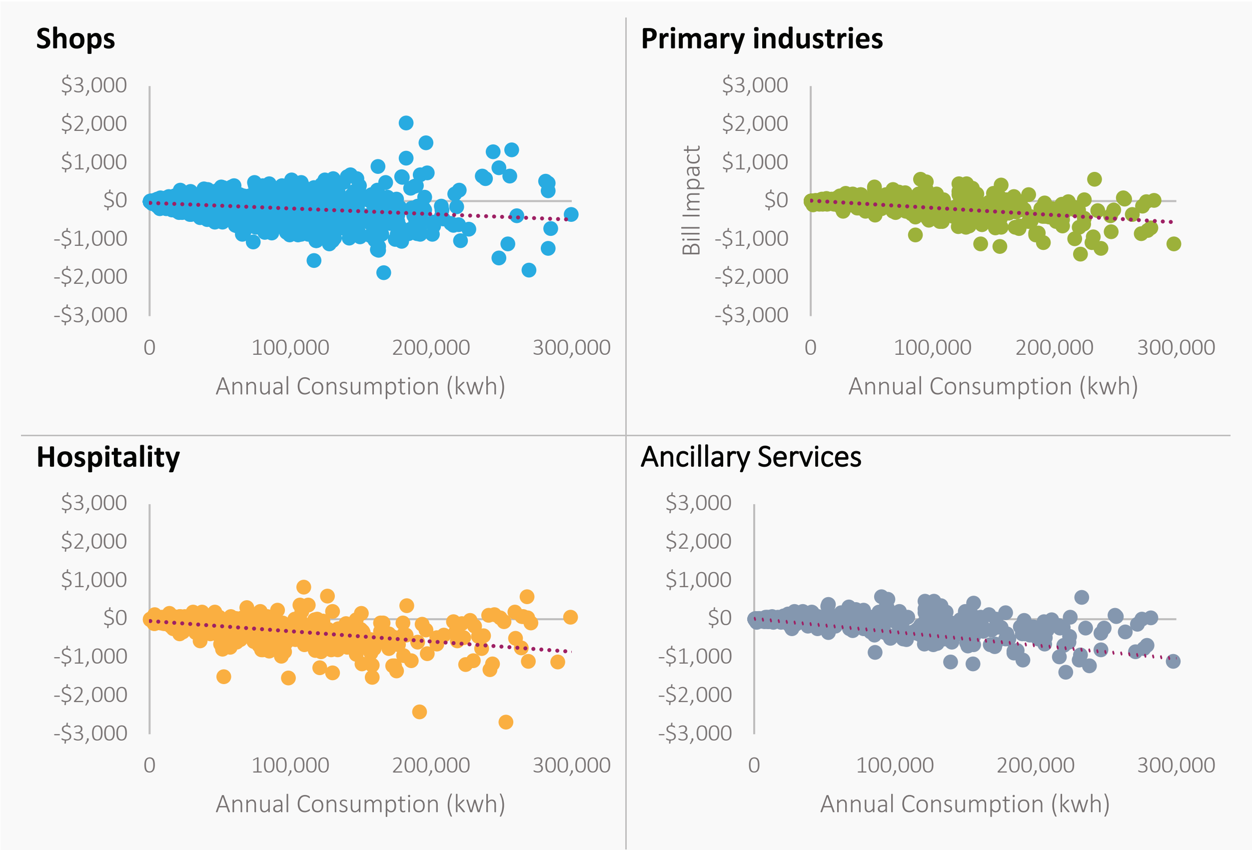
Figure 59. Small business industry load profiles



In section 22.7.3.4, Figure 33 shows the customer impact of changing the low voltage small business time of use consumption network tariff (TAS94) to the proposed time of use structure in the 2024-2029 regulatory control period for the entire small business customer group. TasNetworks has undertaken further analysis to better understand how the proposed network tariff changes impact key industries within our small business customer base.

Our analysis indicates that the proposed tariff changes, particularly the introduction of a midday shoulder period during weekdays, will likely benefit a wide range of industry types and result in network charge savings for the majority of our small business customers. The findings summarised in Figure 60 illustrates the indicative network charge outcomes for individual customers within these industries, relative to their level of total annual consumption. Each dot in the customer impact charts shows how a particular customer's indicative network charges are likely to compare under the proposed and existing tariff structures, dots below zero representing customers who are likely to incur lower charges under the proposed structure.

Figure 60. Small business time of use consumption (TAS94) rebalancing impact (annual network charge impact) [63]



The above analysis shows that the proposed changes will benefit those customers who use large proportions of their energy during the former peak windows, which have now become shoulder and off-peak periods.

63 Prepared using the indicative prices for 2024-2025

22.12 Export Tariff Transition Strategy

TasNetworks is required to set out its strategy for the introduction of export tariffs.[64] The determination of this provision in the NER was made by the Australian Energy Market Commission (**AEMC**) in August 2021.[65]

Export tariffs refer to the charging of CER exports at particular times (e.g., non-peak periods where there is excess supply) where CER exports contribute towards increased network costs. To incentivise customers, export tariffs would be expected to reward customers for the export of electricity at favourable times, such as peak periods.

TasNetworks is not proposing export tariffs in the 2024-2029 regulatory control period.

Rationale to TasNetworks export tariff transition strategy

TasNetworks has not yet established that solar PV exports are currently or expected to drive network expenditure and is therefore not able to justify the introduction of export tariffs in Tasmania for the 2024-2029 regulatory control period.

Tasmania has a relatively low penetration of solar PV installations compared to other jurisdictions. While solar PV capacity is expected to grow significantly throughout the 2024-2029 regulatory control period and beyond, solar PV generation will in large part be absorbed by storage (for later use, such as in peak times) and increasingly by electric vehicles. Tasmania has a comparatively stable minimum (and base) demand as discussed in section 22.6.4.

Importantly, any introduction of export tariffs would require there to be an attributable cost to the network related to the export of CER (likely solar PV). This relates to the intrinsic hosting capacity of the network, which was initially designed for the (one-way) delivery of electricity to load customers from large scale generation units. However, the network has some inherent ability to provide for two-way flows of electricity – facilitating the export from CER to other load points.

To determine whether CER exports will contribute to increased network costs, it is important to assess the intrinsic hosting capacity throughout the network. The hosting capacity will vary considerably throughout the network and at different times and will affect various customers differently. Assessment of the hosting capacity is also critical in planning for increased electrification of the system, such as to support increased electric vehicles in Tasmania. To fully inform whether there is a rationale for export tariffs to be introduced in the future, TasNetworks will also consider projections for CER installations, including solar PV, storage, and electric vehicles, all of which will influence how the hosting capacity is consumed.

Should there be a constrained hosting capacity in the short to medium term, and informed by aforementioned projections, TasNetworks will consider the design and results of tariff trials over the 2024-2029 period and prior to formally proposing export tariffs to be introduced in Tasmania to the AER. Tariff trials provide an avenue for innovation and are effective in testing customers' engagement and responsiveness to price signals. Export tariffs are only one type of trial that TasNetworks will consider over the 2024-2029 regulatory control period.

TasNetworks is eager to adopt the learnings from other distributors through their respective tariff trials but will also consider unique Tasmanian-specific considerations – such as Tasmania's peak supply and demand profiles which differ to mainland regions.

Tasmanian customers' sentiments regarding export tariffs, particularly two-way pricing, is a key consideration. This will continue to be tested with stakeholders through the PRWG.

There are likely to be benefits in reducing long term costs if customers can store excess CER generation and consume it later (peak times). However, price signals to contribute towards this outcome could be achieved through export tariffs or through time-of-use tariffs, such as those being proposed as part of TasNetworks' proposal.

64 NER clause 6.18.1A(2A)

65 National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021

ALTERNATIVE CONTROL SERVICES

22.13 Alternative control services tariff class

In addition to our standard control services, we also provide user-requested, public lighting and metering services, known as alternative control services. The full cost of these services is attributed to the customer who receives the service.

This section outlines our proposed changes to our metering, fee-based services and quoted services strategy.

Table 12. ACS strategy

Tariff classes	Typical customer
Ancillary services – fee based	Retail customers requesting standard services, including basic connection services, site visits and basic supply augmentations.
Ancillary services – quoted	Retail customers requesting non-standard services such as complex connection services.
Public lighting	State and local government.
Metering services	Retail customers.
Connection services	A retail customer requesting a routine connection service.

22.14 Fee based services

Fee based services are largely homogeneous services provided on request (often from retailers) for the benefit of a single customer, rather than a service supplied to customers collectively. Set fees are developed using approved labour rates and average timing and materials based on historical actuals.

22.15 Quoted services

Quoted services vary in scope and cost and are specific to an individual customers' needs. This precludes the utilisation of a set fee, requiring for each job a quote for the provision of the requested service, developed using approved labour rates.

22.16 Public lighting

Public lighting tariffs are developed based on the individual lighting types and do not include charges for the utilisation of TasNetworks' electricity network. Contributions towards the costs of the electricity network are recovered from public lighting customers through separate network tariffs.

22.17 Metering

TasNetworks' metering charges are made up of a capital charge, which recoups the cost of the meter, and an operational charge, which recovers the cost of reading the meter and managing the data. As with our network charges, rather than bill customers directly, TasNetworks recovers its metering costs from electricity retailers, which factor in those metering charges when setting their retail tariffs.

22.18 Connection Services

Basic connection services are provided via fee-based services. Complex connections that vary in scale and scope are provided as quoted services.

Appendix A – Setting our tariffs

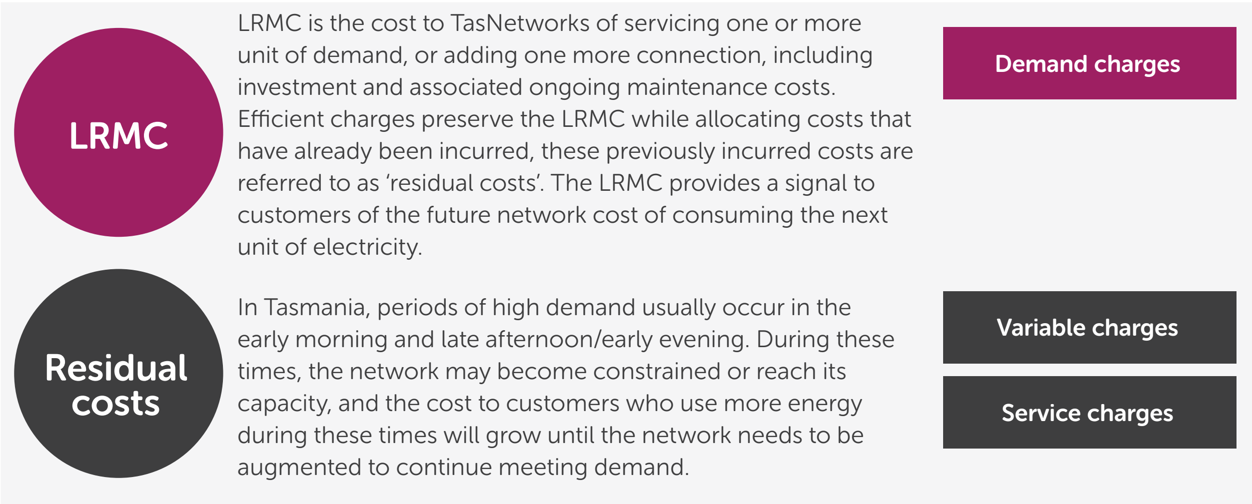
Our network tariffs are set to achieve our pricing objectives, like cost reflectivity, while taking into account forecasts of customer numbers, consumption and demand, and new connections relating to each network tariff.

Appendix A.1 What does efficient charging mean?

The NER state that our network charges for each customer should reflect TasNetworks' efficient costs of providing these services to that customer, meaning that the network charges for each of our services must be based on the LRMC[66] of providing the service to the retail customers assigned to the tariff.

The difference between LRMC driven costs and our allowed revenues are our residual costs (Figure 61).

Figure 61. Long run marginal cost and residual cost



However, if we set charges based only on our LRMC, we would not recover the required revenue. Therefore, to minimise distortions to our charging signals, the residual cost is equal to the total efficient cost[66] of that tariff.

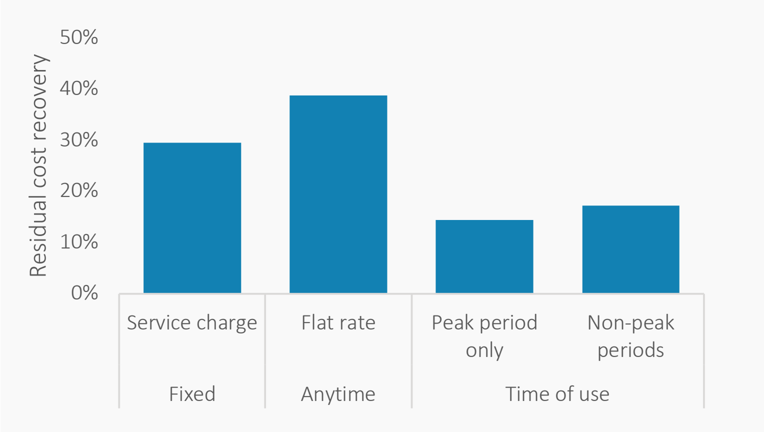
This approach means that our most efficient network charges – demand charges and peak consumption charges[67] – most closely reflect the LRMC estimate for those tariffs. Our least efficient network charges are anytime charges, these are reflected in our flat rate tariffs.

We have sought to allocate our residual costs – the difference between the LRMC-driven costs and our allowed revenues – in a manner that minimises distortions to efficient charging signals and encourages opt-in uptake to our cost-reflective tariffs. Figure 62 shows that where the charging parameters are not closely linked to the drivers of TasNetworks' costs, a higher allocation of residual costs is apparent, for example with our flat rate tariffs.

66 The methodology for calculating the LRMC is provided in TasNetworks' Distribution Pricing Methodology

67 LRMC are signalled through the more cost-reflective charging parameters which most closely relate to time of high network utilisation

Figure 62. Allocation of residual costs by charge category



How we apply efficient charging to our tariffs

Our tariffs are designed to align with the Rules' requirement that tariffs be based on LRMC and the recovery of our TEC. However, a different approach is taken for legacy tariffs compared to newer more cost reflective tariffs.

- **Legacy tariffs:** Legacy tariffs include our residential general light and power, plus the heating and hot water (TAS31/41), and our small business general light and power (TAS22) tariffs. These tariffs have been available to customers for a long period of time and exhibit varying degrees of cost reflectivity. We are gradually transitioning these tariffs towards full cost reflectivity across multiple regulatory control periods thereby minimising price shocks to our customers. Each year we incrementally transition our legacy tariffs closer to the target of cost reflectivity. We aim to have these tariffs fully aligned to their respective time of use tariffs by the end of the 2024-2029 regulatory control period.
- **New tariffs:** Any network tariffs recently introduced by TasNetworks have been designed to have a high degree of cost reflectivity from the outset. To encourage customer uptake of our more cost reflective tariffs, we have historically provided customers with a discounted price point. This is a transitional approach that has applied for demand based tariffs introduced during the 2019-2024 regulatory control period.

Appendix A.2 What does cost reflectivity look like?

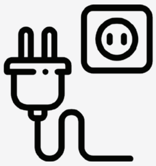
When designing a new tariff, we determine the costs to be recovered from the tariff class, and design the charging parameters within a tariff, in order to reflect the long-term costs of providing that service to our customers. Effective price signalling is a consideration in the tariff design which includes understanding our customers' use of electricity and cost that use has on the network.

The charging parameters of our network tariffs are designed to:

- Recover revenue from our tariff classes that reflect the costs of providing services to customers within those tariff classes
- Send a price signal to customers about the cost of their use of the network through the selection of appropriate charging parameters.

Our network tariffs may include some or all the following components:

Figure 63. Network tariff components



Service charge

This charge relates to the connection to the grid. It is the ability for customers to receive energy.

Capacity charge

The maximum rate energy is used at the connection point. It refers to the maximum demand at a point in time (KVA).

Demand charge

Reflects the rate energy is used. It is measured using maximum demand at point(s) in time over a defined period (KVA or kW)

Consumption charge

Refers to the amount of energy used and is liked to a cost per unit of energy consumed over a period of time (kWh).

Within the consumption and demand components of a network tariff, there may be different tariff parameters to reflect customers' usage and their impact on the network, for example:

- Seasonality
- Anytime usage charges
- Maximum demand
- Specified demand
- Time of use.

These components of our network tariffs allow us to offer prices which are lower at times of spare capacity and higher prices at time when there is greater demand for electricity. Time of use reflects the potential investment required in the network during periods of high demand. The setting of time periods are referenced to system load profiles for the electricity network as a whole.

Setting demand charges with reference to the LRMC

The demand charge component of a network tariff is based on the LRMC calculated at the voltage level (for example, high voltage and low voltage), which is then applied to our tariffs. Our LRMC is determined by forecasting demand as well as forecast augmentation and relevant replacement capital expenditure[68].

Where we have been able, we have set the demand component of our network charges at, or approaching the LRMC for the relevant tariff class. The cost components of the estimates have been developed utilising the ten-year Program of Work (**PoW**) forecasts. The PoW forecast include the projects that are related to augmentation of the network as they relate to increasing capacity as well as a proportion of forecast replacement expenditure (**repex**), plus associated incremental operating expenditure (**opex**). Further information on how we have derived our LRMC is found in our Distribution Pricing Methodology.

The use of Total Efficient Cost in our tariff setting process

The total efficient cost methodology is used to determine the proportion of TasNetworks' total annual revenue requirement to be recovered from each network tariffs in a manner which reflects the cost of supplying customers who are using these tariffs. Transitioning tariffs towards full TEC recovery provides customers with efficient price signals and removes cross-subsidies within TasNetworks' suite of networks tariffs.

For the upcoming 2024-2029 regulatory control period, TasNetworks' TEC model:

- sends a clear and transparent price signal to our customers
- better capture where costs occur on the network
- increase TasNetworks' ability to fulfil our obligations to energy reform
- remove complexity and allow for the transparent allocation of costs
- respond to innovation
- manage impacts to customers.

The revenue is allocated to tariff classes and ultimately onto individual tariffs for each network level, by considering which tariff class uses which part of the network.

68 The methodology for calculating the LRMC is provided in TasNetworks' Distribution Pricing Methodology

Appendix A.3 Treatment of transmission costs

Transmission related costs are allowed to be recovered from our distribution customers. TasNetworks recovers a proportion of these costs in recognition of the distribution customers' use of the transmission assets for their power supply.

These are referred to as transmission use of system (**TUOS**) charges and are incorporated into all network tariffs. TUOS charges are generally recovered through the same tariff parameters as our distribution revenue[69] and the same tariff setting approach (as outlined in Appendix A.1 and Appendix A.2) is applied. The only exceptions are our high voltage business tariffs TAS15 and TASCUS1 for which locational TUOS charges are applied to enhance the cost-reflectivity of the price signals.

69 TUOS charges are not recovered through TasNetworks' Service Charges

Appendix B – Engaging customers in our pricing plan and tariff designs

To develop our pricing strategy for the 2024-2029 regulatory period, we have engaged extensively with a range of external stakeholders, including retailers, end-use customers and their advocates, regulators and government bodies. We have done this to understand their preferences and seek their input 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 PRWG. The group includes representatives from business and industry, the community sector, the electricity industry and renewable energy advocates.

Our initial engagement with the PRWG involved the design of our pricing principles. These principles guide the development of our network tariffs and products, which help us refine our service offerings to ensure customer expectations are met. Over the past 18 months we have held seven stakeholder workshops and published seven reading packs which provide information on the changes which have been occurring in the network, customer behaviour and market trends.

The following table summarises each of the PRWG engagement workshops conducted to date in support of the development of TasNetworks' regulatory proposal for the 2024-2029 regulatory control period.

Table 13. PRWG engagement and outcomes

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
4 June 2020	The key purpose of the June forum was to collaborate on TasNetworks' pricing principles. The forum focussed on two key areas, customer engagement and pricing. The first half of the forum provided an overview of key customer engagement trends and TasNetworks' Revenue Reset engagement roadmap. The second half of the forum took a deep dive into TasNetworks' pricing principles. The forum concluded with an introduction on a new TasNetworks business initiative, the Customer Outage Review.	• Industry engagement trends and best practice, presented by Energy Consumers Australia (ECA). • Revenue Determination 2024-2029, timeline and milestones and engagement approach. • Activity – pricing principles collaboration.	PRWG engagement forum held via Skype	Members provided feedback on our draft pricing principles. From this feedback, we shaped our pricing principles for the 2024-2029 regulatory period.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
20 October 2020	The forum focussed on TasNetworks' pricing strategy, progress to date, barriers to the uptake of cost reflective tariffs and the emergence of CER. The first half of the forum focussed on the rollout of advanced meters and the uptake of cost reflective tariffs. Members were then asked to provide their input on what the barriers are to customers moving to cost reflective tariffs. The second half of the forum discussed the growth of CER, such as solar PV, electric vehicles and batteries, and the impact and opportunities on the Tasmanian distribution network. Following this, members were asked for their input on what they perceive are the key challenges of CER on the network.	• Purpose and objectives of pricing strategy engagement. • Pricing strategy re-cap: update on rollout of advanced meters and uptake of cost reflective tariffs. • Engagement activity – what are the barriers to TasNetworks' achieving its pricing strategy and why / how can we reduce these barriers? • Growth, opportunity and impact of CER. • What are the challenges of CER on the network and how can TasNetworks work with stakeholders to develop pricing options in response to the emergence of CER?	PRWG engagement forum held via Zoom	• TasNetworks shared the finalised pricing principles to complete the pricing principles development engagement. • Members provided key insights on how TasNetworks can achieve its pricing strategy. Feedback focussed on customer engagement and information provision relating to financial benefits of ToU pricing. • Members discussed a range of opportunities and impacts of DER. The feedback was varied but an underlying theme was that CER such as solar, especially in Tasmania, solely benefits the individual consumer (rather than the network or wider community) and so should be priced accordingly. • Members also requested further information from TasNetworks in the form of background information papers and releasing these to the wider public for further community consultation.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
3 March 2021	The forum objective was to determine whether there are any changes needed to our network tariff assignment policy. The forum's purpose was to continue the development of TasNetworks' 2024-2029 distribution pricing strategy and to demonstrate the pace of network tariff reform both in the NEM and Tasmania. Further, to identify and understand whether there are barriers that may be impacting the pace of reform in Tasmania, including: • understanding the impact of network charges on customers • determining whether there is a need to incentivise certain customer groups to take-up cost reflective network tariffs • whether changes to the network tariff assignment policy can assist with increasing the uptake of cost reflective network tariffs.	• Residential customer analysis • Residential engagement activity • Small business customer analysis • Small business engagement activity • Customer education engagement activity	PRWG engagement forum held face-to-face.	• The PRWG determined that a change is required to TasNetworks' tariff assignment policy for 2024-2029 to incentivise the take-up of cost reflective network tariffs, however the pace of change is yet to be decided. • PRWG members discussed the option of making the flat rate network tariff obsolete for both residential and small business customers over the next 5 – 10 years. • To determine the pace of this change, members noted that further information would assist in understanding customer impacts. • Members also discussed the option of introducing a discount for residential customers on the ToU network tariff relative to the flat rate network tariff but determined that quantification of the benefits of such a discount was required to better understand this option.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
1 July 2021	The workshop's objective was to demonstrate the trends TasNetworks is seeing on the network and understand customers' preferences in relation to using network pricing to facilitate increasing levels of DER technology and embedded networks. In particular, the forum centred on a discussion about TasNetworks' network tariff assignment policy, options for tariff trials and the potential introduction of an embedded network tariff in 2024-2029.	• Tariff assignment policy discussion – making the flat rate network tariff obsolete • Tariff trial options and co-design of principles governing any trial(s) • Embedded network discussion, including designing an embedded network tariff	PRWG engagement forum held face-to-face.	• The PRWG determined that a change is required to TasNetworks' tariff assignment policy in the next regulatory period to account for the growing uptake of DER, particularly EVs. • Three triggers were identified by the PRWG for making flat rate network tariffs obsolete for residential and small business customers: (1) new builds, (2) new connections when a customer moves into a property where the previous resident was on a ToU network tariff, and (3) when a customer chooses to move onto a ToU tariff (and is not permitted to revert back to flat rate). • Identified customer protections, include a cooling off period (potentially to first bill), better visibility of usage and differentiating between customers who choose to move onto a ToU tariff and just choose to change their meter. • Together with TasNetworks' representatives, the PRWG co-designed a set of tariff trial principles. • A number of tariff trial opportunities were identified for 2024-2029, including trials of export charging, community batteries and EVs. • Discussion was commenced regarding a possible network tariff for embedded network operators, with the PRWG indicating a preference for a capacity-based network tariff structure.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
16 November 2021	The purpose of the forum was to engage with PRWG members on aspects of TasNetworks' pricing strategy for the regulatory control period beginning on 1 July 2024 and ending 30 June 2029. Specifically, the workshop considered: • network tariff options that could better reflect the value of network connection for embedded networks • alternative time-of-use windows for the TAS94 small business network tariff • findings from a survey of customers with Consumer Energy Resources • possible revisions to TasNetworks' existing CER network tariff that might better suit the behaviours and needs of prosumers.	• Engagement roadmap • Embedded network tariffs • Reviewing time of use windows • Prosumer network tariff • Network tariff assignment rules	PRWG engagement forum held face-to-face, in conjunction with a meeting of TasNetworks' Customer Council. Topics relevant to both groups were explored in a joint session.	• A capacity charge was assessed by PRWG members as being a good means of applying, or passing-through, cost-reflective network charges to embedded network tenants. • The PRWG was supportive of the concept of a capacity-based charge as part of a network tariff designed specifically for embedded networks, although there was some support for the use of a smaller number of wider/less granular capacity allowances than the five-tier structure presented to the Group. • Concerns were expressed by PRWG members about perpetuating any current inequities if existing embedded network customers are allowed to remain on a less appropriate network tariff once an embedded network tariff had been introduced. • Of four alternative changes to the TAS97 network tariff for customers with CER put forward to the PRWG, extending the evening peak period emerged as the group's preferred option, ahead of extending the morning peak period and extending the duration of the average demand windows. • Feedback previously provided by the PRWG about the triggers for the default assignment of residential customers to time of use consumption-based network tariffs has been considered by TasNetworks' wider stakeholder base and used to shape the assignment rules that are to be proposed in TasNetworks' Tariff Structure Statement for 2024-2029.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
7 April 2022	The purpose of the forum was to ascertain PRWG members' preferences regarding network pricing to facilitate increasing levels of technology and embedded networks, and inform the PRWG of proposed changes to TasNetworks' connections policy and alternative control services for the 2024-2029 regulatory control period. The workshop's objectives were: • to build understanding amongst the PRWG of alternative control services and seek the group's input on TasNetworks' proposed metering services strategy • to present and consult on the revised tariff structure of TasNetworks' CER demand-based time of use network tariff • to inform and consult with the PRWG regarding revisions to the time of use periods applying to the small business time of use network tariff by TasNetworks • to confirm the approach being taken by TasNetworks' in developing a network tariff for embedded network operators • to seek PRWG endorsement of TasNetworks' proposed export tariff trial engagement.	• Alternative Control Services • Consumer Energy Resources • Export services • Small business time of use peak windows • Embedded network tariffs	PRWG engagement forum held face-to-face. In addition to members of the PRWG, officers from the AER and members of the AER's Consumer Challenge Panel attended the meeting in an observational capacity.	• PRWG members supported TasNetworks' proposal to fully recoup the remaining capital cost of its superseded accumulation meters by the end of 2028-29, instead of continuing the current rate of recovery that would take until 2030-31. It was agreed that this approach would better align the cost recovery with the reduced service life of the meters, while still delivering a reduction in the level of metering charges for customers. • A member of the PRWG suggested more wide-spread use of estimated meter reads by TasNetworks, as a means of reducing meter reading costs in the face of declining numbers of legacy meters and declining economies of scale as the rollout of advanced meters by electricity retailers in Tasmania continues. • A number of PRWG members expressed support for the use of a demand threshold as part of network tariffs applying to customers with CER, as a means of discouraging consumer behaviour that creates new peaks in demand in what are currently off-peak periods for the network. • In relation to TasNetworks' existing network tariff for customers with CER, PRWG members did not support either continuation of the existing tariff structure (but with extended peak period duration), or the use of an **ATMD** charge. Support was divided between two alternative modifications to the design of the CER tariff, with the introduction of a demand threshold and excess demand applying throughout the day rated by the group as the preferred option.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
				• It was noted that TasNetworks does not intend introducing an export tariff in the next regulatory period, but intends conducting a tariff trial in the next regulatory period. • PRWG members indicated a preference for preserving the existing relativities when setting the peak, shoulder and off-peak prices for small business customers on the small business time of use network tariff. • Any embedded networks tariff introduced in the coming regulatory period will only apply to new embedded networks. Existing embedded networks would also be able to switch to the new tariff on an opt-in basis, however won't be able to switch back to a non-embedded network tariff once assigned to a network tariff for embedded networks.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
16 August 2022	The purpose of the forum was to conclude discussions about the new network tariffs being proposed for the 2024-2029 regulatory period for embedded network operators and residential customers with CER, to test proposed improvements in the way TasNetworks prices quoted services and seek PRWG advice about the topics of importance to customers in relation to network tariff reform. Representatives of the AER were also in attendance to provide PRWG members with an overview of the Regulator's role in setting distribution network pricing.	• The role of the AER in price setting • Standard control services • Engaging with our customers • Alternative control services	PRWG engagement forum held face-to-face. In addition to members of the PRWG, officers from the AER attended the meeting in person and online.	• PRWG members were accepting of the analysis of residential customers' time of use metering data undertaken by TasNetworks to arrive at the proposal for an anytime maximum demand threshold of 8.5kW to apply to customers assigned to the residential CER network tariff in the 2024-2029 regulatory control period. • It was noted that if, approved by the AER, the proposed network tariff would be available to customers on an opt-in basis, as an alternative to the default residential network tariff applying in the 2024-2029 regulatory control period. • A proposal to reduce the number of labour categories used to price the delivery of quoted services from 16 to eight was generally supported by the members of the PRWG attending the workshop. • A proposal to reduce the number of labour categories used to price the delivery of quoted services from 16 to eight was generally supported by the members of the PRWG attending the workshop. • PRWG members rated the proposal to reduce the number of labour categories used to price quoted services highly against three of the pricing principles developed by the PRWG: Fairness, Simplicity, and Consistency. • It was noted that the methodology used to price quoted services is designed with competitive neutrality in mind, with the AER looking to ensure that the prices charged are both cost-reflective, consistent and transparent.

Meeting	Forum purpose	Agenda	Form of engagement	Engagement outcomes
				• The PRWG members in attendance were fundamentally supportive of a proposal to discontinue the practice of applying rebates to the cost of relocating assets based on the age of the assets being removed, in the interests of improving customer equity and providing a more cost-reflective, efficient price signal to parties that request asset relocations in the future. • It was noted that TasNetworks does not stand to receive more income from the relocation of network assets as a result of the change, but that the change result in those requesting asset relocations paying the full cost or removing and replacing the assets. • The change will increase the cost of asset relocations for the customers/third parties that request them, although the overall cost to TasNetworks of removing assets and relocating network infrastructure will be unaffected. • To guide TasNetworks' customer communications in the future, PRWG members were asked to vote for the issues which they considered would be of the greatest relevance to end-use customers in the coming regulatory control period. Four topics were voted as the topics having the greatest importance: ` - advanced meters - time of use tariffs - pricing principles - obsolete network tariffs.

Not all customers want the same things from their electricity network, nor do stakeholders always agree on the actions they think TasNetworks should take in relation to a particular issue. Through our engagement activities we have tried to capture feedback from a diverse range of customers and stakeholders. The following table summarises the key questions and suggestions raised by members of TasNetworks' PRWG regarding issues relevant to TasNetworks' regulatory proposal for the 2024-2029 regulatory period.

Table 14. Issues raised by customers

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Information provision	Customers need more information to make a decision on which tariff option best suits their needs. Information needs to provided during the meter change process, with a call to action regarding tariff choice. Working together on local research on effective customer education and understanding customer behaviour in response to tariff options. Provision of data and information on usage and trends.	TasNetworks will provide further background papers to the PRWG and wider public to facilitate further community consultation.	PRWG members	20 October 2020	Policy and Regulatory Working Group
Financial benefits of ToU tariffs	There is an opportunity to provide customers with information on the most appropriate ToU tariff, including: • more data on customer's usage of electricity on a ToU basis and evidence that time of use is of benefit • more education required on different tariff types	TasNetworks provided PRWG members a response regarding the research on the benefits of cost reflective network tariffs at the following PRWG in March 2021. TasNetworks stated that the rollout of advanced meters was providing better insights into customers' network usage. TasNetworks has agreed to develop complementary measures to keep customers better informed.	PRWG member	20 October 2020	Policy and Regulatory Working Group
Simple language	Information shared with customers regarding the best tariff option for them should be provided in simple, easy to understand language. More information on what tariff options could be provided in association with relatable customer groups, i.e. large, working family or stay at home couple.	Feedback shared with retailers.	PRWG member	20 October 2020	Policy and Regulatory Working Group

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
CER	Customers without CER shouldn't be disadvantaged. The CER input should be of prime benefit to the owner. TasNetworks needs to understand the drivers of customers considering CER and the impact on the network of a CER. Lack of understanding of localised value of CER, otherwise it costs to use the network – change the mentality.	TasNetworks agrees that continued monitoring of network utilisation is required to better understand localised issues relating to CER.	PRWG member	20 October 2020	Policy and Regulatory Working Group
CER Network Impact	The world is changing. The use of solar PV micro-embedded generation is increasing, and TasNetworks needs to manage the current network but also understand what the network will look like in 2050. TasNetworks needs to plan for this network and understand how trials, such as the Bruny Island Battery Trial, would be possible on the wider network.	Future-ready pricing structures.	PRWG members	20 October 2020	Policy and Regulatory Working Group
Public engagement	TasNetworks needs to consult extensively. Seeking public submissions would be one way of getting more stakeholders involved and help TasNetworks get more 'buy-in' and acceptance of its plans for the coming regulatory control period. To this end TasNetworks should develop various scenarios, with case studies, publish them and then have lots of meetings/consultations.	TasNetworks will provide further background papers to the PRWG and wider public for further community consultation.	PRWG members	20 October 2020	Policy and Regulatory Working Group
Network benefits of ToU	Members requested information from TasNetworks that would explain the network impact of a 20 per cent reduction in peak demand by residential customers, to help quantify the benefit of making changes to TasNetworks' tariff assignment policy (i.e. making the flat rate network tariff obsolete).	TasNetworks committed to providing this information at the next PRWG (June 2021).	PRWG member	3 March 2021	PRWG, March 2021

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Tariff assignment	TasNetworks' tariff assignment policy should be changed for 2024-2029 to incentivise the uptake of cost reflective network tariffs, however the pace of change is yet to be decided.	Tariff assignment policy information will be provided to our customers to help them understand the pace of tariff reform. Changes to our assignment rules to be shared 16 November 2021.	Consensus throughout PRWG group	3 March 2021	PRWG, March 2021
Engaging with customers	In order to engage with customers, TasNetworks should consider using representative bodies to access distinct customer groups.	TasNetworks will consider how to best utilise representative groups as part of its forward engagement strategy.	PRWG member	3 March 2021	PRWG, March 2021
Pricing strategy	There was strong consensus from within the group that a change is required to TasNetworks' pricing strategy to prepare for the significant uptake of CER likely in the next regulatory period. This includes changes to TasNetworks' tariff assignment rules, tariff trials and the introduction / revision of new CER tariffs.	Response to be shared at 16 November 2021 workshop.	Consensus view amongst PRWG members	3 March 2021	PRWG, March 2021
Tariff assignment	Members indicated a preference to include customer protections when making any changes to tariff assignment rules that make flat rate network tariffs obsolete, including a cooling-off period.	Incorporated in our proposed assignment rules. 12-month cooling off period applied to customers who are placed on ToU Consumption due to advanced meter installation (as opposed to new connections). Shared 16 November 2021.	General consensus from the group	1 July 2021	PRWG, July 2021
Tariff assignment	Another customer protection was differentiating between choosing to go on a ToU network tariff and choosing just to go on an advanced meter.	Incorporated in our proposed assignment rules. A 12-month cooling-off period will be applied to customers who are placed on a ToU consumption-based network tariff due to advanced meter installation (as opposed to new connections). Shared with the PRWG on 16 November 2021.	PRWG member	1 July 2021	PRWG, July 2021
Tariff trials	Members opined that any trials conducted by TasNetworks must have a clear intent and purpose defined prior to starting the trial.	This point has been addressed in the co-designed tariff trial principles developed in conjunction with the PRWG.	PRWG members	1 July 2021	PRWG, July 2021

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Tariff trials	Members indicated a strong preference for TasNetworks to explore trial opportunities related to community-batteries. Members shared that this would allow a wider range of customers to share in the benefits of renewable energy technology.	TasNetworks is exploring options for a community battery trial in 2024-2029.	PRWG members	1 July 2021	PRWG, July 2021
Embedded Networks	Members shared a preference for TasNetworks to explore a capacity-based tariff structure for any purpose-designed embedded network tariff.	TasNetworks will present capacity charge options for consideration by the PRWG at the 16 November 2021 workshop.	General consensus from the group.	1 July 2021	PRWG, July 2021
Relationship between tariff reform and service classification	A question was raised regarding the linkage between the tariff change proposals which the PRWG was being asked to consider and changes to TasNetworks' framework and approach which had been proposed to the AER by TasNetworks.	It was explained that the two issues are not directly related. The processes for developing and approving the tariffs used to recover the cost of providing services is not part of the framework and approach setting process.	PRWG member	16 November 2021	PRWG, November 2021

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Embedded networks	One stakeholder questioned the need to recover a greater contribution towards the cost of the shared network from embedded networks than would result from the application to an embedded network operator of the network tariffs that are currently applied to individual residential or small-business customers. It was suggested by that stakeholder that this scenario would be at odds with the reduction in costs for networks (and retailers) associated with the presence of embedded networks, and that any reduction in costs for the network should be reflected in the network tariffs applied to embedded networks.	When the PRWG first considered the issue of equity in relation to embedded network operators, the Group agreed that having embedded networks pay the same network service charges as a residential customer was not equitable. In the interests of greater cost reflectivity and, therefore, equity, it may also be appropriate for any embedded network tariffs to distinguish between embedded networks connected at low and high voltages – noting that residential customers and most small businesses are connected at low voltage, and to apply the same network tariff to an embedded network operator taking supply at high voltage would exacerbate any inequity. TasNetworks concurs with comments made to the PRWG by the AER that cost-reflectivity is a principle the AER likes to adhere to in relation to embedded networks, and on that basis, TasNetworks maintains the position that embedded networks should face network pricing similar to that which is applied to customers with similar connection characteristics and load profiles.	PRWG member	16 November 2021	PRWG, November 2021

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Embedded networks	A member of the PRWG questioned why the operator of an embedded network would voluntarily opt-in to an embedded network tariff arrangement involving higher network charges than those applied to single residential customers, and that this called into question the need for a network tariff specifically for embedded networks. The down-stream customers of embedded networks were also characterised by the PRWG member as being vulnerable, the implication being that a greater contribution towards the cost of the shared network from embedded network operators would be passed on to those vulnerable 'tenants' by the owner/operator of the embedded network.	At the time of the query, TasNetworks was continuing to develop its thinking in relation to embedded networks and remained open to alternative arguments, including the possibility that there may not be sufficient demand for a network tariff specifically designed for embedded networks to warrant its development. Consideration to date in relation to embedded network tariffs has focussed on new connections with a view to the tariff being the charging mechanism for these new customers, while remaining opt-in for existing customers. As noted by several stakeholders, there is an equity issue with the current arrangements, which don't distinguish between an embedded network that supplies multiple downstream customers and a stand-alone single customer with their own network connection, with the biggest beneficiaries of this imbalance being larger embedded networks. It was suggested by one stakeholder that applying embedded network tariffs to larger commercial enterprises operating embedded networks would help protect customers in vulnerable situations.	PRWG member	16 November 2021	PRWG, November 2021
Embedded networks	Should TasNetworks introduce a network tariff(s) specifically for the operators of embedded networks, and were that network tariff to be based on a number of tiered 'capacity allowance', a query was received regarding how often customers on such a network tariff would be able to change their nominated capacity level.	It was noted that business customers assigned to TasNetworks' existing 'specified demand tariffs' are permitted to request a mid-year change to their nominated demand once a year, in addition to the process of annual review. TasNetworks will take into account the PRWG's feedback when designing the terms and conditions applying to any network tariff proposed specifically for embedded networks operators.	PRWG member	16 November 2021	PRWG, November 2021

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Small business time of use windows	The PRWG accepted the position presented by TasNetworks that the time of use periods applying to the consumption-based time of use tariff for businesses (TAS94) could be better aligned to reflect the collective load profile of the customers on that network tariff and times of high network utilisation. Of the three options put-forward to the PRWG by TasNetworks to gauge support for revised time-of-use windows for the TAS94 tariff, an option involving removal of the weekend shoulder period which is part of the current tariff design was considered to align well with the load profile of typical business customers, although for different reasons all three options received not dissimilar overall levels of endorsement.	TasNetworks has incorporated the PRWG's feedback into the small business time of use network tariff being proposed for the 2024-2029 regulatory control period.	PRWG members	16 November 2021	PRWG, November 2021
Legacy metering	A member of the PRWG suggested the more wide-spread use by TasNetworks of estimated meter reads, as a means of reducing meter reading costs in the face of declining numbers of legacy meters. Estimated meter reads were employed early in the Covid-19 pandemic and, for customers on a quarterly billing cycle, two estimated reads could be used per annum, alternating with meter reads.	The scope for TasNetworks to use estimated meter reads under the current rules is not clear and would need to be investigated before contemplating such a course of action. Estimated meter reads can also sometimes lead to bill shocks when trued-up by subsequent meter reads, in cases where an estimated meter read materially understated a customer's consumption of electricity. Self-reading of meters by customers is another alternative to site visits by a meter reader that is sometimes used in order to reduce the scope for a customer to receive a bill from the retailer based on an inaccurate estimate.	PRWG member	7 April 2022	PRWG, April 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Demand thresholds	When considering potential demand-based elements of network tariffs designed for customers with CER, members of the PRWG sought clarification of whether TasNetworks could cut a customer's supply off if they exceeded a certain level of demand.	There is currently no network tariff under which TasNetworks disconnects customers if they exceed a particular load. Some tariffs, such as the high voltage specified demand tariffs applying to some business customers, impose higher demand charges if customers exceed their nominated maximum demand. But the customer is not disconnected or their load restricted. Any demand threshold applying to a revamped network tariff for customers with CER would need to be determined in conjunction with TasNetworks' engineering teams and draw on analysis of customers' loads. This includes consideration of minimum demand due to solar exports, although – unlike some distribution networks in other states – Tasmania is yet to experience the situation where exports of energy by customers exceed minimum levels of demand on the network.	PRWG member	7 April 2022	PRWG, April 2022
Primary versus secondary tariffs	Are the CER tariffs being considered intended to be primary or secondary network tariffs, in the way that the space heating and hot water tariff (TAS41) has been a secondary tariff to the general network tariffs applying to residential customers and small businesses?	If a customer opts-in or is assigned to a CER network tariff, that tariff will apply to the customer's entire load profile.	PRWG member	7 April 2022	PRWG, April 2022
Time of use tariffs and daylight savings time	How do the time of use periods associated with any of the CER tariff options under consideration interact with Daylight Savings in Tasmania?	The network is operated, and network tariffs time of use periods framed with reference to Australian eastern standard time.	PRWG member	7 April 2022	PRWG, April 2022
Tariff trials and CER tariffs	Does TasNetworks intend making changes to the existing CER tariffs in the next regulatory control period, based on the feedback it receives from the PRWG, or is it TasNetworks' intention to merely conduct a trial of those changes?	TasNetworks' intention is to make changes to the existing CER tariffs in the next regulatory control period, not to conduct a trial of those changes.	PRWG member	7 April 2022	PRWG, April 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Export tariffs	Does TasNetworks intend introducing an export tariff in the next regulatory control period?	TasNetworks does not intend introducing an export tariff in the next regulatory control period, as CER take-up levels in Tasmania lag behind the levels in other states where export-driven network issues are being experienced. TasNetworks may conduct a trial of an export tariff in the next regulatory control period, as well as draw on the experience of other jurisdictions. Tasmania is not yet facing the imbalance during the middle of the day between renewable energy production and the demand for electricity that is being experienced in other states and territories, which lessens the impetus for the introduction of export charges.	PRWG members	7 April 2022 16 August 2022	PRWG, April 2022 PRWG, August 2022
Export tariffs	When the prospect of export charges, as a result of changes to the National Electricity Rules to recognise the provision of export services by networks, was first announced, the announcement attracted a lot of negative publicity. The messaging about not introducing an export tariff in the next regulatory control period needs to be communicated to customers and stakeholders by TasNetworks.	TasNetworks accepts the advice from the PRWG in relation to the sensitivities surrounding export charges and will focus in the immediate term on the rationale, if any, for export tariffs to be potentially introduced, which may justify a two-way pricing, export tariff trial being undertaken in the 2024-2029 regulatory control period.	PRWG member	7 April 2022	PRWG, April 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Export tariffs	Why should embedded generators pay export charges when large generators connected to the transmission network do not?	The introduction of export charges for embedded generators connected to the distribution network is not necessarily just about charging for exports, and there is the potential for export pricing to be used to encourage and reward exports in certain circumstances, such as a times of peak demand on the network. Further, generators face different charges and revenues depending on whether they connect to a transmission network or a distribution network. They also receive different levels of service. Unlike embedded generators, large transmission connected generators do not have 'firm' access to the network in order to export the energy they produce, having to be 'dispatched' by the Australian Energy Market Operator before they can inject energy into a transmission network. In this sense, the network service being provided to embedded generators and large generators supplying the wholesale market could be said to be quite different. Generators connected to a transmission network also typically have to pay for any dedicated connection assets, which can include a length of transmission line linking the generator with the backbone network if there are no other generators or load customers connected to that line.	PRWG member	7 April 2022	PRWG, April 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Time of use pricing	Some PRWG members support the use of stronger network pricing signals (in terms of the differential between peak and off-peak network charges), in the interests of preserving the pricing signal by the time if flows through into retail pricing. Alternatively, other PRWG members expressed the view that stronger pricing signals may not sit well with many small businesses, which may have limited capacity to move their time of use.	This was noted at the meeting, and it was agreed that a fair pricing signal, consistent with the PRWG's voting outcomes, would be developed.	PRWG members	7 April 2022	PRWG, A pril 2022
Quoted service labour rates	Over 85 per cent of the local governments polled supported a reduction in the number of labour categories used by TasNetworks to build quoted services pricing for the coming 2024-2029 regulatory period. Council stakeholders considered that reducing the number of labour categories would make it easier to achieve pricing consistency between similar jobs and between customers and make it easier for customers to understand what they are being charged. Members of TasNetworks' PRWG were also broadly supportive of the proposal, considering that it would deliver improvements in fairness, simplicity and consistency.	TasNetworks noted the feedback received and will be proposing a reduction of quoted service labour categories for the 2024-2029 regulatory control period.	Local governments PRWG	19 May 2022 16 August 2022	Online council forum PRWG, August 2022
Public lighting	Over 90 per cent of councils polled supported a proposed strategy to replace all legacy public lights with LED fittings.	TasNetworks noted the feedback received and will progress the strategy to replace all legacy public lights with LED fittings.	Local governments	19 May 2022	Online council forum
Advanced metering	Do customers pay for the replacement of their accumulation meters with advanced meters?	Meters are changed over by retailers, not TasNetworks, with any cost recovery managed by the retailer.	Local governments	19 May 2022	Online council forum

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Demand charges	Is TasNetworks looking to apply a flat fee based on the maximum kW drawn in a month? This would be a disincentive to the adoption of electric vehicles.	The proposed residential CER tariff is predominantly a consumption-based tariff with a demand threshold. The demand charge will only be charged if the customer exceeds the threshold. The pricing arrangements of this tariff are yet to be finalised, but it is likely that the demand charge will be based on the daily ATMD where it exceeds the threshold, noting that the customer would only pay for the difference between the threshold and the ATMD. E.g., if the threshold is set of 7kW and the customer's ATMD for a particular day is 7.5 kW, they would be charged an excess demand charge for the day based on the 0.5 kW by which the threshold was exceeded.	Local governments	19 May 2022	Online council forum
Demand charges	What sample size was used by TasNetworks in its analysis of minimum and maximum demand amongst residential customers that informed the proposed ATMD threshold of 8.5 kW proposed for the residential CER tariff?	There was no sampling used, in that load data for every residential customer with an advanced meter was included in the analysis (noting that approximately 40 per cent of residential customers currently have advanced meters). The measurement of maximum demand is based on average demand over 30 minute intervals as the advanced meters in use in Tasmania record usage (i.e. consumption) over 30 minute intervals, which can then be converted into a demand figure for that interval.	PRWG member	16 August 2022	PRWG, August 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Demand charges	Given the lack of customer familiarity with the concept of demand, will customers assigned to the proposed network tariff for residential customers with CER be understood by customers?	The tariff is to be made available on an opt-in basis, targeting prosumers, who tend to be more heavily engaged in managing their energy use and interested in the technology to do so, and are likely to be more able to understand the different elements of the proposed network tariff. There are also two elements to the pricing principle in the Rules regarding understanding of network tariffs: a requirement that customers be able to understand a network tariff and/or that a retailer is able to incorporate the network tariff into their retail offering.	PRWG members	16 August 2022	PRWG, August 2022
State Government policy and network pricing	Questions were received about the interaction between State Government policy and the AER's regulatory determinations.	The AER is an independent economic regulator. The network revenues set by the AER are an input cost of retail electricity prices and are levied on all retailers with customers in Tasmania. In setting the standing offer tariffs applying to residential and small business customers who have not opted-in to a market offer, the Tasmanian Economic Regulator is effectively setting the retail price of electricity, of which network charges are but one component.	PRWG members	16 August 2022	PRWG, August 2022

Theme	Customer feedback	TasNetworks' response	Raised by	Date raised	Forum
Pricing signals	What means exist to compel retailers to incorporate the cost reflective network tariffs that TasNetworks has collaboratively developed with customers into their retail tariffs if a retailer doesn't want to do so?	Retailers are not economically regulated by the AER in the same way that the AER sets network revenues and approves network prices. There is nothing (in a regulatory sense) to prevent retailers from offering flat retail tariffs. As long as TasNetworks is giving an efficient pricing signal in relation to use of the network the AER has no problem with retailers continuing to offer flat tariffs. There is no longer just one retailer servicing residential and small business customers in Tasmania and competition can encourage innovation. When the number of customers assigned to cost reflective network tariffs reaches sufficient levels, experience interstate suggests that retailers will incorporate these network price signals into their retail tariffs.	PRWG members	16 August 2022	PRWG, August 2022
Obsolete network tariffs	Noting plans to make a number of flat consumption based network tariffs obsolete during the coming regulatory control period and transition customers to time of use tariffs, customers need to know that they're going to be transferred to new tariffs and the opportunities and risks this presents.	The phasing out of existing network tariffs, particularly any that may have been in use for some time, is acknowledged by TasNetworks and the PRWG as one of the key communication issues identified for the coming regulatory control period.	PRWG members	16 August 2022	PRWG, August 2022

TasNetworks

Powering a
Bright Future

Combined Proposal 2024-2029

Attachment 23
List of supporting documents

TasNetworks | Powering a Bright Future

Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	**List of supporting documents**
Attachment 24	Glossary

23 List of supporting documents

Primary Attachments

Doc ID	Author	Title	Date	Public/ confidential
TN001	TasNetworks	TasNetworks-Combined Proposal Overview-Jan-23-Public	Jan-23	Public
TN002	TasNetworks	TasNetworks-Combined Proposal Attachment 1 - Customer & Stakeholder Engagement-Jan-23-Public	Jan-23	Public
TN003	TasNetworks	TasNetworks-Combined Proposal Attachment 2 - Annual Revenue Requirement-Jan-23-Public	Jan-23	Public
TN004	TasNetworks	TasNetworks-Combined Proposal Attachment 3 - Regulatory asset base -Jan-23-Public	Jan-23	Public
TN005	TasNetworks	TasNetworks-Combined Proposal Attachment 4 - Rate of return-Jan-23-Public	Jan-23	Public
TN006	TasNetworks	TasNetworks-Combined Proposal Attachment 5 - Regulatory depreciation-Jan-23-Public	Jan-23	Public
TN007	TasNetworks	TasNetworks-Combined Proposal Attachment 6 - Capital expenditure-Jan-23-Public	Jan-23	Public
TN008	TasNetworks	TasNetworks-Combined Proposal Attachment 7 - Contingents Projects-Jan-23-Public	Jan-23	Public
TN009	TasNetworks	TasNetworks-Combined Proposal Attachment 8 - Operating expenditure-Jan-23-Public	Jan-23	Public
TN010	TasNetworks	TasNetworks-Combined Proposal Attachment 9 - Corporate income tax-Jan-23-Public	Jan-23	Public
TN011	TasNetworks	TasNetworks-Combined Proposal Attachment 10 - Efficiency Benefit Sharing Schemes-Jan-23-Public	Jan-23	Public
TN012	TasNetworks	TasNetworks-Combined Proposal Attachment 11 - Capital expenditure sharing schemes-Jan-23-Public	Jan-23	Public
TN013	TasNetworks	TasNetworks-Combined Proposal Attachment 12 - Service target performance incentive schemes-Jan-23-Public	Jan-23	Public
TN014	TasNetworks	TasNetworks-Combined Proposal Attachment 13 - Demand management incentives and allowance-Jan-23-Public	Jan-23	Public
TN015	TasNetworks	TasNetworks-Combined Proposal Attachment 14 - Customer Service Incentive Scheme-Jan-23-Public	Jan-23	Public
TN016	TasNetworks	TasNetworks-Combined Proposal Attachment 15 - Classification of services-Jan-23-Public	Jan-23	Public
TN017	TasNetworks	TasNetworks-Combined Proposal Attachment 16 - Control mechanisms-Jan-23-Public	Jan-23	Public
TN018	TasNetworks	TasNetworks-Combined Proposal Attachment 17 - Pass through events-Jan-23-Public	Jan-23	Public
TN019	TasNetworks	TasNetworks-Combined Proposal Attachment 18 - Alternative control services-Jan-23-Public	Jan-23	Public

Doc ID	Author	Title	Date	Public/ confidential
TN020	TasNetworks	TasNetworks-Combined Proposal Attachment 19 - Negotiated services-Jan-23-Public	Jan-23	Public
TN021	TasNetworks	TasNetworks-Combined Proposal Attachment 20 - Connection policy-Jan-23-Public	Jan-23	Public
TN022	TasNetworks	TasNetworks-Combined Proposal Attachment 21 - Tariff structure statement-Jan-23-Public	Jan-23	Public
TN023	TasNetworks	TasNetworks-Combined Proposal Attachment 21 - Tariff structure statement - Appendix A - Indicative Network Tariff Prices-Jan-23-Public	Jan-23	Public
TN023C	TasNetworks	TasNetworks-Combined Proposal Attachment 21 - Tariff structure statement - Appendix A - Indicative Network Tariff Prices-Jan-23-Confidential	Jan-23	Confidential
TN024	TasNetworks	TasNetworks-Combined Proposal Attachment 21 - Tariff structure statement - Appendix B - Indicative ACS Prices-Jan-23-Public	Jan-23	Public
TN025	TasNetworks	TasNetworks-Combined Proposal Attachment 22 - Tariff structure explanatory statement-Jan-23-Public	Jan-23	Public
TN026	TasNetworks	TasNetworks-Combined Proposal Attachment 23 - List of supporting documents-Jan-23-Public	Jan-23	Public
TN027	TasNetworks	TasNetworks-Combined Proposal Attachment 24 - Glossary-Jan-23-Public	Jan-23	Public

Models

Doc ID	Author	Title	Date	Public/ confidential
TN101	TasNetworks	TasNetworks-Ancillary Services Model-Dec-22-Public	Dec-22	Public
TN102	TasNetworks	TasNetworks-Capex Forecast Model Prescribed-Dec-22-Public	Dec-22	Public
TN103	TasNetworks	TasNetworks-Capex Forecast Model Standard Control-Dec-22-Public	Dec-22	Public
TN104	TasNetworks	TasNetworks-Depreciation Model - Prescribed-Dec-22-Public	Dec-22	Public
TN105	TasNetworks	TasNetworks-Depreciation Model - Standard Control-Dec-22-Public	Dec-22	Public
TN106	TasNetworks	TasNetworks-Labour Rates Model-Dec-22-Public	Dec-22	Public
TN106C	TasNetworks	TasNetworks-Labour Rates Model-Dec-22-Confidential	Dec-22	Confidential
TN107	TasNetworks	TasNetworks-Long Run Marginal Cost Model-Dec-22-Public	Dec-22	Public
TN108	TasNetworks	TasNetworks-Metering - Roll Forward Model (RFM) -Dec-22-Public	Dec-22	Public
TN109	TasNetworks	TasNetworks-Metering Capex and Opex Model-Dec-22-Public	Dec-22	Public
TN110	TasNetworks	TasNetworks-Metering Post Tax Revenue Model (PTRM)-Dec-22-Public	Dec-22	Public
TN111	TasNetworks	TasNetworks-Metering Pricing Model-Dec-22-Public	Dec-22	Public
TN112	TasNetworks	TasNetworks-Operating Expenditure Model - Prescribed-Dec-22-Public	Dec-22	Public
TN113	TasNetworks	TasNetworks-Operating Expenditure Model - Standard Control-Dec-22-Public	Dec-22	Public
TN114	TasNetworks	TasNetworks-Post Tax Revenue Model - Prescribed-Dec-22-Public	Dec-22	Public

Doc ID	Author	Title	Date	Public/ confidential
TN115	TasNetworks	TasNetworks-Post Tax Revenue Model - Standard Control-Dec-22-Public	Dec-22	Public
TN116	TasNetworks	TasNetworks-Public Lighting Annuity Model-Dec-22-Public	Dec-22	Public
TN116C	TasNetworks	TasNetworks-Public Lighting Annuity Model-Dec-22-Confidential	Dec-22	Confidential
TN117	TasNetworks	TasNetworks-Roll Forward Model (RFM) Prescribed-Dec-22-Public	Dec-22	Public
TN118	TasNetworks	TasNetworks-Roll Forward Model (RFM) Standard Control-Dec-22-Public	Dec-22	Public
TN119	TasNetworks	TasNetworks-STPIS Model Customer Service target Distribution-Dec-22-Public	Dec-22	Public
TN120	TasNetworks	TasNetworks-STPIS Model Reliability of Supply Distribution-Dec-22-Public	Dec-22	Public
TN121	TasNetworks	TasNetworks-STPIS targets Transmission-Dec-22-Public	Dec-22	Public
TN122	TasNetworks	TasNetworks-Customer Service Incentive Scheme model-Dec-22-Public	Dec-22	Public
TN123	TasNetworks	TasNetworks-Distribution Capital Expenditure Sharing Scheme-Dec-22-Public	Dec-22	Public
TN124	TasNetworks	TasNetworks-Transmission Capital Expenditure Sharing Scheme-Dec-22-Public	Dec-22	Public

Regulatory Information Notices

Doc ID	Author	Title	Date	Public/ confidential
TN201	TasNetworks	TasNetworks-(T) Workbook 1 Forecast-Dec-22-Public	Dec-22	Public
TN202	TasNetworks	TasNetworks-(T) Workbook 1 Forecast-Dec-22-Confidential	Dec-22	Confidential
TN203	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2015-Dec-22-Public	Dec-22	Public
TN204	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2016-Dec-22-Public	Dec-22	Public
TN205	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2017-Dec-22-Public	Dec-22	Public
TN206	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2018-Dec-22-Public	Dec-22	Public
TN207	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2019-Dec-22-Public	Dec-22	Public
TN208	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2020-Dec-22-Public	Dec-22	Public
TN209	TasNetworks	TasNetworks-(T) Workbook 2 MIC 2021-Dec-22-Public	Dec-22	Public
TN210	TasNetworks	TasNetworks-(T) Workbook 3 EBSS-Dec-22-Public	Dec-22	Public
TN211	TasNetworks	TasNetworks-(T) Workbook 4 CESS-Dec-22-Public	Dec-22	Public
TN212	TasNetworks	TasNetworks-(T) Workbook 5 Indicative Bill-Dec-22-Public	Dec-22	Public
TN213	TasNetworks	TasNetworks-(T) Workbook 8 Historical-Dec-22-Public	Dec-22	Public
TN214	TasNetworks	TasNetworks-(D) Workbook 1 Forecast-Dec-22-Public	Dec-22	Public
TN215	TasNetworks	TasNetworks-(D) Workbook 2 Historical-Dec-22-Public	Dec-22	Public
TN216	TasNetworks	TasNetworks-(D) Workbook 3 EBSS-Dec-22-Public	Dec-22	Public
TN217	TasNetworks	TasNetworks-(D) Workbook 4 CESS -Dec-22-Public	Dec-22	Public
TN218	TasNetworks	TasNetworks-(D) Workbook 5 Indicative Bill-Dec-22-Public	Dec-22	Public
TN219	TasNetworks	TasNetworks-Reset RIN Response Compliance Checklist Transmission -Dec-22-Public	Dec-22	Public

Doc ID	Author	Title	Date	Public/ confidential
TN220	TasNetworks	TasNetworks-Reset RIN Response Compliance Checklist Distribution -Dec-22-Public	Dec-22	Public
TN221	TasNetworks	TasNetworks-Reset RIN Basis of Preparation Transmission-Dec-22-Public	Dec-22	Public
TN222	TasNetworks	TasNetworks-Reset RIN Basis of Preparation Distribution-Dec-22-Public	Dec-22	Public
TN223C	TasNetworks	TasNetworks-CEO Reset RIN Statutory Declaration - Transmission -Jan 23-Confidential	Jan-23	Confidential
TN224C	TasNetworks	TasNetworks-CEO Reset RIN Statutory Declaration - Distribution -Jan 23-Confidential	Jan-23	Confidential

Asset Management Plans

Doc ID	Author	Title	Date	Public/ confidential
TN301	TasNetworks	TasNetworks-Asset Management Information System Asset Management Plan-Dec-22-Public	Dec-22	Public
TN302	TasNetworks	TasNetworks-Connection Assets Asset Management Plan-Oct-22-Public	Oct-22	Public
TN303	TasNetworks	TasNetworks-Customer Development Asset Management Plan-Aug-22-Public	Aug-22	Public
TN304	TasNetworks	TasNetworks-EHV Disconnector and Earth Switch Asset Management Plan-Dec-22-Public	Dec-22	Public
TN305	TasNetworks	TasNetworks-Facilities Asset Management Plan -Dec-22-Public	Dec-22	Public
TN306	TasNetworks	TasNetworks-Ground Mounted Substations Distribution Asset Management Plan-Dec-22-Public	Dec-22	Public
TN307	TasNetworks	TasNetworks-High Voltage Switchgear Asset Management Plan-Dec-22-Public	Dec-22	Public
TN308C	TasNetworks	TasNetworks-IT Infrastructure Asset Management Plan-Jan-23-Confidential	Jan-23	Confidential
TN308	TasNetworks	TasNetworks-IT Infrastructure Asset Management Plan-Jan-23-Public	Jan-23	Public
TN309	TasNetworks	TasNetworks-IT Software Asset Management Plan -Dec-22-Public	Dec-22	Public
TN309C	TasNetworks	TasNetworks-IT Software Asset Management Plan -Dec-22-Confidential	Dec-22	Confidential
TN310	TasNetworks	TasNetworks-Network Operations Asset Management Plan-Dec-22-Public	Dec-22	Public
TN310C	TasNetworks	TasNetworks-Network Operations Asset Management Plan-Dec-22-Confidential	Dec-22	Confidential
TN311	TasNetworks	TasNetworks-Overhead Line Structures Distribution Asset Management Plan-Oct-22-Public	Oct-22	Public
TN312	TasNetworks	TasNetworks-Pole Mounted Transformers Asset Management Plan-Dec-22-Public	Dec-22	Public
TN313	TasNetworks	TasNetworks-Power Transformer Asset Management Plan-Dec-22-Public	Dec-22	Public
TN314	TasNetworks	TasNetworks-SCADA Systems Asset Management Plan Transmission-Dec-22-Public	Dec-22	Public
TN315	TasNetworks	TasNetworks-Strategic Asset Management Plan-Dec-22-Public	Dec-22	Public

Doc ID	Author	Title	Date	Public/ confidential
TN316	TasNetworks	TasNetworks-Telecommunications Network Management Systems (TNMS) Asset Management Plan-Dec-22-Public	Dec-22	Public
TN316C	TasNetworks	TasNetworks-Telecommunications Network Management Systems (TNMS) Asset Management Plan-Dec-22-Confidential	Dec-22	Confidential
TN317	TasNetworks	TasNetworks-Tool of Trade Fleet Asset Management Plan-Jan-23-Public	Jan-23	Public
TN317C	TasNetworks	TasNetworks-Tool of Trade Fleet Asset Management Plan-Jan-23-Confidential	Jan-23	Confidential
TN318	TasNetworks	TasNetworks-Transmission Line Insulator Assemblies Asset Management Plan-Dec-22-Public	Dec-22	Public
TN319	TasNetworks	TasNetworks-Transmission Line Support Structure Asset Management Plan-Dec-22-Public	Dec-22	Public
TN320	TasNetworks	TasNetworks-Transmission Line Support Structure Foundations Asset Management Plan-Dec-22-Public	Dec-22	Public
TN321	TasNetworks	TasNetworks-Transmission Protection Asset Management Plan-Dec-22-Public	Dec-22	Public

Investment Evaluation Summaries

Doc ID	Author	Title	Date	Public/ confidential
TN401	TasNetworks	TasNetworks-Asset Management Information System enhancements Investment Evaluation Summary-Oct-22-Public	Oct-22	Public
TN401C	TasNetworks	TasNetworks-Asset Management Information System enhancements Investment Evaluation Summary-Oct-22-Confidential	Oct-22	Confidential
TN402	TasNetworks	TasNetworks-Customer initiated general supply underground Investment Evaluation Summary-Oct-22-Public	Oct-22	Public
TN402	TasNetworks	TasNetworks-Cyber Security Program of Work Investment Evaluation Summary-Oct-22-Public	Oct-22	Public
TN402C	TasNetworks	TasNetworks-Cyber Security Program of Work Investment Evaluation Summary-Oct-22-Confidential	Oct-22	Confidential
TN403	TasNetworks	TasNetworks-Data and Analytics Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN403C	TasNetworks	TasNetworks-Data and Analytics Investment Evaluation Summary-Dec-22-Confidential	Dec-22	Confidential
TN404	TasNetworks	TasNetworks-DER and other projects Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN405	TasNetworks	TasNetworks-Enterprise Asset Management Improvement Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN406	TasNetworks	TasNetworks-Fleet Replacement Program of Work Investment Evaluation Summary-Feb-22-Public	Feb-22	Public
TN406C	TasNetworks	TasNetworks-Fleet Replacement Program of Work Investment Evaluation Summary-Feb-22-Confidential	Feb-22	Confidential
TN407	TasNetworks	TasNetworks-General Supply Overhead Investment Evaluation Summary-Dec-22-Public	Dec-22	Public

Doc ID	Author	Title	Date	Public/ confidential
TN408	TasNetworks	TasNetworks-High Voltage Switchgear Replacement Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN409	TasNetworks	TasNetworks-Insulator Assembly Program Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN410	TasNetworks	TasNetworks-Irrigation Supply Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN411	TasNetworks	TasNetworks-IT Infrastructure Core Services Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN412	TasNetworks	TasNetworks-LV Crossarms Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN413C	TasNetworks	TasNetworks-Market Data Management System Replacement Investment Evaluation Summary-Jan-23-Confidential	Jan-23	Confidential
TN413	TasNetworks	TasNetworks-Market Data Management System Replacement Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN414	TasNetworks	TasNetworks-Market Data Management System Upgrades Program Investment Evaluation Summary-Nov-22-Public	Nov-22	Public
TN414C	TasNetworks	TasNetworks-Market Data Management System Upgrades Program Investment Evaluation Summary-Nov-22-Confidential	Nov-22	Confidential
TN415	TasNetworks	TasNetworks-North West Coast Depot Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN416	TasNetworks	TasNetworks-Permanent Residence Underground Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN417	TasNetworks	TasNetworks-Pole Staking Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN418	TasNetworks	TasNetworks-Power Quality Low Voltage Transformers Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN419	TasNetworks	TasNetworks-Replace Conductor Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN420	TasNetworks	TasNetworks-Replace Overhead Services Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN421	TasNetworks	TasNetworks-Replace Overhead Transformer Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN422	TasNetworks	TasNetworks-Replace Pole Fault Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN423	TasNetworks	TasNetworks-Replace Pole fibre reinforced concrete complex Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN424	TasNetworks	TasNetworks-Replace Pole Wood Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN425	TasNetworks	TasNetworks-Replacement of Ground Mounted Substations Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN426	TasNetworks	TasNetworks-Roseberry Transformer Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN427	TasNetworks	TasNetworks-SAP Enhancements Program Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN427C	TasNetworks	TasNetworks-SAP Enhancements Program Investment Evaluation Summary-Dec-22-Confidential	Dec-22	Confidential

Doc ID	Author	Title	Date	Public/ confidential
TN428	TasNetworks	TasNetworks-SCADA NOCS enhancements Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN429	TasNetworks	TasNetworks-SCADA System renewal Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN430	TasNetworks	TasNetworks-Subdivision Underground Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN431	TasNetworks	TasNetworks-Transmission Line Replacement I nvestment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN432	TasNetworks	TasNetworks-Upper Derwent 110 kV Losses Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN433	TasNetworks	TasNetworks-West Coast Reliability Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN434	TasNetworks	TasNetworks-Works management Tool Upgrades Investment Evaluation Summary-Dec-22-Public	Dec-22	Public
TN434C	TasNetworks	TasNetworks-Works management Tool Upgrades Investment Evaluation Summary-Dec-22-Confidential	Dec-22	Confidential

Reports

Doc ID	Author	Title	Date	Public/ confidential
TN501	TasNetworks	TasNetworks-Annual Planning Report-Dec-22-Public	Dec-22	Public
TN502	TasNetworks	TasNetworks-Contingent Projects Overview report-Nov-22-Public	Nov-22	Public
TN503	TasNetworks	TasNetworks-CutlerMerz-Internal Summary Report - Project Implementation Reviews-Jan-23-Public	Jan-23	Public
TN503C	TasNetworks	TasNetworks-CutlerMerz-Internal Summary Report - Project Implementation Reviews-Jan-23-Confidential	Jan-23	Confidential
TN504	TasNetworks	TasNetworks-Ernst and Young Fleet Utilisation and Optimisation Report-Aug-22-Public	Aug-22	Public
TN5054C	TasNetworks	TasNetworks-Ernst and Young Fleet Utilisation and Optimisation Report-2022-Confidential	Aug-22	Confidential
TN505	TasNetworks	TasNetworks-Insurance Premium Forecast Report-May-22-Public	May-22	Public
TN505C	TasNetworks	TasNetworks-Insurance Premium Forecast Report-May-22-Confidential	May-22	Confidential
TN506	TasNetworks	TasNetworks-Oxford Economics-Labour Cost Input Forecasts-Nov-22-Public	Nov-22	Public
TN507	TasNetworks	TasNetworks-Reset Advisory Comittee Engagement Report-Jan-23-Public	Jan-23	Public
TN508C	TasNetworks	TasNetworks-PWC-Cyber Security Expenditure Review-2022-COnfidential	Nov-22	Confidential

Miscellaneous

Doc ID	Author	Title	Date	Public/ confidential
TN601	TasNetworks	TasNetworks-AEMO Review of TasNetworks' Network Capability Incentive Parameter Action Plan-Dec-22-Public	Dec-22	Public
TN602	TasNetworks	TasNetworks-Ancillary services - Fee based services-Dec-22-Public	Dec-22	Public
TN603	TasNetworks	TasNetworks-Asset Management Policy -Aug-22-Public	Aug-22	Public
TN604	TasNetworks	TasNetworks-Capital Contributions Forecasting Methodology-Sep-22-Public	Sep-22	Public
TN605	TasNetworks	TasNetworks-Capitalisation Policy-Jan-23-Public	Jan-23	Public
TN606	TasNetworks	TasNetworks-Certification of key assumptions for 2024-29 regulatory proposal-Jan-23-Public	Jan-23	Public
TN607	TasNetworks	TasNetworks-Distribution Pricing Methodology-Dec-22-Public	Dec-22	Public
TN608	TasNetworks	TasNetworks-Distribution Rules Compliance Checklist-Nov-22-Public	Nov-22	Public
TN609	TasNetworks	TasNetworks-Expenditure Forecasting Methodology-Jun-22-Public	Jun-22	Public
TN610C	TasNetworks	TasNetworks-Letter to AER Debt Averaging Periods-Dec-22-Confidential	Dec-22	Confidential
TN610	TasNetworks	TasNetworks-Letter to AER Debt Averaging Periods-Dec-22-Public	Dec-22	Public
TN611	TasNetworks	TasNetworks-Network Capability Incentive Parameter Action Plan-Dec-22-Public	Dec-22	Public
TN612	TasNetworks	TasNetworks-Network Tariff Application Guide-Dec-22-Public	Dec-22	Public
TN613	TasNetworks	TasNetworks-Percentage of confidential information-Jan-23-Public	Jan-23	Public
TN614	TasNetworks	TasNetworks-Summary of Confidential and Non-Confidential Material-Jan 23-Public	Jan-23	Public
TN615	TasNetworks	TasNetworks-Towards 2030-Oct-20-Public	Oct-20	Public
TN616	TasNetworks	TasNetworks-Transmission Pricing Methodology-Dec-22-Public	Dec-22	Public
TN617	TasNetworks	TasNetworks-Transmission Rules Compliance Checklist-Nov-22-Public	Nov-22	Public

TasNetworks | Powering a Bright Future

Combined Proposal 2024-2029

Attachment 24
Glossary

Outline: This attachment to TasNetworks' Combined Proposal outlines the abbreviations and definitions used in the Combined Proposal documents and attachments.

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Note

This attachment forms part of TasNetworks' Combined Proposal for the 2024-2029 regulatory control period and should be read in conjunction with the other parts of the proposal. TasNetworks' Combined Proposal is made up of the documents and attachments listed below, as well as the supporting documents that are listed in Attachment 23.

Document	Description
	Combined Proposal overview
Attachment 1	Customer and stakeholder engagement summary
Attachment 2	Annual revenue requirement
Attachment 3	Regulatory asset base
Attachment 4	Rate of return
Attachment 5	Regulatory depreciation
Attachment 6	Capital expenditure
Attachment 7	Contingent projects
Attachment 8	Operating expenditure
Attachment 9	Corporate income tax
Attachment 10	Efficiency benefit sharing scheme
Attachment 11	Capital expenditure sharing scheme
Attachment 12	Service target performance incentive scheme
Attachment 13	Demand management incentives and allowance
Attachment 14	Customer service incentive scheme
Attachment 15	Classification of services
Attachment 16	Control mechanisms
Attachment 17	Pass through events
Attachment 18	Alternative control services
Attachment 19	Negotiated services framework and criteria
Attachment 20	Distribution connection pricing policy
Attachment 21	Tariff structure statement
Attachment 22	Tariff structure explanatory statement
Attachment 23	List of supporting documents
Attachment 24	**Glossary**

Glossary

Term or Abbreviation	Description
ABS	Australian Bureau of Statistics
ADMS	Advanced distribution management system
ACS	Alternative control services
AEC	Accredited electrical contractor
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMIS	Asset management information system
ARR	Annual revenue requirement
APR	Annual Planning Report
CC	Customer Council
CCP	Consumer Challenge Panel
CER	Consumer energy resources
CESS	Capital Expenditure Sharing Scheme
CSBA	Customer Service Benchmarking Australia
CPA	Contingent project application
CPI	Consumer Price Index
CSIS	Customer Service Incentive Scheme
DM	Developer mains
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider
DSO	Distribution System Operator
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Australia
ERP	Enterprise resource planning
ESB	Energy Security Board
GIS	Geographical information system
GSL	Guaranteed Service Level
HBLCA	High bushfire loss consequence area
HBRM	Health based risk management

Term or Abbreviation	Description
ICT	Information communication and technology
IoT	Internet of Things
IRR	Incremental Revenue Rebate
ISP	Integrated System Plan
LED	Light-emitting diode
MAR	Maximum allowed revenue
MDMS	Market data management system
MIC	Market impact component
Negotiated distribution service	A distribution service that is a negotiated network service within the meaning of section 2C of the NEL
NEL	National Electricity (Tasmania) Law pursuant to the *Electricity – National Scheme (Tasmania) Act 1999*
NEM	National Electricity Market
NEO	National Electricity Objective
NER, or the Rules	National Electricity Rules
NCIPAP	Network Capability Incentive Parameter Action Plan
NMI	National Metering Identifier
NOCS	Network operating and control systems
NPV	Net present value
NSP	Network Service Provider
NWTD	North West Transmission Development
OMS	Outage management system
OTTER	Office of the Tasmanian Economic Regulator
OWZ	Offshore wind zone
PMU	Phasor measurement unit
PRWG	Policy and Regulatory Working Group
PTRM	Post tax revenue model
RAB	Regulatory asset base
RAC	Reset Advisory Committee
Regulatory control period	A period for which TasNetworks is subject to a control mechanism imposed by a revenue determination for the transmission network and a regulatory determination for the distribution network, as defined by the Rules
Resilience	The ability for our distribution and transmission networks to resist, absorb, accommodate, adapt to, transform and recover from the effects of a hazard
REZ	Renewable Energy Zone
RFM	Roll forward model
RIT-T	Regulatory investment test for transmission
ROLR	Retailer of Last Resort
RoR Instrument	Rate of Return Instrument
SAIDI	System average interruption duration index

Term or Abbreviation	Description
SAIFI	System average interruption frequency index
SAPS	Stand-alone power system
SCADA	System control and data acquisition
SCS	Standard Control Services
Service Applicant	A person who asks TasNetworks for access to a distribution service, as defined by the NER
STPIS	Service Target Performance Incentive Scheme
SSS Provider	System strength service provider
TAB	Tax asset base
TasNetworks	Tasmanian Networks Pty Ltd (ABN 24 167 357 299).
TEC	Tasmanian Electricity Code
TFCD	Task Force on Climate-related Financial Disclosures
TISPS	Tasmanian Integrated System Protection Scheme
TNSP	Transmission network service providers
TREAP	Tasmanian Renewable Energy Action Plan
TRET	Tasmanian Renewable Energy Target
TRHAP	Tasmanian Renewable Hydrogen Action Plan
VCR	Value of customer reliability

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