Revised Proposal 2024-2029

Outline: This document forms part of TasNetworks' Revised Proposal to the Australian Energy Regulator for the 2024-2029 regulatory control period, along with supporting information.

It provides a summary of our Revised Proposal for both the transmission and distribution networks in Tasmania.

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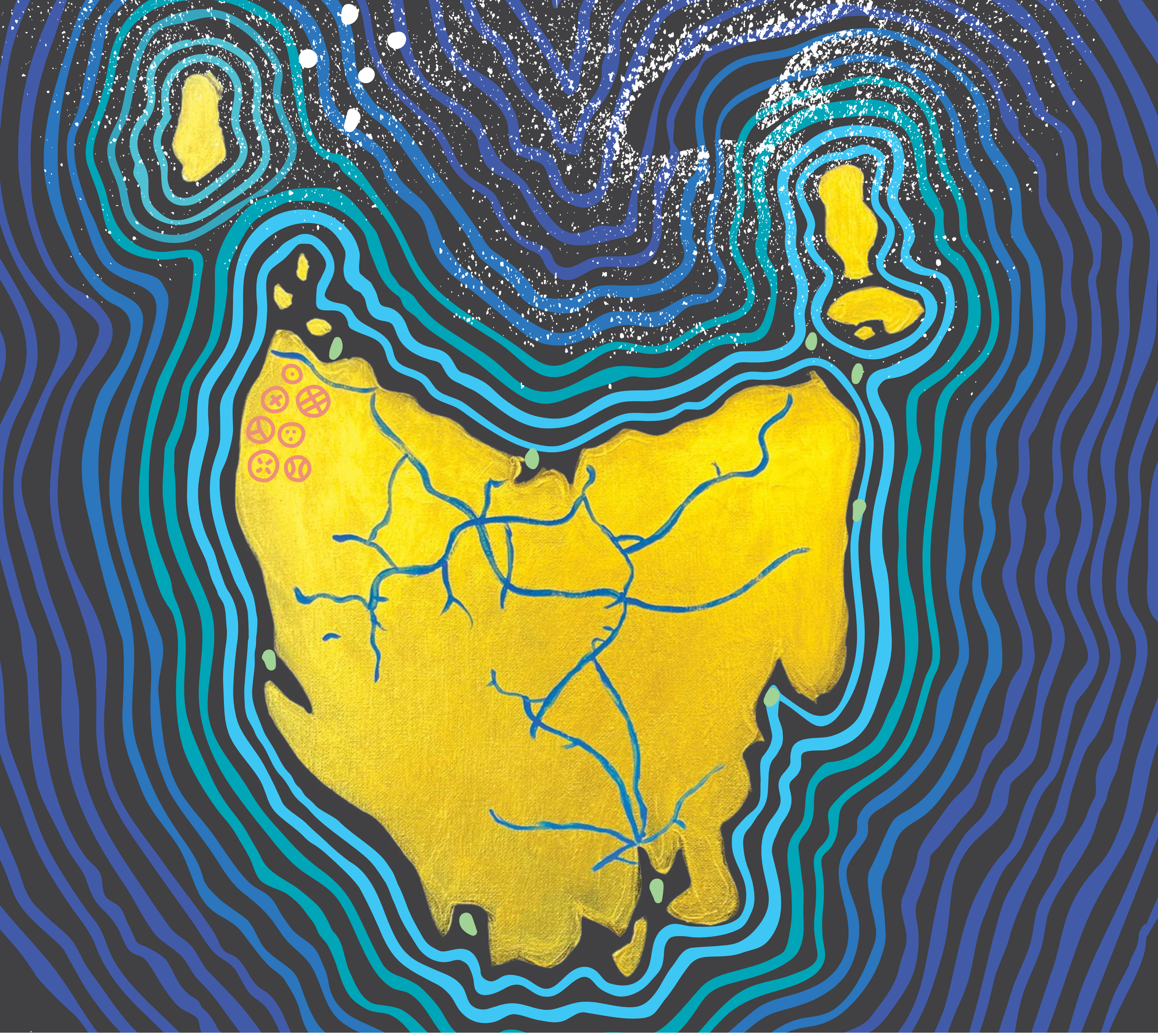

Welcome

TasNetworks acknowledges the palawa (Tasmanian Aboriginal community) as the original owners and custodians of lutruwita (Tasmania). TasNetworks acknowledges the palawa have maintained their spiritual and cultural connection to the land and water. We pay respect to Elders past and present and all Aboriginal and Torres Strait Islander peoples.

CEO's foreword

We are pleased to lodge our Revised Proposal for the Australian Energy Regulator (**AER**)'s consideration. This document details the critical revenue we require to continue delivering safe, reliable, and efficient electricity services to Tasmanian energy users for the 2024-2029 regulatory control period.

Our Original Proposal, submitted to the AER in January 2023, was developed in a time of significant energy transition, economic uncertainty and rising cost of living pressures. It reflected the voices of our customers and stakeholders, shaped by insights gathered during our most comprehensive and diverse engagement program to date. It was a roadmap to deliver the outcomes our customers value most while also enabling Tasmania's transition to a clean energy future.

While keeping customer bills affordable remains the top concern for our customers, we have also heard that customers want proactive investment in renewables, consistent reliability statewide, and a transparent commitment to sustainability. Balancing these preferences in the current economic climate has been our most complex yet crucial task. We made strategic trade-offs in our Original Proposal, placing deliberate downward pressure on costs without compromising reliability, safety, or undermining our other priorities. These trade-offs have been carried into our Revised Proposal, and we stand by them.

We welcome the AER's Draft Decision, and after careful review, have accepted the majority of matters raised by the AER.

Looking forward, we remain committed to supporting the Tasmanian Government's goal of doubling Tasmania's available clean energy and aiding the state's broader energy transition. While investment required to support customer-driven solar and storage and connect new renewable generation is not cheap, simple, well-understood or popular, it is the right path to take if we want to continue to provide Tasmanians with the some of the lowest power prices in Australia – now and into the future. We have therefore re-proposed five contingent projects not accepted by the AER in the Draft Decision, updating the trigger events to reflect the AER's and stakeholder feedback, and proposed a new contingent project to support the energy transition.

I want to extend my personal gratitude to each customer and stakeholder who has invested their time and thoughts in the crafting of our Original and Revised Proposals. Your voice is heard, your contribution is the backbone of our future direction, and we are committed to ongoing genuine and transparent engagement with you to build trust and deliver outcomes that are meaningful to you. Thank you.

Seán Mc Goldrick

Dr Seán Mc Goldrick
Chief Executive Officer

Executive summary

On 30 January 2023 TasNetworks submitted its Combined Proposal (**Original Proposal**) for the 2024-2029 regulatory control period, setting out our capital expenditure (**capex**) plans and forecasts of operating expenditure (**opex**), as well as the total revenue required to recover the costs of building, maintaining and operating Tasmania's electricity transmission and distribution networks.

Following a detailed review of TasNetworks' Original Proposal, on 28 September 2023 the AER published its draft decision. The AER accepted many aspects of the Original Proposal, including our capex and opex forecasts for both transmission and distribution, our tariff structure statement and our proposed customer service incentive scheme. The most material aspect of the Original Proposal that the AER did not accept in its draft decision is the project triggers for the seven transmission contingent projects put forward in the Original Proposal.

The draft decision allows TasNetworks to recover an estimated revenue of $1,677.0 million for the distribution network and $809.1 million for the transmission network from customers over the 2024-2029 regulatory control period ($2023-24). The draft decision is a 3.2 per cent increase from TasNetworks' forecast of overall transmission revenue and an 8.2 per cent increase from TasNetworks' forecast overall distribution outlined in the Original Proposal..

The drivers for the increase in our revenue requirements for transmission and distribution are lower expected inflation, which impacts the regulatory depreciation building block, and an increase in the Weighted Average Cost of Capital (**WACC**). The AER also corrected errors in the depreciation modules within TasNetworks' roll forward models that increased the revenue requirement for distribution while decreasing the revenue requirement for transmission.

We have accepted most aspects of the AER's draft decision in our Revised Proposal, including accepting the expenditure decision. However, we do not accept the AER's draft decision in relation to transmission contingent projects. An overview of the approach we have taken to key aspects of our revised forecasts is set out in Table 1.

Table 1 Summary of TasNetworks' response to AER draft decision

Element	TasNetworks' response
Capital expenditure (capex)	We accept the AER's draft decision on total capex. We have not updated any aspect of 2024-2029 capex as part of the revised proposal with the exception of equity raising costs, which have been derived through the standard Post Tax Revenue Model (**PTRM**) derivation. For further information refer to sections 4 Revised capital and operating expenditure for 2019-2024 regulatory control period and 5 Forecast capital expenditure.
Transmission contingent projects	We do not accept the AER's draft decision. We have presented revised projects and triggers as part of this Revised Proposal. For further information refer to section 6 Contingent projects and Appendix A – Contingent projects supporting information.
Operating expenditure (opex)	We accept the AER's draft decision on total opex. We have not updated any aspect of 2024-2029 operating expenditure as part of the Revised Proposal. For further information refer to section 7 Forecast operating expenditure.
Rate of return and Inflation	We accept the AER's draft decision and have applied the AER's draft decision rate of return and inflation estimates in our Revised Proposal. The AER will update the rate of return and inflation in its final decision. For further information refer to section 11 Rate of return and inflation.

Element	TasNetworks' response
Regulatory Asset Base (**RAB**)	We accept the AER's draft decision on our RAB. We have updated our revenue modelling to reflect actual capex for 2022-23 and also updated forecast capex for 2023-24. In addition, we have removed reclassified assets from the transmission RAB that were not included in the Original Proposal. For further information refer to section 8 Regulatory asset base.
Revenue Adjustments	We accept the AER's draft decision in relation to the Efficiency Benefit Sharing Scheme (**EBSS**), Capital Expenditure Sharing Scheme (**CESS**), shared assets, the Demand Management Incentive Scheme (**DMIS**) and the Demand Management Innovation Allowance Mechanism (**DMIAM**). We have updated our CESS outcomes to reflect actual capex for 2022-23 and also updated forecast capex for 2023-24. We have updated EBSS outcomes to reflect actual opex for 2022-23. Demand management innovation allowances (**DMIA**) have been updated to reflect the revised revenue forecasts. For further information refer to sections 12 Efficiency benefit sharing scheme, 13 Capital expenditure sharing scheme and 14 Demand management incentives and allowance.
Maximum Allowed Revenue (**MAR**)	We have updated the remaining building block revenue outcomes and forecast MAR to reflect the changes to RAB and revenue adjustments. Based on feedback from our stakeholders, we have proposed a non-default smoothing approach to our MAR. For further information refer to section 15 Revenue and section 3 Customer and stakeholder engagement.
Pass Through Events	We accept the AER's draft decision on pass through events. We have not proposed any additional pass through events as part of the Revised Proposal. For further information refer to section 17 Pass through events.
Alternative Control Service (**ACS**)	We accept the AER's draft decision on ACS. For metering services, we have updated 2022-23 for actual opex as required as it is the base year. For further information refer to section 20 Alternative control services
Tariff structure statement (**TSS**)	We accept the AER's draft decision on our TSS. We have only updated the TSS to include revised prices reflecting updated inputs from our Revised Proposal. For further information refer to section 16 Networking pricing and price impacts.
Distribution Connection Pricing Policy	We accept the AER's draft decision on our Distribution Connection Pricing Policy. For further information refer to section 21 Distribution Connection Pricing Policy.
Transmission Pricing Methodology	The AER did not accept our proposed Transmission Pricing Methodology. We have amended the methodology in line with the AER's recommendations. For further information refer to section 16 Networking pricing and price impacts.
Service Target Performance Incentive Scheme (**STPIS**)	We accept the AER's draft decision on STPIS. For distribution STPIS we have updated the Reliability of Service performance targets as requested by the AER. For further information refer to section 18 Service target performance incentive schemes.
Customer Service Incentive Scheme (**CSIS**)	We accept the AER's draft decision on the CSIS. However, we have proposed an amendment to correct an error in relation to the incentive rates. For further information refer to section 19 Customer service incentive scheme.

As we have accepted most aspects of the AER's draft decision there is no change in a number of key financial elements between the draft decision and our Revised Proposal (for example capex and opex for the 2024-2029 regulatory control period). The main drivers of the difference between our Revised Proposal revenue forecasts and the AER's draft decision outcomes are updates for actual opex in 2022-23 and updated capex forecasts for 2023-24.

The Revised Proposal results in an overall forecast revenue requirement that is $8.2 million lower (less than a 0.3 per cent) than the AER's draft decision. For comparative purposes, a summary of the key elements is shown in Table 2 and Table 3.

Table 2 Distribution network comparison – Original Proposal, AER draft decision and Revised Proposal ($2023-24)

	Original Proposal	AER draft decision	Revised Proposal
Total revenue – smoothed ($m)	$1,549.2m	$1,677.0m	$1,676.7m
Net capital expenditure ($m)	$729.4m	$729.3m	$729.3m
Operating expenditure ($m)	$541.0m	$541.0m	$541.0m
Rate of return (%)	5.71%	5.80%	5.80%
Return on capital ($m)	$640.3m	$655.7m	$649.1m
Depreciation – return of capital ($m)	$327.3m	$440.0m	$450.9m
Revenue adjustments ($m)	$7.8m	($3.4m)	($9.0m)
Corporate tax ($m)	$32.2m	$42.8m	$43.1m
Inflation Forecast	3.35%	2.80%	2.80%
Regulated asset base – end of period	$2,268.0m	$2,235.0m	$2,208.0m
Residential Prices[1]	$833 (2.4%)	$898 (4.5%)	$897 (4.0%)
Small Business Prices[2]	$2,960 (1.3%)	$3,167 (3.1%)	$3,171 (2.7%)

Table 3 Transmission network comparison – Original Proposal, AER draft decision and Revised Proposal ($2023-24)

	Original Proposal	AER draft decision	Revised Proposal
Total revenue – smoothed ($m)	$784.1m	$809.1m	$801.2m
Net capital expenditure ($m)	$287.8m	$287.8m	$287.8m
Operating expenditure ($m)	$209.2m	$209.2m	$209.2m
Rate of Return (%)	5.68%	5.77%	5.77%
Return on capital ($m)	$492.2m	$479.0m	$480.7m
Depreciation – return of capital ($m)	$70.9m	$104.4m	$100.5m
Revenue adjustments ($m)	$4.4m	$4.4m	($1.90m)
Corporate tax ($m)	$7.7m	$12.0m	$13.0m
Inflation Forecast	3.35%	2.80%	2.80%
Regulated asset base – end of period	$1,697.8m	$1,628.1m	$1,635.8m
Transmission $/MWh[3]	$11.33/MWh 1.0%	$11.65/MWh[4] 2.6%	$11.63/MWh 2.6%

Notes:

- $ million, 2023-24
- Expenditure and revenue are for the five year regulatory control period (2024-2029)
- Capex is net expenditure (as incurred)
- Rate of return is nominal vanilla WACC in 2024-25
- RAB is the closing value for 30 June 2029

1 This represents average 2024-2029 prices ($ real) for a typical residential customer with an annual energy consumption of 7,834 kWh

2 This represents average 2024-2029 prices ($ real) for a typical small business customer with an annual energy consumption of 33,578 kWh

3 The average $/MWh over the 2024-2029 regulatory control period

4 This represents TasNetworks' modelling of the AER's draft decision

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Figures and tables in the Revised Proposal and attachments may not add due to rounding

1. Introduction

TasNetworks owns, maintains, and operates the electricity transmission and distribution networks in Tasmania, as well as a telecommunications network that supports the operation of those networks. TasNetworks also provides approximately 50,000 public lights on behalf of councils and other government road authorities.

Electricity networks are natural monopolies, and the AER regulates TasNetworks under the National Electricity Law (**NEL**) and National Electricity Rules (**NER**). A major part of the AER's role as an economic regulator involves setting the maximum revenue that TasNetworks is allowed to recover from its customers, as well as the prices that TasNetworks can charge for the provision of a range of network ancillary services and public lighting. Under the NER, the AER must set separate revenue allowances for our transmission and distribution networks.

Every five years, TasNetworks is required to propose the revenue it needs to recover from its customers to recoup the cost of building, operating, and maintaining both the transmission and distribution networks in Tasmania. We are also required to set out the network charges (tariffs) that will be used to recover TasNetworks' revenue allowances, as well as the prices that will apply to network ancillary services, public lighting and metering.

On 30 January 2023 TasNetworks submitted its Original Proposal for the 2024-2029 regulatory control period, setting out our capex plans and forecasts of opex, as well as the total revenue required to recover the costs of building, maintaining and operating Tasmania's electricity transmission and distribution networks.

The Original Proposal was a product of significant engagement and consultation with customers and stakeholders, analysis, and planning. During the delivery of our engagement program, four key themes clearly emerged as priorities for our customers and their advocates:

- affordable network services and electricity for all customers
- reliable networks now and resilient networks in the future for the entire State
- long-term investment in the networks that increases Tasmania's renewable energy capability and unlocks associated community benefits
- a transparent, socially responsible approach to the provision of network services that ensures a sustainable solution for Tasmania.

Since the submission of the Original Proposal, the AER published its Issues Paper on the Original Proposal in March 2023 and invited submissions from customers and stakeholders. Eight submissions were received, covering issues such as our proposed capex and opex, tariff reform, contingent projects, revenue drivers and legacy meter recovery.

Between February and September 2023, the AER reviewed the Original Proposal in detail. We have engaged with the AER staff to provide clarification and further information to support their assessments. We have also continued engagement with our stakeholder representatives to keep them informed of the process and our considerations for the Revised Proposal.

On 28 September 2023 the AER published its draft decision. The AER accepted many aspects of the Original Proposal, including our capex and opex forecasts for both transmission and distribution, our tariff structure statement and our proposed customer service incentive scheme. The most material aspect of the Original Proposal that the AER did not accept in its draft decision were the project triggers for the seven transmission contingent projects put forward in the Original Proposal.

This document forms part of TasNetworks Revised Proposal for the 2024-2029 regulatory control period, lodged in response to the AER's draft decision and in accordance with the NER.

A comparison of the key elements of the Original Proposal, the AER's draft decision and the Revised Proposal are outlined in Table 2 and Table 3. Final revenue and pricing outcomes will depend on movements in interest rates and inflation estimates between now and the time of the AER's final decision in April 2024.

2. Operating environment

TasNetworks' Original Proposal reflected the operating environment for the Tasmanian power system at that time, as well as the known customer driven changes, technological developments and regulatory reforms shaping the electricity supply industry of the future. In the time since we lodged the Original Proposal with the AER, there have been some significant changes in the external operating environment. Not all of those changes have necessitated changes to the Revised Proposal, but all will impact on the regulated network services TasNetworks will provide in the 2024-2029 regulatory control period and beyond. Some of these developments are discussed below.

Project Marinus

Project Marinus is a proposed undersea interconnector linking the Tasmanian and Victorian power systems. To be progressed as a joint venture between the Commonwealth, Victorian and Tasmanian governments, the project involves the construction of a high voltage direct current (**HVDC)** cable (Marinus Link) and supporting high voltage alternating current (**HVAC**) transmission network in North West Tasmania (North-West Transmission Developments).

The Australian Energy Market Operator (**AEMO**)'s 2022 Integrated System Plan (**ISP**) identified Project Marinus as "actionable" and part of the National Electricity Market (**NEM**)'s optimal development pathway. At the time TasNetworks was developing its 2024-2029 revenue proposal for the Tasmanian transmission network, the project had entered the Design and Approval phase, with work underway to enable a final investment decision by the end of 2024.

In September 2023, the Commonwealth and Tasmanian governments announced that the original plan for two cables had been revised and that Project Marinus will prioritise the delivery of one cable as close as possible to 2028. Negotiations are continuing for the second cable.

As a consequence of the revised timing, the staging of the North West Transmission Developments has also been revised, impacting the proposed connection of new generation and load in North West Tasmania. To address this concern, TasNetworks has proposed a new contingent project in this Revised Proposal to improve the hosting capacity of the network in North West Tasmania. Refer to section 6 Contingent projects and Appendix A – Contingent projects supporting information for more information.

Inflation and the weighted average cost of capital

A key driver of the increase in proposed revenues is the return on capital allowed by the AER. This is calculated by combining the returns of two sources of funds for investment – equity and debt. The allowed rate of return provides us with a return on capital to service the interest rate on our loans and provides a return on equity to our investors, the people of Tasmania. The AER's draft decision applied the 2022 Rate of Return Instrument.

Given the volatility in financial markets and uncertainty in interest rates (driven by concerns around the rate of inflation), the return on capital is likely to change from the draft to the final decision.

Amended National Electricity Objective

The National Electricity Objective (**NEO)** is a statement in the NEL that promotes efficient investment in, as well as efficient operation and use of, electricity services. The NEO promotes the long-term interests of consumers of electricity with respect to the price, quality, safety, and reliability of their energy supply, requiring network service providers (**NSPs**) and the AER to act in ways that promote delivery of the NEO.

In May 2023, Energy Ministers approved an update of the NEO that embeds emissions reduction and allows for the consideration of emissions by market bodies and other market participants in their planning and decision making. TasNetworks is one of the first NSPs in the NEM to be affected by the changes to the NEO, which apply to the AER's regulatory determinations for TasNetworks' distribution and transmission networks for the 2024-2029 regulatory control period.

TasNetworks has not proposed any expenditure directly related to this change in our Revised Proposal. We will, however, continue our efforts to lower our greenhouse gas emissions by reducing emissions from our vehicle fleet and minimising leakage of SF6 gas used as an insulating material in many switchgear and circuit breakers. We will also continue to support new renewable generation in Tasmania, whether it be micro-embedded generation connected to the distribution network or large-scale renewable generation connecting to the transmission network, and we anticipate that the value of emissions reductions will be a significant influence on elements of TasNetworks' regulatory proposals in the future.

Australian Energy Market Commission metering review

In December 2020, the Australian Energy Market Commission (**AEMC**) began a review of the regulatory framework for metering services. It was primarily focussed on accelerating the replacement of all distribution network owned accumulation meters but also looked at how to unlock benefits from advanced meter data and services.

During the 2019-2024 regulatory control period, the number of accumulation meters that TasNetworks owns has progressively reduced as they are replaced with advanced meters. At the time we submitted the Original Proposal, we expected the rollout of new meters to be nearly complete by the end of 2027. We have factored this into our metering expenditure forecasts for the 2024-2029 regulatory control period and, as a result, our metering charges were set to decrease over this timeframe.

Access to power quality data from advanced meters, such as voltage, current and power factor, will help distribution network service providers (**DNSPs**) manage their networks, allow greater flexibility in the use of Consumer Energy Resources (**CER**) by consumers, and detect and fix potentially life-threatening electrical faults like broken neutrals. One of the concerns raised during the AEMC's review was that access to this data was not regulated, with access being commercially negotiated between DNSPs, metering coordinators and their metering data providers.

At the time of submitting the Original Proposal, the AEMC had proposed[5] that DNSPs would have to procure basic power quality data from metering coordinators as an operational expenditure and recover the cost from customers via distribution use of system (**DUoS**) charges. Pending the AEMC's final recommendation, TasNetworks did not propose an opex step change in the Original Proposal but flagged this as a consideration for the Revised Proposal.

In its final report in August 2023, the AEMC recommend that DNSPs should have free access to power quality data from all advanced meters in their service area. Based on this recommendation, TasNetworks has not proposed any additional expenditure for the procurement of basic power quality data in the Revised Proposal.

Classification of metering services

In its draft decision for TasNetworks, the AER retained its classification of metering services as alternative control services but noted that a reclassification of legacy meter services to standard control services may be more appropriate in light of a number of factors, including the outcome of the AEMC's metering review. Classification of metering services as standard control services would see TasNetworks' metering costs recovered through the revenue cap from the wider customer base.

TasNetworks has not sought to reclassify metering services as part of this Revised Proposal for the reasons outlined in section 20 Alternative control services.

5 AEMC, *Review of the regulatory framework for metering services: draft report, 3 November 2022.*

3. Customer and stakeholder engagment

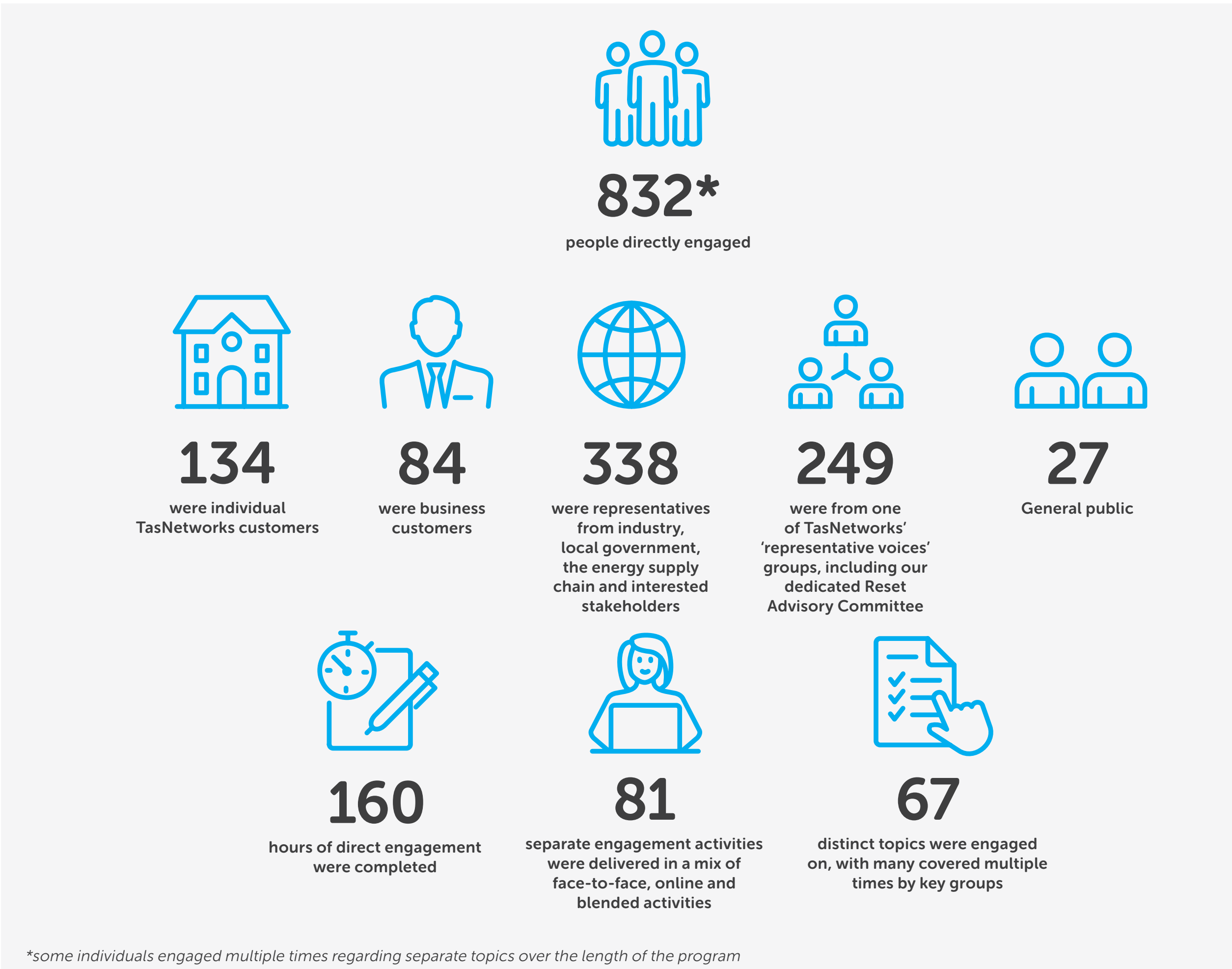
Running from July 2021 to December 2023, this engagement program has been the most comprehensive and diverse suite of customer and stakeholder engagement activities we have ever undertaken in support of a revenue or regulatory proposal.

Commencing with a co-design process involving key stakeholders in 2021, the program has aimed to:

- identify and understand what is important to both customers and stakeholders
- increase their knowledge and understanding of the energy sector, our business and the revenue reset process
- identify the areas they could influence and enable them to shape our Proposal
- build trust in TasNetworks and our Proposal.

Figure 1 illustrates the breadth and depth of the program, showing we have engaged with a wider range of customers and stakeholders than ever before. This also included adopting new methods, such as the creation of the Reset Advisory Committee to provide expertise and oversight across the length of the program, and the running of state-wide customer Discussion Circles to gain the perspectives of people living with vulnerability.

Figure 1 Customer and stakeholder engagement statistics



An essential component of the program was our ongoing evaluation against pre-determined benchmarks. This approach enabled us to:

- ensure our engagement was fit for purpose and best-practice
- make sure we were honestly and accurately appraising our efforts
- refine our approach, activities and materials when necessary.

In addition to the above objectives, we also sought to develop an Original Proposal that was capable of acceptance by our stakeholders, customers and the AER. In doing this we were guided by the AER's Better Resets Handbook (released in December 2021), along with regular review sessions with the AER Consumer Challenge Panel.

When combined, each of the above steps helped create a more accessible, customer-focused engagement program. This marked a positive step-change from previous engagement efforts, helping to drive an increase in participants' trust in TasNetworks to act in the best interests of customers from 66 per cent in late 2021 to 77 per cent at the conclusion of the engagement program in November 2023.

Beyond 2024-2029

Preparatory work has already commenced for the 2029-2034 revenue reset, with the embedding of recommendations from our external stakeholders and customers, as well as suggestions made by the 100+ TasNetworks staff involved in delivering this regulatory proposal.

While not a perceptible change for those outside the business, this functional shift will see more genuine, iterative engagement with a wider range of customers and stakeholders in the future – enabling us to better meet the changing needs and priorities of our customers and stakeholders as the NEM continues its rapid evolution.

Original Proposal

Four key themes emerged as priorities while engaging with our customers, their advocates and stakeholders during the development of the Original Proposal. These are outlined in Figure 2.

Figure 2 Customer and stakeholder priorities – Original Proposal

Given the primary concern for all was affordability, we made trade-offs and changes to the Original Proposal to place downward pressure on our costs without sacrificing reliability and safety or undermining the delivery of the other customer and stakeholder priorities. These priorities were reflected in the Original Proposal, which was built around:

- combined capital and operating expenditure requirements for our transmission and distribution networks that were approximately one per cent lower than in the current 2019-2024 regulatory control period
- targeted improvements in the reliability of parts of our distribution network that are not performing as well as we, or our affected customers, would like them to
- a range of measures intended to improve the resilience of our networks to climate change, including transitioning to assets with increased bushfire resilience, such as fibreglass reinforced composite concrete poles instead of wooden poles, and using fire-retardant coatings on wood poles.

Ongoing engagement

Table 4 summarises the engagement activities we have conducted since the lodgement of our Original Proposal in January 2023. The majority of engagement in this phase of the program was at the International Association for Public Participation (**IAP2**) inform level, geared towards keeping customers and stakeholders abreast of the revenue reset process and addressing the area of greatest concern, contingent projects triggers and price impacts. The exceptions to this were the engagements around the proposed introduction of a CSIS and associated targets, and price path options for our distribution customers (residential and small business) – both of which occurred at the IAP2 level of collaborate.

For the CSIS, stakeholders and representative voices were presented with updated CSIS parameter targets based on TasNetworks most recent customer satisfaction performance, and options for the incentive rates associated with each parameter. 85 per cent of attendees supported the updated CSIS targets and 100 per cent of attendees supported the proposed incentive rates and that TasNetworks should adopt a CSIS.

For the price path options for distribution customers, stakeholders and representative voices were presented with the Revised Proposal indicative revenue outcomes for transmission and distribution and the indicative price impacts for customers. Attendees were presented with two distribution price paths for consideration – the first based on the default revenue smoothing approach, the second based on a non-default revenue smoothing approach. 85 per cent of attendees supported TasNetworks adopt a non-default revenue smoothing approach, which has been reflected in the Revised Proposal.

Table 4 Engagement activities post-submission

Audience	Topics	Timing
Reset Advisory Committee	Executive update, revenue reset update, AER issues paper, 2023 engagement program	12 April 2023
Customer Council and Policy and Regulatory Working Group	Executive/CEO update, revenue reset update	28 April 2023
Customer Council and Policy and Regulatory Working Group	Proposed Customer Service Incentive Scheme	29 July 2023
Reset Advisory Committee, Customer Council and Policy and Regulatory Working Group	Tasmanian Government update, transmission and distribution revenue update, AER issues paper submission overview	23 August 2023
Interested stakeholders	Role of the Annual Planning Report, key highlights; Future Distribution System, new ways for the network and customers to create value.	3 November 2023
Reset Advisory Committee, Customer Council, Policy and Regulatory Working Group, Marinus Link Consumer Advisory Panel	AER Draft Decision, Revised Proposal and distribution customer price path, Marinus Link project update, North West Transmission Developments project update, contingent project changes and new project, and the customer price impacts of all the discussed elements	22 November 2023
Transmission customers	Transmission revenue update, contingent project triggers and price impacts	28 November – 01 December 2023
Interested stakeholders	Revised Proposal overview (differences from Original Proposal)	28 November 2023

Revised Proposal

The AER invited public submissions on the Original Proposal between 28 March and 12 May 2023. A total of eight submissions covering 15 topics were received from a range of stakeholders, including the AER's Consumer Challenge Panel.

In addition to the feedback received from stakeholders, we also worked closely with the AER as it evaluated the prudency and efficiency of our plans and forecasts for the 2024-2029 regulatory control period. This involved responding to information requests and making adjustments to the Original Proposal.

Feedback on the top five topics received from stakeholders and the AER and how we have responded is summarised in Table 5.

Table 5 How engagement has shaped our Revised Proposal

Key theme	What we've heard	How we've responded
Affordability	There was general support for TasNetworks to pursue an overall objective of affordability for customers, but also widespread concern about potential bill impacts and affordability for all customers, particularly if contingent projects proceed. It was also noted there are more effective ways to reduce customer costs than lowering prices. A more aggressive approach to pursuing affordability for customers was called for, with one stakeholder group advising TasNetworks to retest customer priorities to see if willingness to pay for key initiatives had changed due to increasing economic pressures since the Original Proposal was developed.	• We share customer concerns over the rising costs of living. We are committed to keeping our costs as sustainably low as possible without sacrificing reliability and safety, or undermining the delivery of our other priorities. • We have developed expenditure forecasts that satisfy the AER's top-down assessment. We have not proposed any changes to our expenditure in the Revised Proposal, despite increasing real costs and inflation. • We will continue to absorb cost increases and pursue cost reductions and efficiencies in our expenditure to pass back through to our customers via the EBSS and CESS. • We have updated our contingent project triggers to remove the connection of new generation from all but two of the proposed projects. The result of this is that if any contingent projects are to proceed, the costs of network upgrades will be contributed to by new connecting load(s), sharing the bill impact with existing customers. • Based directly on stakeholder and customer representative feedback, we have proposed a non-default smoothing approach to our MAR to moderate the price impact for our distribution customers (residential and small business). If approved by the AER, this would see a 10.8% price increase in 2024-25, followed by 2.3% per annum from 2026-29.

Key theme	What we've heard	How we've responded
Contingent projects	There was broad and significant concern about the potential pricing/bill impacts of contingent projects on all customer segments, and a perceived lack of transparency from TasNetworks regarding the sharing of the potential impacts. There were several calls for more consultation on the need for these projects, their triggers and bill impacts. One stakeholder noted that it was appropriate for contingents to be funded by government or developers, given they are related to achieving Tasmanian Government policies.	• Contingent projects aren't certain enough to be included in our base forecasts. However, there is a degree of probability that they will be triggered and needed during the 2024-2029 regulatory control period. As such, we need to include them as part of the Revised Proposal, otherwise they cannot be considered for action during that timeframe. • We have updated our contingent projects and their triggers, and shared the bill impact of the proposed contingent projects in engagement activities and the Revised Proposal. • We have updated our contingent project triggers to remove the connection of new generation from all bar two of the proposed projects. The result of this is that if any contingent projects are to proceed, the costs of network upgrades will be contributed to by new connecting load(s), sharing the bill impact with existing customers. • In response to the revised staging of the North West Transmission Developments, we have proposed a new contingent project (North West Network Upgrade) to improve the hosting capacity of the network in North West Tasmania.
Customer benefits	Multiple questions were received regarding whether customers should be paying for capital and operational investments driven by government policies. There were several calls for greater clarity and targeted consultation on how costs are allocated (who pays) and cross-subsidies are managed, and a suggestion that the business should be more customer-focused (and less network focused) with greater transparency regarding customer benefits.	• Our proposed capex and opex delivers clean and reliable power to our customers, as safely and affordably as possible. • The proposed investments in the 2024-2029 regulatory control period being driven by government policies are the proposed contingent projects. There are still rigorous processes to be followed to assess if these projects proceed and what revenue can be recovered from customers: • The Regulatory Investment Test for Transmission (**RIT-T**) process is focused on identifying the solution with the highest net benefits for customers. • The contingent project application process ensures that customers only pay for costs that are prudent and efficient to deliver the project. • Continuing our commitment to transparent and genuine engagement, we have broadened our engagement to cover topics outside of the 2024-2029 revenue reset, such as Tasmanian Government policy and Project Marinus. We will continue engaging with our customers on this beyond this revenue reset.

Key theme	What we've heard	How we've responded
Engagement	TasNetworks' engagement program was acknowledged by external stakeholders as being greatly improved over previous revenue resets (seen as broad and deep, as well as using a good variety of methods), but further improvement is needed to empower customers, provide clearer evidence of how plans have changed as a result of feedback, and give greater clarity around what can (and cannot) be influenced. There was broad concern that feedback hadn't made any tangible difference to the Original Proposal, and several calls for engagement to be ongoing (not just during resets). There were also several requests to increase the diversity of participants and feedback, as well as the number of individual customers being engaged. Having TasNetworks' key decision makers present at engagement activities was noted as desirable.	• From mid-2023, we commenced embedding revenue resets into everyday business, enabling an earlier start to the overall program, including engagement planning. This will allow time to identify topics and investments customers can genuinely influence, and ensure the business is committed to hearing and actioning customer feedback. • We will undertake a full review of the composition of TasNetworks' advisory groups in early 2024 to ensure greater diversity in representation - as identified through 2023 customer segmentation research. • We will introduce a broader engagement framework to the business in early 2024 – paving the way for a more effective and consistent engagement approach across the whole business. This will focus on building capability internally to drive a more customer centric approach, and also externally with our stakeholders so they are able to engage at a deeper level. This will ensure TasNetworks remains responsive to changes in customers' needs and market pressures.
Revenue	Submissions acknowledged that the proposed revenue for both transmission and distribution networks is higher than the current regulatory control period, and the pressure this will place on prices. Concern was also expressed over the impacts and uncertainty of inflation, the rate of return and financing costs for small businesses and customers.	• Movements in market variables, such as updates for expected inflation and the rate of return, have led to higher revenue outcomes than the Original Proposal. The AER will update the Revised Proposal for these variables prior to the final decision in April 2024. • We have not proposed any changes to our expenditure in the Revised Proposal, despite increasing real costs and inflation. • We have updated our contingent project triggers to remove the connection of new generation from all but two of the proposed projects. Meaning that if any contingent projects are to proceed, the costs of shared network upgrades will be shared with the new connecting load(s), sharing the bill impact with existing customers.

4. Revised capital and operating expenditure for 2019-2024 regulatory control period

TasNetworks' capex and opex performance during the current 2019-2024 regulatory control period provides context for forecast expenditure in the 2024-2029 regulatory control period. It is also a key input to a range of building block elements such as the EBSS, CESS and the RAB.

The Revised Proposal updates capex and opex for 2022-23 actual expenditure and forecast capex for 2023-24, impacting revenue building block outcomes through changes to the EBSS, CESS and RAB. There is no change to our expenditure profile for the first three years of the 2019-2024 regulatory control period.

Revised capex for 2019-2024 regulatory control period

The revised capex for the 2019-2024 regulatory control period is $646.0 million on the distribution network and $267.0 million on the transmission network, as shown in Table 6 and Table 7. Distribution capex in the Revised Proposal is $17.8 million lower ($ nominal) than the AER's draft decision capex while our revised forecast of transmission network capex is $11.2 million higher ($ nominal). The differences between the Original Proposal and the Revised Proposal reflect:

- lower actual capex in 2022-23 than forecast in the Original Proposal for both the distribution and transmission networks
- revised capex forecasts for 2023-24 with distribution being slightly lower than previously forecast and transmission being higher, reflecting budgeted expenditure for the year.

Table 6 Distribution net capex – draft decision v Revised Proposal ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24 (forecast)	Total
Draft decision	115.6	133.5	117.6	141.1	155.9	663.8
Revised Proposal	115.6	133.5	117.6	127.7	151.5	646.0
Difference	-	-	-	(13.4)	(4.4)	(17.8)
Difference (%)	-	-	-	-9.5%	-2.8%	-2.7%

Table 7 Transmission net capex – draft decision v Revised Proposal ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24 (forecast)	Total
Draft decision	50.3	44.8	45.4	60.8	54.5	255.8
Revised Proposal	50.3	44.8	45.4	56.3	70.3	267.0
Difference	-	-	-	(4.5)	15.8	11.2
Difference (%)	-	-	-	-7.4%	29.0%	4.4%

Revised opex for 2019-2024 regulatory control period

As 2021-22 is the base year nominated by TasNetworks for the purpose of determining TasNetworks' opex allowance in the AER's draft decision and final expenditure for that year was provided in the Original Proposal, there is no update to our base year efficient opex in the Revised Proposal for the purposes of setting our opex allowances in the 2024-2029 regulatory period. However, we have updated our opex forecasts for 2022-23 used in the EBSS with actual expenditure for that year. These updates and the impact on the EBSS outcome are discussed in section 12 Efficiency benefit sharing scheme.

5. Forecast capital expenditure

Our capex forecasts for the 2024-2029 regulatory control period have been developed with the objective of maintaining a safe, reliable and secure network at a sustainable cost.

Original Proposal

The Original Proposal included the following total forecast net capex for the 2024-2029 regulatory control period ($2023-24):

- $729.3 million for the distribution network
- $287.8 million for the transmission network.

We also proposed seven contingent projects for the transmission network in the 2024-2029 regulatory control period, which are discussed further in section 6 Contingent projects. No contingent projects were identified in relation to the distribution network.

Draft decision

The AER's draft decision accepted TasNetworks' total capex forecasts for both the distribution and transmission networks, deeming them to be both prudent and efficient at an overall level. Specifically, the AER considered that both forecasts:

> *"...reasonably reflect the capex criteria and will provide for a prudent and efficient service provider in TasNetworks' circumstances to maintain the safety, reliability and security of electricity supply of the network."*

and that,

> *"...TasNetworks' total forecast capex ... reflects TasNetworks' commitment to affordability. We are also satisfied that TasNetworks can maintain its existing levels of safety and reliability. This is because overall, TasNetworks' forecast capex reflects a similar work program to its current period."*

TasNetworks acknowledges the AER's feedback regarding opportunities for continued improvement for future revenue proposals and investment governance practices, and this work has commenced.

Response to the draft decision

TasNetworks accepts the AER's draft decision in relation to capex forecasts for both the distribution and transmission networks in the 2024-2029 regulatory control period. TasNetworks' forecast capex is presented in Table 8. These forecasts are consistent with the Original Proposal and the AER's draft decision.

Table 8 Forecast net capex 2024-2029 ($million, 2023-24)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Distribution	155.5	160.7	141.9	136.9	134.4	729.3
Transmission	52.0	67.8	58.7	57.7	51.6	287.8

Figure 3 and Figure 4 present TasNetworks' forecast capex in the 2024-2029 regulatory control period for its distribution and transmission networks respectively, and how it compares to past expenditure. These forecasts have been updated from those provided in the Original Proposal to reflect actual expenditure for 2022-23, and the most recent forecast of the level of capex expected in 2023-24.

Figure 3 Distribution network capex – historical and forecast

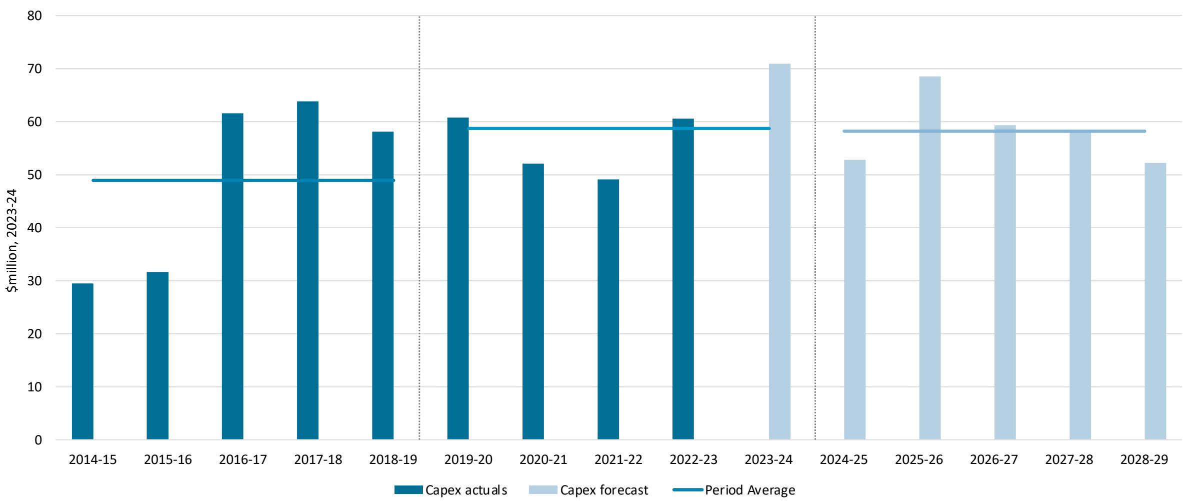
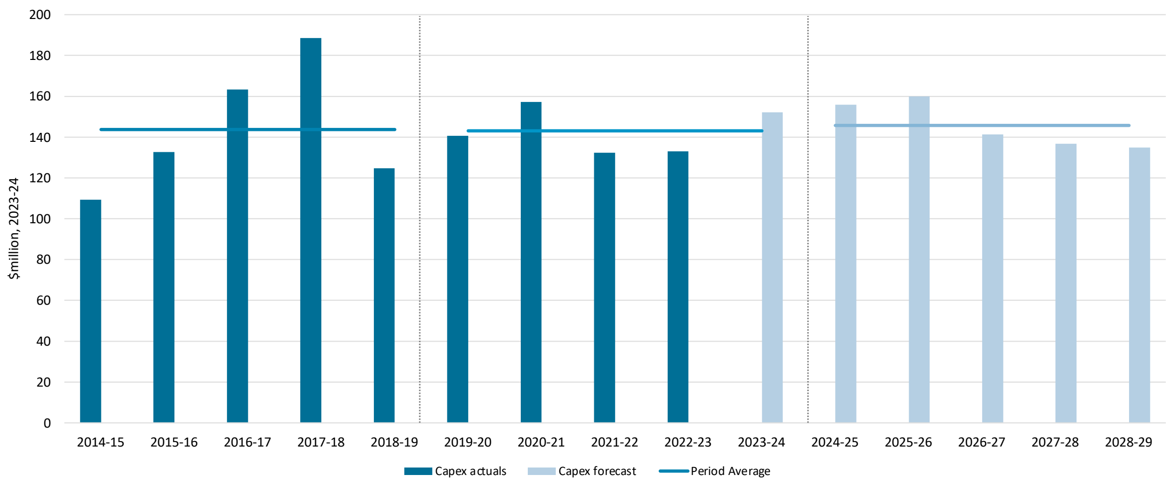


Figure 4 Transmission network capex – historical and forecast



6. Contingent projects

Original Proposal

In the Original Proposal, TasNetworks nominated seven contingent projects relating to major augmentations of our transmission network. These projects were deemed necessary to support the Tasmanian Government's renewable energy objectives, including the Tasmanian Renewable Energy Target (**TRET)** and Tasmanian Renewable Hydrogen Action Plan (**TRHAP**). Given the scale and timing of the TRET and TRHAP, all seven projects were considered likely to occur during the 2024-2029 regulatory control period. These projects are summarised in Table 9.

Table 9 Original Proposal contingent projects

Contingent Project	Driver	Project Summary
George Town Reactive Support (Stage 1)	New load connecting to the transmission network in the George Town-Bell Bay area	Provide dynamic reactive support to meet power system voltage and system stability requirements following new load connections in George Town.
George Town Reactive Support (Stage 2)		Provide further reactive support to meet power system voltage and system stability requirements. We expected this project would be required to connect load above 300 MW in George Town.
George Town Substation Network Reinforcement		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 standard obligations following new load in George Town.
Palmerston to Sheffield Network Upgrade	New load connecting to the transmission network in the George Town-Bell Bay area and / or New generator commitment in North West or Central Highlands	Upgrade the transmission corridor between Palmerston and Sheffield to maintain network stability following connection of new load in George Town or connection of new generation in north west or central Tasmania.
Sheffield to George Town Network Upgrade		Upgrade the transmission corridor between Sheffield and George Town to maintain network stability. We expected this project would be required to connect load above 300 MW in George Town or new generation in north west or central Tasmania.
Palmerston to George Town via Hadspen Network Upgrade		Upgrade the transmission corridor between Palmerston and George Town to address thermal capacity issues. We expected this project would be required to connect load above 700 MW in George Town or connect new generation in north west or central Tasmania.
Waddamana to Palmerston transfer capability upgrade	New generator commitment in the Central Highlands or Southern Tasmania	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.

For new load or generation to trigger the need for these contingent projects, TasNetworks proposed that the project must be "committed", consistent with AEMO's commitment criteria for generation projects[6] and TasNetworks' commitment criteria for new load connections[7] respectively.

In addition to the load/generation trigger, TasNetworks proposed Board approval to pursue the project and successful completion of a RIT-T as additional triggers. The exact triggers presented to the AER can be found in Attachment 7 of the Original Proposal.

Draft decision

In its draft decision, the AER did not accept any of our nominated load-related contingent projects on the basis that the triggers did not meet the requirements of the NER. In making its decision, the AER stated that it is generally supportive of the need for the projects, but that the trigger definitions were not sufficient to allow objective assessment that the projects have been triggered. Specifically, the AER suggested TasNetworks refer to the amount of new load required to trigger the projects.

The AER did not accept the Waddamana-Palmerston transfer capability upgrade contingent project, reflecting its view that projects required to connect new generation should be delivered through AEMO's ISP.

Response to the draft decision

Since submitting the Original Proposal we have undertaken further technical and economic studies to refine the trigger events associated with our proposed contingent projects and quantify the volume of new connections at exact locations in our network that would trigger the need for these specific projects.

The AER acknowledged this work in their draft decision but had insufficient time to consider them for inclusion in the draft decision.

A summary of the changes from the Original Proposal are:

- updated technical analysis to confirm the new load / generator connections that will trigger the contingent projects
- simplification of the first trigger event so that it is objectively verifiable and refers to a specific location
- a simplified regulatory investment test (**RIT**) trigger that removes references to specific NER clauses and has been updated to reference AER satisfaction
- removal of the Palmerston to George Town via Hadspen Network Upgrade contingent project, which is no longer considered likely in the 2024-2029 regulatory control period
- amalgamation of the George Town Reactive Support (Stage 1) project and the George Town Substation Network Reinforcement project into a single project, the George Town Network Upgrade
- addition of the North West Network Upgrade contingent project required following amendments to the scope of Project Marinus.

These changes are described in more detail in Appendix A – Contingent projects supporting information and the Contingent Project Overview report attached as part of this submission.

Of the six contingent projects put forward in the Revised Proposal, four are considered necessary to support new load developments in the George Town area, one is required to support new wind generation in the Central Highlands Renewable Energy Zone (**REZ**), and one is required to support new load or generation in the North West. Except for the removal of the Palmerston-George Town project, and the addition of the North West Network Upgrade project, the indicative solutions and costs remain unchanged from the Original Proposal. A summary of each of the contingent projects can be found in Table 10.

6 AEMO, *NEM Generation Information, July 2023*

7 TasNetworks', *Guide to Transmission Connections, p.14*

Table 10 Revised Proposal contingent projects

Project	Summary	Revised triggers	Indicative cost ($m, 2023-24)[8]
George Town Network Upgrade • Reactive support (stage 1) • Substation reinforcement	With new load developments in George Town, TasNetworks becomes non-compliant with our reliability requirements. The proposed augmentations to address this issue include: • construction of a new substation in George Town and rearranging the existing substation; and • installation of additional reactive support. We expect this project to be required following 210 MW of new load at George Town.	1. Commitment of at least 210 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates a network investment 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.	135 (52+83)
Palmerston to Sheffield Network Upgrade	Despite the George Town Network Reinforcement, TasNetworks is still non-compliant with our reliability requirements following 210 MW of new load at George Town. This project is included as a separate contingent project as it is also part of the North West Transmission Developments associated with Project Marinus.	1. Commitment of at least 210 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates a network investment 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.	240
George Town Reactive Support (stage 2)	Following further load at George Town, stability constraints will begin to emerge. This project is needed to avoid constraining supply to George Town. We expect this project to be required following 350 MW of new load at George Town.	1. Commitment of at least 350 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates a network investment 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.	90

8 Direct capex only for options identified in November 2023. Further refinement to occur through the planning process.

Project	Summary	Revised triggers	Indicative cost ($m, 2023-24)[8]
Sheffield to George Town Network Upgrade	Further increase in George Town load will introduce thermal and stability issues in the network. This project is needed to avoid constraining supply to George Town. We expect this project to demonstrate net market benefits following 712 MW of new load at George Town.	1. Commitment of at least 712 MW of additional load to connect to the transmission network at George Town 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates that 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	188
Waddamana to Palmerston Transfer Capability Upgrade	With new wind development in the Central Highlands' REZ, constraints begin to emerge in the Waddamana to Palmerston corridor. This project will improve the hosting capacity of the REZ. We expect this project to be required following 660 MW of new generation in the Central Highlands REZ.	1. Commitment of at least 660 MW of new generation in the Central Highlands REZ 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the transfer capability of the Waddamana–Palmerston transmission corridor is the preferred option that provides net market benefits and / or addresses a reliability corrective action 3. Commitment by TasNetworks' Board to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER	128
North West Network Upgrade	With new wind or load development in North West Tasmania, constraints begin to emerge in the Burnie to Hampshire corridor. This project will improve the hosting capacity of the network in North West Tasmania. We expect this project to be required following 100 MW of new generation or load in North West Tasmania.	1. Commitment of at least 100 MW of new generation or load to connect at Hampshire 2. AER is satisfied that TasNetworks has successfully completed a RIT-T that demonstrates upgrading the network in North West Tasmania is the preferred option that provides net market benefits and / or addresses a reliability corrective action 3. Commitment by TasNetworks' Board to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER	174

7. Forecast operating expenditure

Opex refers to the operational and other non-capital expenditure required to operate and maintain our transmission and distribution networks, and includes the costs associated with the following important activities:

- ongoing inspection, maintenance, and repair of network assets
- control of vegetation growth close to our assets, to reduce safety hazards and interruptions to supply
- fault and emergency repairs and supply restoration following adverse events like storms and equipment failures
- customer service and corporate support activities like procurement, as well as the financial, legal, and regulatory reporting required to meet our legislative obligations.

Original Proposal

The proposed total opex in the Original Proposal, including debt raising costs, was $541 million for the distribution network ($2023-24) and $209.2 million for the transmission network ($2023-24).

Our opex forecasts were developed using the AER's preferred base-step-trend methodology. The Original Proposal adopted 2021-22 as the base year for both the transmission and distribution networks, on the basis that our opex in that year was efficient and provided a sound basis for projecting our future opex requirements using the base-step-trend methodology.

The Original Proposal also proposed a productivity factor of 3.0 per cent efficiency to apply to the base year expenditure for both networks in the first year of the 2024-2029 regulatory control period (2024-25), with a further 0.5 per cent efficiency applied in each year of the regulatory control period thereafter. These opex efficiencies help offset the step changes proposed to cover anticipated increases in insurance and cyber security costs.

Draft decision

In its draft decision, the AER accepted our total forecast opex, including debt raising costs, as in total it was not materially different to the AER's alternative forecasts. While there was no material difference in total opex, there were some key differences between the AER's approach and the Original Proposal, including:

- productivity growth - we adopted a higher than industry average productivity growth rate of 3.0 per cent in the first year of the next regulatory control period, followed by 0.5 per cent per annum, whereas the AER applied its standard approach of using the latest industry average rate of 0.6 per cent for transmission and 0.5 per cent for distribution across each year of the regulatory control period
- step changes – the AER reduced the proposed step changes by $6.3 million for transmission and $6.6 million for distribution.

We accept the AER's draft decision on our total opex, including debt raising costs, for the transmission and distribution networks. TasNetworks' forecast total opex for the 2024-2029 regulatory control period in the Revised Proposal is the same as approved by the AER in the draft decision.

8. Regulatory asset base

The value of the RAB is the largest determinant of TasNetworks' revenue and, therefore, the network charges paid by the end users of electricity in Tasmania. The NER requires the transmission and distribution building block proposals to each include a calculation of the RAB for each year of the 2019-2024 regulatory control period, derived using the AER's roll forward model (**RFM).** In this way, the RFM is used to calculate the value of the RAB at the beginning of the 2024-2029 regulatory control period, which feeds into the AER's model to forecast TasNetworks' RAB in the 2024-2029 regulatory control period.

Original Proposal

The Original Proposal proposed an opening RAB for the distribution network of $2,223.0 million ($ nominal) as at 1 July 2024 and a closing RAB as at 30 June 2029 of $2,674.0 million ($ nominal). For Tasmania's transmission network we proposed an opening RAB value of $1,758.7 million ($ nominal) and a closing value of $2,001.7 million ($ nominal).

Draft decision

In its draft decision, the AER largely accepted our proposed RAB values, with some adjustments including:

- the correction of some input errors
- updates for actual and forecast inflation
- an updated WACC for 2023-24

The AER determined an opening RAB value for the distribution network of $2,242.0 million ($ nominal) as at 1 July 2024 and a closing value as at 30 June 2029 of $2,565.9 million ($ nominal). For TasNetworks' transmission network the AER determined an opening RAB value of $1,665.1 million ($ nominal) and a closing value as at 30 June 2029 of $1,869.3 million ($ nominal).

Response to the draft decision

We accept the AER's draft decision approach. We have applied standard updates to our RAB forecasts in the Revised Proposal to reflect updated capex inputs for final 2022-23 expenditure and updated forecasts for 2023-24. In addition, for the transmission network we have reclassified $6.9 million of asset value previously used for prescribed services to negotiated services at the start of the 2024-2029 regulatory control period. This amount was inadvertently not included as a RAB adjustment in the Original Proposal. We have now included that adjustment for the Revised Proposal, as shown in Table 13.

Our updated opening RAB value for the distribution network as at 1 July 2024 is now forecast to be $2,222.8 million ($ nominal) with a closing value as at 30 June 2029 of $2,534.9 million ($ nominal). For the transmission network the updated opening RAB value is $1,669.6 million ($ nominal) with a closing value as at 30 June 2029 of $1,878.0 million ($ nominal). The updated RAB roll forwards for both the 2019-2024 regulatory control period and the 2024-2029 regulatory control period are detailed in Table 11 through to Table 14.

Table 11 Revised distribution RAB roll-forward for the 2019-2024 period ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening RAB	1,771.1	1,822.5	1,867.5	1,940.8	2,106.8
Actual/estimated capital expenditure, net of contributions and disposals	118.2	135.8	121.2	134.2	156.5
Indexation on opening RAB	32.6	15.7	65.3	152.0	86.4
Less: Straight-line depreciation	(99.4)	(106.5)	(113.2)	(120.2)	(133.2)
Final year (2018-19) adjustments					6.3
Closing RAB	1,822.5	1,867.5	1,940.8	2,106.8	2,222.8

Table 12 Revised distribution RAB roll-forward for the 2024-2029 period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	2,222.8	2,299.7	2,377.9	2,433.4	2,485.0
Actual/estimated capital expenditure, net of contributions and disposals	162.2	172.3	156.5	155.3	156.8
Indexation on opening RAB	62.2	64.4	66.6	68.1	69.6
Less: Straight-line depreciation	(147.5)	(158.5)	(167.5)	(171.7)	(176.5)
Closing RAB	2,299.7	2,377.9	2,433.4	2,485.0	2,534.9

Table 13 Revised transmission RAB roll-forward for the 2019-2024 period ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening RAB	1,445.3	1,472.1	1,472.6	1,510.5	1,625.0
Actual/estimated capital expenditure, net of contributions and disposals	51.5	45.6	46.8	59.2	72.6
Indexation on opening RAB	26.6	12.7	51.5	118.3	66.6
Less: Straight-line depreciation	(51.2)	(57.8)	(60.4)	(63.0)	(71.7)
Final year (2018-19) adjustments					(16.0)
Reclassified assets removed from RAB					(6.9)
Closing RAB	1,472.1	1,472.6	1,510.5	1,625.0	1,669.6

Table 14 Revised transmission RAB roll-forward for the 2024-2029 period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	1,669.6	1,700.8	1,752.7	1,793.5	1,838.3
Actual/estimated capital expenditure, net of contributions and disposals	54.3	72.7	64.8	65.4	60.2
Indexation on opening RAB	46.7	47.6	49.1	50.2	51.5
Less: Straight-line depreciation	(69.7)	(68.5)	(73.1)	(70.8)	(70.9)
Closing RAB	1,700.8	1,752.7	1,793.5	1,838.3	1,878.0

9. Corporate income tax

The building block for the estimated cost of corporate income tax takes into account 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 the costs that would be incurred by a benchmark efficient entity operating the energy network, meaning the forecasts will typically differ from an NSP's actual tax liabilities.

Original Proposal

The corporate income tax allowance approved by the AER is calculated using the Australian corporate tax rate of 30 per cent, reduced by a forecast benefit to network owners of imputation credits.

Given the timing of the completion of the AER's review of the 2022 Rate of Return Instrument (**RoR Instrument)** TasNetworks applied the AER's 2018 RoR Instrument in the Original Proposal. The value of imputation credits was based on a gamma value of 0.585 and a statutory tax rate of 30 per cent.

On this basis, in the Original Proposal we proposed a corporate income tax allowance of $35.4 million ($ nominal) for the distribution network and $8.5 million ($ nominal) for the transmission network.

Draft decision

The AER accepted most elements of our Original Proposal, including:

- no immediate expensing of forecast capex
- no forecast capex associated with buildings (capital works) that is exempted from the diminishing value tax depreciation method
- continued use of the tracking depreciation method to calculate the forecast tax depreciation of existing assets
- standard tax asset lives.

The AER also updated other elements related to the estimate of corporate income tax that impact on the outcome, including:

- higher regulatory depreciation (and higher revenue) driven by the use of lower rate of expected inflation (2.8%) than TasNetworks used in developing its Original Proposal (3.35%)
- adjustments to our depreciation which result in lower tax depreciation for the transmission network and higher tax depreciation for the distribution network (see section 10 Regulatory depreciation)
- a lower gamma value of 0.57 for the value of imputation credits consistent with the 2022 RoR Instrument, which increases the estimate of corporate income tax as it reduces the imputation credit offset.

The AER's draft decision includes a higher estimated cost of corporate income tax than the Original Proposal, allowing for corporate income tax of $46.5 million ($nominal) for the distribution network and $13.1 million ($nominal) for the transmission network.

Response to the draft decision

We accept the AER's draft decision approach. We have only updated our estimate of corporate income tax to reflect the updated inputs from our revised annual revenue requirement, including a revised opening value for the tax asset base (**TAB**) reflecting final 2022-23 capital expenditure and updated forecasts for 2023-24 (refer section 4 Revised capital and operating expenditure for 2019-2024 regulatory control period). This results in an opening TAB value for the 2024-2029 regulatory control period of $1,691.3 million for the distribution network and $1,089.8 million for the transmission network. The Revised Proposal now incorporates corporate income tax allowances of $46.8 million ($ nominal) and $14.1 million ($ nominal) for the distribution and transmission networks, respectively. These revised TAB and corporate tax outcomes are detailed in Table 15 through to Table 18.

Table 15 Revised distribution TAB roll forward to 30 June 2024 ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening TAB	1,383.8	1,446.9	1,519.4	1,574.8	1,629.8
Plus capex, net of contributions and disposals	132.1	152.1	146.5	154.9	165.1
Less tax depreciation	(69.0)	(79.6)	(91.1)	(99.9)	(103.7)
Closing TAB	1,446.9	1,519.4	1,574.8	1,629.8	1,691.3

Table 16 Revised distribution forecast tax allowance ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Tax payable	21.8	21.5	20.5	21.9	23.2	108.8
Less: value of imputation credits	(12.4)	(12.2)	(11.7)	(12.5)	(13.2)	(62.0)
Net corporate income tax allowance	9.4	9.2	8.8	9.4	10.0	46.8

Table 17 Revised transmission TAB roll forward to 30 June 2024 ($million, nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Opening TAB	1,105.7	1,120.6	1,109.5	1,102.1	1,085.6
Plus capex, net of contributions and disposals	58.0	37.4	43.3	33.6	62.1
Less tax depreciation	(43.2)	(48.5)	(50.7)	(50.2)	(51.0)
Closing TAB	1,120.6	1,109.5	1,102.1	1,085.6	1,089.8

Table 18 Revised transmission forecast tax allowance ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Tax payable	8.2	4.9	5.7	6.2	7.8	32.8
Less: value of imputation credits	(4.7)	(2.8)	(3.3)	(3.5)	(4.4)	(18.7)
Net corporate income tax allowance	3.5	2.1	2.5	2.7	3.3	14.1

10. Regulatory depreciation

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. In the context of a building block revenue determination, the inclusion of depreciation as one of the building blocks is intended to enable networks to recover the cost of their capital investments over the expected useful lives of the assets associated with the provision of network services.

Original Proposal

We calculated depreciation using the year-by-year tracking approach approved by the AER for our 2019-2024 regulatory control period. We continue to apply the same standard asset lives and straight-line depreciation approach previously approved by the AER.

Our regulatory depreciation (also referred to as return of capital) in any given year is calculated by deducting the inflation adjustment made to the RAB from forecast depreciation.

In the Original Proposal we proposed regulatory depreciation forecasts of $362.4 million ($ nominal) for the distribution network and $78.5 million ($ nominal) for the transmission network.

Draft decision

The AER accepted most elements of the Original Proposal in relation to regulatory depreciation, including:

- the straight-line depreciation method used to calculate the regulatory depreciation amount
- the continuation of the year by year tracking approach to depreciation
- the proposed asset classes and asset lives (except the AER adjusted the asset life for distribution equity raising and created a new asset class for composite poles)
- standard tax asset lives

The AER also updated the commencement date for our year by year tracking to reflect previous determinations and updated the expected inflation rate. The updates have a material impact on regulatory depreciation. The AER's draft decision allows for regulatory depreciation of $479.1 million ($ nominal) for the distribution network and $113.2 million ($ nominal) for the transmission network.

Response to the draft decision

TasNetworks accepts the AER's draft decision approach in relation to regulatory depreciation. In the Revised Proposal we have only applied standard updates to our depreciation forecast to reflect updated capex inputs for final 2022-23 expenditure and updated forecasts for 2023-24, as well as updated RAB inputs. Our updated regulatory depreciation forecast of $490.9 million for distribution ($ nominal) and $108.9 million for transmission ($ nominal) is set out in Table 19 and Table 20.

Table 19 Updated distribution forecast regulatory depreciation ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Forecast straight-line depreciation	147.5	158.5	167.5	171.7	176.5	821.8
Less: RAB indexation	(62.2)	(64.4)	(66.6)	(68.1)	(69.6)	(330.9)
Regulatory depreciation	85.3	94.1	101.0	103.6	106.9	490.9

Table 20 Updated transmission forecast regulatory depreciation ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Forecast straight-line depreciation	69.7	68.5	73.1	70.8	71.9	354.0
Less: RAB indexation	(46.7)	(47.6)	(49.1)	(50.2)	(51.5)	(245.1)
Regulatory depreciation	23.0	20.8	24.0	20.6	20.5	108.9

11. Rate of return and inflation

A key component of TasNetworks' revenue allowances set by the AER is the return on capital. 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 RoR Instrument – to the value of each network's RAB.

The RoR Instrument prescribes 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). The rate of return that is set by the AER needs to have appropriate regard to the prevailing financial market conditions and outlook at the time of the revenue determination.

A key parameter in the AER's RoR Instrument is estimated using the Australian Government bond yield. This is reset close to the commencement of each regulatory control period based on prevailing market rates.

Original Proposal

In the Original Proposal, we applied the AER's binding 2018 ROR Instrument to estimate our forecast rate of return. The Original Proposal estimated a placeholder rate of return of 5.71 per cent for the distribution network and 5.68 per cent for the transmission network for 2024-25, the first year of the 2024-2029 regulatory control period.

TasNetworks applied a placeholder estimate of expected inflation during the 2024-2029 regulatory control period of 3.35 per cent, based on the application of the AER's methodology for forecasting inflation.

Draft decision

In its draft decision, the AER:

- updated the rate of return to reflect the 2022 RoR Instrument which was published in February 2023
- accepted our proposed risk free rate and debt averaging periods
- updated WACC and inflation for later input data, with a further update to the AER's estimates of WACC and inflation expected in the AER's final decision.

The AER's draft decision applies a placeholder rate of return of 5.80 per cent for the distribution network and 5.77 per cent for the transmission network in the first year of the 2024-2029 regulatory control period (2024-25). The AER's draft decision updated the estimate of expected inflation during the 2024-2029 regulatory control period to 2.8 per cent.

Response to the draft decision

We accept the AER's draft decision approach to setting the return on capital to apply to TasNetworks in the 2024-2029 regulatory control period. We have not updated for either the rate of return or inflation in the Revised Proposal. For inflation the AER's draft decision uses data from the latest (August 2023) Reserve Bank of Australia's (**RBA's)** Statement of Monetary Policy, meaning no further update could be undertaken. Although later data could be applied to the placeholder rate of return calculation in the Revised Proposal, there has been no material change since the AER's draft decision and future movement is highly uncertain. The AER will update the value for WACC and expected inflation in its final decision.

Consistent with the AER's draft decision, our Revised Proposal estimates rates of return of 5.80 per cent for the distribution network and 5.77 per cent for the transmission network for 2024-25, the first year of the 2024-2029 regulatory control period. Also consistent with the AER's draft decision, we have utilised an expected inflation forecast of 2.80 per cent. The rate of return parameters used for the Revised Proposal are set out in Table 21.

Table 21 Rate of return parameters

	Value (Distribution)	Value (Transmission)
Risk-free rate	3.95%	3.95%
Market risk premium	6.20%	6.20%
Equity beta	0.6	0.6
Gearing	60%	60%
Return on equity	7.67%	7.67%
Return on debt	4.56%	4.51%
WACC – post tax nominal	5.80%	5.77%
Inflation	2.80%	2.80%

12. Efficiency benefit sharing scheme

The EBSS gives NSPs a continuous incentive to pursue 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 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.

Original Proposal

In the Original Proposal, we included forecast net carryover amounts for the EBSS for the current 2019-2024 regulatory control period and targets for the 2024-2029 regulatory control period. These amounts were calculated consistent with the AER's 2013 EBSS (Version 2).

In addition to the excluded cost categories from the 2019-2024 regulatory control period, we proposed two new exclusions for the transmission EBSS – opex arising from actionable ISP projects and opex arising from REZ developments.

Draft decision

The AER's draft decision:

- corrected movements in our opex provisions from 2017-18 to 2021-22
- updated 2021-22 actual opex
- updated the excludable costs from 2020-21 to 2022-23
- updated actual and forecast inflation
- included self-insurance costs from 2017-18 to 2018-19 that TasNetworks had excluded.

The AER accepted our proposed exclusions from the EBSS, except for:

- NEM levy payments (distribution)
- opex arising from actionable ISP projects and opex arising from REZ developments (transmission).

The AER's draft decision EBSS net carryover from the 2019-2024 regulatory control period is a $9.7 million ($ nominal) penalty for distribution and a $3.5 million ($ nominal) penalty for transmission. In the final decision, the AER will update the EBSS carryover calculations to reflect actual opex for 2022-23 and also updates for inflation.

Response to the draft decision

We accept the AER's draft decision and have only updated our opex forecasts for 2022-23 with actual expenditure for that year, as required.

The EBSS net carryover amounts for the revised proposal have been updated for actual 2022-23 opex. Our updated EBSS net carryover from the 2019-2024 regulatory control period is a $23.0 million ($ nominal) penalty for distribution and a $6.6 million ($ nominal) penalty for the transmission network, as shown in Table 22 and Table 23.

Table 22 Revised distribution EBSS carryover amount from the 2019-2024 regulatory control period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Distribution EBSS carryover	(5.4)	(5.3)	2.6	-	(15.0)	(23.0)

Table 23 Revised transmission EBSS carryover amount from the 2019-2024 regulatory control period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Transmission EBSS carryover	1.2	(4.1)	(1.1)	-	(2.6)	(6.6)

13. Capital expenditure sharing scheme

The CESS provides an incentive for NSPs to pursue efficiency improvements in their capital works programs and provides for a fair sharing of those efficiency gains between NSPs and customers. Under the AER's CESS Guideline, 70 per cent of any capex efficiencies are shared with customers, with 30 per cent retained by the NSP. The AER determines separate CESS rewards or penalties for TasNetworks' transmission and distribution networks.

Original Proposal

In the Original Proposal, we included forecast net carryover amounts for the CESS for the current 2019-2024 regulatory control period and targets for the 2024-2029 regulatory control period. These amounts were calculated consistent with the AER's 2013 CESS (Version 1).

We also proposed excluding ISP projects from the transmission CESS in the 2024-2029 regulatory control period.

Draft decision

The AER's draft decision:

- updated modelling inputs for inflation and the rate of return
- updated the true-up calculation relating to the previous period (2018-19)

The AER did not accept the exclusion from the CESS for an actionable ISP project as they considered it is more appropriate to consider this as part of the actionable ISP project contingent project application (**CPA**).

The AER's draft decision CESS net carryover from the 2019-2024 regulatory control period is a $5.9 million ($nominal) bonus for the distribution network and a $7.2 million ($nominal) bonus for the transmission network. In its final decision, the AER will update the CESS carryover calculations to reflect actual capex for 2022-23 and updated forecasts for 2023-24, along with updates for inflation.

Response to the draft decision

We accept the AER's draft decision and have only updated our capex forecasts for 2022-23 with actual expenditure for that year and provided an updated forecast of capex for 2023-24 as required.

Our revised CESS net carryover for the 2019-2024 regulatory control period is positive $12.4 million ($ nominal) for the distribution network and a positive carryover of $3.3 million ($ nominal) for the transmission network, as shown in Table 24 and Table 25 respectively.

Table 24 Revised distribution CESS carryover amount from the 2019-2024 regulatory control period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Distribution CESS carryover	2.4	2.4	2.5	2.6	2.6	12.4

Table 25 Revised transmission CESS carryover amount from the 2019-2024 regulatory control period ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Transmission CESS carryover	0.6	0.6	0.7	0.7	0.7	3.3

14. Demand management incentives and allowance

The Demand Management Incentive Scheme (**DMIS**) provides financial incentives for DNSPs to undertake efficient demand management solutions in operating its distribution network. The Demand Management Innovation Allowance Mechanism (**DMIAM**) is intended to provide NSPs with access to funds to research and develop demand management projects that have the potential to reduce long-term network costs.

Original Proposal

The Original Proposal sought to have the DMIS apply to the distribution network and DMIAM apply to the transmission and distribution networks for the 2024-2029 regulatory control period and identified two potential DMIAM projects on the distribution network. The DMIAM allowance is based on our overall revenue requirement. We estimated DMIAM allowances of $1.1 million for the transmission network and $2.6 million for the distribution network ($ nominal).

Draft decision

The AER's draft decision applies the DMIS and the DMIAM to TasNetworks for the 2024-2029 regulatory control period. The AER's final decision will determine the amount of the DMIAM allowance based on the final revenue allowance.

Response to the draft decision

We accept the AER's draft decision in relation to DMIS and the DMIAM. We have updated the DMIAM allowance based on the revenue forecasts in the Revised Proposal, resulting in estimated DMIAM allowances of $2.7 million ($ nominal) for the distribution network and $1.1 million for the transmission network ($ nominal).

15. Revenue

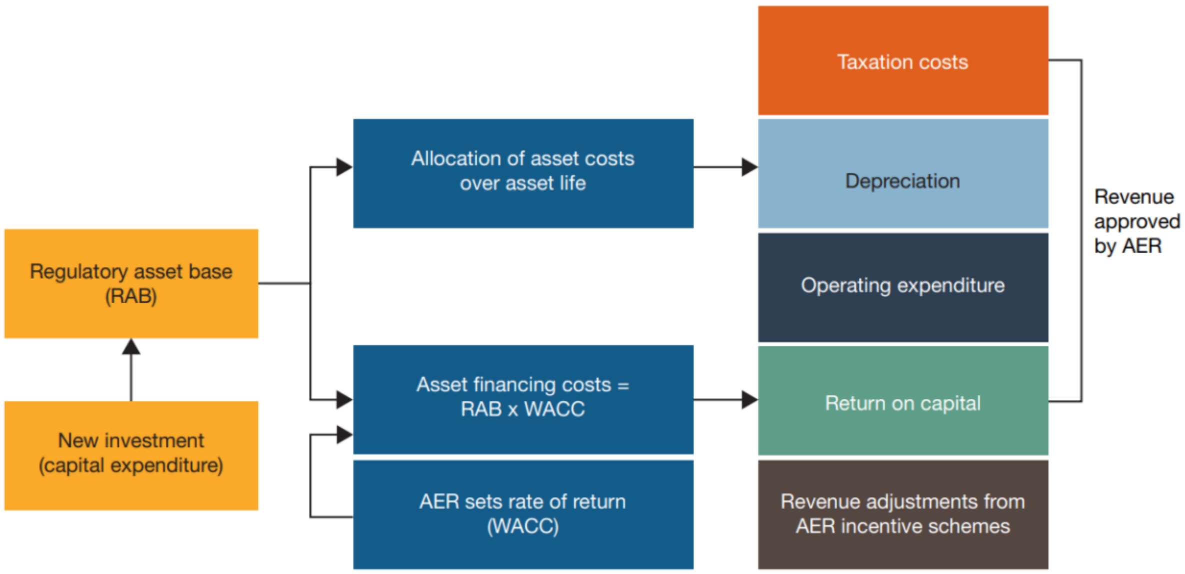
The revenue TasNetworks is allowed to earn through its network charges is intended to recover the cost of building, maintaining, and operating both the transmission and distribution networks. It also provides TasNetworks with a fair return on its investment in the assets used to transmit and distribute electricity, and enables TasNetworks to recover the cost of that investment over time (through a depreciation allowance).

The AER sets the maximum revenues that TasNetworks can collect from customers over the course of each regulatory control period using a 'building block' approach that sums the efficient costs incurred by TasNetworks in delivering safe, reliable, and secure network services. While the AER determines separate revenue allowances for the transmission and distribution networks, the revenue allowances for each network comprise the same five building block components:

- a return on capital
- depreciation
- forecast opex
- the estimated cost of corporate income tax
- revenue adjustments resulting from the application of the AER's incentive schemes.

Forecasts of capex, the value of each network's RAB and the rate of return – which is set by the AER as part of its determination process – are key inputs into a number of the building blocks used to set maximum revenues (see Figure 5).

Figure 5 Revenue building blocks



The individual components of revenue and our response to the AER's draft decision and the corresponding impacts have been discussed in the relevant preceding sections. This section consolidates those components into our overall revenue requirement or maximum allowed revenue (**MAR).**

Original Proposal

The forecast total revenue requirement in the Original Proposal for the 2024-2029 regulatory control period was $866.9 million for the transmission network and $1,714 million for the distribution network ($nominal, smoothed).

Draft decision

The AER's draft decision allows TasNetworks revenues of $1,826.0 million ($nominal, smoothed) for operating the distribution network and $880.1 million ($nominal, smoothed) for operating the transmission network, to be recovered from customers over the 2024-2029 regulatory control period. The AER's draft decision represents a 6.5 per cent increase from our forecast of distribution network revenue and a 1.5 per cent increase from our forecast of transmission revenue contained in the Original Proposal.

The drivers for the increase in our revenue requirements for the transmission and distribution networks are the same. The use of a lower expected rate of inflation by the AER impacts on the regulatory depreciation building block and there has been a slight increase in the WACC used by the AER. The AER also corrected errors in the depreciation modules within the RFMs that increased the revenue requirement for the distribution network while decreasing the revenue requirement for the transmission network.

Response to the draft decision

We have revised our forecast MAR for each network in the Revised Proposal consistent with the updates made to each building-block element in the AER's draft decision, as outlined in the preceding sections. These changes reflect updates to expenditure in the current regulatory control period, either to reflect actual expenditure outcomes for 2022-23 or to take into account the latest forecasts for 2023-24, in line with year-to-date expenditure and projected full-year outcomes.

Our revised revenue requirement for the distribution network in the 2024-2029 regulatory control period is $1,825.6 million ($nominal, smoothed), which is $0.4 million or 0.02 per cent lower than the AER's draft decision. For the transmission network the revised revenue requirement is $870.9 million ($nominal, smoothed), which is $9.2 million or 1.0 per cent lower than the AER's draft decision. The lower revenue requirement compared to the AER's draft decision predominantly reflects the updated negative outcomes of the EBSS and CESS through the revenue adjustment building block.

The distribution revenue requirement in the 2024-2029 regulatory control period is considerably higher than in the current 2019-2024 regulatory control period due to changes in financial parameters (WACC and forecast inflation) and improved efficiency scheme outcomes. Application of the default smoothing approach in the PTRM results in a significant increase in revenue (and consequentially price) in 2024-25 with low uniform increases over the final four years.

TasNetworks presented to stakeholders and customer representatives an alternate revenue smoothing option that reduced the 2024-25 price increases through a lower uniform revenue increase over the first three years of the regulatory control period and real decreases over the final two years. As required, the alternate smoothing is net present value (**NPV**) neutral from a revenue perspective and the final year smoothed revenue is within three percent of the unsmoothed revenue. Stakeholder consultation showed overwhelming support for the alternate smoothing approach, which has been applied in the Revised Proposal.

The breakdown of the revised revenue requirements into the building blocks is provided in Table 26 and Table 27.

Table 26 Revised distribution revenue requirement ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Return on capital	129.0	135.3	141.8	147.1	153.0	706.3
Return of capital	85.3	94.1	101.0	103.6	106.9	490.9
Operating expenditure	109.0	113.9	118.2	121.8	125.6	588.5
Taxation allowance	9.4	9.2	8.8	9.4	10.0	46.8
Revenue adjustments	(2.9)	(2.8)	5.2	2.6	(12.2)	(10.1)
Unsmoothed revenue requirement	329.7	349.8	375.0	384.5	383.3	1,822.4
Smoothed revenue requirement	316.4	346.9	380.3	387.4	394.7	1,825.6

Table 27 Revised transmission revenue requirement ($million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Return on capital	96.4	100.5	104.5	108.4	113.2	523.0
Return of capital	23.0	20.8	24.0	20.6	20.5	108.9
Operating expenditure	40.9	43.9	46.2	47.6	49.0	227.7
Taxation allowance	3.5	2.1	2.5	2.7	3.3	14.1
Revenue adjustments	2.1	(3.2)	(0.2)	0.9	(1.6)	(2.2)
Unsmoothed revenue requirement	165.9	164.1	177.0	180.2	184.4	871.5
Smoothed revenue requirement	165.9	169.9	174.1	178.3	182.7	870.9

16. Network pricing and price impacts

As a combined Transmission Network Service Provider (**TNSP**) and Distribution Network Service Provider (**DNSP**), TasNetworks prepares prices for both networks.

TasNetworks allocates our regulated transmission revenue among customers to ensure that the costs of the transmission network are shared equitably. The transmission revenue is allocated through the setting of prices at each connection point throughout Tasmania. The TNSP prices are charged to the DNSP, to be included in our distribution network pricing calculations.

DNSPs are required to prepare a tariff structure statement that sets out tariff classes, proposed tariffs and the structures and charging parameters, the strategy for the introduction of export tariffs, and the approach to setting tariff levels in each year of the regulatory control period. The policies and procedures a DNSP will use to assign customers to tariffs or reassign customers from one tariff to another must also be outlined.

Transmission network pricing

Original Proposal

TasNetworks' proposed Transmission Pricing Methodology (**methodology**) outlined our compliance with the pricing principles in Part J of Chapter 6A of the NER and with the AER's Pricing Methodology Guidelines. Our 2024-2029 methodology was amended from our 2019-2024 methodology to include:

- the *Reallocation of national transmission planner costs* rule 2020
- incorporating the *Integrating Energy Storage systems into the NEM* rule 2021
- incorporating the *Recovering the cost of the AEMO's participant fees* rule 2022
- more clearly outline the existing arrangement for TasNetworks as the co-ordinating network service provider (**CNSP)** in Tasmania.

The Original Proposal forecast a smoothed price path consistent with the smoothed revenue requirement over the 2024-2029 regulatory control period in real ($2023-24) terms. The Original Proposal indicated a price path for transmission customers that decreased by one per cent in the first year of the regulatory control period (2024-25), followed by increases of approximately 1.5 per cent each year after.

Draft decision

The AER did not accept our proposed methodology and recommended the following amendments:

- to incorporate the connection to dedicated assets rule 2021
- to further clarify the pricing arrangements should TasNetworks become the CNSP in Tasmania
- more clearly outline the arrangements for energy storage systems
- to incorporate changes to clarify how the prudent discount arrangement is consistent with NER clause 6A.26.1.

Response to the draft decision

We accept the AER's recommendations and proposed amendments and have resubmitted this document as part of our Revised Proposal with these changes.

We have updated forecast price impacts with the updates to the forecasted MAR for the transmission network outlined in previous sections. Figure 6 shows the price path for the average transmission network charges ($/MWh). Prices have increased on average by 2.6 per cent over the period, compared to 0.8 per cent in the Original Proposal. However, in real terms (2023-24), prices continue to remain relatively steady, consistent with TasNetworks' pricing strategy of predictable and sustainable prices.

Figure 6 Average network transmission charges - $ per MWh ($, 2023-24)

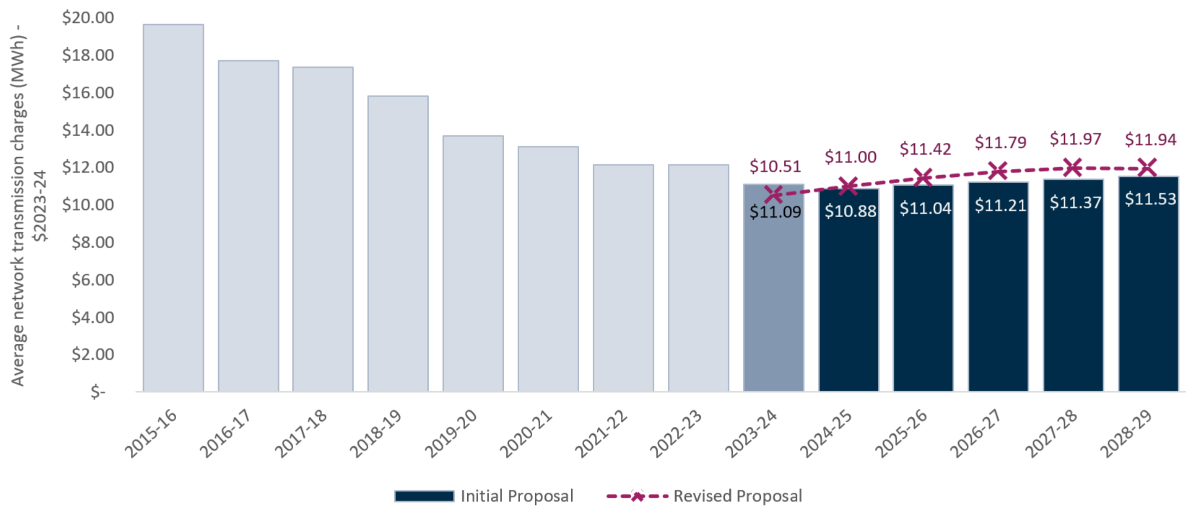


Table 28 Average increase in transmission charges (per MWh) over the period

	2023-24 Actual	2024-25	2025-26	2026-27	2027-28	2028-29	5 year average
Average transmission charge ($/MWh, 2023-24)	$10.51	$11.00	$11.42	$11.79	$11.97	$11.94	$11.62
Annual percentage change		4.7%	3.9%	3.2%	1.5%	-0.2%	2.6%

Distribution network pricing

Original Proposal

We set out the distribution network price setting process in two documents, our Tariff Structure Statement (**TSS**) and Tariff Structure Explanatory Statement (**TSES**). The TSS demonstrates our compliance with the NER and the associated pricing principles, and sets out the proposed network tariff structures, with indicative prices, to recover the allowed annual revenue as determined by the AER for the 2024-2029 regulatory control period. The accompanying TSES provides the supporting explanations and analysis of the network tariffs, structures and assignment policies proposed in the TSS.

The Original Proposal forecast a smoothed price path consistent with the smoothed revenue requirement over the 2024-2029 period in real ($ 2023-24) terms. The forecast price impacts for customers in the Original Proposal were:

- residential customers increased by 5.9 per cent in the first year (approximately $45 per annum) followed by increases between 1.4 per cent and 1.7 per cent each year thereafter
- small business customers increased 2.2 per cent in the first year (approximately $62 per annum), followed by increases of between 0.9 per cent and 1.2 per cent each year thereafter.

Draft decision

The AER's draft decision accepted our proposed TSS and TSES. The AER considered the proposed TSS and TSES complied with the distribution pricing principles in the NER and would contribute to the achievement of the network pricing objective. The AER has acknowledged the significant engagement we undertook with our customers, vulnerability advocates, businesses and retailers that informed the development of our tariff structure statement.

The AER made several observations regarding potential network tariff trials, specifically supporting EV charging, grid scale batteries and future enhancements to our long run marginal cost methodology (**LRMC).**

Response to the draft decision

We accept the AER's draft decision on the TSS and TSES. We have updated the TSS to include revised prices reflecting updated inputs from the Revised Proposal. We note the recommendations for future methodology refinements and will consider these for our 2029-2034 regulatory control period.

The figures below present updated forecast price impacts with the updated inputs from the Revised Proposal outlined in previous sections. Figure 7 shows the price path for the typical residential customer. Prices are projected to increase on average by 4.0 per cent over the period, compared to 2.4 per cent in the Original Proposal.

Figure 8 shows the price path for the typical small business customer. Prices are projected to increase on average by 2.7 per cent over the period, compared to 1.3 per cent in the Original Proposal.

Figure 7 Indicative distribution network charges, residential customers ($, 2023-24)

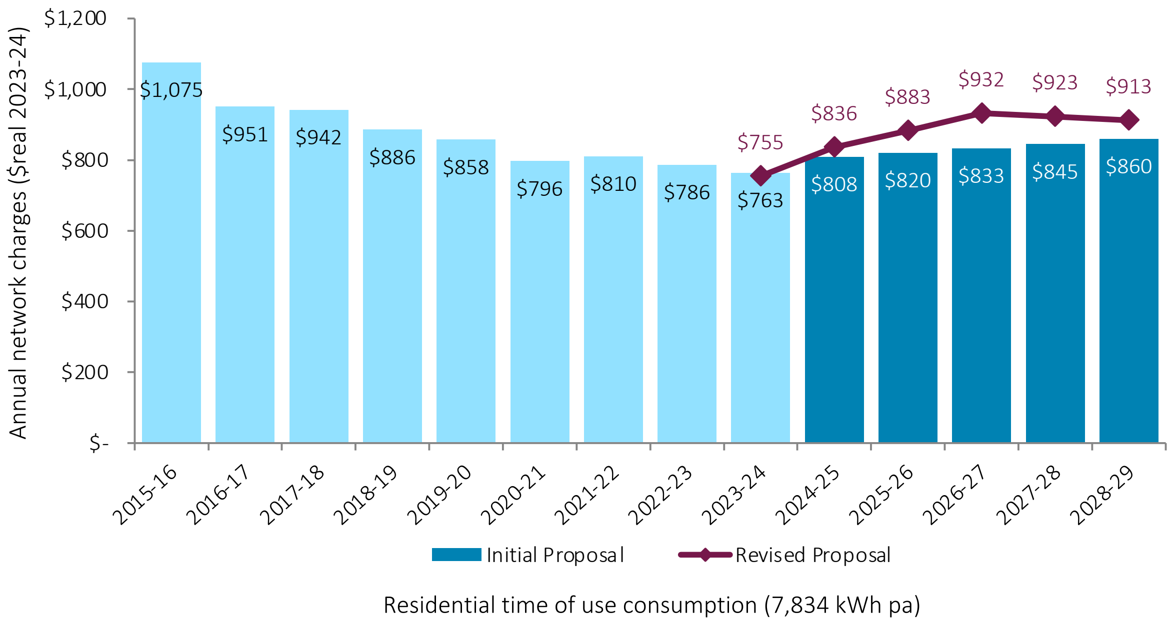
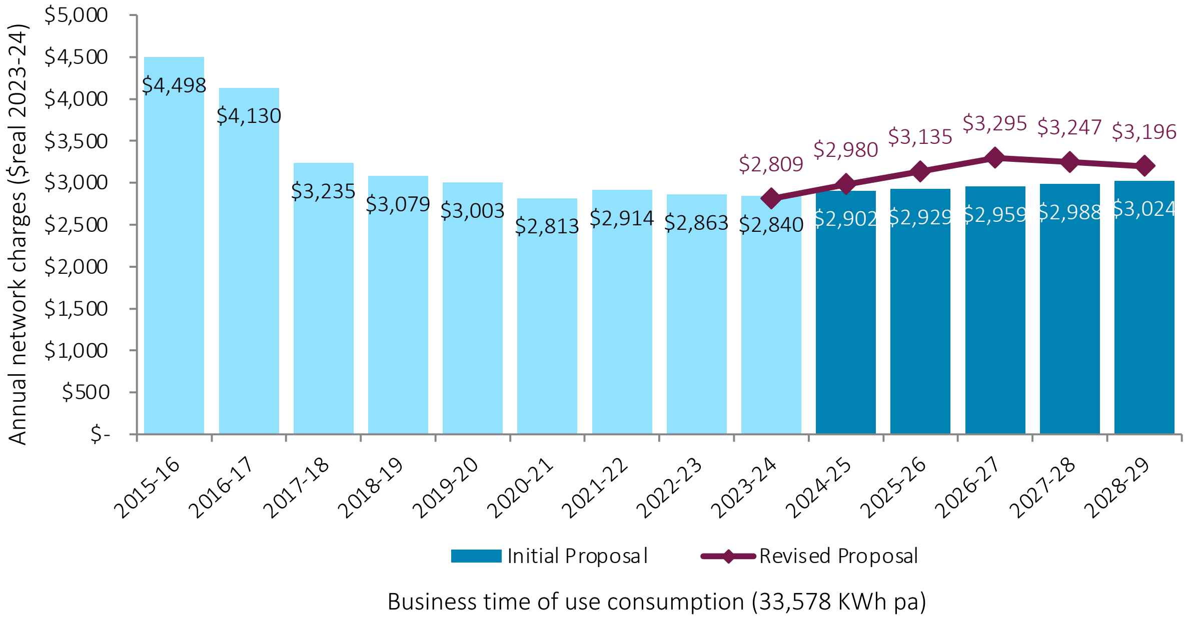


Figure 8 Indicative distribution network charges, small business customers ($, 2023-24)



We have also updated our assumptions to provide forecast price impacts for the contingent projects proposed for the 2024-2029 regulatory control period. Table 29 shows the indicative price impacts of the contingent projects on network charges for the typical residential customer and small business customer. The price impacts are provided for 2031-32, which is an indicative year incorporating future price impacts for these projects, and incorporates a price baseline that includes Project Marinus. The contingent projects, except Waddamana to Palmerston and the North West Network Upgrade, are associated with a trigger based on additional load. The regulated network charges attributable to the additional load is forecast to be greater than the additional revenue associated with the contingent projects which means the overall price impact of the contingent projects to existing customers is forecast to be lower.

Table 29 Contingent project indicative price impacts[9] – distribution customers ($, 2023-24)

Annual outcomes for 2031-32 $2023-24 real terms	**Residential customers**		**Small business customers**	
Baseline (including Project Marinus)	$981		$2,381	
210 MW Contingent Projects	-$8	-0.8%	-$20	-0.8%
350 MW Contingent Projects	-$12	-1.2%	-$30	-1.3%
712 MW Contingent Projects	-$24	-2.4%	-$60	-2.5%
712 MW Contingent Projects and Waddamana to Palmerston	-$16	-1.6%	-$39	-1.7%
712 MW Contingent Projects, Waddamana to Palmerston and North West Network Upgrade	-$6 (generation) -$12 (load)	-0.6% -1.2%	-$14 (generation) -$30 (load)	-0.6% -1.3%

9 Network charges only. Excludes any wholesale energy benefits

17. Pass through events

The NER provides a 'pass through' mechanism that enables NSPs to pass through to customers substantial cost increases or reductions that arise due to unforeseen events that are beyond the ability of networks to anticipate, prevent or reasonably mitigate, and are not reflected in the revenue allowances approved by the AER.

The NER prescribes a number of pass through events such as regulatory changes, taxation changes or changes in service standards that might cause material changes to expenditure. TasNetworks can also 'nominate' additional pass through events to apply for the regulatory control period.

Original Proposal

In addition to the NER prescribed pass through events, the Original Proposal nominated six 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)
- AEMO participant fee structure event (distribution)
- REZ design report (transmission).

Draft decision

The AER's draft decision accepted our proposed terrorism, natural disaster, insurer's credit risk and insurance coverage pass through events, but with amended definitions, to provide consistency between TasNetworks and other NSPs.

The AER's draft decision also accepted the REZ design report event. The AER did not accept our proposal to apply the materiality threshold across regulatory years when reviewing a cost pass through application for REZ design report costs. However, the AER noted the Energy Security Board's view on cost recovery relating to REZ design reports and, on this basis, the AER agreed that multiple REZ design reports can be grouped together in a single application, as long as these occur within the same year as per the NER requirement.

The AER did not approve the nominated AEMO participant fee structure event due to the substantial level of uncertainty around AEMO charging participant fees to DNSPs within the 2024-2029 regulatory control period. The AER considered that if AEMO participant fees were to be recovered from DNSPs, arrangements would be made to enable the recovery of those costs by DNSPs as they were when TNSPs first became liable for participant fees.

Response to the draft decision

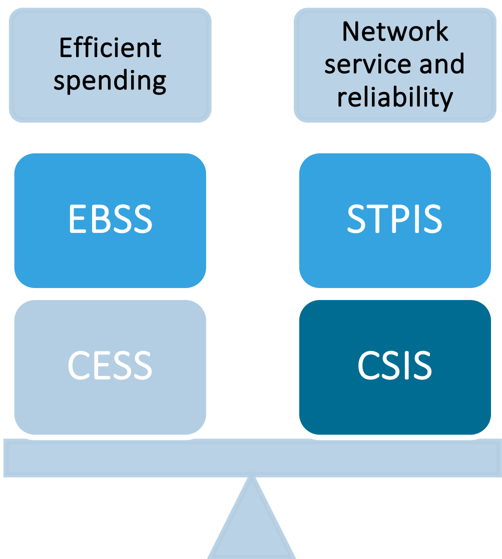
We accept the AER's draft decision on cost pass throughs in full. We have not nominated any additional pass through events in the Revised Proposal.

18. Service target performance incentive schemes

The STPIS plays a significant role in counterbalancing the incentives to minimise operating and capital expenditure that are provided by other aspects of the regulatory framework, including the EBSS and CESS. It ensures that NSPs are not incentivised to reduce costs (through the EBSS and CESS) at the expense of reliability.

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 NSPs incentives to maintain and improve network reliability and performance.

Figure 9 AER incentive schemes



Original Proposal

In the Original Proposal, we proposed to apply version 5 of the transmission STPIS and version 2 of the distribution STPIS. Version 5 of the transmission STPIS has three applicable components – the Service Component (**SC**), the Market Impact Component (**MIC**) and the Network Capability Component (**NCC**). Version 2.0 of the distribution STPIS has three components – the Reliability of Supply component (**RoS**), the Customer Service (**CS**) component and the Guaranteed Service Level (**GSL**) component.

We proposed for the transmission STPIS:

- the use of performance data from 2017 to 2021 for SC target setting as the 2022 data was not available to inform the Original Proposal. We noted we would update the targets as part of the Revised Proposal with 2018 to 2022 data
- the use of performance data from 2015 to 2021 for MIC target setting as the 2022 data was not available to inform the Original Proposal, noting that we would update the targets with 2016 to 2022 data as part of the Revised Proposal
- SC and MIC performance targets that satisfied the requirements of version 5 of the STPIS, other than the historical data range
- a single Network Capability Incentive Parameter Action Plan (**NCIPAP)** project, with the potential to pursue additional projects within the 2024-2029 regulatory control period, given the total cost of the nominated project is below the expenditure limit.

We proposed for the distribution STPIS:

- revenue at risk of ± 5.0%
- to segment the network according to the Tasmanian Electricity Code's (**TEC**) supply reliability categories
- to apply the RoS parameters, and the CS parameter if a CSIS was not accepted by the AER
- to apply the latest published values of customer reliability (**VCR**) to set the incentive rates
- not to apply the GSL component as TasNetworks is subject to a jurisdictional GSL scheme under the TEC
- the use of data from 1 July 2017 to 30 June 2022 to set performance targets, noting that we would update the targets with 1 July 2018 to 30 June 2023 data as part of the Revised Proposal
- to apply the standard exclusions and determination of the major event day threshold as outlined in version 2.0 of the STPIS.

Draft decision

In its draft decision for transmission STPIS, the AER:

- applied Version 5 of the STPIS for transmission
- did not accept TasNetworks' SC performance targets based on 2017 to 2021 data and determined performance targets, caps and floors based on the 2018 to 2022 performance data available to the AER at the time of the draft decision
- did not accept TasNetworks' MIC performance target based on 2015 to 2021 data and determined a performance target based on the 2016 to 2022 performance data available to the AER at the time of the draft decision
- accepted the NCC proposal and included the proposed NCIPAP project in the 2024-2029 regulatory control period.

In its draft decision for the distribution STPIS, the AER:

- applied version 2.0 of the STPIS for distribution without the CS parameter, as a CSIS will apply, and without the GSL component, due to the jurisdictional scheme
- set the revenue at risk at ± 4.5% (with ± 0.5% applied to the CSIS)
- segmented the network according to the TEC supply reliability categories
- set performance targets based on TasNetworks' most recent average performance over the past five regulatory years and noted TasNetworks is required to submit 2022-23 STPIS actual performance data in its Revised Proposal
- accepted TasNetworks' proposal to calculate the major event day threshold in accordance with the STPIS
- calculated RoS performance targets with no adjustments for capex programs to improve reliability
- calculated incentive rates using the most recent VCR
- noted that TasNetworks is still required to annually report on telephone answering.

Response to the draft decision

We accept the AER's draft decision on the transmission STPIS and have updated our SC performance targets with the 2022 performance data.

We also accept the AER's draft decision on the distribution STPIS and have updated the RoS performance targets with the most recent average performance over the past five regulatory years (1 July 2018 to 30 June 2023).

19. Customer service incentive scheme

The CSIS was introduced by the AER in July 2020 to provide an incentive for DNSPs to pursue improvement services identified by customers as important. It is a flexible 'principles-based' scheme that allows DNSPs to tailor the scheme to the specific preferences and priorities of customers.

Original Proposal

We proposed the adoption of a CSIS for the 2024-2029 regulatory control period in the Original Proposal. This position was supported by customers and stakeholders and the proposed parameters and targets were identified through engagement with them.

Three performance parameters were proposed for the CSIS:

- customer satisfaction with complaints handling
- customer satisfaction with outage management (planned and unplanned)
- customer satisfaction with new connections

The proposed targets were set using the highest of either our three-year average actual performance or Customer Service Benchmarking Australia (**CSBA**) three-year average industry benchmarks. We proposed that the revenue at risk for the CSIS be equivalent to the current Customer Service component of the STPIS at ±0.5% of revenue and proposed incentive rates that aligned with customer preferences for those services.

There was insufficient stakeholder feedback on the proposed CSIS to confirm that stakeholders were supportive of the CSIS proposal prior to the submission of the Original Proposal. We committed to re-engaging with the Customer Council on the CSIS with updated performance targets for 2022-23 prior to submission of the Revised Proposal.

Draft decision

We presented a CSIS update at a stakeholder engagement workshop in July 2023 and received conclusive support from the Customer Council for the proposed CSIS.

The AER considered the feedback from the Customer Council and our proposed incentive design and determined in its draft decision:

- to apply the proposed incentive design, as it achieves the CSIS objectives and meets the design criteria
- the proposed CSIS will replace the Customer Service component of the STPIS
- the proposed revenue at risk will be ± 0.5%.

Response to the draft decision

We accept the AER's draft decision and, as agreed with the AER, propose a correction to the incentive rates as outlined in Table 30.

Table 30 CSIS parameters and updated incentive rates

Parameter	Draft decision baseline target	Revised Proposal	Draft decision incentive rate	Revised Proposal
Customer satisfaction with complaints handling	6.41	No change	0.010%	No change
Customers satisfaction with outage management (planned and unplanned)	7.82	No change	0.005%	0.010%
Customer satisfaction with new connections	7.61	No change	0.010%	0.005%

20. Alternative control services

TasNetworks 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**) and are specific to distribution networks. For ACS, the AER either caps the prices that can be charged or sets the input costs that can be used by TasNetworks to quote for work.

Our ACS proposal has been divided into three sub-categories:

- ancillary network services
- public lighting
- metering services.

Ancillary network services

The term "ancillary network 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 we 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 ancillary network services. Ancillary network services capture a wide-range of activities, which are delivered as both fee-based and quoted services.

Original Proposal

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. 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, we proposed, on average, an increase in fee-based service prices when compared with the prices that apply in the last year of the current regulatory control period (2023-24).

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. For the 2024-2029 regulatory control period, we proposed to reduce the number of labour categories used to price the delivery of quoted services from 16 to eight. This approach removes skill-set duplication yet still allows labour rate diversity. We also proposed that vehicle costs be recovered in the materials costs of quoted services rather than in some labour rates.

Draft decision

As a result of benchmarking, the AER did not accept the following proposed labour rates and replaced them with alternative labour rates (business hours only):

- Quoted Services Administration
- Quoted Services Distribution Operator
- Quoted Services Project Administration.

The AER did not accept our proposed margin of 5.86 per cent because they consider a margin is already accounted for the in the total overhead allowance of 61 per cent.

The AER updated labour escalators, WACC and inflation forecasts in line with other aspects of their draft decision. This reduced our proposed prices by an average of 4.16% across all fee-based services.

The AER accepted our proposed reduction of quoted services labour categories from 16 to eight and the inclusion of the new traffic control service.

Response to the draft decision

We accept the AER's draft decision on ancillary network services in full.

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).

Original Proposal

We proposed continuing 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; and
- in response to legislative requirements, ending the like-for-like replacement of mercury and sodium vapour globes by installing LED fittings instead.

Draft decision

The AER's draft decision noted our public lighting proposal to be largely reasonable. However, the AER updated our public lighting proposal to apply its draft decision on labour escalators, WACC and inflation for consistency with other aspects of the AER's draft decision.

Response to the draft decision

We accept the AER's draft decision on public lighting in full.

Metering services

Original Proposal

Our metering charges are made up of a capital component, which recoups the cost of legacy meters, and an operational charge, which recovers the cost of reading legacy meters and managing the metering data.

Legacy accumulation meters are being progressively replaced by advanced meters in Tasmania. The remaining accumulation meters are expected to be retired prior to the end of the next regulatory control period on 30 June 2029. To better align the recovery of our past investment in metering with the significantly reduced service life of our accumulation meters, we proposed to recover the remaining asset value of its superseded fleet of meters by the end of the 2024-2029 regulatory control period.

Our opex forecasts for the 2024-2029 regulatory control period and, therefore, our proposed annual revenue requirements, factored in the reduction in costs associated with the winding down of the metering services provided by TasNetworks. There is not, however, a linear relationship between the reduction in the volume of legacy meters and our 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).

To manage the cost to customers from the reduction of legacy meters, we proposed two metering opex step changes to fund the costs of:

1. a targeted meter replacement program from 2026-2029, to help electricity retailers replace legacy meters where installation issues exist, such as the lack of an isolation point
2. meter reads undertaken 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 remaining legacy meters.

Draft decision

The AER's draft decision was to not accept our proposed prices for type 5 (interval) and type 6 (accumulation) routine metering services. In its draft decision, the AER:

- did not accept our proposed metering opex, particularly in relation to the trend component, and applied an updated trend of metering volumes, with weighting of the forecast volume trend, labour cost escalation, and inflation
- did not accept our annual revenue requirement, which needed to be revised to reflect the updated building blocks
- did not accept our price cap calculation for legacy metering services, instead substituting an alternative price cap calculation which reflects the recovery of costs through a fixed fee charged to a wider customer base.

The AER noted that maintaining metering as an ACS but recovering the costs from the wider customer base is considered a transitional solution to support the accelerated deployment of advanced meters, as the number of customers with legacy meters becomes much smaller. The AER considers it appropriate to integrate metering services into SCS at some point in time. At the very least this would apply to residual legacy meters in a future regulatory control period but could also be considered in the Revised Proposal, which would also permit metering cost recovery across all customers in the 2024-2029 regulatory control period, rather than only customers with legacy metering.

Response to the draft decision

We accept the AER's draft decision and the updates made to our proposed metering services opex trend component. Specifically, we accept the AER's draft decision on the weighting of customer numbers and updates to labour cost escalation and inflation.

We have updated our metering expenditure model to include actual opex for the metering base year of 2022-23 and the metering PTRM.

Regarding service classification, we propose to maintain an ACS classification for metering services in Tasmania for the 2024-2029 regulatory control period for the following reasons:

- the Tasmanian Government has committed to the installation of advanced meters across Tasmania by the end of 2026, and we are forecasting limited legacy meters to remain in service out to the end of the 2024-2029 regulatory control period
- metering costs are currently socialised at the retailer level in Tasmania under the Office of the Tasmanian Economic Regulator's 2022 Standing Offer Price Determination, resulting in Tasmanian customers paying the same for metering services irrespective of their metering type (legacy or advanced).

We will, however, seek to recover any residual metering costs (if any) in the 2029-2034 regulatory control period as part of SCS.

21. 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.

The Distribution Connection Pricing Policy (**connection 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.

Original Proposal

TasNetworks reviewed its connection policy and proposed minimal change for the 2024-2029 regulatory control period. TasNetworks proposed to continue applying the connection charge principles outlined in Chapter 5A of the NER, with the only substantive change in the connection policy being the treatment of costs associated with asset relocations.

We proposed removing the accumulated depreciation rebate on asset relocations due to the rebate being funded by the broader customer base. This change would bring the connection policy into alignment with TasNetworks' pricing principles, specifically that our prices be "fair" and provide transparent and cost reflective pricing signals.

Draft decision

The AER accepted our proposal to remove the accumulated depreciation rebate on asset relocations but did not approve the connection policy because it:

did not contain the new conditions set out in the AER's amended connection charge guidelines regarding the imposition of static zero export limits on new installations of rooftop solar generation

lacked sufficient clarity for connection applicants to understand that the policy is intended to apply to both connections to the shared network and regulated standalone power systems.

In the draft decision, in consultation and agreement with TasNetworks, the AER have amended the connection policy to the extent necessary to meet the NER requirements and the AER's updated connection charge guideline.

Response to the draft decision

We accept the AER's proposed amendments to the connection policy and have resubmitted this document as part of the Revised Proposal with the changes agreed with the AER.

22. Next steps

TasNetworks welcomes your feedback on the Revised Proposal, either directly or through the AER's submission process. The Revised Proposal is subject to review by the AER, and the AER's final decision will determine how much we spend on our transmission and distribution networks over the next five years and the network charges applied to customers over the same period.

How to get in touch with us:

revenue.reset@tasnetworks.com.au

1300 555 727

tasnetworks.com.au

The expected timeframes for the revenue determination process are as follows:

Milestone	Timing
TasNetworks submits revised proposal	30 November 2023
Submissions on revised proposal and draft decision close	19 January 2024
AER issues final determination	By 30 April 2024

Submissions on the AER's draft decision and the Revised Proposal can be sent to:

AERresets2024-29@aer.gov.au or

Arek Gulbenkoglu
General Manager

Australian Energy Regulator
GPO Box 1313
Canberra ACT 2601

The AER requests submissions be in Microsoft Word or another text readable document format and will treat submissions as public documents unless otherwise requested.

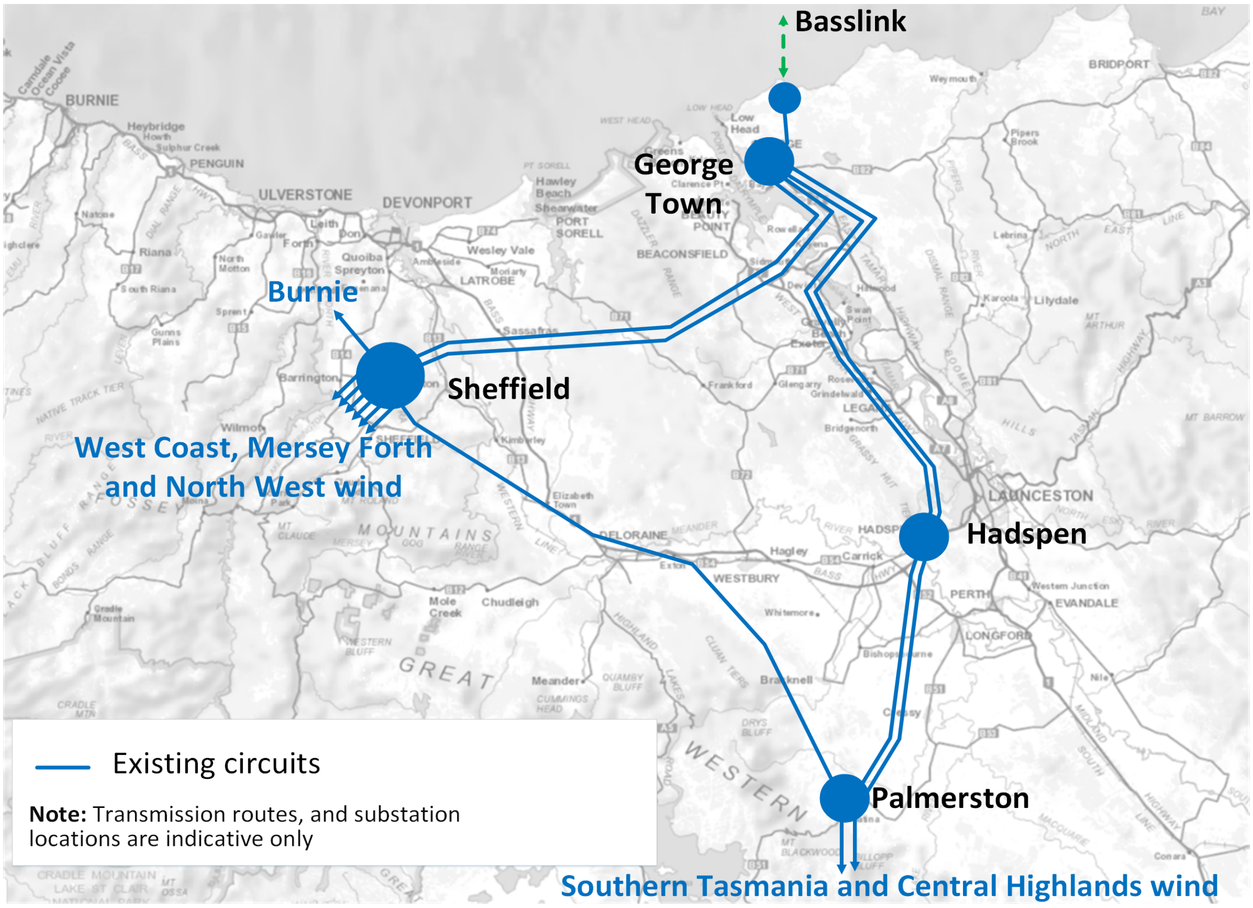
Appendix A – Contingent projects supporting information

Description of George Town Network

Transmission network

George Town Substation is supplied from two 220 kV main corridors (i.e. Sheffield–George Town and Palmerston–Hadspen–George Town) and these two corridors are interconnected through the Palmerston–Sheffield 220 kV line. Transmission network limitations to supply George Town are, therefore, generally evaluated with reference to the capacity of the Palmerston–Sheffield–George Town–Hadspen transmission loop.

Figure 10 220 kV network supply to George Town Substation



George Town Substation is the only substation to supply loads in and around George Town and Bell Bay. It provides the connections to load and generator customers and Basslink, the HVDC interconnector which links the Tasmanian and Victorian networks. The existing network has very marginal capacity to accommodate any new developments in George Town.

The *Electricity Supply Industry (Network Planning Requirements) Regulations 2018* (**ESI regulations**) provide the customer reliability levels to be considered in planning the network. As per the 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.[10] A single asset failure means one single incident (other than a credible contingency event) that results in the failure of one single asset to perform its intended function.

TasNetworks adopts AEMO's definition of a black system from its Power System Security Guidelines.[11] The guidelines define a black system in a region as loss of more than 60 per cent of predicted regional load, following a major power system emergency, affecting one or more power stations.

Likelihood of new load

The Tasmanian Government has developed the TRHAP, which describes the Government's vision to capitalise on low-cost reliable renewable energy resources to establish a Tasmanian hydrogen industry.

The TRHAP has three staged goals: commence production of renewable hydrogen in 2022 to 2024, commence hydrogen exports in 2025 to 2027 and be a significant global producer and exporter of renewable hydrogen from 2030. Furthermore, the TRHAP considers a 1,000 MW facility could be feasible in George Town. The Tasmanian Government has received a $70 million grant from the Australian Government to establish the first Tasmanian hydrogen hub near George Town at Bell Bay.[12]

AEMO's Electricity Statement of Opportunities (**ESOO**) has identified Bell Bay as a potential hydrogen export port. The ESOO predicts a significant increase in hydrogen production in Tasmania towards the end of the 2024-2029 regulatory control period and into the beginning of the 2029-2034 period.[13] TasNetworks considers it probable that several hydrogen projects will become committed during the 2024-2029 regulatory control period to meet this forecast.

TasNetworks is also aware of over 500 MW of new publicly announced hydrogen projects in the Bell Bay area. Given the Tasmanian Government's TRHAP objectives and forecast load developments, TasNetworks considers it likely that significant new load becomes committed to connect in George Town by 2029.

Palmerston to Sheffield Network Upgrade/George Town Network Upgrade contingent project

Need

Large-scale load developments at George Town will mean TasNetworks will not meet its minimum network performance requirements under the ESI regulations that load interrupted by a single asset failure is not to be capable of resulting in a black system.

During 2022, George Town Substation load was always below 60 per cent of the Tasmanian regional load (maximum George Town Substation load is 51 per cent). However, with the addition of 210 MW flat load to the George Town Substation, the maximum percentage of George Town load reaches 60 per cent of the Tasmanian regional load. At this point, the loss of all load connected to George Town Substation becomes a system black event.

George Town Substation has three 220/110 kV transformers and two 110/22 kV transformers next to the existing 220 kV switchyard. It is also supplied by two double circuit 220 kV transmission lines (Sheffield – George Town and Hadspen – George Town). A fire in any of these five transformers or the loss of one of the double circuit lines can also lead to a system black event.

As a consequence, an additional 210 MW of new load at George Town will result in TasNetworks being non-compliant with the ESI regulations' requirement that the failure of a single asset not be capable of resulting in system black.

To avoid non-compliance with the ESI regulations, an additional 210 MW load at George Town will require:

- rearrangement of the existing George Town Substation and the construction of a new substation nearby to avoid a transformer fire potentially leading to system black
- installation of additional reactive support in George Town to avoid loss of a double circuit potentially resulting in system black
- construction of a new 220 kV double circuit transmission line between Sheffield and Palmerston to avoid loss of a double circuit potentially resulting in system black.

10 ESI regulations, Clause 5(1)(a)(iii)

11 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf

12 https://www.stategrowth.tas.gov.au/recfit/future_industries/green_hydrogen/tasmanias_green_hydrogen_hub_vision

13 AEMO, Electricity Statement of Opportunities, 2023, p.145

In the Original Proposal, these three augmentations were classified as separate contingent projects. However, following further analysis TasNetworks has determined that all three projects are needed to address the same non-compliance following new load at George Town. Consequently, in the Revised Proposal the substation and reactive support augmentation have been combined into a single project called the George Town Network Upgrade. The new transmission line has been kept separate and is referred to as the Palmerston to Sheffield Network Upgrade.

Despite the Palmerston to Sheffield Network Upgrade being required to address the same need as the George Town Network Upgrade, TasNetworks has chosen to propose it as a separate contingent project in the Revised Proposal, as it also forms part of the network investment associated with Project Marinus. To promote transparency for customers, TasNetworks has included this augmentation as a separate contingent project to explain the multiple needs and pathways for delivery of this project.

Triggers

TasNetworks considers customer commitment of 210 MW of additional load connecting at George Town a load trigger, as this is sufficient for TasNetworks to be non-compliant with the ESI regulations.

In addition to the 210MW load trigger, TasNetworks will undertake a RIT-T and obtain Board approval prior to commencing the project.

George Town Reactive Support contingent project

Need

The reactive power requirement at George Town is expected to increase proportionately as load increases. This is particularly true for price responsive loads (such as hydrogen production) that result in rapid changes to active power requirements. If the active power requirements vary rapidly, the reactive power demand also varies accordingly to maintain the voltage. Dynamic reactive support is needed to accommodate new loads, provide rapid changes in reactive power demand and maintain system stability.

Triggers

TasNetworks is proposing to install reactive support in response to 210 MW of new load at George Town under the George Town Network Upgrade contingent project. Although the final solution is subject to the RIT-T, we expect this augmentation would support up to 350 MW of new load. As a result, TasNetworks expects 350 MW of new load will trigger the requirement to install additional reactive support.

In addition to the 350MW load trigger, TasNetworks will undertake a RIT-T and obtain Board approval prior to commencing the project.

Sheffield to George Town Network Upgrade contingent project

Need

As load continues to grow in George Town, thermal issues will begin to emerge in the network. As a consequence, constraints will begin to bind more frequently to maintain the network within thermal limits. Following the Palmerston to Sheffield Network Upgrade, the next most constraining component of supplying George Town is the Sheffield–George Town 220 kV transmission corridor. These constraints represent foregone benefits as generation that would have otherwise been dispatched is not available.

The cost of the constraints increases with load. At some point, the cost of the constraint exceeds the cost of augmenting the corridor. The proposed solution is to augment the Sheffield to George Town corridor to increase the thermal limit.

Triggers

Following market simulation and economic analysis, TasNetworks considers 712 MW of new load in George Town would result in the cost of constraining generation exceeding the cost of constructing a new 220 kV double circuit transmission line between Sheffield and George Town. As a result, 712 MW of new load at George Town is the trigger for this contingent project.

In addition to the load trigger, TasNetworks will undertake a RIT-T and obtain Board approval prior to commencing the project.

Description of Central Highlands REZ network

Transmission network

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.

The Central Highlands and a portion of the southern transmission network area form the Central Highlands REZ. The Central Highlands REZ has excellent wind resources, which offer the highest availability of all REZs across the NEM.[14] New large-scale wind generation is expected to connect to the 220 kV transmission network surrounding Waddamana Substation and to the transmission lines south.

Likelihood of new generation

In the Original Proposal, TasNetworks acknowledged there were several wind farm developers undertaking preliminary feasibility work in the Central Highlands REZ. These are now publicly announced or reached a point where a public announcement is anticipated soon (referred to as "undisclosed" in Table 31). There are now six publicly announced wind farm proposals in the Central Highlands REZ with a combined capacity totalling more than 1,700 MW. These proposals are presented in Table 31. All proposals have lodged a connection enquiry with TasNetworks.

Table 31 Wind farm proposals in the Central Highlands REZ

Wind Farm	Capacity (MW)
Bashan	460
Cellars Hill	400
Derwent Valley	150
Hollow Tree	420
St Patricks Plains	291
Triabunna	30
(undisclosed)	420
Total	**1,751**

Furthermore, the ISP forecasts new wind generation in excess of 1,000 MW installed capacity to be constructed in the Central Highlands REZ by 2030. This is built to meet the interim TRET, which requires 5,250 GWh of new renewable energy generation by 2030 (equivalent to 1,500 MW of new wind[15]).

Given the publicly announced projects and ISP forecast, TasNetworks considers it probable that at least 660 MW of new wind generation projects in the Central Highlands REZ will be become committed (or connect) in the 2024-2029 regulatory control period.

Waddamana–Palmerston Transfer Capability Upgrade contingent project

Need

TasNetworks does not agree with the AER's assessment that the Waddamana-Palmerston transfer capability upgrade is not necessary or appropriate for inclusion as a contingent project in a revenue determination. In its draft decision, the AER took the view that augmentation projects required to support the connection of new generation is to be provided for by AEMO's ISP and its optimal development path (**ODP**).

TasNetworks notes that, given the forecasts of new generation published in the 2022 ISP, it is possible that an upgrade in transfer capability between Waddamana and Palmerston will be declared by AEMO as an actionable ISP project during the 2024-2029 regulatory control period. In this circumstance, TasNetworks would likely pursue the project under the actionable ISP framework, including reliance on the prescribed triggers in the NER. However, TasNetworks does not agree with the AER that this is the only or most likely pathway for delivery of this project.

14 2023 IASR Assumptions Workbook (Capacity Factors tab) AEMO, published 28 July 2023 https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

15 Assuming 40% capacity factor

While the ODP is an overall plan for the future of the power system, it is not necessarily reflective of where generation proponents will, or are planning to, connect. The ODP is an economic outcome informed by cost-based engineering optimisation, and generation proponents may choose to locate in areas of the network for commercial and other reasons not captured by AEMO in its central planning. This is particularly relevant for projects to support the Central Highlands REZ as there is currently a discrepancy between the assumptions underpinning the 2022 ISP and the information obtained by TasNetworks' through direct engagement with the proponents of new wind farm developments in Tasmania. As a consequence, the 2022 ISP does not correctly identify the limitation of the Waddamana-Palmerston corridor.

TasNetworks considers that the economic assessment process and ISP should be flexible and recognise that there are multiple pathways of supporting new renewable generation, other than the ODP. Further, an exclusive reliance on biennial ISPs to identify all the transmission upgrades needed to support new generation in the NEM risks delaying projects, potentially resulting in foregone benefits.

Triggers

TasNetworks has undertaken additional analysis to identify the quantum of new generation that can be accommodated in the Central Highlands REZ before the capacity of the existing Waddamana to Palmerston corridor is reached.

TasNetworks considers that 660 MW of new generation in the Central Highlands REZ would be sufficient to introduce constraints on the Waddamana to Palmerston transmission line. Conversely, when the installed capacity of new (wind) generation at Waddamana Substation is 660 MW, the available network capacity of the Waddamana–Palmerston 220 kV transmission line would be exhausted.

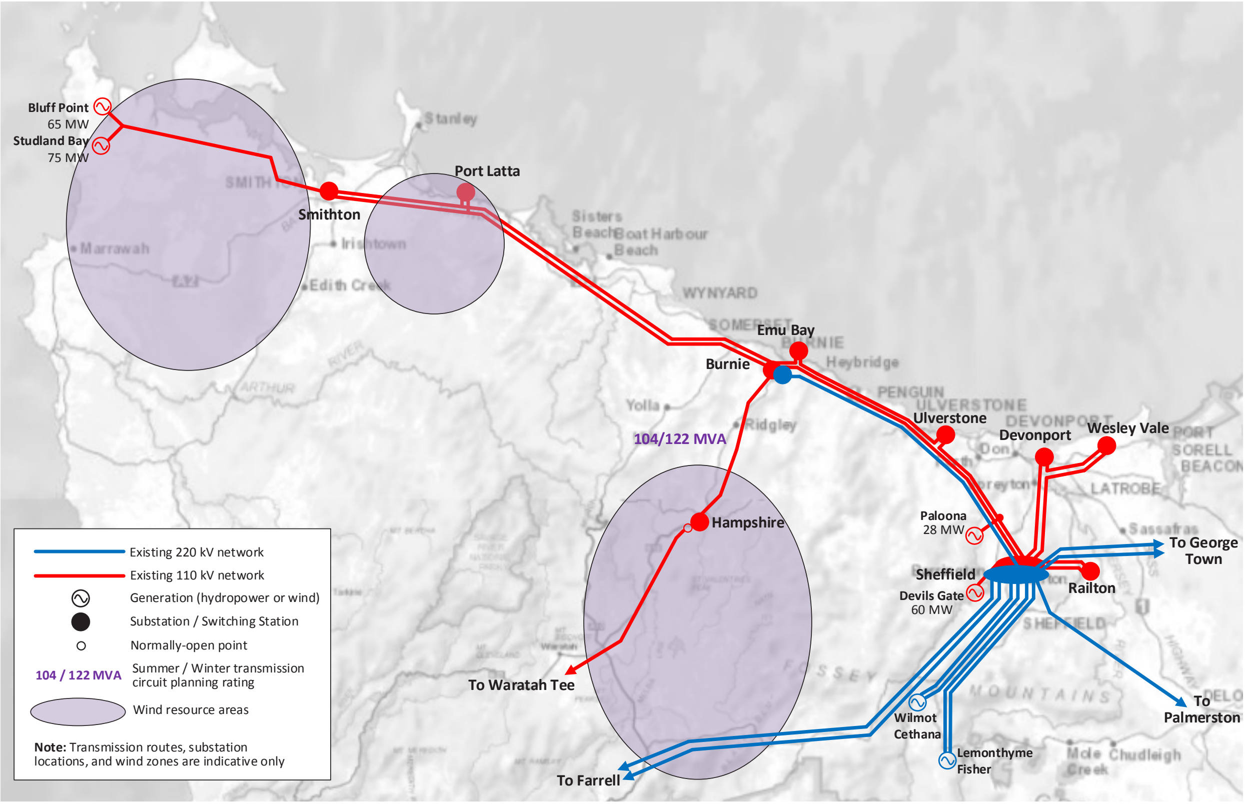
TasNetworks notes that, at least initially, introducing constraints on the existing line may be more economical than increasing transfer capacity within the corridor. As a result, TasNetworks will undertake a RIT-T to identify the option to address the need that maximises net benefits across the NEM, to mitigate any risk of inefficient investment. The AER must be satisfied that TasNetworks has correctly applied the RIT-T and obtained Board approval prior to commencing the project.

Description of North West Tasmania network

Transmission network

The North West Tasmania network mainly supports electricity supply to local communities and connects the Bluff Point and Studland Bay wind farms. The existing network is not adequate to support large-scale developments such as interconnection, further wind farms, or major industrial loads. As shown in Figure 11, the existing network around Hampshire consists solely of the Burnie–Hampshire 110 kV transmission line and associated 110 kV substation.

Figure 11 North West Tasmania network



North West Tasmania has excellent wind resources. Figure 11 shows new large-scale wind generation is expected around the Hampshire area and far North West Tasmania. Hampshire is also a candidate site for new industrial load development. A number of new load proponents have proposed to establish at Hampshire in recent years.

The publicly-announced large-scale new wind farms and industrial load proposals in North West Tasmania proposed to connect at Hampshire following the development of the new Sheffield-Hampshire-Burnie corridor associated with Project Marinus. Following the September 2023 announcement that the focus initially will be on developing one Marinus Link cable, TasNetworks announced it would be progressing the Palmerston-Sheffield and Sheffield-Heybridge-Burnie 220 kV transmission corridors required to connect one cable. The Sheffield-Hampshire-Burnie corridor is still required for the second cable, but is not being progressed for cable one. These stages are shown in Figure 12.

Figure 12 Staging of Project Marinus transmission developments

The existing network in the Hampshire area is not adequate to connect the new generation and load proposing to connect at Hampshire. Therefore, network upgrades around Hampshire are required to support new generation and load connect to the network prior to the second stage of Project Marinus.

Likelihood of new generation

TasNetworks is aware of a number of wind farm proponents that are likely to be committed in North West Tasmania during the 2024-2029 regulatory control period. There are now four publicly announced wind farm proposals in the North West with a combined capacity totalling more than 1,600 MW. These proposals are presented in Table 32. All proposals have lodged a connection enquiry with TasNetworks and propose to connect to the transmission network around Hampshire.

Table 32 Wind farm proposals in North West Tasmania

Wind Farm	Capacity (MW)
Guildford	525
Hellyer	155
Robbins Island (including Jims Plain)[16]	929
Total	**1,609**

TasNetworks considers it probable that at least 100 MW of new wind generation projects in the North West will become committed (or connect) in the 2024-2029 regulatory control period.

Likelihood of new load

TasNetworks is aware of at least one large industrial load project that is likely to be committed during the 2024-2029 regulatory control period near Hampshire. This proposal is presented in Table 33 and has lodged a connection enquiry with TasNetworks.

16 The Jims Plain and Robbins Island renewable energy parks (predominantly wind energy, with some solar energy and battery storage) are two separate projects but are often referenced simply by the larger Robbins Island Wind Farm.

Table 33 Load proposals in North West Tasmania

Facility	Load (MW)
HIF eFuels Facility	250

TasNetworks considers is probable that at least 100 MW of new load becomes committed (or connects) in the 2024-2029 regulatory control period.

North West Network Upgrade

Need

As noted above some of the transmission network upgrades to support the second Marinus Link cable have been deferred beyond 2029. This includes the new double-circuit 220 kV lines between Sheffield and Burnie via Staverton and Hampshire Hills. TasNetworks has previously been engaging with proponents about connecting to the network in Hampshire Hills[17] following commissioning of these lines. Following the decision to progress a staged development, this network is no longer available to support proponents proposing to connect to Hampshire during the 2024-2029 regulatory control period.

This contingent project would effectively accelerate part of the second stage of transmission developments shown in Figure 12 if it is required to support new generation in North West Tasmania during the 2024-2029 regulatory control period. TasNetworks considers a new double-circuit 220 kV transmission line from Burnie to a new switching station at Hampshire Hills is capable of addressing this need. The remaining Stage 2 developments will be developed following commissioning of the second Marinus Link cable.

This is similar to the treatment of the Palmerston to Sheffield Network Upgrade, which could be progressed at part of the Stage 1 Marinus development or a contingent project if needed earlier to support load in George Town.

Triggers

TasNetworks has undertaken analysis to identify the quantum of new generation and load that can connect to the existing 110 kV transmission corridor at Hampshire before the capacity of the line is reached.

TasNetworks considers that 100 MW of new generation or load to connect at Hampshire would be sufficient to introduce constraints on the Burnie to Hampshire transmission line. Conversely, when the installed capacity of new (wind) generation or load at Hampshire is 100 MW, the available network capacity of the Burnie to Hampshire 110 kV transmission line would be exhausted.

TasNetworks notes that, at least initially, introducing constraints on the existing line may be more economical than increasing transfer capacity within the corridor. As a result, TasNetworks will undertake a RIT-T to identify the option to address the need that maximises net benefits across the NEM, to mitigate any risk of inefficient investment. The AER must be satisfied that TasNetworks has correctly applied the RIT-T and obtained Board approval prior to commencing the project.

Removed contingent projects

Palmerston to George Town via Hadspen Network Upgrade contingent project

This contingent project has been removed from the Revised Proposal. We are expecting to improve utilisation of the Sheffield–George Town corridor by adding series reactors in the Palmerston–George Town via Hadspen corridor, as part of the Sheffield to George Town Network Upgrade.

17 Stage 2 of the North West Transmission Developments include a new 220 kV switching station at "Hampshire Hills" near the existing 110 kV Hampshire substation.

Glossary

Term or Abbreviation	Description
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Capex	Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
CER	Consumer Energy Resources
CNSP	Co-ordinating Network Service Provider
CPA	Contingent Project Application
CPI	Consumer Price Index
CS	Customer Service
CSIS	Customer Service Incentive Scheme
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DMIA	Demand Management Innovation Allowances
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUoS	Distribution Use of System
EBSS	Efficiency Benefits Sharing Scheme
ESI regulations	Electricity Supply Industry (Network Planning Requirements) Regulations 2018
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicle
GSL	Guaranteed Service Level
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IAP2	International Association for Public Participation
ISP	Integrated System Plan
LED	Light-Emitting Diode
LRMC	Long Run Marginal Cost
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
ODP	Optimal Development Path

Term or Abbreviation	Description
Opex	Operating Expenditure
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RFM	Roll Forward Model
REZ	Renewable Energy Zone
RIT	Regulatory Investment Test
RIT-T	Regulatory Investment Test – Transmission
RoR Instrument	Rate of Return Instrument
RoS	Reliability of Supply
SC	Service Component
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TEC	Tasmanian Electricity Code
TNSP	Transmission Network Service Provider
TSES	Tariff Structure Explanatory Statement
TSS	Tariff Structure Statement
TRET	Tasmanian Renewable Energy Target
TRHAP	Tasmanian Renewable Hydrogen Action Plan
VCR	Values of Customer Reliability
WACC	Weighted Average Cost of Capital

Revised Proposal Attachments

Models

Title	Author	Date	Public/ Confidential
TasNetworks-Revised Proposal-Transmission-PTRM-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Transmission-DTM- Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Transmission-RFM- Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Transmission-EBSS- Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Transmission-CESS- Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Distribution-PTRM-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Distribution-DTM-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Distribution-RFM-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Distribution-EBSS-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Distribution-CESS-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Metering PTRM-Nov 23-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-Metering expenditure model-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-STPIS targets Transmission-Nov 2023-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-STPIS Model Reliability of Supply Distribution-Nov 23-Public	TasNetworks	Nov 2023	Public
TasNetworks-Revised Proposal-LRMC Model-Nov 23-Public	TasNetworks	Nov 2023	Public

Regulatory Information Notices

Title	Author	Date	Public/ Confidential
TasNetworks-AER MIC Data Template - V7 - TasNetworks 2022-Nov 2023-Public	TasNetworks	Nov 23	Public

Supporting Documents

Title	Author	Date	Public/ Confidential
TasNetworks-Revised Proposal-Summary of Confidential and Non-Confidential Material-Nov 23-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Percentage of confidential information-Nov-23-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Transmission Pricing Methodology-Nov 23-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Distribution Connection Pricing Policy-Nov 23-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Tariff Structure Explanatory Statement-Nov 2023-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Tariff Structure Statement-Nov 2023-Public	TasNetworks	Nov 23	Public
TasNetworks-Revised Proposal-Tariff Structure Statement-Nov 2023-Confidential	TasNetworks	Nov 23	Confidential
TasNetworks-Revised Proposal-Contingent Projects Overview report-Nov 23-Public	TasNetworks	Nov 23	Public
TasNetworks-TAO- RIN - 2024-29 Reset - TNSP Non Financial Information review conclusion 2023-Oct 2023-Public	Tasmanian Audit Office	Oct 23	Public
TasNetworks-TAO- RIN - 2024-29 Reset - TNSP Non Financial Information review conclusion 2023-Oct 2023-Confidential	Tasmanian Audit Office	Oct 23	Confidential

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