FINAL DECISION

TasNetworks
Transmission and Distribution Determination
2019 to 2024

Overview

April 2019

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165

Email: AERInquiry@aer.gov.au

AER reference: 60152

About this decision

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set the amount of revenue that network businesses can recover from customers for using these networks.

The National Electricity Law and Rules (NEL and NER) provide the regulatory framework governing electricity transmission and distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[1]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

TasNetworks is the sole owner and operator of the monopoly electricity transmission and distribution networks in Tasmania. The networks comprise the towers, poles, wires and transformers used for transporting electricity to homes and business. TasNetworks designs, constructs, operates and maintains the distribution and transmission electricity networks in Tasmania.

On 31 January 2018, TasNetworks submitted joint regulatory proposals covering both its distribution and transmission networks for the five years commencing 1 July 2019. Its proposals set out the revenue it proposes to recover from its customers for the provision of electricity distribution and transmission services, and the methodology it proposes to use to set its prices each year. We made our draft decision for TasNetworks on 27 September 2018 and TasNetworks submitted its revised joint regulatory proposals, in response to the draft decision, on 29 November 2018.

Although TasNetworks has submitted joint regulatory proposals for its distribution and transmission networks, under our legislative framework we must undertake separate assessments and make separate transmission and distribution determinations. This overview sets out our final decisions for TasNetworks' transmission and distribution determinations. We have published separate attachments for each component of the determination required for transmission and distribution.

A key component of our determination for TasNetworks is the total revenue it can recover from customers for the provision of common transmission and distribution services (or 'standard control services') –those used by most of TasNetworks' customers. This is our 'building block determination' (section 2), and will form the basis of TasNetworks' transmission and distribution tariffs for the 2019–24 regulatory control period.

---

[1] NEL, s. 7.

TasNetworks' transmission pricing methodology allocates the regulated revenue associated with its transmission network and determines the structure of prices that TasNetworks may charge for its transmission services.

In the case of distribution services, TasNetworks' Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for distribution standard control services from customers (section 4).

TasNetworks' also provides distribution alternative control services, such as metering and public lighting services, the costs of which are separately recovered from users of those services directly, through a capped price on the individual service.[2] We discuss TasNetworks' alternative control services in attachment 15 to this final decision.

2 AER, *Framework and Approach for TasNetworks*, July 2017, p. 44.

Note

This overview forms part of the AER's final decision on TasNetworks' 2019–24 transmission and distribution determinations. It should be read with all other parts of the final decisions.

As a number of issues were settled at the draft decision stage or required only minor updates we have not prepared all attachments. The attachments have been numbered consistently with the equivalent attachments to our longer draft decision. In these circumstances our draft decision reasons form part of this final decision.

In addition to this overview, the final decisions include the following attachments:

Transmission determination	Distribution determination
TasNetworks transmission determination 2019–24	Attachment 1 – Annual revenue requirement
Attachment 1 – Maximum allowed revenue	Attachment 2 – Regulatory asset base
Attachment 2 – Regulatory asset base	Attachment 4 – Regulatory depreciation
Attachment 4 – Regulatory depreciation	Attachment 5 – Capital expenditure
Attachment 5 – Capital expenditure	Attachment 6 – Operating expenditure
Attachment 7 – Corporate income tax	Attachment 7 – Corporate income tax
Attachment 9 – Capital expenditure sharing scheme	Attachment 9 – Capital expenditure sharing scheme
Attachment 10 – Service target performance incentive scheme	Attachment 10 – Service target performance incentive scheme
Attachment A - Pricing methodology	Attachment 13 – Control mechanisms
	Attachment 15 – Alternative control services
	Attachment 18 – Tariff structure statement
	Attachment B - Negotiating framework

Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	annual service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP 13	Consumer Challenge Panel, sub-panel 13
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA/DMIAM	demand management innovation allowance (mechanism)
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MAR	maximum allowed revenue
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market

Shortened form	Extended form
NEO	national electricity objective
NER	national electricity rules
NPV	net present value
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCS	standard control services
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
TSS	tariff structure statement
TUoS	transmission use of system
WACC	weighted average cost of capital

1 Our final decision

Our final decisions allow TasNetworks to recover $2012.5 million ($nominal, smoothed) from its customers for the 2019–24 regulatory control period, from 1 July 2019 to 30 June 2024. This includes $1276.4 million ($nominal, smoothed) for distribution and $736.1 million ($nominal, smoothed) for transmission.

As a result of these decisions, the costs of electricity network services across Tasmania will increase moderately over the next five years, with an overall increase on average of 1.3 per cent annual ($nominal) increase in TasNetworks' combined network charges over the next five years from 2018-19 levels.[3]

Network costs represent 42 per cent of total electricity bills on average in Tasmania. Because most Tasmanian households and small businesses are on a regulated standing offer, these determinations will not directly impact the prices households pay for their electricity. But they are a key input into the retail prices set by the Office of the Tasmanian Economic Regulator (OTTER) and will impact the electricity bills of Tasmanian businesses using more than 150MWh.

Having assessed TasNetworks' revised proposal, we believe these small nominal increases:

- address affordability concerns by keeping any increases under inflation through improved business planning and governance, and by deferring some capital expenditure and contingent projects; while
- improving network safety and reliability in Tasmania over the next five years.

Our final decisions include $241.1 million ($2018–19) for transmission and $651.1 million for distribution capital expenditure (both 7 per cent lower than TasNetworks' revised proposal). This reflects a business as usual approach, consistent with the current expenditure for the 2014–19 period. We consider TasNetworks can defer a number of its proposed transmission replacement expenditure projects into the following 2024–29 period and still continue to maintain reliability for its customers.

But these decisions do allow for the future development of the Project Marinus interconnector by including it as a contingent project for the 2019–24 period. This means that if more information becomes available TasNetworks can apply for consideration of the required funding.

[3] This has been calculated by us, using the weighted proportions of transmission and distribution charges to the total networks component of an average Tasmanian electricity bill. TasNetworks' proposal did not include a composite figure for comparative purposes.

Transmission

Our final decision would allow TasNetworks to recover $736.1 million ($nominal, smoothed) revenue from its transmission customers over the five years from 1 July 2019 to 30 June 2024. On average this is a decrease of $40.1 million ($2018–19) or 22.7 per cent compared to the average revenue allowed for in the 2014–19 regulatory control period.[4]

Looking ahead, we estimate our 2019–24 final decision would mean that by the end of the 2019–24 regulatory control period (as at 30 June 2024):

- average transmission tariffs would decrease by 10.6 per cent ($nominal) for TasNetworks compared to the 2018–19 level (as at 30 June 2019)
- average annual electricity bills would decrease by 1.1 per cent ($nominal) for residential and 1.2 per cent ($nominal) for small business customers on TasNetworks' transmission network compared to the 2018–19 level (as at 30 June 2019), holding all other components of the bill constant.[5] This suggests that average annual bills would be $24 and $76 lower for residential and small business customers, respectively.

Our final decision for transmission is largely attributed to our decision on TasNetworks' rate of return and forecast capital expenditure. We have accepted TasNetworks' proposed transmission operating expenditure.

In Tasmania, more than half the energy delivered in the State is used by major industrial customers connected to the transmission network. This means that the proposed transmission network expenditure and as a consequence, the overall affordability of transmission charges, is critical to the few large businesses that underpin the Tasmanian market. This is also important for all customers in Tasmania, including small business and residents because a large proportion of TasNetworks' costs are shared across all network users.

Distribution

For distribution services, our final decision would allow TasNetworks to recover $1276.4 million ($nominal, smoothed) in revenue from its distribution customers over the five years from 1 July 2019 to 30 June 2024. On average this is a decrease of $1.2 million ($2018–19) or 0.5 per cent compared to the average annual revenue allowed for in the 2017–19 regulatory control period.

---

4 TasNetworks' proposed a real 17 percent decrease in the annual average revenues from our previous determination for 2014–19. See AER, Issues Paper, *TasNetworks Distribution and Transmission Determination 2019 to 2024*, p. 15.

5 We estimate the expected bill impact by varying the transmission network charges in accordance with our final decision, while holding all other components constant. This approach isolates the effect of our final decision on the core transmission network charges, and does not imply that other components will remain unchanged across the regulatory control period.

Looking ahead, we estimate our 2019–24 final decision would mean that by the end of the 2019–24 regulatory control period (as at 30 June 2024):

- average distribution tariffs would increase by 12.8 per cent ($nominal) for TasNetworks compared to the 2018-19 level (as at 30 June 2019)
- average annual electricity bills would increase by 4.1 per cent ($nominal) for residential or small business customers on TasNetworks' distribution network compared to the 2018–19 level (as at 30 June 2019), holding all other components of the bill constant.[6] This suggests that average annual bills would be $92 and $264 higher for residential and small business customers, respectively.

As is the case for transmission stated above, our final decision for distribution can be largely attributed to our assessment of TasNetworks' rate of return and forecast capital expenditure. We have accepted TasNetworks' proposed distribution operating expenditure in this draft decision.

Our final decision also recognises TasNetworks' need to take measures designed to create more cost reflective network tariffs for customers in Tasmania. TasNetworks has been consulting on its TSS with its customers prior to and after submission of its regulatory proposal to us. This consumer engagement is helping to shape TasNetworks' tariff policy reflected in the TSS that we approve as part of our decision for distribution customers. Our final decision broadly accepts TasNetworks tariff strategy to rely on time of use energy tariffs. We did however amend TasNetworks tariff assignment policy to promote an orderly transition to cost–reflective network tariffs by requiring a uniform opt–out approach for small customers which includes a data sampling period after a tariff reassignment is triggered.

Contingent projects

Contingent projects are significant network augmentation projects that may arise during the regulatory control period but at the time of the determination the need and or timing is uncertain. While the costs for such projects do not form a part of our assessment of the total forecast capital expenditure that we approve in this determination, the cost of the projects may ultimately be recovered from customers in the future if certain conditions are met.

We did not include TasNetworks' proposed contingent projects in our draft decision because we considered that the project trigger events were not reasonably specific

[6] We estimate the expected bill impact by varying the distribution network charges in accordance with our final decision, while holding all other components constant. This approach isolates the effect of our final decision on the core distribution network charges, and does not imply that other components will remain unchanged across the regulatory control period.

as required by the NER, and did not support the conclusion that the projects are probable to occur in the 2019–24 regulatory control period.[7]

TasNetworks has now proposed three contingent projects instead of the five initially proposed, including Project Marinus (second Basslink interconnector). It undertook further analysis and provided additional supporting information, having engaged with its stakeholders and us prior to submitting its revised proposal, to substantiate the inclusion of the contingent projects in our determination for 2019–24.

We have included TasNetworks' proposed contingent projects in our final decision. This is not a decision on the prudence or efficiency of the proposed contingent capex, which is ultimately a matter for any future contingent project application. Rather our decision to include contingent projects with appropriate project triggers allows for these projects to proceed in a timely manner should the need for these investments be confirmed within the 2019–24 regulatory control period. For this to occur, TasNetworks will be required to undertake a cost benefit analysis as outlined in the NER and supporting guidelines (the regulatory investment test) as well as further consumer consultation in advance of submitting any future proposal to recover costs associated with a contingent project. Our process would be to thoroughly test TasNetworks' application of the regulatory investment test and any proposed capital expenditure in arriving at a future decision to provide for incremental revenue associated with these projects.

A number of stakeholders questioned how the Project Marinus interconnector would be funded and the costs and benefits shared across electricity consumers in the NEM.[8]

TasNetworks considers that, ideally, changes should be made to interconnector pricing arrangements to ensure that Tasmanian customers only pay costs that are commensurate with the benefits they receive.[9] If this cannot be achieved, TasNetworks states that it would only seek to include the proportion of Project Marinus costs in its RAB that is commensurate with the benefits Tasmanian consumers receive from that investment.[10]

---

7 AER, Draft Decision, *TasNetworks' transmission determination 2019 to 2024*, Capital Expenditure, Attachment 5, September 2018, pp. 50–51.

8 Tasmanian Small Business Council, *Response to the AER's Draft Decision and TasNetworks' Revised Proposals*, January 2019, p. 32; Aurora Energy, *TasNetworks' Distribution and Transmission Determination 2019–24*, 16 January 2019, p. 3; Consumer Challenge Panel Sub Panel 13, *Response to TasNetworks revised proposal for a revenue reset for the 2019–224 regulatory period*, 11 January 2019, p. 5; TasCOSS, *Submission to the AER's Draft Decision on the TasNetworks Transmission and Distribution Determination 2019 to 2024*, December 2018, p. 5; Tasmanian Government, *TasNetworks - Regulatory Determination 2019–24*, 11 January 2019, p. 4; Tasmanian Minerals & Energy Council, *AER draft decisions on TasNetworks' electricity distribution and transmission determinations for the 2019–24 regulatory control period dated 27 September 2018*, 6 January 2019, p. 3; Anonymous, *Submission on TasNetworks' revised regulatory proposal*, January 2019, p. 2.

9 TasNetworks, Marinus Link Contingent Project Explanatory Statement, 18 December 2018, p. 8.

10 TasNetworks, Marinus Link Contingent Project Explanatory Statement, 18 December 2018, p. 9.

We acknowledge TasNetworks' stated position in this regard, in response to the concerns expressed by stakeholders. However, this is not a matter for our final decision on the regulatory determination for TasNetworks. Interconnector pricing arrangements remain a policy consideration for the NER. In this regard, we note that the AEMC is reviewing elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment.

Listening to customers

TasNetworks has undertaken a comprehensive program of engagement with its customers and the proposals put forward clearly recognise customer priorities and a strong focus on affordability.

TasNetworks made significant progress in maturing its risk forecasting and assessment strategies, and improving investment evaluations, between its initial and revised proposals. This has provided us with greater confidence in the proposed capital expenditure for this final decision.

The decision to push some capital works projects originally planned for this period to beyond 2024 is a prudent decision which prevents any significant rise in network prices.

Whilst we recognise these enhancements, our final decision has not accepted all of TasNetworks' proposed capital expenditure for asset replacements and management systems. This represents the key difference between TasNetworks' revised proposal and our final decision.

Other relevant decisions

This final decision incorporates the outcomes of three reviews progressed in parallel to our consideration of TasNetworks' 2019–24 regulatory proposal, namely:

- 2018 rate of return guideline review:[11] We released our final decision on this review on 17 December 2018. Legislative amendments to the National Electricity Law (NEL) and National Gas Law (NGL) that established the guideline as a binding instrument were made on 13 December 2018. As the instrument is binding, we have determined a rate of return using the approach set out in the instrument
- regulatory tax approach review:[12] We released our final report on this review on 17 December 2018. Our post tax revenue model (PTRM) has been updated to implement the findings from this review, allowing for immediate expensing of

[11] AER, *Rate of return instrument*, 17 December 2018.

[12] AER, Final report – *Review of regulatory tax approach*, 17 December 2018.

forecast capital expenditure and applying the diminishing value (DV) method to calculate the tax depreciation for new assets[13]

- approach to forecasting operating expenditure (opex) productivity growth for electricity distributors review:[14] We released our final decision on 8 March 2019. Productivity growth is one element in the trend component of our opex forecasting approach. Our forecast of productivity growth is intended to capture the efficiency improvements distributors can make in providing distribution services. In our review, we determined that a prudent electricity distributor, acting efficiently, can achieve opex productivity growth of 0.5 per cent each year. We have applied this finding in our 2019–24 final decision for TasNetworks.

1.1 What is driving revenue

The changing impact of inflation over time makes it difficult to compare revenue from one period to the next on a like-for-like basis. To do this we use 'real' values based on a common year (in this case 2018–19), which have been adjusted for the impact of inflation.

In real terms, TasNetworks' proposed a 17.5 percent decrease in real average annual transmission revenue than it recovered from customers in the 2014–19 regulatory control period. Our transmission final decision would allow 22.7 per cent less revenue (difference of 5.2 per cent).

Our previous determination for TasNetworks distribution network only covered the 2017–19 two–year period. In real terms, our distribution final decision would allow on average 0.5 per cent less revenue per year than recovered from customers in the 2017–19 regulatory control period. TasNetworks revised proposed a 4.9 per cent increase in its real average annual revenue, in its revised proposal.

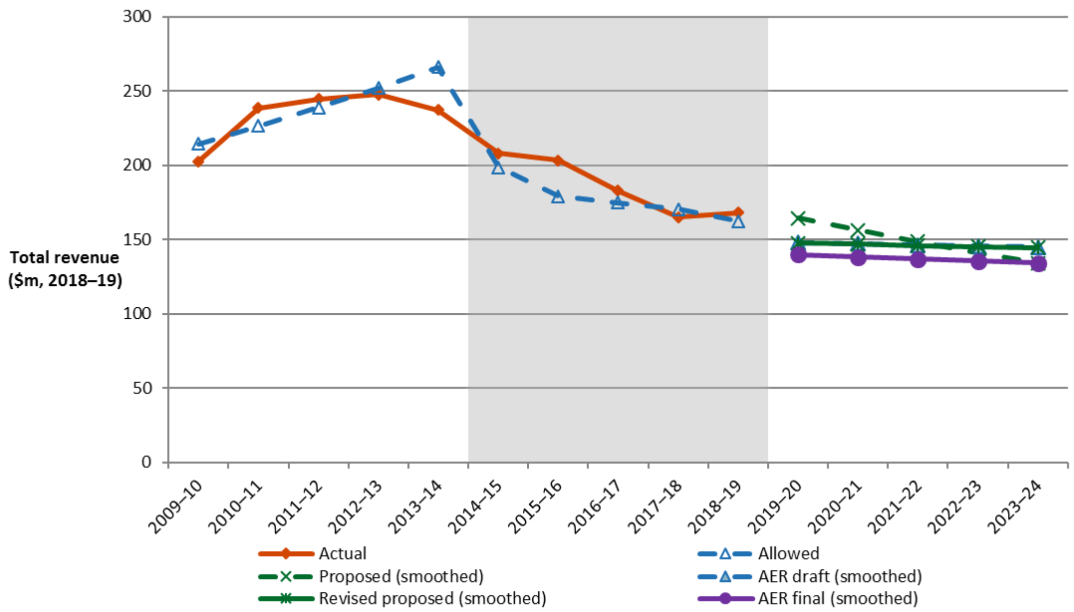
Figure 1 and Figure 2 show our final decision for transmission and distribution, together with TasNetworks' actual and forecast revenues for the 2019–24 regulatory control period. These show our transmission revenue will fall in the first year and then slightly decline for subsequent years, whereas, our distribution revenue will fall in the first year and then slightly increase for subsequent years, of the 2019–24 regulatory control period. Overall the combined transmission and distribution revenue impact is relatively flat.

---

13 AER, *Distribution PTRM (version 4)*, April 2019; AER, *Transmission PTRM (version 4)*, April 2019.

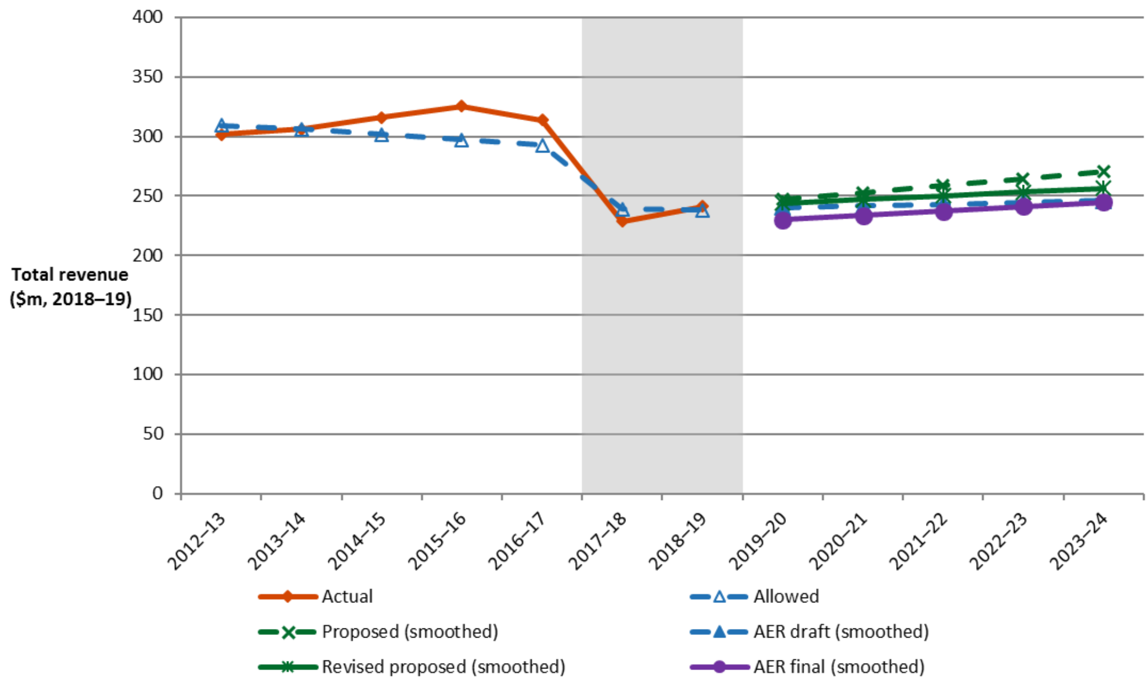
14 AER, Final decision – *Forecasting productivity growth for electricity distributors*, 8 March 2019.

Figure 1 Transmission revenue over time ($millions, 2018–19)



Source: AER analysis, smoothed revenue.

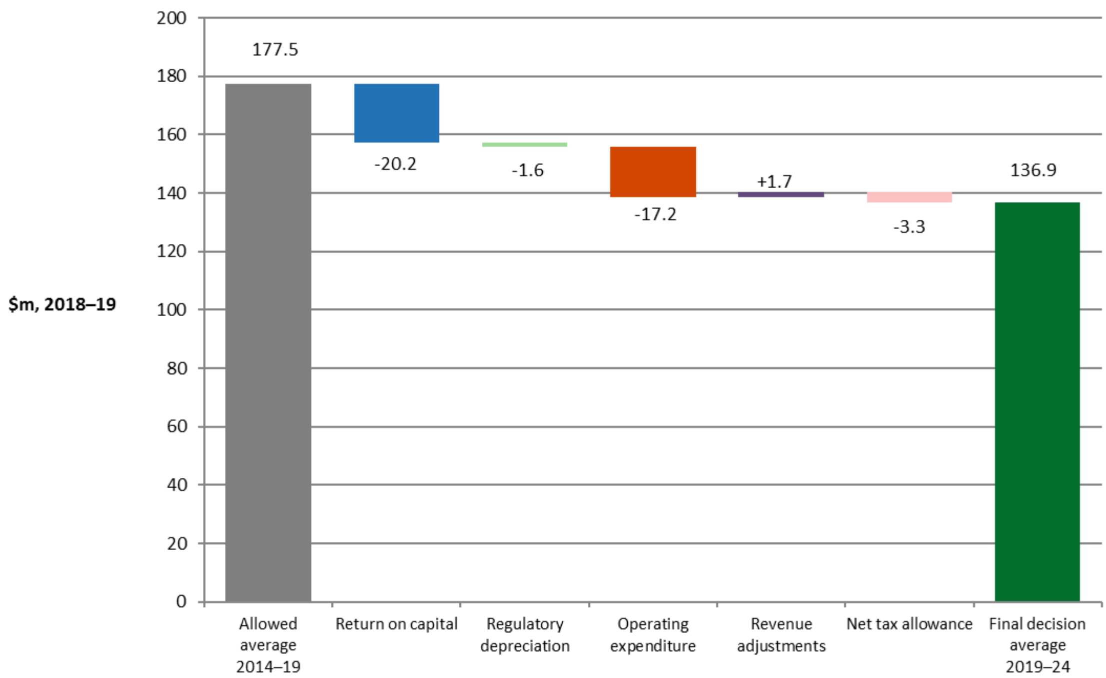
Figure 2 Distribution revenue over time ($millions, 2018–19)



Source: AER analysis, smoothed revenue.

Figure 3 and Figure 4 highlight the key drivers of the decrease in TasNetworks' transmission and distribution revenues that would result from this final decision, by reference to the revenue 'building blocks' that form the basis of our assessment.[15] These figures compare our final decision against the allowances for the previous regulatory control period (2014–19 for transmission and 2017–19 for distribution). They illustrate that our final decisions for TasNetworks' transmission network and distribution network are quite different. While the building blocks for transmission and distribution show an overall reduction, the average annual revenue for transmission decreases by a much larger margin, particularly for return on capital and opex.

Figure 3 Change in transmission revenue from 2014–19 to 2019–24 ($million, 2018–19)

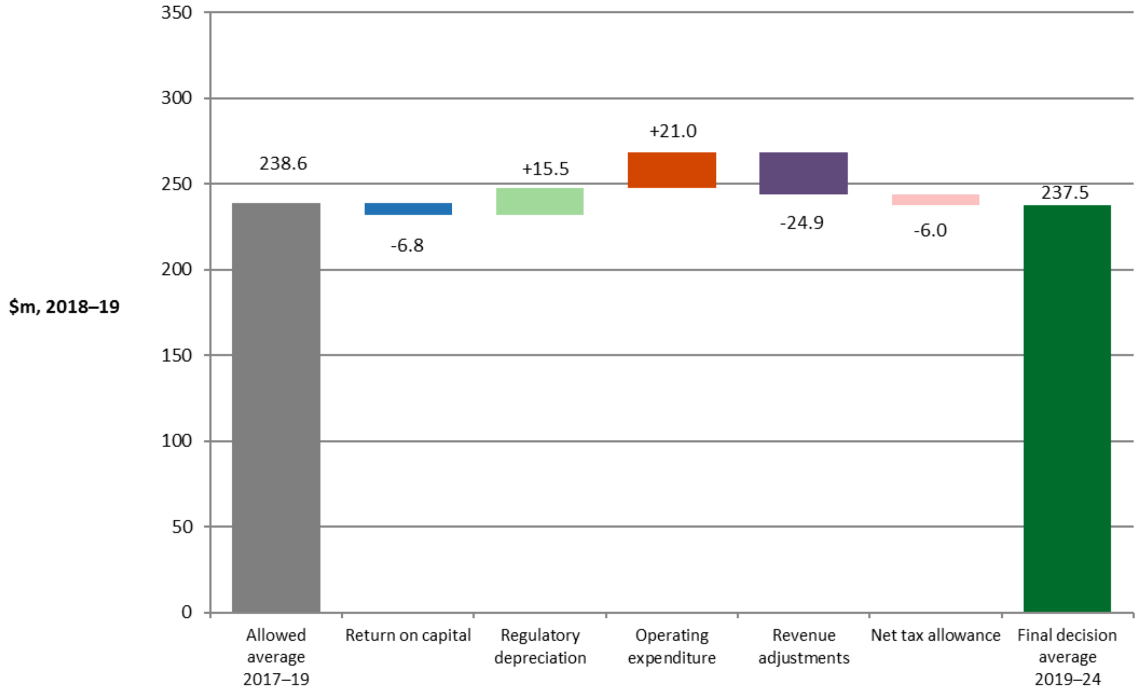


Source: AER analysis, average annual unsmoothed revenue.

Note: The revenue adjustment is a decrement carried over from the previous regulatory control period as a result of the application of the efficiency benefit sharing scheme and capital expenditure sharing scheme.

[15] These comparisons are of average annual revenues because our previous determination for TasNetworks only spanned two financial years (2017–19).

Figure 4 Change in distribution revenue from 2017–19 to 2019–24 ($million, 2018–19)



Source: AER analysis, average annual unsmoothed revenue.

Note: The revenue adjustment is a decrement carried over from the previous regulatory control period as a result of the application of the efficiency benefit sharing scheme and capital expenditure sharing scheme, and also includes an allowance provided under the demand management innovation allowance mechanism.

1.2 Key differences between our final decision and TasNetworks' proposal

As we noted above, our final decision does not reflect the full $2132.4 million in revenue ($nominal, smoothed) proposed by TasNetworks, in its revised proposal, for its network services, and instead allows a lower total revenue of $2012.5 million, a reduction of 5.6 percent. In a number of areas, the information provided has not justified TasNetworks' revised proposal.

The areas of difference are:

- TasNetworks' total capex forecast includes provision for a level of capital investment that we consider goes beyond what is efficient and prudent for the maintenance and operation of its network and given expected demand.

  The lower capex forecast we have substituted for the purposes of this final decision has resulted in a reduction in TasNetworks' RAB over the 2019–24 period, and also a reduction in the regulatory depreciation allowance. We have approved $892.5 million in transmission and distribution capex compared to TasNetworks' proposed value of $963.3 million (7 per cent reduction). This is driven by reductions in repex and non-network expenditure (section 2.4)

- rate of return, which is a large contributor to the difference between our final decision and TasNetworks' proposal (and therefore the return on capital). We have approved a rate of return of 5.55 per cent for transmission and 5.28 per cent for distribution (nominal vanilla, indicative) for the first year of the 2019–24 regulatory control period, compared to TasNetworks' revised proposal rate of return of 5.77 per cent for transmission and 5.51 per cent for distribution[16]
- a $2.5 million and $5.3 million ($nominal) reduction in the depreciation allowance for TasNetworks transmission and distribution respectively (section 2.3)
- a $7.2 million and $18.2 million ($nominal) reduction in the corporate income tax for TasNetworks transmission and distribution respectively (section 2.7).

In addition to the standard control components outlined above, there are also key differences in our final decision for alternative control services, in particularly, we have not approved TasNetworks' proposed public lighting charges. Our final decision on alternative control services is set out in attachment 15.

1.3 Expected impact of our final decision on electricity bills

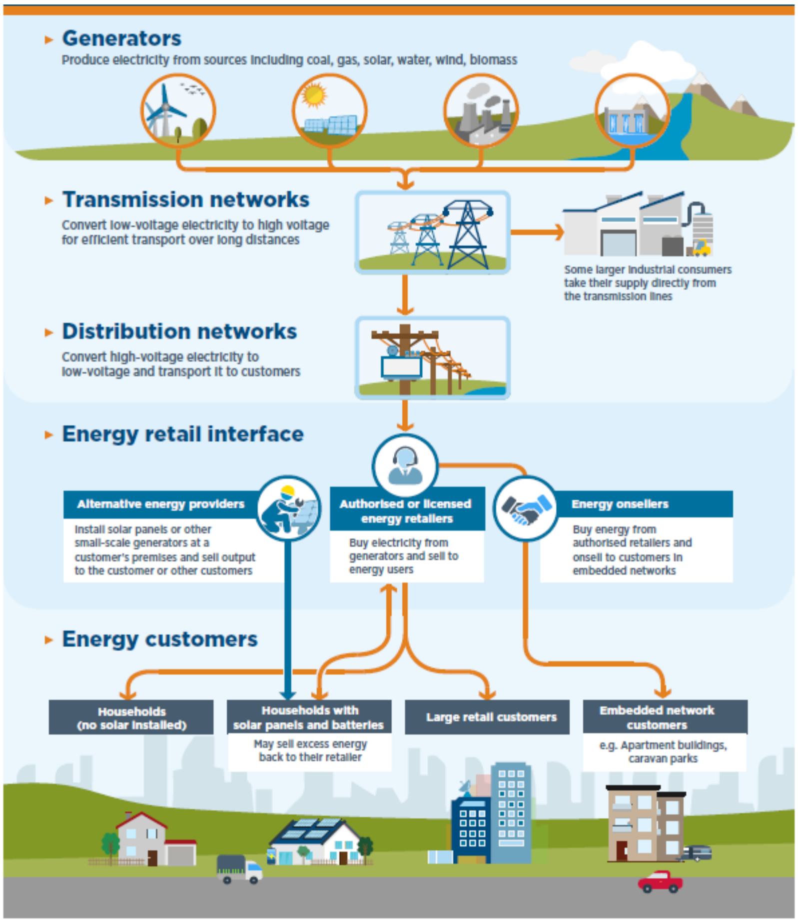
TasNetworks' network charges make up a significant component—around 42 per cent—of the electricity bills paid by residential customers in Tasmania.[17] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 5 illustrates the different components of the electricity supply chain.

The cost of the network components of the electricity supply chain are ultimately recovered through electricity retail charges. The Office of the Tasmanian Economic Regulator is responsible for setting maximum retail prices for the sale and supply of electricity services to (regulated) standing offer customers.

[16] TasNetworks applied the AER's draft 2018 Rate of Return Guidelines, consistent with our draft decision, in its revised proposal. See section 2.2 for further discussion on the rate of return.

[17] AEMC, *2017 Residential electricity price trends – Tasmanian information sheet*, December 2017; AER analysis.

Figure 5 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

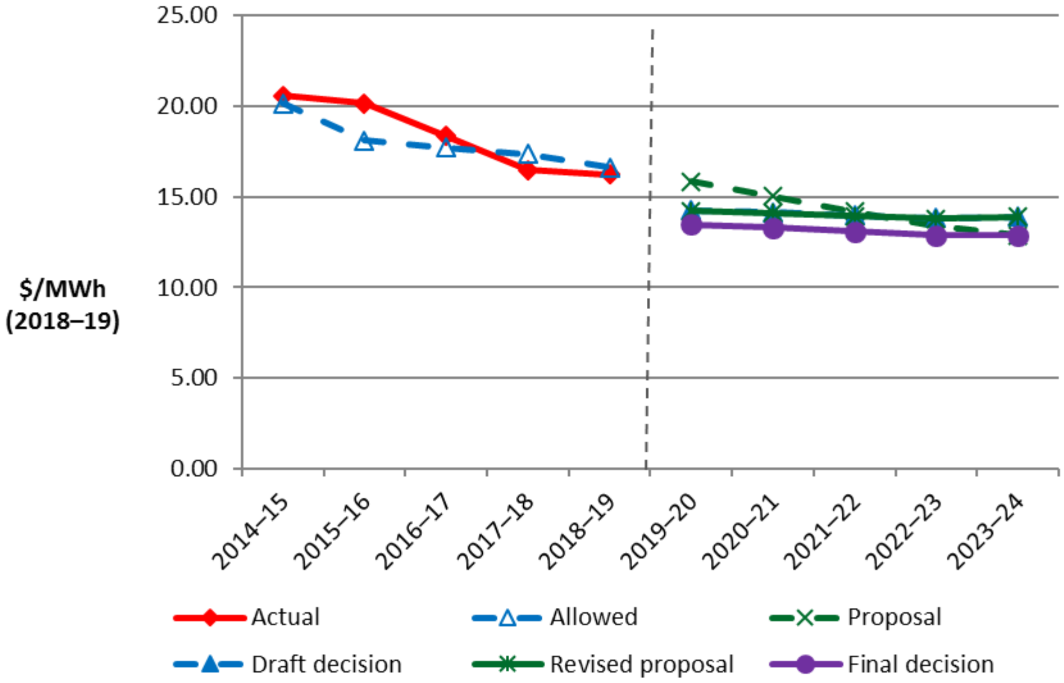
Transmission charges

Figure 6 below shows the indicative average transmission charges over the period 2014–15 to 2023–24 in real 2018–19 dollar terms. These amounts are an approximation of transmission charges as they are simply TasNetworks' transmission forecast revenue divided by TasNetworks' proposed forecast energy delivered (measured in MWh).[18] The average transmission charges are expected to decrease from around $18.4/MWh for the 2014–19 regulatory period[19] to $13.1/MWh for the 2019–24 regulatory period.

[18] TasNetworks, *Response to information request #037 – Indicative bill impact information source,* August 2018.

[19] Transmission charges for 2014–15 to 2017–18 are based on actual revenue, while 2018–19 transmission charges are based on estimated revenue.

Figure 6 Indicative transmission price path for Tasmania ($/MWh, 2018–19)



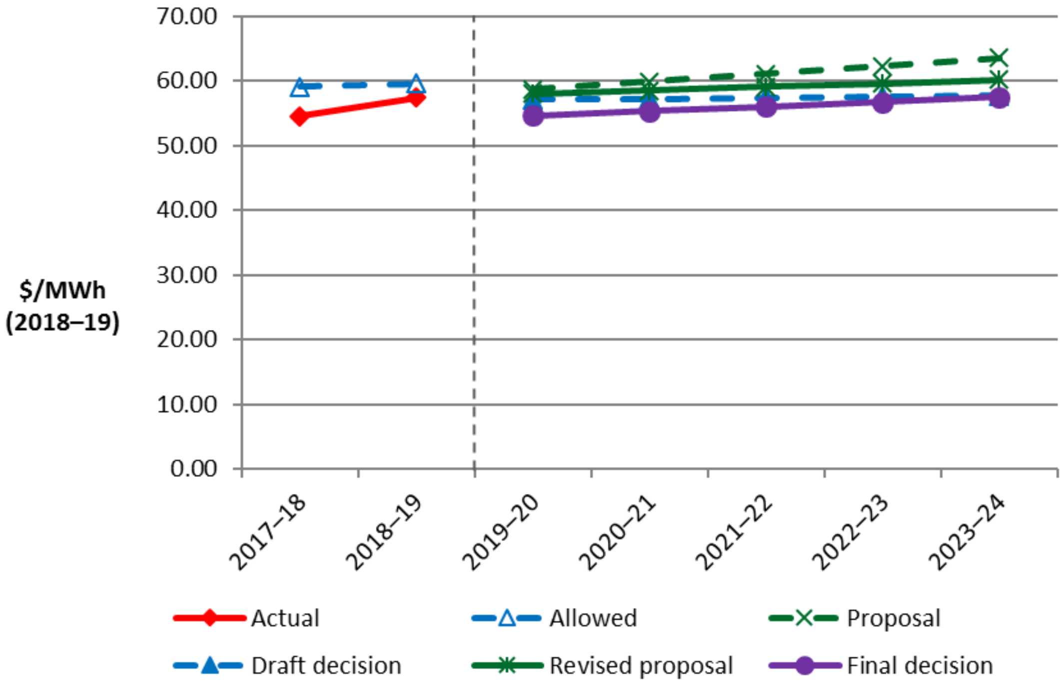
Source: AER analysis.

Distribution charges

Figure 7 below shows the indicative average distribution charges over the period 2017–18 to 2023–24 in real 2018–19 dollar terms. Like the transmission charges above, these amounts are an approximation of distribution charges as they are simply TasNetworks' distribution forecast revenue divided by their forecast energy delivered (measured in MWh). Based on our final decision, the average distribution charges are expected to remain steady from around $56.0/MWh for the 2017–19 regulatory period[20] to $56.0/MWh for the 2019–24 regulatory period.

[20] Distribution charges for 2017–18 are based on actual revenue, while 2018–19 distribution charges are based on estimated revenue.

Figure 7 Indicative distribution price path for Tasmania ($/MWh, 2018–19)



Source: AER analysis.

Potential bill impact

We estimate the combined impact of TasNetworks' transmission and distribution charges on the average annual residential electricity bill in Tasmania. We expect that, holding other components of bills constant, our final decision will result in an increase of $68 or 3.0 per cent ($nominal) in the average annual electricity bills for residential customers in Tasmania over the period compared to the current, 2018–19 levels.[21] This involves a $53 ($nominal) decrease in the first year, followed by gradual increases of around $30 ($nominal) per annum for the remaining years.

1.4 TasNetworks' consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions as a regulator and the way TasNetworks operates its network. An important part of this is ensuring the regulatory proposals TasNetworks puts to us for approval reflects the NEO, and that TasNetworks has engaged with its consumers to determine how best to provide services that align with their long term interests.

---

[21] This consists, in nominal terms, of a $92 or 4.1% increase attributable to the distribution determination and a reduction of $24 or 1.1% as a result of the transmission determination.

Consumer engagement in this context is about TasNetworks working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence TasNetworks' decisions. In the regulatory process, stronger consumer engagement can help us test service providers' expenditure proposals, and can raise alternative views on matters such as service priorities, capital expenditure proposals and tariff structures.

TasNetworks was one of the first network businesses to develop an early consumer engagement framework, which it undertook prior to submitting its electricity distribution regulatory proposal for the current regulatory control period. This included the release of a preliminary revenue proposal for consultation, which now sets the benchmark for all network service providers.

TasNetworks has continued its established approach to early consumer engagement for the 2019–24 regulatory control period. However, with its regulatory proposal now covering both distribution and transmission, it has tailored its consultation approach to its distribution and transmission customers.[22] TasNetworks consulted extensively in developing its regulatory proposal commencing in May 2016. This consultation included the publication of a Directions and Priorities Paper which set out its preliminary revenue proposal.[23]

We consider TasNetworks continues to recognise the importance of consumer engagement and the value it delivers for the network business and customers. It has been one of a handful of network businesses that has commenced its engagement with consumers well in advance of submitting its regulatory proposal and appears to be responsive to customer feedback in shaping outcomes. This is reflected in the AER's Consumer Challenge Panel (CCP13) advice to us on TasNetworks' regulatory proposals.

We tasked CCP13 specifically with advising us on the effectiveness of TasNetworks' engagement activities with consumers and how this was reflected in the development of its proposal. CCP13 attended a number of TasNetworks workshops and met on several occasions with TasNetworks executives and staff. CCP13 also talked to a number of stakeholders who are represented on TasNetworks’ formal Customer Council[24] and Pricing Reform Working Group.

We were particularly encouraged to see CCP13 confirm that post lodgement of its initial proposal, TasNetworks is to be commended for a committed, well planned and

[22] It engaged more one on one and through small workshops with its transmission customers - large industrial customers and generators that make up over 50 percent of the demand for electricity in Tasmania. Whereas with distribution customers, residential and business, engagement included surveys, public forums and workshops.

[23] TasNetworks, *Direction and Priorities Consultation Paper Transmission and Distribution Determination 2019–24*, August 2017.

[24] TasNetworks' Customer Council is a standing body of representatives of consumer bodies and other stakeholders including TasCOSS, Anglicare, Aged Care Association, representatives of small business, agriculture, local government, the State Ombudsman and the incumbent retailer Aurora Energy.

well executed consumer engagement process, particularly on its contingent projects[25]

Concerns surrounding TasNetworks' consumer engagement on its proposed contingent projects were expressed by CCP13[26] and noted in our draft decision.[27] We are pleased to have seen a marked improvement in TasNetworks engagement on its proposed contingent projects since submitting its initial proposal in January 2018. This has contributed to material enhancements and our approval of the contingent project and trigger events for the final decision, which are considered further in attachment 5. The CCP13 did however note the need for improvement in TasNetworks engagement with its public lighting customer.[28] This is evident in the submission received from the Local Government Association of Tasmania.[29] We consider TasNetworks and its public lighting customers would benefit from on-going engagement.

Consistent with CCP13's advice[30], we accept that TasNetworks has undertaken a high quality consumer engagement process and is well informed of consumers' interests and concerns in framing its revenue proposals.

---

[25] Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to TasNetworks revised proposals for a revenue reset for the 2019–24 regulatory period*, 11 February 2019, p. 3.

[26] Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to proposals from TasNetworks for a revenue reset for the 2019–24 regulatory period,* 16 May 2018, p. 35.

[27] AER, Draft Decision, *TasNetworks transmission and distribution determination 2019 to 2024*, Overview, September 2018, pp. 25–26.

[28] Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to TasNetworks revised proposals for a revenue reset for the 2019–24 regulatory period*, 11 February 2019, p. 11.

[29] Local Government Association of Tasmania, *Submission on TasNetworks Pricing Reset 2019–24, Response to AER Draft Determination,* 11 January 2019, p. 2.

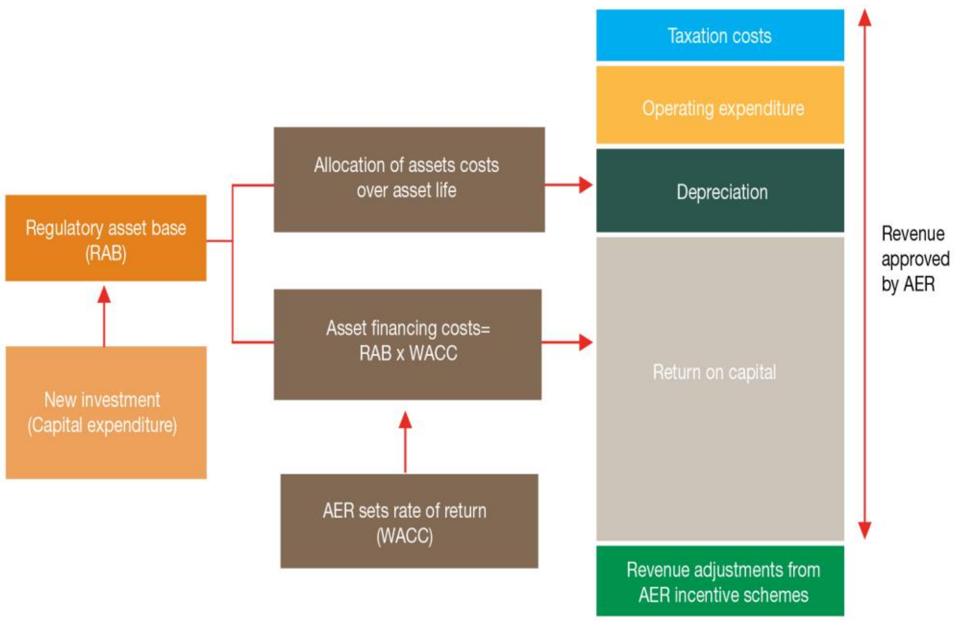
[30] Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to TasNetworks revised proposals for a revenue reset for the 2019–24 regulatory period,* 11 February 2019, p. 3.

2 Key components of our final decision on revenue

The total revenue TasNetworks has proposed reflects its forecast of the efficient cost of providing its transmission and distribution network services over the 2019–24 regulatory control period. TasNetworks' proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determine a total revenue allowance (see Figure 8) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex—the capital costs and expenditure incurred in the provision of network services—mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services (section 2.5)
- revenue adjustments, including revenue increments or decrements resulting from the application of various schemes (section 2.6)
- the estimated cost of corporate income tax (section 2.7).

Figure 8 The building block model to forecast network revenue



Source: AER, *State of the Energy Market*, December 2018, p. 138.

We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs, while maintaining safety and reliability, retain part of the benefit. This benchmark incentive framework is a foundation of our regulatory approach and promotes the delivery of the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our final decision on TasNetworks' transmission and distribution revenues for the 2019–24 regulatory control period are set out in Table 2-1 and Table 2-2 below.

Table 2-1 AER's final decision on TasNetworks' transmission annual building block revenue requirement, annual expected MAR, estimated total revenue cap and X factor ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Return on capital	80.1	80.7	80.8	80.6	79.8	402.0
Regulatory depreciation[a]	16.5	22.4	25.2	26.4	31.1	121.7
Operating expenditure[b]	30.8	31.6	32.6	33.5	34.5	163.0
Revenue adjustments[c]	18.5	9.8	10.8	5.0	0.9	44.9
Net tax allowance	0.7	0.4	0.5	0.6	1.4	3.6
Annual building block revenue requirement (unsmoothed)	146.6	144.9	149.8	146.2	147.7	735.3
Annual expected MAR (smoothed)	143.2	145.2	147.2	149.3	151.3	736.1[d]
X factor (%)[e]	n/a[f]	1.00%	1.00%	1.00%	1.00%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS) and the capital expenditure sharing scheme (CESS).

(d) The estimated total revenue cap is equal to the total annual expected MAR.

(e) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(f) TasNetworks is not required to apply an X factor for 2019–20 because we set the 2019–20 MAR in this decision. The MAR for 2019–20 is around 16.9 per cent lower than the approved MAR for 2018–19 in real terms, or 14.9 per cent lower in nominal terms.

Table 2-2 AER's final decision on TasNetworks' distribution revenues for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Return on capital	93.6	97.2	100.1	102.0	104.3	497.2
Regulatory depreciation[a]	57.1	62.7	69.3	73.8	78.6	341.5
Operating expenditure[b]	92.9	94.8	96.1	97.5	98.9	480.2
Revenue adjustments[c]	–21.0	–21.5	–22.0	2.4	–2.2	–64.2
Net tax allowance	5.6	4.7	4.4	4.7	5.1	24.4
Annual revenue requirement (unsmoothed)	228.2	237.9	248.0	280.4	284.7	1279.1
Annual expected revenue (smoothed)	235.4	244.9	254.9	265.2	276.0	1276.4
X factor[d]	n/a[e]	–1.60%	–1.60%	–1.60%	–1.60%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS) and demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) TasNetworks is not required to apply an X factor for 2019–20 because we set the 2019–20 expected revenue in this decision. The expected revenue for 2019–20 is around 4.7 per cent lower than the approved expected revenue for 2018–19 in real terms, or 2.3 per cent lower in nominal terms.

In the sections below, we discuss each component of our decision on TasNetworks' revenue for 2019–24 in turn:

- incentive schemes, including the EBSS and CESS are discussed in section 3
- the tariff structure statement is discussed in section 4
- other price terms and conditions, including the classification of services, control mechanism, pass throughs, the negotiating framework, pricing methodology and the connection policy are discussed in section 5.

2.1 Regulatory asset base

The RAB accounts for the value of TasNetworks regulated assets over time. The size of the RAB—and therefore the revenue generated from the return on capital and return of capital building blocks—is directly affected by our assessment of capex.

Our final decision is to determine an opening RAB value as at 1 July 2019 of $1445.3 million and $1771.1 ($nominal) for TasNetworks' transmission and distribution networks respectively. We roll forward these opening RAB values year-by-year by indexing it for inflation, adding new capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions).[31] This gives us a closing value of the RAB at the end of each year of the regulatory control period. The value of the RAB is used to determine:

- the return on capital building block, which is the product of the RAB and our approved rate of return
- regulatory depreciation (or the return of capital, discussed further below in section 2.3).

RAB growth is a key issue for stakeholders.[32] TasNetworks' transmission and distribution RABs tell a different story.

Transmission RAB

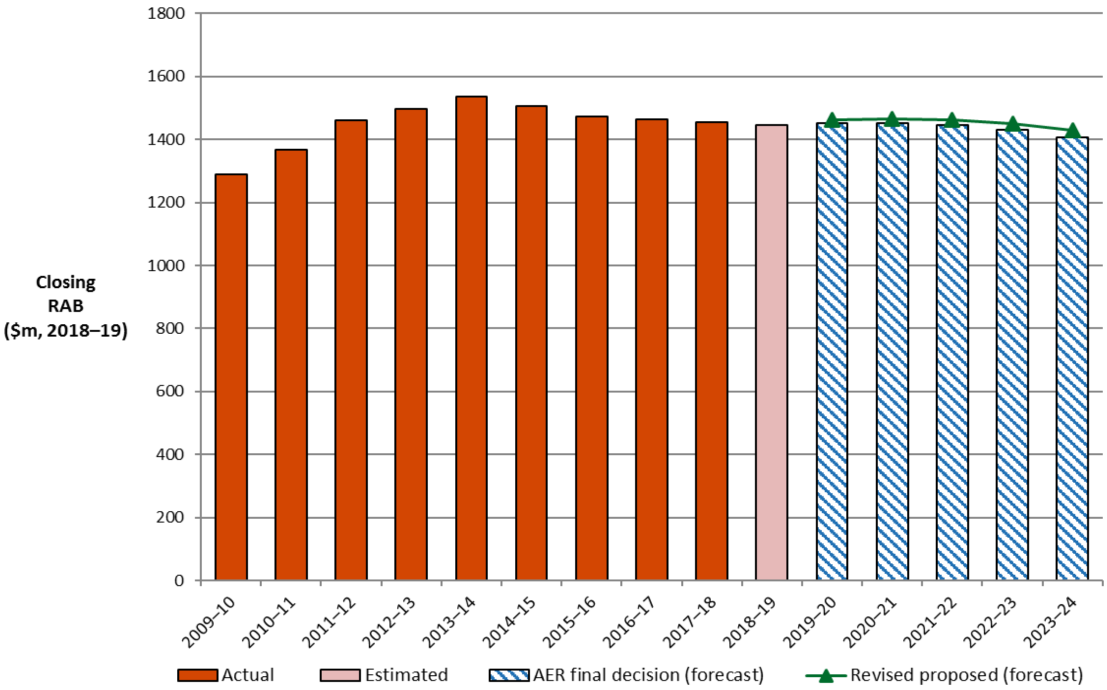
Figure 9 compares our transmission final decision on TasNetworks' forecast RAB to TasNetworks' proposal and actual RAB in real dollar terms. This shows that TasNetworks' transmission RAB is decreasing in value. However, TasNetworks' transmission RAB may well increase by the end of the period. TasNetworks has proposed three contingent projects estimated at over $642 million, or more than twice TasNetworks' proposed forecast capex for 2019–24. Should all these contingent projects proceed, they would increase TasNetworks' transmission RAB by more than 40 per cent.33 These contingent projects cover a second Bass Strait interconnector and upgrades to manage new generation. Our final decision on TasNetworks' contingent projects is discussed further in section 2.4 below.

31 The term 'rolled forward' means the process of carrying over the value of the capital base from one regulatory year to the next.

32 Tasmanian Small Business Council, *Response to the AER's Draft Decision and TasNetworks' Revised Proposals*, January 2019, p. 46.

33 This is based on TasNetworks' revised proposal estimated share of the costs for the contingent projects including Project Marinus ($445 million). See TasNetworks, *Project Marinus Second Bass Strait interconnector - TasNetworks Revised Revenue Proposal 2019-24*, November 2018, p. 9.

Figure 9 TasNetworks' actual transmission RAB, proposed forecast RAB and AER final decision ($millions, 2018–19)



Source: AER analysis.

TasNetworks' transmission proposal calculated its opening RAB as at 1 July 2019 and its closing RAB at 30 June 2024 in accordance with our RFM. Table 2-3 sets out our final decision on the forecast RAB values for TasNetworks' transmission network over the 2019–24 regulatory control period.

Table 2-3 AER's final decision on TasNetworks' transmission RAB for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
Opening RAB	1445.3	1487.1	1522.1	1552.2	1573.4
Capital expenditure[a]	58.4	57.4	55.2	47.7	43.3
Inflation indexation on opening RAB	35.0	36.1	36.9	37.6	38.2
Less: straight-line depreciation[b]	51.6	58.5	62.1	64.1	69.3
Closing RAB	1487.1	1522.1	1552.2	1573.4	1585.5

Source: AER analysis.

(a) As-incurred, and net of forecast disposals. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

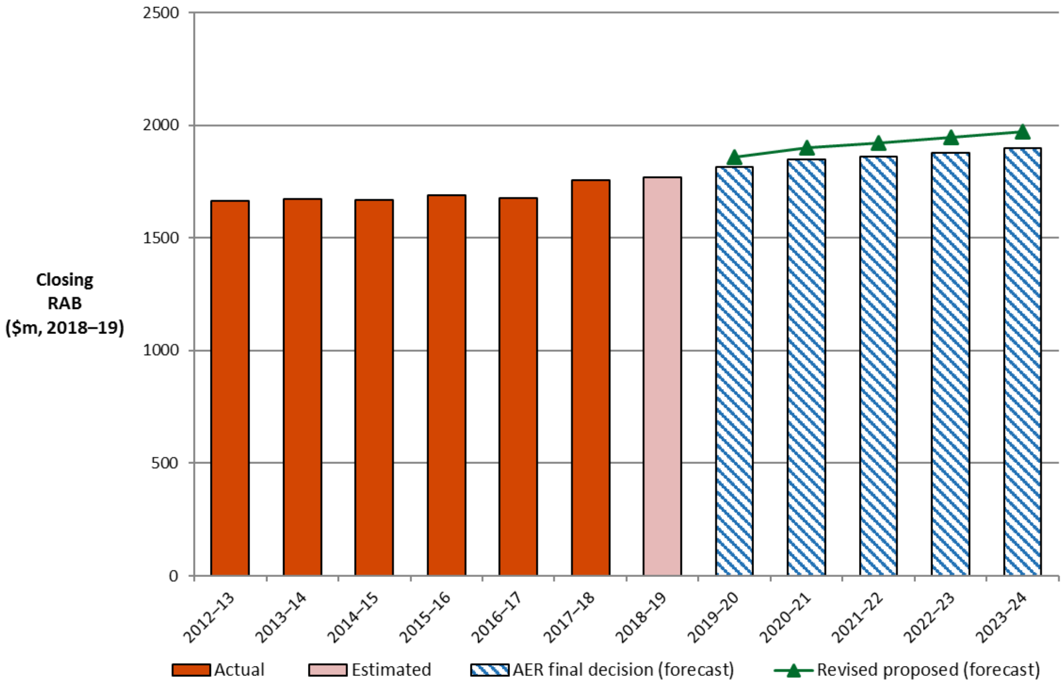
(b) Based on as-commissioned capex.

Further details regarding the roll forward of TasNetworks' transmission RAB is set out in attachment 2 of the transmission determination.

Distribution RAB

Figure 10 compares our distribution final decision on TasNetworks' forecast RAB to TasNetworks proposal and actual RAB in real dollar terms. This shows that TasNetworks' distribution RAB is increasing in value, due to increases in capex, but only slightly compared to TasNetworks' proposed forecast. Our final decision on TasNetworks' capex is discussed further in section 2.4 below.

Figure 10 TasNetworks' actual distribution RAB, proposed forecast RAB and AER final decision ($millions, 2018–19)



Source: AER analysis

TasNetworks' distribution proposal likewise also calculated its opening RAB as at 1 July 2019 and its closing RAB at 30 June 2024 in accordance with our RFM.

Table 2-4 sets out our final decision on the forecast RAB values for TasNetworks' distribution network over the 2019–24 regulatory control period.

Table 2-4 AER's final decision on TasNetworks' distribution RAB for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
Opening RAB	1771.1	1860.9	1938.2	1999.0	2067.7
Capital expenditure[a]	146.9	139.9	130.2	142.5	150.4

Inflation indexation on opening RAB	42.9	45.1	47.0	48.5	50.1
Less: straight-line depreciation	100.0	107.8	116.3	122.3	128.7
Closing RAB	1860.9	1938.2	1999.0	2067.7	2139.6

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

Further details regarding the roll forward of TasNetworks' distribution RAB is set out in attachment 2 of the distribution determination.

2.2 Rate of return and value of imputation credits

The return (the 'return on capital') each business is to receive on its RAB continues to be a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

An accurate estimate of the rate of return is necessary to promote efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

In November 2018, the national electricity and gas laws were amended to require us to make a binding rate of return instrument. As a binding instrument, it sets out the methodology for calculating the rate of return. The method must be capable of automatic application to all regulated network service providers without the exercise of discretion. The 2018 Rate of Return Instrument (2018 Instrument) specifies the return on debt as a formula, being the trailing average portfolio approach, with a 10 year transition from an on-the-day approach to a trailing average, and based on third part debt data.

As required under the NER we have applied the 2018 Instrument and estimate an allowed rate of return of 5.55 per cent for the prescribed transmission services and 5.28 per cent for the direct control services (nominal vanilla).[34] TasNetworks' revised

[34] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision. The legislative amendments to replace the (previous) non-binding Rate of Return Guidelines with a binding legislative instrument were passed by the South Australian Parliament in December

proposal adopted the draft 2018 rate of return guidelines and noted that the 2018 Instrument would apply to its final decision.[35] Submissions to this process and also separate but concurrent regulatory processes support the immediate full application of the binding 2018 Instrument to all resets.[36]

Our calculated rate of return, in Table 2-5, will apply to the first year of the 2019–24 period control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 Instrument to use a ten-year trailing average portfolio return on debt that is rolled-forward each year. Our final decision is to accept its return on equity and debt averaging periods because they satisfied the 2018 Instrument.[37]

Table 2-5 Final decision on TasNetworks' rate of return (% nominal)

	TasNetworks draft decision (2019–24)		AER final decision (2019–24)		Allowed return over regulatory control period
	Transmission	Distribution	Transmission	Distribution	
Nominal risk free rate	2.66% [a]	2.66% [a]	2.14% [b]	2.14% [b]	
Market risk premium	6%	6%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	0.6	
Return on equity (nominal post–tax)	6.3%	6.3%	5.80%	5.80%	Constant (%)
Return on debt (nominal pre–tax)	5.42%	4.98%	5.38%[c]	4.94%[d]	Updated annually
Gearing	60%	60%	60%	60%	Constant (60%)
Nominal vanilla	5.77%	5.51%	5.55%	5.28%	Updated

2018. See, Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA). NGL, Part 1, division 1A; NEL, Part 3, division 1B.

35 TasNetworks, *Tasmanian Transmission and Distribution Revised Proposals 2019–2024*, 29 November 2018, pp. 87–88.

36 For example, see: EUAA, *Submission to NSW DNSP's 2019-24 revenue reset*, January 2019, p. 5 ; Origin, *Letter to the AER: AER draft decision for NSW electricity distributors 2019-24*, 5 February 2019, p. 1; PIAC, *Submission to the AER's draft determinations and the NSW DNSPs' 2019-24 revised proposals*, 7 February 2019, p. 9; ECA, *Submission to the AER's draft decision on the Endeavour Energy 2019 to 2024 distribution determination*, 15 February 2019, p. 2; CCP10, *Response to the Ausgrid revised regulatory proposal 2019-24 and AER draft determination*, January 2019, p. 48; and CCP10, *Response to the Evoenergy revised regulatory proposal 2019-24 and AER draft determination*, January 2019, pp. 43–44.

37 AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25; TasNetworks, *Letter to AER proposing return on debt averaging periods for 2019 to 2024*, 24 January 2018.

WACC					annually for return on debt
Forecast inflation	2.45%	2.45%	2.42%	2.42%	Constant (%)

Source: AER analysis

[a] Calculated using a placeholder averaging period of 20 business days ending 31 July 2018.

[b] Final decision to accept proposed period of 1 February 2019 to 28 February 2019.

[c,d] Return on debt for 2019–20 updated for latest averaging period 1 February 2019 to 28 February 2019.

Final decision is to accept the proposed debt averaging periods.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Our final decision forecasts for debt and equity raising costs are included in the opex and capex attachments, respectively. TasNetworks' revised proposal has adopted our approach for equity raising costs.[38] We have updated our estimates to set equity raising costs at zero for its prescribed transmission services and $1.2 million ($2018–19, rounded) for its standard control services.

We accepted TasNetworks’ revised opex proposal therefore we do not provide substitute estimates of its debt raising costs using our benchmark approach.[39]

Imputation credits

Our final decision applies a gamma of 0.585 as per the binding 2018 Instrument to TasNetworks' prescribed transmission and standard control services.[40] This was the result of extensive analysis and consultation conducted as part of the 2018 rate of return review.[41] TasNetworks’ revised proposal adopted the draft 2018 rate of return guidelines' value of 0.5 and noted that the 2018 Instrument would apply to its final decision.[42]

---

38 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 89.

39 See our opex attachment for our final opex decision.

40 AER, *Rate of return instrument*, December 2018, clause 27.

41 AER, *Rate of return instrument explanatory statement*, December 2018, pp. 307–382.

42 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, pp. 87–88, 92.

2.3 Regulatory depreciation (return of capital)

In our final decision, we include an allowance for the depreciation of TasNetworks' asset base (otherwise referred to as return of capital). Regulated service providers invest in large sunk assets to provide electricity services to customers. While some of the cost of such assets may be recovered from customers upfront, a greater proportion is recovered over time. The depreciation allowance is used for this purpose.

In deciding whether to approve the regulatory depreciation allowance proposed by TasNetworks, we make determinations on the indexation of the RAB and depreciation building blocks for TasNetworks' 2019–24 regulatory control period.[43]

Below we consider TasNetworks' regulatory depreciation allowance for transmission and distribution separately. Further detail on our final decisions regarding depreciation are set out in attachment 4.

Transmission

Our final decision approves a regulatory depreciation allowance of $121.7 million ($nominal) for the 2019–24 regulatory control period. This is $2.5 million (or 2.0 per cent) lower than TasNetworks' revised proposed value of $124.2 million ($nominal). This reduction occurs mainly as a consequence of our determinations on other components of TasNetworks' revised proposal that affect the forecast regulatory depreciation allowance. Specifically, they relate to the opening RAB as at 1 July 2019 (attachment 2) and forecast capital expenditure (attachment 5) including its effect on the projected RAB over the 2019–24 regulatory control period.[44]

For our final decision on TasNetworks' regulatory depreciation, we accept TasNetworks' proposal to use the year-by-year tracking approach to calculate the straight-line depreciation of existing assets. However, we made a few amendments to the depreciation model to update inputs and properly account for the removal of the forecast depreciation associated with a number of assets being removed from the RAB.[45] We also accept TasNetworks' proposed straight-line method used to calculate the regulatory depreciation allowance and its proposed asset classes and standard asset lives for its existing asset classes (but did not retain the proposed new 'Business Management Systems' asset class and the proposed standard asset life of 10 years for this asset class).

---

43 NER, cll. 6.12.1, 6.4.3, 6A.5.4 and 6A.14.1.

44 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our draft decision on the RAB (attachment 2) also reflects updates made to the WACC for the 2019–24 regulatory control period.

45 These assets are changing classification from providing prescribed transmission services to negotiated services. TasNetworks, *Tasmanian Transmission and Distribution Revised Proposals 2019–24*, November 2018, p. 82.

Table 2-6 shows our final decision on TasNetworks' transmission depreciation allowance for the 2019–24 regulatory control period.

Table 2-6 AER's final decision on TasNetworks' transmission depreciation allowance for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Straight-line depreciation	51.6	58.5	62.1	64.1	69.3	305.5
Less: inflation indexation on opening RAB	35.0	36.1	36.9	37.6	38.2	183.8
Regulatory depreciation	16.5	22.4	25.2	26.4	31.1	121.7

Source: AER analysis.

Distribution

Our final decision approves a regulatory depreciation allowance of $341.5 million ($nominal) for the 2019–24 regulatory control period. This is $5.3 million (or 1.5 per cent) lower than TasNetworks' revised proposed value of $346.8 million ($nominal). Similar to transmission, this reduction occurs mainly as a consequence of our determinations on other components of TasNetworks' revised proposal that affect the forecast regulatory depreciation allowance. Specifically, they relate to the opening RAB at 1 July 2019 (attachment 2) and forecast capital expenditure (attachment 5) including its effect on the projected RAB over the 2019–24 regulatory control period.[46]

For our final decision on TasNetworks' regulatory depreciation, we accept the continuation of TasNetworks' year-by-year tracking approach to calculate the straight-line depreciation of existing assets. However, we made a few amendments to the depreciation model to update inputs and correct minor modelling errors. We also accept TasNetworks' proposed asset classes, its straight-line depreciation method, and the standard asset lives used to calculate the regulatory depreciation allowance, consistent with those approved for the 2017–19 distribution determination.

Table 2-7 shows our final decision on TasNetworks' distribution depreciation allowance for the 2019–24 regulatory control period.

[46] Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our draft decision on the RAB (attachment 2) also reflects our updates to the WACC for the 2019–24 regulatory control period.

Table 2-7 AER's final decision on TasNetworks' distribution depreciation allowance for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Straight-line depreciation	100.0	107.8	116.3	122.3	128.7	575.2
Less: inflation indexation on opening RAB	42.9	45.1	47.0	48.5	50.1	233.7
Regulatory depreciation	57.1	62.7	69.3	73.8	78.6	341.5

Source: AER analysis.

2.4 Capital expenditure

Capital expenditure (capex) refers to the investment in assets to provide services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return of and on capital) as part of the building blocks that form part of TasNetworks' total revenue requirement.

Below we consider TasNetworks' proposed capex for transmission and distribution separately. Further detail on our final decision regarding capex is set out in attachment 5.

Transmission capital expenditure

Our final decision on TasNetworks' revenue includes $241.4 million ($2018–19) in forecast total net transmission capex for the 2019–24 regulatory control period. This is $19.0 million (or 7.3 per cent) lower than TasNetworks' proposed value of $260.4 million. Table 2-8 shows our decision compared to TasNetworks' forecast.

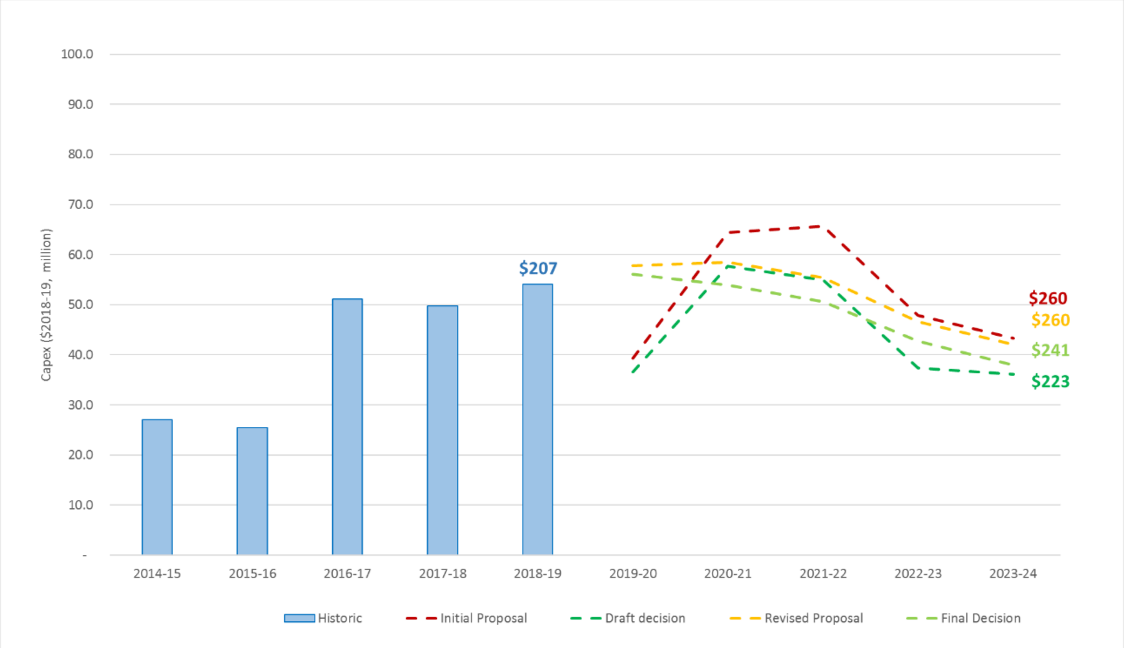
Table 2-8 AER final decision on total net transmission capex ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' proposal	57.8	58.4	55.4	46.7	42.0	260.4
AER draft decision	56.1	54.0	50.7	42.8	37.9	241.4
Difference	-1.7	-4.4	-4.7	-3.9	-4.1	-19.0
Percentage difference (%)	-2.9%	-7.5%	-8.5%	-8.4%	-9.8%	-7.3%

Source: AER analysis.
Note: Numbers may not total due to rounding.

Figure 11 shows our transmission capex final decision compared to TasNetworks' initial and revised proposals, its past allowances and past actual expenditure.

Figure 11 AER final decision on total forecast transmission capex ($million, 2018–19)



Source: AER analysis.

In its revised proposal, TasNetworks proposed total forecast net capex of $260.4 million ($2018–19) for the 2019–24 regulatory control period. TasNetworks' revised total capex forecast is $0.2 million (0.1 per cent) lower than its initial total capex forecast of $260.6 million ($2018–19).

TasNetworks has not justified its revised total capex forecast of $260.4 million ($2018–19) reasonably reflects the capex criteria.[47] We have included an amount of $241.4 million ($2018–19) in our substitute estimate of total capex. We are satisfied that our substitute estimate reasonably reflects the capex criteria. Below outlines our final decision.

[47] NER, cl. 6A.6.7(a).

Table 2-9 AER assessment of required capex by driver 2019–24 ($2018–19, million)

Driver	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Augmentation	6.9	11.3	3.3	0.0	0.0	21.5
Connections	0.0	1.1	$1.8	4.1	0.5	7.6
Replacement	31.8	24.1	30.4	24.6	24.1	135.1
Non-network	7.5	7.7	5.5	4.4	3.7	28.7
Capitalised overheads	10.3	10.1	10.0	9.9	9.9	50.1
Modelling adjustments	-0.4	-0.4	-0.3	-0.3	-0.2	-1.6
Total capex	56.1	54.0	50.7	42.8	37.9	241.4

Source: AER analysis.

Notes: Numbers may not add due to rounding.

TasNetworks' transmission capex consists of replacement capex (repex), non-network capex (including asset management information systems), augmentation capex (augex) and connections capex.

For asset replacement capex (repex), we have included an amount of $135.1 million ($2018–19) in our substitute estimate of total capex. Our substitute estimate is based on our assessment of the cost-benefit analysis and engineering justification for individual major repex projects. Our decision focussed on six repex projects for which TasNetworks did not accept our draft decision.

We accepted TasNetworks' revised proposal for two projects, reduced the scope and associated capex requirement for two projects, and deferred the remaining two projects. We derived our substitute estimate by adjusting TasNetworks' conservative risk and consequence input assumptions, and deferring expenditure where allowed by asset condition. TasNetworks' revised proposal accepted our position in relation to 7 of the 13 projects amended through the draft decision. Our substitute repex estimate accepts TasNetworks' revised proposal for two of the remaining six, on the basis of our assessment of asset condition and identified need. These reductions produce a substitute repex estimate that is $12.6 million ($2018–19) (8.5 per cent) lower than TasNetworks' revised repex forecast.

For non-network capex, we have included an amount of $28.7 million ($2018–19) in our substitute estimate of total capex. TasNetworks has not adequately justified the proposed increase in capex for its asset management information system (AMIS). We have included the amount accepted in our draft decision for the AMIS project in our final decision substitute estimate.

We have accepted TasNetworks' demand forecast, and proposed augex and connections capex, consistent with our draft decision.

Transmission contingent projects

Contingent projects provide early transparency to consumers on significant investments for which they may ultimately be asked to pay, while providing some assurance to network service providers and other market participants that investments can proceed in a timely way should certain project triggers be met. As the economic regulator in the NEM, our focus is on ensuring that network investments are prudent and efficient, provide the maximum net benefit to the market, and are in the long term interests of consumers. We only allow for contingent projects in our regulatory determinations where we are satisfied that doing so will contribute to achieving these objectives, in accordance with the requirements of the NER.[48] Contingent projects can be included in a revenue determination only where they are reasonably required to achieve the capital expenditure objectives in the NER.

We consider that TasNetworks' proposed contingent projects should be classified as contingent projects for the 2019–24 regulatory control period. These projects may be reasonably required to be undertaken in order to maintain the quality, reliability and security of supply, or to meet or manage the expected demand for transmission services over the 2019–24 regulatory control period.[49]

TasNetworks’ trigger events for the proposed contingent projects are generally appropriate. The projects will be triggered by the successful completion of a RIT-T process, and our determination that the preferred option of the proposed investment satisfies the RIT-T.

We have reviewed the additional information provided by TasNetworks in its revised proposal, in particular the Project Specification Consultation Report and explanatory document for Project Marinus, and the Project Needs Analysis for the Sheffield to Palmerston 220 kV Augmentation and the North West 220 kV Network Redevelopment projects. We consider that for each of these projects, TasNetworks has provided sufficient details to inform our assessment of whether each proposed contingent project meets the contingent project criteria. In particular, we consider that TasNetworks has provided us with sufficient information to enable us to assess the likelihood of the project commencing during the 2019–24 regulatory control period, the need for the project and that the proposed trigger events are appropriate, reasonably specific and capable of objective verification, and consistent with the identified need for each project. We also consider that TasNetworks has more effectively engaged with stakeholder concerns in regards to its proposed contingent projects, including the alignment of benefits and costs, and that its revised proposal has reasonably addressed these concerns.

48 NER, cll. 6A.8.1 (a), 5.16.1(c).

49 NER, cl. 6A.8.1(b)(1).

Distribution capital expenditure

Our final decision on TasNetworks' revenue includes $651.1 million ($2018–19) in forecast total net distribution capex for the 2019–24 regulatory control period. This is $51.9 million (or 7 per cent) lower than TasNetworks' proposed value of $703.0 million ($2018–19). Table 2-10 shows our final decision compared to TasNetworks' revised forecast.

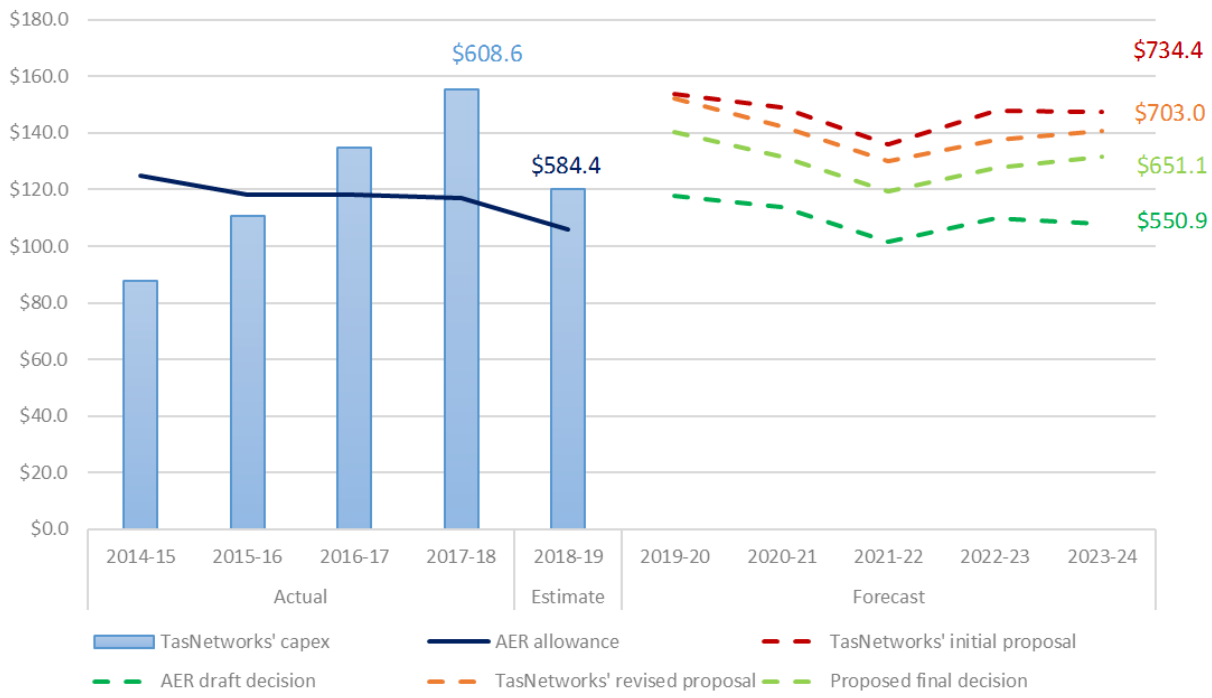
Table 2-10 AER final decision on total net distribution capex ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' revised proposal	152.3	142.3	130.0	137.5	140.9	703.0
AER final decision	140.3	131.6	119.6	127.8	131.8	651.1
Difference	-12.0	-10.7	-10.4	-9.7	-9.1	-51.9
Percentage difference	-8%	-8%	-8%	-7%	-6%	-7%

Source: AER analysis.
Note: Numbers may not add due to rounding.

Figure 12 shows our distribution capex final decision compared to TasNetworks' proposal, its past allowances and past actual expenditure.

Figure 12 AER final decision on total forecast distribution capex ($million, 2018–19)



Source: AER analysis.

The key aspects of our final decision are highlighted below.

Replacement

TasNetworks' revised repex proposal of $274.2 million ($2018–19) does not appear to be a reasonable estimate of the prudent and efficient costs required for this capex category. We have included an amount of $244.9 million ($2018–19) in our substitute estimate of total capex.

In our draft decision, we highlighted that TasNetworks' forecast for modelled repex was significantly higher than our repex model threshold. In addition, our bottom-up review highlighted that TasNetworks had not sufficiently justified its proposed proactive replacement programs for the overhead conductor, service line and underground cable asset groups.

In its revised proposal, TasNetworks reduced its repex forecast from $349.2 million ($2018–19) to $274.2 million ($2018–19) (21 per cent). In addition, TasNetworks provided cost-benefit analysis for several key programs, most notably its proactive overhead conductor, service line and underground cable programs. However, TasNetworks' revised repex forecast remains 18 per cent higher than our draft decision. TasNetworks' revised modelled repex forecast of $263.8 million ($2018–19), although lower than its initial proposal, still lies $49.0 million higher than our updated repex model threshold of $214.9 million. In addition, our assessment of TasNetworks' cost-benefit analysis highlighted that TasNetworks has applied extremely conservative input assumptions in its cost-benefit analysis models, which significantly overstates the risks associated with its replacement programs.

We have derived our substitute repex estimate by adjusting ten overhead conductor programs and three service line programs using our revised repex modelling results. Our adjustments bring TasNetworks’ proposed repex for overhead conductors and service lines to the industry median level. The consistent application across all 13 programs is appropriate on this occasion as it addresses the systemic issues that we have identified with TasNetworks’ cost-benefit analysis models, such as the double counting of benefits and the consistent overestimation of forecast failure rates. Three of the ten overhead conductor programs relate to TasNetworks’ bushfire mitigation program. We acknowledge that addressing a level of bushfire risk is an important consideration in establishing a prudent and efficient level of capex for the 2019–24 regulatory control period. However, TasNetworks has not adequately established that this is prudent and efficient. These reductions produce a substitute repex estimate that is $29.2 million ($2018–19) (11 per cent) lower than TasNetworks' revised repex forecast. In addition, our substitute repex estimate is consistent with TasNetworks' actual repex spend over the 2014–19 period. As we assessed that TasNetworks has not sufficiently justified its forecast increase in repex, we consider a repex allowance consistent with its business-as-usual spend is reasonable. We set out the reasons for our final decision on distribution capex in greater detail in attachment 5.

Growth

We have accepted TasNetworks' demand forecast, and proposed augex and connections capex, consistent with our draft decision.

Non-network

For non-network capex, we have included an amount of $134.2 million ($2018–19) in our substitute estimate of total capex. TasNetworks has not adequately justified the proposed increase in capex for its asset management information system (AMIS). We have included the amount accepted in our draft decision for the AMIS project in our final decision substitute estimate.

2.5 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of prescribed transmission services and distribution standard control services. Forecast opex is one of the building blocks we use to determine TasNetworks' total regulated revenue requirement.

Our final decision is to accept TasNetworks' forecast transmission and distribution opex.

Below we consider TasNetworks' proposed opex for transmission and distribution separately. We have not published a separate attachment for TasNetworks final decision transmission opex but further detail on our final decision regarding distribution opex is set out in attachment 6.

Transmission operating expenditure

We accept TasNetworks' revised transmission total opex forecast of $151.6 million ($2018–19) for the 2019–24 regulatory control period.[50] We are satisfied that TasNetworks' forecast reasonably reflects the criteria set out under the NER for accepting forecast opex and is efficient.[51] On this basis we accept TasNetworks' transmission total opex forecast.

Table 2-11 shows TasNetworks' revised opex proposal that we accept.

Table 2-11 TasNetworks transmission forecast opex ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' revised proposal for opex	30.1	30.2	30.3	30.5	30.6	151.6

Source: TasNetworks, *Revenue proposal, PTRM*, 29 November 2018; AER analysis.

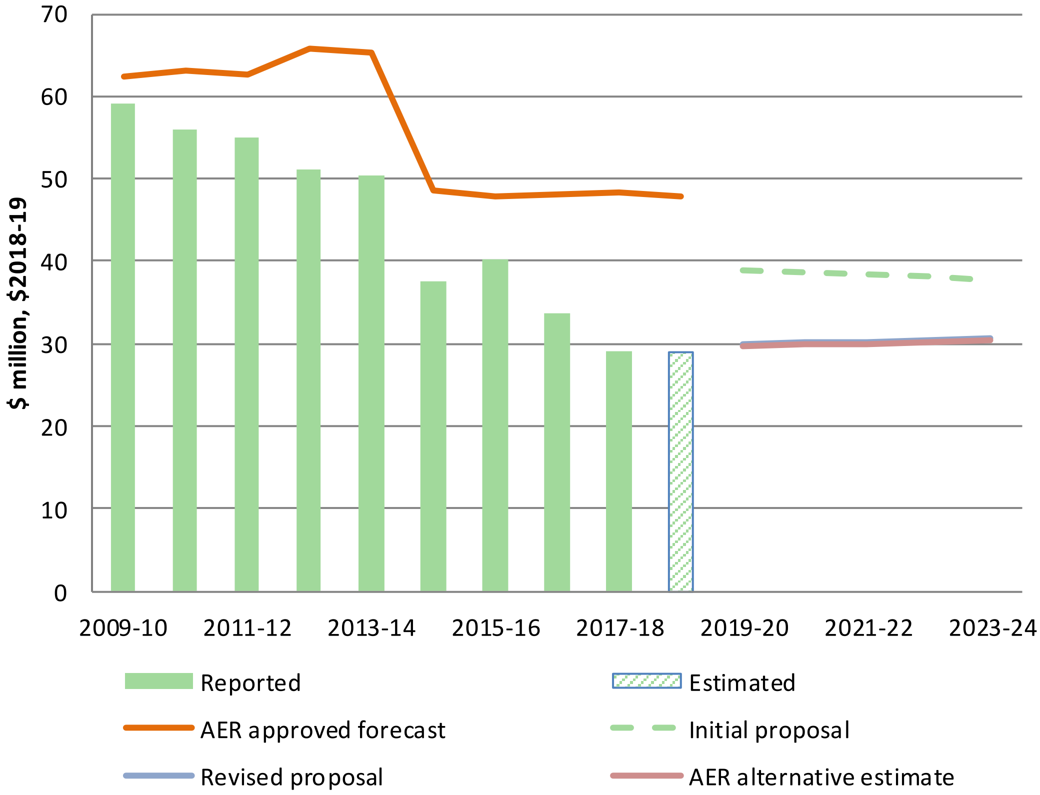
Note: Includes debt raising costs. Numbers may not add up to total due to rounding.

50 Including debt raising costs; TasNetworks, *Revenue proposal, PTRM*, 29 November 2018.

51 NER, cl. 6A.6.6(c)

Figure 13 shows TasNetworks' revised opex proposal and our alternative estimate, along with TasNetworks' past allowances, as approved by the AER, and past actual expenditure.

Figure 13 Our final decision – forecast transmission opex ($million, 2018–19)



Source: TasNetworks, Regulatory accounts; TasNetworks, Economic benchmarking RIN response; AER analysis.

Note: Includes debt raising costs

TasNetworks adopted our standard base-step-trend approach, as we had used in our draft decision. The key difference between the revised opex forecast and our draft decision is the lower base year opex, reflecting actual costs of $28.9 million ($2018–19) in 2017–18, as compared to estimated costs of $38.3 million ($2018–19) used in the draft decision. TasNetworks noted this reflects an increased focus on distribution activities in 2017–18, with offsetting increases in distribution opex (see below). This change reduced base opex by $9.4 million compared to the initial proposal.

Our decision to accept TasNetworks' revised total opex proposal of $151.6 million ($2018–19) reflects there is no material difference, in approach and quantum, between the revised proposal and our alternative estimate. The difference between our alternative opex forecast and TasNetworks' revised forecast primarily reflects updated CPI since the revised proposal, as well as different amounts for debt raising costs.[52] We developed our alternative estimate using the same approach as in the draft decision, updated with the latest information. Our alternative estimate:

- uses the lower base year opex proposed by TasNetworks, reflecting actual costs in 2017–18, updated to take into account the RBA's lower CPI forecast from February 2019. In using the lower base year opex we have taken into account that TasNetworks:
  - appears to be responding to the incentives of the ex-ante regulatory framework, and EBSS, with the lower opex
  - appears to be operating relatively efficiently compared to other electricity transmission businesses in the National Electricity Market reflecting the latest results from the opex multilateral partial factor productivity index analysis for transmission,[53] although we note that this analysis is limited by (amongst other things) the small sample size and its relatively newness as a technique (both in Australia and globally).
- updates price growth to reflect Deloitte Access Economics' wage price index forecasts from February 2019, averaged with the forecasts proposed by TasNetworks in its initial proposal from Jacobs, to forecast labour price growth
- incorporates output growth, reflecting the weighted average growth in the following output measures from the 2017 benchmarking report: circuit line length, ratcheted maximum demand, energy throughput and customer numbers
- uses a forecast of zero productivity growth, reflecting that the most recent estimate for the transmission sector of opex multilateral partial factor productivity is slightly negative, but close to zero[54] and Economic Insights' previous recommendation that a forecast opex productivity growth rate of zero should be used when measured productivity growth is negative.[55]

Distribution operating expenditure

We accept TasNetworks' distribution total opex forecast of $446.8 million ($2018–19) for the 2019–24 regulatory control period.[56] We have tested TasNetworks' revised proposal by comparing it to our alternative estimate of total opex forecast of $448.4 million ($2018–19), which is not materially different from TasNetworks' proposal. On this basis we accept TasNetworks' distribution total opex forecast.

Table 2-12 shows our alternative estimate compared to TasNetworks' revised proposal. This is also reflected in Figure 14.

---

52 Our opex model, which calculates our alternative estimate of opex, is available on our website.

53 AER, *Annual benchmarking report, Electricity transmission network service providers*, November 2018, p. 17.

54 Economic Insights, *Economic benchmarking results for the Australian Energy Regulator's 2018 TNSP benchmarking report*, 16 August 2018, p. 3.

55 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 8 September 2014, pp. 55–57.

56 Including debt raising costs; TasNetworks, *Regulatory* proposal*, PTRM*, 28 November 2018.

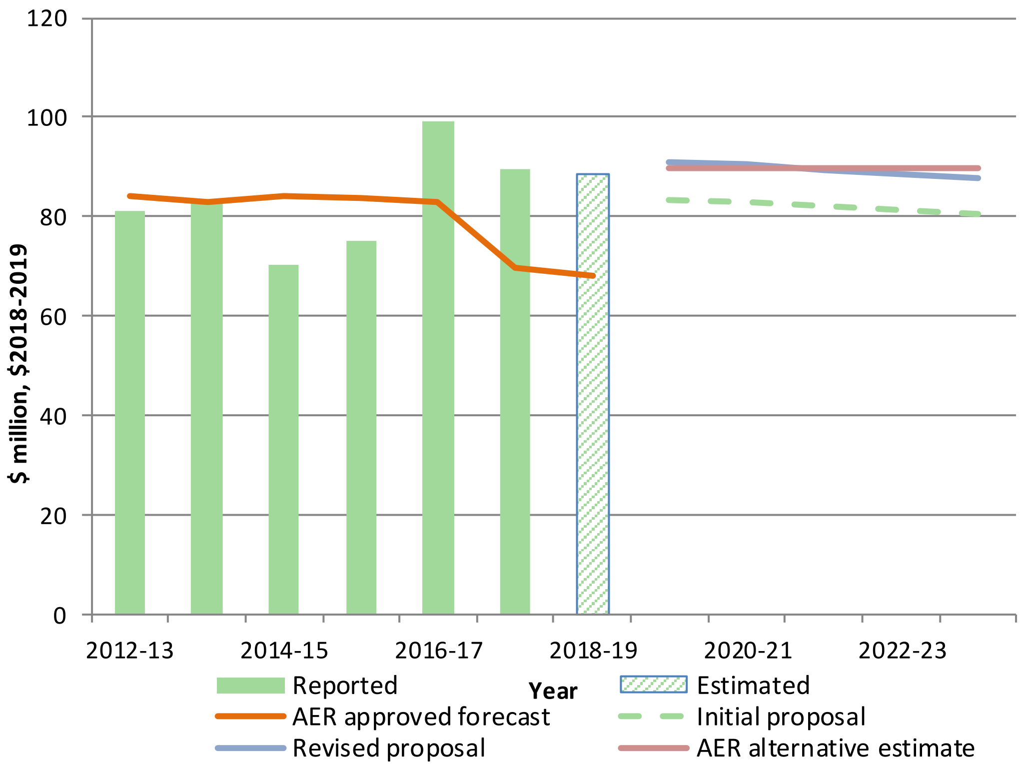
Table 2-12 Our alternative estimate of distribution forecast opex compared to TasNetworks' proposal ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' revised proposal for opex	90.7	90.3	89.5	88.6	87.7	446.8
AER alternative estimate	89.6	89.6	89.7	89.7	89.8	448.4
Difference	-1.2	-0.7	0.2	1.1	2.1	1.5

Source: TasNetworks, *Revenue proposal, PTRM*, 28 November 2018; AER analysis.

Note: Includes debt raising costs. Numbers may not add up to total due to rounding.

Figure 14 Our final decision - forecast distribution opex ($million, 2018–19)



TasNetworks' revised opex forecast largely adopted the approach we used in our draft decision. The key differences between the revised opex forecast and our draft decision alternative estimate are:

- the higher base year opex, reflecting actual costs of $89.6 million ($2018–19) in 2017–18, as compared to estimated costs of $81.8 million ($2018–19) used in the draft decision. TasNetworks noted this reflects an increased focus on distribution activities in 2017–18. This change increased base opex by $7.8 million compared to the initial proposal

- the continued inclusion of forecast cost of four step changes, with a cost of $13.0 million ($2018–19). These proposed step changes relate to additional costs for damage to assets, ring fencing, voltage management and a capex-opex trade-off[57]
- the inclusion of productivity savings of $19.5 million ($2018–19) over the 2019–24 regulatory control period. TasNetworks noted this, combined with its reduced claim for step changes, results in savings exceeding the 1 per cent per annum we proposed in the draft decision for the opex productivity growth review.[58]

Our decision to accept TasNetworks' revised total opex proposal of $446.8 million ($2018–19) reflects there is no material difference between the revised proposal and our alternative estimate of $448.4 million ($2018–19). We developed our alternative estimate using the same approach as in the draft decision, updated with the latest information. Our alternative estimate:

- uses the higher base year opex proposed by TasNetworks, reflecting actual costs in 2017–18, updated to take into account the RBA's lower CPI forecast from February 2019. We have relied on the revealed opex because our most recent benchmarking results continue to indicate that TasNetworks is operating relatively efficiently. We note that TasNetworks will be penalised under the EBSS for its higher than allowed opex in 2017–18
- updates price growth to reflect Deloitte Access Economics' wage price index forecasts from February 2019, averaged with the forecasts proposed by TasNetworks in its initial proposal from Jacobs, to forecast labour price growth
- updates output growth to reflect the average output weights from the four benchmarking models included in our 2017 annual benchmarking report (consistent with the draft decision) for the period 2006–17
- incorporates the 0.5 per cent per year opex productivity growth forecast established in our recent review, as compared to the $19.5 million TasNetworks included in its revised proposal.[59] We consider this captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations
- includes $6.2 million for step changes reflecting our view of the prudent and efficient costs required to meet new obligations and for the proposed demand management project.

We have considered the issues raised in submissions in establishing our alternative opex estimate. Both CCP 13 and the Tasmanian Small Business Council

[57] In the draft decision we did not consider step changes as even without considering them our alternative estimate was higher than the proposal.

[58] In the draft decision we included opex productivity growth of zero per cent, but noted that we were conducting an industry wide review and that we may change our approach to forecasting opex productivity growth.

[59] We estimate the $19.5 million is equivalent to annual productivity growth of 1.6 per cent.

encouraged us to undertake a thorough examination of the revised opex forecasts for the final decision given the changes and rebalancing between transmission and distribution opex.

We have set out the reasons for our final decision on distribution opex in greater detail in attachment 6. Our opex models, which calculate our alternative estimates of opex, are available on our website.

2.6 Revenue adjustments

Our final decision on TasNetworks total revenue also includes a number of adjustments. These are outlined below.

Transmission

- Capital Expenditure Sharing Scheme (CESS) – TasNetworks has accrued a reward of $4.0 million ($2018–19) under the CESS in the 2019–24 regulatory control period. This results from an under-spend in capex against the forecast for the 2015–19 regulatory control period
- Efficiency Benefit Sharing Scheme (EBSS) – A carryover amount totalling $38.7 million ($2018–19) from the application of the EBSS in the 2014–19 regulatory control period.

Distribution

- CESS – TasNetworks has accrued a penalty of $11.9 million ($2018–19) in the 2019–24 regulatory control period. This results from an over-spend in capex against the forecast for the 2017–19 regulatory control period
- EBSS – A carryover amount totalling –$51.2 million ($2018–19) from the application of the EBSS in the 2017–19 regulatory control period
- Demand Management Innovation Allowance Mechanism (DMIAM) – DMIAM allowance of $1.9 million ($2018–19) has been applied to TasNetworks over the 2019–24 regulatory control period.

2.7 Corporate income tax

Our final decision includes a decision on the estimated cost of corporate income tax for TasNetworks' 2019–24 regulatory control period as part of our revenue determination.[60] It enables TasNetworks to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

Our transmission final decision includes an estimated cost of corporate income tax of $3.6 million ($nominal) for TasNetworks over the 2019–24 regulatory control

60 NER, cll. 6A.6.4 and 6.5.3.

period. This is $7.2 million (or 66.8 per cent) lower than TasNetworks' revised proposed value of $10.7 million.[61]

Our distribution final decision includes an estimated cost of corporate income tax of $24.4 million ($nominal) for TasNetworks over the 2019–24 regulatory control period. This is $18.2 million (or 42.7 per cent) lower than TasNetworks' revised proposed value of $42.6 million.[62]

The key reasons for these reductions are:

- we amended the PTRM to implement the findings in our final report on the review of the regulatory tax approach (the tax review), which concluded after the submission of TasNetworks' revised proposal. Specifically, for this final decision, we have applied the diminishing value (DV) method for tax depreciation to all new depreciable assets except for forecast capex associated with equity raising costs and buildings. These changes have reduced the revised proposed corporate income tax allowances by about $5.2 million (or 48.1 per cent) and $9.0 million (or 21.0 per cent) for TasNetworks distribution and transmission, respectively
- we reduced TasNetworks' revised proposed return on equity (section 2.2). Our final decision on the forecast return on equity affects the amount of estimated taxable income. Therefore, it has contributed to the reduction on the revised proposed corporate income tax allowances by about $2.7 million (or 25.4 per cent) and $3.5 million (or 8.3 per cent) for TasNetworks distribution and transmission, respectively
- we increased the value of imputation credits (gamma) to 0.585 from TasNetworks' revised proposal of 0.5 (section 2.2). This has reduced the revised proposed corporate income tax allowances by about $0.9 million (or 8.0 per cent) and $5.9 million (or 13.8 per cent) for TasNetworks distribution and transmission, respectively.

Our final decision on the regulatory depreciation (section 2.3) affects the calculation of the estimated taxable income, which in turn impacts the corporate income tax allowance.

Table 2-13 and Table 2-14 set out our final decision on TasNetworks' corporate income tax allowances for transmission and distribution for the 2019–24 regulatory control period, respectively.

[61] TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 93.

[62] TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 93.

Table 2-13 AER's transmission final decision on corporate income tax allowance for TasNetworks ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Tax payable	1.8	0.9	1.2	1.4	3.3	8.6
Less: value of imputation credits	1.0	0.5	0.7	0.8	1.9	5.0
Net corporate income tax allowance	0.7	0.4	0.5	0.6	1.4	3.6

Source: AER analysis.

Table 2-14 AER's distribution final decision on corporate income tax allowance for TasNetworks ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Tax payable	13.4	11.2	10.6	11.2	12.2	58.8
Less: value of imputation credits	7.9	6.6	6.2	6.6	7.2	34.4
Net corporate income tax allowance	5.6	4.7	4.4	4.7	5.1	24.4

Source: AER analysis.

Further detail on our final decision regarding corporate income tax is set out in attachment 7.

3 Incentive schemes to apply for 2019–24

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2, to encourage TasNetworks to pursue expenditure efficiencies and demand side alternatives to capex and opex, while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity network as part of our decision are:

- the opex efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS)
- the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM). This applies to TasNetworks' distribution network but not transmission.

Once we make our decision on TasNetworks' revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers.

Our final decision is that each of the EBSS, CESS, STPIS, DMIS and DMIAM will apply to TasNetworks for the 2019–24 regulatory control period. TasNetworks' performance under these schemes in the 2019–24 regulatory control period will be reflected in its annual pricing proposals throughout that period and its revenue proposal for the subsequent, 2024–29 regulatory control period.

Our final decision on the incentive schemes are outlined below.

3.1 EBSS

The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between transmission businesses and network users. Consumers benefit from improved efficiencies through lower regulated prices.

Transmission carryover

Our final decision is to approve carryover amounts totalling $38.7 million ($2018–19) from the application of the EBSS in the 2014–19 regulatory control period. This is marginally lower than TasNetworks' revised proposal of $39.1 million ($2018–19), due to updated inflation forecasts.[63] TasNetworks accepted our draft decision but updated its carryover calculations to reflect actual opex and movements in provisions for 2017–18.[64]

Table 3-1 sets out our final decision on the EBSS carryover amounts TasNetworks accrued during the 2017–19 regulatory control period.

Table 3-1: AER's final decision on TasNetworks' transmission EBSS carryover amounts ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' proposal	6.7	–1.6	–0.1	–5.1	0	–0.1
AER draft decision	8.4	–0.2	0.5	–5.1	0	3.6
TasNetworks' revised proposal	17.3	8.6	9.3	3.8	0	39.1
AER final decision	17.2	8.5	9.2	3.8	0	38.7

Source: TasNetworks, Post Tax Revenue Model (PTRM) Distribution, 31 January 2018; AER, Draft Decision – PTRM, September 2018; TasNetworks, Post Tax Revenue Model (PTRM) Distribution, 29 November 2018, AER analysis.

Distribution carryover

Our final decision is to approve carryover amounts totalling –$51.2 million ($2018–19) from the application of the EBSS in the 2017–19 regulatory control period. Broadly, this reflects TasNetworks' opex overspend relative to its opex allowance, and this amount is deducted from TasNetworks' revenue allowance. This is marginally higher than TasNetworks' revised proposal of –$51.5 million ($2018–19).[65] While TasNetworks adopted our draft decision approach in its revised proposal, it updated its carryover calculations to reflect actual opex and movements in provisions for 2017–18.[66] TasNetworks also excluded NEM and retail

---

63 TasNetworks, *TasNetworks Transmission EBSS model*, 29 November 2018.

64 TasNetworks reported 2017–18 actual opex that is 22 per cent lower than the estimated amount we used in our draft decision. This is the key driver of the difference between our draft decision carryover amounts ($3.6 million, $2018–19) and our final decision ($38.7 million, 2018–19). For more details, see: TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 65.

65 TasNetworks, *TasNetworks Distribution EBSS model*, 29 November 2018

66 TasNetworks reported 2017–18 actual opex that is 9 per cent lower than the estimated amount we used in our draft decision. This is the key driver of the difference between our draft decision carryover amounts ($-22.5 million, $2018–19) and our final decision (-$51.2 million, $2018–19). For more details, see: TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 72.

contestability costs from the scheme, which we did not exclude in our draft decision.[67]

As indicated in the draft decision, we have updated our carryover amounts to reflect actual opex and movements in provisions for 2017–18, as well as inflation numbers as set out in the Reserve Bank of Australia's latest Statement on Monetary Policy.[68] We have also excluded National Electricity Market (NEM) and retail contestability costs from the scheme consistent with our draft decision.[69]

Table 3-2 sets out our final decision on the EBSS carryover amounts TasNetworks accrued during the 2017–19 regulatory control period.

Table 3-2: AER's final decision on TasNetworks' distribution EBSS carryover amounts ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
TasNetworks' proposal	–11.3	–11.3	–11.3	12.3	0	–21.5
AER draft decision	–11.3	–11.3	–11.3	11.5	0	–22.5
TasNetworks' revised proposal	–18.7	–18.7	–18.7	4.6	0	–51.5
AER final decision	–18.5	–18.5	–18.5	4.2	0	–51.2

Source: TasNetworks, Post Tax Revenue Model (PTRM) Distribution, 31 January 2018; AER, Draft Decision – PTRM, September 2018; TasNetworks, Post Tax Revenue Model (PTRM) Distribution, 29 November 2018, AER analysis.

Note: Numbers may not add up to total due to rounding.

Application in the 2019-24 period

We will continue to apply version two of the EBSS to TasNetworks in the 2019–24 regulatory control period. This is consistent with our draft decision and TasNetworks' revised proposal.

We will exclude the following cost categories from the scheme for transmission:

- debt raising
- network support and
- network capability incentive projects.

For distribution, we will exclude the following cost categories from the scheme:

[67] AER, *Draft decision - TasNetworks distribution determination 2019–24: Attachment 8 – Efficiency benefit sharing scheme*, September 2018, p. 8–10.

[68] Reserve Bank of Australia, *Statement on Monetary Policy*, November 2018.

[69] AER, *Draft decision - TasNetworks distribution determination 2019–24: Attachment 8 – Efficiency benefit sharing scheme*, September 2018, p. 8–10.

- debt raising costs
- Guaranteed Service Level (GSL) payments
- Electrical Safety Inspection (ESI) levy payments
- National Energy Market (NEM) levy payments.

Table 3-4 and Table 3-3 set out our final decision on the target opex for the EBSS we will use, are subject to adjustments required by the EBSS, to calculate efficiency gains in the 2019–24 regulatory control period, for transmission and distribution, respectively.

Table 3-3: Forecast opex for the transmission EBSS ($million, 2018–19)

	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Forecast total opex	48.0	47.4	30.1	30.2	30.3	30.5	30.6
Less debt raising costs	– 1.1	– 1.1	–1.0	–1.0	–1.0	–1.0	–1.0
Total opex for the EBSS target	46.9	46.4	29.0	29.2	29.3	29.4	29.6

Source: TasNetworks, Post Tax Revenue Model (PTRM) PTRM Distribution, 31 January 2018; TasNetworks, Distribution Operating Expenditure Model, 31 January 2018; AER, Final Decision – PTRM, April 2017; AER analysis.

Note: Numbers may not add up to total due to rounding.

Table 3-4: Forecast opex for the distribution EBSS ($million, 2018–19)

	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Forecast total opex	68.9	67.4	90.7	90.3	89.5	88.6	87.7
Less debt raising costs	– 1.1	– 1.1	– 0.9	– 0.9	– 0.9	– 0.9	– 1.0
Less GSL payments	– 2.4	– 2.4	– 3.1	– 3.1	– 3.1	– 3.1	– 3.1
Less ESI levy payments	– 2.1	– 2.1	– 4.0	– 4.0	– 4.0	– 4.0	– 4.0
Less NEM levy payments	– 0.4	– 0.4	– 0.7	– 0.7	– 0.7	– 0.7	– 0.7
Total opex for the EBSS	62.9	61.4	82.1	81.6	80.7	79.9	79.0

Source: TasNetworks, Post Tax Revenue Model (PTRM) PTRM Distribution, 31 January 2018; TasNetworks, Distribution Operating Expenditure Model, 31 January 2018; AER, Final Decision – PTRM, April 2017; AER analysis

Note: Numbers may not add up to total due to rounding.

3.2 CESS

The CESS provides financial rewards for network service providers whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. We first applied the CESS to TasNetworks in the 2015–19 regulatory control period for transmission and the 2017–19 regulatory control period for distribution.

For transmission, our final decision is to apply a CESS revenue increment amount of $4.0 million ($2018–19) in the 2019–24 regulatory control period. This results from an under-spend in capex against the forecast for the 2015–19 regulatory control period. For distribution, our final decision is to apply a CESS revenue decrement amount of $11.9 million ($2018–19) in the 2019–24 regulatory control period. This results from an over-spend in capex against the forecast for the 2017–19 regulatory control period.

We will also apply the CESS as set out in version 1 of the capital expenditure incentives guideline to TasNetworks in the 2019–24 regulatory control period.

Further detail on our final decisions regarding the CESS are set out in attachment 9.

3.3 STPIS

The STPIS is intended to balance a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance where customers are willing to pay for these improvements.

Transmission

TasNetworks accepted our draft decision on applying version 5 of the transmission STPIS.[70] For the final decision, we updated the performance targets and incentive rates to include 2018 actual performance outcomes data.[71]

Our final decision is to apply version 5 of the transmission STPIS to TasNetworks in the 2019–24 regulatory control period. Attachment 10 provides the details of this decision.

Distribution

Under the distribution STPIS, distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply to customers. Once improvements are made, the benchmark performance targets will be tightened in future years.

Our final decision is to apply the service standards component (the s-factor) of our national STPIS, STPIS version 1 (November 2009)[72], to TasNetworks for the 2019–

---

[70] TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposal, 2019–2024*, 29 November 2018, pp. 94–95.

[71] TasNetworks, *TasNetworks response to AER Information request #50 – Transmission STPIS service component - 05032019*; 8 March 2019.

24 regulatory control period. We will not apply the guaranteed service level component to TasNetworks as the existing jurisdictional arrangements will continue to apply. Attachment 10 provides the details of this decision.

3.4 DMIS

On 13 December 2017, we published a new DMIS[73] and a new DMIAM.[74] These will replace the current DMIS and demand management innovation allowance (DMIA) in the forthcoming regulatory control periods for all electricity distributors.

In our draft distribution determination, our decision was to apply the new DMIS and DMIAM to TasNetworks for the 2019–24 regulatory control period, without any modification.[75] TasNetworks' revised proposal accepted our draft decision.[76]

We received no submissions on TasNetworks' proposed implementation of the new DMIS and DMIAM.

The DMIS contains three elements:[77]

- a cost uplift on expected costs of efficient demand management projects
- a net benefit constraint, to ensure the incentive payment for any project cannot be higher than that project's expected net benefit
- an overall incentive constraint, which limits the total incentive in any year to one per cent of the distributor's allowed revenue for that year.

The cost multiplier (uplift) applicable to any eligible project will be the cost multiplier specified in the version of the DMIS that is in effect under clause 6.6.3 of the NER at the time the eligible project becomes a committed project.[78]

The DMIAM comprises:[79]

---

72 AER, *Electricity distribution network service providers—service target performance incentive scheme*, November 2009. (AER, *STPIS*, November 2009).

73 AER, *Demand management incentive scheme*, Electricity distribution network service providers, December 2017.

74 AER, *Demand management innovation allowance mechanism*, Electricity distribution network service providers, December 2017.

75 AER, *Draft decision, TasNetworks distribution determination 2019-24, Attachment 11, Demand management incentive scheme*, September 2018, pp. 6–7.

76 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 94.

77 AER, *Demand management incentive scheme*, Electricity distribution network service providers, December 2017.

78 AER, *Demand management incentive scheme*, Electricity distribution network service providers, December 2017, clause 2.1(2).

79 AER, *Demand management innovation allowance mechanism*, Electricity distribution network service providers, December 2017.

- a fixed allowance of $200,000 ($2016–17), plus 0.075 per cent of the annual revenue requirement for each regulatory year, as set out in AER's Post-Tax Revenue Model (PTRM) for TasNetworks
- project eligibility requirements
- compliance reporting requirements.

Our calculation of TasNetworks' DMIAM funding over the 2019–24 regulatory control period is shown below. The total DMIAM funding is $1.93 million ($2018–19) over the period. This calculation is based on the smoothed annual revenue requirement as set out in the PTRM for TasNetworks in our final distribution determination.

Table 3-5 AER's final distribution determination on the Demand Management Innovation Allowance for TasNetworks ($million, 2018–19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total 2019-24
DMIA	0.37	0.38	0.38	0.40	0.40	1.93

Source: AER analysis.

4 Tariff structure statement

TasNetworks' 2019–24 proposal includes the second iteration of its tariff structure statement (TSS). Its current TSS applies from 1 July 2017 to 30 June 2019.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[80] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

While an indicative pricing schedule must accompany the TSS, TasNetworks' tariffs for the entire 2019–24 regulatory control period are not set as part of this determination. Rather, tariffs for 2019–20 will be subject to a separate approval process that takes place in May 2019, after this final revenue determination in April 2019. Tariffs for the following four years will also be approved on an annual basis in May of each year.

Our final decision is to amend TasNetworks revised tariff structure statement by:

- changing its tariff assignment policy from opt–in to an opt–out approach for small business (non–residential LV) customers
- adopting a 12 month delay in its tariff reassignment trigger for all customers, to allow a data sampling period
- clarifying procedural aspects relating to its estimate of long run marginal cost, individually calculated tariffs, tariff assignment criteria as well as document structure and completeness.

These amendments complement the changes TasNetworks' has already made in response to our draft decision. These include:

- changing its assignment policy for residential customers from opt–in to opt–out
- removing its proposal to include an embedded network tariff
- improving the transparency regarding its unwinding of cross customer discounted legacy tariffs.[81]

80 NER, cl. 6.18.1A(a).

81 TasNetworks, *Tasmanian Transmission and Distribution Revised Proposals Overview Regulatory Control Period 1 July 2019 – 30 June 2024*, November 2018.

Attachment 18 of this final decision provides the detailed reasons for our changes to TasNetworks' revised TSS.

5 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how TasNetworks must set its prices. These include the classification of services, the conditions under which we may grant TasNetworks additional revenues to cover unforeseen circumstances and the framework for TasNetworks' negotiated services, customer connections and transmission pricing.

5.1 Distribution classification of services

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

The classification of distribution services must be as set out in the relevant framework and approach (F&A) paper unless we consider that a material change in circumstances justify departing from that proposed classification.[82] We set out our proposed approach to the classification of distribution services for TasNetworks in our F&A.[83]

Our draft decision made an amendment to our final F&A, changing the classification of 'Extensions', under the Connection Services grouping, from alternative control to standard control. The change was made to correct an error in the final F&A, to ensure that the classification of 'Extensions' is consistent with the previous classification and TasNetworks' connection policy.[84] Aside from this amendment, our draft decision was consistent with the final F&A. Our final decision is to retain the classification structure consistent with our draft decision.

In its revised proposal, TasNetworks accepted our draft decision on service classification in full and did not seek any changes. A full list of TasNetworks' classified services for the 2019–24 regulatory control period can be found in Attachment 12 to the AER's draft decision.

82 NER, cl. 6.12.3(b).

83 AER, *Final framework and approach for TasNetworks – Regulatory control period commencing 1 July 2019*, July 2017.

84 AER, *Draft Decision, TasNetworks transmission determination 2019 to 2024*, September 2018, Attachment 12, p. 12–6.

5.2 Pass throughs

In our draft decision, we approved TasNetworks' nominated pass through events.[85] TasNetworks revised proposal accepted our draft decision.[86]

Our final decision is to approve TasNetworks' transmission and distribution nominated pass through events and associated definitions:

- Insurance cap event
- Terrorism event
- Natural disaster event.[87]

These will apply to TasNetworks throughout the regulatory control period in addition to the pass through events which are prescribed by the NER. These include the events dealing with regulatory change, service standards, tax change, insurance and, in the case of transmission inertia and fault level shortfalls[88] and for distribution, retailer insolvency.[89]

Table 5-1 Approved nominated pass through events

Event	Definition
Insurance Cap Event	An insurance cap event occurs if: 1. TasNetworks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy; 2. TasNetworks incurs costs beyond the relevant policy limit; and 3. the costs beyond the relevant policy limit materially increase the costs to TasNetworks in providing direct control services or prescribed transmission services. For this insurance cap event: a relevant insurance policy is an insurance policy held during the 2019–24 regulatory control period or a previous regulatory control period in which TasNetworks was registered as a NSP for the purposes of s.11 of the NEL. Note: In making a determination on an insurance cap event, the AER will have regard to, amongst other things: i. the relevant insurance policy for the event; ii. the level of insurance that an efficient and prudent NSP would obtain in

85 AER, *Draft Decision, TasNetworks transmission determination 2019 to 2024*, September 2018, Attachment 12, p. 6.

86 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024,* 29 November 2018, p. 114.

87 For definitions of the nominated pass through events see: AER *Draft Decision, TasNetworks transmission determination 2019 to 2024*, September 2018, Attachment 12, pp. 7–8 and AER *Draft Decision, TasNetworks distribution determination 2019 to 2024*, September 2018, Attachment 14, pp. 7–8

88 NER, cl. 6A.7.3(a1)(1)–(7). Each of these prescribed events is defined in Chapter 10 (Glossary).

89 NER, cl. 6.6.1(a1)(1)-(5). Each of these prescribed events is defined in Chapter 10 (Glossary).

Event	Definition
	respect of the event; and iii. any assessment by the AER of TasNetworks' insurance in making its transmission and distribution determination for the relevant period.
Terrorism Event	A terrorism event occurs if: An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which increases the costs to TasNetworks in providing direct control services or prescribed transmission services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: i. whether TasNetworks has insurance against the event; ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.
Natural disaster event	Natural disaster event means: Any natural disaster including but not limited to fire, flood, or earthquake that occurs during the 2019–24 regulatory control period and that increases the costs to TasNetworks in providing direct control services or prescribed transmission services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider. Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things: i. whether TasNetworks has insurance against the event; and ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

5.3 Transmission pricing methodology

The role of TasNetworks' pricing methodology is to answer the question 'who should pay how much'[90] in order for TasNetworks to recover its costs. The pricing methodology must provide a 'formula, process or approach'[91] that when applied:

- allocates the aggregate annual revenue requirement to the categories of prescribed transmission services that a transmission business provides and to the connection points of network users[92]

90 AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

91 NER, cl. 6A.24.1(b).

92 NER, cl. 6A.24.1(b)(1).

- determines the structure of prices that a transmission business may charge for each category of prescribed transmission services.[93]

In our draft decision, we approved TasNetworks' proposed pricing methodology for the 2019–24 regulatory control period.[94] TasNetworks' revised proposal accepted our draft decision.[95] Our final decision is to approve TasNetworks' pricing methodology. TasNetworks pricing methodology relates to prescribed transmission services only.

The transmission pricing methodology that will apply to TasNetworks for the period of this determination is set out in Attachment A.

5.4 Distribution negotiating framework and criteria

In our draft decision, we approved TasNetworks' proposed distribution negotiating framework for the 2019–24 regulatory control period.[96] TasNetworks' revised proposal accepted our draft decision.[97] Our final decision is to approve TasNetworks' negotiating framework.

The distribution negotiating framework that will apply to TasNetworks for the period of this determination is set out in Attachment B.

We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[98] Our final decision is to retain the NDSC that we published for TasNetworks in February 2018 for the 2019–24 regulatory control period. The NDSC give effect to the negotiated distribution services principles.[99]

5.5 Distribution connection policy

We made our draft distribution determination in September 2018[100] and modified TasNetworks' proposed connection policy that it submitted in its regulatory proposal.[101] TasNetworks accepted our draft decision.[102]

---

93 NER, cl. 6A.24.1(b)(2).

94 AER, *Draft Decision, TasNetworks transmission determination 2019 to 2024*, September 2018, Attachment 11, p. 6.

95 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 102.

96 AER, *Draft Decision, TasNetworks transmission determination 2019 to 2024*, September 2018, Attachment 16, p. 6.

97 TasNetworks, *Tasmanian Transmission and Distribution Revised Revenue Proposals 2019–2024*, 29 November 2018, p. 114.

98 NER, cl. 6.12.1(16).

99 NER, cl. 6.7.1.

100 AER, *Draft Decision TasNetworks Distribution Determination 2019 to 2024, Attachment 17 Connection policy*, September 2018.

101 TasNetworks, *Tasmanian Transmission and Distribution Regulatory Proposals 2019–2024*, 31 January 2018.

102 TasNetworks, *Tasmanian Transmission and Distribution Revised Regulatory Proposals 2019-2024,* 29 November 2018.

We did not receive any submissions on our draft decision and TasNetworks' revised proposal that addressed TasNetworks' proposed connection policy.

Our final decision is to approve the connection policy submitted by TasNetworks in its revised proposal on 29 November 2018.[103]

---

[103] TasNetworks, *Distribution Connection Pricing Policy*, November 2018. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24/revised-proposal

6 The National Electricity Objective

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[104] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.[105] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[106]

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[107] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account. [108]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[109] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market. [110] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[111] This could have significant longer term pricing implications for those consumers who continue to use network services
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable.[112] This could create longer term problems in the network, and could have adverse consequences for safety, security and reliability of the network.

---

[104] NEL, section 16(1).

[105] This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

[106] Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

[107] Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

[108] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

[109] Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].

[110] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

[111] NEL, s. 7A(7).

[112] NEL, s. 7A(6).

The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

6.1 Achieving the NEO to the greatest degree

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. Very often, there will be more than one plausible forecast,[113] and much debate amongst stakeholders about relevant costs. For certain components of our decision there may therefore be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. In these cases, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[114]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

6.2 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. We have considered these interrelationships in our analysis of the constituent components of our draft decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6)
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance;

113 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006,* (16 November 2006), p. 52.

114 NEL, s. 16(1)(d).

the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7)

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

A Transmission constituent decisions

Our final decision on TasNetworks' transmission determination includes the following constituent components:[115]

Constituent component
In accordance with clause 6A.14.1(1)(i) of the NER, the AER's final decision is not to approve the total revenue cap set out in TasNetworks' building block proposal. Our final decision on TasNetworks' total revenue cap is $736.1 million ($nominal) for the 2019–24 regulatory control period. This decision is discussed in Attachment 1 of this final decision.
In accordance with clause 6A.14.1(1)(ii) of the NER, the AER's final decision is not to approve the maximum allowed revenue (MAR) for each regulatory year of the regulatory control period set out in TasNetworks' building block proposal. Our decision on TasNetworks' MAR for each year of the 2019–24 regulatory control period is set out in Attachment 1 of this final decision.
In accordance with clause 6A.14.1(1)(iii) of the NER, the AER's final decision is to apply the service component, network capability component and market impact component of Version 5 of the service target performance incentive scheme (STPIS) to TasNetworks for the 2019–24 regulatory control period. The values and parameters of the STPIS are set out in Attachment 10 of this final decision.
In accordance with clause 6A.14.1(1)(iv) of the NER, the AER's final decision on the values that are to be attributed to the parameters for the efficiency benefit sharing scheme (EBSS) that will apply to TasNetworks in respect of the 2019–24 regulatory control period are set out in section 3.1 of this final decision overview.
In accordance with clause 6A.14.1(1)(v) of the NER, the AER's final decision is to approve the commencement and length of the regulatory control period as TasNetworks' proposed in its revenue proposal. The regulatory control period will commence on 1 July 2019 and the length of this period is five years, expiring on 30 June 2024.
In accordance with clause 6A.14.1(2) of the NER and acting in accordance with clause 6A.6.7(d), the AER's final decision is not to accept TasNetworks' total forecast capital expenditure of $260.4 million ($2018–19). Our final decision therefore includes a substitute estimate of TasNetworks' total forecast capex for the 2019–24 regulatory control period of $241.4 million ($2018–19). The reasons for our final decision are set out in Attachment 5 of this final decision.
In accordance with clause 6A.14.1(3) of the NER and acting in accordance with clause 6A.6.6(c), the AER's final decision is to accept TasNetworks' proposed total forecast operating expenditure inclusive of debt raising costs of $151.6 million ($2018–19). This is discussed in section 2.5 of this final decision overview.
In accordance with clause 6A.14.1(4)(i) and 6A.14.1(4)(iii) of the NER, the AER has determined that the following proposed contingent projects are contingent projects for the purpose of the revenue determination and the triggers proposed by TasNetworks are consistent with the NER:

[115] NEL, s. 16(1)(c).

- Project Marinus - Second Bass Strait Interconnector
- Palmerston to Sheffield Reinforcement
- Sheffield to Burnie Reinforcement.

This is discussed in Attachment 5 of this final decision.

In accordance with clause 6A.14.1(4)(ii), the AER is satisfied that the capital expenditure in the range of $278 million to $1007 million for the three contingent projects as described in TasNetworks revised regulatory proposal reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors. This is discussed in Attachment 5 of this final decision.

In accordance with clause 6A.14.1(5A) of the NER, the AER's final decision is that version 1 of the capital expenditure sharing scheme (CESS) as set out the Capital Expenditure Incentives Guideline will apply to TasNetworks in the 2019–24 regulatory control period. This is discussed in Attachment 9 of this final decision.

In accordance with clause 6A.14.1(5B) and 6A.6.2 of the NER, the AER's final decision is that the allowed rate of return for the 2019–20 regulatory year is 5.55 per cent (nominal vanilla), as set out in section 2.2 of this final decision overview. The rate of return for the remaining regulatory years 2020–24 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

In accordance with clause 6A.14.1(5C) of the NER, the AER's final decision is that the return on debt is to be estimated using a methodology referred to in clause 6A.6.2(i)(2), and using the formula to be applied in accordance with clause 6A.6.2(l). The methodology and formula are set out in the 2018 Rate of Return Instrument.

In accordance with clause 6A.14.1(5D) of the NER, the AER's final decision is that the value of imputation credits as referred to in clause 6A.6.4 is 0.585. This is set out in section 2.2 of this final decision overview.

In accordance with clause 6A.14.1(5E) of the NER, the AER's final decision, in accordance with clause 6A.6.1 and schedule 6A.2, is that the opening regulatory asset base (RAB) as at the commencement of the 2019–24 regulatory control period, being 1 July 2019, is $1445.3 million ($nominal). This is set out in Attachment 2 of this final decision.

In accordance with clause 6A.14.1(5F) of the NER, the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of TasNetworks' regulatory control period as at 1 July 2024. This is discussed in Attachment 2 of this final decision.

In accordance with clause 6A.14.1(8) of the NER, the AER's final decision is to approve TasNetworks' proposed pricing methodology. This is set out in section 5.3 of this final decision overview.

In accordance with clause 6A.14.1(9) of the NER, the AER's final decision is to apply the following nominated pass through events to apply to TasNetworks for the 2019–24 regulatory control period in accordance with clause 6A.6.9:

- Insurance cap event
- Natural disaster event
- Terrorism event.

These events have the definitions referred to in section 5.2 of this final decision overview.

B Distribution constituent decisions

Our final decision on TasNetworks' distribution determination includes the following constituent components:[116]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the following classification of services will apply to TasNetworks for the 2019–24 regulatory control period (listed by service group): • Standard control services include common distribution services and type 7 metering services • Alternative control services includes type 5–6 metering services (for meters installed before 1 December 2017), public lighting services (including new/emerging public lighting technology) and ancillary network services (fee based and quoted services) • Unregulated services include type 1-4 metering services, distribution asset rental to third parties and contestable metering support roles. This is set out in section 5.1 of this final decision overview and attachment 12 of the draft decision discusses classification of services.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in TasNetworks' building block proposal. Our final decision on TasNetworks' annual revenue requirement for each year of the 2019–24 regulatory control period is set out in attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve TasNetworks' proposal that the regulatory control period will commence on 1 July 2019. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve TasNetworks' proposal that the length of the regulatory control period will be 5 years from 1 July 2019 to 30 June 2024.
In accordance with clause 6.12.1(3)(ii) of the NER and acting in accordance with clause 6.5.7(c), the AER's final decision is not to accept TasNetworks' proposed total forecast capital expenditure of \$703.0 million (\$2018–19). Our final decision therefore includes a substitute estimate of TasNetworks' total forecast capex for the 2019–24 regulatory control period of \$651.1 million (\$2018–19). The reasons for the final decision are set out in attachment 5 of the final decision.
In accordance with clause 6.12.1(4)(i) of the NER and acting in accordance with clause 6.5.6(c), the AER's final decision is to accept TasNetworks' proposed total forecast operating expenditure inclusive of debt raising costs and exclusive of DMIAM of \$446.8 million (\$2018–19). The reasons for this are set out in attachment 6.
In accordance with clause 6.12.1(5) of the NER, the AER's final decision is that the allowed rate of return for the 2019–20 regulatory year is 5.28 per cent (nominal vanilla), as set out in section 2.2 of this final decision overview. The rate of return for the remaining regulatory years 2020–24 will be

116 NEL, s. 16(1)(c).

updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

In accordance with clause 6.12.1(5A) of the NER, the AER's final decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and using the formula to be applied in accordance with clause 6.5.2(l). The methodology and formula are set out in the 2018 Rate of Return Instrument.

In accordance with clause 6.12.1(5B) of the NER, the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this final decision overview.

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on TasNetworks' regulatory asset base as at 1 July 2019 in accordance with clause 6.5.1 and schedule 6.2 is $1771.1 million ($nominal). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NER, the AER's final decision is not to accept TasNetworks' proposed corporate income tax of $42.6 million ($nominal). Our final decision on TasNetworks' corporate income tax is $24.4 million ($nominal). Our estimated cost of corporate income tax for each year of the regulatory control period is set out in attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is not to approve the depreciation schedules submitted by TasNetworks. Our final decision substitute's alternative depreciation schedules in accordance with clause 6.5.5(b) and this is set out in attachment 4 of the final decision.

In accordance with clause 6.12.1(9) of the NER, the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management incentive scheme or small-scale incentive scheme is to apply:

- the AER's final decision is to apply version two of the EBSS to TasNetworks in the 2019–24 regulatory control period. This is set out in section 3.1 of this final decision overview
- we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to TasNetworks in the 2019–24 regulatory control period. CESS is discussed in attachment 9 of the final decision
- we will apply our Service Target Performance Incentive Scheme (STPIS) to TasNetworks for the 2019–24 regulatory control period
- our final decision on the STPIS reliability of supply and customer service parameters, along with the incentive rates and performance targets, are set out in Attachment 10 of this final decision
- the AER has determined to apply the Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance Mechanism (DMIAM) for TasNetworks in the 2019–24 regulatory control period. DMIS and DMIAM are discussed in section 3.4 of this final decision overview.

In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for TasNetworks for any given regulatory year is the total annual revenue calculated using the formula in attachment 13 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 13 of the final decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply price caps for all services. This is discussed in attachment 13 of the final decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is TasNetworks must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 13 of this final decision.

In accordance with clause 6.12.1(14) of the NER, the AER's final decision is to apply the following nominated pass through events for the 2019–24 regulatory control period in accordance with clause 6.5.10:

- terrorism event
- insurance cap event
- natural disaster event.

These events have the definitions set out in section 5.2 of this final decision overview.

In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is not to approve the tariff structure statement proposed by TasNetworks. This is discussed in attachment 18 of the final decision and is accompanied by the final version of the revised tariff structure statement.

In accordance with clause 6.12.1(15) of the NER, the AER's final decision is to apply the negotiating framework as proposed by TasNetworks for the 2019–24 regulatory control period. The negotiating framework is set out in section 5.4 of this final decision overview.

In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria published in February 2018 to TasNetworks. This is set out in section 5.4 of this final decision overview.

In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning retail customers to tariff classes for TasNetworks is set out in attachment 13 of the final decision.

In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of TasNetworks' regulatory control period as at 1 July 2024. This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how TasNetworks' is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is set out in attachment 13 of the final decision.

In accordance with clause 6.12.1(20) of the NER, the AER's final decision is to require TasNetworks to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 13 of the final decision.

In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to accept TasNetworks' proposed connection policy as set out in section 5.5 of this final decision overview.

C List of submissions

We received 9 submissions in response to our draft decision and TasNetworks' revised revenue proposal. These are listed below.

Submission from	Date received
Anonymous	16 January 2019
Aurora Energy	16 January 2019
Consumer Challenge Panel (CCP13)	11 January 2019
John Herbst	10 January 2019
Local Government Association of Tasmania	11 January 2019
Tasmanian Council of Social Services	December 2018
Tasmanian Government	11 January 2019
Tasmanian Minerals and Energy Council	6 January 2019
Tasmanian Small Business Council	January 2019