FINAL DECISION

Power and Water Corporation Distribution Determination 2019 to 2024

Overview

April 2019

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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 NT 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.

Power and Water is the electricity distribution network service provider for the Northern Territory. It is important to note that this is the first determination being made for Power and Water under the NEL and NT NER. The current determination for the period 2014–19 was made by the Utilities Commission of the Northern Territory. We assumed responsibility for the economic regulation of Power and Water's electricity distribution services on 1 July 2015.

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

The key component of our distribution determination for Power and Water will be the total revenue it can recover from customers for the provision of common distribution services (or 'standard control services') –those used by most of Power and Water's customers. This is our 'building block determination' (section 2), and will form the basis of Power and Water's distribution tariffs for the 2019–24 regulatory control period. Power and Water's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for standard control services from customers (section 4).

Power and Water also provides alternative control services, such as metering 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 Power and Water's alternative control services in attachment 15 to this final decision.

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[1] NEL, s. 7.

[2] AER, *Framework and Approach for Power and Water Corporation*, July 2017, pp. 41–43.

Note

This overview forms part of the AER's final decision on Power and Water's 2019–24 distribution determination. It should be read with all other parts of the final decision.

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 decision includes the following attachments:

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Return on debt transition

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 13 – Control mechanisms

Attachment 15 – Alternative control services

Attachment 18 – Tariff structure statement

Attachment A - Negotiating framework

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
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
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
ECA	Energy Consumers Australia
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NT NER or the rules	National Electricity Rules As in force in the

Shortened form	Extended form
	Northern Territory
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
Pricing Order	electricity pricing order
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
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Our final decision

Our final decision allows Power and Water to recover $759.3 million ($nominal, smoothed) from its customers over the five years from 1 July 2019 to 30 June 2024.

As a result of this decision, the costs of electricity distribution network services in the Northern Territory will fall by 9.4 per cent ($nominal) over the next five years.

Because prices are regulated by the Northern Territory Government, this determination will not impact the prices households pay for their electricity. But it sets a limit on the costs that can be recovered from retailers for network costs and will reduce the electricity bills of the NT's 200 largest commercial, industrial and government customers by an average of 3.3 per cent.

This outcome is $104.2 million ($nominal, smoothed) lower than Power and Water's revised proposal. This is a decrease of $159.7 million ($2018–19) or 18.5 per cent in revenue allowed[3] in the current 2014–19 regulatory control period.

Having assessed Power and Water's revised proposal, we believe these savings can be made as they are driven by our forecast of lower operating expenditure (opex) and the application of a lower rate of return on the debt and equity needed to fund the network.

While lowering overall costs through greater efficiencies, the decision also allows for increased spending to improve network reliability in urban and rural areas over the next five years. It recognises the unique challenges in providing electricity to small, remote and geographically dispersed communities and enables Power and Water to improve reliability for poor performing rural and urban areas, roll out smart meters on a new and replacement basis and replace power poles in Alice Springs to address the safety risks associated with pole corrosion. We are also supportive of Power and Water's implementation of more cost reflective tariffs.

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[3] This is compared to the Ministerial Direction allowance. It is important to note that there were in effect two revenue allowances given to Power and Water in the current 2014–19 period –the initial allowance determined by the Utilities Commission in April 2014 and the lower allowance subsequently determined by the NT Government by Ministerial Direction. It is this lower revenue path that Power and Water recovered from customers during the 2014–19 regulatory control period. It should be noted that the Ministerial Direction revenue included metering services, which going forward will be recovered separately in alternative control services, so this is not a like for like comparison.

The Utilities Commission made its 2014 Network Price Determination under the Northern Territories Network Access Code on 24 April 2014. However, on 13 May and 6 June 2014, the Treasurer, as the Shareholding Minister of Power and Water, made a direction under the Government Owned Corporations Act 2001 (NT), reducing Power and Water's revenue path. There are a number of comparisons throughout Power and Water's proposal and this decision to the allowance made by the Utilities Commission and the Ministerial Direction. For the most part we will be making comparisons to the Ministerial Direction allowance, unless otherwise explicitly noted.

Increasing efficiency

This is the first time that Power and Water has submitted a regulatory proposal, tariff structure statement and regulatory information notices to the AER.

We recognise that Power and Water, and the Northern Territory energy market have undergone extensive changes in recent years and Power and Water has made progress in enhancing the quality of its business planning, investment and operations. Nevertheless, we have identified additional efficiencies that Power and Water should realise during the 2019–24 regulatory control period which result in a lower allowed operating expenditure and rate of return on its assets than proposed.

Our final decision is to allow operating expenditure of $18.7 million ($2018–19), or 5.3 per cent, lower than Power and Water's proposal, resulting in savings to customers. This includes:

- a reduction to base opex of $3.8 million ($2018–19) for non-recurrent network overhead costs we do not consider to be prudent or efficient
- the 10 per cent network and corporate overhead efficiencies to base opex proposed by Power and Water. Given it is the first time we have regulated Power and Water, and the likely nature of the overhead efficiencies, which may require some structural changes, we consider it appropriate to include the efficient costs of transitioning to a lower opex base. We have included $8.2 million of efficient transition costs over the 2019–24 regulatory control period
- the 0.5 per cent annual opex productivity growth forecast from our recent electricity distribution sector-wide opex productivity growth forecast review. 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.

In terms of capital expenditure (capex) we are approving $338.4 million ($2018–19), which is consistent with the amount sought by Power and Water in its revised proposal, and $35.5 million higher than for the 2014–19 regulatory control period. In addition to the reliability, smart meter and pole replacement programs, specific projects include the construction of a new Berrimah zone substation, the replacement of 33 kilometres of high voltage cables in Darwin and an upgrade of the 19 Mile Depot.

Power and Water has undergone significant change in a relatively short period of time and that has created challenges for them. However, we consider that there is scope for Power and Water to continue progressively to make improvements over the 2019–24 period.

Listening to customers

Consumer engagement has been important in developing Power and Water's revenue proposal. Power and Water undertook the largest network focussed customer engagement program in its history, through the combination of consumer focus groups, customer interviews, deliberative forums and presentations to and feedback from its Customer Advisory Council. Through these, Power and Water identified a number of key themes:

- maintaining reliability and responsiveness levels for most customers and improving reliability for poor performing rural and urban areas
- consumer representatives agreed that all customers that have a meter that is capable of measuring the maximum amount of power that they consume at any point during a period of time (demand) should be charged according to demand. They also supported cost reflective tariffs for large energy users
- supporting new technology, including the roll out of smart meters to all customers on a new and replacement basis.

Consumer engagement has been a central element of Power and Water's key themes, as reflected in its revenue proposal. Our final decision supports a number of the key themes expressed through Power and Water's regulatory proposal and reflecting input from its stakeholders. It is also encouraging to see that Power and Water has continued to engage with its customers following its initial proposal and our draft decision. This has provided a valuable contribution to Power and Water's revised proposal. Power and Water's engagement with its stakeholders and our concerns surrounding its initial forecast capex, as expressed in our draft decision, has been influential in our approval of Power and Water's revised capital capex in our final decision.

What the decision means

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 network tariffs would decrease by 9.4 per cent ($nominal) for Power and Water compared to the 2018–19 level (as at 30 June 2019)
- average annual electricity bills would decrease by 4.1 per cent ($nominal) for residential customers and 3.3 per cent ($nominal) for small business customers on Power and Water’s network compared to the 2018–19 level, holding all other components of the bill constant.[4] This suggests that average annual bills would be $102 and $319 lower for residential and small business customers, respectively.

In making this final decision, we have had regard to a range of sources including Power and Water's revised proposal, submissions received as well as additional analysis undertaken and published by us. We are satisfied that the revenue we have determined that Power and Water can recover from its customers for the 2019–24 regulatory control period is in the long-term interests of consumers and that its customers are paying no more than they should for safe and reliable electricity.

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4 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.

Other relevant decisions

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

- 2018 rate of return guideline review:[5] 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:[6] 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 forecast capital expenditure and applying the diminishing value (DV) method to calculate the tax depreciation for new assets[7]
- approach to forecasting operating expenditure (opex) productivity growth for electricity distributors review:[8] 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 Power and Water.

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 to remove the impact of inflation.

In real terms, our final decision would allow 18.5 per cent less revenue than recovered from customers in the 2014–19 regulatory control period. Figure 1 shows a large reduction in revenue in the first year commencing 1 July 2019, followed by gradual increases per annum over the remaining four years.

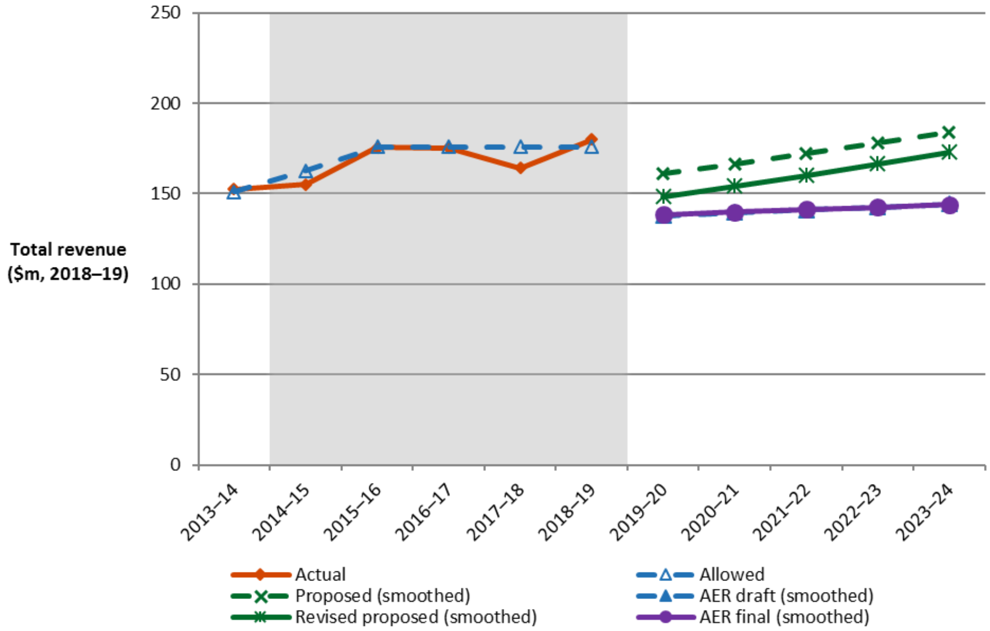
5 AER, *Rate of return instrument*, 17 December 2018.

6 AER, *Final report – Review of regulatory tax approach*, 17 December 2018.

7 AER, *Distribution PTRM (version 4)*, April 2019.

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

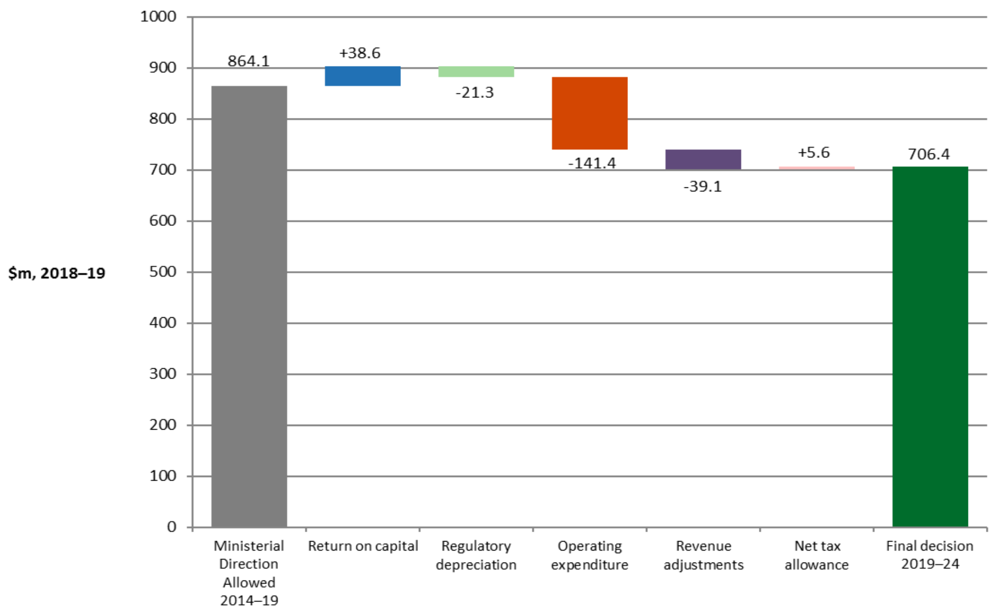
Figure 1 Revenue over time ($million, 2018–19)



Source: AER analysis.

Figure 2 below highlights the key drivers of the decrease in Power and Water's revenues that would result from this final decision, by reference to the revenue 'building blocks' that form the basis of our assessment. This figure shows a comparison of our final decision against the allowances for the 2014–19 regulatory control period determined by Ministerial Direction – these are the key drivers of the change.

Figure 2 Change in total revenue from 2014–19 to 2019–24 - Ministerial Direction approved allowance compared to AER final decision ($million, 2018–19)



Source: AER analysis.

There are a number of factors contributing to the change in revenue from period to period.

Power and Water's revenue for 2019–24 is being driven by:

- increases in capex
- a higher rate of return compared to that established by the Ministerial Direction[9]
- reduction in regulatory depreciation
- opex reductions; this is a key driver for the reduction in revenue for the next period
- a negative revenue adjustment. In its 2014–19 revenue determination, the Utilities Commission allowed $42 million for the costs of implementing the recommendations of the Davies review.[10] This was also allowed in the Ministerial Direction. However, because the cost pass-through has now been completed, this revenue adjustment is not required for the 2019–24 regulatory control period [11]
- increases in corporate income tax, which is largely a result of the move to the post-tax revenue framework.[12]

1.2 Key differences between our final decision and Power and Water's revised proposal

As we noted above, our final decision does not accept the full $863.5 million in revenue ($nominal, smoothed) proposed by Power and Water, and instead allows a lower total revenue of $759.3 million. In a number of areas, the information provided has not justified Power and Water's proposal.

These include:

- the revised opex forecast, which we do not consider meets the opex criteria. We have developed an alternative opex forecast, which is $18.7 million ($2018–19) or 5.3 percent, lower than proposed by Power and Water in its revised proposal. This largely reflects reductions we have made in relation to achieving the efficient level of base opex and applying opex productivity growth going forward.

  While we agree with Power and Water's proposal to use an updated base year of 2017–18, and to make adjustments for non-recurrent opex and efficiencies, we

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9 The rate of return applied by the AER is higher than the rate of return applied by the Ministerial Direction, additional details about the Ministerial Direction can be found at Footnote 3 of this document. Further detail about the 2018 Rate of Return Instrument and its application to this Determination can be found at section 2.2.

10 Utilities Commission, *2014 Network Price Determination; Final Determination, Part B - Network Price Determination*, April 2014, p. 5. Note that the $42 million in costs was, at the time, dependent on the rate of return, which was subsequently lowered as a result of the Ministerial Direction (see footnote 3 above). This has resulted in a $39 million ($2018–19) revenue adjustment in the 2019–24 regulatory control period.

11 Utilities Commission, *2014 Network Price Determination; Final Determination, Part A - Statement of Reasons*, April 2014, pp. 139–140.

12 The change to the post-tax framework has resulted in a new tax building block and there is a corresponding lower post-tax rate of return compared to a pre-tax rate of return, all things being equal.

have formed a different view about the prudent and efficient level of these adjustments. We reduced our alternative estimate of efficient base year costs by an additional $3.8 million ($2018–19) to remove non-recurrent network overhead costs, such as professional fees and personnel costs, as we do not consider Power and Water has justified as being recurrent.

We have also accepted efficiencies of 10 per cent to base year network and corporate overhead costs (which make up 60 per cent of base year opex) in our alternative estimate, as proposed by Power and Water. This reduces base year opex by $4.0 million.

Power and Water proposed to apply these 10 per cent overhead efficiencies to the base year. Given this is the first time we have regulated Power and Water under the NT NER, and the likely nature of the efficiencies, which may require some structural changes, we consider it is appropriate to include the efficient costs of transitioning to a lower opex base. As such we apply a gradual (linear) path of reductions to network and corporate overheads, such that a 10 per cent efficiency is fully realised by the last year of the 2019–24 regulatory control period. This means $8.2 million of efficient transition costs are included over the 2019–24 regulatory control period. We consider this will allow for an efficient yet practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services to Power and Water's customers.

Our alternative estimate trends forward the efficient base opex. This includes the 0.5 per cent per year opex productivity growth forecast established in our recent electricity distribution sector-wide review which reduces opex by $6.2 million over the 2019–24 regulatory control period. The productivity growth forecast is not intended to capture the inefficiencies in the costs of an individual distributor (these are a part of our base year assessment outlined above). It 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. (section 2.5)

- the rate of return, which is a large contributor to the difference between our final decision and Power and Water's proposal (and therefore the return on capital). In accordance with the binding 2018 rate of return instrument,[13] we have approved a rate of return of 4.88 per cent compared to Power and Water's proposed 6.08 per cent. Power and Water's proposed immediate transition to the trailing average approach for debt is inconsistent with the 2018 rate of return instrument. Instead, the 10 year transition to the trailing average will commence in the first year of Power and Water's 2019–24 regulatory control period. (section 2.2)
- a $0.7 million ($nominal) reduction in the depreciation allowance (section 2.3)
- a $14.6 million ($nominal) reduction in the corporate income tax (section 2.7).

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13 AER, *Rate of Return Instrument*, December 2018.

1.3 Expected impact of our final decision on electricity bills

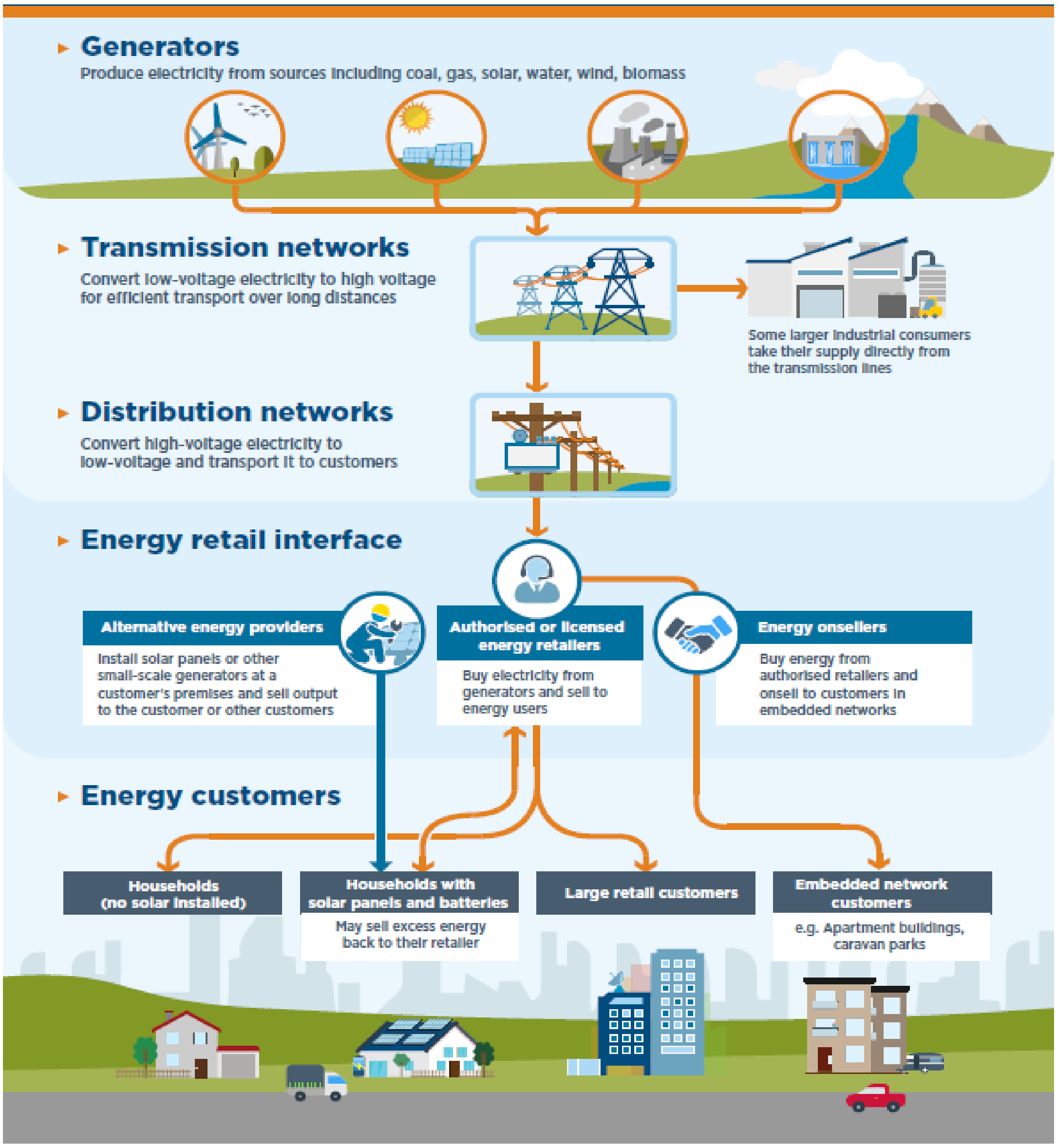
Power and Water's proposed charges are for the network[14] component of the electricity bill for NT. Power and Water's network charges make up about 44 per cent of the average household electricity bill, and 35 per cent for the average small business customer, in the NT.[15]

Each of the components in the electricity supply chain, as reflected in Figure 3 below, can affect the electricity charges that customers receive in their bills. The cost of the network components of the electricity supply chain are ultimately recovered in electricity retail charges.

14 All of Power and Water's electricity network is deemed to be distribution for the purposes of economic regulation. Darwin, Katherine, Tennant Creek, Alice Springs and the Darwin to Katherine 132kV power line represent the local distribution systems in the NT (See section 9 and schedule 2 of the *National Electricity (Northern Territory)(National Uniform) Legislation Act)*.

15 Power and Water, *Revenue Proposal Overview*, Attachment 01.1, p. 1.

Figure 3 Electricity supply chain



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

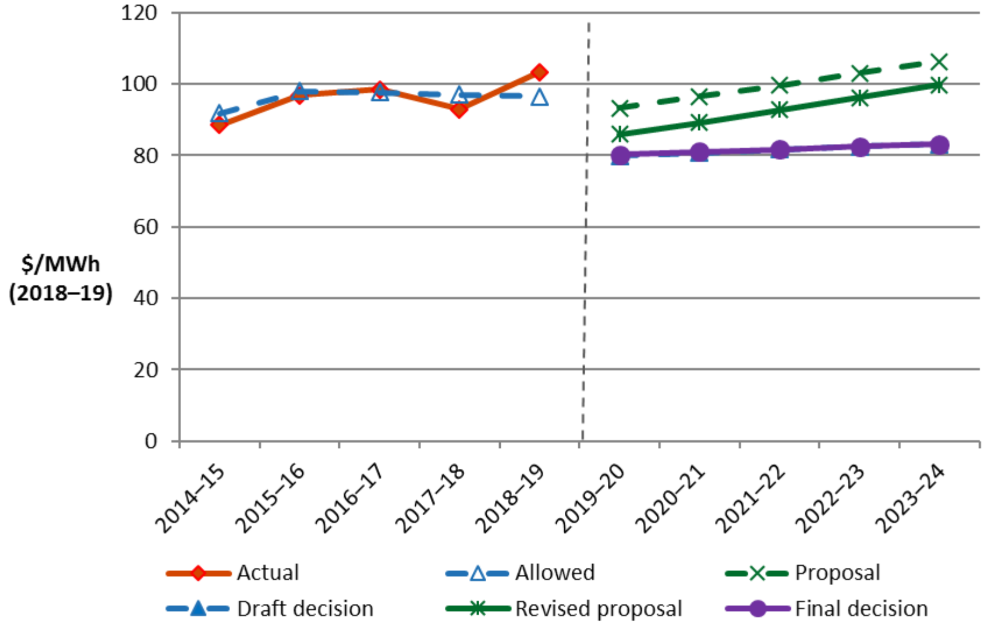
Distribution charges

Figure 4 below shows the indicative average distribution charges over the period 2014–15 to 2023–24 in real dollar terms. These amounts are an approximation of distribution charges as they are simply Power and Water's forecast revenue divided by its forecast energy delivered (measured in MWh). Based on this, the indicative distribution charges are expected to decrease from an average of $96.0 per MWh[16]

[16] Distribution charges for 2014–19 are based on actual revenue.

over 2014–19 to an average of $81.7 per MWh over 2019–24. This is a 14.9 per cent decline in distribution charges between the two periods.

Figure 4 Indicative distribution price path for NT ($/MWh, 2018–19)



Source: AER analysis.

Potential bill impact

We expect that, holding other components of bills constant, our final decision will result in the average annual electricity bill for residential customers in the NT to decrease by about $102 or 4.1 per cent ($nominal) in 2023–24 compared to the current, 2018–19 level. This involves a $225 decrease in the first year of regulatory control period (2019–20) followed by gradual increases of around $31 for the remaining four years of the 2019–24 regulatory control period.

We note the majority of customers in the NT are subject to the government's Electricity Pricing Order (Pricing Order). This caps retail prices for customers using less than 750MWh of electricity per annum.[17] It is important to recognise that the customer impact of any changes to Power and Water's revenue as a result of our decision is constrained by the Pricing Order.

The Pricing Order stipulates a fixed charge and volume based tariff structure (including a time of use tariff) but does not account for demand based tariffs. The Pricing Order prevents price increases but does allow for prices to be set lower than prescribed.

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[17] The fixed daily charge and the charge for the volume of electricity consumed is not to exceed the amount specified in the Pricing Order (See clauses 4 and 5). The Pricing Order can be found on the Utilities Commission's website at: http://www.utilicom.nt.gov.au/Electricity/pricing/Pages/Electricity-Retail-Pricing.aspx.

However, it is up to retailers to determine the price in accordance with the Pricing Order and pass on to customers any cost savings from lower network revenue determined for Power and Water. This means that only a small number of customers who are not covered by this retail price protection benefit directly from our determination.

For large customers with an average annual electricity usage of around 1000 MWh per annum, we expect that the distribution component of the average annual electricity bill in 2023–24 to decrease by about $7395 ($nominal) from the 2018–19 level.[18]

Further detail on our final decision impact on overall bills is set out in attachment 1.

1.4 Power and Water's consumer engagement

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

Consumer engagement in this context is about Power and Water working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence Power and Water's 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.

Power and Water undertook a comprehensive engagement process in developing its regulatory proposal, commencing in February 2017. It's the largest network consumer engagement and research program in its history and included establishing a Customer Advisory Council (CAC),[19] undertaking focus groups, in-depth customer and stakeholder interviews, deliberative forums, a large energy users forum and tariff structure statement consultation.[20] This comes at a time of significant changes in the way that Power and Water manages its business and we acknowledge the challenges that this presents for a business that operates in the dispersed geographic area of the Northern Territory, and the work it has done to get the business and customers engaged. Power and Water is on a good path to recognising the importance of consumer engagement and the value it delivers for the network business and

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18 This equates to a 3.3 per cent decrease in the average large customer's total electricity bill over five years.

19 Power and Water's Consumer Advisory Council is made up of 14 consumer representative bodies and other stakeholders including: Central Australian Health Services, NT Chamber of Commerce, The GPT Group, St Vincent De Paul, NT Farmers Association, Charles Darwin University, Tenant Advice Council, Master Builders Association, Council on the Aging (COTA), Multicultural Council of Australia, Urban Development Institute, NT Airports, Environment Centre and Department of Defence.

20 Power and Water, *Engagement Overview; How we engaged, what we heard and how we are responding*, 31 January 2018.

customers. Power and Water's consumer engagement program represents a reasonable starting point to build on into the future.

We tasked CCP13 specifically with advising us on the effectiveness of Power and Water's engagement activities with consumers and how this was reflected in the development of its proposals. CCP13 attended a number of Power and Water’s workshops and met on several occasions with Power and Water executives and staff. CCP13 also talked to a number of stakeholders who are represented on Power and Water’s CAC and met with a number of large consumers.

CCP13 confirm that:

- they are encouraged by Power and Water's commitment to ongoing consumer engagement, building on the reset process to improve the capability in consumer organisations to more effectively engage[21]
- post lodgement of the initial proposal, Power and Water has undertaken a range of consumer engagement activities that have continued their quality consumer and stakeholder engagement programme[22]
- Power and Water's engagement has resulted in a much more informed CAC that will continue to meet business as usual consumer engagement.[23]

Unlike some other businesses, Power and Water did not consult stakeholders on its full regulatory proposal, including its proposed capex, opex, rate of return and other aspects at a sufficiently early stage. We consider that this early engagement approach has proved useful to businesses, stakeholders and ourselves where it has been used. Power and Water may wish to consider early engagement when developing its proposal for 2024–29. Consistent with CCP13's advice,[24] we accept that Power and Water has undertaken a high quality consumer engagement process and is well informed of consumers interests and concerns in framing its revenue proposal.

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21 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019–24 regulatory period,* 11 January 2019, p. 4.

22 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019–24 regulatory period,* 11 January 2019, p. 8.

23 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019–24 regulatory period,* 11 January 2019, p. 8.

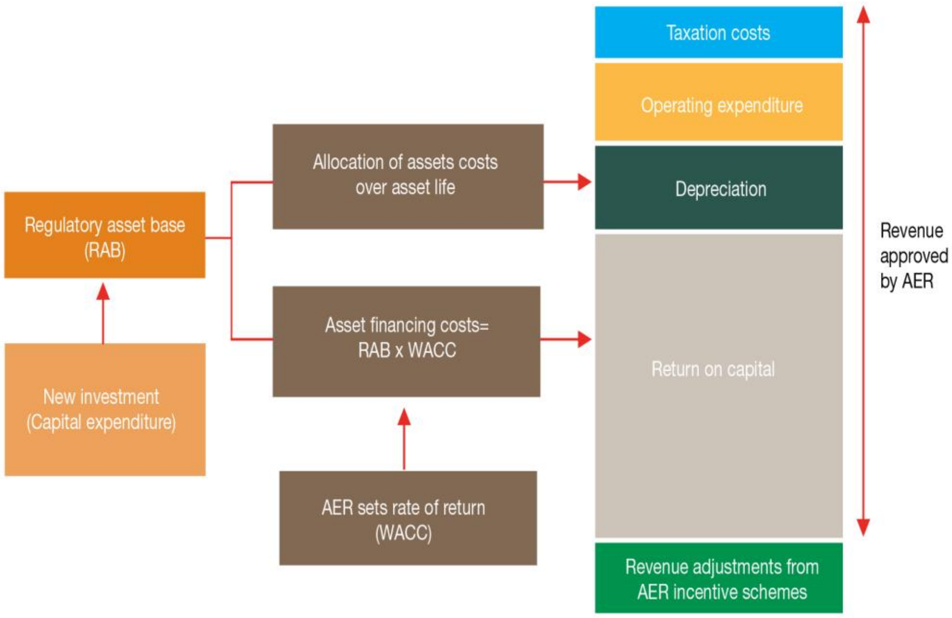
24 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for revenue reset for the 2019–24 regulatory period,* 11 January 2019, p. 8.

2 Key components of our final decision on revenue

The total revenue Power and Water has proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2019–24 regulatory control period. Power and Water's proposal, and our assessment of it under the NEL and NT NER, are based on a 'building block' approach to determine a total revenue allowance (see Figure 5) 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 increments or decrements carried over from the previous regulatory control period - the 2014–19 Network Price Determination made by the Utilities Commission (section 2.6)
- the estimated cost of corporate income tax (section 2.7).

Figure 5 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 Power and Water's revenues for the 2019–24 regulatory control period is set out in Table 2-1 below.

Table 2-1 AER's final decision on Power and Water's revenues for the 2019–24 regulatory control period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Return on capital	46.9	50.4	52.8	55.7	57.1	262.9
Regulatory depreciation[a]	18.5	23.5	26.6	31.0	34.2	133.8
Operating expenditure[b]	69.0	70.1	71.5	72.8	74.1	357.5
Revenue adjustments[c]	0.0	0.1	0.1	0.1	0.1	0.3
Net tax allowance	1.7	1.0	1.1	0.9	1.2	5.9
Annual revenue requirement (unsmoothed)	136.2	145.1	152.1	160.4	166.6	760.5
Annual expected revenue (smoothed)	**141.7**	**146.6**	**151.7**	**156.9**	**162.3**	**759.3**
X factor[d]	n/a[e]	–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 shared assets and demand management innovation allowance mechanism (DMIAM).

(d) 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) Power and Water 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 23.0 per cent lower than the approved expected revenue for 2018–19 in real terms, or 21.2 per cent lower in nominal terms.

In the sections below, we discuss each component of our decision on Power and Water's 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 mechanisms, pass throughs, the negotiating framework and the connection policy are discussed in section 5.

2.1 Regulatory asset base

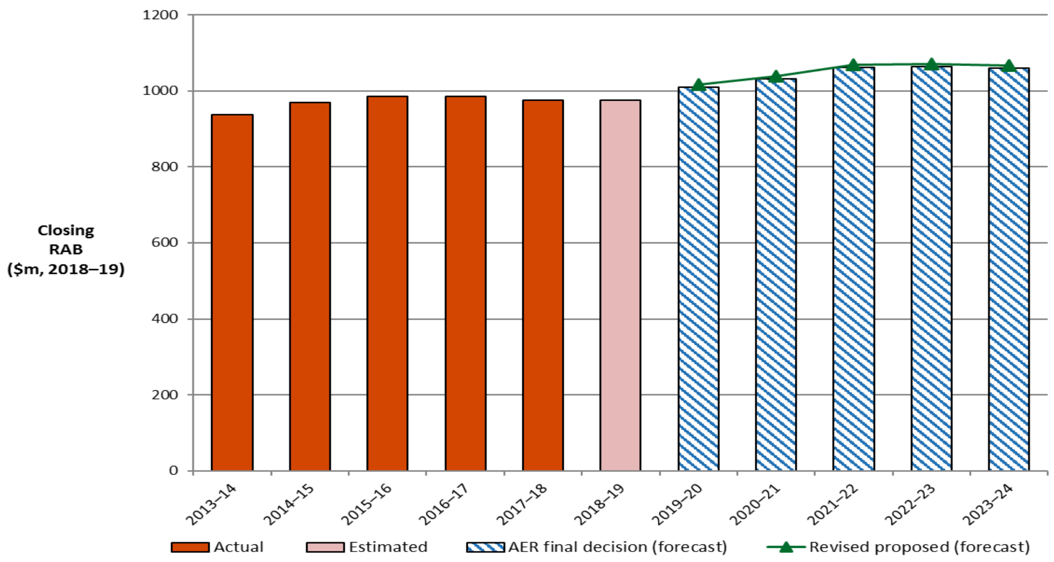
The RAB accounts for the value of Power and Water's regulated assets over time. The size of the RAB—and therefore the revenue generated from the return on capital and return of capital building blocks—is directly affected by our assessment of capex.

Our final decision is to determine an opening RAB value of $962.0 million ($nominal) as at 1 July 2019 for Power and Water. We roll forward this opening RAB value year-by-year by indexing it for inflation, adding new capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions).[25] This gives us a closing value of the RAB at the end of each year of the 2019–24 regulatory control period. The value of the RAB is then 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 many stakeholders. Figure 6 shows growth in Power and Water's RAB. It has been largely stable in the 2014–19 regulatory control period, but forecast to grow slightly in the 2019–24 regulatory control period. This is driven by increased capex forecast in the 2019–24 regulatory control period.

Figure 6 Projected RAB growth[26]



Source: AER analysis.

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

[26] Note that the RAB has been adjusted to account for the correction to the opening RAB at 1 July 2014. Clause S6.2.3A of the NT NER was amended on 19 December 2018 to correct the value of Power and Water's opening RAB.

Power and Water's proposal calculated its opening RAB as at 1 July 2019 and its closing RAB at 30 June 2024 in accordance with our roll forward model (RFM). Table 2-2 sets out our final decision on the forecast RAB values for Power and Water over the 2019–24 regulatory control period.

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

	2019–20	2020–21	2021–22	2022–23	2023–24
Opening RAB	962.0	1033.5	1082.8	1141.6	1170.3
Capital expenditure[a]	90.0	72.8	85.5	59.7	57.9
Inflation indexation on opening RAB	23.3	25.1	26.3	27.7	28.4
Less: straight-line depreciation	41.8	48.6	52.9	58.7	62.6
Closing RAB	1033.5	1082.8	1141.6	1170.3	1194.0

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 Power and Water's RAB is set out in attachment 2.

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, and requires a business that is not already using a trailing average to transition to it over a 10 year period that is in the future.

As required under the NT NER we have applied the 2018 Instrument and estimate an allowed rate of return of 4.88 per cent (nominal vanilla).[27] Submissions to this process and also separate but concurrent regulatory processes support the immediate full application of the binding 2018 Instrument to all resets.[28]

Our calculated rate of return, in Table 2-3, 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 Power and Water's proposed return on equity and debt averaging periods because they satisfied the 2018 Instrument.[29]

Table 2-3 AER's final decision on Power and Water's rate of return (nominal)

	AER draft decision (2019–24)	Revised proposal (2019–24)	AER final decision (2019–24)	Allowed return over regulatory control period
Nominal risk free rate	2.66% [a]	2.59% [b]	2.21% [c]	
Market risk premium	6%	6%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	6.3%	6.19%	5.87%	Constant (%)
Return on debt (nominal pre–tax)	4.5%	6%	4.21%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	5.22%	6.08%	4.88%	Updated annually for

[27] 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 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.

[28] 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.

[29] AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25; NT Power and Water, *Rate of Return Averaging Periods - Confidential*, 31 January 2018.

				return on debt
Forecast inflation	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] Calculated using an indicative averaging period of 20 business days ending 31 August 2018.

[c] Final decision to accept proposed period of 18 January 2019 to 15 February 2019.

[d] Final decision is to accept the proposed debt averaging periods and return on debt updated for the latest averaging period.

Power & Water's proposed immediate transition to the trailing average

We have reviewed Power and Water's revised rate of return proposal. Power and Water's revised proposal adopted the draft 2018 rate of return guidelines and noted that we would apply the 2018 Instrument to its final decision.[30] However, it continued to disagree with the application of full debt transition.[31] As its revised proposal was submitted prior to the release of the 2018 Instrument, Power and Water also provided follow-up submissions in February 2019 which reiterated its position on debt transition.[32]

Power and Water submitted that a full transition (that is, a gradual transition to the trailing average on a prospective basis over the next ten years) was not appropriate. It proposed that its debt transition effectively started on 1 July 2009 due to the impact of the Ministerial Direction given in 2014.[33] Hence, it proposed an immediate transition to a full trailing average from the start of the 2019–24 regulatory control period.

Our final decision is to commence a full 10-year transition to the trailing average in the first year of Power and Water's 2019–24 regulatory control period.

We have engaged with Power and Water on the debt transition issue through the development of the 2018 Instrument and at the draft decision stage of this distribution

30 Power and Water's revised rate of return proposal adopted the draft 2018 rate of return guidelines for all aspects except for the return on debt transition, where it continued to disagree with the application of full debt transition. See: Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp. 49–50, 54.

31 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 49. This can be called either immediate transition or no transition as both aim to estimate a 10-year trailing average return on debt based on historical data without a transition period.

32 Power and Water, *Impact of rate of return binding instrument on revised proposal*, 21 February 2019, p. 1; Power and Water, *Chronology and outcomes of our customer and stakeholder engagement on rate of return*, 21 February 2019.

33 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024, Attachment 01.10 – Return on debt transition, PUBLIC*, 31 January 2018; Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 49; and Power and Water, *Impact of rate of return binding instrument on revised proposal*, 21 February 2019, p. 1.

revenue review. We have also examined the additional material recently submitted by Power and Water.[34]

We find Power and Water's core contention—that it was already effectively on a trailing average approach—to be substantively similar to that previously put to us.[35] Consistent with our earlier considerations, our assessment of the NT Ministerial Direction and the revised proposal does not support Power and Water's view that it is already effectively on a trailing average return on debt. Further, we found that a full transition ensures that the move to a trailing average occurs in a manner that prevents ex ante windfall gain or loss to either the network business or consumers.[36]

We are also bound to apply a full transition as per the 2018 Instrument because 2019–24 will be the first time Power and Water is on a trailing average return on debt.[37] The 2018 Instrument requires a business that is not already using a trailing average to transition to it over a 10 year period that is in the future. Power and Water agreed with this proposition in its response to our draft determination.[38]

Further details on our final decision regarding the return on debt transition are included in attachment 3.

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. We have set equity raising costs at zero. We rejected Power and Water's revised opex proposal and set debt raising costs of $2.5 million ($2018-19) using our benchmark approach which it has adopted (see Table 2-4 below).[39]

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[34] Power and Water, *Impact of rate of return binding instrument on revised proposal*, 21 February 2019; Power and Water, *Chronology and outcomes of our customer and stakeholder engagement on rate of return*, 21 February 2019.

[35] AER, *Draft rate of return guidelines explanatory statement*, July 2018, pp. 334–335; AER, *Rate of return instrument explanatory statement*, December 2018, pp. 280–284; AER, *Draft decision Power and Water Corporation Distribution Determinations 2019 to 2024 Attachment 3 Rate of return,* September 2018, pp. 16–17.

[36] AER, *Draft rate of return guidelines explanatory statement*, July 2018, p. 335.

[37] For example, see: NGL, Part 1, division 1A; NEL, Part 3, division 1B.

[38] AER, *Rate of return instrument*, December 2018, clause 9; AER*, Rate of return instrument explanatory statement*, December 2018, pp. 58, 276; Power and Water, *Return on debt transition: response to the AER's draft decision*, 29 November 2018, p. 7.

[39] Power and Water adopted our benchmark approach in its revised proposal. See: Power and Water, *Regulatory Proposal*, 31 January 2018, p. 108; Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 35. Also see our opex attachment for our final opex decision.

Table 2-4 AER's final decision on debt raising costs ($million, 2018-19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
	0.5	0.5	0.5	0.5	0.5	2.5

Source: AER analysis.

Note: Columns may not add to total due to rounding for presentation in table.

Imputation credits

Our final decision applies a gamma of 0.585 as per the 2018 Instrument.[40] This was the result of extensive analysis and consultation conducted as part of the 2018 rate of return review.[41] Power and Water's revised proposal adopted the draft 2018 rate of return guidelines' value of 0.5 and noted that we would apply the 2018 Instrument to its final decision.[42]

2.3 Regulatory depreciation (return of capital)

In our final decision, we include an allowance for the depreciation of Power and Water's 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 Power and Water, we make determinations on the indexation of the RAB and depreciation building blocks for Power and Water's 2019–24 regulatory control period.[43]

Our final decision approves a regulatory depreciation allowance of $133.8 million ($nominal) for the 2019–24 regulatory control period. This is $0.7 million (0.5 per cent) lower than Power and Water's proposed value of $134.6 million ($nominal).

Our final decision on Power and Water's regulatory depreciation is that we accept its revised proposed straight-line depreciation method used to calculate the regulatory depreciation allowance, which is consistent with our draft decision. We accept Power and Water's revised proposed asset classes and standard asset lives, subject to some changes arising from the tax review (section 2.7).

Our determinations on other components of Power and Water’s revised proposal affect the forecast regulatory depreciation allowance. Specifically, they relate to our

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

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

42 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 54.

43 NT NER, cll. 6.12.1, 6.4.3.

adjustments to the opening RAB as at 1 July 2019 and projected RAB over the 2019–24 regulatory control period (section 2.1).[44]

Table 2-5 shows our final decision on Power and Water's depreciation allowance for the 2019–24 regulatory control period.

Table 2-5 AER's final decision on Power and Water's depreciation allowance for the 2019–24 period ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Straight-line depreciation	41.8	48.6	52.9	58.7	62.6	264.5
Less: inflation indexation on opening RAB	23.3	25.1	26.3	27.7	28.4	130.7
Regulatory depreciation	**18.5**	**23.5**	**26.6**	**31.0**	**34.2**	**133.8**

Source: AER analysis.

Further detail on our final decision regarding depreciation is set out in attachment 4.

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 Power and Water's total revenue requirement.

Our final decision approves Power and Water's proposed $338.4 million total forecast net capex for the 2019–24 regulatory control period. Table 2-6 shows our final decision.

Table 2-6 AER final decision on total net capex ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Power and Water's revised proposal	86.8	68.6	78.6	53.6	50.7	338.4
AER final decision	86.8	68.6	78.6	53.6	50.7	338.4

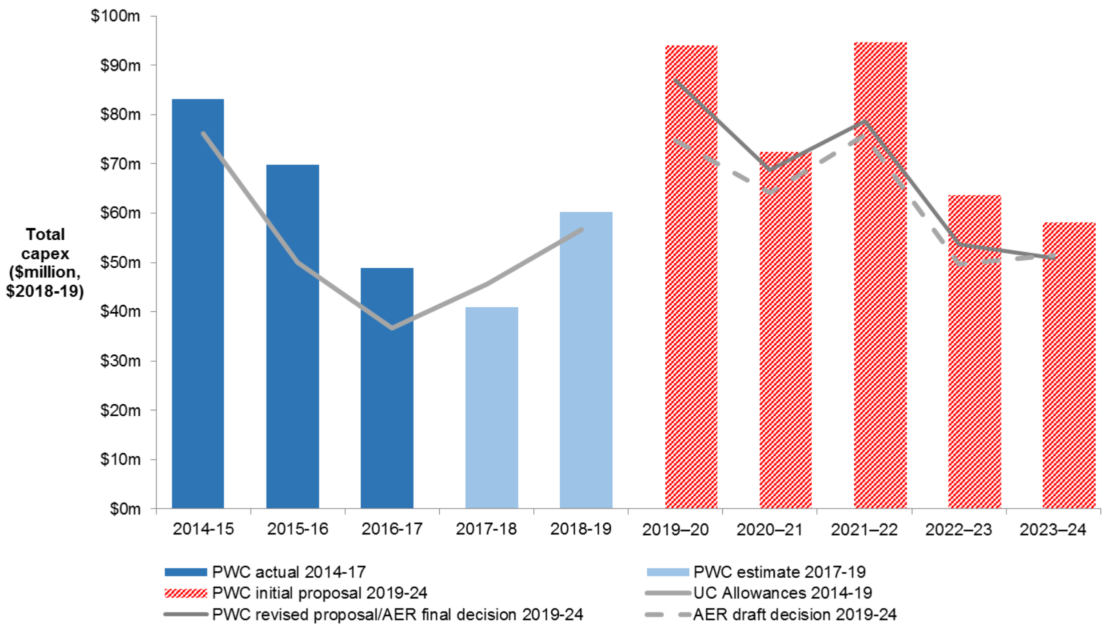
Source: AER analysis.

Note: Numbers may not total due to rounding.

[44] 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. We have accepted Power and Water's revised proposed forecast capex for the 2019–24 regulatory control period (section 2.4). However we have amended the revised proposed rate of return (section 2.2). Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2019–24 regulatory control period (section 2.1).

Figure 7 shows our capex final decision compared to Power and Water's initial and revised proposals, past allowances and past actual expenditure.

Figure 7 AER final decision on total forecast capex ($million, 2018–19)



Source: Power and Water, Capex overview 2019-20 to 2023-24, 16 March 2018, p. 11 and pp. 13–14; and AER analysis.

Power and Water's revised capex proposal demonstrated its engagement with all aspects of our draft capex decision, and acknowledged the need for ongoing improvement in its risk assessment and asset management approaches to align with industry best practice. For some capex categories, such as augex, Power and Water accepted our draft decision. In other cases, Power and Water provided further evidence to address the issues highlighted in our draft decision and justify a revised capex forecast that is higher than our draft decision. Specifically, Power and Water:

- accepted our draft decision on forecast augex, including adopting a lower cost non-network solution in place of the major Wishart augmentation project
- sought updated customer connections forecasts from AEMO, resulting in a reduction in forecast connections capex below our draft decision, and confirmed its maximum demand forecasts
- reduced its forecast repex by 5 per cent, by revising the scope of its Alice Springs poles and HV cable replacement programs, and sought to rely on new methods and additional data to justify its revised forecasts. Power and Water also proposed a replacement option for the Berrimah substation that maintains the existing capacity, in line with the reasoning set out in our draft decision
- sought to address our concerns regarding the deliverability of its forecast IT capex program by reducing the proposed capex and smoothing the expenditure more evenly over the forecast regulatory period

- largely accepted our draft decision on non-network other capex, while providing additional supporting information to justify a reduced scope of works at the 19 Mile depot
- updated its base year capitalised overheads costs in line with its approach to forecast opex, resulting in a slight reduction to capitalised overheads from its initial proposal.

Overall, based on the information before us, Power and Water has demonstrated that its revised total capex forecast reasonably reflects the capex criteria. We consider this capex forecast should be sufficient for a prudent and efficient service provider in Power and Water’s circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations. While our final decision on Power and Water's forecast capex again identifies some areas for future improvement, we commend Power and Water on the thorough and meaningful engagement it has demonstrated in responding to our draft decision.

Further detail on our final decision regarding forecast capex is set out in attachment 5.

2.5 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

Our final decision on Power and Water's revenue includes $332.7 million ($2018–19) in total forecast opex for the 2019–24 regulatory control period. This is $18.7 million (5.3 per cent) lower than Power and Water's revised total opex proposal of $351.3 million ($2018–19). We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria.

Table 2-7 shows our final decision compared to Power and Water's revised forecast.

Table 2-7 AER final decision on total opex ($million, 2018–19)

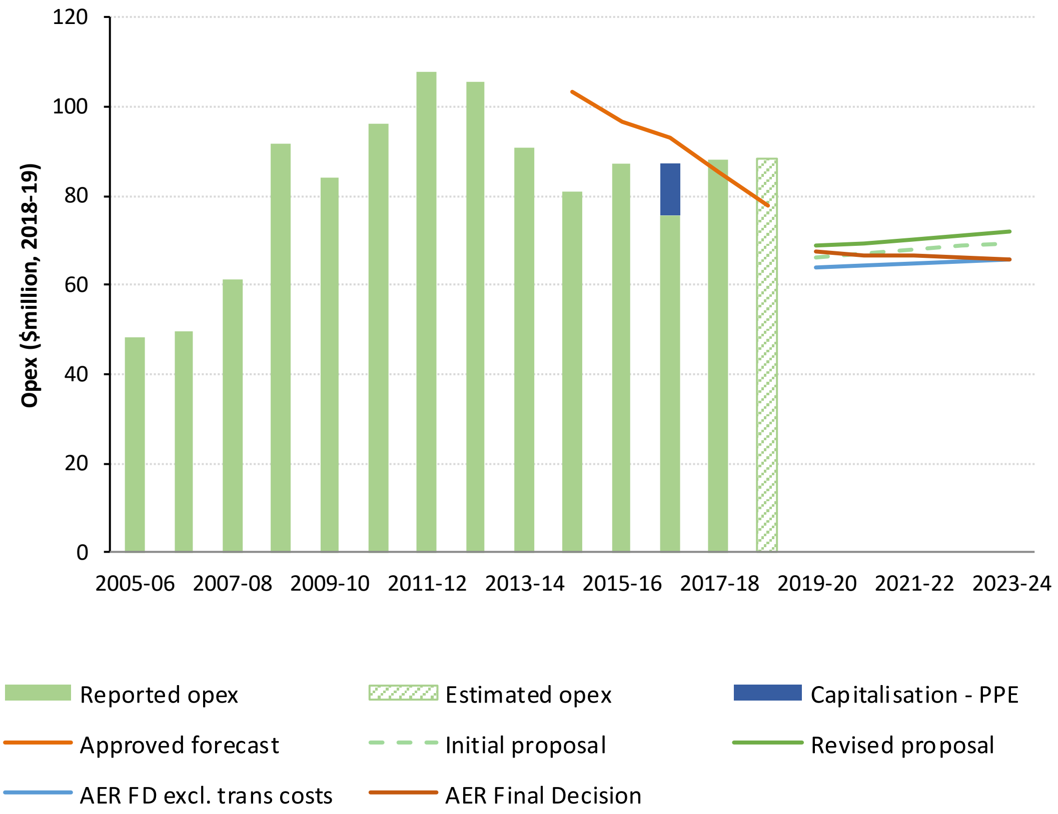
	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Power and Water's proposed opex	68.7	69.3	70.3	71.1	71.9	351.3
AER final decision	67.4	66.9	66.6	66.1	65.7	332.7
Difference	-1.3	-2.5	-3.7	-4.9	-6.2	-18.7

Source: Power and Water, Revenue proposal, *PTRM*, 29 November 2018; AER analysis.

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

Figure 8 shows our opex decision compared to Power and Water's revised proposal, its past allowances approved by the Utilities Commission and past actual expenditure.

Figure 8 AER final decision on total forecast opex ($million, 2018–19)



Source: Power and Water, Regulatory accounts; Power and Water, Economic benchmarking RIN response; Utilities Commission NTRM; AER analysis.

Note: Includes debt raising costs.

Power and Water's revised opex forecast adopted many aspects of the approach we used in our draft decision. The key differences between Power and Water's revised opex forecast and our draft decision are:

- the updated base year of 2017–18, which Power and Water considered provides a better indication of what will be required in the future to meet regulatory obligations and deliver the outcomes customers expect. This included application of its revised Cost Allocation Method to corporate overheads, leading to increased actual opex. Power and Water also adjusted the actual (revealed) costs in its base year to remove what it considered to be non-recurrent opex in emergency response and network overheads and to incorporate specific efficiencies for maintenance and 10 per cent efficiency targets for network and corporate overheads. Overall, these changes added $23.1 million over five years to its initial proposal
- an updated price growth forecast, which reflected Power and Water's inclusion of a wage price index forecast from BIS Oxford, that it averaged with the Deloitte Access Economics forecast to determine labour price growth. This led to a reduction of $2.4 million over five years from its initial proposal

- a new step change for a demand management solution in relation to deferral of capex at the Wishart zone substation. This added $0.2 million over five years to its initial proposal.

Our decision to not accept Power and Water's revised total opex proposal of $351.3 million ($2018–19) reflects the material difference between the revised proposal and our alternative estimate of $332.7 million ($2018–19). Our alternative estimate reflects our view of the efficient level of opex required by a prudent operator. We developed our alternative estimate using the same approach as in the draft decision, updated with the latest information. The details of our alternative estimate compared to Power and Water's revised proposal are set out in Table 2-8.

Table 2-8 AER final opex decision and comparison to Power and Water revised proposal

	Power and Water revised regulatory proposal	AER final decision	Difference
Based on reported opex in 2017-18	439.8	436.5	-3.2
Other adjustments (capitalisation)	-31.5	-31.6	-0.1
Non-recurrent costs	-39.8	-58.6	-18.8
Efficiency adjustment	-33.2	-31.4	1.8
Transition costs	0.0	8.2	8.2
Output growth	9.3	8.0	-1.3
Price growth	3.6	4.6	1.0
Productivity growth	0.0	-6.2	-6.2
Step changes	1.1	1.3	0.1
Category specific forecasts	-0.6	-0.6	0.0
Debt raising costs	2.6	2.5	-0.1
Total opex	**351.3**	**332.7**	**-18.7**

While we agree with Power and Water's proposal to use an updated base year of 2017–18, and to make adjustments for non-recurrent opex and efficiencies, we have formed a different view about the prudent and efficient level of these adjustments in developing our alternative estimate. In particular, we reduced our alternative estimate by an additional $3.8 million ($2018–19) to remove non-recurrent network overhead costs, such as professional fee and personnel costs, that we do not consider Power and Water has justified as being recurrent. This results in lower opex of $18.8 million ($2018-19) over the 2019–24 regulatory control period.

Power and Water proposed a 10 per cent reduction to base year network and corporate overhead costs (which make up 60 per cent of base year opex) to reflect what they consider to be achievable efficiencies over the regulatory period. We accept this amount as reasonable as it is supported by the results of its partial performance indicator benchmarking and taking into account the impact of its operating environment. This reduces base year opex by $4.0 million ($2018–19) (in addition to the non-recurrent network overhead adjustment noted above). Over the 2019–24 regulatory control period this is $1.8 million less of a reduction compared to Power and Water's revised proposal as the efficiencies are applied to a lower base year.

Power and Water proposed to apply these 10 per cent overhead efficiencies to the base year. Given this is the first time we have regulated Power and Water under the NT NER, and the likely nature of the 10 per cent network and corporate overhead efficiencies, which may require some structural changes, we consider it is appropriate to include the efficient costs of transitioning to a lower opex base.

As such we apply a gradual (linear) path of reductions to network and corporate overheads, such that a 10 per cent efficiency is fully realised by the last year of the 2019–24 regulatory control period. This gradual application reflects that we expect transition costs to decline over time. The downward sloping orange line from 2019–20 in Figure 8 illustrates this outcome. This means total opex is $8.2 million higher over the 2019–24 regulatory control period compared to an alternative estimate that does not allow for these transition costs (illustrated by the blue line in Figure 8). We consider this will allow for an efficient yet practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services to Power and Water's customers.

Our alternative estimate trends the efficient base opex we have established forward. This includes the 0.5 per cent per year opex productivity growth forecast established in our recent electricity distribution sector-wide review (compared to the 0.0 per cent per year included in Power and Water's revised proposal). This reduces opex by $6.2 million over the 2019–24 regulatory control period. As set out in *Forecasting productivity growth for electricity distributors*, the opex productivity growth forecast is not intended to capture the inefficiencies in the costs of an individual distributor (these are a part of our base year assessment outlined above).[45] It 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.

Our alterative estimate also includes:

- updated base opex to reflect the RBA's lower inflation forecast from February 2019
- updated price growth which reflects Deloitte Access Economics' wage price index forecasts from February 2019, averaged with the forecasts proposed by Power and Water from BIS Oxford, to forecast labour price growth

[45] AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

- updated output growth which reflects 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
- the new step change proposed by Power and Water for the demand management solution in relation to Wishart zone substation, which we consider to be prudent and efficient.

We have considered the issues raised in submissions about opex in establishing our alternative estimate. CCP 13 encouraged us to closely review the revised opex proposal[46] and Electrical Trades Union of Australia questioned Power and Water's proposed efficiency targets, as well as suggesting there was an opportunity to undertake a comparative assessment of labour costs.[47] The Northern Territory Treasurer noted that given the operating efficiencies in Power and Water's revised proposal it was unclear whether the business had capacity to make further significant reductions and requested consideration be given to its unique circumstances and operating environment.[48]

We have set out the reasons for our final decision on opex in greater detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

2.6 Revenue adjustments

Our final decision on Power and Water's total revenue includes a number of adjustments:

- the current determination for the 2014–19 regulatory control period was made by the Utilities Commission of the Northern Territory. In its 2014–19 revenue determination, the Utilities Commission allowed $42 million for the costs of implementing the recommendations of the Davies review. [49] This was also allowed in the Ministerial Direction. However, because the cost pass-through has now been completed, this revenue adjustment is not required for the 2019-24 regulatory control period [50]
- demand management innovation allowance mechanism (DMIAM) – A DMIAM allowance of $1.6 million ($2018–19) has been applied to Power and Water over

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[46] Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019–24 regulatory period,* 11 January 2019, p. 13.

[47] Electrical Trades Union of Australia, *Power and Water Corporation - Revised Regulatory Proposal 2019–2024*, 11 January 2019, p. 3.

[48] NT Treasurer, *Submission on draft decision and Power and Water's revised proposal*, 8 January 2019, pp. 1–2.

[49] Utilities Commission, *2014 Network Price Determination; Final Determination, Part B - Network Price Determination*, April 2014, p. 5. Note that the $42 million in costs was dependent on the rate of return, which was subsequently lowered as a result of the Ministerial Direction (see footnote 3 above). This has resulted in a $39 million ($2018–19) revenue adjustment in the 2019–24 regulatory control period.

[50] Utilities Commission, *2014 Network Price Determination; Final Determination, Part A - Statement of Reasons*, April 2014, pp. 139–140.

the 2019–24 regulatory control period. The DMIAM aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions

- shared asset decrements – an adjustment of –$1.3 million ($2018–19) has been applied for the use of shared assets used to provide unregulated services.

2.7 Corporate income tax

Our final decision includes a decision on the estimated cost of corporate income tax for Power and Water's 2019–24 regulatory control period as part of our revenue determination.[51] It enables Power and Water to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

We determined an estimated cost of corporate income tax of $5.9 million ($nominal) for Power and Water over the 2019–24 regulatory control period. This is $14.6 million (or 71.1 per cent) lower than Power and Water's revised proposed value of $20.6 million.[52]

One of the key reasons for this reduction is because 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 Power and Water's revised proposal. Specifically, for this final decision, we have recognised immediately expensed capital expenditure (capex) for the calculation of tax depreciation. We also applied the diminishing value (DV) method for tax depreciation to all new depreciable assets except for forecast capex associated with in-house software, equity raising costs and buildings. These changes have reduced the revised proposed corporate income tax allowance by $11.8 million (or 57.5 per cent).

Our final decision to increase the value of imputation credits (gamma) to 0.585 from Power and Water’s revised proposal of 0.5 also contributes to the reduction to the corporate income tax allowance (section 2.2). Further, our determinations on other components of Power and Water’s revised proposal also affect the corporate income tax allowance. Specifically, they relate to Power and Water’s revised proposed return on capital (section 2.2 and section 2.4) and the regulatory depreciation (section 2.3) building blocks. These building blocks affect total revenues, which in turn impacts the tax calculation.

We amended other proposed inputs for forecasting the cost of corporate income tax which further reduced the estimated tax allowance. These inputs are the opening tax asset base (TAB) as at 1 July 2019, standard tax asset lives and the remaining tax asset lives as at 1 July 2019.

As part of its transition to the NT NER and the AER’s PTRM which operates under a post-tax framework, Power and Water has to establish an opening TAB value for the first time for regulatory purposes. This is because the determination for the 2014–19

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51 NT NER, cl. 6.4.3(a)(4).

52 Power and Water, *PWCR04.01- SCS Post-tax Revenue Model*, November 2018 – PUBLIC.

regulatory control period was set by the Utilities Commission using a pre-tax framework. Power and Water's revised proposal has adopted our draft decision on the establishment of an opening TAB as at 1 July 2019. However, it has proposed to exclude capital contributions incurred in the 2014–19 regulatory control period in its revised proposed opening TAB value.[53] We accept Power and Water's revised proposal to exclude the capital contributions received prior to the start of the 2019–24 regulatory control period for the purposes of establishing the opening TAB value at 1 July 2019.

Table 2-9 shows our final decision on Power and Water's corporate income tax allowance for the 2019–24 regulatory control period.

Table 2-9 AER's final decision on corporate income tax allowance for Power and Water ($million, nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Tax payable	4.2	2.5	2.7	2.1	2.9	14.3
Less: value of imputation credits	2.4	1.5	1.6	1.2	1.7	8.4
Net corporate income tax allowance	**1.7**	**1.0**	**1.1**	**0.9**	**1.2**	**5.9**

Source: AER analysis.

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

53 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, November 2018, pp. 55 and 56.

3 Incentive schemes

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 Power and Water 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).

Once we make our decision on Power and Water's 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. If networks reduce their costs to below our forecast of efficient costs, the savings are shared with their customers in future regulatory periods through the EBSS and CESS.

The DMIS and DMIAM encourage businesses to pursue demand side alternatives to opex and capex. The incentive schemes encourage businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

Power and Water accepted the AER's draft decision in relation to each of the incentive schemes for the 2019–24 regulatory control period.[54] No submissions were received in response to our draft decision.

The incentive schemes that will apply to Power and Water for the 2019–24 regulatory control period are:

- the CESS
- DMIS[55] and DMIAM.[56]

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[54] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 57.

[55] AER, *Demand management incentive scheme, Electricity distribution network service providers*, December 2017.

We will not apply the STPIS to Power and Water in the next regulatory control period, due to the unavailability of reliable historic supply interruption data. However, we will be collecting relevant data during the course of the 2019–24 regulatory control period in order to establish suitable targets for the following regulatory control period. This is consistent with our draft decision[57] and Framework and Approach for Power and Water.[58] Power and Water's 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.

Given our decision to not use revealed costs to forecast opex in 2019–24, and uncertainty on whether we will rely on revealed costs to forecast opex in the period starting 1 July 2024, our final decision is to not apply the EBSS in the 2019–24 regulatory control period. This is because consumers would not share the benefits of any efficiency improvements if revealed opex is not used to forecast opex in the 2024–29 regulatory control period. We consider Power and Water will already face strong continuous incentives to make efficiency improvements without an EBSS. The decision not to apply an EBSS was supported by CCP 13.[59]

Our calculation of Power and Water's DMIAM funding over the 2019–24 regulatory control period is shown in Table 3-1 below. The total DMIAM funding is $1.57 million ($2018–19) over the period. This calculation is based on the smoothed annual revenue requirement as set out in the PTRM for Power and Water in our final distribution determination.

Table 3-1 AER's final decision on the Demand Management Innovation Allowance for Power and Water ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
DMIA	0.31	0.31	0.31	0.32	0.32	1.57

Source: AER analysis.

Details regarding each scheme can be found in our draft decision, attachments 8 to 11.[60]

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

57 AER, *Draft Decision, Power and Water distribution determination 2019 to 2024*, Attachment 10.

58 AER, *Final framework and approach for Power and Water Corporation*, July 2017, pp. 44–45.

59 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019–24 regulatory period, 11 January 2019,* p. 13.

60 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/power-and-water-corporation-determination-2019-24/draft-decision

4 Tariff structure statement

Power and Water's 2019–24 proposal includes its first tariff structure statement (TSS).

The requirement on distributors to prepare a TSS arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills
- transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for the entire duration of the regulatory control period.

Among other matters, Power and Water's TSS must set out its proposed tariffs, structures and charging parameters for each proposed tariff, and the policies and procedures the distributor proposes to apply assigning customers to tariffs or reassigning customers from one tariff to another.[61]

Our decision in this determination is on the structure of tariffs that will form the basis of tariff proposals throughout the regulatory period. While an indicative pricing schedule must accompany the TSS, Power and Water's tariffs for the entire 2019–24 regulatory control period are not set as part of this determination.[62] Rather, tariffs for 2019–20 will be subject to a separate approval process that takes place in May 2019, after we make our 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 accept Power and Water's revised TSS following Power and Water's agreement to remove its proposed excess kVAr charge.[63] We consider the revised proposal, with this amendment, contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Power and Water proposed some significant changes to its tariffs and tariff structures for the 2019–24 regulatory control period. We note that small customers—those

[61] NT NER, cl. 6.18.1A(a).

[62] NT NER, cl. 6.8.2(d1).

[63] Power and Water proposed to introduce an excess kVAr charge to customers with a smart meter consuming more than 40 MWh per annum from the 2021–22 regulatory year.

consuming less than 750 MWh per annum—are protected by the NT Government's Pricing Order, which caps electricity retail prices. Power and Water considers the Pricing Order provides it the opportunity to accelerate network tariff reform. The main reforms Power and Water proposed include:

- a mandatory assignment policy
- a new demand tariff for small customers (Smart Meter LV consumer <750 MWh pa)
- removal of the declining block structure from large customer tariffs
- individually calculated tariffs for large customers
- seasonal charging windows.

Our final decision supports the direction of these changes.

In our draft decision, we requested Power and Water provide further information on the following aspects of its initial TSS:

- unmetered tariffs, particularly with regard to charging parameters and assignment policies
- individually calculated tariffs such as criteria for assigning customers to such tariffs and the method for determining the structures and levels of prices
- the approach it will use to set prices in each pricing proposal over the 2019–24 regulatory control period.

We are satisfied Power and Water's revised TSS addressed our concerns with these issues.

5 Other pricing 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 Power and Water must set its prices. These include the classification of services, conditions under which we may grant Power and Water additional revenues to cover unforeseen circumstances and the framework for Power and Water's negotiated services and customer connections.

5.1 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.[64] We set out our proposed approach to the classification of distribution services for Power and Water in our F&A.[65] Our final decision is to retain the classification structure consistent with our F&A[66] and draft decision. In its revised proposal, Power and Water accepted our final F&A and draft decision on service classification in full and did not seek any changes. A full list of Power and Water classified services for the 2019–24 regulatory control period can be found in Attachment 12 to the AER's draft decision.

5.2 Pass throughs

In our draft decision, we accepted three of the five pass through events nominated by Power and Water.[67] These included the insurer credit risk, insurance cap and natural disaster events. We proposed an alternative definition for the 'terrorism event' and did not accept Power and Water's proposed 'NT transitional regulatory change event from 1 July 2019'.

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64 NER, cl. 6.12.3(b)

65 AER, *Final framework and approach for Power and Water Corporation – Regulatory control period commencing 1 July 2019*, July 2017.

66 AER, *Final framework and approach for Power and Water Corporation – Regulatory control period commencing 1 July 2019*, July 2017.

67 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024*, September 2018, Attachment 14, Pass through events, p. 7.

Power and Water's revised proposal nominated pass through events for the 2019–24 regulatory control period that reflected our draft decision.[68] Our final decision is to approve Power and Water's nominated pass through events and associated definitions:

- Insurance cap event
- Insurer's credit risk event
- Terrorism event
- Natural disaster event.

These will apply to Power and Water 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 and insurance.

Table 5-1 Approved nominated pass through events

Event	Definition
Insurance Cap Event	An insurance cap event occurs if: (a) Power and Water makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy; (b) Power and Water incurs costs beyond the relevant policy limit; and (c) the costs beyond the policy limit increase the costs to Power and Water in providing direct control services or prescribed transmission services. For this Insurance Cap Event: (a) a relevant insurance policy is an insurance policy held during the 2019–24 regulatory control period or a previous regulatory control period in which Power and Water was regulated; and (b) Power and Water Corporation will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party of Power and Water Corporation in relation to any aspect of the Network or Power and Water Corporation's business. Note: In making a determination on an insurance cap event, the AER will have regard to, amongst other things: i. the relevant insurance policy for the event; ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and iii. any assessment by the AER of Power and Water's insurance in making its transmission and distribution determination for the relevant period.
Insurer's Credit Risk Event	An insurer credit risk event occurs if: An insurer of Power and Water Corporation becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, Power and Water Corporation: (a) is subject to a higher or lower claim limit or a higher or lower deductible

[68] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp. 63–64.

Event	Definition
	than would have otherwise applied under the insolvent insurer's policy; or (b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.
Terrorism Event	Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which (a) 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 (b) which increases the costs to Power and Water in providing direct control services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: i. whether Power and Water 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 cyclone, fire, flood, or earthquake that occurs during the 2019–20 to 2023–24 regulatory control period that increases the costs to Power and Water Corporation in providing direct control 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 Power and Water 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 Negotiating framework and criteria

In our draft decision, we approved Power and Water's proposed distribution negotiating framework for the 2019–24 regulatory control period.[69] We did not receive any submissions on our draft decision. Our final decision is to approve Power and Water's negotiating framework.

The negotiating framework that will apply to Power and Water for the period of this determination is set out in Attachment A.

[69] AER, Draft Decision, *Power and Water determination 2019 to 2024*, September 2018, Attachment 16, p. 6.

We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[70] Our final decision is to retain the NDSC that we published for Power and Water in February 2018 for the 2019–24 regulatory control period. The NDSC give effect to the negotiated distribution services principles.[71]

5.4 Connection policy

We made our draft distribution determination in September 2018[72] and modified Power and Water's proposed connection policy that it submitted in its regulatory proposal.[73] Power and Water accepted our draft decision.[74]

We received a submission on the draft decision and Power and Water's revised proposal regarding Power and Water's connection policy. Jacana Energy submitted, in relation to Power and Water's proposed connections capex, that it supports a 'user pays' framework for shared network costs relating to generator and large customer connections.[75] Jacana Energy's submission in effect supports our connection charge guideline, which provides that there should be no undue cross subsidies between new connection applicants and existing network users.[76] We approve distributors' connection policies only if these comply with our connection charge guideline, among other requirements. We consider that Power and Water's revised connection policy complies with our connection charge guideline and will not create cross subsidies between new and existing network users.[77]

Our final decision is to approve the connection policy submitted by Power and Water in its revised proposal on 29 November 2018.[78]

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70 NER, cl. 6.12.1(16).

71 NER, cl. 6.7.1.

72 AER, *Draft Decision Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 17 Connection policy*, September 2018.

73 Power and Water, *Regulatory proposal 1 July 2019 to 30 June 2024*, 16 March 2018.

74 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 83.

75 Jacana Energy, *Power and Water Corporation's revised regulatory proposal*, 18 January 2019, p. 1.

76 AER, *Connection charge guidelines for electricity retail customers, Under chapter 5A of the National Electricity Rules, Version 1.0*, June 2012, p. 9.

77 Power and Water, *Proposed Customer Connection Services Policy 2019–2024*, 29 November 2018, section 6 pp. 8–14.

78 Power and Water, *Proposed Customer Connection Services Policy 2019–2024*, 29 November 2018. See 'PWC - 03.4 - Proposed Customer Connection Service Policy - 29 November 2018'; https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/power-and-water-corporation-determination-2019-24/revised-proposal; NT NER cl. 6.12.1(21).

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.[79] 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.[80] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[81]

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.[82] 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. [83]

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.[84] 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. [85] 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.[86] 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.[87] This could create longer term problems in the network, and could have adverse consequences for safety, security and reliability of the network.

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79 NEL, section 16(1)

80 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.

81 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.

82 Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

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

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

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

86 NEL, s. 7A(7).

87 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,[88] 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.[89]

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; 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)

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

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

- 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 Constituent decisions

Our final decision on Power and Water's distribution determination includes the following constituent components:[90]

Constituent decision
In accordance with clause 6.12.1(1) of the NT NER, the AER's final decision is that the following classification of services will apply to Power and Water for the 2019–24 regulatory control period (listed by service group): • Standard control services include common distribution services, augmentation to the network and type 7 metering services • Alternative control services includes type 1–6 metering services and ancillary network services (fee based and quoted services) • Unregulated services include the rental of distribution assets to third parties. 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 NT NER, the AER's final decision is not to approve the annual revenue requirement set out in Power and Water's building block proposal. Our final decision on Power and Water's 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 NT NER, the AER's final decision is to approve Power and Water's proposal that the regulatory control period will commence on 1 July 2019. Also in accordance with clause 6.12.1(2)(ii) of the NT NER, the AER's final decision is to approve Power and Water's 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 NT NER and acting in accordance with clause 6.5.7(d), the AER's final decision is to accept Power and Water's proposed total forecast net capital expenditure of $338.4 million ($2018–19). The reasons for our final decision are set out in attachment 5 of the final decision.
In accordance with clause 6.12.1(4)(ii) of the NT NER and acting in accordance with clause 6.5.6(d), the AER's final decision is not to accept Power and Water's proposed total forecast operating expenditure inclusive of debt raising costs and exclusive of DMIAM of $351.3 million ($2018-19). Our final decision therefore includes a substitute estimate of Power and Water's total forecast opex for the 2019–24 regulatory control period of $332.7 million ($2018–19) including debt raising costs and exclusive of DMIAM. The reasons for our final decision are set out in attachment 6 of the final decision.
In accordance with clause 6.12.1(4A)(i) of the NT NER, the AER determines that there are no

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

contingent projects for the purposes of the distribution determination.

In accordance with clause 6.12.1(5) of the NT NER, the AER's final decision is that the allowed rate or return for the 2019–20 regulatory year is 4.88 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 6.12.1(5A) of the NT 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 NT 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 NT NER, the AER's final decision on Power and Water's regulatory asset base as at 1 July 2019 in accordance with clause 6.5.1 and schedule 6.2 is $962.0 million ($nominal). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NT NER, the AER's final decision is not to accept Power and Water's proposed corporate income tax of $20.6 million ($nominal). Our final decision on Power and Water's corporate income tax is $5.9 million ($nominal). This is set out in attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NT NER, the AER's final decision is to not approve the depreciation schedules submitted by Power and Water. 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 NT 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 not apply version 2 of the EBSS to Power and Water in the 2019–24 regulatory control period
- we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Power and Water in the 2019–24 regulatory control period
- we will not apply our Service Target Performance Incentive Scheme (STPIS) to Power and Water for the 2019–24 regulatory control period
- the AER has determined to apply the Demand Management Incentive Scheme (DMIS) and the Demand Management Innovation Allowance Mechanism (DMIAM) for Power and Water in the 2019–24 regulatory control period.

These are all set out in section 3 of this final decision overview.

In accordance with clause 6.12.1(10) of the NT 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 NT 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 Power and Water for any given regulatory year is the total annual revenue calculated using the formula in attachment 13 of the final decision 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 NT 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 NT NER, to demonstrate compliance with its distribution determination, the AER's final decision is Power and Water 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 the final decision.

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

- insurance cap event
- insurer's credit risk event
- terrorism 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 NT NER, the AER's final decision is to approve the tariff structure statement proposed, and subsequently amended, by Power and Water. This is discussed 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 NT NER, the AER's final decision is to apply the negotiating framework as proposed by Power and Water. The negotiating framework is set out in section 5.3 of this final decision overview.

In accordance with clause 6.12.1(16) of the NT NER, the AER's final decision is to apply the negotiated distribution services criteria published in February 2018 to Power and Water. This is set out in section 5.3 of this final decision overview.

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

In accordance with clause 6.12.1(18) of the NT 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 Power and Water's 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 NT NER, the AER's final decision on how Power and Water 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 NT NER, the AER's final decision is to require Power and Water 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 NT NER, the AER's final decision is to accept Power and Water's proposed connection policy as set out in section 5.4 of this final decision overview.

B List of submissions

We received 6 submissions in response to our draft decision and Power and Water's revised revenue proposal. These are listed below.

Submission from	Date received
Consumer Challenge Panel (CCP13)	11 January 2019
Electrical Trades Union of Australia	11 January 2019
Jacana Energy	18 January 2019
Local Government Association of the Northern Territory	11 January 2019
Northern Territory Treasurer	8 January 2019
NT WorkSafe	9 January 2019