Attachment 01.2

Revised Regulatory Proposal

1 July 2019 to 30 June 2024

29 November 2018

Contents

Executive Summary

This is our Revised Regulatory Proposal for our 2019-24 regulatory control period. It is our response to the Australian Energy Regulator's (AER) September 2018 Draft Decision, which itself responded to our Initial Regulatory Proposal and supporting documentation. We submitted these documents to the AER between 31 January and 16 March 2018.

This Revised Regulatory Proposal is guided by our commitment to deliver the electricity distribution services our customers need and value, as efficiently as possible.

Since submitting our Initial Regulatory Proposal, we have continued to engage actively with our customers to understand their needs and preferences. We welcome and accept much of the AER's Draft Decision because we recognise it will enable us to provide services which benefit and meet the needs of our customers, including:

- improving reliability in poor performing rural and urban areas;
- rolling out smart meters on a new and replacement basis, thereby helping make energy technology and pricing innovations available to them; and
- providing more cost reflective tariff structures.

In this Revised Regulatory Proposal, we have adjusted or further justified our plans in response to the AER's Draft Decision. However, there are a limited number of matters where we do not agree with the AER's Draft Decision and seek changes in its Final Decision.

Our revised Standard Control Services (SCS) Proposal

Table 1 details our proposed revised building block forecast for our SCS total revenue requirement and Table 2 details our proposed revised SCS capital expenditure (capex) forecast and regulatory asset base (RAB), for 2019-20 to 2023-24.

Table 1 – Revised SCS total revenue requirement 2019-20 to 2023-24

M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Return on capital	58.8	63.2	66.2	69.8	71.6	329.6
Return of capital	18.7	23.7	26.8	31.1	34.2	134.6
Operating expenditure	70.4	72.7	75.5	78.2	81.1	377.9
Revenue adjustments	0.1	0.1	0.1	0.1	0.1	0.4
Net tax	3.9	4.0	4.2	4.2	4.2	20.6
Building blocks	151.8	163.8	172.8	183.5	191.2	863.0
Smoothed revenue	151.8	161.6	172.0	183.1	194.9	863.5
X-factors (revenue)	17.57%	-3.92%	-3.92%	-3.92%	-3.92%	0.17%

Table 2 – Revised SCS capex and RAB 2019-20 to 2023-24

M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Total net capex (including Equity Raising)	87.8	68.6	78.6	53.6	50.7	**339.3**
Closing RAB	1,015.5	1,038.7	1,069.2	1,070.1	1,066.0	n/a

Our capex and operational expenditure (opex) forecasts are our best estimate of what we need to provide safe and reliable services at the required service performance levels. If these forecasts are cut further beyond the substantial cuts we have proposed, we risk lower service performance or greater safety risk.

Our revised capex forecast

We are proposing revised net capex of $339.3 million (Real $2018-19) for the 2019-24 regulatory control period, which is $44.9 million (Real $2018-19) less than our Initial Regulatory Proposal of $ 384.2 million (Real $2018-19). This compares with the AER's substitute capex allowance in its Draft Decision of $316.4 million (Real $2018-19). Our revised capex forecast:

- fully accepts the AER's findings to use demand management to defer the timing of Wishart zone substation;
- revises down parts of our capex forecast to respond to issues raised by the AER, including our Alice Springs poles, Darwin Suburbs cables, Information and Communication Technology (ICT) program, 19 Mile Depot project, property and fleet leases and capitalised overheads;
- maintains our Initial Regulatory Proposal to replace our Berrimah zone substation because it is more efficient for customers than the AER's suggested alternative; and

- is based on a review of our customer connection and demand forecasts by the Australian Energy Market Operator (AEMO), together with revised cost escalators.

Our revised opex forecast

How we operate and maintain our assets and provide customer service is critical to our customers' service experience, as well as the safety of our staff and the communities within which our assets operate. We initiated a program to design and implement cost efficiency improvements, which led us to propose a 10% opex saving – $35.2 million (Real $2018–19) – as an ambitious stretch target over the 2019-24 regulatory control period.

In its Draft Decision, the AER proposed a further opex cut of 9.8%, or $33.4 million (Real $2018–19). We don't consider this supports our customers' expectation of safe and reliable energy supply. This Revised Regulatory Proposal identifies category level savings to achieve our proposed savings. The AER is not correct to think the efficiency enabling initiatives in the Target Operating Model or ICT programs are in addition to, rather than facilitating, the 10% that we had proposed.

We are proposing a revised net opex of $351.3 million (Real $2018-19) for the 2019-24 regulatory control period, which is $12.0 million (Real $2018-19) more than our Initial Regulatory Proposal of $339.3 million (Real $2018-19). This compares with the AER's substitute opex allowance in its Draft Decision of $305.9 million (Real $2018-19). Our revised opex forecast:

- updates our base opex to $66.9 million (Real $2018-19) to reflect our 2017-18 audited opex and to remove non-recurrent expenditure and inefficiencies (or built-in efficiency targets). We considered and, where appropriate, incorporated the adjustments made by the AER and introduced additional targets that we consider reasonable – this equates to a $21.4 million adjustment;
- revises the labour escalation forecast to combine a new forecast from BIS Oxford with that from Deloitte Access Economics (DAE), adopted by the AER; and
- adds a new step change for the opex costs associated with the Wishart demand management solution.

Our revised regulatory asset base (RAB) and regulatory depreciation

The AER's Draft Decision largely accepted our proposed approaches and inputs to establish our opening RAB as at 1 July 2019 and to forecast regulatory depreciation over the 2019-24 regulatory control period. We have adopted the AER's specific changes in this Revised Regulatory Proposal, updating them where necessary for actual expenditure in 2017-18, and revised capex and inflation forecasts for 2018-24.

Due to these updates, our revised opening RAB as at 1 July 2019 increases to $967.4 million (Real $2018–19), up from $966.4 million (Real $2018–19) in the Draft Decision. Our revised closing RAB as at 30 June 2024 increases to $1,066.0 million ($Nominal), up from $1,043.6 million (Real $2018–19) in the Draft Decision.

Similarly, our forecast regulatory depreciation over the 2019-24 regulatory control period increases to $134.6 million ($Nominal) in our Revised Regulatory Proposal, up from $131.8 million ($Nominal) in the Draft Decision.

Our revised rate of return

The AER's Draft Decision rejected our proposed rate of return, adopting a nominal vanilla weighted average cost of capital (WACC) of 5.22% per annum compared to 6.62% per annum that we proposed. The AER accepted our proposed approaches to estimating forecast inflation and debt and equity raising costs. The AER:

- reduced the equity beta parameter to 0.60;
- reduced the market risk premium (MRP) parameter to 6%;
- updated the risk-free and prevailing return on debt parameters;
- updated the prevailing return on debt parameter; and
- applied a 10-year transition to a 10-year trailing average return on debt, starting in 2019-20.

Our Revised Regulatory Proposal adopts the parameter updates from the AER's draft 2018 Rate of Return Guideline, noting that we expect the AER's Final Decision (expected in April 2019) to reflect the final 2018 Rate of Return Guideline (expected in December 2018). We have also updated the market yields used to estimate the risk-free rate and return on debt to reflect a 20-business day sample averaging period from 6 to 31 August 2018 (inclusive).

However, we don't accept the AER's Draft Decision to apply a return on debt transition. We maintain our position from our Initial Regulatory Proposal and provide further justification for why we consider this appropriate in Attachment PWCR01.5. Importantly, our concerns do not mean the draft 2018 Rate of Return Guideline needs to be changed. Rather, it simply means when applying the Guideline, the AER should interpret the first year of the transition as being the 2009-10 year, which – as we explained in our Initial Regulatory Proposal – is the first year of the effective trailing average as reflected in our current tariffs.

Our Revised Regulatory Proposal rate of return is 6.08% per annum. This is consistent with the rate of return the AER's Guideline gives for any business operating in a steady state (i.e. not transitioning to a trailing average). We are not seeking any special treatment – only the full vanilla treatment.

Our revised estimated cost of corporate income tax

The AER's Draft Decision largely accepted the approaches and inputs that we proposed to establish the opening tax asset base (TAB) as at 1 July 2019 and to forecast our estimated corporate income tax over the 2019-24 regulatory control period, including through revisions provided to the AER in response to questions it raised about our Initial Regulatory Proposal.

The AER also foreshadowed – but did not adopt – a further potential change to exclude capital contributions from the TAB when rolling it forward over the 2014-19 regulatory control period and invited us to consider such a change as part of our Revised Regulatory Proposal.

We have adopted the specific changes that the AER made, and the foreshadowed potential change, updating where necessary for actual expenditure in 2017-18, revised expenditure forecasts for 2018-24, and changes to the other building blocks.

Due to these updates, our revised opening TAB as at 1 July 2019 decreases to $922.9 million (Real $2018–19), down from $972.5 million (Real $2018–19) in the Draft Decision. Our revised closing TAB as at 30 June 2024 decreases to $1,005.1 million (Real $2018–19), down from $1,026.7 million (Real $2018–19) in the Draft Decision.

As a result, our forecast estimated corporate income tax over the 2019-24 regulatory control period increases to $20.6 million ($Nominal) in our Revised Regulatory Proposal up from $20.1 million ($Nominal) in the Draft Decision.

The application of the AER's incentive schemes

We accept the AER's decision for our 2019-24 regulatory control period:

- not to apply the Efficiency Benefit Sharing Scheme (EBSS);
- to apply the Capital Expenditure Sharing Scheme (CESS);
- not to apply the s-factor, or the national guaranteed service level (GSL), components of the Service Target Performance Incentive Scheme (STPIS); and
- to apply the demand management incentive scheme (DMIS) and the demand management innovation allowance mechanism (DMIAM).

Our regulatory baseline and nominated pass through events

Our capex and opex forecasts are based on applicable legislative and regulatory instruments as in force on 1 July 2018 (i.e. "the regulatory baseline"), provided their form, content and application from 1 July 2019 is certain. Where eligible, we will manage any increased costs for changes in our obligations above the regulatory baseline through pass through applications in the next regulatory control period.

Our nominated pass through events are an insurance cap event, an insurer's credit risk event, a terrorism event, and a natural disaster event. We have amended the definition of a Terrorism Event as suggested by the AER.

Our revised Alternative Control Services (ACS) metering services

We welcome the AER's approval of our smart meter rollout on a new and replacement basis and proposed metering charges structure. Our Revised Regulatory Proposal addresses the concerns raised by the AER, which had prevented it approving our proposed metering charges in the Draft Decision.

However, we don't accept the AER's Draft Decision to apply a return on debt transition. We maintain our position from our Initial Regulatory Proposal, for the same reasons outlined for our SCS.

We also don't accept the AER's Draft Decision to apply a standard life for mechanical meter/electronic meter classes of 22.1 years and maintain our position from our Initial Regulatory Proposal that the standard asset life should be 15 years, having regard for AEMO and AER precedent.

Our SCS and ACS revised indicative prices and bill impacts

This Revised Regulatory Proposal will deliver network bill savings (excluding the impact of inflation) for most of our customers:

- **small households** – 20% or $219 reduction for a typical small residential customer consuming 8,500kWh per year with an accumulation meter, or 7% or $71 reduction if the customer has a smart meter. This customer class currently has retail price protection through the electricity Pricing Order, so our charges will not directly affect their retail electricity bill;
- **large households** – 27% or $489 reduction for a typical large residential customer consuming 15,000kWh per year with an accumulation meter, or 24% or $427 reduction if the customer has a smart meter. This customer class currently has retail price protection through the Northern Territory (NT) Government's Electricity Pricing Order (the Pricing Order), so our charges will not directly affect their retail electricity bill;
- **small businesses** – 1% or $18 increase for a typical small business customer consuming 30,000kWh per year with an accumulation meter, or 31% or $1,065 reduction if the customer has a smart meter. This customer class currently has retail price protection through the Pricing Order, so our charges will not directly affect their retail electricity bill; and
- **large businesses** – 2% or $2,033 increase for a typical large business customer consuming 1,000,000kWh per year

Our Revised Regulatory Proposal addresses the AER's Draft Decision residual Tariff Structure Statement (TSS) concerns by:

- updating our proposed unmetered supply tariffs to address local councils' feedback;

- providing greater detail on the individually calculated tariff eligibility criteria and calculation approach; and
- providing greater detail on how we will set tariffs annually in compliance with our approved TSS.

Our Revised Regulatory Proposal updates our proposed ACS for the outcomes of our holistic review of our fee-based and quoted services, corrects the labour rate escalation issue identified by the AER and updates cost inputs to align to our revised proposal for SCS and to reflect actual 2017-18 Regulatory Information Notices (RIN) data.

Our revised Connection Policy

We have accepted the revisions to our draft Connection Policy that the AER included in its Draft Decision and have reflected them in the version of our Customer Connection Policy, at Attachment PWCR03.4.

Next steps

We look forward to engaging with the AER as it reviews this Revised Regulatory Proposal and our supporting documentation.

We also welcome customer and other stakeholder feedback on this Revised Regulatory Proposal. The AER will conduct formal consultation and is inviting submissions until 11 January 2019. We will continue to engage with customers and other stakeholders, including through our Customer Advisory Council (CAC).

We expect that the AER will issue its Final Decision on our Revised Regulatory Proposal in April 2019. We will then prepare our prices for our distribution services for the 2019-20 regulatory year, commencing 1 July 2019, based on that Final Decision.

1. About this Revised Regulatory Proposal

Key messages

- This Revised Regulatory Proposal only revises our Initial Regulatory Proposal to address matters raised by the AER's Draft Decision or its reasons for it.
- It therefore needs to be read in conjunction with our Initial Regulatory Proposal to gain a complete view of our positions.
- Our revised positions have benefited from customer and other stakeholder consultation and input, including discussions with the AER about its Draft Decision.

This is our Revised Regulatory Proposal for our next regulatory period, 1 July 2019 to 30 June 2024 (2019-24 regulatory control period). It responds to the AER's Draft Decision published on 27 September 2018, which :

- was their response to our Initial Regulatory Proposal and supporting documentation, which we submitted to the AER between 31 January and 16 March 2018; and
- was informed by our extensive dialogue with the AER about our Initial Regulatory Proposal and supporting documentation, which included our formal responses to 386 questions from the AER.

As required by clause 6.10.3(b) of the NT National Electricity Rules (NT NER), this Revised Regulatory Proposal only revises our Initial Regulatory Proposal to address matters raised by the AER's Draft Decision, or its reasons for it. This means that the positions in our Initial Regulatory Proposal stand, except where they are replaced in this Revised Regulatory Proposal. In this way, this Revised Regulatory Proposal needs to be read with our Initial Regulatory Proposal to gain a complete view of our positions.

This Revised Regulatory Proposal details the revenues that we require to maintain the safety, quality, reliability and security of our distribution services and the assets that we use to deliver them. It:

- addresses the requirements of the NT NER;
- applies, and complies with, the regulatory baseline discussed in chapter 4 of the Initial Regulatory Proposal – this is discussed further in chapter 9 of this document;
- has benefited from customer and other stakeholder consultation and input referred to throughout this document, including discussions with the AER about its Draft Decision;

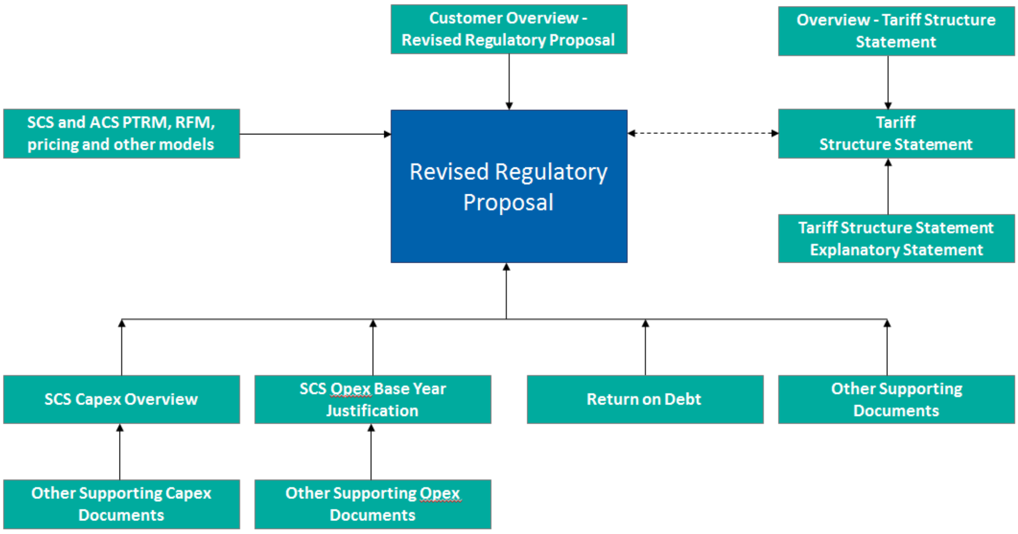
- implements our Expenditure Forecasting Method, submitted to the AER in May 2017; and
- implements our AER-approved Cost Allocation Method (CAM), which we have submitted to the AER.

The remainder of this Revised Regulatory Proposal is structured as follows:

- **chapter 2** - details how we will continue to engage with our stakeholders in the lead up to the AER's Final Decision;
- **chapter 3** - details our revised capex forecast;
- **chapter 4** - details our revised opex forecast;
- **chapter 5** - details our revised regulatory asset base and our regulatory depreciation forecast;
- **chapter 6** - details our revised rate of return forecast;
- **chapter 7** - details our revised estimated cost of corporate income tax forecast;
- **chapter 8** - details our revised proposals on the application of the AER's incentive schemes;
- **chapter 9** - details our revised proposals on prescribed and nominated pass through events;
- **chapter 10** - details our revised annual revenue requirements and X-factor forecasts;
- **chapter 11** - details our revised ACS metering services' forecasts;
- **chapter 12** - details our revised fee-based and quoted services' forecasts;
- **chapter 13** - details our revised forecasts of our SCS and ACS metering indicative prices and bill impacts;
- **chapter 14** - provides information about our revised proposed connection policy; and
- **chapter 15** - details how we have addressed the AER's Confidentiality Guideline for the matters for which we are claiming confidentiality.

The structure of this Revised Regulatory Proposal and our supporting documents and models is illustrated in Figure 1.1.

Figure 1.1 – Our revised regulatory proposal and accompanying documentation



2. Next steps and stakeholder feedback

Key messages

We will continue to engage with our customers and stakeholders throughout 2018 and 2019, as the AER reviews our Revised Regulatory Proposal and makes its Final Decision, which we expect in April 2019.

We welcome customer and stakeholder feedback on this Revised Regulatory Proposal. Please share your feedback with us by:

- email: YourSay@powerwater.com.au; or
- post: Ms Jodi Triggs
  Power and Water Corporation
  Senior Executive Manager Network Regulation and Commercial
  GPO Box 3596
  Darwin NT 0801

The AER is inviting submissions on our Revised Regulatory Proposal until 11 January 2019. We will continue to engage with our customers and other stakeholders on our Revised Regulatory Proposal up to and after this date, including through our CAC.

We expect that the AER will issue its Final Decision on our Revised Regulatory Proposal in April 2018. We will then prepare our prices for our distribution services for the 2019-20 regulatory year, commencing 1 July 2019, based on their Final Decision.

2.1 Engagement since Initial Regulatory Proposal

We have continued to engage strongly with our customers since we submitted our Initial Regulatory Proposal. This engagement has predominately been with our CAC, as well as a Network Tariff Forum conducted with NT energy sector participants.

The first post-submission CAC meeting included an overview of our proposal and a tour of some of our key network assets. Our second post-submission CAC meeting provided our CAC an overview of the AER's Draft Decision and sought feedback and direction on how we should respond. At this meeting we highlighted to our CAC which parts of the draft decision we would adopt, adjust to account for, or seek to retain our original proposal. This sought to assist our CAC's understanding of what items remained unresolved and how material these were, so that they could best engage with the remainder of the review process.

At this meeting, the CAC were also asked for feedback and direction on how we should respond on areas where the Draft Decision had cut our capex forecasts and where we needed to further explain the consequences of these cuts. Issues discussed with our CAC included:

- corroded poles in the Alice Springs region – acceptable levels of risk;
- 19 Mile Depot refurbishment – road access options;
- Berrimah zone substation – brownfield versus greenfield solution; and
- our revised approach to our ICT plan.

The CAC provided strong direction that it:

- wanted us to proceed with replacing all corroded poles in the Alice Springs area as per our original proposal, noting that "one death is one death too many" and the dangers involved in not replacing these poles was too high of a risk to be taken;
- supported our revised ICT plan, ensuring that all customer facing systems were still on track to be delivered by 2024; and
- believed road access to the 19 Mile Depot needed to be upgraded, at a minimum, in this period (2019-24), appreciating that this facility services rural areas and the current road access is dangerous for staff and the general public.

We also held a Network Tariff Forum with the major stakeholders in the NT Electricity Market in October 2018. In attendance at the forum were representatives from licensed retailers (Jacana Energy, Rimfire Energy and QEnergy), Department of the Chief Minister, Utilities Commission of the Northern Territory and Power and Water's CAC (including major customer representation).

During the forum, participants provided us with valuable feedback on Power and Water's future tariff structures and Alternative Control Services (ACS) charges including:

- changes to ACS descriptions to more clearly articulate their application; and
- a proposed increase to the peak kVA charging window to 12pm to 12am, Monday to Friday from the 12pm to 9pm, Monday to Friday we had initially proposed and had been agreed to by the AER in its Draft Decision.

In this revised proposal, we have incorporated the feedback received on the ACS descriptions. However, after further analysis we will leave the proposed peak charging (12pm to 9pm, Monday to Friday) window unchanged as our analysis showed the proposed window will sufficiently convey pricing signals for customers to shift usage into off peak times and this has already been approved by the AER.

Since our Initial Regulatory Proposal, we have also met with and responded publicly to the parties that made submissions to the AER to address their questions and concerns. Outcomes of this engagement for this revised proposal include:

- Through our direct engagement with local councils and the Local Government Association of the Northern Territory (LGANT) we have worked to ensure our revised network tariffs for public lighting (unmetered supply) do not discourage innovation and energy efficiency in how councils provide this important community service. This has resulted in us now proposing to retain a ¢/kWh charge for unmetered supplies instead of our original proposal to move this to $/kW.
- Our productive engagement with the Consumer Challenge Panel (CCP) has led us to:
  - engage the Australian Energy Market Operator (AEMO) to update its demand forecasts for new data and to better ensure our updated demand forecasts account for forecast growth of renewable energy;
  - update our capex forecast for the updated demand forecast; and
  - hold the abovementioned Network Tariff Forum.
- Our regular engagement with Jacana Energy coupled with the Network Tariff Forum have enabled us to ensure a smooth transition to the new pricing arrangements, including through refined ACS service definitions.

3. SCS capex

Key messages

- We are proposing a revised net capex of $339.3 million (Real $2018-19) for the 2019-24 regulatory control period, which is $44.9 million (Real $2018-19) less than our Initial Regulatory Proposal of $384.2 million (Real $2018-19). This compares with the AER's substitute capex allowance in its Draft Decision of $316.4 million (Real $2018-19).
- Our revised program has carefully considered the constructive feedback in the AER's Draft Decision for our capex. We consider the AER has undertaken a deep and thorough review of our proposed program and genuinely engaged with the material we provided.
- We have also listened to the views of our stakeholders to identify how we can address the issues they have raised through the process. This includes the views raised by our CAC before submitting our Revised Regulatory Proposal.
- We have fully accepted the AER's findings to use demand management to defer the timing of Wishart zone substation. We have also accepted the AER's findings on our fault level replacement program, and the reductions to property and fleet lease capex.
- We have revised down parts of our capex forecast to respond to issues raised by the AER. This includes reducing capex for Alice Springs poles, Darwin Suburbs cables, our ICT program, the 19 Mile Depot project, and capitalised overheads. This is based on new information and analysis.
- We have maintained our Initial Regulatory Proposal for replacing Berrimah zone substation. After extensive new analysis we have formed the view that our original scope is more efficient for customers than the AER's suggested alternative.
- In revising our proposal, we have also examined whether there have been any material changes since submitting the Initial Regulatory Proposal. We have asked AEMO to review our demand forecasts, and we have updated our cost escalators.

Our Revised Capex Overview document (Attachment PWCR03.1) provides further detail on our SCS capex for the 2019-24 regulatory control period. It expands on the summary provided in this chapter and references other supporting documentation and models.

3.1 Overview of our revised capex

Table 3.1 compares our revised capex for the 2019-24 regulatory control period compared to our Initial Regulatory Proposal and the AER's Draft Decision.

Our revised net capex of $339.3 million (Real $2018-19) is 11.7% lower than our Initial Regulatory Proposal of $384.2 million (Real $2018-19) and 7.3% higher than the AER's Draft Decision of $316.4 million (Real $2018-19).

Table 3.1 – Forecast capex 2019-20 to 2023-24

$M, Real 2018-19	IRP	Draft Decision	RRP
Augmentation	60.6	35.9	35.8
Connections (including gifted assets)	62.7	61.6	55.5
Replacement	148.6	129.0	141.0
Non-Network ICT	37.5	25.7	32.1
Non-Network Other	69.4	54.8	56.1
Capitalised overheads	66.9	58.4	65.1
Equity raising costs	1.2	0.7	0.9
Total gross capex[1]	**446.9**	**366.2**	**386.7**
Less capital contributions	(62.7)	(49.0)	(46.6)
Less disposals	-	(0.8)	(0.8)
Total net capex[1]	**384.2**	**316.4**	**339.3**

3.1.1 Responding to AER feedback

We have carefully considered the issues raised by the AER in its Draft Decision for our capex forecast.

Through the review process we have had fruitful and constructive discussions with the AER on our forecast capex. This has provided us with clarity on key issues from the AER's perspective and has allowed us to test and challenge our program. For this Revised Regulatory Proposal, we have undertaken additional analysis and provided more information to address issues raised by the AER.

In its Draft Decision, the AER observed that we had submitted a robust Initial Regulatory Proposal, which reflected our understanding of our network and our capex requirements. However, the AER identified the following areas for improvement: our asset management framework; our risk-based cost benefit analysis; and our overall forecasting approach. It considered that our total capex was likely to exceed the requirements of a prudent and efficient operator.

We agree with the AER that there is opportunity to improve our asset management approach. We will continue to refine our approach to ensure we meet industry best practice. For the Revised Regulatory Proposal, we have improved our risk quantification on key projects. We have also taken on board the AER's suggestions where we believe it will result in better outcomes for our customers.

The AER's substitute allowance was based on its review of our capex categories. Sections 3.2 to 3.6 provide more detail on how we have responded to the AER's Draft Decision on our augmentation, connections, replacement, non-network and capitalised overheads forecasts.

3.1.2 Listening to our customers and stakeholders

Our stakeholders and the CAC have provided feedback on our Initial Regulatory Proposal. We have discussed capex issues with our stakeholders in detail through face-to-face meetings, telephone conferences and emails.

The CCP and an anonymous party raised specific issues with our proposed capex program in their submissions. This Revised Regulatory Proposal responds to this feedback and provides relevant information requested by the CCP and the anonymous party. This includes requesting AEMO to review our customer connection and demand forecasts, and provide more granular information on replacement programs.

We also met with the CAC on capex issues prior to submitting this Revised Regulatory Proposal and have incorporated their feedback.

3.1.3 Updating proposed capex for new information

The AER sought updated data and information on changes since we submitted our Initial Regulatory Proposal. We have addressed:

- **Demand forecasts** – We engaged AEMO to revise our customer connection forecasts based on the latest available information. This has impacted our customer connection capex. AEMO also reviewed our system demand forecasts and concluded that no material change is required.
- **Undergrounding** – In April 2018, the NT Government announced it would underground some of Darwin's electricity network. We are awaiting the NT Government's decision on the suburb roll-out schedule. This means we do not have accurate information to estimate how undergrounding will affect our capex program. However, we anticipate that the

undergrounding project will not materially overlap with our proposed capex program or pose delivery issues.

- **Labour escalation** – We have updated our cost escalators for the latest available economic data and have considered the AER's independent advice.

3.2 Augmentation capex

We have revised our proposed augmentation capex from $60.6 million (Real $2018-19) down to $35.8 million (Real $2018-19). Table 3.2 shows that we have accepted the AER's findings but have made minor adjustments to the timing of the forecasts and have incorporated our revised labour escalators.

Table 3.2 – Augmentation capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	7.4	5.8	15.5	17.6	14.4	60.6
Draft decision	7.1	5.5	5.7	6.7	11.0	35.9
Revised proposal	11.4	5.4	5.7	6.7	6.6	35.8

The AER undertook a detailed review of our augex programs. It found that most programs were efficient and prudent. The AER substituted a lower capex for two proposed projects - Wishart zone substation and the Darwin switchgear fault level replacement program. These are discussed below.

3.2.1 Wishart zone substation

The AER reduced our proposed capex by 79% for a project that sought to address capacity issues at Wishart. This Revised Regulatory Proposal is consistent with the AER's findings.

In our Initial Regulatory Proposal, we had proposed constructing Wishart zone substation to support forecast load growth in the Wishart and East Arm (port) areas. The AER noted uncertainty in load growth, particularly the timing of spot (large customer) loads. It also considered there was potential for non-network and demand management options to defer or avoid the proposed augmentation. Based on this view, the AER provided an allowance for a demand management solution, rather than constructing a new zone substation.

We accept the AER's findings. We have undertaken deeper analysis of the potential demand management options. Our proposed solution is to use small mobile generators to maintain reliability if a major asset fails in service. Our costing of this solution is very similar to the AER's allowance, but we have included a minor amount of opex to run the generators. This has been included as a step change in our opex forecasts.

3.2.2 Switchgear fault level replacement

The AER reduced our proposed capex by 22% for the switchgear fault replacement program. Our revised proposal accepts the AER's findings.

In our Initial Regulatory Proposal, we sought a small amount of augmentation capex to rectify fault issues with switchgear equipment in Darwin. We had proposed replacing 34 units of switchgear to address these faults.

The AER noted that some proactive replacement is likely to be justified in the 2019-24 regulatory control period. However, it found that only 27 switchgear units had fault levels that currently exceed the equipment fault rating. The AER considered only these units should be replaced.

We have reviewed the AER's findings and accept that we should only replace the 27 units that have exceeded the fault rating and delay investment in the remaining seven units which are nearing their fault rating levels. We are cautious in accepting the AER's findings due to the high safety risks from explosive failure of switchgear equipment. We will continue to monitor the condition of the assets to manage the risks.

3.3 Connection capex and capital contributions

We have revised our forecast for (gross) connection capex and our forecast of capital contributions. We discuss the revisions below.

3.3.1 Gross connections capex

Gross connection capex refers to the total costs of connecting customers to our network including assets built by the customer and gifted to us.

The AER accepted our gross capex in its Draft Decision but made minor reductions for labour escalation costs. Our Revised Regulatory Proposal is $7.1 million (Real $2018-19) lower than our Initial Regulatory Proposal and $6.0 million (Real $2018-19) lower than the AER's Draft Decision, as can be seen in Table 3.3 below. This reflects lower numbers of large commercial and industrial customer connections, which are a key driver of the level of customer connection capex.

Table 3.3 – Gross connection capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	12.6	13.4	13.6	11.5	11.6	62.7
Draft decision	12.6	13.2	13.3	11.2	11.3	61.6
Revised proposal	10.7	11.0	11.9	10.9	11.0	55.5

In our initial proposal, we forecast customer connection volumes and unit costs to estimate gross capex. We sourced our customer connection volumes from AEMO. Our unit costs were based on historical estimates.

The AER's Draft Decision noted that AEMO's connection volumes were consistent with measures of new housing. It considered this provided evidence the methodology produced a realistic and unbiased forecast of connection volumes. It noted the methodology was reliant on underlying macroeconomic drivers, and the revised proposal should reflect the latest available forecasts. The AER also found the unit costs were efficient.

The CCP raised concerns the connection forecast may be overstated. They noted changes in economic activity and population may result in lower growth in connections. Similar concerns were raised in the submission of an anonymous party. In our engagement with the CCP, we committed to reviewing our customer connection forecasts.

In September 2018, we engaged AEMO to review the customer connection forecasts considering the issues raised by the CCP. AEMO's report shows an increase in customer connection forecasts for the Darwin-Katherine region, but a decline in Alice Springs and Tennant Creek. However, there has been a reduction in the number of large commercial and industrial customers. This has resulted in an overall reduction in our proposed gross capex.

3.3.2 Capital contributions

Capital contributions are deducted from gross capex to calculate net capex for the 2019-24 regulatory control period. They comprise gifted assets and cash contributions. Gifted assets represent the portion of gross connection capex built by third parties and given to us to operate and maintain.

Cash contributions relate to the amount we recover directly from the connecting customer when we undertake connection works on their behalf. The residual amount is funded by existing customers through the capex allowance. Our Connection Policy will determine when a customer makes a cash contribution or when a portion of works is funded by existing customers.

In our Initial Regulatory Proposal, we submitted a Customer Connections Policy to apply for the 2019-24 regulatory control period. It required customers to fully pay for their connection costs, meaning that 100% of gross connections were capital contributions.

The AER found that our connections policy was inconsistent with the classification of services. It considered that new customers should only pay the incremental costs of their connection, with the remaining capex funded by existing customers through the capex allowance. The AER's Draft Decision provided $12.6 million (Real $2018-19) in net capex, and $49.0 million (Real $2018-19) for capital contributions.

This Revised Regulatory Proposal includes a new Connection Policy that reflects the AER's feedback. New customers will only have to fund the incremental costs of upgrading the network. Based on the new policy, our capital contributions will be $46.6 million (Real $2018–19) and net connections capex will be $8.9 million (Real $2018–19) in the 2019-24 regulatory control period, as shown in Table 3.4.

Table 3.4 – Capital contribution capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	12.6	13.4	13.6	11.5	11.6	62.7
Draft decision	9.8	10.0	10.0	9.6	9.6	49.0
Revised proposal	9.2	9.3	9.5	9.3	9.4	46.6

Chapter 14 discusses our new Connection Policy further.

3.4 Replacement capex

We have revised our replacement capex from $148.6 million (Real $2018-19) to $141.0 million (Real $2018-19) for the 2019-24 regulatory control period. This revised proposal for replacement is $12.0 million (Real $2018-19) more than the AER's Draft Decision of $129.0 million (Real $2018-19), as shown in Table 3.5.

Table 3.5 – Replacement capex (repex)

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	34.9	38.5	33.4	22.0	19.7	148.6
Draft decision	28.9	33.6	30.2	19.4	17.0	129.0
Revised proposal	33.9	37.1	31.4	20.5	18.1	141.0

The AER's Draft Decision was informed by the predictions of its repex model. The AER reduced capex for the Berrimah zone substation project, Alice Springs corroded poles program, and the Darwin suburbs XLPE cable program.

Stakeholders also questioned our replacement program. The CCP considered demand forecasts can provide opportunities for smaller capacity replacement or a non-network solution. The anonymous submission raised specific issues with our replacement programs.

We have carefully considered the AER's feedback and stakeholder concerns. This included understanding the AER's findings from its repex model. We also looked afresh at the evidence for key replacement projects and undertook further quantitative analysis.

3.4.1 Repex model

The AER's repex model predicts replacement capex based on asset age, unit costs and asset lives. The AER examined our historical data together with benchmark unit costs and asset lives. The AER's preferred scenario suggested that our proposed repex was $14 million (Real $2018-19) higher than the repex model's prediction. The key differences related to our substations, poles, and cables. This informed the AER's bottom up review of our projects.

We support the AER's approach to use the repex model to inform its bottom up review of projects. We note using benchmark data in the repex model is not likely to produce reliable estimates, and a degree of caution and further analysis should be applied to interpreting the results.

3.4.2 Berrimah zone substation

The AER's Draft Decision reduced the capex forecast in our Initial Regulatory Proposal for the Berrimah zone substation project by 30%. Based on further detailed analysis, we have not revised our initial capex for this project.

In our Initial Regulatory Proposal, we provided evidence to justify replacing Berrimah zone substation. We showed that many assets were at the end of their serviceable lives. In particular, the circuit breakers in the substation were in very poor condition with a high risk of explosive failure. We proposed building a lower capacity substation adjacent to the current site ("greenfield"), with work commencing in the current regulatory control period and being completed in 2021.

The AER considered that some degree of capex is required for this substation. However, it considered that we provided insufficient information to justify replacing the entire substation. The AER raised the following issues:

- The AER considered we had used a "worst-case" scenario which brings forward the need for the forecast repex. For instance, we assumed that the condition of two transformers is identical, when analysis showed the transformers to have different asset health ratings.
- The condition report provided to the AER indicated that there are no significant issues with the substation's building and civils works.
- Building a low capacity substation brings forward the need for Wishart zone substation, as the projects are linked.

The AER's alternative solution was to refurbish the existing substation ("brownfield replacement"). The AER provide an allowance to replace the poor condition assets identified in our reports, together with a spare transformer.

We genuinely considered whether the AER’s alternative suggestion would be more efficient for customers. We accept the reasoning that maintaining the existing capacity at Berrimah will assist in reducing risk associated with deferring construction of Wishart substation. However, our analysis indicates:

- The AER’s allowance to refurbish the substation has excluded some essential costs, including decommissioning, transformer bundings and firewalls, and higher labour costs from working within the substation.
- A greenfield solution that maintains existing capacity at the site has a lower long term cost for customers than the AER’s refurbishment solution. This reflects that assets such as the 11kV switchboard and control building will need to be replaced in the subsequent regulatory period under the refurbishment option.

Based on this analysis, we consider a greenfield solution is more optimal for customers. We have not revised our initial forecast of capex for this project, despite there being some minor increases in costs related to maintaining capacity at the site.

3.4.3 Alice Springs poles

The AER reduced our proposed capex on the Alice Springs pole program by 49%. Our revised proposal is 19% less than in our Initial Regulatory Proposal.

In our Initial Regulatory Proposal, we identified a program to treat corroded steel poles in Alice Springs. The program targeted poles that were at most risk of failing due to corrosion. We noted that the program would minimise safety risks to the public and our field crews.

The AER found that replacing some of the Alice Springs poles is necessary. However, it observed that our supporting quantitative analysis overstated the risk as it did not account for joint probabilities for risk and consequence. The AER considered that our cost benefit analysis overstated risk and is not likely to represent the most efficient outcome. The AER based its alternative capex forecast on capex incurred on poles in the 2014-19 regulatory control period.

We have examined the AER’s Draft Decision and agree that further risk-based analysis is required to justify the program. Nonetheless, we consider that a step-up in capex is required to address emerging safety risks associated with corroded poles. We only identified corrosion issues when a pole failed in service, which sparked investigations into the severity of the issues. For this reason our current expenditure is not reflective of the costs required to address the safety risks. Our view is that we have a duty to protect the public and our field crews as soon as we become aware of issues such as this.

In October 2018, we sought feedback from our CAC on what approach should be adopted to address issues with the condition of poles in Alice Springs. The CAC clearly highlighted that public safety should be the priority in our decision making. We asked the CAC's view on whether they considered we should reduce capex by only targeting poles in high density areas, where there is a higher likelihood of a pole falling on a person. This was to address the AER's suggestion to use joint probability analysis. The CAC considered that we should address all poles at serious risk of falling, regardless of location or probability of consequence.

This Revised Regulatory Proposal aligns with the views of the CAC. We agree that safety is paramount and should not be compromised. However, we understand the AER's constructive advice to use better analysis to target the riskiest poles. To inform this Revised Regulatory Proposal:

- We examined condition data in finer detail and found that poles in high salinity and flood prone areas are more likely to be in severe or very severe condition.
- We undertook predictive modelling of the likely number of poles in severe and very severe condition. Our *Weibull* modelling identified a lower number of poles that require treatment, compared to our Initial Regulatory Proposal.
- We considered joint probabilities of risk and consequence by developing a matrix which looked at the underlying condition of the pole and the population density. Population density provided a metric for the likely risk of a pole failure harming a person. We note that additional metrics could be considered, such as proximity to road and fences. Our program sought to rectify all very severe condition poles, regardless of population density. However, we considered that the program could be optimised by deferring replacement of severe condition poles in areas with low population density.

We consider the lower replacement capex in our revised proposal addresses the substantive issues raised by the AER, while adhering to the safety principles reflected in feedback from our CAC.

3.4.4 Darwin suburbs' cables

The AER's Draft Decision reduced the capex forecast in our Initial Regulatory Proposal to replace XLPE high voltage cables located in Darwin by 30%. This Revised Regulatory Proposal is 15% less than our Initial Regulatory Proposal.

Our Initial Regulatory Proposal included a program to replace 44 kilometres of XLPE cable in Darwin. Our investigations had shown that the sheath and insulation of some cables were damaged. This damage impacts the effectiveness of the earthing system, leading to safety risks and more outages for customers.

The AER's Draft Decision considered replacing these cables to be prudent, noting the direct impact on outage time when a fault occurs. However, it noted a lack of conclusive evidence that all the proposed cables had failed an earthing test. The AER also noted we had not considered the cost of consequence. The AER's substitute allowed for 31 kilometres of cables that (based on sampling data) were likely to fail an earthing test, and which had a large impact on outage time.

We accept the AER's view that we provided limited evidence to justify the replacement of 44 kilometres of cables. We note that issues with the cables were only discovered in the 2014-19 regulatory control period. At the time of providing our Initial Regulatory Proposal to the AER, we had undertaken limited testing and the sample data could not be relied on to form an estimate of cables that are likely to fail. We examined additional test results to develop our revised capex forecast. We also reviewed cables by each segment, rather than by feeder, to provide more granular information on condition. The test results found that 42 cable segments (24.3% of total segments tested) had failed testing in the last year.

We applied statistical techniques to infer that an expected 33 kilometres of cable population would currently fail testing. We then analysed the deterioration rate of the cables to infer that an additional five kilometres of cable would fail sometime within the 2019-24 regulatory control period. This was the basis for revising the volumes of replacement down from 44 kilometres to 38 kilometres.

We considered whether there are opportunities to reduce capex only by targeting cables which have high consequence. This would mean that we do not address some cables which have failed earthing tests. We found the consequences of keeping failed cables on the electricity network to be too high, given our obligations to keep the public and our field crews safe.

3.5 Non-network capex

We have revised our non-network capex from $106.9 million (Real $2018-19) to $88.2 million (Real $2018-19) for the 2019-24 regulatory control period. This is $7.7 (Real $2018-19) more than the AER's Draft Decision of $80.5 (Real $2018-19).

Table 3.6 – Non-network capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	38.7	15.0	32.3	10.6	10.4	106.9
Draft decision	24.6	10.3	25.1	10.3	10.2	80.5
Revised proposal	27.4	11.6	26.1	11.8	11.3	88.2

In the following sections, we identify revisions to our proposed ICT program, the 19 Mile Depot project, and property and fleet leases. We show how our revised program addresses the issues raised by the AER and our stakeholders in response to our Initial Regulatory Proposal.

3.5.1 Information Communication and Technology (ICT)

The AER's Draft Decision reduced the ICT capex forecast in our Initial Regulatory Proposal by 31%. Our revised forecast is 14% lower than our Initial Regulatory Proposal.

In our Initial Regulatory Proposal, we forecast a prudent ICT program that maintained existing hardware and software, upgraded existing enterprise-wide systems, and invested in new capability. We noted that our forecast investment was higher than our historical capex. This increase was to replace our ageing billing system and to upgrade our asset management system. We also proposed enhancing ICT capabilities to meet new compliance obligations efficiently under the NT NER, and to help us deliver broader business efficiencies.

The AER found that we had a real need to update and upgrade many of our ICT systems. It also observed that the recent adoption of the NT NER requires additional functionality to comply with new regulatory obligations. However, the AER considered that we had not sufficiently demonstrated our ability to deliver a significantly expanded ICT program efficiently and completely. We had not demonstrated how we can adapt and accommodate the extent and rate of ICT change proposed.

The AER also encouraged us to provide detail on when and how we expect to realise the efficiency benefits, and evidence that these efficiency benefits have been accounted for in our forecast opex.

Stakeholders also commented on the ICT program in our Initial Regulatory Proposal. The CCP noted that there is little information on the quantified benefits or detailed engagement with customers on the benefit and costs of proposed investments. An anonymous submission noted issues with elements of our ICT program, such as the outage management system and the customer relationship management system.

We acknowledge that the AER and our stakeholders have raised important issues that require further analysis and revision. In our Initial Regulatory Proposal, we proposed an ICT portfolio to extract benefits as soon as possible to support our operational improvements. We considered the major system investments could be delivered on time by relying on external vendors.

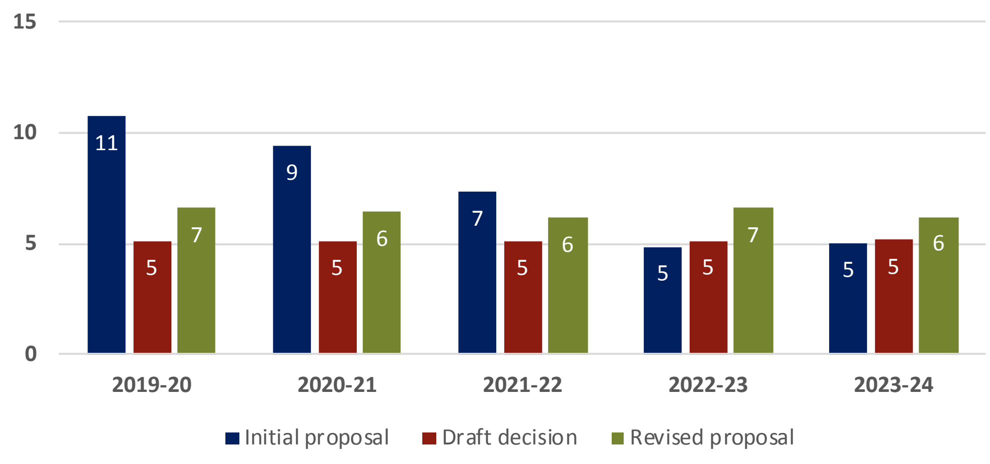
We recognise we may have had difficulty in realising the full benefits of our proposed program. Our Initial Regulatory Proposal had many projects with significant front loading of the portfolio in the early years of the 2019-24 regulatory control period.

Our revised ICT capex responds to the AER's concerns on the deliverability by:

- Deferring some projects beyond the 2019-24 regulatory control period. This includes the EBA interpreter program, operational risk reporting, and project management system.
- Flattening the profile of our ICT forecast across the 2019-24 regulatory control period. This allows us to stage, sequence and prioritise our investments better in major ICT systems. For example, we propose delaying the upgrades to our asset management system to the later years of the 2019-24 regulatory control period.

Figure 3.1 below shows the difference between our initial proposal, revised proposal and the AER's Draft Decision for our ICT capex. We are proposing $5.4 million (Real $2018–19) less than our Initial Regulatory Proposal with a smoother profile over the 5 years.

Figure 3.1 – ICT capex forecast (Real $2018-19)



We are proposing a higher forecast than the AER included in its Draft Decision. We consider that our revised ICT capex proposal is integral to delivering efficiencies, meeting our compliance obligations and delivering improvements in our customer service outcomes. While we have not been able to quantify the full savings, we have provided more information in our Revised Capex Overview document (Attachment PWCR03.1) on how the program will assist us to deliver our Operating Model efficiency program.

We also note that the Operating Model program provides a vehicle for driving the benefits of the ICT program. The program will provide the people and processes to realise the benefits of the ICT program.

3.5.2 19 Mile Depot

The AER rejected the capex proposal in our Initial Regulatory Proposal to expand our 19 Mile Depot. Our revised forecast is 79% lower than our Initial Regulatory Proposal.

In our Initial Regulatory Proposal, we set out our strategy to re-locate our crews at our leased East Arm Depot to the existing site at 19 Mile Depot, which we own. This had the advantages of reducing our lease costs on depots while also keeping our field crews close to the rural areas of Darwin. We proposed capex on the site to upgrade facilities for additional staff and to upgrade access to the site.

The AER considered it was unclear if the project would proceed given the absence of a Power and Water Board or management endorsed depot strategy. It also noted that a report prepared by one of our consultants did not support access upgrade works. The AER also noted that we did not provide dilapidation reports or similar documentation to demonstrate the existing facilities at the 19 Mile Depot site are in poor condition and/or are not fit-for-purpose and require refurbishment.

We accept the AER's view that relocating staff to our 19 Mile Depot may be a longer-term aspiration, and further analysis is required before proceeding. We note that the crews who were located at our East Arm Depot have since been relocated to the Ben Hammond Depot. We also recognise the information we submitted did not provide clear evidence of the need to update access and conditions at the site.

We have looked afresh at the evidence on access and condition of the 19 Mile Depot for this Revised Regulatory Proposal. We have assumed there will not be a major relocation of staff to the site in the 2019-24 regulatory control period. Based on current advice, we consider there is still a need to upgrade the current facility:

- Recent discussions with the Department of Infrastructure, Planning and Logistics (DIPL) indicate that a deceleration lane is required on the current site, and upgrades are needed to the intersection. Our revised capex forecast for access is 50% lower than our Initial Regulatory Proposal.

- We engaged a certification expert (Hodgkison) to provide advice on whether the existing facility is fit for purpose. They advised minor works are required at the site to meet planning certification. Our revised capex for upgrading the site is 93% lower than our Initial Regulatory Proposal.

3.5.3 Property and fleet leases

Our revised forecast accepts the AER's finding to reduce our capex on property and fleet leases by 14%.

In our Initial Regulatory Proposal, we noted that we were capitalising our property and fleet leases to be consistent with a new Australian Accounting Standard.

Stakeholders noted concerns with our Initial Regulatory Proposal. The CCP observed accounting standards are separate from regulatory accounts. It considered the change in accounting treatment would increase the regulatory asset base (RAB). An anonymous submission raised similar concerns to those of the CCP and sought further analysis of whether the costs have been calculated on a net present value basis.

The AER considered stakeholder concerns and found our lease capex forecast reflected the sum of expected future lease payments, rather than the present value of these payments.

We accept the AER's findings on the calculation of payments and have revised our capex to reflect the lower amount for property and fleet leases.

3.6 Capitalised overheads and forecast disposals

We have revised our capitalised overheads capex from $66.9 million (Real $2018-19), down to $65.1 million (Real $2018-19) for the 2019-24 regulatory control period. This is $6.7 million (Real $2018-19) more than the AER's Draft Decision of $58.4 million (Real $2018-19).

Table 3.7 – Capitalised overheads

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	13.0	13.2	13.4	13.6	13.7	66.9
Draft decision	11.5	11.6	11.7	11.8	11.9	58.4
Revised proposal	12.7	12.9	13.0	13.2	13.3	65.1

Capitalised overheads are the amount of unallocated network and corporate costs which are capitalised in line with the AER approved cost allocation method (CAM). In our Initial Regulatory Proposal, we forecast capitalised overheads using the base-step-trend approach we applied to forecast our opex. We capitalised corporate and network overheads in proportion to the ratio of direct capex to total direct costs.

Stakeholders raised issues with our proposed capitalised overheads. The CCP noted significant variation across networks on the level of capitalisation of overheads. They asked the AER to undertake a general review. An anonymous submission stated overheads should be reviewed by the AER at an aggregate level as part of opex reviews.

The AER considered we had used a reasonable methodology to forecast our capitalised overheads. However, it noted an error in our base year estimate of capitalised overheads. The AER also substituted a lower rate of change to trend our base year costs, noting it was consistent with its opex decision. The AER also noted our intention to update our forecast of capitalised overhead with actual 2017-18 data.

We have revised our forecast from our Initial Regulatory Proposal to address the AER's findings. We agree there was an error in our base year calculation. We also agree with the AER's method to use a consistent rate of change with its opex decision.

Our revised capitalised overheads' forecast uses our latest 2017-18 actual costs to update the base year. In line with the treatment of opex, we have adjusted some of the indirect labour recoveries from opex to capex. This is to account for the unusually low level of capex in 2017-18, which resulted in a low capex/totex ratio that does not reflect historical rates or the forecast for the 2019-24 regulatory control period.

We have also revised our forecast disposals from nil to $0.8 million (Real $2018-19) for the 2019-24 regulatory control period. This is the same as the AER's Draft Decision. Disposals have the effect of reducing net capex.

Table 3.8 – Forecast disposals

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	-	-	-	-	-	-
Draft decision	0.2	0.2	0.2	0.2	0.2	0.8
Revised proposal	0.2	0.2	0.2	0.2	0.2	0.8

The Draft Decision found we should include forecast disposals in line with the historical level of asset disposals. We have consequently accepted the AER's findings and approach. We have used our actual 2017-18 data to forecast our disposals in line with the AER's methods.

4. SCS opex

Key messages

- The AER accepted our proposal to use the base, step and trend approach to forecast opex over the 2019-24 regulatory control period.
- However, the AER changed key components of this approach, including to:
  - reduce base opex from $63.3 million (Real $2018-19) to $59.1 million (Real $2018-19) by replacing our top-down 10% efficiency adjustment with category-level adjustments to remove non-recurrent expenditure and remove identified inefficiencies;
  - adopt a lower labour escalation forecast;
  - adopt a lower output growth forecast; and
  - reject all our proposed step changes, except for guaranteed service levels (GSLs).
- This resulted in the forecast opex for the 2019-24 regulatory control period being reduced from our Initial Regulatory Proposal of $339.3 million (Real $2018-19) to the AER's Draft Decision of $305.9 million (Real $2018-19).
- Whilst we have used the AER's adjustments for non-recurrent expenditure and efficiency measures as a guide for our revised base year, we do not agree that the base year opex proposed in the Draft Decision is sufficient to meet our ongoing opex requirements.
- In this Revised Regulatory Proposal, we have:
  - updated our base opex to $66.9 million (Real $2018-19) to reflect our 2017-18 audited opex and to remove non-recurrent expenditure and certain inefficiencies (or built-in efficiency targets). We considered, and where appropriate incorporated, the adjustments made by the AER and introduced additional targets that we consider reasonable - this equates to a $21.4 million adjustment as detailed in Table 4.2;
  - revised the labour escalation forecast to combine a new forecast from BIS Oxford with that from DAE, adopted by the AER; and
  - added a new step change for the opex costs associated with the Wishart demand management solution.
- Our revised opex forecast for the 2019-24 regulatory control period is $351.3 million (Real $2018-19), which is $45.4 million (Real $2018-19) higher than the forecast in the Draft Decision. We consider this revised forecast reflects the efficient costs of meeting our current and expected regulatory obligations and the service outcomes required by our customers.

4.1 Draft Decision

The AER largely accepted our proposed approach to forecasting opex, including using 2016-17 as the base year. The AER, however, rejected our proposed 10% top-down efficiency adjustment and replaced it with category level adjustments that it determined after reviewing our 2016-17 expenditure.

The AER also largely accepted our overall approach to forecasting the opex trend, subject to:

- replacing our placeholder labour escalation forecast (based on South Australian data) with one specific to the NT; and
- adopting a wider range of output measures and weights to forecast output growth.

Finally, the AER rejected all our proposed step changes, except for GSLs which it updated to correct for calculation errors. We had proposed the rejected step changes to cover the expected costs of meeting new regulatory obligations related to our transition to the NT NER. The AER considered that these costs were already reflected in the base opex forecast.

4.2 Our response

The AER engaged with us on opex throughout its consideration of our Initial Regulatory Proposal, which is reflected in its Draft Decision. We appreciated the opportunity to clarify our proposal and to respond to the AER's questions, and welcome continued engagement after its Draft Decision.

Whilst we have used the AER's adjustments for non-recurrent expenditure and efficiency measures as a guide for our revised base year, we do not agree that the base year opex proposed in the Draft Decision is sufficient to meet our ongoing opex requirements.

We are, however, committed to driving efficiencies within our business. In doing so, we have cut $21.4 million from our opex base year by removing both non-recurrent expenditure and applying efficiencies to our proposed expenditure, as detailed in Table 4.2. This is the lowest level of expenditure that we believe is necessary without resulting in significant customer, safety or reliability impacts. How we operate and maintain our assets and provide customer service is critical to our customers' service experience and the safety of our staff and the communities within which our assets operate.

Table 4.1 explains our response to the AER opex changes, noting where we have adopted them and where we have not. Sections 4.3, 4.4 and 4.5 explain our updates to the base year, trend and step change components of our opex forecast. Section 4.6 compares our revised opex forecast to that in our Initial Regulatory Proposal and the AER's Draft Decision.

Table 4.1 – Response to AER opex changes

Changes in AER's Draft Decision	Our response
The AER accepted using a base, step and trend method to forecast opex over the 2019-24 regulatory control period. We had used a recent version of the AER's opex model. The AER updated this for its Draft Decision, including to allow for alternative output growth weights.	We have used the updated opex model to forecast opex for SCS (as well as ACS metering). This is provided at Attachment PWCR04.4 for SCS (and Attachment PWCR04.5 for ACS metering).
The AER accepted using 2016-17 audited opex as base opex in its Draft Decision. The AER also noted our intent to update this for 2017-18 audit opex, once available.	We have updated our base opex to reflect our 2017-18 audited opex.
The AER reconsidered our proposed adjustments to base opex. Specifically, the AER: • rejected our proposed top-down 10% efficiency adjustment and replaced this with category-level adjustments that reduced base opex by 14% – which sought to remove non-recurrent expenditure and adjust for specific inefficiencies; and • reduced base opex by the change in provisions in 2016-17. The AER retained our proposed capitalisation and GSL adjustments, which were based on 2016-17 data.	We have adopted the AER approach of identifying category-level adjustments and applied it to the 2017-18 base opex. We disagree with some of the adjustments that the AER has made. Our alternative category level adjustments are explained in Attachment PWCR02.1 and equate to 18% of base opex, or 8% in efficiency adjustments, once non-recurrent expenditure is removed. We have updated our capitalisation and GSL adjustments to reflect the 2017-18 base year. The AER-approved Cost Allocation Method has also been applied to our 2017-18 corporate costs for the first time.
The AER accepted forecasting output growth using measures that aligned to industry-wide economic benchmarking. However, the AER updated this to include results from four economic benchmarking techniques, rather than the one we had proposed.	We have adopted the AER's updated approach, including the weights used based on the 2017 annual benchmarking report. We expect the AER to update the weights to reflect those based on the 2018 report, once finalised. We have updated the customer number and circuit length output measure forecasts to reflect updates from AEMO and our capex forecasts. See chapter 3 for further discussion.

Changes in AER's Draft Decision	Our response
The AER accepted our proposal to incorporate forecast real escalation for labour costs in the opex forecast and not for materials. However, the AER adopted an alternative forecast. We had proposed using an average of forecasts from DAE and BIS Oxford but used placeholder estimates for South Australia (as none were publicly available for the NT). The AER instead commissioned and used a DAE forecast for the NT.	We have used the average of the DAE forecast and a new updated forecast for the NT prepared by BIS Oxford that we commissioned. The BIS Oxford forecast is provided at Attachment PWCR01.7.
The AER accepted our proposal to not include a productivity growth forecast. The AER also noted that it was intending to consult on how it should set productivity factors in future decisions as part of an industry-wide review.	We have retained the no productivity growth forecast and note the AER's consultation. We intend to contribute actively to the AER's industry-wide review.
The AER rejected all our proposed step changes. The AER did accept our proposed GSL step change in principle, updating it to correct some minor calculation issues.	We have adopted the updated GSL step change forecast. We have also adopted the AER's position on the other step changes as part of our revised proposal to use 2017-18 audited opex and to adjust it to remove non-recurrent and inefficient expenditure identified at a category level. We consider that the adjusted base opex is enough to cover our current regulatory obligations and those that underpinned the proposed step changes. Consistent with our capex forecast, we have included a step change for the Wishart demand management solution. This step change reflects a capex-opex tradeoff, described in the Draft Decision, where this solution meant that capital expenditure on the Wishart zone substation could be deferred. See chapter 3 for further discussion.
The AER accepted our proposed approach to forecasting debt raising costs. The AER slightly reduced the debt raising cost input parameter from 8.7 basis points to 8.4 basis points.	We have retained the same approach and have adopted the updated debt raising cost input parameter.

4.3 Updating base year opex

We have updated our base year opex to start with our 2017-18 audited opex. As foreshadowed in our Initial Regulatory Proposal, we consider our more recent actual opex year provides a better indication of what will be required in the future to meet our regulatory obligations and to deliver the outcomes our customers expect.

However, to ensure only the expenditure that is reflective of our ongoing requirements is included in our opex base year, we have undertaken a proactive and detailed review of our 2017-18 costs to remove all expenditure determined to be non-recurrent.

We have also identified both specific efficiencies and efficiency targets at the expenditure category level for our Revised Regulatory Proposal. This is unlike the approach taken in our Initial Regulatory Proposal, where we included a top down 10% efficiency reduction that recognised room for improvement in our expenditure but did not allocate it out.

The removal of non-recurrent expenditure and our further efficiency adjustments ensures that the proposed expenditure included in our Revised Regulatory Proposal is both prudent and efficient.

4.3.1 Non-recurrent expenditure

We removed from our base opex:

- non-recurrent expenditure from Tropical Cyclone Marcus, which caused us to incur more emergency response expenditure than normal;
- non-recurrent professional fees we incurred to prepare our first regulatory proposal which will not be required in future determinations – and to assist with our transition to the national framework;
- direct labour costs that would ordinarily be treated as capex and maintenance, however in 2017-18 were treated as overhead due to a lower than normal capex and maintenance spend; and
- indirect overhead costs whih would ordinarily be capitalised, however in 2017-18 were treated as opex due to a lower than normal capitalisation rate.

We are awaiting the NT Government's decision on the suburb roll-out schedule for the undergrounding project. This means we do not have accurate information to estimate how undergrounding will affect our opex. However, we anticipate the project will not materially impact our opex forecasts.

4.3.2 Efficiencies

In accordance with the approach adopted in the AER's Draft Decision, we have reviewed the efficiencies applied to both the vegetation management and maintenance expenditure categories. Whilst we do not agree with the AER's proposed level of expenditure, we recognise there is opportunity to further reduce our vegetation management and maintenance expenditure from the 2016-17 levels presented in our Initial Regulatory Proposal.

In addition to the specific efficiencies, we have also applied efficiency targets to our recurrent network overheads and corporate overheads. We consider several of our priority projects, such as our Target Operating Model and ICT capital program, will be essential in realising these efficiencies. This is consistent with our Initial Regulatory Proposal which recognised these projects as important in achieving the top down 10% efficiency reduction.

Consistent with our approach in our Initial Regulatory Proposal, the efficiency enabling initiatives in the Target Operating Model and the ICT capital program facilitate the category level efficiency targets we have proposed and are not in addition to them.

Whilst we are yet to define the individual initiatives that will be implemented, with a continued focus and commitment to driving efficiencies through our business, we are prepared to take on the challenge to drive to this level of spend by 2023-24.

The AER noted in its decision not to apply the Efficiency Benefits Sharing Scheme that we have strong continuous incentives to make efficiency improvements. Given the significant impact that achieving our proposed efficiencies will have on the business, in addition to increased regulatory obligations throughout the period, we do not believe an additional opex productivity growth factor is appropriate in our circumstances.

There will be a timeframe associated with transitioning towards realising the benefits of organisational change. We have committed to including these future efficiencies in our base year opex but recognise they will be achieved over the 2019-24 regulatory control period. We, rather than customers, will proactively fund the difference in costs during the transition period.

4.3.3 Other adjustments

We also retained our GSL and capitalisation adjustments and adopted the AER's provisions' adjustment, updating all three to reflect our 2017-18 base opex.

4.3.4 Further detail

Attachment PWCR02.1 provides further detail on our proposed base opex and the adjustments made to it. The 'Input|Reported opex' and 'Input|Base year adjustments' sheets of Attachment PWCR04.4 provide the calculations used.

Table 4.2 compares the adjusted base opex in our Revised Regulatory Proposal to the forecasts in our Initial Regulatory Proposal and the AER's Draft Decision.

Table 4.2 – Updated base year opex

$M, Real 2018-19	Initial Regulatory Proposal	Draft Decision	Revised Regulatory Proposal
Source for base year	2016-17 audited actual opex	2016-17 audited actual opex	2017-18 audited actual opex
Base opex (before adjustments)	75.8	75.8	88.4
Removal of provisions	-	(0.8)	(0.4)
Removal of GSLs	0.0	0.0	(0.1)
Capitalisation change	(5.5)	(5.5)	(6.3)
Non-recurrent expenditure adjustments	-	(10.4)	(7.9)
Efficiency adjustments	(7.0)		(6.6)
Adjusted base opex (before trending)	**63.3**	**59.1**	**66.9**

4.4 Updating the trend

We have updated the output growth and price growth components of the trend and retained the productivity growth component (of 0% per annum). These are explained in the following three sub-sections.

4.4.1 Output growth

The AER updated the output growth to add a fourth output measure – energy throughput – and a wider range of potential weights. We accept these updates are sensible and have adopted them in our Revised Regulatory Proposal.

We have retained the weights and updated two of the measures – customer numbers and circuit length – to reflect updates to other parts of our proposal. Following the Draft Decision, we asked AEMO to reforecast our customer connection numbers over the 2019-24 regulatory control period to reflect more recent population growth and other drivers. We have reflected the reforecast in our updated connection capex forecast discussed in section 3.3.

Similarly, this Revised Regulatory Proposal includes an alternative expenditure forecast, which affects our circuit length forecast. Attachment PWCR04.8 calculates our updated circuit length forecast.

Table 4.3 shows our updated output growth forecasts for each output measure and the weighted average across them.

Table 4.3 – Updated output growth forecast

%	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Cumulative
Customer numbers	1.17	0.77	0.89	1.22	0.76	0.77	5.71
Circuit length	0.55	0.77	0.57	0.61	0.60	0.59	3.76
Ratcheted maximum demand	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy throughput	-1.60	-0.76	0.00	0.05	0.09	0.20	-2.02
Weighted average[1]	0.76	0.57	0.64	0.86	0.57	0.57	4.04

[1] Weights are based on those adopted by the AER in its draft decision. These are included in the 'Input|Rate of change' sheet in Attachment PWCR04.4.

4.4.2 Price growth

The AER accepted our proposal to incorporate real labour escalation into the opex forecast and not to include an escalation for materials.

Our Initial Regulatory Proposal proposed forecasting our labour escalation using the simple average of forecasts developed by DAE and BIS Oxford. We have retained this approach for our Revised Regulatory Proposal, using the DAE forecast for the NT, published with the Draft Decision and a recently-commissioned forecast for the NT from BIS Oxford. We consider that an average of two independent forecasts provides a better estimate than relying on one, provided they both measure the labour costs likely to apply to us – which in our view they do.

Table 4.4 shows the two forecasts and the simple average of them over the 2019-24 regulatory control period.

Table 4.4 – Updated real labour escalation forecast

%	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Cumulative
Deloitte Access Economics	-0.41%	-0.23%	-0.21%	0.29%	0.53%	0.58%	0.56%
BIS Oxford	0.65%	0.67%	1.07%	1.33%	1.49%	1.40%	6.80%
Average	**0.12%**	**0.22%**	**0.43%**	**0.81%**	**1.01%**	**0.99%**	**3.64%**

4.4.3 Productivity growth

We have forecast 0% productivity growth over the 2019-24 regulatory control period, largely because our base opex has been adjusted to an efficient level we expect to achieve by 2023-24 and because recent industry-wide economic benchmarking suggests productivity is flat. The AER adopted this forecast in its Draft Decision.

We understand that the AER has initiated an industry-wide review of how it determines productivity forecasts. We intend to contribute actively to this review.

However, as noted above, our proposed efficiencies were made on the basis that a 0% productivity factor would apply and they would be achieved by 2023-24. If a positive productivity factor were adopted (such as the 1% included in the AER discussion paper on the review), then the base year efficiencies would need to reduce.

Given the significant efficiency improvements we need to make over the 2019-24 period just to realise what we have built into our base year opex, it is unrealistic to build in further reductions through a positive productivity factor. This would set the opex allowance for that period below what is required to operate our network safely and reliably.

4.5 Adopting step changes decision

We have accepted the AER's Draft Decision to reject all our proposed step changes on the basis that our revised base opex is sufficient to cover the costs of current regulatory obligations and those underpinning the step changes included in our Initial Regulatory Proposal.

We have also adopted the AER's decision on the Wishart zone substation demand management solution. As this solution involves some opex, we have included this as a step change in our Revised Regulatory Proposal. The solution is discussed further in chapter 3.

Table 4.5 shows our updated step change forecast. The GSL forecast is the same as in the AER's Draft Decision, updated to reflect a slightly different inflation forecast for the year to 30 June 2019.

Table 4.5 – Updated step change forecast

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
GSLs	0.2	0.2	0.2	0.2	0.2	**0.9**
Wishart DM solution	0.0	0.0	0.0	0.0	0.1	**0.2**
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**1.1**

4.6 Updated forecasts

Table 4.6 compares our Revised Regulatory Proposal opex forecast – and its components – to that in the Draft Decision and our Initial Regulatory Proposal.

Table 4.6 – Updated operating expenditure forecasts

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal						
Base opex						
Based on actuals	75.8	75.8	75.8	75.8	75.8	**378.9**
Adjustments	(12.5)	(12.5)	(12.5)	(12.5)	(12.5)	**(62.4)**
Trend						
Output growth	0.4	0.9	1.4	1.7	2.0	**6.6**
Price growth	0.3	0.7	1.2	1.7	2.1	**6.1**
Productivity growth	-	-	-	-	-	**-**
Step changes[1]	1.5	1.5	1.5	1.5	1.5	**7.4**
Debt raising costs	0.5	0.5	0.5	0.6	0.6	**2.7**
Total opex	**66.0**	**66.9**	**68.0**	**68.8**	**69.5**	**339.3**
Draft decision						
Base opex						
Based on actuals	75.8	75.8	75.8	75.8	75.8	**379.1**
Adjustments	(16.7)	(16.7)	(16.7)	(16.7)	(16.7)	**(83.4)**
Trend						
Output growth	0.7	2.3	1.8	2.2	1.8	**8.9**
Price growth	(0.2)	(1.5)	(0.4)	(0.4)	0.4	**(2.2)**

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Productivity growth	-	-	-	-	-	**-**
Step changes[1]	0.2	0.2	0.2	0.2	0.2	**0.9**
Debt raising costs	0.5	0.5	0.5	0.5	0.5	**2.6**
Total opex	**60.3**	**60.6**	**61.2**	**61.7**	**62.1**	**305.9**
Revised proposal						
Base opex						
Based on actuals	88.4	88.4	88.4	88.4	88.4	**441.8**
Adjustments	(21.4)	(21.4)	(21.4)	(21.4)	(21.4)	**(107.1)**
Trend						
Output growth	0.9	1.3	1.9	2.3	2.7	**9.2**
Price growth	0.1	0.3	0.6	1.1	1.5	**3.6**
Productivity growth	-	-	-	-	-	**-**
Step changes[1]	0.2	0.2	0.2	0.2	0.2	**1.1**
Debt raising costs	0.5	0.5	0.5	0.5	0.5	**2.6**
Total opex	**68.7**	**69.3**	**70.3**	**71.1**	**71.9**	**351.3**

[1] The minor difference in the value of step changes between the Draft Decision and the Revised Regulatory Proposal is due to a slight change in forecast inflation for the year to 30 June 2019.

5. Regulatory asset base and depreciation

Key messages

- The AER's Draft Decision largely accepted the approaches and inputs we proposed to establish our opening RAB as at 1 July 2019 and to forecast regulatory depreciation over the 2019-24 regulatory control period. The AER made changes to:
  - apply actual depreciation to roll-forward the RAB over the 2014-19 regulatory control period, rather than forecast depreciation, and use the December quarter actual inflation rather than the March quarter;
  - slightly amend the standard and remaining lives applying to the opening RAB as at 1 July 2014;
  - treat the written down value for rolling-in our corporate assets as at 30 June 2019 as a final year adjustment in the roll-forward model, rather than capex in the 2018-19 year;
  - update the standard lives for 'Property' and 'Equity raising costs' asset classes; and
  - make some consequential and other minor updates to the year-on-year tracking depreciation calculation.
- We have adopted these changes in our Revised Regulatory Proposal, updating where necessary for actual expenditure in 2017-18, and revised capex and inflation forecasts for 2018-24.
- Due to these updates, our revised opening RAB as at 1 July 2019 increases to $967.4 million (Real $2018–19), up from $966.4 million (Real $2018–19) in the Draft Decision. Our revised closing RAB as at 30 June 2024 increases to $1,066.0 million ($Nominal), up from $1,043.6 million (Real $2018–19) in the Draft Decision.
- Similarly, our forecast regulatory depreciation over the 2019-24 regulatory control period increases to $134.6 million ($Nominal) in our Revised Regulatory Proposal, up from $131.8 million ($Nominal) in the Draft Decision.

5.1 Draft Decision

Our Initial Regulatory Proposal sought to establish an opening RAB as at 30 June 2019 by starting with the Utilities Commission's determined RAB as at 30 June 2014 and:

- adjusting it for an error in the initial valuation; and
- remapping it to new asset classes which we considered better reflected how we operate our electricity network.

The AER's Draft Decision largely accepted our calculation, with some relatively minor changes to the mapping and resulting standard and asset lives.

We also proposed to use the AER's published roll forward model (RFM), and to apply it using forecast depreciation and the inflation calculated using the March quarter consumer price index (CPI). The AER's Draft Decision accepted using that model, but instead used actual depreciation and inflation calculated using the December quarter CPI.

To forecast regulatory depreciation over the 2019-24 regulatory control period, we proposed to use the year-on-year tracking method and to align this to our proposed RFM. The AER's Draft Decision accepted this approach but updated the calculations to incorporate changes to the RFM and to fix some other minor modelling issues.

Finally, we also proposed new asset classes for 'Property leases' and 'Fleet leases'. The AER accepted these additions – and the associated proposed standard asset lives – but extended the standard lives applying to the 'Property' and 'Equity raising cost' asset classes.

5.2 Our response

As with opex, the AER engaged with us throughout its consideration of our Initial Regulatory Proposal on depreciation and the RAB and this is reflected in its Draft Decision. We appreciated the opportunity to clarify our proposal and to respond to the AER's questions.

As explained in Table 5.1, our Revised Regulatory Proposal adopts the changes in the AER's Draft Decision to the approaches and inputs included in our Initial Regulatory Proposal. The only updates made to the RAB and forecast regulatory depreciation are to incorporate actual gross capital expenditure, asset disposals, and customer contributions in 2017-18 and revised forecasts for 2018-24 (including inflation). The next section shows the impact of these updates.

Table 5.1 – Our response to AER's RAB and regulatory depreciation changes

Changes in AER's Draft Decision	Our response
The AER largely accepted our remapping of the RAB as at 30 June 2014 from the asset classes used by the Utilities Commission to those we proposed, with some minor updates to the standard and remaining asset lives applying to those asset classes.	We have adopted the updated standard and remaining asset lives applying to the RAB as at 30 June 2014.
The AER rejected our proposal to use forecast depreciation to roll-forward the RAB over the 2014-19 regulatory control period, and instead adopted actual depreciation as determined by the Utilities Commission.	We have adopted the AER's Draft Decision RFM, including the updates to apply actual depreciation over the 2014-19 regulatory control period.
The AER rejected our proposal to use the March quarter CPI series to determine the inflation used to roll-forward the RAB over the 2014-19 regulatory control period, and instead used the December quarter.	We have adopted the December quarter inflation series in the RFM.
The AER accepted our proposal to roll-in corporate ICT, property and other assets into the RAB as at 30 June 2019 but treated it as a final year adjustment rather than capex in 2018-19.	We have adopted the treatment as a final year adjustment.
The AER amended our proposed standard asset lives: • for the 'Property' asset class from 14.3 years to 40 years; and • for the 'Equity raising costs' asset class from 5 years to 48.1 years (based on a weighted average of the lives of all other asset classes).	We have adopted the longer asset life for 'Property' and applied the same weighted average approach for equity raising costs.
The AER accepted our proposal to use the year-on-year tracking method to forecast depreciation on the opening 1 July 2019 RAB over the 2019-24 regulatory control period, but updated the calculation to: • use actual depreciation over the 2014-19 regulatory control period; • correct the depreciation calculation for 'Land and easements'; and • extend the depreciation calculation by three years from 2074 to 2077.	We adopt the AER's Draft Decision version of the SCS PTRM, including the updates to the year-on-year tracking depreciation calculation.

5.3 Updated forecasts

Table 5.2 and Table 5.3 compare RAB and regulatory depreciation forecasts in our Revised Regulatory Proposal with those in the Draft Decision and our Initial Regulatory Proposal.

Table 5.2 – Updated opening and closing RABs

$M, Real 2018-19	Opening RAB as at 1 July 2019	Closing RAB as at 30 June 2024	Change
Initial proposal	973.5	1,092.7	**119.2**
AER Draft decision	966.4	1,043.6	**77.2**
Revised proposal	967.4	1,066.0	**98.7**

Table 5.3 – Updated regulatory depreciation forecasts

$M, Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal						
Real straight-line depreciation	48.2	54.8	58.1	64.1	68.9	**294.2**
Less indexation of RAB	(23.6)	(25.4)	(26.6)	(28.3)	(29.2)	**(133.2)**
Regulatory depreciation	24.6	29.4	31.5	35.8	39.7	**161.0**
AER Draft Decision						
Real straight-line depreciation	42.3	48.4	52.4	58.0	61.5	**262.7**
Less indexation of RAB	(23.7)	(25.1)	(26.2)	(27.6)	(28.2)	**(130.9)**
Regulatory depreciation	18.6	23.3	26.2	30.4	33.3	**131.8**
Revised proposal						
Real straight-line depreciation	42.2	49.0	53.2	59.0	62.8	**266.1**
Less indexation of RAB	(23.5)	(25.2)	(26.4)	(27.9)	(28.6)	**(131.5)**
Regulatory depreciation	18.7	23.7	26.8	31.1	34.2	**134.6**

6. Rate of return, inflation and debt and equity raising costs

Key messages

- The AER's Draft Decision rejected our proposed rate of return, adopting a nominal vanilla weighted average cost of capital (WACC) of 5.22% compared to 6.62% that we proposed. The AER accepted our proposed approaches to estimating forecast inflation and debt and equity raising costs.
- The AER made changes to:
  - reduce the equity beta parameter to 0.60;
  - reduce the market risk premium (MRP) parameter to 6%;
  - update the risk-free and prevailing return on debt parameters to reflect a later sample averaging period;
  - update the prevailing return on debt parameter to reflect (a) an average of Bloomberg, Reuters and Reserve Bank of Australia (RBA) bond yield data, (b) a weighted average of bond yields with a BBB band credit rating (2/3 weight) and those with an A band credit rating (1/2 weight); and
  - apply a 10-year transition to a 10-year trailing average return on debt, starting in 2019-20.
- Our Revised Regulatory Proposal adopts the parameter updates from the AER's draft 2018 Rate of Return Guideline, noting we expect the AER's Final Decision (expected in April 2019) to reflect the final 2018 Rate of Return Guideline (expected in December 2018). We also updated the market yields used to estimate the risk-free rate and return on debt to reflect a 20-business day sample averaging period from 6 to 31 August 2018 (inclusive).
- However, we reject the AER's Draft Decision to apply a return on debt transition. We maintain our position from our Initial Regulatory Proposal and provide further justification for why we consider this appropriate.
- Our Revised Regulatory Proposal rate of return is 6.08% and forecast inflation is 2.42%.

6.1 Draft Decision

Our Initial Regulatory Proposal calculated the rate of return using all aspects of the AER's 2013 Rate of Return Guideline, except the return on debt transition. Instead, we proposed applying a trailing average return on debt from the start of the 2019-24 regulatory control period, given the unique circumstances affecting our move to the NT NER.

The AER's Draft Decision rejected our proposal for two key reasons:

- firstly, the AER intends replacing the 2013 Rate of Return Guideline with a 2018 version – and so sought to apply the draft 2018 Rate of Return Guideline it published in July 2018 (after we submitted our Initial Regulatory Proposal). This led to updates to the market risk premium (MRP), equity beta, and prevailing return on debt estimation; and
- secondly, the AER's preliminary view was a 10-year return on debt transition should be applied to us on an ex ante basis – and so it sought to start this in 2019-20.

6.2 Our response

The AER is currently reviewing how it should determine the rate of return and expects to publish its 2018 Rate of Return Guideline in December 2018.

Our Revised Regulatory Proposal is cognisant of this, adopting for now the positions reflected in the same *draft* 2018 Rate of Return Guideline the AER applied in its Draft Decision. The only exception to this is the return on debt transition, which – as explained in section 6.3 – we do not consider should apply to us, because we have either already effectively transitioned or because a transition is not required. We also expect the AER's Final Decision for us to reflect the final 2018 Rate of Return Guideline. We expect the final Guideline will enable the AER not to apply a transition to us in the 2019-24 regulatory control period.

Table 6.1 shows that we have adopted most of the AER's changes, except for the return on debt transition.

Table 6.1 – Response to AER's rate of return changes

Changes in AER's Draft Decision	Our response
The AER accepted our proposal to use the Sharpe-Lintner CAPM to estimate the return on equity, but: • reduced the MRP from 6.5% to 6.0%; • reduced equity beta from 0.7 to 0.6; • removed rounding on the estimated return on equity; and • updated for a later averaging period.	We have adopted the AER's updates, noting we expect the final 2018 Rate of Return Guideline to be applied. We have also updated the averaging period to the 20 business days between 6 and 31 August 2018 (inclusive).
The AER accepted using 10-year bond yield data published by third party data providers to estimate the return on debt, but: • included another third party (Reuters) along with the two that we had proposed (Bloomberg and RBA); • used a weighted average of BBB band and A band bond yield data, with weights 2/3 and 1/3 to get a BBB+ average; and • adopted a 10-year transition to a 10-year trailing average, starting in 2019-20.	We have adopted all of the AER's updates, except the transition (which we discuss in section 6.3 below). As with the return on equity, we expect the final 2018 Rate of Return Guideline will be used by the AER to determine the return on equity. We have also updated the average period for the prevailing return on debt observation to the 20 business days between 6 and 31 August 2018 (inclusive).
The AER accepted our proposal to use a nominal WACC formula to estimate the rate of return, with assumed leverage of 60%.	We have retained this formula with 60% leverage.
The AER accepted our proposal to use the geometric average of two years of RBA inflation forecast and eight years of 2.5% (being the mid-point of the RBA's inflation target range). The AER, however, updated forecast inflation to reflect the latest RBA statement on monetary policy.	We have retained this approach and updated it to reflect the RBA's August 2018 statement on monetary policy.
The AER accepted our proposed approaches for estimating debt and equity raising costs, with some minor updates to the parameters used (e.g. the assumed payout ratio was increased to 83%).	We have retained these approaches and adopted the updated parameters.

6.3 Return on debt transition

Return on debt transition is a key point of difference between us and the AER. Our Initial Regulatory Proposal[1] made clear we do not consider it appropriate to apply a transition to us because:

- our tariffs in the 2014-19 regulatory control period do *not* reflect an on-the-day approach to setting the return on debt allowance, unlike all other networks to which the AER applied a transition; and, rather,
- they better reflected a trailing average return on debt allowance when considered over the 2009-19 period.

This meant our customers benefited from a lower return on debt allowance over the 2014-19 regulatory control period and – importantly – we would not receive a windfall gain if a trailing average approach were used to set the return on debt over the 2019-24 regulatory control period. Our customers would not pay twice for high interest rates experienced in the post-global financial crisis (GFC) period.

The AER's Draft Decision did not engage directly with our justification for not applying a transition. However, since then, we have had constructive engagement with AER staff and the AER board.

Attachment PWCR01.5 explains how our proposal – not to apply a transition – *is* consistent with the legal and economic framework used by the AER to justify applying a transition to other networks. This rests heavily on the circumstances affecting our transition to the NT NER and the jurisdictional regime that applied to set tariffs over the 2019-24 regulatory control period.

The attachment also explains how our proposal can be given effect under the draft 2018 Rate of Return Guideline – which is important because it means that it can be applied automatically and in a way consistent with the return on debt decisions for other service providers.

We encourage the AER to make a pragmatic decision for the NT within the limits of its framework.

6.4 Updated estimates

Table 6.2 compares our Revised Regulatory Proposal rate of return estimate to that in the AER's Draft Decision and our Initial Regulatory Proposal.

[1] Refer to Attachment 1.10 of Initial Regulatory Proposal

Table 6.2 – Updated rate of return

%	Initial proposal	Draft decision	Revised proposal
Risk-free rate	2.44%	2.70%	2.59%
MRP	6.50%	6.00%	6.00%
Equity beta	0.7	0.6	0.6
Return on equity	7.00%	6.30%	6.19%
Credit rating	BBB+	BBB+	BBB+
Term	10 years	10 years	10 years
Return on debt method	Trailing average, no transition	Trailing average, with 10-year transition	Trailing average, no transition
Return on debt	6.37%	4.50%	6.00%
Gearing	60%	60%	60%
Forecast inflation	2.42%	2.45%	2.42%
Nominal vanilla WACC	**6.62%**	**5.22%**	**6.08%**

7. Estimated cost of corporate income tax

Key messages

- The AER's Draft Decision largely accepted the approaches and inputs we proposed to establish the opening tax asset base (TAB) as at 1 July 2019 and to forecast our estimated corporate income tax over the 2019-24 regulatory control period, including through revisions provided to the AER in response to questions it raised about our Initial Regulatory Proposal.
- The AER made changes to:
  - incorporate the value of work-in-progress capex as at 1 July 2014 into the TAB of the same date (which we incorporated into an amended version of the opening TAB);
  - as with the RAB, treat the written down value for the roll-in of corporate assets as at 30 June 2019 as a final year adjustment in the RFM, rather than as capex in the 2018-19 year;
  - update the remaining tax lives for 'Property', 'ICT and communications' and 'Plant and equipment' asset classes and the standard tax life for the 'Property' asset class;
  - update for changes it made to the other building blocks that are used to estimate taxable revenue and expenses; and
  - increase the assumed value of imputation credits (gamma) from 0.4 to 0.5, to reflect its draft 2018 Rate of Return Guideline.
- We have adopted these changes in this Revised Regulatory Proposal, updating where necessary for actual expenditure in 2017-18, revised expenditure forecasts for 2018-24, and changes to the other building blocks (discussed throughout this Revised Regulatory Proposal).
- Due to these updates, our revised opening TAB as at 1 July 2019 decreases to $922.9 million (Real $2018–19), from $972.5 million (Real $2018–19) in the Draft Decision. Our revised closing TAB as at 30 June 2024 decreases to $1,005.1 million (Real $2018–19), from $1,026.7 million (Real $2018–19) in the Draft Decision.
- Our forecast estimated corporate income tax over the 2019-24 regulatory control period increases to $20.6 million ($Nominal) in our Revised Regulatory Proposal up from $20.1 million ($Nominal) in the Draft Decision.

7.1 Draft Decision

Our Initial Regulatory Proposal used the AER's post-tax revenue model (PTRM) to calculate the estimated corporate income tax allowance over the 2019-24 regulatory control period. We estimated a TAB as at 30 June 2019 by first establishing a TAB as at 1 July 2014 using data from the tax asset register which we use to prepare our tax returns for the Australian Tax Office (ATO).

The AER accepted this approach in principle, but asked questions about how the TAB was established that led to it making changes. A key change was to incorporate the value of work in progress assets as at 1 July 2014 as part of transition from a pre-tax building block framework – as applied by the Utilities Commission – to a post-tax framework, as reflected in the PTRM.

The AER also updated some standard and remaining tax lives for a few asset classes.

7.2 Our response

As with opex, depreciation and the RAB, the AER engaged with us throughout its consideration of our Initial Regulatory Proposal on the estimated corporate income tax forecast – this is reflected in its Draft Decision. We appreciated the opportunity to clarify our proposal and to respond to questions raised.

As explained in Table 7.1, our Revised Regulatory Proposal adopts the changes made by the AER to the approaches and inputs included in our Initial Regulatory Proposal. The only updates made to the TAB and forecast estimated corporate income tax are to incorporate actual gross capital expenditure and asset disposals in 2017-18 and revised forecasts for 2018-24, as well as consequential changes to the other building blocks that affect estimated taxable revenue and expenses. The next section shows the impact of these updates.

Although we have adopted the approaches and inputs used in the Draft Decision to estimate corporate income tax, we note the AER is currently reviewing the way it does this as part of an industry-wide review. We are actively contributing to that review. We welcome the opportunity to engage further with the AER on how the outcomes from this review may affect how the corporate income tax allowance is determined for our 2019-24 regulatory control period.

For present purposes we simply note it will be important to consider how implementing any outcomes from that review may affect other aspects of the final determination. For instance, the draft findings paper notes that the AER is considering using the diminishing value approach to forecast tax depreciation. There may be logic to this for some networks.

However, we are mindful that the AER is intending to use our actual tax asset register to establish our opening TAB. Given that this register was established using the straight line method, it would be inappropriate to then depreciate the opening TAB using a diminishing value method as, under tax law, it is not possible for methods to be changed in that way for existing assets.

Table 7.1 – Response to AER TAB and estimated corporate income tax changes

AER changes	Our response
The AER largely accepted our proposed approach to establishing the opening TAB as at 1 July 2014, as amended in response to questions raised by the AER on our Initial Regulatory Proposal. The key amendment was to incorporate the value of work in progress capex as at 1 July 2014.	We have adopted the same opening TAB value and mapping to asset classes as per the Draft Decision. At the time of our Initial Regulatory Proposal, the ATO was assessing our re-lodged tax returns for 2014-15 and 2015-16, and in particular the re-build of our tax asset registers. The ATO has now finished that assessment and did not raise any concerns.
The AER also accepted our proposal to use the RFM to roll-forward the TAB from 1 July 2014 to 30 June 2019. Although the AER adopted – for the purposes of the Draft Decision – our inclusion of capital contributions in the TAB as part of that roll-forward, it noted that "in the past we have accepted a service provider's proposal to only include capital contributions in the TAB after the transition into the post-tax framework."[2]	We have continued to use the RFM to roll-forward the TAB. However, we amended it to exclude capital contributions incurred over the 2014-19 regulatory control period – consistent with past AER decisions – as part of our transition from a pre-tax to post-tax building blocks framework. We explain this further in section 7.3 below.
The AER accepted our proposal to roll-in corporate ICT, property and other assets into the TAB as at 30 June 2019 but treated it as a final year adjustment rather than capex in 2018-19.	We have adopted the treatment as a final year adjustment.
The AER also largely accepted our proposed approach to determining standard and remaining asset lives, except to adopt: • remaining tax asset lives of 18.3, 7.4 and 5.0 years for the 'Property', 'IT and communications' and 'Plant and equipment' asset classes respectively; and • a standard tax life of 40 years for the 'Property' asset class.	We have adopted updated remaining and standard lives.
The AER rejected our proposed value of gamma (0.4), and instead adopted the value in the draft 2018 rate of return guideline (0.5).	We have adopted a gamma of 0.5 and note this will be updated to reflect the value in the AER's final 2018 Rate of Return Guideline, which we expect the AER to publish in December 2018.

[2] AER, September 2018, Draft decision, Attachment 7, p. 16, footnote 30.

7.3 Treatment of capital contributions for tax purposes over 2014-19

As we explained in our Initial Regulatory Proposal, we are transitioning from a pre-tax building blocks framework applied by the Utilities Commission to a post-tax building blocks framework applied by the AER (in the PTRM). This meant we had to determine a TAB for the first time.

In past decisions, the AER had accepted that capital contributions received prior to the start of the regulatory control period should *not* be included in the TAB as part of that transition as:[3]

- capital contributions have not been included in the RAB historically;
- including capital contributions would create a shortfall, given that past contributions had not been indexed; and
- the tax assets received from capital contributions compensated for the corporate tax incurred from receiving them.

This rationale applies equally to us. We have therefore excluded capital contributions received over the 2019-24 regulatory control period from the TAB roll-forward in the RFM for this Revised Regulatory Proposal.

7.4 Updated forecasts

Table 7.2 and Table 7.3 compare our TAB and estimated cost of corporate income tax forecasts in this Revised Regulatory Proposal with those in the AER's Draft Decision and our Initial Regulatory Proposal.

Table 7.2 – Updated opening and closing TABs

$M, Real 2018-19	Opening TAB as at 1 July 2019	Closing TAB as at 30 June 2024	Change
Initial proposal	673.5	834.0	**160.5**
Draft decision	972.5	1,026.7	**54.3**
Revised proposal	922.9	1,005.1	**82.2**

[3] See, for instance, AER, November, ETSA Framework and Approach Paper, Final, p. 101.

Table 7.3 – Updated estimated cost of corporate income tax

$M, Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	8.2	7.9	7.4	6.9	7.1	**37.4**
Draft decision	3.9	4.0	4.1	4.1	4.1	**20.1**
Revised proposal	3.9	4.0	4.2	4.2	4.2	**20.6**

8. Incentive schemes

Key messages

We accept the AER's decision for our 2019-24 regulatory control period:

- not to apply the EBSS;
- to apply the CESS;
- not to apply the s-factor, or the national GSL, components of the STPIS; and
- to apply the DMIS and the DMIAM.

We accept the AER's Draft Decision in relation to each of its incentive schemes for our 2019-24 regulatory control period.

8.1 EBSS

In our Initial Regulatory Proposal, we proposed applying the EBSS in our 2019-24 regulatory control period because we believed our forecast opex was prudent and efficient.

In its Draft Decision, the AER assessed our historical opex was not prudent and efficient. It determined not to apply the EBSS in our 2019-24 regulatory control period, including because it considered:

- we will face strong continuous incentives to be efficient without an EBSS;
- an EBSS would not necessarily provide a continuous incentive for us to reduce our opex;
- applying an EBSS may not be in consumers' interests; and
- not having an EBSS will provide the best balance between the incentive to capitalise and expense expenditure, and to implement non-network options.

For the reasons set out in chapter 4, we do not accept the AER's assessment of our opex forecast and we have proposed an alternative forecast for our 2019-24 regulatory control period.

We nevertheless accept the AER's view that we will face strong continuous incentives for our future opex to be prudent and efficient without an EBSS. We therefore accept the AER's Draft Decision not to apply its EBSS in our 2019-24 regulatory control period.

8.2 CESS

In our Initial Regulatory Proposal, we proposed applying the CESS in our 2019-24 regulatory control period, consistent with the position in the AER's Framework and Approach (F&A) paper. The AER maintained its position in its Draft Decision.

We accept applying the CESS as set out in version 1 of the Capital Expenditure Incentive Guideline in our 2019–24 regulatory control period.

8.3 STPIS

In our Initial Regulatory Proposal, we proposed not applying the s-factor component of the STPIS, or the national GSL scheme, in our 2019-24 regulatory control period. The AER accepted this position in its Draft Decision:

- due to the unavailability of reliable historical data required for the s-factor component, although it indicated it would require relevant data to be collected within the 2019-24 regulatory control period so that targets could be set for the subsequent regulatory control period; and
- as a jurisdictional GSL scheme applies in the NT.

We accept the AER's Draft Decision not to apply its STPIS in our 2019-24 regulatory control period and will work with the AER to collect the required information within the period so that targets can be set for the subsequent regulatory control period.

We note that the NT GSL scheme will continue to apply in our 2019-24 regulatory control period.

8.4 DMIS and DMIAM

In our Initial Regulatory Proposal, we proposed applying both the DMIA and the DMIAM in our 2019-24 regulatory control period, consistent with the position in the AER's F&A paper. The AER maintained its position in its Draft Decision.

We accept applying the DMIA and the DMIAM, where the DMIAM would be based on a fixed allowance of $200,000 plus 0.075% of our Annual Revenue Requirement (ARR).

9. Pass through events

Key messages

Regulatory baseline and pass through

- Our Initial Regulatory Proposal was based on a pragmatic regulatory baseline of 1 July 2017 that was to be updated in this Revised Regulatory Proposal for changes to our regulatory obligations made in the period to 1 July 2018.
- There have been no material changes to our regulatory obligations and requirements in that period that have led to adjustments in our forecast costs from those submitted in our Initial Regulatory Proposal.
- Our expenditure forecasts are therefore based on applicable legislative and regulatory instruments *as in force* on 1 July 2018 (i.e. "the regulatory baseline"), provided their form, content and application from 1 July 2019 is certain.
- The phased transition from NT to national regulation is continuing. Significant further regulatory changes are still expected, but there remains uncertainty about their nature, likelihood and timing. That uncertainty is likely to continue into the 2019-24 regulatory control period, with material changes expected during that period.
- Where eligible, we will manage any increased costs for changes in our obligations above the regulatory baseline through pass through applications in the next regulatory control period.

Pass through events

- We accept the AER's Draft Decision in Attachment 14 Pass through events, September 2018.
- Our nominated pass through events for the purpose of clause 6.6.1(1a)(5) of the NT Rules are an insurance cap event, an insurer's credit risk event, a terrorism event, and a natural disaster event.
- We have amended the definition of a Terrorism Event as suggested by the AER and we seek approval accordingly.

9.1 Regulatory baseline

In our Initial Regulatory Proposal, we highlighted the challenges and importance of achieving a common understanding with the AER as to which regulatory obligations and requirements form the basis of our forecast expenditure, and the AER's determination. [4]

We noted the legislative and regulatory framework within which we operate is undergoing extensive changes. Importantly, the NT Government's strategy for the transition is a phased process that is intended to deliver bespoke instruments and differential rules suitable for the NT.[5]

Despite these challenges, we need a clear and agreed starting point, from which any future pass through application may be made by us and assessed by the AER.

In our Initial Regulatory Proposal, we adopted a pragmatic approach whereby our expenditure forecasts were based on applicable legislative and regulatory instruments as in force on 1 July 2017 (i.e. "the regulatory baseline").[6] We also undertook to update our expenditure forecasts in this Revised Regulatory Proposal for any further regulatory changes between 1 July 2017 and 30 June 2018.

The baseline instruments are set out in detail in Reset RIN Template 7.3. As noted in our Initial Regulatory Proposal, the baseline does not include NT NER obligations where notes within the rules stipulate the rules do not apply, or that application will be revisited in the future as part of the phased implementation of the rules in the NT.[7]

9.1.1 Changes to regulatory instruments between 1 July 2017 and 30 June 2018

The NT NER changed from Version No. 9 in force from 30 May 2017 to Version No. 24 in force at 1 July 2018.[8] However, those rule changes mainly reflect changes to underlying NER provisions that do not yet apply in the NT, rather than the transition of NT arrangements to the national framework. They have not materially affected our assumptions or forecast costs in delivering our network services.

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[4] See Power and Water, Regulatory Proposal 1 July 2019 to 30 June 2024, 16 March 2018, Chapter 4 and Attachment 1.3

[5] See Power and Water, Regulatory Proposal 1 July 2019 to 30 June 2024, 16 March 2018, section 4.3

[6] Note, Version 9 of the NT NER was in force at 1 July 2017 (not Version 19, as incorrectly typed on p.28 of our Initial Regulatory Proposal)

[7] The consequences of the transition uncertainty remain as set out in section 4.4 of our 16 March 2018 Regulatory Proposal.

[8] Note, there have been three subsequent changes, with Version 27 of the NT NER commencing on 5 October 2018.

There have been delays in the NT NER transition program and, as such, there have been no significant changes to NT regulatory instruments since the Initial Regulatory Proposal was submitted.

9.1.2 Continuing areas of uncertainty

The future application of significant areas of the NT NER remains unclear. The application of many provisions in the current NT NER is subject to being 'revisited as part of the phased implementation of the Rules in this jurisdiction'. These include six whole chapters, more than seven parts of chapters, 19 rules, as well as various clauses, schedules and individual paragraphs.

Box 9-1 – NT NER provisions expressed as being revisited – NT NER Version 24

The statement, "*The application of this [Chapter/Part/rule/clause/paragraph] will be revisited as part of the phased implementation of the Rules in this jurisdiction*" appears in relation to:

- Chapters 2, 2A, 3,4, 6A, 6B
- Parts of chapters: Part G of Chapter 5A; Parts J, K, L, M, N of Chapter 6; Part B of Chapter 8; large parts of Chapter 11
- Rules: 5.1, 5.2, 5.3, 5.3A, 5.4A, 5.6, 5.7, 5.8, 5.9, 5.14, 5.15, 5.16, 5.17, 5.18, 18A, 19, 20, 21, 22
- Clauses: 5.10.1, 5.10.3, 5.12.1(b)(3), 5.12.2, 5A.A.3, 5A.D.1(a)(7) and (b), 5A.D.1A
- Schedules: S5.1a, S5.1, S5.2, S5.3, S5.3a, S5.4, S5.4A, S5.4B, S5.5, S5.6
- Individual paragraphs e.g. S5.8 paragraphs (b)(5)(iii), (h) and (i); S5.9 paragraph (h)

Many other provisions are expressed as having no effect in this jurisdiction until the National Energy Retail Law is applied as a law of the NT. Those provisions are not included in our regulatory baseline.

Extensive work is continuing to identify practical and regulatory options and implications, to ensure final arrangements are fit-for-purpose and are appropriate for the NT. This work is expected to extend beyond 1 July 2019, and it will affect both the NT NER and other NT regulatory instruments.[9]

It is not prudent for us to assume the adoption of many of the 'revisited' provisions, or to pre-empt the nature of possible future changes, and include

[9] See our Initial Regulatory Proposal, Attachment 01.3 Changing Regulatory Obligations and Requirements applicable to Power and Water, 31 January 2018

associated cost estimates in our forecasts for the 2019-24 regulatory control period. Where there remains uncertainty about their nature, likelihood and timing, we have not included provisions in our assumptions and forecasts.

9.1.3 Implications of uncertainty

This uncertainty creates risks associated with future changes in our regulatory obligations and requirements. The appropriate way to address this regulatory change risk is to absorb the associated costs where manageable, or if the costs are material, to seek the AER's approval to pass them on through our regulated tariffs.

9.1.4 Matters that have become clearer

A review of both the Network and System Control Technical codes is currently underway to support generator connections, as the wholesale electricity market develops. The review is expected to be finalised prior to 1 July 2019, but has not been incorporated in the Regulatory Baseline.

9.2 Pass through events

9.2.1 Prescribed pass through events

The NT NER prescribe the following pass through events:

- a "local event", which relates to an insolvent retailer failing to pay us for our services before the National Energy Retail Law (NERL) applies in the NT[10];
- a "NT transitional regulatory change event", which relates to changes in our regulatory obligations or requirements between 1 July 2017 and 30 June 2019[11];
- a "regulatory change event", which relates to changes in our regulatory obligations or requirements during the next regulatory control period[12];
- a "service standard event", which relates to a legislated or administrative act or decision that changes the nature of, service standards for, or requirement to provide, our services in the next regulatory period[13];

[10] See clause 6.6.1(a1)(1AA) of the NT NER and regulation 10 of the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations.

[11] See clause 6.6.1(a1)(1AB) of the NT NER and regulation 10A of the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations.

[12] See clause 6.6.1(a1)(1) of the NT NER and the definition in Chapter 10 of the NT NER.

- a “tax change event”, which relates to a change in a tax or the imposition of a new, or removal of an existing, tax in the next regulatory period[14]; and
- a “retailer insolvency event”, which relates to an insolvent retailer failing to pay us for our services after the NERL applies in the NT.[15]

9.2.2 Nominated pass through events

The NT NER also allows us to nominate additional pass through events having regard for “nominated pass through event considerations”.[16] Our proposed nominated pass through events for the 2019-24 regulatory control period reflect the AER’s Draft Decision.[17] They are:

Table 9.1 – Nominated pass through events

Event	Definition
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 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.
Insurance Cap Event	An insurance cap event occurs if: (a) Power and Water Corporation makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy; (b) Power and Water Corporation incurs costs beyond the policy limit; and (c) the costs beyond the policy limit increase the costs to Power and Water Corporation in providing direct control 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

[13] See clause 6.6.1(a1)(2) of the NT NER and the definition in Chapter 10 of the NT NER

[14] See clause 6.6.1(a1)(3) of the NT NER and the definition in Chapter 10 of the NT NER.

[15] See clause 6.6.1(a1)(4) of the NT NER and the definition in Chapter 10 of the NT NER.

[16] See clause 6.5.10(a) and clause 6.6.1(a1)(5) of the NT NER and the definitions in Chapter 10 of the NT NER.

[17] AER, Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 14 Pass through events, September 2018, at p.14-7

Event	Definition
	control period in which Power and Water Corporation 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.
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) increases the costs to Power and Water Corporation in providing direct control services.
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.

9.2.3 Application to SCS and ACS

We propose that the pass through provisions for defined and nominated pass through events apply to both SCS and ACS, on the basis that the pass through provisions in the NT NER apply to direct control services, which includes both SCS and ACS. This is consistent with the AER’s decision for other distribution network service providers (DNSPs), where it has defined pass through events for direct control services.

Applying pass through provisions to both SCS and ACS will promote section 7(A)(2) of the NT National Electricity Law (NT NEL), which provides that we should be given a reasonable opportunity to be able to recover at least the efficient costs the operator incurs in providing direct control services and complying with regulatory obligations or requirements.

10. Annual revenue requirements, X-factors

Key messages

- Our proposed 'smoothed' revenue requirement (or maximum allowed revenue) for SCS over the 2019-24 regulatory control period is $863.5 million ($Nominal), which is $104.7 million ($nominal) higher than that in the AER's Draft Decision and $64.4 million ($Nominal) lower than that in our Initial Regulatory Proposal.
- We have adopted most of the positions in the Draft Decision. However, the two key drivers of the revenue increase (from the Draft Decision) are:
  - higher forecast operating expenditure due to higher base opex – discussed in chapter 4; and
  - a higher rate of return due to a higher return on debt – discussed in chapter 6.
- The revised proposal revenue requirement results in a 17.57% revenue reduction in 2019-20 and 3.92% increase in the four years after this, in real terms (i.e. ignoring inflation). The resulting price impacts are discussed in chapter 13.

10.1 Draft Decision

Our Initial Regulatory Proposal used the AER's PTRM to forecast smoothed revenues over the 2019-24 regulatory control period. The AER accepted this approach in its Draft Decision but updated many of the inputs used to apply it.

Those input updates are discussed in chapters 3, 4, 5, 6, and 7 and not repeated here.

10.2 Our response

Our Revised Regulatory Proposal also uses the AER's PTRM to forecast smoothed revenues. We have updated some inputs as discussed throughout this Revised Regulatory Proposal, including to reflect higher expenditure forecasts and the return on debt estimate.

The models (i.e. Excel workbooks) used to prepare our Revised Regulatory Proposal include an updated:

- SCS PTRM (Attachment PWCR04.1);
- ACS metering PTRM (Attachment PWCR04.2);
- SCS and ACS metering capex forecast model (Attachment PWCR04.7);
- SCS opex forecast model (Attachment PWCR04.4); and
- rate of return model (Attachment PWCR04.9).

10.3 Updated forecasts

Table 10.1 compares our Revised Regulatory Proposal revenue and X-factor forecasts to those in the Draft Decision and our Initial Regulatory Proposal.

Table 10.1 – Updated revenue and X-factor forecasts

$M, Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal						
Return on capital	64.5	69.4	72.6	77.4	79.8	**363.7**
Return of capital	24.6	29.4	31.5	35.8	39.7	**161.0**
Operating expenditure	67.6	70.2	73.0	75.7	78.4	**365.0**
Revenue adjustments	0.1	0.1	0.1	0.1	0.1	**0.4**
Net tax	8.2	7.9	7.4	6.9	7.1	**37.4**
Building blocks	165.0	177.1	184.6	195.9	205.0	**927.5**
Smoothed revenue	165.0	174.7	185.0	195.9	207.4	**927.9**
X-factors (revenue)	9.42%	-3.38%	-3.38%	-3.38%	-3.38%	**-4.63%**
Draft decision						
Return on capital	50.4	53.5	55.9	58.8	60.1	**278.8**
Return of capital	18.6	23.3	26.2	30.4	33.3	**131.8**
Operating expenditure	61.8	63.6	65.8	67.9	70.1	**329.2**
Revenue adjustments	0.0	0.1	0.1	0.1	0.1	**0.3**
Net tax	3.9	4.0	4.1	4.1	4.1	**20.1**
Building blocks	134.7	144.5	152.0	161.3	167.7	**760.3**
Smoothed revenue	141.2	146.3	151.6	157.0	162.7	**758.8**
X-factors (revenue)	23.34%	-1.12%	-1.12%	-1.12%	-1.12%	**17.92%**
Revised proposal						
Return on capital	58.8	63.2	66.2	69.8	71.6	**329.6**
Return of capital	18.7	23.7	26.8	31.1	34.2	**134.6**
Operating expenditure	70.4	72.7	75.5	78.2	81.1	**377.9**
Revenue adjustments	0.1	0.1	0.1	0.1	0.1	**0.4**

$M, Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Net tax	3.9	4.0	4.2	4.2	4.2	**20.6**
Building blocks	151.8	163.8	172.8	183.5	191.2	**863.0**
Smoothed revenue	151.8	161.6	172.0	183.1	194.9	**863.5**
X-factors (revenue)	17.57%	-3.92%	-3.92%	-3.92%	-3.92%	**0.17%**

11. ACS metering services

Key messages

- We welcome the AER's approval of our smart meter rollout on a new and replacement basis and proposed metering charges' structure.
- Our revised proposal addresses the concerns raised by the AER, which had prevented it approving our proposed metering charges in the Draft Decision.
- However, we don't accept the AER's Draft Decision to apply a return on debt transition. We maintain our position from our Initial Regulatory Proposal, for the same reasons we explain in section 6.3 for our SCS, and provide further justification for why we consider this appropriate in Attachment PWCR01.5.
- We also don't accept the AER's Draft Decision to apply a standard life for mechanical meter/electronic meter classes of 22.1 years and maintain our position from our Initial Regulatory Proposal that the standard asset life should be 15 years, having regard for AEMO and AER precedent.

11.1 Draft Decision

The AER's Draft Decision on our ACS metering services accepted many of the positions in our Initial Regulatory Proposal, including:

- our proposal, which itself reflected the AER's F&A paper, to classify our metering services as ACS and to apply a price cap control mechanism to them in the 2019-24 regulatory control period;
- our smart meter rollout on a new and replacement basis; and
- our proposed metering charges' structure for Type 1-6 metering services.

However, the AER:

- rejected some elements of our proposed metering RAB roll forward in the 2014-19 regulatory control period, including by allocating metering assets installed before 30 June 2019 to the mechanical meter/electronic meter classes, with a standard life of 22.1 years;
- required us to update some elements of how we undertake our capex cost benefit analysis;
- required us to adjust our customer numbers for AEMO's growth forecast;
- based its rate of return forecast on its draft 2018 Rate of Return Guideline;
- rejected our opex step change for Southern Region metering technical staff; and

- used DAE’s wage index to forecast the metering opex labour escalation.

11.2 Our response

Table 11.1 details our revised proposals for our ACS metering services in response to the changes that the AER made in its Draft Decision to our Initial Regulatory Proposal. We have largely adopted the AER’s changes. Most of our cost input updates reflect those we have also applied to our SCS services. There are two areas where we have not accepted the AER’s Draft Decision.

Firstly, we have adopted the parameter updates from the AER’s draft 2018 Rate of Return Guideline, noting that we expect the AER’s Final Decision (expected in April 2019) to reflect the final 2018 Rate of Return Guideline (expected in December 2018). We have also updated the market yields used to estimate the risk-free rate and return on debt to reflect a 20-business day sample averaging period from 6 to 31 August 2018 (inclusive). However, we have maintained our position from our Initial Regulatory Proposal not to apply a return on debt transition for our ACS metering services for the same reasons that we set out in section 6.3 for our SCS. We provide further justification for this position in Attachment PWCR01.5.

Secondly, we have not accepted the AER’s Draft Decision to apply a standard life for mechanical meter/electronic meter classes of 22.1 years, rather than the 15 years we proposed in our Initial Regulatory Proposal. Our proposal to use 15 years was based on a variety of precedent:

- the Australian Energy Market Commission (AEMC) accepted in its Power of Choice review that the life of a meter “tends to be around 15 years”[18];
- the AER’s Final Decision for Ergon Energy’s 2015-20 regulatory control period, in which it adopted a 15-year useful life for electronic meters. Ergon Energy experiences similar climacteric condition to ourselves[19]; and
- The AER’s Final Decision for United Energy’s 2016-20 regulatory control period, in which it also adopted a “standard asset lives of 15-years for metering assets and 7 years for communications, ICT and other metering assets”.[20.]

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[18] AEMC, “Final Report – Power of choice review – giving consumers options in the way they use electricity”, 30 November 2012, page 99

[19] AER, “Final Decision - Ergon Energy distribution determination 2015−16 to 2019−20, Attachment 16 − Alternative control services” October 2015, page 16-20

[20] AER, “Final Decision – United Energy distribution determination 2016 to 2020, Attachment 16 − Alternative control services” May 2016, page 16-20

We consider that, given this precedent, it is appropriate for the AER to apply a 15-year asset life to our ACS metering assets.

Table 11.1 – Our response to AER's ACS metering changes

Changes in AER's Draft Decision	Our response
Metering RAB roll forward in 2014-19 regulatory control period – the AER: • rejected our use of more detailed asset classes; • rejected our use of forecast depreciation; • allocated our metering assets installed before 30 June 2019 to the mechanical meter/electronic meter classes, with a standard life of 22.1 years.	We have: • accepted the AER's metering RFM and updated it with our 2017-18 actual metering capex; • accepted the AER's position that the new asset classes only start from 1 July 2019; • accepted the AER's use of actual depreciation over the 2014-19 regulatory control period (rather than the forecast depreciation that we used in our Initial Regulatory Proposal); and • rejected the AER's position to apply a standard life of 22.1 years, for the reasons discussed above.
Metering capex forecast – the AER accepted our capex forecast for the 2019-24 regulatory control period in our Initial Regulatory Proposal, subject to us updating the rate of return and inflation in our cost-benefit analysis, and adjusting customer numbers for AEMO's growth forecast.	We have retained our approved capex forecast and updated it for: • rate of return[21] and inflation[22] in our cost-benefit analysis; and • updated AEMO customer forecast[23]. Our Revised Regulatory Proposal rate of return is 6.08% and forecast inflation is 2.42%. These updates are consistent with the forecasts that we have used in other parts of this Revised Regulatory Proposal.
Metering RAB asset classes in 2019-24 regulatory control period – the AER accepted our proposal to the following asset classes in the PTRM for ACS metering services: • Mechanical Meters; • Electronic Meters; • Metering Communications; • Metering Dedicated CTs and VTs; • Metering Non Network Other; and • Metering Non Network ICT and	We have retained our use of these asset classes in the 2019-24 regulatory control period in the PTRM for ACS metering services, consistent with our Initial Regulatory Proposal.

[21] Explained in chapter 6.

[22] Explained in chapter 6.

[23] Explained in chapter 3.

Changes in AER's Draft Decision	Our response
Communications.	
Rate of return and gamma – the AER substituted our proposed rate of return and gamma with those based on its draft 2018 Rate of Return Guideline.	We have adopted the parameter updates from the AER's draft 2018 Rate of Return Guideline, noting that we expect the AER's Final Decision (expected in April 2019) to reflect the final 2018 Rate of Return Guideline (expected in December 2018). We updated the market yields used to estimate the risk-free rate and return on debt to reflect a 20-business day sample averaging period from 6 to 31 August (inclusive). However, as discussed in section 6.3, we have rejected the AER's Draft Decision to apply a return on debt transition. We maintain our position from our Initial Regulatory Proposal and provide further justification in Attachment PWCR01.5.
Metering base opex – the AER accepted our base opex forecast from our Initial Regulatory Proposal.	We have retained our approved base opex forecast and updated it for our actual 2017-18 RIN data.
Metering opex step changes – AER accepted approved two of the three positive step changes for new metering obligations, and approved our step change for metering savings arising from the smart meter rollout opex forecast. The rejected step change related to Southern Region metering technical staff.	We have accepted the AER position in relation to our metering opex step changes.
Metering opex labour escalation – the AER substitutes wage index forecasts using DAE's forecast instead of PWC's forecast.	Consistent with our opex forecast in section 4.4.2, we have updated our labour escalation forecast consistent with our SCS approach by adopting an average of a new forecast from BIS Oxford and the forecast prepared by DAE adopted by the AER.

Our Revised Regulatory Proposal for ACS metering services uses the AER's PTRM to forecast smoothed revenues. The models (i.e. Excel workbooks) used to prepare our Revised Regulatory Proposal include an updated:

- ACS metering PTRM (Attachment PWCR04.2);
- SCS and ACS metering capex forecast model (Attachment PWCR04.7); and
- rate of return model (Attachment PWCR04.9).

11.3 Updated forecasts

Table 11.2 compares our Revised Regulatory Proposal ACS metering revenue and X-factor forecasts to those in the Draft Decision and our Initial Regulatory Proposal.

Table 11.2 – Updated ACS metering revenue and X-factor forecasts

$M, Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal						
Return on capital	1.1	1.5	1.7	1.9	2.3	**8.5**
Return of capital	0.7	1.2	1.4	1.7	2.2	**7.3**
Operating expenditure	5.1	5.2	5.2	5.3	5.3	**26.1**
Revenue adjustments	-	-	-	-	-	**-**
Net tax	0.1	0.1	0.1	0.2	0.2	**0.7**
Building blocks	7.0	8.0	8.5	9.0	10.0	**42.5**
Smoothed revenue	7.0	7.7	8.4	9.3	10.1	**42.6**
X-factors (price)	0.00%	-6.98%	-6.98%	-6.98%	-6.98%	**-25.14%**
Draft decision						
Return on capital	0.9	1.2	1.4	1.5	1.9	**6.9**
Return of capital	0.6	0.9	1.0	1.2	1.6	**5.2**
Operating expenditure	4.8	4.9	5.0	5.1	5.2	**25.0**
Revenue adjustments	-	-	-	-	-	**-**
Net tax	-	-	-	-	-	**-**
Building blocks	6.2	7.0	7.4	7.8	8.7	**37.1**
Smoothed revenue	6.2	6.7	7.4	8.1	8.8	**37.2**
X-factors (price)	12.24%	-5.80%	-5.80%	-5.80%	-5.80%	**-11.64%**
Revised proposal						
Return on capital	0.9	1.3	1.5	1.6	2.1	**7.3**
Return of capital	0.5	0.9	1.2	1.4	1.9	**6.0**
Operating expenditure	5.6	5.6	5.7	5.7	5.8	**28.4**
Revenue adjustments	-	-	-	-	-	**-**
Net tax	-	-	-	-	-	**-**
Building blocks	7.0	7.8	8.3	8.8	9.8	**41.7**
Smoothed revenue	7.0	7.6	8.3	9.1	9.9	**41.8**
X-factors (price)	3.36%	-5.62%	-5.62%	-5.62%	-5.62%	**-17.98%**

12. ACS fee-based and quoted services

Key messages

- We have accepted the AER's Draft Decision and we have listened to our stakeholders by simplifying our fee structure further, and by increasing the cut-off time for same day reconnections from 3:00pm to 4:00pm. We have also substantially decreased our after-hours fee for reconnections.
- We are proposing to decrease our fee for reconnections and disconnections over time as we replace accumulation meters with smart meters.
- We have aligned the inputs to the RIN and SCS modelling where appropriate.

12.1 Overview

Our Initial Regulatory Proposal to the AER split our ACS into fee-based, quoted and metering service. These services, except metering services are, one-off, customer specific services.

This section focuses on fee-based and quoted services.

We have undertaken a study to estimate the cost of providing each service, which includes, direct labour, materials, vehicles, corporate overheads and network overheads. There is no profit provision included.

Our proposed fees in this Revised Regulatory Proposal reflect the resulting cost per service. The names and descriptions of our proposed fee-based and quoted services are detailed in chapter 5 of our TSS.

Our total revenue is estimated to be around $ 4.0 million (Real $2018-19) per annum for fee-based services and $2.3 million (Real $2018-19) per annum for quoted services.

12.2 Initial Regulatory Proposal

The major changes that we proposed in our Initial Regulatory Proposal from our current approach for fee-based and quoted services were:

- the inclusion of network safety services;
- the inclusion of planned interruption – customer request;
- the inclusion of training to third parties for network related access;
- moving normal connections and disconnection services from SCS to ACS. Note that connections and disconnections relating to non-payment are already an ACS; and

- the removal, consolidation and inclusion of certain new fees.

12.3 Stakeholder feedback and Draft Decision

Jacana Energy's submission stated that it receives consistent feedback from its customers about:

- the costs of reconnecting their electricity supply after hours;
- the fairness of the amount of the reconnection fee for after business hours connections; and
- why the reconnection fee is applied from 3:00pm, not 4:00pm.

Following stakeholder feedback, we requested the AER stay its Draft Decision on ACS so that we could further review and amend our proposed fees.

The AER's Draft Decision[24]:

- confirmed the classifications of services to be included as ACS and its application of price caps for ACS;
- stated that the changes reduce complexity and provide for a simplified fee structure;
- accepted the proposed service structures; and
- accepted our proposed quoted service labour rates in-principle, subject to correcting an inflation adjustment calculation error on the basis of our labour rates being within the benchmarking conducted by the AER's consultant, Marden Jacobs.

The AER's main concern regarding our Initial Regulatory Proposal related to the proposed level of the after-hours fee, which we proposed as $563 (Real $2018-19) in 2019-20[25]. The AER invited us to complete an holistic review of our fee-based and quoted services for inclusion in this Revised Regulatory Proposal.

12.4 Disconnection and Reconnections

Most disconnections and reconnections we undertake are scheduled, however, we do receive many priority requests (i.e. same day). Most priority

[24] AER, Draft Decision – Power and Water Corporation Distribution Determination 2019 to 2024. Attachment 15: Alternative Control Services, section 1.5, page 15-6

[25] Note all fees shown in this section exclude GST (unless otherwise stated).

requests for reconnections our metering team receives before 3:00pm are actioned the same day with no additional 'priority' charge.

We now propose that the 3:00pm same day cut-off be extended to 4:00pm. We expect that this would, under normal circumstances, give us sufficient time to reconnect customers the same day without triggering additional costs related to an after-hours call out. This addresses Jacana Energy's feedback. Requests we receive after 4:00pm for same day reconnection will incur an after-hours reconnection fee. We will amend our Standard Customer Connection Agreement to reflect this timing change.

While we will endeavour to provide an after-hours service, there may be circumstances where this is not possible or safe. In these circumstances, we would complete the service the next business day, and a standard reconnection charge would apply.

We have renamed this service in this Revised Regulatory Proposal from "after-hours call out" to "Reconnection – After Hours" to reflect the fee now solely relates to reconnections. As discussed below, we are proposing a new and separate, after-hours surcharge fee that will cover other circumstances where an ACS may be provided outside of business hours. Our proposed after-hours reconnection fee is $123 (Real $2018-19).

In our Initial Regulatory Proposal, we proposed having a different fee for reconnecting and disconnecting smart meters (remotely) and accumulation meters (physically), which would incentivise customers to switch to smart meters. We now propose retaining the current single fee arrangement.

This revised position is a result of us reviewing the actual incentive and control customers have over their choice of meter. Customers have limited choice over when their meter gets upgraded from an accumulation meter to a smart meter and the decision to move to smart meters relates to system-wide benefits. All customers should therefore benefit from the lower operational costs arising from smart meters. This Revised Regulatory Proposal supports this by calculating a charge based on the weighted forecast of manual and remote reconnections.

We estimate that as the ratio of smart meters increases across our fleet of meters the average cost of reconnecting and disconnecting will also decrease.

12.5 New Fees

We have undertaken an holistic review, which has identified several additional services that are either new market developments in the NT or have been overlooked in the Initial Regulatory Proposal. The new fees we have added in this Revised Regulatory Proposal are:

- a prepayment vending charge;

- a prepayment meter support charge;
- a prepayment meter software;
- a class 3 solar PV assessment; and
- an after-hours surcharge.

Our Revised Regulatory Proposal includes an after-hours surcharge of 125% for all services (other than reconnections) undertaken after-hours. This uplift reflects the additional labour costs we incur for staff working outside normal business hours. The surcharge relates to services provided after-hours during the working week. Any service required on weekends or public holidays will be a quoted service.

12.6 Variation in specific rates

Our current charge for the installation of minor apparatus is $502 (Real $2018-19). Generally, this service relates to the installation of poly-loggers. Our Initial Regulatory Proposal proposed a fee of around $76 (Real $2018-19), which is the cost of physically installing and removing the poly-loggers. However, there is a significant level of analysis that is undertaken to interpret the data collected. Accounting for these costs results in the charge being increased to $620 (Real $2018-19) in the Revised Regulatory Proposal.

12.7 Updates

Since our Initial Regulatory Proposal, we have updated our cost and volume inputs for our fee-based and quoted services.

Fee-based and quoted services in the Initial Regulatory Proposal were based on the 2017-18 labour rates. Our Revised Regulatory Proposal retains the 2017-18 labour rates and escalates them consistent with the AER-approved CAM using inflation and the BIS Oxford and DAE escalation rates.

The overheads apportioned to ACS in the Revised Regulatory Proposal are consistent with the AER-approved CAM. Our CAM provides that we allocate our indirect costs between our distribution services in the same proportion as we attribute our direct costs. This results in a network overhead rate of 14% of direct costs and a corporate overhead rate of 23% of direct costs. These overheads are added to direct costs to generate a total price for fee-based and quoted services.

The labour rates (including overheads) used for our quoted services remain within Marsden Jacobs' reasonable maximum rates.

The majority of fee-based volumes have been updated for new data reported in our response to the annual RIN for 2017-18. However, where we have expanded or included new services we have included our best estimates, for example disconnections and reconnections.

For quoted services, the information arising from the RIN's required additional modification to break the information into hours, which was undertaken based on total expenditure and labour rates.

12.8 Further engagement

Our proposed changes were presented to the CAC on 26 October 2018, who received them positively, especially the change in cut-off time for after-hours reconnections and the reduction in the after-hours reconnection fee.

On 8 November 2018, we held an energy stakeholder forum with retailers, and interested stakeholders to discuss our proposed SCS and ACS tariffs and implementation plans ahead of the proposed 1 July 2019 start date. At this forum, we consulted stakeholders on our proposed updated list of fee-based services and tested the definitions and eligibility arrangements. This process has allowed us to test and refine the service descriptions and eligibility requirements, and ensure the list is comprehensive and administratively simple to meet retailers' and customers' needs for the 2019-24 regulatory control period.

We have taken on board the suggested changes and, where they are not appropriate; have discussed them with the relevant retailers.

Table 12.1 overviews our response to the AER's Draft Decision on our fee-based and quoted services.

Table 12.1 – Response to AER ACS fee-based and quoted services' changes

Changes in AER's Draft Decision	Our response
The AER Board largely accepted our Initial Regulatory Proposal, but at our request rejected ACS fee-based charges so that we could submit reviewed and updated prices in our Revised Regulatory Proposal.	• Changed our after-hours cut-off from 3:00 pm to 4:00 pm for standard reconnections • Reviewed model to update inputs, and correct for escalation. • Reviewed service list to incorporate new prepayment meter services, class 3 solar PV assessments and after-hours' surcharge. • Review service descriptions proposed in our Initial Regulatory Proposal.

13. SCS and ACS metering indicative prices and bill impacts

Key messages

- We welcome the AER's Draft Decision that approved most of our proposed SCS pricing arrangements, including:
  - tariff classes and tariff assignment policy;
  - tariff structures for small customers (<750MWh pa);
  - tariff structures for large customers (>750MWh pa);
  - a 12pm to 9pm peak charging window for all customers and seasonal application to small customers; and
  - the method for estimating long run marginal cost (LRMC) and our approach to incorporating this into tariff design.
- Our Revised Regulatory Proposal addresses the AER's Draft Decision residual TSS concerns by:
  - updating our proposed unmetered supply tariffs to address local councils' feedback;
  - providing greater detail on the individually calculated tariff eligibility criteria and calculation approach; and
  - providing greater detail on how we will set tariffs annually in compliance with our approved TSS.
- The customer bill impacts of our proposed SCS tariffs are set out in Table 13.1.
- Our Revised Regulatory Proposal updates our proposed ACS for the outcomes of our holistic review of the fee-based and quoted services, corrects the labour rate escalation issue identified by the AER and updates cost inputs to align to our revised proposal for SCS and to reflect actual 2017-18 RIN data.

13.1 Draft Decision on SCS pricing

While the Draft Decision substantively approved the material aspects of our proposed tariff strategy, it rejected our proposed TSS, requiring that the revised TSS provide:

- our updated proposal for unmetered supply tariffs for infrastructure such as public lighting because we had foreshadowed revising these tariffs due to local councils' concerns regarding a possible impact on their energy efficient LED lighting and smart device roll outs, and due to expected NT NER chapter 7A changes; and
- greater detail on how we would apply the proposed provision for introducing individually calculated tariffs for very large customers, including the individually calculated tariff eligibility criteria and calculation approach; and

- greater detail on setting tariffs annually during the 2019-24 regulatory control period.

While not strictly a rule requirement (as acknowledged by the AER), the Draft Decision also requested we split our TSS into a short-form TSS and separate explanatory statement to address matters raised in the Draft Decision.

13.2 Our response on SCS pricing

13.2.1 Responding to AER feedback

We have carefully considered the residual SCS pricing and TSS issues the AER raised in its Draft Decision. In formulating this Revised Regulatory Proposal, we have had valuable discussions with AER staff to ensure we best meet the AER's remaining concerns.

Reflecting these discussions, we have split our revised TSS into a short-form TSS (Attachment PWCR01.8) and separate explanatory statement (Attachment PWCR01.9), where the explanatory statement only addresses the changes and further justifications responding to the Draft Decision.

Below we summarise our proposal for the three items requiring revision. Section 4.2 of our TSS explanatory statement (Attachment PWCR01.9) details these revisions and their reasoning.

13.2.2 Low Voltage <750MWh unmetered tariff

After further engaging with the Local Government Association of the Northern Territory (LGANT) and various local councils to identify their plans for upgrading unmetered connection points, we have:

- constructed a new more realistic forecast of unmetered energy use over the 2019-24 regulatory control period; and
- reviewed our pricing approach and propose to revert to retaining a kWh charge.

The NT NER Chapter 7A requirements for calculating Type 7 consumption are still unclear and as such we will continue engaging with the Department of Treasury and Finance to determine an appropriate calculation methodology prior to 1 July 2019.

13.2.3 Low voltage (LV) and high voltage (HV) individually calculated tariffs

Section 2.1 of our revised TSS now sets out the eligibility requirements for individually calculated tariffs in the LV >750MWh tariff class and HV tariff class. Chapter 4 of our revised TSS sets out our approach to calculating these tariffs. We summarise these arrangements below.

Tariff eligibility

In exceptional circumstances, we may offer an individually calculated tariff. This tariff may be made available to new HV or LV > 750MWh connection points or material alterations to existing HV or LV >750MWh connection points, where the conditions outlined below hold. It does not apply to existing HV or LV >750MWh connection points.

Any customer offered an individually calculated tariff can still opt for the relevant default tariff (i.e. either Tariff 5 or Tariff 6b depending the voltage at which they connect).

The circumstances in which we may offer the option of an individually calculated tariff are where the connecting or augmenting party's apparent power requirement is >2MVA, and one or more of the following exists:

- the impact of connection charges should be reflected in a dedicated tariff;
- material network support benefits can be captured and shared; and/or
- material uneconomic network bypass risk exists.

Tariff setting

We will adopt a tariff structure that has a demand charge and an access charge, and may include a usage charge where additional residual costs are to be recovered but cannot be recovered through the other charging parameters, whilst still adhering to the pricing principles.

When determining the tariff levels for each charging parameter we will:

- draw on the system-wide voltage level long-run marginal cost (LRMC) estimates and the more detailed locational cost data underpinning the incremental cost used in assessing connection;
- account for any connection contributions paid by the customer;
- account for circumstances whether the connection makes only limited use of our shared system; and
- consider the desirable connection, demand management, and revenue sufficiency outcome that best supports efficient connection and usage decisions by the customer.

13.2.4 Approach to setting annual tariffs

Chapter 4 of our revised TSS now sets out the annual tariff setting considerations, with which we will demonstrate compliance annually. These include:

- the relative residual cost recovery from different tariffs including disclosing relative allocations in percentage terms for all tariffs;
- how demand charges will be aligned to LRMC estimates over time, including how legacy tariffs without a demand charge recover an appropriate contribution to LRMC through translating LRMC from $/kVA/Year into an equivalent kWh proxy; and
- showing our estimates of standalone and avoidable cost.

13.3 Bill impacts of indicative prices

Table 13.1 details the indicative movement in a range of typical customers' network bills between 2018-19 and 2019-20.

Table 13.1 – Indicative movement in customers' network bills 2018-19 to 2019-20 (excluding GST)

Customer Type	Network Bill		Network Bill Movement	
	2018-19	2019-20	$	%
Small Residential Accumulation Meter (8,500 kWh pa)	1,093	875	**(219)**	(20%)
Small Residential Smart Meter (8,500 kWh pa)	1,093	957	**(71)**	(7%)
Large Residential Accumulation Meter (15,000 kWh pa)	1,808	1,319	**(489)**	(27%)
Large Residential Smart Meter (15,000 kWh pa)	1,808	1,381	**(427)**	(24%)
Non-Residential Accumulation Meter (38,000kWh pa)	3,407	3,425	**18**	1%
Non-Residential Smart Meter (38,000 kWh pa)	3,407	2,343	**(1,065)**	(31%)
Industrial (1,000,000 kWh pa)	79,075	78,855	**+2,033**	+2%
Large Industrial HV (8,000,000 kWh pa)	392,474	435,792	**(18,586)**	(6%)

+ Includes ACS Metering

Table 13.2 – Response to AER SCS and ACS metering indicative prices and bill impact changes

AER Position (Draft Determination)	Proposed PWC Response (RRP)
The AER rejected our proposed provision for introducing individually calculated tariffs pending further explanation of how these will be set.	We will provide more detailed dedicated tariff eligibility criteria and method for determining tariff levels (whilst adopting the same efficient tariff structure as existing large user tariffs (i.e. demand, access and flat use)).

14. Connection Policy

Key messages

- We have accepted the revisions to our draft Connection Policy that the AER included in its Draft Decision and have reflected them in the version of our Customer Connection Policy at Attachment PWCR03.4.

Our Connection Policy sets out the circumstances in which a retail customer or real estate developer must pay a connection charge, and how these charges are calculated, for the provision of new or modified connections from 1 July 2019.

Our Connection Policy will apply only to connection applicants for electrical installations in the local electricity systems as defined in Schedule 2 of the *National Electricity (Northern Territory) (National Uniform Legislation) Act*.

We submitted a draft Connection Policy with our Initial Regulatory Proposal.

We subsequently liaised with the AER about revisions to our draft Connection Policy to ensure that it meets the requirements of:

- clause 6.7A.1(a) of the NT NER;
- the connection charge principles in Part E of Chapter 5A of the NT NER; and
- the connection charge guidelines for electricity retail customers, published by the AER.

The revisions that we agreed with the AER were reflected in the version of the Connection Policy that it included in its Draft Decision.

We accept these revisions and have reflected them into the version of our Customer Connection Policy at Attachment PWCR03.4 that accompanies this Revised Regulatory Proposal. This version is the same as that which the AER included in its Draft Decision, with minor typographical corrections.

15. Confidentiality

Key messages

- We have addressed the requirements of the AER's Confidentiality Guideline for the matters for which we are claiming confidentiality.

We have completed a confidentiality template at Attachment PWCR01.3 of this Revised Regulatory Proposal that details the matters for which we are claiming confidentiality. The confidentiality template is consistent with the AER's Confidentiality Guideline.

The objective of the AER's Guideline is to ensure all stakeholders have access to sufficient information to enable them to understand and assess the substance of all issues affecting their interests. We strongly agree with the principles of accountability and transparency and have therefore sought to minimise our claims to confidentiality.

The AER's Confidentiality Guideline identifies the following confidentiality categories:

- **Information affecting the security of the network** - information which, if made public, may jeopardise security of the network or a NSP's ability to effectively plan and operate its network.
- **Market sensitive cost inputs** - information such as supplier prices, internal labour costs, and information which would affect the NSP's ability to obtain competitive prices in future infrastructure transactions, such as tender processes.
- **Market intelligence** - information which may provide an advantage to a NSP's competitors for non-regulated or contestable activities.
- **Strategic information** – information such as the acquisition of land and easements, where the release of this information might adversely impact the NSP's ability to negotiate a fair market price for these items.
- **Personal information** - information about an individual or customer whose identity is apparent or can reasonably be ascertained from the information which raises privacy considerations.
- **Other** - information which the NSP claims is confidential but does not fit into one of the above categories.

Our confidentiality template makes clear where our confidential information fits into one of these categories.

16. Abbreviations

Abbreviations	
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
ATO	Australian Taxation Office
CAC	Customer Advisory Council
CAM	Cost Allocation Method
Capex	Capital expenditure
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer price index
CT	Current transformer
DAE	Deloitte Access Economics
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
F&A paper	Framework and Approach paper
GFC	Global financial crisis
GSL	Guaranteed Service Level
HV	High voltage
ICT	Information and Communications Technology
Jacana	Jacana Energy
kVA	Kilovolt ampere
kWh	Kilowatt hour
LRMC	Long run marginal cost
LV	Low voltage
M	Millions
MRP	Market risk premium

Abbreviations	
MW	Megawatt
MWh	Megawatt Hour
NEL	National Electricity Law
NER (or Rules)	National Electricity Rules
NERL	National Energy Retail Law
NT	Northern Territory
NT GSL	Northern Territory Guaranteed Service Level
NT NEL	Northern Territory National Electricity Law
NT NER (or NT Rules)	Northern Territory National Electricity Rules
Opex	Operating Expenditure
p.a.	per annum
Power and Water	Power and Water Corporation
PTRM	The AER's Post-Tax Revenue Model
PV	Photovoltaic
PWC Act	Power and Water Corporation Act
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Repex	The AER's Repex model
RFM	The AER's Roll-Forward Model
RIN	Regulatory Information Notice
SCS	Standard Control Services
SME	Small Medium Enterprise
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TSS	Tariff Structure Statement
VT	Voltage Transformer
WACC	Weighted average cost of capital
XLPE cable	cross-linked polyethylene cable