Attachment PWCR03.1P

Revised Capex Overview Document

2019-20 to 2023-24

Contents

1. Purpose and structure of this document

The purpose of this document is to provide an overview of our revised capex forecast for standard control services (SCS). We demonstrate how we have addressed issues raised by our stakeholders and the AER. We also identify our revisions to incorporate updated connection data and labour escalators.

1.1 Structure

This document is structured as follows:

- Chapter 2 provides a summary of our revised forecast. We identify how we considered the AER's high level findings and the feedback from stakeholders when revising our capex forecast.
- Chapter 3 sets out how we have addressed the AER's draft findings on augmentation.
- Chapter 4 provides background on our revised connections policy and revised connection capex to address the AER's findings.
- Chapter 5 sets out how we have addressed the AER's draft findings on replacement capex.
- Chapter 6 sets out our revised non-network capex to address the AER's draft findings. This includes our revised Information and Communication Technology (ICT) program, and our property and fleet programs.
- Chapter 7 provides our revised forecast of capitalised overheads and forecast disposals.

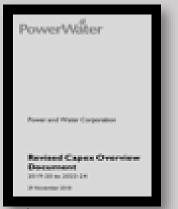
1.2 Supporting documents and models

Box 1 identifies the supporting documents for our revised capex including advice from external parties, and other quantitative data. The supporting documents relate to chapters in this revised overview document.

In each chapter, we explain the nature and purpose of the documents and models, and how they support our capex forecasts. Our confidentiality template provides details on what information has been made confidential.

Box 1 – Supporting attachments for revised capex

PWCR03.1: Revised capex overview document



Chapter 2 - Overview

- PWCR03.2: AEMO - Forecasting advice for the revised regulatory proposal

Chapter 3 – Augmentation capex

- PWCR03.3: Cutler Merz - Wishart Non-network and DM Investment Analysis

Chapter 4 – Connections capex

- PWCR03.4: Revised Customer Connection Policy

Chapter 5 – Replacement capex

- PWCR03.5: Berrimah replacement options - Economic Analysis
- PWCR03.6: Alice Springs poles quantitative analysais
- PWCR03.7: Darwin Suburbs cables replacement quantitative analysis

Chapter 6 – Non-network capex

- PWCR03.8: Hodgkinson - Proposed works to the PWC 19 Mile
- PWCR03.9: DIPL - Access issue with 19 Mile Depot

Supporting capex models and information

- PWCR01.7: BIS Oxford report on labour escalators
- PWCR04.7: SCS and ACS Metering Capex Model
- PWCR04.11: Connection Capex and Contribution Forecast Model

2. Overview of our revised capex forecast

This chapter provides a high-level overview of our revised capex. Unless otherwise stated all capex forecasts are expressed in real $2018-19.

We have revised our net capex forecast to $339.3 million, or on average $67.9 million per year.[1] This compares to our:

- Initial Regulatory Proposal capex of $384.2 million for net capex, or $76.8 million per year.
- The AER's Draft Decision capex of $316.4 million for net capex, or $63.3 million per year.

The key reason we have revised our forecasts is to address issues raised by our stakeholders and the AER in its draft decision. We have also amended our proposal to incorporate revised customer connections forecasts and labour escalators.

2.1 Overview of issues raised by stakeholders

Our stakeholders have provided feedback through the review process. We have reached out to stakeholders to discuss capex issues in greater detail through face to face meetings, telephone conferences and emails.

2.1.1 Consumer Challenge Panel (CCP)

The Consumer Challenge Panel (CCP) provided a detailed submission on all elements of our proposed capex including the following key issues:

- Regulatory Asset Base (RAB) – The CCP noted that our proposed capex will increase the real size of our RAB. The CCP was concerned about the implications of a high RAB on prices when interest rates rise in the future.
- Demand Forecasts – The CCP sought more information on our proposed demand forecasts that were prepared by AEMO. The CCP considered this may have influenced the level of augmentation capital including connections.

[1] Net capex includes equity raising costs but excludes capital contributions and asset disposals.

- Connections Policy - The CCP welcomed our proposed connections policy which it considered would avoid unnecessary increases in the RAB and inefficient cross-subsidies from all customers to new connections.

- Information and Communication Technology (ICT) – The CCP noted a significant increase in ICT capex over our historical level of expenditure, observing that we had not quantified the benefits.

- Replacement capex – The CCP noted that replacement capex is our largest expenditure category. It suggested that the AER should use its repex model and individual project assessments to guide its review. The CCP also observed that demand forecasts can influence replacement capital by providing opportunities for smaller capacity replacement or a non-network solution.

- Capitalisation Policy – The CCP noted concern with our approach to capitalising costs that were previously opex such as fleet and property leases. The CCP also observed more generally that there is great variation in the capitalisation of overheads between DNSPs.

In June 2018, we met with the CCP to discuss the details of their submission. We also met again in October 2018 to discuss our proposed responses we intended to incorporate in our Revised Regulatory Proposal. We found these meetings helpful in understanding key issues from the CCP's perspective and identifying how the feedback can be incorporated into our Revised Regulatory Proposal.

Our Revised Regulatory Proposal has changed to address some of the issues raised by the CCP including integration of updated AEMO customer connection forecasts. We have also amended our expenditure programs significantly with respect to augmentation, replacement, connections and ICT. In this document we set out in more detail how we have considered the CCP's feedback on specific issues. We look forward to continued engagement and dialogue with the CCP through the review process.

2.1.2 Anonymous submission

An anonymous party provided a submission on our Initial regulatory proposal, including issues that relate to our capex proposal. While we have not had the opportunity to meet with the anonymous party, we still considered the issues raised in the submission including:

- Capitalised leases – The anonymous party noted that while treating operating leases as capex is logical from an accounting point of view, it creates issues from a regulatory point of view by adding capex to the regulatory asset base.

- Capitalised overheads – The anonymous party noted that our approach to treating a fraction of indirect costs as capex does not provide a good incentive to minimise our overhead costs. The submission suggested that the capitalised overheads should be added back into the opex forecast, which is then subject to the usual assessment of prudency and efficiency by the AER.

- Short lived assets – The anonymous party noted that capex on short service-life assets such as vehicle, fleet and information technology should be subject to a higher degree of scrutiny due to the higher relative impact on customer prices.

- Demand and consumption forecasts – The anonymous party noted that there may be an over-estimation of forecasts because our AEMO forecasts did not consider higher vacancy rates in rental properties.

- Capex projects – The anonymous party made specific comments on individual capex projects and programs.

We note that the AER's Draft Decision considered the comments made by the anonymous submission including on approaches to capitalise lease costs and overheads. We also note that our Revised Regulatory Proposal has revised down our capex proposal in many of the areas identified by the anonymous submission.

2.1.3 Customer Advisory Council (CAC)

We met with our CAC in June 2018 to discuss feedback on our submission, and in October 2018 to discuss our initial direction on the Revised Regulatory Proposal. At a high level, the CAC was generally comfortable with our approach to revising our capex forecast. We directly sought the CAC's feedback on two revisions to our proposed capex:

- Alice Springs poles – The CAC noted that safety should continue to be our top priority. In this context, the CAC supported maintaining the Alice Springs program, and not adopting an approach which only targets poles in high density (non-rural) areas.

- 19 Mile project – The CAC supported upgrading road access to the 19 Mile Project based on safety considerations, but adopting a revised lower cost option.

We have incorporated the feedback of our CAC in revising our proposal, while also responding to the issues raised by the AER.

2.2 Overview of AER findings

We have had fruitful and constructive discussions with the AER on our proposed capex. This has provided us with clarity on key issues from the AER's perspective and allowed us to test and challenge our program.

2.2.1 General feedback

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

We have carefully considered the AER's concerns with our initial capex forecast and agree that there is opportunity to improve our asset management practices. Over time, we will be refining our approach by benchmarking our processes with industry best practice. For our Revised Regulatory Proposal, we have sought to undertake improved risk quantification on key projects. We have also sought to take on-board the AER suggestions if it resulted in a better outcome for our customers.

2.2.2 Specific feedback and draft decisions

The AER's substitute allowance was based on its findings for individual capex categories. The AER's decision is summarised below:

- Augmentation – The AER reduced our proposed capex from $60.6 million to $35.9 million. This reflected the AER's findings that our proposed construction of Wishart zone substation could be deferred through a demand management solution, and that we could reduce the scope of the proposed switchgear fault level replacement.
- Connections – The AER reduced our gross connections capex from $62.7 million to $61.6 million to reflect the AER's forecasts of lower labour escalation. The AER did not accept our proposed connection policy. As a result, it substituted lower capital contributions which had the effect of increasing our net capex by $12.6 million.
- Replacement – The AER reduced our proposed capex from $148.6 million to $129.0 million. The AER noted that its 'repex model' forecast differed from our forecast for transformers, poles and underground cables. Its

detailed review found that capex for Berrimah zone substation, the Alice Springs poles program and Darwin Suburbs XLPE program should be reduced.

- Non-network – The AER reduced our ICT capex from $37.5 million to $25.7 million. The AER noted that our proposed ICT program was significantly higher than historical expenditure, and that its substitute allowance provides capacity to efficiently deliver the program. The AER also reduced other non-network capex from $69.4 million to $54.8 million. This was to address an error in the calculation of property and fleet leases, and because it rejected capex for our proposed 19 Mile Depot project.
- Capitalised overheads and forecast disposals - The AER reduced our capitalised overheads from $66.9 million to $58.4 million to correct an error in the base year calculation and a reduced rate of change calculation. The AER also increased our forecast disposals from $0 to $0.8 million in line with the AER's calculation of average historical level of asset disposals.

We have reviewed the AER's Draft Decision for each category. Our Revised Regulatory Proposal has taken into account the AER's reasons and requests for additional information.

2.3 Updated information

The AER has sought updated data and information on changes that have occurred since submitting our Initial Regulatory Proposal. We discuss key updates in the sections below.

2.3.1 Customer and demand forecasts

In response to feedback from our stakeholders, we engaged AEMO to provide an update of system demand, energy, and customer connection forecasts in our Initial Regulatory Proposal. We also asked AEMO to consider the issues raised by stakeholders on our demand forecasts.

AEMO advised that the Darwin-Katherine connection numbers have been revised upwards, reflecting revisions to AEMO's methodology . The forecasts for Alice Springs and Tennant Creek are lower than the previous AEMO forecast reflecting declining population projections. Overall connection number forecasts have increased due to the higher number of customers in the Darwin-Katherine region.

We have made a downward revision to connections capex based on updating our connections model for 2017-18 actual data. Gifted assets and unit costs were lower in 2017-18, resulting in lower connection capex forecasts.

AEMO concluded that maximum demand and energy forecasts do not need updating. Its assessment of the impacts of updating driver variables indicated that changes to demand and energy consumption would be immaterial and within historical variability for our network.

The CCP and AER have sought further information on the impact of the NT Government's announcement of a Roadmap to Renewables which aspired to a 50 per cent target for renewables by 2030. We requested AEMO to address this specific issue when providing us its advice.

AEMO noted that at this stage the most likely pathway to increasing renewable generation in a large way is through large-scale solar farms. It noted that this type of generation is considered a generation source rather than behind-the-meter generation. On this basis, AEMO found that the current forecast of rooftop PV is expected to increase in line with current trends. AEMO's full report is Attachment PWCR03.2.

2.3.2 Undergrounding of Darwin suburbs

On 27 April 2018, the NT Government announced a long-term program to recommence undergrounding power lines in Darwin suburbs.

During the review process, we notified the AER that the announcement may have a potential impact on our expenditure and revenue in the 2019-24 regulatory control period. The expectation is that the Government would fund the undergrounding program, rather than the program being funded through the capex allowance. We advised the AER that we did not have sufficient information to identify the materiality of the Government's announcement on our proposed capex and opex programs.

The AER's Draft Decision noted that it expects us to address this issue in our Revised Regulatory Proposal should we receive information showing the impact on our proposed capex (or opex) in the 2019-24 regulatory control period.

At this stage, we have no information before us that can help identify the impact on proposed capex or opex in the 2019-24 regulatory control period. The key information we would require are the suburbs or locations in Darwin that the Government intends to target its undergrounding program. We note however that the undergrounding of lines in Darwin is not expected to have a material impact on reducing capex or opex in the 2019-24 regulatory control period. We will advise the AER and stakeholders if we receive any new information before the AER's that helps us determine the impact on our capex or opex program from the Government's undergrounding program.

2.3.3 Labour escalation

In our Initial Regulatory Proposal, we applied labour escalators to capex and opex on a consistent basis. Our method assigned the AER's preferred weightings for labour and non-labour based on the AER's November 2017 annual benchmarking report.

We then applied the AER's preferred forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (i.e. the utilities' industry) as the forecast change in the labour price. Specifically, we used the average of the utilities' WPI growth forecasts from Deloitte Access Economics and BIS Shrapnel adopted in recent AER decisions. Finally, we applied a zero rate of change for the non-labour component consistent with the AER's Final Decision for the Victorian distribution networks in May 2016.

The AER did not accept Power and Water's forecast real labour cost escalators. It revised those estimates in line with its opex decision. The AER's method used the most up-to-date WPI for the Northern Territory utilities industry forecast by Deloitte Access Economics. This had a consequential impact on all categories of forecast capex.

For the Revised Regulatory Proposal, we engaged BIS Shrapnel to provide advice on the most current WPI growth forecasts. We have then used the midpoint between the updated BIS Shrapnel forecasts and the Deloitte Access Economics forecasts used in the AER's Draft Decision. We consider that this approach is consistent with previous AER decisions and incorporates the most current forecasts.

The revised data and methodology has decreased the impact of labour escalators on our proposed capex from $8.9 million to $3.0 million. This is $0.9 million more than the AER's Draft Decision of $2.1 million. The revised labour escalators have also been reflected in our opex forecasts as discussed in our Revised Regulatory Proposal.

2.4 Our revised capex forecast

Our revised capex program has carefully considered the constructive feedback in the AER's Draft Decision. 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.

Table 2.1 shows that our revised net capex of $339.3 million is $44.9 million lower than our Initial Regulatory proposal. Table 2.1 details our capex forecast for our 2019-24 regulatory control period by capex category.

Table 2.1 – Capex forecast ($M, Real 2018-19, SCS)

$M, Real 2018-19	Initial Regulatory Proposal	AER Draft Decision	Revised Regulatory Proposal
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]	1.2	0.7	0.9
Total gross capex	**446.9**	**366.2**	**386.7**
Less capital contributions	(62.7)	(49.0)	(46.6)
Less disposals	-	(0.8)	(0.8)
Total net capex	**384.2**	**316.4**	**339.3**

[1]We discuss revisions to our equity raising costs in Chapter 6 of our Revised Regulatory Proposal document.

Key revisions we have made include:

- Augmentation capex – We have fully accepted the AER's findings to use demand management to defer the timing of our Wishart zone substation capex. We have also accepted the AER's findings on our fault level replacement program. Chapter 3 provides more information.

- Connections capex – We have revised down our proposed gross connections capex to reflect updated AEMO's customer connections forecasts. We have also revised down our capital contributions to reflect changes in our Customer Connection Policy. Chapter 4 provides more details.

- Replacement capex – We have revised down parts of our proposed capex to respond to issues raised by the AER. This includes reducing capex for Alice Springs poles and Darwin Suburbs cables. We have maintained our initial capex forecast for replacing Berrimah zone substation. Chapter 5 provides further information.

- Non-network capex – We have revised down our ICT program and forecast expenditure on the 19 Mile depot project. We have also accepted the AER's findings on property and fleet leases. Chapter 6 provides more detail.

- Capitalised overheads and forecast disposals – We have revised down our capitalised overheads and increased our forecast of disposals. This is discussed in Chapter 7.

3. Augmentation capex

This chapter explains the revisions to our proposed augmentation capex for the 2019-24 regulatory control period. Augmentation capex is required to manage network capacity constraints in our network due to growth in maximum demand. We also incur augmentation capex to comply with power quality and performance consistent with our regulatory obligations.

3.1 Overview of our revised augmentation capex

We have revised our proposed augmentation capex from $60.6 to $35.8 million. Table 3.1 shows we have accepted the AER's findings but adjusted our expenditure profile and also included revised labour escalators.

Table 3.1 – 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**

In our Initial Regulatory Proposal, we noted that the key driver of augex in the 2019-24 regulatory control period is growth in maximum demand in localised areas which lead to capacity constraints. Based on AEMO forecasts we have targeted projects in Wishart and Archer where we forecast growth in large customer connections. We also identified projects to address compliance with our planning standards and a program to target worst performing feeders.

As discussed in section 2.1, the CCP and the anonymous submission raised concerns on the AEMO demand forecasts. The CCP asked us to update our demand forecasts to account for more recent data such as population and economic growth. The anonymous submission noted the inter-relationship between the Wishart zone substation and other key projects such as the replacement of the Berrimah zone substation.

The AER's Draft Decision reduced our proposed capex from $60.6 million to $35.9 million. The AER included the majority of our proposed augex projects and programs in its augex forecast. However, the AER substituted a lower amount of capex for the Wishart zone substation and the Darwin switchgear fault level replacement project.

The AER noted that forecast load-driven capex is relatively low compared to our historical levels of augex, and this appears consistent with the drivers of capex in this category. The AER noted that this reflects AEMO's forecast of flat or declining overall peak demand on our electricity network, but with growth in demand in some localised areas over the 2019-24 regulatory control period.

For the most part, the AER has accepted our proposed programs having regard to stakeholder submissions. Our revised augex program has carefully considered the AER's findings on Wishart zone substation and the fault level replacement project. As discussed in sections 3.2 and 3.3 we have largely accepted the AER's findings on these projects subject to minor adjustments and the application of our updated labour escalators.

We have also considered how we could address the issues raised by the CCP on our demand forecasts. As discussed in section 2.4.1, we asked AEMO to review its demand forecasts in light of updated information. AEMO's analysis indicated the changes in inputs would not materially impact energy or demand at the system level. We note that we have incorporated updated information on local demand, spot loads and embedded generation in the Wishart and Berrimah areas to guide our revised capex. This is discussed in section 3.2 below.

3.2 Wishart zone substation

We have revised our proposed augmentation capex for the Wishart zone substation from [redacted] to [redacted] ($2018-19). We have largely accepted the AER's Draft Decision but made adjustments to timing and costs to reflect our revised non-network solution, and to incorporate updated labour escalators. Table 3.2 provides more details. We have also included an amount of [redacted] ($2018-19) in our opex forecast for the 2019-24 regulatory control period associated with our non-network solution.

Table 3.2 – Wishart zone substation capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	[redacted]					
AER Draft						
RRP						

In our Initial Regulatory Proposal, we had forecast [redacted] to construct Wishart zone substation to meet increased load from commercial customers and industrial estates in the Berrimah and Wishart areas.

From 2015, we had used a mobile 'NOMAD' substation at Wishart to support load if a transformer failed at Berrimah zone substation. In our Initial Regulatory Proposal, we noted that AEMO's demand forecast showed significant growth over the 2019-24 regulatory control period for the Wishart and East Arm areas.

We showed that without additional transformer capacity in the area, there was insufficient firm capacity to meet forecast load growth when Berrimah zone substation is replaced with a lower capacity substation. We had proposed constructing a permanent Wishart zone substation by 2024 to follow the commissioning of the replacement Berrimah zone substation.

In its Draft Decision, the AER considered we had not demonstrated the need to construct the Wishart zone substation in the 2019-24 regulatory control period. The AER's findings were based on the following factors:

- There is uncertainty in our load growth for the Berrimah and Wishart areas, particularly regarding the timing of spot loads.
- The AER's Draft Decision for Berrimah zone substation (see section 5.3 of this overview) provided an alternative repex solution which maintains the existing capacity at Berrimah. In the AER's view this was likely to reduce or defer the potential need for augmentation at Wishart.
- We had not fully considered the potential for non-network or demand management options to defer or avoid the proposed augmentation at Wishart.

The AER noted a report prepared by our consultant (CutlerMerz) submitted after our Initial Regulatory Proposal which identified a potentially viable and lower cost non-network solution to address potential constraints in the Berrimah and Wishart areas. Based on this report, the AER's Draft Decision provided capex of [redacted] ($2018-19) to pursue an appropriately sized non-network solution to address capacity constraints in the later years of the 2019-24 regulatory control period.

In revising our proposal we have considered the additional analysis and constructive solutions put forward by the AER in its Draft Decision. We accept the AER's view that there is uncertainty about the timing and magnitude of spot loads, and that non-network solutions may mitigate the reliability and security risks from insufficient firm capacity. We engaged CutlerMerz to provide us with advice on viable non-network solutions. Their approach was to:

- Revise and review demand forecast in the area including analysis of scenarios for base load, committed load, uncommitted load, and embedded generation. The purpose was to provide a current view of the load at risk. A key assumption was that our proposed replacement scope for Berrimah zone substation would maintain existing capacity at the site (see section 5.3 of this overview) which reduces the load at risk.
- Review the potential non-network and demand management solutions that may address capacity constraints.

- Undertake an options study to compare the net present costs of viable non-network and demand management solutions and the construction of the Wishart zone substation.

CutlerMerz found that back up generation presented a viable non-network solution to address load at risk. The proposed solution would be to install two 1.2 MVA generators in 2019-20 and a third generator in 2023-24. This would also involve minor opex costs such as inspections of the generators. CutlerMerz found that this option had marginally lower net present costs than constructing Wishart zone substation.

A key reason for installing generators in 2019-20 is to address our current non-compliance with the network planning criteria. There is currently no supply redundancy for the load supplied from Wishart substation.

CutlerMerz's analysis validates the AER's view that a non-network solution is a lower cost solution to address emerging capacity constraints in the Wishart and Berrimah areas. We have revised our capex and opex for the 2019-24 regulatory control period to reflect the costings in the CutlerMerz memo to us. The memo is at Attachment PWCR3.3.

3.3 Substation fault level replacement program

We have revised our proposed augmentation capex for the Darwin distribution substation fault level replacement program from [redacted] to [redacted]. We have largely accepted the AER's Draft Decision but have made a minor amendment to reflect our updated labour escalators. Table 3.3 provides more details.

Table 3.3 – Substation fault level replacement program capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	[redacted]					
AER Draft						
RRP						

In our Initial Regulatory Proposal, we forecast [redacted] to upgrade 34 units of switchgear in our Darwin region. The project was to address issues with switchgear that no longer meet or are approaching minimum system fault levels. We noted that three phase fault levels had increased over time with additional generation and transformation capacity. We had identified that there were significant safety consequences associated with failing switchgear, including explosions that could harm our field crew and the public. The risks are exacerbated when switchgear is operated close to or above equipment ratings.

The AER found that some level of proactive replacement is required to target high risk switchgear units in the 2019-24 regulatory control period. It noted evidence we had provided which demonstrated that 27 switchgear units are currently at, or exceeding, equipment ratings.

However, the AER considered we had not provided adequate evidence to suggest fault levels will continue to rise in the Darwin CBD in the 2019-24 regulatory control period such that the other equipment will exceed their ratings. The AER's substitute forecast capex reduces the program from 34 to 27 unit replacements to address only the switchgear that are at or exceeding equipment ratings.

We have accepted the AER's findings. We agree that the 27 switchgear should be replaced as a priority.

The evidence we provided the AER demonstrated there are an additional 12 units that are within 5 per cent of equipment fault levels. We are concerned that some of these units will be exposed to increased fault levels in the 2019-24 regulatory control period, and that this increases the risk of explosive failure. However, we have not been able to adequately quantify the expected increase in fault levels over the 2019-24 regulatory control period.

For this reason, we have accepted the AER's approach to only provide the minimum capex to address known issues at this time. We will continue to monitor the condition of the assets to manage the risks. This may result in us spending above the capex allowance to ensure the safety of our field crews and the public.

4. Connections capex and capital contributions

This chapter explains the revisions to our proposed connection capex and customer connection policy for the 2019-24 regulatory control period. Connections capex is required to service new, altered or upgraded connections for residential, commercial and industrial customers.

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

Cash contributions relate to the amount we recover directly from the connecting customer when we undertake connection works on their behalf. Net connection capex is the amount funded by existing customers through the capex allowance. Our AER approved Customer Connection Policy determines when a customer makes a cash contribution or when connection capex is funded through the capex allowance.

The gifted assets and cash contributions (termed “capital contributions”) are deducted from gross capex to calculate net capex for the 2019-24 regulatory control period.

4.1 Overview of revised connections capex

We have revised our proposed gross connection capex and our capital contributions as set out in sections 4.2 and 4.3.

In our Initial Regulatory Proposal we forecast our gross connections capex by developing a unit cost per connection type based on our 2016-17 aggregate cost per connection type divided by the number of connections per customer type. We then considered the annual volumes per connection type based on AEMO’s forecast. We separately developed a forecast for gifted assets as historical data showed there is not a close correlation between gifted assets and connections capex.

We also submitted a Customer Connection Policy to apply for the 2019-24 regulatory control period. The policy sought to fully recover our costs of connection works from the connecting party. The implication was that existing customers would not fund the costs of connection, and that there would be no capex funded through the AER’s capex allowance.

The CCP and the anonymous submission raised issues with our customer connection volumes. In particular, the CCP asked whether we would update the forecasts for more recent population and economic growth forecasts. The CCP welcomed our proposed Customer Connections Policy which it considered would avoid unnecessary increases in the RAB and inefficient cross-subsidies from all customers to new connections.

The AER reduced our proposed (gross) connections capex from $62.7 million to $61.6 million. The only adjustment related to applying labour escalators consistent with its Draft Decision.

The AER found that our forecast connections volumes appear reasonable and unbiased. In particular, it noted that customer connections are consistent with the Housing Industry Association's independent forecast of new housing in NT. The AER noted the reliance of the forecasting methodology on underlying macroeconomic drivers. It requested that we seek updated customer connections forecasts that address the issues raised by stakeholders.

The AER reduced our capital contributions from $62.7 million to $49.0 million. The AER noted that our proposed Customer Connection Policy connection charging policy was inconsistent with the classification of connection services as SCS. During the review process, the AER asked us to provide a draft revised Customer Connection Policy that was consistent with the classification of services, together with an estimate of capital contributions under the draft revised policy. The AER used this information as the basis for its substitute estimate.

We have been mindful of the issues raised by our stakeholders on customer connection forecasts. We engaged AEMO to provide revised connection forecasts that address the issues the raised by our stakeholders.

We have also listened to the feedback of the AER on our proposed Customer Connection Policy. While the CCP were supportive of our proposed policy, we recognise the AER's view that the policy is inconsistent with the AER's service classification. We have therefore revised our Customer Connection Policy to ensure we are compliant. This has led to a downward revision in our capital contributions as discussed in Section 4.3 below.

4.2 Gross connections capex

We have revised our proposed gross connection capex from $62.7 million to $55.5 million ($2018-19) as seen in Table 4.1. This is $6.1 million less than the AER's Draft Decision of $61.6 million ($2018-19).

Table 4.1 – Gross connections

$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**

The key reason for revising our gross connections capex is to ensure the underlying inputs reflect the most up to date information. In September 2018, we engaged AEMO to update customer connection forecasts and to address issues raised by stakeholders. We also updated our connections model to incorporate most recent connection volumes and expenditure for 2017-18.

AEMO advised that the Darwin-Katherine connection numbers have been revised upwards, reflecting revisions to the connections model. The forecasts for Alice Springs and Tennant Creek are lower than the 2017 forecast reflecting a decline in population projections. AEMO advised that customer numbers are projected to increase overall relative to the advice provided for our Initial Regulatory Proposal.

However, we have revised our proposed connections capex to incorporate most recent data for 2017-18. There are three drivers of our lower connections capex:

- Gifted assets reduced in 2017-18. Gifted assets are a key driver of connections capex.
- Unit cost per connection fell in 2017-18 which has also reduced connections capex.
- The mix of customer connection segments changed in 2017-18. This was due to a reduction in large commercial and industrial customers in 2017-18, following a change in our categorisation of customers.

4.3 Capital contributions

We have revised our capital contributions from $62.7 million to $46.6 million. This is $2.4 million less than the AER's Draft Decision of $49.0 million as shown in Table 4.2. This is due to revisions to our Customer Connection Policy to address the AER feedback. The implication is that $8.9 million will be funded by existing customers through the net capex allowance compared to zero in our Initial Regulatory Proposal.

Table 4.2 – Capital contributions

$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**

The Customer Connections Policy we submitted in our Initial Regulatory Proposal required customers to fully pay for their connection costs, meaning that 100 per cent of gross connections were to be funded by capital contributions.

The AER found our Customer Connection 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 in net capex, and $49.0 million for capital contributions.

We have revised our Customer Connections Policy at Attachment 3.4 to address the AER's findings. The revised policy adopts the "incremental revenue less incremental cost test" when determining connection charges. Based on the new policy, capital contributions will comprise a smaller element of gross connections, with existing customers funding a greater proportion of capital works through the net capex allowance.

5. Replacement capex

This chapter explains the revisions to our proposed replacement capex for the 2019-24 regulatory control period. Replacement capex is required to replace or refurbish our existing assets and is typically driven by asset condition and related risks including technical obsolescence.

5.1 Overview of revised replacement capex

We have revised our r capex from $148.6 million to $141.0 million ($2018-19) for the 2019-24 regulatory control period. Our revised proposal for replacement expenditure is $12.0 million more than the AER’s Draft Decision of $129.0 million ($2018-19) as seen in Table 5.1 below.

Table 5.1 – Replacement capex

$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**

In our Initial Regulatory Proposal, we noted the key driver of the proposed replacement program was to address risks with condition issues with assets on our network. We also identified replacement programs to meet our compliance obligations under the Network Technical Code and Network Planning Criteria. In addition, we proposed replacement projects to meet a reliability and power quality obligation or technical standard.

We noted that our proposed replacement program would be less than the 2014-19 regulatory control period. In part, this reflected the maturing of our asset management and risk management approaches. This has helped us to respond to emerging risks as well as to ensure positive customer outcomes.

We engaged Nuttall Consulting to benchmark our proposed replacement capex with the “repex model” used by the AER in regulatory determinations. Nuttall Consulting assessed approximately $100 million (69 per cent) of our repex forecast using the Repex Model. Based on three studies, Nuttall Consulting found that applying the AER’s repex model results in replacement forecast between 27 and 48 per cent higher than our proposed repex forecast for modelled categories.

The CCP noted that replacement is our largest capex category. It noted that demand forecasts can also influence replacement capital. For instance, it noted that lower demand could provide alternatives to “like for like” replacement such as a smaller capacity replacement or a non-network solution. The submission by an anonymous party provided detailed comments on a series of our proposed replacement projects. A general theme of the feedback was that many capital projects are inter-related and that it would seem reasonable to consider combined and optimised solutions.

The AER's Draft Decision reduced our proposed replacement capex from $148.6 million to $129.0 million ($2018-19).

The AER observed that overall our proposal for replacement reflected a reasonable understanding of the specific needs of our business. It also noted that our modelling demonstrated a broad understanding of some of the principles of cost benefit analysis. However, it identified a number of issues in our forecasting approach including:

- Overestimation of replacement volumes in our bottom-up forecasts for a sample of projects it assessed. The AER considered this was a consequence of an overly conservative and risk-averse approach.
- A subjective approach to risk assessment which does not account for joint probability, inconsistent with good industry practice.
- A degree of subjectivity where there is in-built conservatism attached to our project costing forecasts.

In coming to its position, the AER was informed by the results of its predictive 'repex model'. The AER considered that the model showed our forecast replacement capex for modelled categories was higher than the predictions of the model, specifically for transformers, poles and cables. The AER focused on these categories in its bottom up review of a sample of replacement projects.

The AER's substitute repex was based on reductions it applied to our proposed replacement capex for Berrimah zone substation, Alice Springs corroded poles and the high voltage cable replacement program in the northern suburbs of Darwin.

5.1.1 Our approach to revising our replacement capex

In revising our proposal, we have sought to address the AER's Draft Decision. We consider that the repex model is a constructive tool to identify where further bottom up review is required. In section 5.2, we show how our Revised Regulatory Proposal has sought to understand the AER's findings on the repex model.

We agree with the AER's feedback there is room to improve in our risk quantification methods. Over time, we have been gradually improving our data quality and analytical tools. We have also been implementing innovative and lower cost solutions to address emerging issues on the network. Our next phase of improvement lies in more sophisticated risk assessment and statistical tools such that we align with best practice methods in other jurisdictions.

For our Revised Regulatory Proposal, we have not had enough time to integrate a new risk framework into our asset management practices. However, we have sought to identify new methods and data that help us look afresh at the specific projects where the AER has made reductions to our capex program.

We set out additional information and risk approaches that we have performed to inform our positions and revisions for Berrimah zone substation, Alice Springs corroded poles and the high voltage cable replacement program in the northern suburbs of Darwin in sections 5.3 to 5.5 respectively.

5.2 Repex model

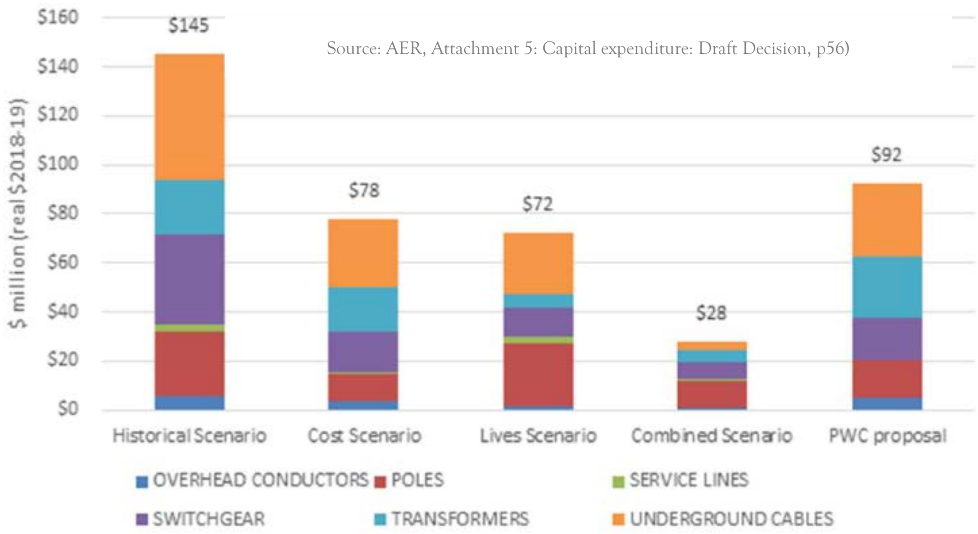
The AER's repex model predicts replacement capex based on asset age, unit cost and expected asset life. In the past, the AER has only used data provided by the distribution network service provider to run the repex model. In its recent round of draft decisions for Northern Territory, New South Wales and Australian Capital Territory, the AER has incorporated benchmark unit cost and asset life data to develop predictions of repex.

In our case, the AER examined four scenarios including our historical data, benchmark unit costs, benchmark asset lives, and a combined benchmark scenario. The AER's analysis was undertaken in $2018-19.

The AER determined that $92 million (62 per cent of our forecast repex) could be used to predict the repex model outcomes. The AER noted that our forecast modelled capex was less than the model's prediction when relying on our historical data ($145 million). However our proposed modelled capex of $92 million was higher than the benchmark cost scenario ($78 million), benchmark lives scenario ($72 million) and the combined scenario ($28 million).

The AER considered that the highest result out of the "cost and expected lives" scenario ($78 million) should be used to set the repex model threshold. This can be seen from Figure 5.1 which has been extracted from the AER's draft decision.

Figure 5.1 - Output of the AER's repex modelling scenario comparison



The AER did not use the repex model threshold to set our repex allowance. The AER instead used the model to target its bottom up review on our transformers, poles and cable replacement programs where the model predicts lower capex. This has informed the AER's alternative forecast of repex for the 2019-24 regulatory control period.

We support the AER's approach to apply the repex model as a guide. We also recognise the benchmark data can provide insights.

However, we consider that the predicted estimates of benchmark scenarios are likely to be highly imprecise with a wide confidence interval. The key issue relates to variations in the way data is reported across networks. For example, there is sometimes overlap between asset categories such as poles and overhead conductors. We consider that the accuracy of the benchmark scenarios could be improved over time by:

- Incorporating operating and environmental factors that may explain the differences between benchmark unit rates and asset lives. For example, we operate in harsh and humid environments that can limit the lives of assets compared to other networks. A key example is our steel pole fleet in Alice Springs which is showing significant corrosion at a relatively young age when exposed to salt and flood conditions.

- Not relying on benchmarks for individual asset categories where there is limited data. We note instances where only two or three networks have the same assets as us.

- Removing obvious outliers if further analysis shows that the reported costs are unrealistic. We have also seen instances of abnormally low costs in other networks.
- Using longer data sets for benchmarks. For example, we note that the Nuttall Consulting report submitted with our Initial Regulatory Proposal reported significantly different unit cost benchmarks based on a longer time series.

5.3 Berrimah zone substation

We have only made a minor reduction from [redacted] to [redacted] for proposed capex to replace the Berrimah zone substation. This is to reflect a minor adjustment to labour escalators. This is [redacted] higher than the AER's Draft Determination allowance of [redacted]. Table 5.2 provides an annual breakdown.

Table 5.2 – Berrimah zone substation capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	[redacted]					
AER Draft						
RRP						

In our Initial Regulatory Proposal, we provided evidence to justify replacing Berrimah zone substation. The substation comprised a 66kV outdoor air insulated 66kV switchyard, two transformers, and an 11kV indoor metal-clad switchboard and associated secondary systems.

We identified that many of the assets are at, or approaching, the end of their serviceable life. We noted that the five ASEA HLC minimum oil 66kV circuit breakers were in the poorest condition of the installed assets and that these circuit breakers have a high risk of explosive failure. We also highlighted a recent safety incident on the 11kV switchboard that resulted in an injury to our field crew at the site.

We proposed replacing the existing Berrimah zone substation with a lower capacity substation located directly adjacent to the existing substation. This is termed a "greenfield" solution. We noted that the project would commence in the 2014-19 regulatory control period and would be completed by June 2021.

The AER's Draft Decision recognised that some capex is required for the Berrimah zone substation. However, it considered we had not adequately shown that a greenfield replacement with a smaller capacity substation is efficient and prudent. The AER made the following observations to support its view:

- The AER noted that our quantitative analysis relied on a worst-case scenario which brings forward the need for forecast repex. The AER noted our assumption that the condition of the two transformers in the zone substation are identical, despite our condition assessment report stating that the transformers have different asset health ratings.
- The AER considered we had not justified developing a new adjacent substation and the associated civil works. The AER had regard to our assessment of the substation's building and civils works which the AER considered indicated that there are no significant issues.
- The AER also considered that a lower capacity new substation at Berrimah brings forward the timing to construct a new zone substation at Wishart.

The AER considered it would be prudent and efficient to replace specific assets identified in our Condition Assessment Report rather than building a new greenfield substation. The AER based its lower capex substitute on the cost estimates in our report. In addition, the AER considered it reasonable to invest in a spare transformer, given the non-standard sized transformers in the zone substation.

We have genuinely considered whether the AER’s alternative scope for Berrimah zone substation would be least cost for customers. We have looked at the issue afresh given the AER’s feedback. As discussed in section 3.2, we accept the reasoning that maintaining existing capacity at Berrimah will assist in reducing risk associated with deferring construction of Wishart substation.

We have framed our assessment on long term cost benefit analysis given that the expected serviceable life of a substation is around 50 years. While not explicit in our quantitative analysis, we have also considered other factors such as promoting a safe working environment, ease of maintenance, and the simplicity involved in upgrading and replacing assets.

At a high level, we consider that the AER’s refurbishment solution is not optimal compared to our Initial Regulatory Proposal. The additional quantitative analysis we have performed has focused on identifying the least cost option to consumers. Our analysis shows that:

- The AER’s allowance to refurbish the substation has excluded some essential costs that should be included in the costs of refurbishing the existing substation. This is discussed in section 5.3.1 below.
- A greenfield solution has a lower cost based on cost benefit analysis over 50 years. This is due to the need to replace items such as the 11kV

switchgear and control building in future years if the substation is refurbished rather than replaced. This is discussed in section 5.3.2 below.

Based on this analysis, we consider a greenfield solution that maintains existing capacity at the site is optimal. We have maintained the capex forecast in our Initial Regulatory Proposal, noting that the additional costs to maintain capacity is minimal.

The quantitative data underlying our analysis of the Berrimah zone substation is Attachment PWCR03.5. The quantitative analysis has been undertaken in $2017-18 consistent with our initial business case. For this reason the values in sections 5.3.1 and 5.3.2 are expressed in $2017-18.

5.3.1 Costs of refurbishing the Berrimah zone substation

The AER relied on information in our initial options study to calculate the cost of its alternative refurbishment option. However, the AER did not have the exact detail of what we had included under each cost line item.

As a result, the AER's substitute allowance removed costs that are required to refurbish the substation. Table 5.3 identifies additional costs required to efficiently implement the AER's solution.

Table 5.3 – Additional items required for a brownfield solution ($2017-18)

Item	Description	Capex
Transformer bunding and firewalls	The existing bunds, pads and fire separation walls are not compliant with the modern standard AS2067. Since the bunds will need to be modified, we will be required to bring them up to the modern equivalent standard. The cost for this was included in the original estimate for the 'Insitu replacement' option under the line item called 'civil works and building'. The AER has inadvertently removed the full cost allocated for the civil works and building replacement. This only includes the cost to build new bunds and firewalls rather than decommissioning,	[redacted]
Decommissioning and reinstatement of civil works	The civils works we had originally included in our proposed scope included decommissioning and removal of the existing 66kV switchyard, protection, power transformers and decommissioned generator transformers. The bulk of the cost of the decommissioning was for the transformers and bunding which will still be required. An allowance of [redacted] was allocated to decommissioning these assets. The civil works in our original scope also included remediating the zone substation surface for the purpose of step and touch potential (crushed aggregate covering) and re-institution of the road within the substation following heavy and construction vehicle damage. An allowance of $0.16M was attributed to these assets.	[redacted]

Increased labour for brownfield construction	Brownfield work takes longer to implement due to factors including additional operational controls for working around live HV assets, limited space within the substation, the need to secure outages from System Control and requirements to implement additional protection settings (including studies) for the different stages of the construction. We recognise that the additional costs of brownfield labour had not been included in our initial analysis provided to the AER. Since the greenfield option was lower cost, no additional effort was made to refine the labour costs for brownfield construction.	[redacted]
Sunk costs	We have already commenced construction of Berrimah zone substation as anticipated in our Initial Regulatory Proposal. We have spent [redacted] on detailed design and preparation of the greenfield solution. This will be a sunk cost that cannot be repurposed for a refurbishment option.	[redacted]

The AER has included [redacted] of capex ($2017-18) for a spare transformer in its costings of the refurbishment solution. We understand the AER's reasoning that it may be prudent to have a spare transformer on stand-by. However, the probability of early life failure of a transformer is very low. We also consider that a spare transformer is likely to degrade in the Northern Territory's harsh environment while in storage.

Taking this into account, we consider the likely capex for the AER's refurbishment solution would be [redacted] ($2017-18).

5.3.2 Analysis of preferred solution

We have undertaken additional cost benefit analysis to compare the whole-of-life costing of a greenfield solution that maintains existing capacity (Option 1) with the AER's alternative refurbishment solution (Option 2).

While the greenfield solution may be more expensive in the short term, the refurbishment option requires piecemeal replacement of existing assets over time. For instance, we will need to replace the 11kV switchgear and control building in years to come. It also costs more to maintain a brownfield site.

In our options analysis, we have assumed that refurbishment will lead to the following costs in the future when the 11kV switchboard requires replacement:

- We have included [redacted] ($2017-18) to replace the 11kV switchgear in the existing substation. This cost does not appear to be accounted for in the AER's estimate of the refurbishment option.[2] We assume the switchgear would need to be replaced in 2025.

- We have included [redacted] ($2017-18) to replace the control building when we replace the 11kV switchgear. This is because only two manufacturers produce switchgear that enables compliance with AS3000 within the space available, but neither of these would comply with our Design Standards that require 1,500mm clearance around the switchboard.[3]

- We have included [redacted] ($2017-18) to replace protection and control assets to ensure the substation can operate during construction of the new building. This is because the 11kV and 66kV protection and SCADA assets will need to remain in service while the new control building is constructed and cannot be reused for this project. In our analysis we included a salvage value to account for its use as spares.

- We have included an additional [redacted] ($2017-18) for design, mobilisation of construction crews, testing and commissioning, and other related project costs.

Our cost benefit analysis has also assumed a higher level of opex over time under the refurbishment option. This is due to the higher costs of operating an existing substation containing older assets compared to new substations. We have used analysis of historical operational expenditure as an input to our analysis.

Our analysis found that the greenfield solution (Option 1) resulted in lower costs than the AER's Draft Decision when considering total lifecycle costs. The net present cost of the greenfield solution was [redacted] ($2017-18) compared to the AER's Draft Decision option of [redacted] ($2017-18).

Our cost benefit analysis did not include a value for the higher safety risks inherent to the refurbishment option. There are additional safety risks from operating the zone substation while undertaking major construction. There are also greater risks from working with assets which are coming to the end of

[2] In the AER's Draft Decision, the AER allowed two thirds of the estimated cost for the 11kV switchgear, citing removal of the Bus 1 and Bus 2 portions of the cost. It is not clear how this proportion was determined, but it is approximately in line with removing the switchboard element from the scope while still allowing replacement of the station service transformers and capacitor banks. The AER allowed for the replacement of the 11kV protection and all secondary systems.

[3] Even if the building were to be retained, it would require significant modification which would be difficult to perform given the building is known to contain asbestos.

their serviceable life, particularly the 11kV switchboard. We also note that there is higher expected cost of energy at risk under the refurbishment option due to retaining the 11kV switchboard.

We also undertook sensitivity analysis on key inputs such as delaying the timing of the 11kV switchgear replacement and different assumptions regarding the cost of the switchgear replacement and transformer replacement. A key finding was that the greenfield replacement option was less costly for all reasonable assumptions regarding transformer refurbishment costs, switchboard replacement costs and switchboard replacement timing. We consider this would be prudent or practical option given the safety consequences of working with old switchgear.

We consider the analysis demonstrates that Option 1, the greenfield solution, is the least cost option. Our Revised Regulatory Proposal has maintained the original costs in our Initial Regulatory Proposal, given that the additional costs of maintaining capacity at the site are minimal.

5.4 Alice Springs poles

We have revised our capex for the Alice Springs corroded poles program from [redacted] to [redacted] for the 2019-24 regulatory period. This is [redacted] higher than the AER's Draft Decision of [redacted]. Table 5.4 provides an annual breakdown.

Table 5.4 – Alice Springs corroded poles capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	[redacted]					
AER Draft						
RRP						

Our Initial Regulatory Proposal identified a program to treat corroded steel poles in Alice Springs. The program targeted poles that were at the greatest risk of failing due to corrosion. The corrosion related to soils conditions including salinity and high moisture levels. A high proportion of poles affected are between the ages of 30 and 50 years when corrosion issues start to impact the integrity of the pole. We considered that the program was required to minimise safety risks to the public and our field crews from failing poles.

The AER's Draft Decision found that replacing some of the Alice Springs corroded poles was necessary. However, the AER observed that our supporting quantitative analysis overstated risk, as it does not account for joint probabilities for risk or consequence. It considered that the cost benefit analysis which incorporates the overstated risk is not likely to represent the most efficient outcome.

The AER observed that we proposed a 48 per cent increase in total pole expenditure compared to the 2014-19 regulatory control period. Its alternative estimate cut expenditure on the Alice Springs program by 48 per cent, which it considered would provide sufficient expenditure to replace only the highest risk poles over the 2019–24 regulatory control period.

At a high level, we consider that the AER has raised some important issues that require further quantitative review of the program. In revising our proposal, we have improved our modelling to identify the number of poles that require treatment, and to find a means of targeting the program while ensuring safety risks are minimised. Nonetheless, we consider the AER's alternative allowance does not recognise the need to address an issue that only emerged in the 2014-19 regulatory control period.

In the following sections, we explain the process we applied to arrive at our revised capex for the Alice Springs poles program:

- We provide more context on why we consider a step up in expenditure on the program is required in the 2019-24 regulatory control period (Section 5.4.1).
- We outline additional data and analysis used to identify factors that drive corrosion among our pole population (Section 5.4.2)
- We identify the statistical techniques we have used to predict the number of poles in severe or very severe condition (Section 5.4.3).
- We have outlined a joint probability approach to target poles that are at most safety risk to the public (Section 5.3.4). We also discuss the feedback of our CAC on risk prioritisation, and how we have sought to address their concerns using an approach that targets the program based on location.

Attachment PWCR03.6 provides the quantitative analysis underlying our revised forecast of Alice Springs poles, including our profile of costs.

5.4.1 Justification for a step up in expenditure on the poles

The AER's Draft Decision reduced our expenditure on the poles program by 48 per cent to reflect historical expenditure. We consider our past expenditure is not reflective of our future needs.

By way of background, our review into the condition of Alice Springs poles was sparked by the failure of a steel power pole in Alice Springs in January 2015. The pole was only 40 years old, considerably less than the expected service life for steel poles. The incident triggered an investigation into the condition of pole footings for poles of similar design in the Alice Springs region and specifically in the High Salinity Area (HSA), as we considered this to be a significant contributing factor to the failure.

Prior to this incident, our knowledge of pole condition and risk across the pole population was limited. We previously had low pole failure rates with very few poles approaching end-of-life. Consequently, our expenditure on pole replacements was low.

The investigation of the pole failure highlighted the elevated risk level posed by steel poles in Alice Springs. Consistent with good asset management practices, we sought to investigate the extent of the issue rather than replace all poles immediately. In 2016, we identified "at risk" areas and commenced a below ground inspection program. During this period, more poles failed in service due to corrosion.

The investigation program and subsequent failures in 2016 clearly established a need for more capex to treat affected poles than in the 2014-19 regulatory control period. Further exacerbating the problem was the age of the fleet in these areas. The poles are now between 43 and 49 years old and are exhibiting deterioration due to corrosion.

We have a general obligation to address safety issues once they are known to us. We cannot knowingly allow poles to deteriorate further without taking action to understand and remediate the situation. Due to the scale of the issue and safety consequences, it would be a breach of our duty of care to the public and our field crew to wait for a high level of failures prior to acting. For these assets it is more prudent to act in a proactive manner rather than being reactive.

5.4.2 Better analysis of factors driving corrosion of poles

We recognise that the AER and our stakeholders require further information and analysis to justify our capex on the program. In our Revised Regulatory Proposal, we have improved the quality and granularity of data to help us to identify the key drivers for pole corrosion. This information was subsequently used to statistically predict the number of poles that we need to treat in the 2019-24 regulatory control period.

The information described in the sections below clearly demonstrates the need for a step up in expenditure to treat corroded poles. Our analysis shows that:

- Poles exposed to flooding and high saline have a higher likelihood of severe to very severe corrosion issues. Age is also a driving factor behind corrosion.
- We expect that the level of failure from corrosion will significantly increase in the 2019-24 regulatory control period unless we proactively treat the poles. About 40 per cent of the fleet is currently aged between 42 and 49 years old, with many of the poles located in high saline and flood areas.

Our first step was to refine the data set for poles. Our refined data identified the cross section of metal and depth in the ground, labelled the location relative to flood plains and HSA, analysed the age of poles that have historically been replaced due to corrosion issues, and filled in gaps where data is not available on poles by using average age of poles in the same suburb. The revised data provided us with improved clarity on the condition of poles in our population, and the factors driving pole corrosion.

Our second step was to look afresh at the refined pole inspection data. The pole fleet is relatively small, consisting of only 5,088 poles in total. We have inspected 328 poles which had conclusive results. Although the inspection was more focused on urban areas for the purpose of this analysis, we considered that this sample is sufficiently random for application of the statistical analysis.

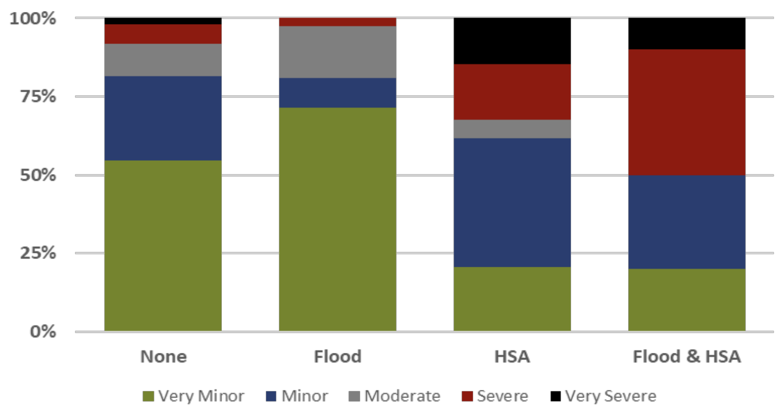
The raw inspection data is set out in table 5.5 below. The data showed that 21 per cent of poles were found to have either "severe" or "very severe" deterioration indicating they have reached the end of their life. 75.6 per cent were found to have very minor to moderate deterioration, indicating that they are not yet approaching, or at the end of their life. Box 5.1 provides more information on what we classify as severe and very severe condition.

Table 5.5 – Pole inspection data

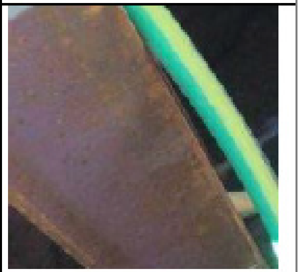
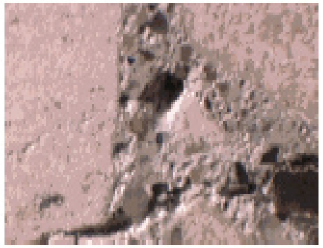
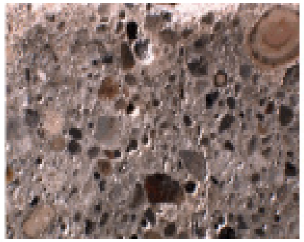
Assessment Criteria	Number	% of population	Margin of error
Inconclusive	11	3.4%	1.61%
Very Minor	146	44.5%	4.43%
Minor	73	22.3%	3.71%
Moderate	29	8.8%	2.53%
Severe	46	14.0%	3.10%
Very Severe	23	7.0%	2.28%

Our third step was to identify the factors that led to poles with severe and very severe condition. Figure 5.2 below shows that HSA and those with both flood and HSA show the highest percentages of deterioration. This indicates that the combination of salt and moisture (flood areas) create the most corrosive environment for steel poles.

Figure 5.2 – Soil conditions impacting severity of pole corrosion

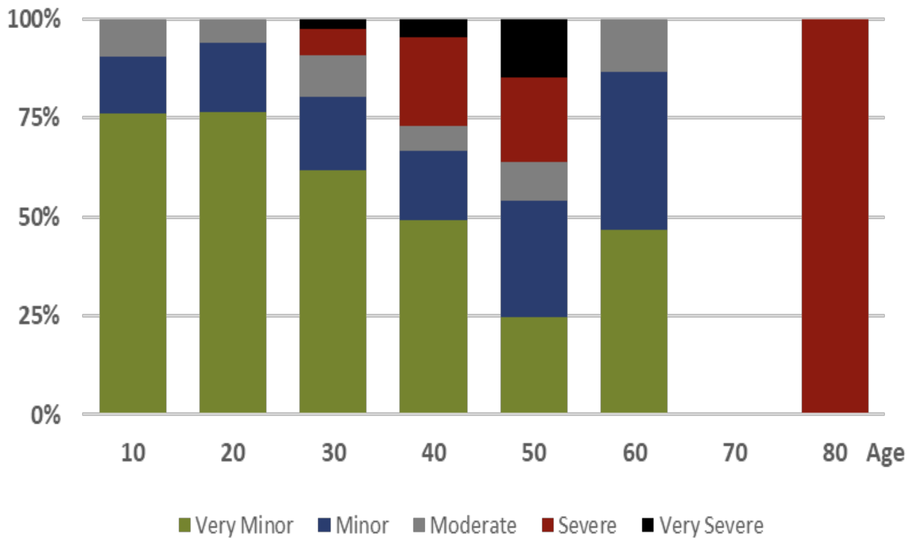


Box 5.1 – Corrosion categories

CORROSION ASSESSMENT CRITERIA					
DECISION	IMMEDIATE ACTION		FOLLOW UP ACTION	FOLLOW UP ACTION	
CORROSION	VERY SEVERE	SEVERE	MODERATE	MINOR	VERY MINOR
METAL EXAMPLES					
CONCRETE EXAMPLES					
ASSESSMENT CRITERIA	• Holes in steel structure • Holes penetrated full thickness • Chunks missing • Pieces on edge missing • Very bad thinning of the edges	• Many deep pits • Rough surface (lumpy) • Substantial flaking • Metal edges missing weds	• Many small pits • Rough surface (but not lumpy) • Some flaking (slightly loose thin piece) • Metal edges& welds not well-defined	• Small pits • Slightly rough surface • Metal edges and welds are well defined	• Few to none pits • Smooth surface • Metal edges and welds are very well defined
OTHER CRITERIA (CONCRETE)	• Metal is not visible but extensive stains found on concrete • Metal is not visible but presence of calcification encapsulation • Very rocky/ boney concrete • Concrete has lots of voids	• Significant frequency of fractures • Boney concrete • Evidence of voids in concrete • Moderate voids • Pocket of concentrated stain • Presence/ patches of calcification	• Evidence of frequent inclusions in concrete • Fractures in concrete • Moderate voids in concrete	• Superficial minor inclusions in concrete • Minor void visible	• Well compacted concrete • No voids visible • Consolidated concrete
ACTIONS	• Temporary propping • Replace IMMEDIATELY	• Temporary propping • If significant tip load → replace within 3 months • If minor/moderate tip load → replace within 6 months	• If significant tip load, temporary propping and replace within 9 months • If minor/ moderate tip load, replace within 12 months	• No repair/replace action • Plan to replace within 5 years	• No repair/replace action

We also found that age was a driving factor of poles in severe and very severe condition. Figure 5.3 identifies the degree of deterioration by age group for poles that were inspected. The chart shows that the percentage of poles in Severe and Very Severe condition increases rapidly from 30 to 50 years.

Figure 5.3 – Impact of age on severity of pole corrosion



Interestingly, the population data shows there are very few poles located in HSA, Flood or Flood and HSA soil condition types that are older than 50 years. This can be seen in Figure 5.4 below.

Figure 5.4 – Number of poles in population by soil condition

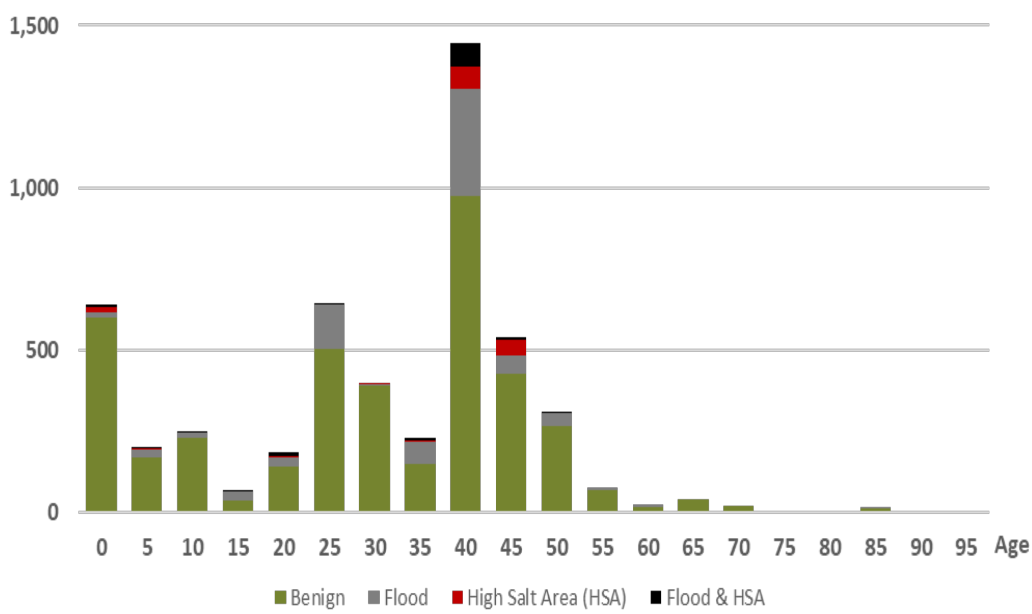
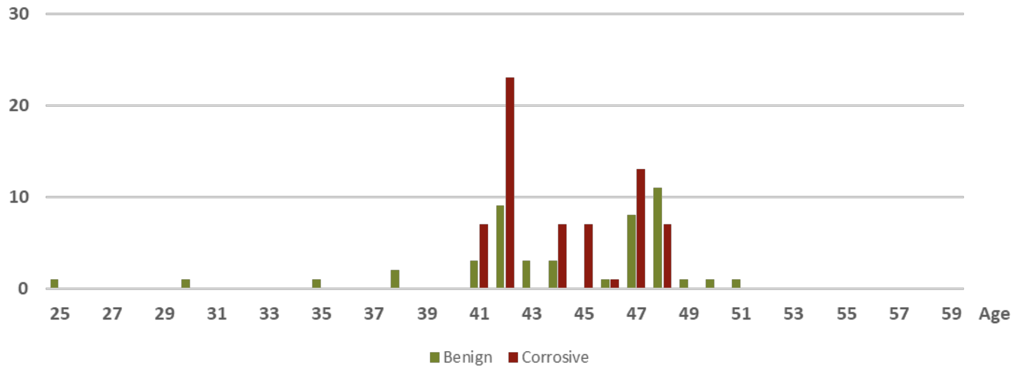


Figure 5.5 shows that most replaced poles had a life of between 41 and 48 years, with the observed life of poles in corrosive environments being slightly shorter. We refer to the soil conditions of Flood, Salt and both Flood and Salt as the Corrosive environment and the other soil conditions as Benign.

Approximately 90 per cent of the fleet is below 49 years old, hence the low number of failures of older poles. As noted above, 38 per cent of the fleet is currently aged between 42 and 49 years old, with 23 per cent being 43 years old. This aligns directly with the ages of poles at replacement and indicates that there is a high probability of a large volume of the poles being in a corroded condition and at the end of their serviceable life.

Figure 5.5 – Replacement age of poles for corrosive and non-corrosive environments



We also used quantitative methods to identify the factors driving corrosion using machine learning techniques. We split the 328 inspections into a training and test set for the algorithm to learn the data characteristics. The analysis found the following inputs to be most important in determining the pole condition, in order of highest to lowest:

- Poles located in high salt areas are much more likely to be in a severe or very severe condition.
- The closer the pole is to the flood zone the more likely it is to be in a severe or very severe condition.
- The older poles are in the worst condition.

5.4.3 Forecasting volumes

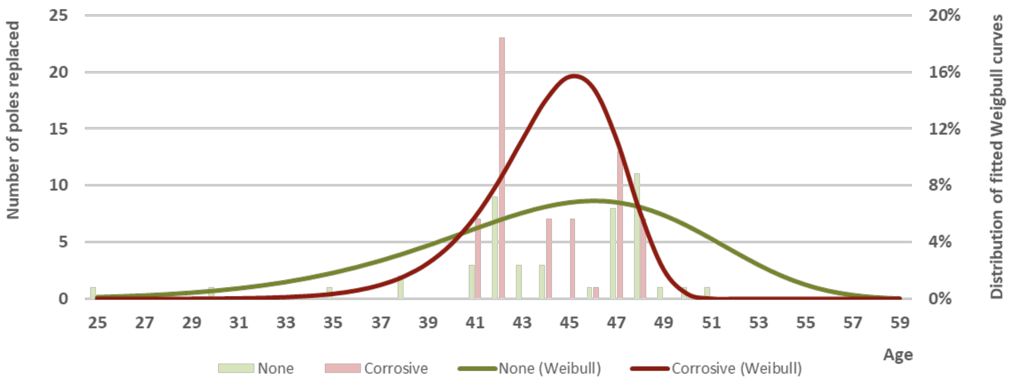
Based on the analysis above, we identified replacement needs based on a probabilistic approach using a Weibull probability distribution. The Weibull curve was calculated based on the historical data set of pole age at replacement, segmented by soil conditions. This type of analysis allowed us to predict volumes for corrosive and non-corrosive environments. Table 5.6 sets out the scale, shape and curve fit (R squared).

Table 5.6– Weibull results

Segment	Scale factor	Shape factor	Curve fit (R2)
None	46.70	8.72	0.87
Corrosive	45.37	19.39	0.77

As shown in Table 5.6, the R square value indicates a good fit of the data (an R square of 1 means a perfect fit) and is therefore appropriate for application for fleet analysis. The profile of the age of poles at failure and the fitted Weibull distribution is shown in Figure 5.6.

Figure 5.6 – Fitted Weibull distribution for corrosive and non-corrosive soil conditions



While there is a good fit for poles in non-corrosive environments, we consider it may be skewed to a younger age due to the age profile of the fleet. We consider that poles in non-corrosive environments will survive longer than predicted. In our modelling we have substituted a mean age of 65.25 years, consistent with the AER's benchmark life for a steel pole in its repex model. This has the effect of reducing the forecast volumes of corroded poles requiring remediation during the 2019-24 regulatory control period. We retained the shape factor because we do not have an alternative valid value to substitute.

The conditional probability of failure is then calculated from the Weibull Distribution and applied to the age profile to forecast the number of poles that will reach the end of their serviceable lives and require replacement during the 2019-24 regulatory control period.

Based on the Weibull analysis we forecast that 786 poles will need to be treated for corrosion by the end of the 2019-24 regulatory control period.

5.4.4 Joint probability analysis

We have considered how to use joint probability to prioritise the poles program based on risk and consequence. We note that the Weibull analysis shows we will have 786 poles that will be in a severe to very severe state of degradation in the 2019-24 regulatory control period.

Assets in this condition have a high risk of failing. Further, failing poles have potentially fatal consequences if a person or our field crews are in the vicinity of the poles. We note that one approach is to identify areas where there is a very low probability of a person being under the pole at the time of failure. For example, we would expect rural areas to have low population densities compared to urban areas.

We sought the views of our CAC on this issue in October 2018. The CAC noted that public safety should be a priority in our decision making. We canvassed the idea of targeting poles in more populated areas as a means of reducing costs to customers in the 2019-24 regulatory control period. In response to a question, we provided a rough calculation of the cost of a pole on customer prices. The CAC considered that we should address all poles at serious risk of failing regardless of location.

We recognise that the AER's Draft Decision requires us to look at measures which allow joint probability analysis, and to consider a more targeted program. We consider that population density provides a reasonable means of rating the likelihood of harm to a person or our field crews. It is not an exact metric, as poles are often located near roads and property fences. In respect of the latter we note that property fences can transfer hazardous voltages to a wider area increasing exposure.

On this basis, we developed a matrix which identifies the number of poles by their expected condition based on the Weibull modelling. We then identify if the poles are located by population density. This can be seen in Table 5.7.

Table 5.7 – Joint probability analysis

Population Density (Person/1000sqkms)	Condition of pole				
	Very minor	Minor	Moderate	Severe	Very sever
110	1,858	134	389	175	94
225	239	29	226	31	13
450	30	5	189	124	13
1000	106	10	239	286	29
1800	142	17	507	171	32

Based on customer feedback, our Revised Regulatory Proposal has identified that all very severe condition poles (highlighted in red in Table 5.7) should be treated regardless of population density. However, we considered that the program could be optimised by only targeting severe poles when they are in higher population densities (highlighted in orange in Table 5.7).

We consider the lower replacement capex in our Revised Regulatory Proposal addresses the substantive issues raised by the AER, while adhering to the safety principles reflected in feedback provided by our CAC.

5.5 Darwin Suburbs cables

We have revised our capex for the Darwin suburbs XPLE cable replacement program from [redacted] to [redacted] for the 2019-24 regulatory period. This is [redacted] higher than the AER's Draft Decision of [redacted]. Table 5.8 provides an annual breakdown.

Table 5.8 – Darwin Suburbs cables capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	[redacted]					
AER Draft						
RRP						

The Darwin northern suburbs cable fleet is comprised of 103 kilometres of high voltage XLPE insulated cables. In our Initial Regulatory Proposal, we included a program to replace 44 kilometres of cable length. Our investigations had shown that the sheath and insulation of some cables are damaged and needed to be addressed to mitigate safety and reliability risks.

We noted that water ingress causes deterioration of the outer sheath. This results in water treeing, where there is accelerated corrosion of the neutral screen when exposed to moisture and electrical stress. Eventually, the XLPE insulation fails causing a fault to ground. The impedance of the fault current return path increases, slowing the response time of protection systems.

This raises safety issues for our field crew using tools or cutting cables. We had recent experience with this when two of our workers experienced severe burns and permanent injuries when cutting the cables.

The AER's Draft Decision considered replacement of these cables is 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 noted that the forecast repex for this program is double the expenditure from actual capex in the 2014-19 regulatory control period. The AER reduced the length of cable to be replaced from 44 to 31 kilometres. The AER's reasoning was that this was the likely amount that is expected to fail an earthing test based on a summary of test data we had provided, and that this would address cables which presented the largest impact on outage time.

We have examined the AER's findings. At a high level we note that the AER's alternative estimate only provides for a small increase from current levels of capex. We consider this is insufficient to address an emerging safety issue on the network.

We recognise that our initial evidence for the project was limited due to the small amount of cable testing we had undertaken at the time of submission. Our Revised Regulatory Proposal has sought to incorporate most recent testing data, as set out in section 5.5.1. This provides for more samples to statistically predict volumes and more granular information on the condition of the fleet. This is set out in section 5.5.2.

Attachment PWCR03.7 provides the quantitative data underlying our analysis on Darwin suburbs cables.

5.5.1 Incorporating recent testing data

The key test we use to assess cable condition is termed "sheath to ground impedance". The neutral screen to earth impedance will be very low for cables that are degraded.

We accept the AER's view that the limited evidence we provided in our Initial Regulatory Proposal did not provide conclusive evidence of the need to replace 44 kilometres of cable. The initial business case we submitted as part of our proposal used the best data available at the time, which consisted of three months of a dedicated test program. This meant there was a limited data set to undertake robust statistical analysis.

Since that time, the dedicated testing program has continued and there is now an additional year of data available for analysis. In total, there are 173 test results available in the northern suburbs of Darwin.

We have refined the data set to identify the results of the cable by segment. The segments mean that there is significantly more kilometres than the cable length of 103 kilometres. We have 851 segments over a total cable length of 136 kilometres.

5.5.2 Forecasting volumes based on recent tests

The test results found that 42 cable segments (24.3 per cent) have failed testing. Based on the sample size of 173, this gives a 95 per cent confidence level that the percentage of the fleet that has deteriorated sheath condition is 24.3 per cent ± 5.7 per cent.

The statistics can be read as there being a 95 per cent probability that the actual number of cables currently degraded within the known population of 851 segments is between 159 and 256 segments, or between 25.4km and 41.0 kilometres with an expected amount of 33.1 kilometres based on the average segment length.

The above analysis above reflects the predicted amount of cable that is currently in a deteriorated condition. It does not take into account the rate of deterioration of other cables over the 2019-24 regulatory control period.

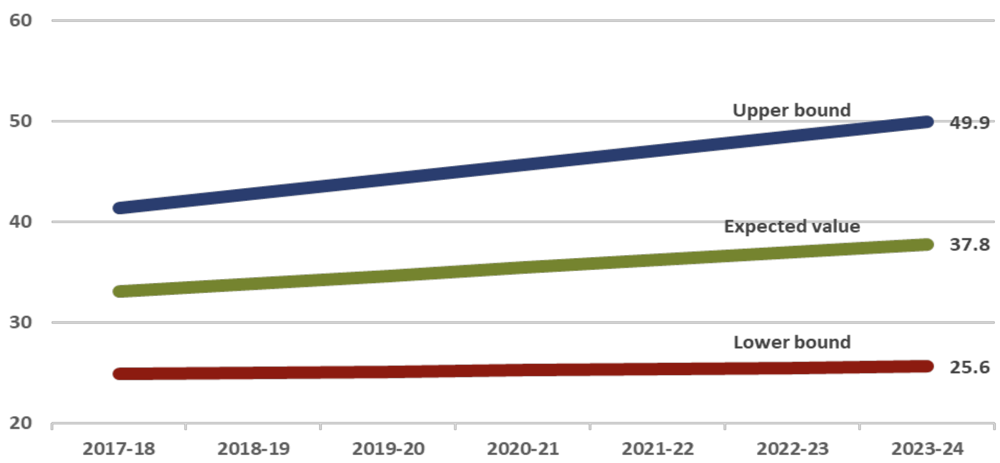
We considered that a good proxy for deterioration rates is the increase in faults on feeders over time. We recognise that fault data for feeders is not entirely accurate as the fault may be associated with the nearest asset such as a distribution transformer, switch or RMU. Nevertheless we have looked at historical data noting that this inaccuracy would be present in all years.

Our analysis of historical data showed a marked step increase in faults on these feeders in 2007. It was not clear if this was due to deterioration or improved data collection. We have specifically considered this in our scenario analysis.

Figure 5.7 below provides a forecast of the high, expected and low scenarios for deterioration of the cables. It demonstrates an increasing trend in failure rates. The assumptions applied in each scenario are:

- The upper bound is based on the higher volume of cables at end of life (24.3% + 5.7%) increasing over time based on the rate of increase of faults from 1997 through to 2018. This rate of increase is the higher rate that includes the step change in data in 2007.
- The lower bound is based on the lower volume of cables at end of life (24.3% - 5.7%) increasing based on the trend of faults from 2007 through to 2018. This rate is after the data change in 2007 and demonstrates a lower rate of increase.
- The expected value is based on the expected volume of cable at end of life (24.3%) increasing at a rate that is the midpoint between the other two fault rates.

Figure 5.7 – Expected, upper and lower bounds of forecast volumes based on deterioration



This analysis shows that by the end of the next period the number of deteriorated segments would increase to between 25.6 kilometres and 49.9 kilometres with an expected value of 37.8 kilometres. We note that the expected unit cost is approximately [redacted] per kilometre.

We have assumed a linear trend for the deterioration rate. However, we consider the deterioration would occur more rapidly as the cables age, meaning that the forecast is likely to be understated. However, without evidence to support this hypothesis it has been excluded from the analysis.

6. Non-network capex

This chapter explains the revisions to our forecast non-network capex. ICT capex includes hardware, software, enterprise wide systems, and devices. Other non-network capex includes fleet, building and property, tools and equipment, and minor capex.

6.1 Overview of non-network capex

We have revised our total non-network capex from $106.9 million to $88.2 million. This is $7.7 million more than the AER's Draft Decision of $80.5 million, as set out in Table 6.1.

Table 6.1 – Non-network capex

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

In our Initial Regulatory Proposal, we forecast $37.5 million for ICT and $69.4 million for other non-network capex. The key driver of our ICT program was to modernise our ICT systems to drive efficiencies, compliance and improve customer service. The increase in other non-network capex related to capitalising fleet and property leases and upgrading the 19 Mile Depot.

The CCP noted the significant increase in ICT capex over historical level of expenditure and observed we had provided little information on quantified benefits. The CCP also questioned our policy to capitalise lease costs due to a change in accounting standard, noting that we should have a business case for doing so. Similar issues were also raised by the anonymous submission.

The AER found we had a real need to update and upgrade many of our ICT systems. It reduced our capex by 31 per cent based on deliverability concerns. The AER also reduced our expenditure on other non-network capex. The AER found an error in the way we calculated our capex for property and fleet leases. The AER also considered that we had not provided sufficient evidence to justify expenditure on the 19 Mile Depot project.

We consider the AER and stakeholders have raised valuable insights on our proposed non-network capex. The AER has accepted most of our proposed expenditure based on its review.

We have revised down our proposed ICT capex to ensure we have the capability and expertise to deliver the program in full, and to realise the benefits as swiftly as we can. This is set out in section 6.2 below.

We have also revised down our forecast capex for 19 Mile Depot as set out in section 6.3. We have accepted the AER's Draft Decision to reduce our proposed capex on fleet and property leases as set out in section 6.4 below.

6.2 ICT capex program

We have revised our total ICT capex from $37.5 million to $32.1 million. This is $6.4 million more than the AER's Draft Decision as set out in Table 6.2.

Table 6.2 – ICT capex

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	10.8	9.4	7.4	4.9	5.1	37.5
AER Draft	5.1	5.1	5.1	5.2	5.2	25.7
Revised proposal	6.6	6.4	6.2	6.6	6.2	32.1

In our Initial Regulatory Proposal, we noted that our forecast investment was higher than our historical capex. Our ICT strategy was directed at supporting key improvements to our business including:

- Driving efficiency to support our Operating Model initiatives. In our Initial Regulatory Proposal we included a top-down efficiency reduction of 10 per cent to our proposed base year opex. While we had not directly quantified the benefits of the ICT program, we considered investments in upgrading and implementing new ICT systems would help us to meet these efficiency targets.

- Improving the ways we communicate with customers. We had proposed investing in a customer relationship management system and outage management system. These systems would improve our abilities to respond to customers' enquiries and to communicate outage times.

- Improving our asset management and network planning capabilities. We recognised that we could improve our planning and expenditure decisions by investing in analytics and data that our peer networks are successfully utilising. This is particularly important in a more complex network with high penetration of household PV, and greater opportunities for non-network solutions.

- Assisting our transition to NER compliance in a prudent and efficient manner.

The AER's Draft Decision found we had a real need to update and upgrade many of our ICT systems. The AER's key concern was our ability to deliver an expanded ICT capex program into a resource constrained business in a short period of time. It noted we provided some evidence to demonstrate that we have established access to suitable external specialist resources to deliver the proposed ICT program, and that we are considering additional internal project management resources.

In particular, it was concerned that we had not demonstrated how the business itself can adapt and accommodate the extent and rate of ICT change proposed. The AER's substitute estimate provided for an increase in ICT capex in the forecast period, but at a reduced level that it considered demonstrably deliverable given historical expenditure.

The AER also responded to the specific concerns of the CCP regarding quantification of benefits of the ICT program. The AER encouraged us to continue our efforts to define and quantify these benefits in this Revised Regulatory Proposal.

We have revised down our ICT program to address the AER's concerns on the deliverability of the proposed program. This is set out in section 6.2.1 below. We have addressed the AER's feedback on the quantification of benefits from the ICT program in section 6.2.2.

6.2.1 Revising ICT capex to address deliverability concerns

In our Initial Regulatory Proposal, we noted that we would use external vendors to deliver most of the ICT program, with increased project management support to drive changes within the business.

We agree with the AER that the ICT program will bring about wide-scale changes to the business that impacts our processes and people. We recognise that the magnitude of the program, together with the lumpiness of capex may have resulted in challenges to realise the benefits.

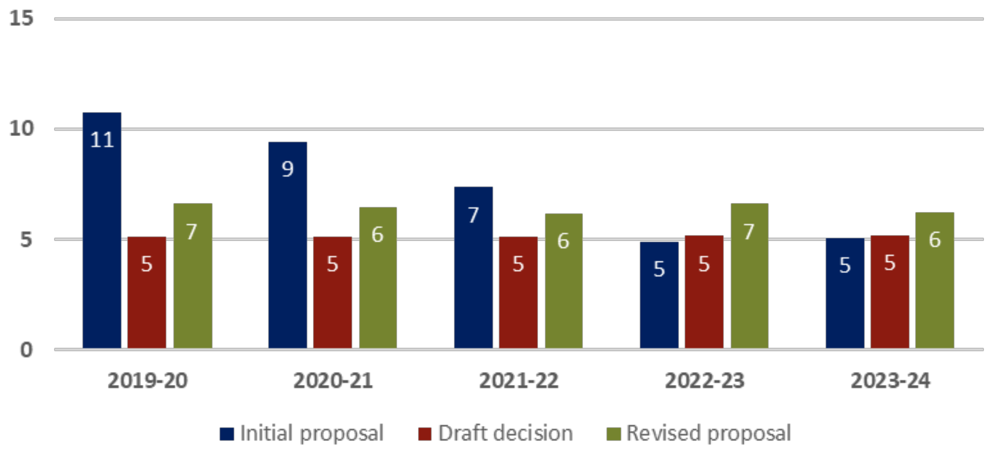
Our revised ICT capex responds to the AER's concerns on deliverability by deferring some projects to the subsequent regulatory control period. We have deferred the EBA interpreter program, the operation risk reporting program and the project management system. These projects were identified as least critical to delivering efficiencies or improving customer service. They were also projects that required internal resources to deliver effectively.

We have also flattened our expenditure profile across regulatory years, so it is no longer front ended. The revised profile allows us to stage, sequence and prioritise better our investments in major ICT systems.

For example, we have proposed delaying the upgrades to our asset management system to the later years of the 2019-24 regulatory control period. We have also deferred capex on our outage management system to outside of the regulatory period. This has provided us with a smoother profile which provides for more gradual change that can be accommodated in the business.

Figure 6.1 below which shows that the revised forecast of ICT capex is relatively flat across regulatory years.

Figure 6.1 – Revised profile of ICT capex



Our Operating Model program will help us drive operational efficiencies from the ICT program. We will have dedicated resources to project manage initiatives. The team will report directly to our Executive and Board on operational savings. This provides focus and transparency within the business to ensure that we realise the benefits of the ICT program as soon as possible.

Table 6.3 identifies the total expenditure for each ICT program in our Revised Regulatory Proposal compared to our Initial Regulatory Proposal. In some cases, we have shifted the capex to the latter years of the 2019-24 regulatory control period compared to our Initial Regulatory Proposal. The small reduction in costs for some projects relates to lower labour cost escalation.

Table 6.3 – ICT capex by program

$M, Real 2018-19	Initial Regulatory Proposal	Revised Regulatory Proposal
ESRI upgrade	[redacted]	[redacted]
Financial Improvement project		
Maximo upgrade		
RMS upgrade		
Meter data management		
Data and Reporting Program		
System Planning Tools		
RIN Reporting		
Mobility		
Investment planning and forecasting		
Outage management system		
Drawing management system		
CATS and B2B System		
CRM		
Scheduling		
Project Management System		
Estimating & Quotation Management		
Fleet Management		
Operational Risk Reporting		
EBA Interpreter		
Hardware Replacement		
Software Upgrades		
Total	**37.5**	**32.1**

6.2.2 Benefits of the ICT program

The AER and our stakeholders would like us to quantify the benefits of the ICT program.

In our Initial Regulatory Proposal, we quantified reductions to staff numbers for some ICT programs. However, we had not undertaken a comprehensive quantification of benefits for each of the 22 ICT projects. To a degree, this reflected our limited experience in performing such analysis. It also reflected the inherent difficulty in identifying the exact dollar benefits from improvements to processes and analytics.

For the Revised Regulatory Proposal, we have not had enough time to develop a robust quantification methodology. We will continue to work on developing a framework as part of our ongoing improvements. However, we have provided more detail in our revised proposal for SCS opex.

6.3 19 Mile Depot project

We have revised our forecast capex for the 19 Mile project from [redacted] to [redacted]. The AER had provided no capex allowance for this project in the 2019-24 period. Table 6.4 sets out the details.

Table 6.4 – 19 Mile Depot (Confidential)

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Initial proposal	[redacted]					
AER Draft						
Revised proposal						

In our Initial Regulatory Proposal, we noted that we currently have two rural depots servicing the Darwin region. The 19 Mile Depot is currently owned by us and the East Arm depot at the time was leased by us. Our proposed strategy at the time was to upgrade 19 Mile, not to renew the lease at East Arm and co-locate both crews at 19 Mile. We noted that the 19 Mile Depot required upgrades for access and to ensure facilities were adequate.

The AER's Draft Decision noted that a depot consolidation strategy may have benefits. However, it was concerned by a lack of an overall strategy for the future management of our depot facilities. It noted that in the absence of a depot strategy and implementation plan agreed by our Board and management it is not clear that we will undertake the 19 Mile project as proposed or in the proposed timeframe. It also noted a lack of evidence to demonstrate that we cannot accommodate staff from our East Arm depot at the existing 19 Mile Depot or other facilities.

In addition, the AER considered a report we provided during the review process from our consultant (Cardno) on access into the 19 Mile Depot. Based on its review, the AER found that existing site access arrangements comply with relevant design guidelines and can accommodate increased traffic volumes.

Further, the AER noted that we did not provide dilapidation reports or similar documentation to demonstrate that the existing facilities at the 19 Mile depot site are in poor condition and/or not fit for purpose and require refurbishment.

We recognise that our property strategy was not well articulated in our Initial Regulatory Proposal due to uncertainties on future direction. We have now vacated our East Arm depot and transferred staff to our existing urban Darwin depot at Ben Hammond.

While we consider there may be benefits from locating staff closer to our rural overhead area, we have not undertaken sufficient analysis to demonstrate benefits. We accept the AER's view that this may be a long term aspiration that requires further exploration. For this reason, we consider that the 19 Mile Depot will not need to accommodate significantly more staff in the 2019-24 regulatory control period.

In this Revised Regulatory Proposal, we have provided new information showing the need to upgrade the current facility and improve access to the site.

We engaged Hodgkinson to prepare a report on the current condition of the 19 Mile site. The report is Attachment PWCR03.8. Hodgkinson identified the shortfalls within the existing facility, and provided a high level description of the works necessary to bring the site to compliance. Hodgkinson identified three streams of work totaling a cost of [redacted]:

- The warehouse contains non-compliant doors which are too narrow, and which block access.
- The office building is not compliant with disability access and does not provide adequate unisex toilet and shower facilities.
- The septic system is no longer compliant to current standards.

This is a significantly smaller scope of works than forecast in our Initial Regulatory Proposal which had been based on accommodating additional staff at the site.

We have also provided additional evidence on the minimum works required to ensure safe vehicle access to the site. In November 2018, we received a letter from Department of Infrastructure, Planning and Logistics (DIPL) with their latest advice on access issues. This is at Attachment PWCR03.9.

DIPL's view was that access to the site is unsafe. It advised that an intersection upgrade is required to access the depot as the existing deceleration lane is slightly less than the requirement for the design speed. We estimate the costs of the works will be [redacted], down from [redacted] in our initial capex forecast.

6.4 Fleet and property leases

We have revised our proposal for fleet and property leases from $53.8 million to $46.0 million. As can be seen from Table 6.5 below, we have accepted the AER's findings for property and fleet leases.

Table 6.5 – Fleet and property leases

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
IRP	19.4	3.8	23.2	3.9	3.5	53.8
AER Draft	17.7	3.4	18.2	3.4	3.3	46.0
RRP	17.6	3.4	18.2	3.4	3.3	46.0

The AER found that our forecast property and fleet lease capex reflected the sum of expected future lease payments, rather than the present value of these payments. The AER noted that this was inconsistent with Australian Accounting Standard AASB16 and our own documentation.

In the course of the AER's review, we acknowledged that this was an unintended error. We agreed with the AER that our calculation has the effect of overstating forecast capex requirements and would lead to an over recovery of expected lease payments. The AER used our re-calculation as the basis for its substitute capex on property and fleet leases.

We have revised our proposal to incorporate the lower capex for property and fleet leases.

7. Capitalised overheads and disposals

This chapter explains the revisions to our capitalised overheads (section 7.1) and forecast asset disposals (section 7.2).

7.1 Capitalised overheads

We have revised our capitalised overheads capex from $66.9 million to $65.1 million for the 2019-24 regulatory control period. This is $6.7 million more than the AER's Draft Decision of $58.4 million. This is seen in Table 7.1 below.

Table 7.1 – 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 unallocated network and corporate costs that we capitalise in accordance with with our approved CAM. In our Initial Regulatory Proposal, we forecast capitalised overheads using the base-step-trend approach that 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 in the level of capitalisation of overheads. They asked the AER to undertake a general review. An anonymous submission stated that overheads should be reviewed by the AER at an aggregate level as part of opex reviews.

The AER considered that we had used a reasonable methodology to forecast our capitalised overheads. It also noted that our decision to capitalise leases brings us into line with the practices of other distribution network service providers.

However, the AER noted an error in our base year estimate of capitalised overheads. It also substituted a lower rate of change to trend our base year costs, noting that 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.

Our Revised Regulatory Proposal uses latest 2017-18 actual costs to calculate the base year forecast for capitalised overheads. We have ensured that our method has corrected the miscalculation error in our Initial Regulatory Proposal. 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 to total expenditure ratio that does not reflect historical rates or the forecast for the 2019-24 regulatory control period.

We have also updated the rate of change calculation to be consistent with other inputs in this Revised Regulatory Proposal.

7.2 Forecast asset disposals

We have revised our forecast disposals from $0 million to $0.8 million for the 2019-24 regulatory control period. This is consistent with the AER's decision. This is seen in table 7.2 below.

Table 7.2 – 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**

Forecast assets disposals are the expected asset sales from the disposal of assets. In our Initial Regulatory Proposal we forecast a zero amount. Our view was that historical data on asset sales was not clear and was difficult to predict asset sales in the next period.

The AER included forecast asset disposals of $0.8 million in our estimate of total forecast net capex, in line with what it considered our average historical level of asset disposals.

We have accepted the AER's Draft Decision on asset disposals and have revised our forecast capex to reflect this amount.