Revised Regulatory Proposal

Response to the AER's draft decision

30 November 2023

PowerWater

Contents

List of tables

List of figures

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition
ACS	Alternative Control Services
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AFL	Available Fault Level
BESS	Battery Energy Storage System
capex	Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
CIM	Common Information Model
CSIS	Customer Service Incentive Scheme
DER	Distributed Energy Resources
DKESP	Darwin-Katherine Electricity System Plan
DKTL	Darwin-Katherine Transmission Line
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DOEs	Dynamic Operating Envelopes
DUoS	Distribution Use of Service
EBSS	Efficiency Benefit Sharing Scheme
EMS	Energy Management System
ESIS	Export Services Incentive Scheme
ESS	Essential System Services
EVs	Electric Vehicles
F&A	Framework & Approach
GIS	Geographic Information System

Term	Definition
HV	High Voltage
ICT	Information and Communications Technology
LRMC	Long Run Marginal Cost
LV	Low Voltage
NEM	National Electricity Market
NPV	Net Present Value
NT	Northern Territory
NT NER	Northern Territory National Electricity Rules
OMS	Outage Management System
opex	Operating Expenditure
OT	Operational Technology
PV	Photovoltaic
RAB	Regulatory Asset Base
RIT-T	Transmission Regulatory Investment Test
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TNSPs	Transmission Network Services Providers
TSS	Tariff Structure Statement
VPP	Virtual Power Plant

About this proposal

Who is Power and Water?

We are the essential service provider in the Northern Territory (**NT**), providing electricity, gas, water and sewerage services. Our purpose is to make a difference to the lives of Territorians. Our business connects our communities to reliable and affordable essential services and provides a foundation for economic growth.

We provide power to 90 townships and communities across a vast landmass, with our three largest networks in Darwin-Katherine, Alice Springs and Tennant Creek delivering electricity to 195,000 people, 72,000 residential customers and 11,000 businesses. These networks are under price regulation.

Where are we in the regulatory process?

Every five years, the Australian Energy Regulator (**AER**) undertakes a review of our proposed expenditure, revenue, and tariff structures for our regulated electricity networks. Our next regulatory period is from 1 July 2024 to 30 June 2029 (the 2024-29 regulatory period). The review process takes about 18 months following the submission of our regulatory proposal, which we lodged with the AER on 31 January 2023.

On 28 September 2023, the AER released its draft decision. The draft decision described in detail the AER's views on our investment plans, proposed services, and the suite of financial instruments that govern the way we run our business.

The AER's draft decision allowed Power and Water to recover an estimated $1,016.4 million ($nominal, smoothed) from NT electricity tariff customers over the 2024–29 period. This is a 6.8% decrease from Power and Water's proposed revenue. The decrease in overall revenue was mainly driven by reductions to our forecast capital expenditure (**capex**) and operating expenditure (**opex**).

What happens next?

The AER's draft decision is an opportunity for electricity customers to provide feedback on Power and Water's plans for the next five years and the AER's draft position on those plans. The draft decision also outlines additional information sought by the AER to allow it to make a final determination, and invites Power and Water to provide that information.

This revised regulatory proposal document outlines Power and Water's response to the AER's draft decision. It includes the additional information requested by the AER (via a suite of attachments provided with this document) and describes how we have addressed the constituent components of the draft decision. We are required under the NT National Electricity Rules (**NT NER**) to submit our response to the draft decision by 30 November 2023.

Our revised proposal will be scrutinised further by the AER. The AER will make its final determination in April 2024.

The AER's final determination is then used to calculate the prices (tariffs) we can charge customers for using our networks. These network tariffs are charged to the electricity retailer. The retailer then passes all or some of these costs through to end users through their electricity bills, subject to NT Government policy settings.[1]

How can you provide feedback?

Since submitting our initial proposal in January 2023, we have continued to engage with customers, energy sector partners and government representatives to hear what is important to them. We have also continued our engagement program since the AER's draft decision. This included engaging with everyday residential customers in Darwin and Alice Springs, with representatives from Katherine and Tennant Creek via our People's Panels, and holding forums with large users and retailers. We will continue to engage during the AER's review process, and welcome further feedback.

The AER has invited public submissions on this revised proposal by 19 January 2024. You can follow the AER's consultation process via the AER website. During the AER's review process, you can also provide feedback directly to us by emailing us at YourSay@powerwater.com.au. We look forward to hearing your thoughts.

Values used in this document

All financial figures in this regulatory proposal are presented in $ real 2024, unless otherwise stated.[2]

Peak demand, energy consumption and customer numbers are prepared as at 30 November 2023.

Numbers may not sum due to rounding.

1 Electricity retail prices charged to residential and commercial customers (those consuming less than 750 megawatt hours of electricity per year) are regulated by the NT Government through a pricing order made by the Treasurer under the *Electricity Reform Act 2000*. The Electricity Pricing Order sets the retail prices that customers may be charged for electricity and related services.

2 Consistent with the AER's draft decision, we report expenditure in real $2024 and revenue, the regulatory asset base, prices, and bill impacts in nominal dollars.

A message from our Chair

Since being appointed as Chair of the Power and Water Board in March 2022, I have seen significant strides forward in modernising Power and Water's operations as a nationally regulated business.

Power and Water has always worked dutifully to provide reliable and affordable essential services to Territorians – and that will never change. The new regulatory environment has helped sharpen our focus on customers and driven a program of meaningful engagement with our stakeholders.

One of the most pleasing aspects is to see how customers have been brought into the energy conversation to have a voice in the future of the Northern Territory's electricity networks. Stakeholder and customer feedback has been vital to developing this proposal and testing ideas on the direction Power and Water is heading. I would like to thank the many Territorians, industry and government stakeholders who have contributed to the process.

The AER's draft decision was a positive step in Power and Water's regulatory journey. There is clear alignment on the majority of issues, and I feel confident the final revenue determination will provide ability for Power and Water to support the Territory's transition towards a lower-emission economy, while delivering the energy resources vital to attract new industries to the NT.

As the economic environment in the NT evolves, Power and Water has a vital role in helping stimulate economic and population growth, while ensuring vulnerable customers are protected. The way we use, share and generate electricity is continually changing. The power system is only getting more complex and it is important Power and Water has the capabilities to manage these challenges.

Part of the solution is to uplift Power and Water's technical capabilities, and I am in favour of the proposed investments to improve the business' information and operational technologies over the coming decade. The other key focus is to uplift organisational culture. To truly place customers at the heart of what we do, we need to be responsive, flexible, and accessible. One of the best ways to achieve this is to bring our people together and create a work environment that allows greater collaboration, problem solving and communication.

A positive workplace culture leads to a positive customer culture and I strongly support the proposed plans to consolidate the majority of Power and Water's Darwin workforce in a single, purpose built facility at the Ben Hammond Complex. By bringing our operations to a single point of focus, we can work more effectively, avoid fragmented activities, and be better placed to deliver quality service to all Territorians. I urge the AER to deeply consider the single site consolidation plans in this revised proposal.

I acknowledge the hard work of Power and Water's people who have helped develop and deliver this revised proposal. I am proud of the way the business has embraced the regulatory framework and the innovative approach it has taken to engagement and investment. I look forward to a positive final determination.

Peter Wilson AM

A message from our Chief Executive Officer

I'm pleased to present our revised proposal for the 2024-29 regulatory period.

This revised proposal outlines the refinements we have made to our investment plans and pricing proposal for the next five years, as well as directly responding to the AER's draft decision.

I was pleased the AER's draft decision was broadly supportive of our investment plans for the Northern Territory's primary electricity networks, and the services we aim to deliver to Territorians. While there is still some work to do to agree the final revenue and expenditure numbers, it is good to see we are aligned with the AER on the majority of issues.

I appreciate the guidance provided by the AER in its draft decision. Since the January 2023 submission we have continued to engage with customers and stakeholders to revise our plans, with a view to reducing costs where practicable. We have sought to ease some of the impact to customers by spreading major investments over several regulatory periods, and smoothing tariffs to avoid sharp increases. We have looked into alternative lower cost options to reduce some of the ongoing challenges facing our network such as voltage issues in the distribution network and the limitations of our operational technology. We have listened and we have acted, reducing our total expenditure forecast for the next regulatory period (opex and capex) by $58 million.

We have sought to provide the AER with more information on our plans and I am confident we can continue to work together over the coming months to finalise a revenue determination that will allow us to continue to deliver quality services to our customers.

Our aim continues to be to build on the progress we have made as a business over recent years. Our revised proposal will allow us to do that and ensure Territorians continue to experience a reliable, affordable and increasingly lower-emission electricity supply.

We will continue on a journey towards a lower emission power system, using contemporary technologies and offering customers the services they need. We will do this while making sure vulnerable customers are not left behind.

Thank you to the many customers, People's Panel participants, energy partners and interested stakeholders who have helped shape and inform our regulatory proposals. I welcome your feedback on this revised proposal and any other aspect of our services.

Djuna Pollard


PowerWater

Overview of our revised proposal

Since submitting our plans in January 2023 for the 2024-29 regulatory period, we have not stood still. Over the past ten months we have taken the opportunity to review our plans, updating them to reflect more recent information and taking on board feedback from our stakeholders, the AER, and most importantly, our customers.

We have kept the conversation going since January, holding a series of People's Panel sessions across the Territory and more than 30 meetings with large and small customers. The engagement journey we've been on over the past two years has shaped our plans for the next regulatory control period, and these most recent rounds of customer input have sharpened our revised proposal.

We have re-tested our strategic priorities for the next five years, and consulted on those projects that came too late in the initial forecasting process to test thoroughly with customers. Our customers and stakeholders have told us they remain supportive of initiatives to utilise more renewable generation, and have expressed a preference for simplicity and transparency in their energy costs. Customers have again stressed the importance of keeping prices affordable and protecting vulnerable customers from sharp increases in the cost of living.

Our strategic priorities for 2024-29 remain:

- Facilitating renewables
- Improving utilisation
- Managing the health of our network
- Uplifting our systems and people

We have factored these conversations into our revised proposal, and attempted to reduce expenditure forecasts or spread costs over longer timeframe, helping to soften the impact on energy prices.

In its draft decision, the AER accepted most aspects of our initial regulatory proposal. There are some outstanding matters and points of difference regarding our opex and capex forecasts, however, Power and Water and the AER are aligned on the vast majority of the constituent decisions.

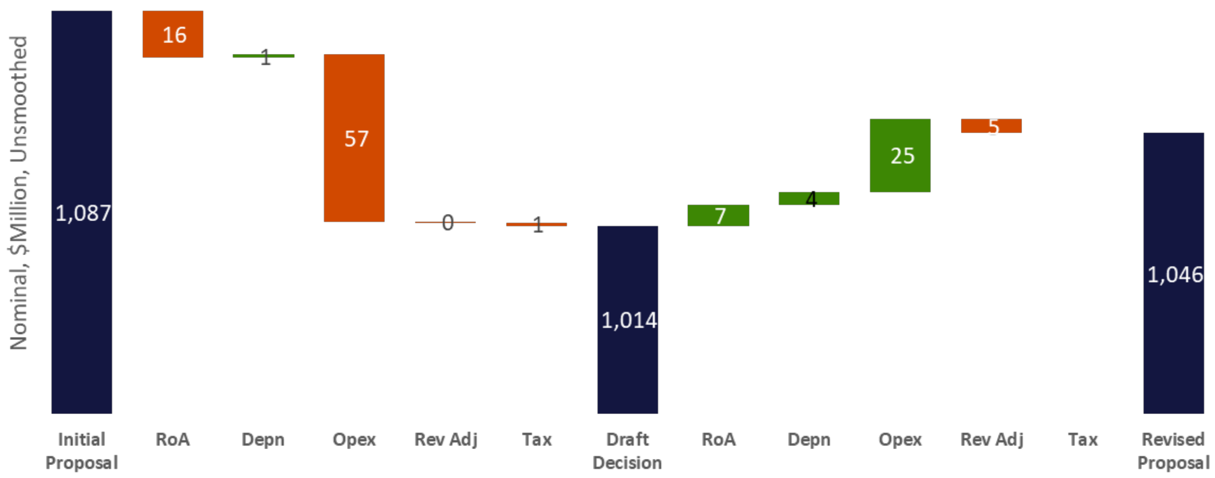
We appreciate the AER's guidance in its draft decision and have worked hard to provide the additional evidence and justification sought by the AER.

The following sections present an overview of the key components of our revised proposal. A summary of our responses to each of the constituent components of the AER's draft decision is provided at the end of this overview section.

Revenue

Our revised proposal results in an unsmoothed (i.e., building block) revenue allowance of $995.8 million (or $1,045.5 million in nominal dollars). As shown in Figure OV.1, this is a $31.5 million ($nominal) increase compared with the AER's draft decision, but $41.7 million ($nominal) less than our initial proposal.

Figure OV.1: Waterfall of SCS unsmoothed building block movements from initial proposal to the AER's draft decision and our revised proposal ($ million, nominal)[3]



The biggest change in the revenue allowance relates to opex step changes, of which $46.7 million were rejected in the draft decision. In this revised proposal we have revisited our opex step change forecasts and have provided additional justification for the operating cost increases.

Our proposed changes to forecast capex have relatively little impact on revenue during the period. This is because the greatest variance between the AER's draft decision and our revised forecast relates to the single site consolidation project, which is not scheduled to be delivered until towards the end of the next regulatory period. Capitalising projects has the effect of deferring cost recovery over the life of the assets, which means the revenue impact of the proposed $76.1 million single site consolidation project[4] is spread over several regulatory control periods.

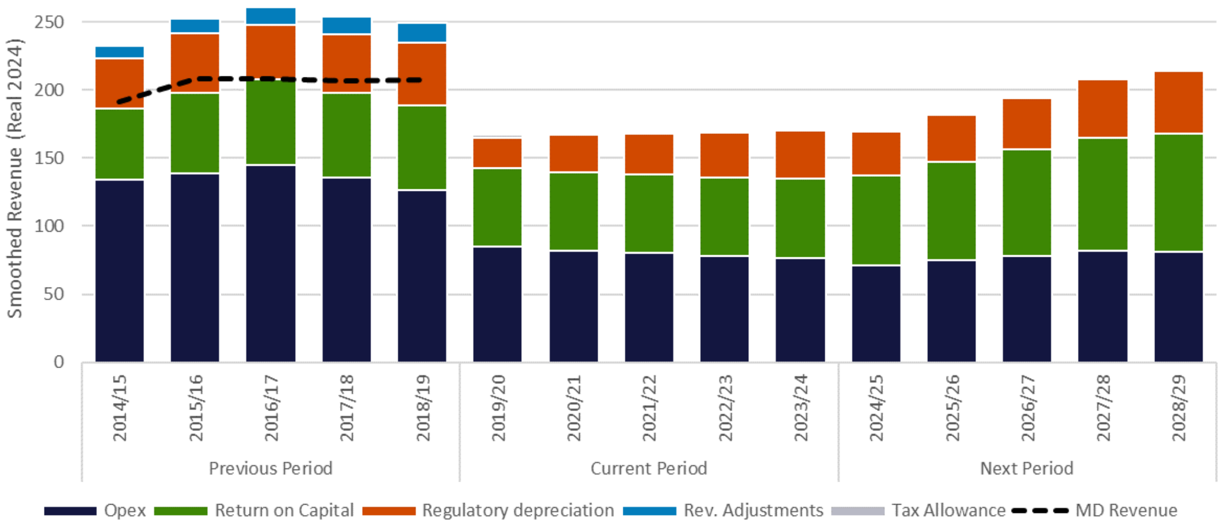
To help reduce the impact on customer's electricity prices, where practicable we have sought to reduce or spread the costs of major capex programs over more than one regulatory period. Examples include our operational technology (**OT**) capability investments and distributed energy resources (**DER**) integration project, which we have scaled back during 2024-29 and aim to deliver in a more staged and considered manner. These projects are discussed further below and in section 3 of this document.

Figure OV.2 shows how our revised revenue proposal compares with the previous two regulatory periods.

3 Consistent with the AER's draft decision, we have reported revenue in nominal dollars and expenditure in real $2024. This means that values for some of the expenditure related items shown in the waterfall in nominal dollars (e.g., opex) will differ from those reported in text in real $2024.

4 The full project cost is $134.8 million, however, only $76.1 million of this will be recovered via network tariffs.

Figure OV.2: Revised SCS smoothed revenue proposal compared with prior regulatory allowances, $ million real 2024



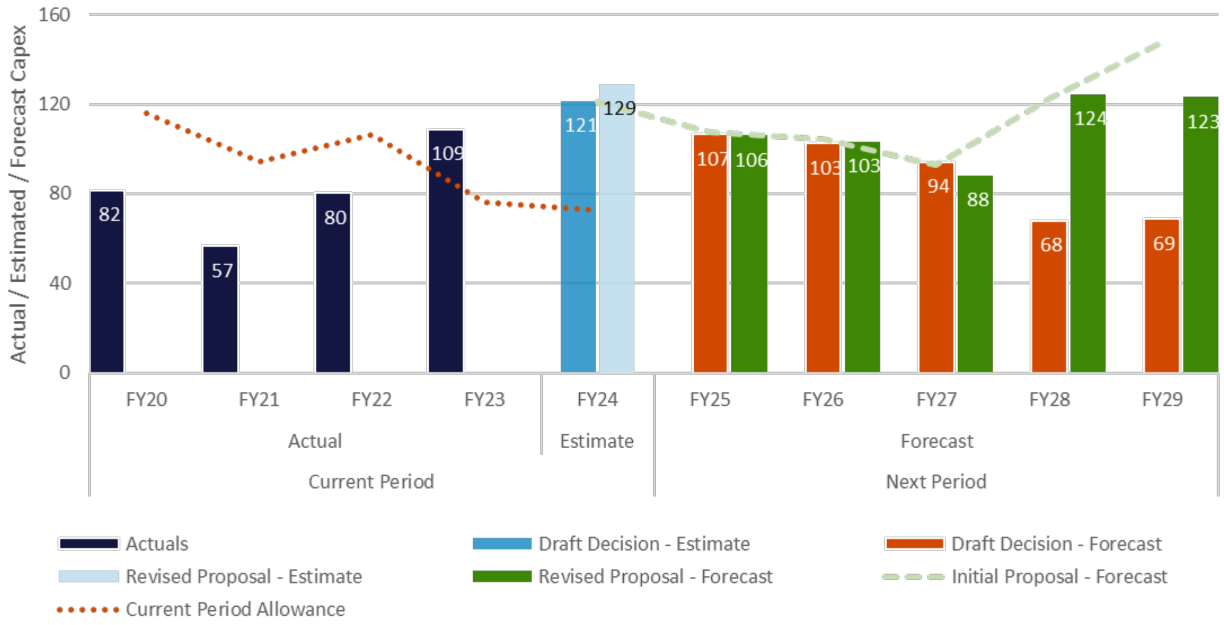
Our forecast revenue is 13.6 per cent higher than 2019-24 (in real terms), but 23.0 per cent lower than the allowance set by the jurisdictional regulator – the NT Utilities Commission – in 2014-19. Following the Utilities Commission's determination, we received a Ministerial Direction to reduce our revenue allowance by 18.2 per cent (the dotted line in Figure OV.2).

Forecast capex

Figure OV.3 shows our revised capex forecast compared with our initial proposal and draft decision. We have updated FY23 capex to reflect actual expenditure rather than the estimate included with our initial proposal. We also updated our estimate for FY24 to reflect higher estimated capitalised overheads.[5]

[5] We used the AER's standardised SCS capex forecast model to estimate capitalised overheads for FY24. These updated automatically after adding actual FY23 capitalised overheads to that model.

Figure OV.3: Revised SCS capex forecast vs the initial proposal and draft decision, $ million real 2024



The key changes in our capex forecast compared with the draft decision are summarised below:

- **DER integration**: The AER removed the majority of costs associated with managing the negative impacts of increasing Distributed Energy Resources (**DER**) on our network. It only allowed $1.1 million of capex associated with installer outreach programs to manage compliance with inverter standards. The AER's draft decision highlighted that alternative, lower-cost options beyond those included in the supporting business case should be considered, and that further detailed analysis of voltage and hosting capacity should be undertaken.

  We have conducted additional analysis of voltage management of our network, based on available smart meters and using tools that have become available from the Alice Springs Future Grid program. This analysis indicates emerging voltage management issues. Coupled with the forecast system security risks at times of minimum demand, we consider that an investment in DER management is compelling. We have revisited the assumptions of our project, and following additional feedback from consumers, propose to deploy the core infrastructure that will lay the foundations for implementing dynamic operating limits when required. We will complement this core infrastructure with a focus on engagement and compliance, such that we minimise the cost and maximise the benefits to consumers. Accordingly, the revised cost of addressing voltage issues in the low voltage network has reduced by $9.5 million to $3.7 million (with a similar reduction to the required opex). The revised DER integration project is discussed in more detail in section 3, and the revised business case is provided in Attachment 3.1.

- **Operational Technology capability uplift**: The AER removed $21.6 million of costs associated with this program of work as it considered the program was not fully required for the 2024-29 period, and the information provided in support of the program had not sufficiently demonstrated the gaps in safety, reliability or compliance that are not already addressed in business as usual expenditures.

  We have revisited the scope and expenditure forecast for this project and provided more information on the drivers for bringing Power and Water's operating technology up to date and in line with standard industry practice. We have targeted the proposed solution of our operational technology (**OT**) uplift program, prioritising the most critical and highest impact OT improvements for the next regulatory period and taking a more pragmatic approach to what OT systems should be upgraded and when. This has reduced the project capex costs by $5.8 million to a revised estimate of $15.8 million and results in a positive net present value (**NPV**). The revised OT capability uplift project is discussed in more detail in section 3, and the revised business case, roadmap and cost benefit analysis are provided in Attachments 3.2, 3.3 and 3.4.

- **Single site consolidation**: The AER removed $89.8 million of costs associated with this project due to a lack of supporting information on the scope of the project and options considered. This information was absent in the January 2023 submission as the project was still at a conceptual stage of design. The Consumer Challenge Panel also noted that it had not observed any engagement with customers or stakeholders on this project.

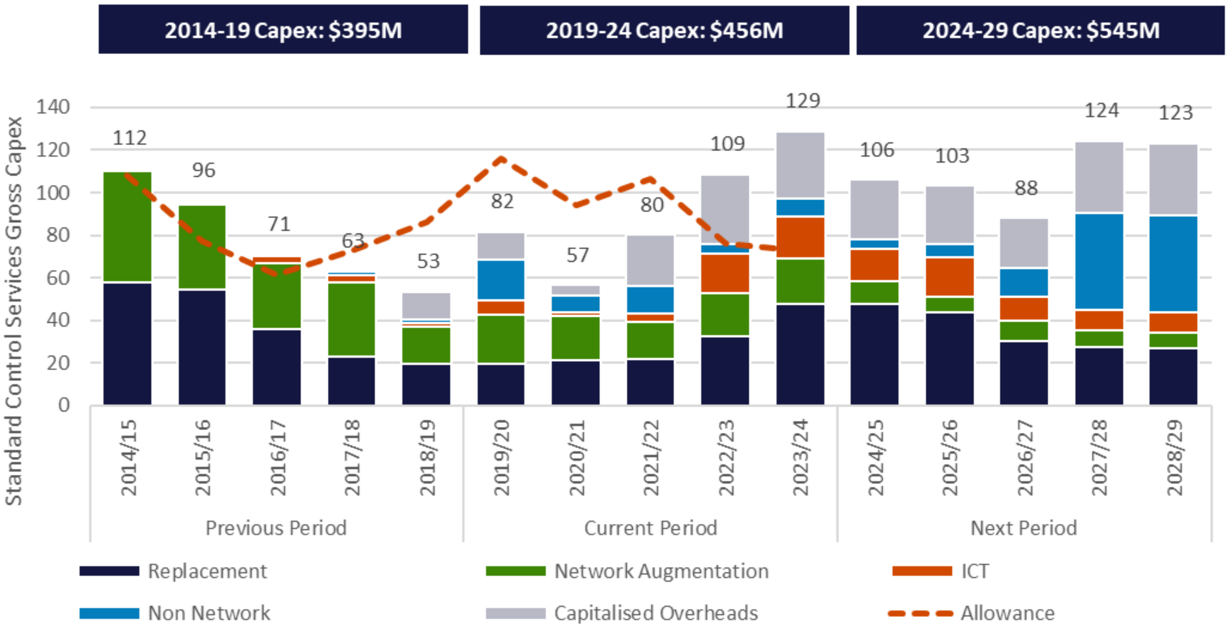
  Since submitting the initial proposal, we have continued our customer engagement program and consulted with stakeholders on the single site consolidation project. Customers and stakeholders have expressed support for the project and appreciate the financial, service quality, and cultural benefits of relocating more of Power and Water's staff and activities into a single site. We have developed a more detailed business case and tightened our capex forecast for the project, reducing the amount proposed to be recovered from network tariffs from $89.8 million, to $76.1 million. The revised single site consolidation project is discussed in more detail in section 3, and the revised business case provided at Attachment 3.5.

Table OV.1 shows our revised capex forecast by category, and Figure OV.4 shows how our revised capex forecast compares with previous regulatory periods.

Table OV.1: Revised SCS capex forecast 2024-29, $ million real 2024

Capex category	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Replacement	47.5	43.7	30.2	27.2	26.9	**175.5**
Augmentation	9.5	6.0	7.2	5.4	4.9	**33.0**
Connections	1.4	1.4	1.4	1.4	1.4	**7.0**
Property	1.1	0.8	8.4	40.9	41.6	**92.8**
ICT	15.2	18.5	11.2	9.7	9.3	**64.0**
Fleet	1.6	3.4	3.4	3.1	2.4	**13.9**
Non-network capex – other	1.8	2.1	1.7	1.5	1.6	**8.6**
DER	0.1	0.1	1.0	1.5	1.0	**3.7**
Capitalised overheads	28.0	27.3	23.6	33.8	33.9	**146.6**
Gross capex	**106.1**	**103.4**	**88.1**	**124.4**	**123.1**	**545.1**
Less customer contributions	-5.0	-0.3	-0.3	-0.3	-0.3	**-6.1**
Less disposals	-0.2	-0.2	-0.2	-0.2	-0.2	**-0.8**
Net capex	**100.9**	**102.9**	**87.7**	**124.0**	**122.7**	**538.2**

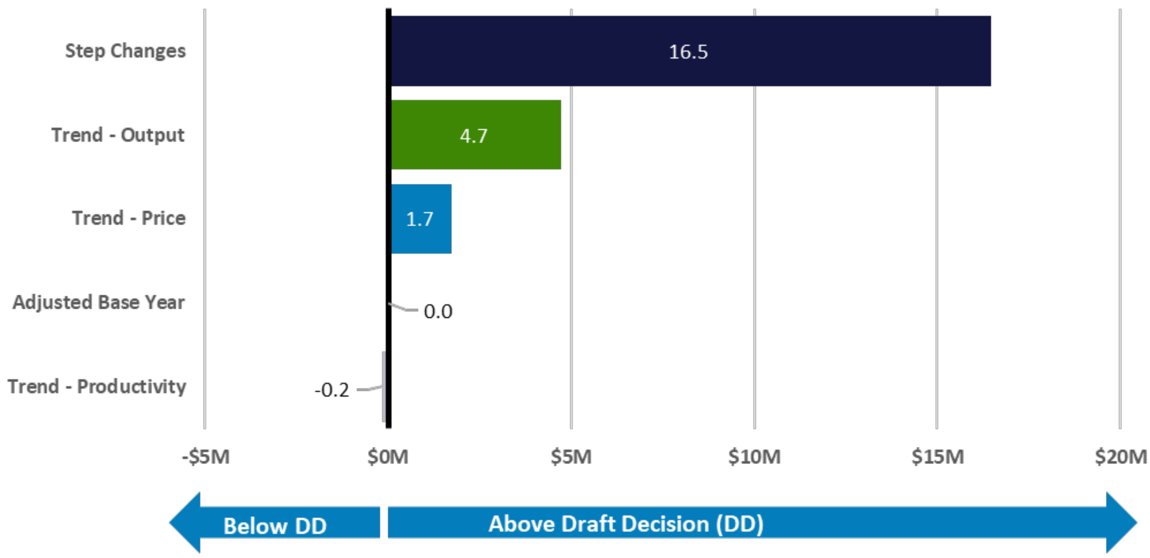
Figure OV.4: Revised SCS capex forecast by category compared with prior periods, $ million real 2024



Forecast opex

Figure OV.5 shows our revised opex forecast compared with the draft decision.

Figure OV.5: Change in SCS opex forecast from draft decision to revised proposal by component, $ million real 2024



The key changes in our opex forecast relates to step changes. The AER excluded $46.7 million of the proposed $52.2 million of opex step changes for the period, citing a need for further justification. In response we are proposing step changes totalling $22.0 million, as described in more detail in section 5 and in the Step Change Model provided with this submission (Attachment 5.4), comprising:

- **Cyber security** ($5.0 million) – the AER approved the proposed $4.4 million step change, subject to Power and Water providing further information on the scope, actions, outcomes and efficiency of the cyber security expenditure. We have provided additional supporting information as requested by the AER in Attachment 3.8.[6] The forecast step change was also updated to align with the business case provided with the initial proposal, to correct a transcription error.

- **Insurance premium** ($4.9 million) – the AER excluded our proposed $4.9 million insurance step change estimate, advising that Power and Water needs to provide an independent estimate of our insurance premium for it to be able to approve any insurance costs. We have provided this independent estimate in Attachment 5.1.
- **Cloud migration – Meter to Cash** ($3.3 million) – the AER excluded the proposed $4.0 million step change on the basis Power and Water needs to provide more information on the scope, actions, outcomes and efficiency of the cloud migration expenditure. We have provided this information in Attachment 5.2.
- **OT capability uplift** ($3.9 million) – the AER excluded the OT capability uplift capex project and consequently excluded the proposed $18.8 million opex step change associated with it. We have since revised the OT capability uplift project forecast downwards, and are proposing a smaller associated opex step change. We have provided an updated business case, roadmap and cost benefits analysis in Attachments 3.2 to 3.4.
- **Future network - DER integration** ($4.9 million) – the AER excluded $13.1 million of the proposed step change for Future Networks, including the bulk of opex associated with the DER integration project. We have revised our future network step change prioritising the most critical and highest impact initiatives for the next regulatory period, taking a more pragmatic approach to the selection of initiatives for the DER integration project. We have provided an updated business case for the DER Integration project in Attachment 3.1.

As shown in Figure OV.5, the revised opex forecast reflects a $6.3 million net increase to the trend components, which result from applying the latest real wage escalation and output growth factor inputs. With these updates, the revised trend components contribute $0.3 million to our revised proposal opex forecast.

Table OV.2 shows our revised capex opex by category.

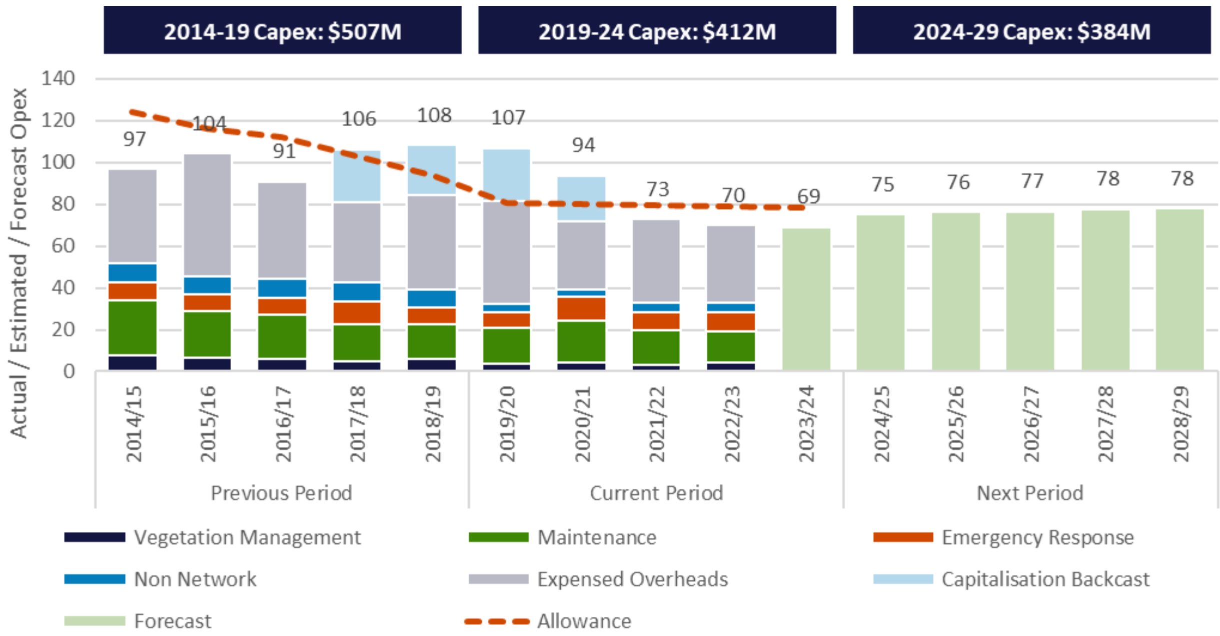
Table OV.2: Revised SCS opex forecast 2024-29, $ million real 2024

Opex forecast component	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Base operating costs	72.3	72.3	72.3	72.3	72.3	361.4
Trend adjustments	-0.5	-0.1	0.1	0.3	0.5	0.3
Step changes						
Cyber security	1.0	1.0	1.0	1.0	1.0	5.0
Insurance premiums	0.7	0.9	1.0	1.1	1.2	4.9
Cloud migration	0.7	0.7	0.7	0.7	0.7	3.3
OT capability uplift	0.6	1.1	0.7	0.8	0.8	3.9

6 Note the AER also included $11.4 million of capex for cyber security as a placeholder, subject to this same additional information being provided. We have retained the proposed $11.4 million in our proposed capex forecast.

Opex forecast component	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Future network (DER integration)	0.4	0.4	1.0	1.6	1.6	4.9
Total step changes	**3.4**	**4.0**	**4.3**	**5.1**	**5.2**	**22.0**
Sub-total	**75.2**	**76.2**	**76.7**	**77.7**	**78.0**	**383.7**
Debt raising costs	0.7	0.7	0.7	0.7	0.7	3.5
Total	**75.9**	**76.9**	**77.4**	**78.4**	**78.8**	**387.2**

Figure OV.6: Revised SCS opex forecast by category compared with prior periods (excluding debt raising costs), $ million real 2024



Tariff structures

Our revised tariff proposal remains broadly unchanged from our initial proposal, except for an adjustment to remove the proposed 'super user' tariff (Tariff 7). Tariff 7 was conceived as a tariff band for very large high voltage (**HV**) connected customers that consume more than 10,000 MWh p.a. such as heavy industry, datacentres etc, offering a flat anytime energy charge. Its purpose was to provide a simple charging structure for our 13 largest users and help attract new major customers who seek simplicity in their tariff structures.

The AER did not approve Tariff 7 as it was not based on the users' long run marginal costs (**LRMC**), and considered that major users should be able to manage a demand-based charge rather than a flat tariff. We accept this finding and have removed Tariff 7 from our revised proposal. All major users will instead be offered Tariff 6, which is based on users' LRMC and includes a demand charge.

The AER accepted our proposed improvements to customer segmentation, the potential introduction of time of day signals, changes to demand charge periods, and our proposal to run tariff innovation trials with NT retailers. We have therefore retained these elements in our revised tariff structure proposal.

Figure OV.7 summarises our revised tariff structure proposal. Further information is provided in section 7 and Attachments 7.1 and 7.2, and 7.3.

Figure OV.7: Overview of our revised proposal

Tariff class	Tariff	Description	System Availability Charge (SAC) ($/NMI/Day)	Energy (KWH's)				Peak Demand (KVA)	
				Anytime (24/7)	Low Period	Mid Period	High Period	On Season	Off Season
LV<750MWh	1	Residential customers with accumulation meter	●	●					
	2	Non-residential customers with accumulation meter	●	●					
	3a (new)	Residential with smart meter consuming 0-160 MWh pa	●		●	●	●		
	3b (new)	Non-Residential with smart meter consuming 0-160 MWh pa	●		●	●	●		
	3c (new)	All customers with smart meter consuming 160-750 MWh pa	●		●	●	●		
	4	All Unmetered		●					
LV>750MWh	5	All LV customers consuming above 750MWh pa	●	●				●	●
HV	6 (revised)	All HV customers	●	●				●	●

Better segmentation of the contestable PO market

No segmentation of our HV

Time of day signals to support load shifting if PO is modified

Removed demand based on stakeholder feedback for some tariffs and modified the periods for others

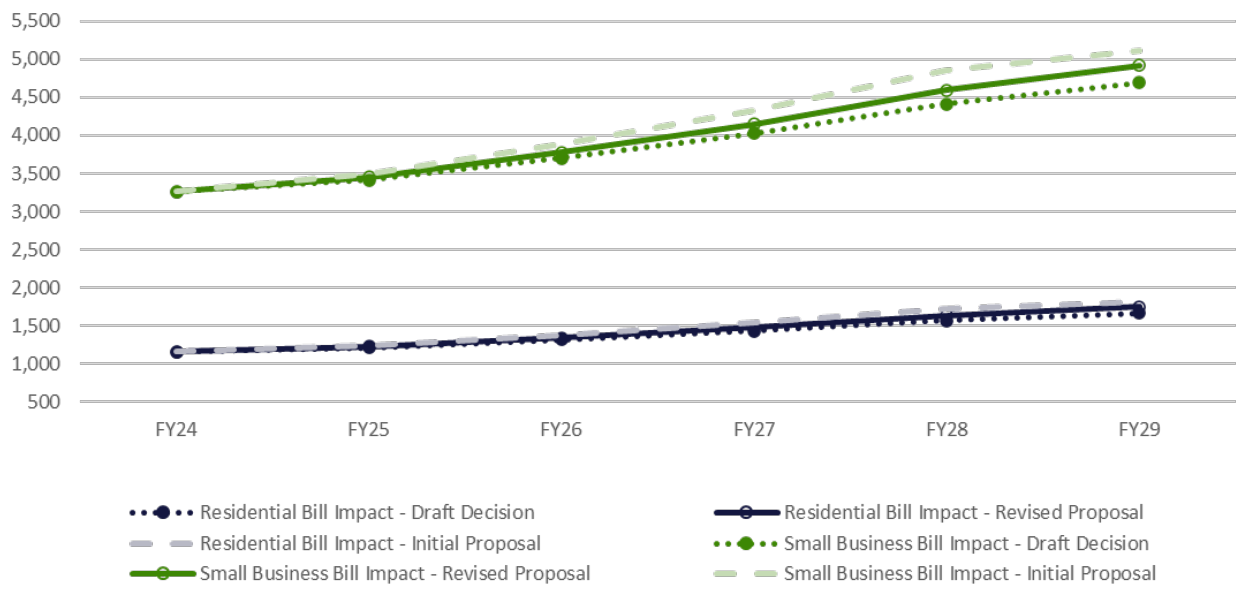
Note: PO = NT Electricity Pricing Order

Indicative price impact

The impact of the revised revenue proposal compared with the draft decision is small. As shown in Figure OV.8, the indicative average residential bill impact[7] over the next regulatory period of our revised revenue allowance is $37.8 (nominal) per year (2.7 per cent) higher than the draft decision, but $46.1 (nominal) per year (3.1 per cent) lower than our initial proposal.

[7] The indicative bill impact shown here is calculated using the AER's standard approach and do not reflect the specific tariffs or customer groupings proposed by Power and Water in the initial proposal.

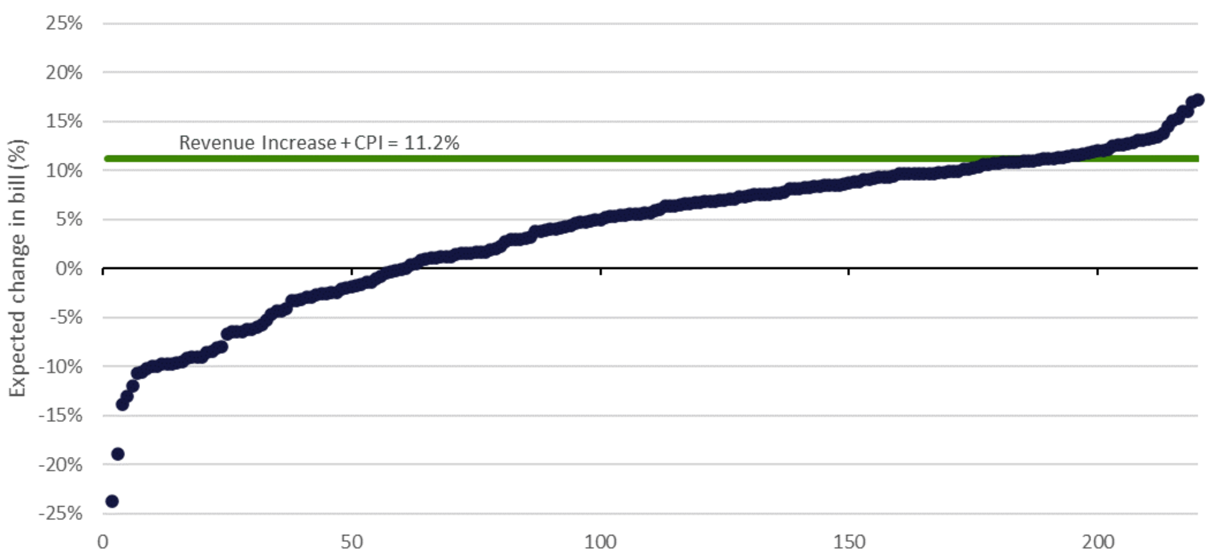
Figure OV.8: Indicative residential and small customer bill impact, $ per customer per year, nominal



Note: The revenue (and therefore bill) profile adopted in the initial proposal was retained in the AER's Draft Decision and is retained for this revised proposal

Figure OV.8, is indicative only. It should be highlighted that the majority of our customers[8] are covered by the NT Government's Electricity Pricing Order. This caps the amount that customers pay, with the Government subsidising retailers to cover the actual cost of service. How much of the network tariff increases flow through to non-Pricing Order customers is ultimately determined by electricity retailers. Figure OV.9 illustrates the potential impact to our major customers. These customers encompass anyone connected to the high voltage network as well as all low voltage customers consuming greater than 750 MWh per annum. Approximately 14.5 per cent of our major customers will experience an impact greater than 11.2 per cent, with the majority experiencing an impact less than 11.2 per cent.

Figure OV.9: Major customer bill impact from 2023-24 to 2024-25 (nominal)



[8] Currently, customers who use less than 750 MWh per annum are protected by the NT Electricity Pricing Order.

PowerWater

Incentives and pass throughs

Incentive schemes

Our revised proposal for incentives is unchanged from our initial proposal. Consistent with the AER's draft decision, the incentive framework for 2024-29 will comprise the following:

- Version two of the efficiency benefit sharing scheme (**EBSS**).
- A capital expenditure sharing scheme (**CESS**) as set out in the AER capex incentive guideline.
- A demand management incentive scheme (**DMIS**) and demand management innovation allowance mechanism (**DMIAM**).

This suite of incentive schemes provides Power and Water rewards for staying within approved expenditure allowances, and enables us to share those efficiencies with customers in the form of a revenue adjustment in the following regulatory period. Critically, the DMIS and DMIAM provide an allowance for us to pursue innovative technologies and seek alternatives to traditional network solutions, which can be expensive. The proposed incentive framework is a step forward for the NT, bringing us more closely aligned with the regulatory framework in other Australian jurisdictions. Over the next regulatory period we will also begin collecting data and implementing systems that will allow us to add a service performance and/or a customer service performance incentive scheme in future regulatory periods.

Cost pass throughs

We have modified our suite of nominated cost pass through events. We have maintained our position on a confidential pass through event that the AER did not approve in its draft decision. The AER considered more information was required on the need for its inclusion as a nominated pass through event. We have provided additional information to substantiate this nominated pass through event in a confidential attachment.

We have added a nominated pass through event to allow Power and Water to recover costs if it is required to pay for voltage management, network support or system strength services (known as essential system services) during the next regulatory period. This matter was raised by Territory Generation in its public submission on our regulatory proposal.[9]

Territory Generation highlighted that it was incurring costs for provision of these essential system services, which it believed should be met by the network operator under local instruments. It considered that ongoing market reform in the NT was likely to introduce obligations for the network operator to provide or procure essential system services.

There remains significant uncertainty as to whether the change flagged by Territory Generation would qualify as a regulatory change event under the Northern Territory National Electricity Rules (**NT NER**). There is also a question around the timing of this change. As the generation mix in the NT power system changes, there are likely to be instances where a network solution may not be the most efficient method to address a need that arises. It may well be the case that provision of essential system services results in a better outcome for customers, and that these services should be provided by the network operator. A nominated

9 Available at: https://www.aer.gov.au/system/files/Territory%20Generation%20-%20Submission%20-%202024-29%20Electricity%20Determination%20-%20PWC%20-%20May%202023.pdf

cost pass through mechanism to enable this as an option is therefore a prudent inclusion in the regulatory determination.

Metering

We have made two key changes affecting the proposed metering revenue requirement and associated prices:

1. We propose to maintain the current rate of smart meter installations across the 2024-29 regulatory period (~11,000 per year), rather than the ~6,000 per year in the initial proposal. As shown in Table OV.3, this means we will have replaced all basic meters with smart meters by the end of the period. This change is consistent with feedback from customers and the AER that it would be preferable to accelerate the smart meter installation program and complete it sooner rather than later.
2. We have revised the metering revenue requirement to reflect the revised capex forecast for the single site consolidation project, which is partially allocated to alternative control services. The revised metering revenue requirement is shown in Figure OV.10, and the revised metering prices are in Table OV.4.

Table OV.3: Change in smart vs basic meter populations over 2024-29 regulatory period

	2024-25	2025-26	2026-27	2027-28	2028-29
Initial regulatory proposal (~6,000 smart meter replacements per year)					
Smart meters	48,028	52,428	59,041	65,458	71,599
Basic meters	41,232	37,391	31,340	25,487	19,913
Total	89,260	89,819	90,381	90,945	91,512
Revised regulatory proposal (~11,000 smart meter replacements per year)					
Smart meters	55,909	66,002	75,837	85,476	91,673
Basic meters	33,511	23,977	14,705	5,630	0
Total	89,420	89,980	90,542	91,106	91,673

Figure OV.10: Metering revenue requirement, $ million real 2024

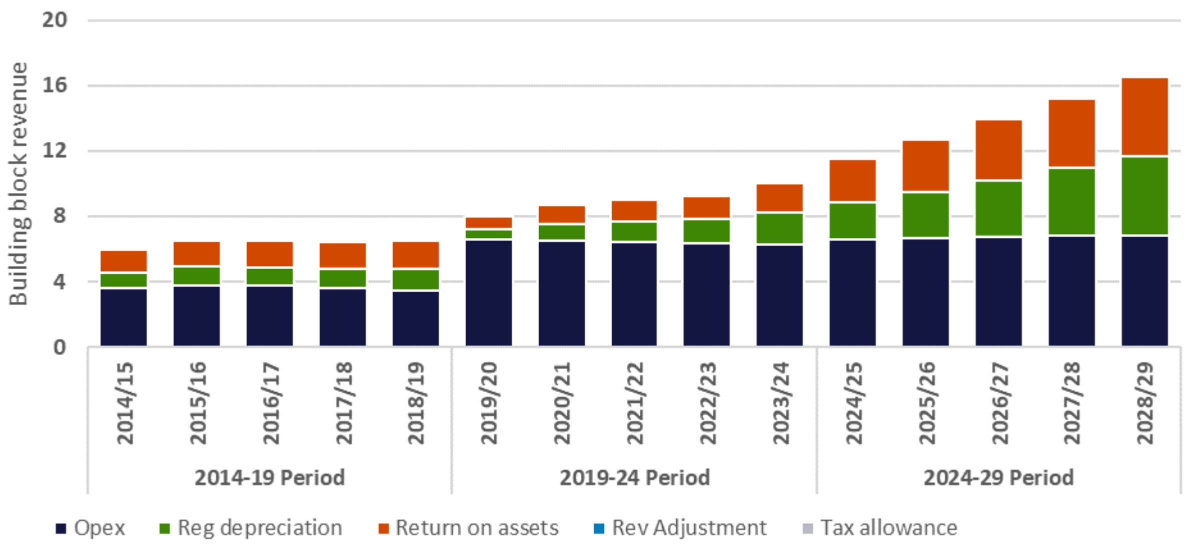


Table OV.4: Metering prices, $ nominal per meter

	2024-25	2025-26	2026-27	2027-28	2028-29
1 Phase Meters (including repayment)	131.1	134.8	138.5	142.4	146.4
3 Phase Meters	173.7	178.5	183.5	188.7	194.0
LV CT	693.1	712.5	732.4	752.9	774.0
HV	2,391.2	2,458.1	2,527.0	2,597.7	2,670.4

Fee-based and quoted services

We have revised our labour and overhead rates associated with fee-based and quoted services in line with the AER's benchmark efficient rates. This has reduced each of our fee-based services, and will reduce the costs associated with our quoted services for the next regulatory period.

We have also reduced three of our fee-based metering services to exclude the costs associated with the physical meter and communications assets. This is because these assets will be recovered through depreciation through the Regulatory Asset Base (**RAB**). These fees now only include labour costs.

The updated fees and labour rates are provided in Attachment 9.1.

Summary of responses to the constituent components of the AER's draft decision

Table OV.5 summarises how we are responding to the constituent components[10] of the AER's draft decision on standard control services. Table OV.6 summarises our response to the AER's draft decision on alternative control services.

Where we have revised our proposal, discussion of our position and justification is provided in sections 1 to 9 of this document, and in the relevant attachments noted in Table OV.5. Where we are accepting the AER's draft decision with no changes, no further commentary is provided in this document.

Table OV.5: Overview of how Power and Water is responding to the constituent components of the AER's draft decision on standard control services

Constituent component	AER draft decision	Our response
Classification of services	The AER maintained its classification of distribution services as per those set out in its final Framework & Approach (**F&A**) published in July 2022[4], with the exceptions of classifying each component of connection services separately and removing standard connection from the service classification table.	We accept this decision, with no changes.[11]
Annual revenue requirement	The AER determined a total revenue requirement of $1,014.0 million ($ nominal, unsmoothed) over the 2024-29 regulatory period. This is a reduction of $73.2 million (6.7 per cent) on Power and Water's proposed $1,087.2 million. The decrease in overall revenue is mainly driven by reductions to forecast capex and opex.	We propose a revised revenue requirement of $1,045.5 million ($ nominal, unsmoothed). We accept the AER's draft decision on all revenue building blocks, except for opex and the return on and of capital (specifically the capex forecast component). Our revised revenue building block calculation is provided in section 2.2.
Regulatory control period	Regulatory control period is 1 July 2024 to 30 June 2029.	We accept this decision, with no changes.
Forecast capex	The AER determined forecast capex of $432.8 million ($2023–24), a 23.8 per	We have provided a revised capex forecast and additional information to justify the

10 As described on page 38 of the AER's Draft Decision Overview document, available at: https://www.aer.gov.au/system/files/2023-10/AER%20-%20Draft%20Decision%20Overview%20-%20Power%20and%20Water%20Corporation%20-%202024-29%20Distribution%20revenue%20proposal%20-%20September%202023.pdf

11 It should be noted that the AER's draft decision service classification. Figure 13.1 includes a public lighting service, however, the 'detailed classification decision' in Appendix A does not include one for Power and Water Corporation. We understand that Figure 13.1 was adopted for all distribution networks in the determination round to cover those who do provide such services. We have sought advice from the AER, and the AER has confirmed it's draft decision did not classify a public lighting service for 2024-29 consistent with our current service classification and our expectation not to provide the service in that period. We have maintained that treatment in our revised proposal.

Constituent component	AER draft decision	Our response
	cent reduction on Power and Water's forecast of $568.0 million. The AER approved all proposed replacement, augmentation, connections, and fleet as proposed. The AER excluded a project to uplift Power and Water's OT, and adjusted the property forecast. The AER also reduced the forecast for a new project to increase network hosting capacity for DER.	following projects that are excluded in the draft decision: • Single site consolidation ($76.1 million). • OT capability uplift ($15.8 million). • DER integration ($3.7 million). We have also adjusted for more recent inflation and real wage escalation values, and a consequential adjustment to capitalised overheads. This results in a revised forecast capex proposal of $538.2 million. Our revised capex forecast is discussed in section 3.2 and Attachments 3.1 to 3.8.
Contingent projects and trigger events	AER accepted four out of five of the proposed contingent projects, only excluding the *Unlocking existing large scale renewable generation in Darwin-Katherine* project. The AER proposes revised trigger events for each project.	We accept the AER's decision on the four approved contingent projects, including the revised trigger events. We have provided additional information to substantiate the need for *the Unlocking existing large scale renewable generation in Darwin-Katherine* contingent project. The revised contingent project is based on more recent power system modelling, and has been split into two components to better reflect the system strength and voltage management issues being addressed. Our revised contingent project proposal is provided in section 4.2 and Attachment 4.1.
Forecast opex	The AER determined forecast opex of $364.4 million ($2023–24), a 12.3 per cent reduction on Power and Water's forecast of $415.3 million. The AER approved 2021-22 as the base year, with minor adjustments to reflect contemporary data. The AER also accepted Power and Water's trend adjustments, again updated for contemporary data. The AER excluded five out of six proposed step changes, requesting further information on each to better substantiate the proposal.	We accept the AER's decision on the opex base year and trend changes. We will retain 2021-22 as the efficient base year. We do not accept the AER's adjustments to step changes. We have provided a revised forecast and additional requested information to substantiate the basis for the excluded step changes, except for the proposed regulatory obligations step change, which we accept should not be included in the opex forecast. The revised step changes are: • Cyber security ($5.0 million). • Insurance costs ($4.9 million). • Cloud migration ($3.3 million).

Constituent component	AER draft decision	Our response
		• OT capability uplift ($3.9 million). • Future network ($4.9 million). We have also adjusted the forecast for 2023 actual customer numbers and line length growth parameters, inflation and real wage escalation. This produces a revised opex forecast of $387.2 million. Our revised opex forecast is discussed in section 5.2 and Attachments 5.1 to 5.4.
Rate of return	Allowed rate of return for 2024-25: 5.61 per cent, subject to annual update. Value of imputation credits for the 2024-29 period: 0.57	We accept this decision, with no changes.
Opening RAB	Opening RAB at 1 July 2024: $1,270.2 million ($ nominal).	We accept the AER's RAB calculation method. We have updated the opening RAB to incorporate FY23 actuals. The revised RAB calculation is provided in Attachment 2.2.
Cost of tax	The AER's draft decision on Power and Water's estimated cost of corporate income tax is zero for each regulatory year of the 2024–29 regulatory control period.	We have recalculated the tax allowance using the AER's methodology, which – consistent with the draft decision – projects a zero tax expense for the 2024-29 period.
Depreciation	The AER has updated the proposed depreciation schedules to reflect the latest information on the expected inflation rate. This increases the regulatory depreciation by $1.8 million, bringing the total to $188.9 million.	We have updated the depreciation forecast to incorporate FY23 actuals. The revised depreciation forecast calculation is provided in section 2.2.2.
Depreciation approach	The AER determined the depreciation approach to be used to establish the RAB at the commencement of Power and Water Corporation's regulatory control period as at 1 July 2029 is to be based on forecast capex.	We accept the AER's approach to depreciation. The revised depreciation forecast calculation is provided in section 2.2.2.
Incentive schemes	The AER included the following incentive schemes: • Version two of the EBSS. • A CESS as set out in the AER capex incentive guideline. • A DMIS and DMIAM.	We accept this decision, with no changes.

Constituent component	AER draft decision	Our response
	The AER did not include: • An export services incentive scheme (**ESIS**). • A service target performance incentive scheme (**STPIS**). • A customer service incentive scheme (**CSIS**).	
Form of price control	The AER applied a revenue cap form of price control in accordance with its F&A.	We accept this decision, with no changes.
Distribution Use of Service (**DUoS**)	The AER required Power and Water to maintain a DUoS unders and overs mechanism. It must provide information on this mechanism to the AER in its annual pricing proposal.	We accept this decision, with no changes.
Reporting designated pricing proposal charges	The AER required Power and Water must report on its recovery of designated pricing proposal charges via the unders and overs mechanism. It must provide information on this mechanism to the AER in its annual pricing proposal.	We accept this decision, with no changes.
Reporting jurisdictional scheme amounts	The AER required Power and Water to report on its recovery of jurisdictional schemes amounts via the unders and overs mechanism. It must provide information on this mechanism to the AER in its annual pricing proposal.	We accept this decision, with no changes.
Pass through events	The AER's draft decision was to apply the following nominated pass through events: • Insurance coverage. • Insurer's credit risk. • Natural disaster. • Terrorism. The AER rejected a confidential pass through on the basis it required more information to be able to determine whether it is required as a nominated pass through event.	We accept the AER's draft decision on our nominated cost pass through events with one amendment to address the risk of a cyber security event. We have provided additional information to help the AER form a view on our proposed confidential nominated cost pass through event. We have also included a further nominated pass through event to provide for network support services, and which is not currently reflected in the NT NER (see section 6.2.2).

Constituent component	AER draft decision	Our response
Tariff structure statement (**TSS**)	The AER accepted most elements of Power and Water's tariff structure statement, but requires a change to include a cost reflective charging parameter in the proposed super user tariff (Tariff 7).	We accept in principle the AER's proposed changes to the TSS regarding Tariff 7. We have adopted a slightly different approach to that proposed by the AER to achieve the same outcome. It involves removing Tariff 7 and adding the super users into the approved Tariff 6, which already has a demand charging component that reflects the long run marginal cost of providing services. Our revised TSS is discussed in section 7.2 and Attachments 7.1 to 7.4.
Negotiating framework and negotiated distribution services criteria	The AER accepted the negotiating framework proposed by Power and Water. The AER applied the negotiated distribution services criteria published in February 2023.	We accept this decision, with no changes.
Connections policy	The AER proposed an alternative Connection Policy, which was amended in consultation with Power and Water.	We accept this decision, with no changes.
Other inputs and values	The AER's draft decision was that all other appropriate amounts, values and inputs are as set out in its draft determination.	We accept the AER's calculation methods and have made updates to several inputs and values to reflect the latest information. A summary of the updated inputs and values is provided in Attachment 2.5.

Table OV.6: Overview of how Power and Water is responding to the AER's draft decision on Alternative Control Services

Service	AER draft decision	Our response
Form of control for ancillary network services	The AER maintained the final position from the F&A to apply price caps to ancillary network services.	We accept this decision, with no changes.
Metering capex	The AER's draft decision was to remove the costs associated with the single site consolidation project. The AER encouraged Power and Water to maintain the current installation rate of smart meters, to accelerate the roll out.	We have revised the single site consolidation project (discussed in section 3.2.3) and updated the costs allocated to metering accordingly. We have adjusted the capex forecast to maintain our current installation rates associated with the smart meter roll out. Our revised capex forecast is provided in section 8.2 and Attachment 8.1.
Metering opex	The AER applied an alternate labour price growth rate to our opex forecast.	We accept this decision, with no changes.
Metering revenue requirement and recovery	The AER's draft decision included alternate smoothed revenue of $70.08 million ($ nominal).	We have updated the revenue requirement consistent with the revised single site consolidation capex contribution. The revised forecasts are provided in Attachments 8.1 to 8.5.
Metering price caps	The AER considered the method for calculating metering price caps is appropriate. The AER has adjusted prices for all other aspects of its draft decision and applied a flat price path.	We accept the AER's draft decision in principle.
Fee-based and quoted services	The AER replaced Power and Water's proposed labour and overhead rates with its benchmark efficient rates.	We accept this decision and have revised three of the metering fees to remove the cost of the metering and communications assets from three of our fee-based metering services. See section 9.2, section 9 and Attachment 9.1.

Revised proposal 2024-29

PowerWater

1. Customer engagement since the initial regulatory proposal

Customer engagement is an ongoing exercise for Power and Water. Since submitting our initial regulatory proposal in January 2023 we have kept the conversation going, hosting a further three People's Panel sessions and more than 30 meetings on our regulatory proposal and plans for the next five years.

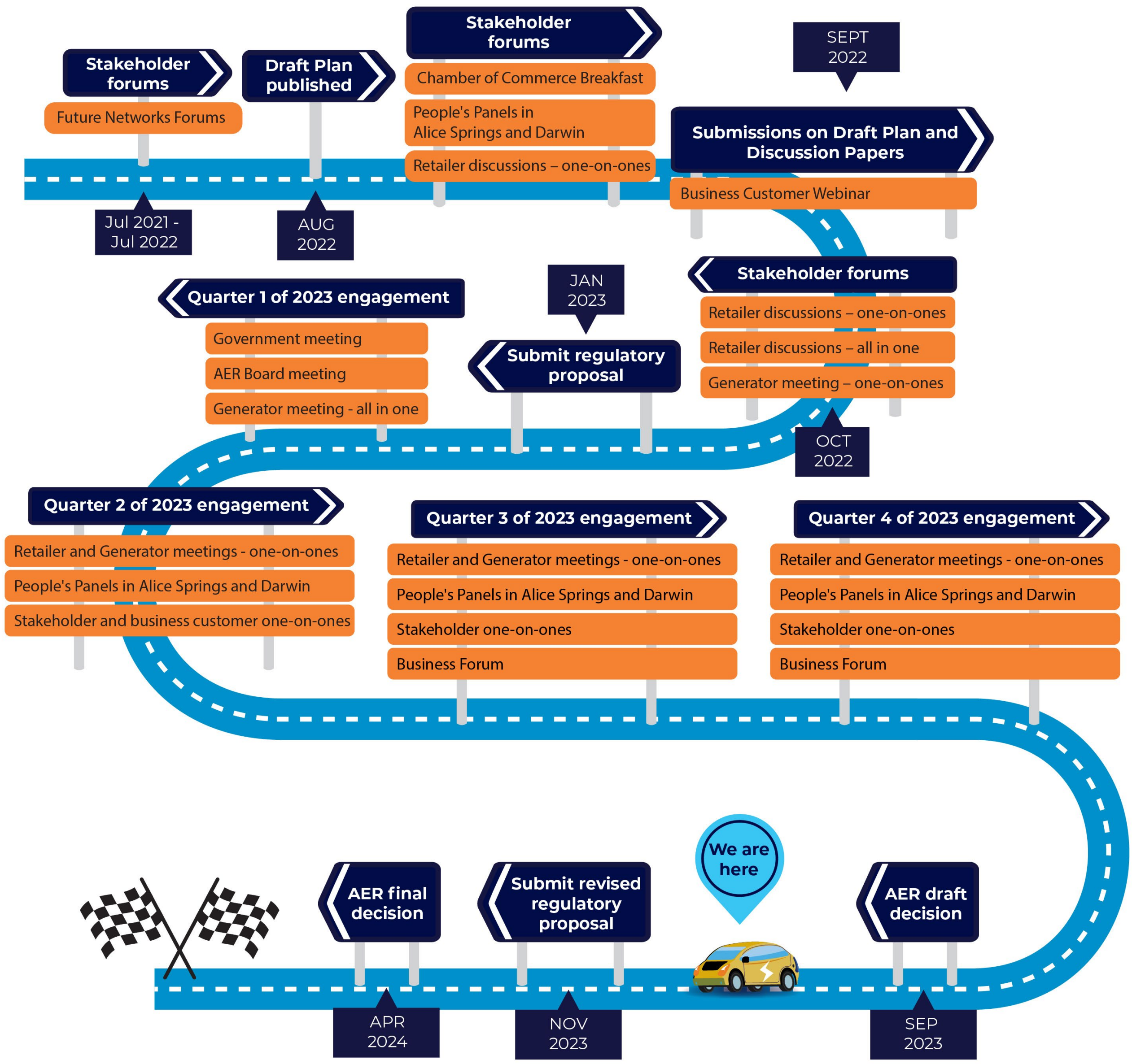
Our stakeholder engagement journey for this regulatory proposal commenced in July 2021, with early testing and conversations with major customers, the NT Government, residential customers, and the AER. Engagement ramped up over 2022 as we developed our regulatory proposal and sought to test our assumptions with customers. Customer feedback was a vital input into our Final Plan and continues to be central to our revised proposal and our ongoing plans.

Our engagement since the January 2023 submission was split into four phases:

- **January to March** – post-submission consultation with energy partners and government stakeholders.
- **April to June** – engagement with customers, energy partners and stakeholders on matters raised in the AER's March Issues Paper.
- **July to September** – engagement with energy partners, stakeholders and customers on aspects of our plans on which we could not fully consult prior to the January 2023 submission (due to timing or information constraints), and testing ideas for our revised proposal.
- **October to December** – engagement with energy partners, stakeholders and customers on the AER's draft decision and key projects and elements of our revised proposal.

Figure 1.1 (on the following page) summarises our engagement journey to date.

Figure 1.1: Stakeholder engagement and regulatory milestones for the 2024-29 regulatory process



During the first quarter of 2023, we engaged with stakeholders to discuss the highlights of our regulatory proposal, and sought opportunities where we could work more closely with our energy partners (specifically retailers and generators) to improve our communication and service offerings to electricity customers. We also explored what research on the Northern Territory energy consumer landscape could be conducted to inform and support future engagement. This is an ongoing area of investigation to improve our future consultation processes.

In the second quarter of 2023, we accelerated our engagement program to focus on specific issues and themes, including large expenditure programs that were highlighted in the AER's March 2023 Issues Paper. As part of this, we continued to engage with our residential and small-to-medium business customers through our People's Panels and one-on-one engagement sessions respectively. We engaged our energy partners through targeted sessions, and other stakeholders via a range of channels.

During the final two quarters of 2023, we continued to refine and revise our forecasts in consultation with our stakeholders and in response to AER feedback. We put particular focus on seeking customers' views on the large capex projects we were unable to engage on prior to the January submission. This included the single site consolidation project, and the OT capability uplift project.

Both these projects were developed late in the regulatory forecasting process and as they were not sufficiently mature during our pre-submission engagement process, we were unable to share any meaningful content with customers. Conscious of this, we committed to keep the conversation going post-submission to allow customers, stakeholders and energy partners to have their say on these material projects. We followed through with that commitment via a series of stakeholder and People's Panel sessions where we sought feedback on these projects and several other matters.

1.1 What we have heard

A detailed discussion of our engagement program since January 2023 and its outcomes is provided in Attachment 1.1. In summary, the ongoing conversation with customers and stakeholders reinforces the value they place on renewable energy and Power and Water's ability to utilise renewable generation and enable more distributed energy resources to be connected to the grid.

1.1.1 Residential customers

Residential customers reiterated the importance of keeping prices affordable, and encouraged Power and Water to do what it can to ease the impact on vulnerable customers. Table 1.1 summarises the key feedback from residential customers during our 2023 People's Panel sessions.

Table 1.1: Summary of People's Panel feedback since the Final Plan was submitted in January 2023

Strategic priority	Stakeholder feedback	Our response
Facilitating renewables	• The facilitation of renewables in the NT during the next regulatory period is important to improve the energy landscape for future generations and provide affordable, reliable and environmentally friendly electricity to current energy users. • Power and Water should also consider progressing slower in its pace of investment to learn from other electricity networks and potentially take advantage of lower costs in the future and balance it with a need to make changes now to accommodate for a growing renewable electricity grid.	Our plans involve investment in facilitating both small-scale solar PV and large-scale renewables across the NT. This includes obtaining better data visibility on rooftop solar to curtail export to the grid at certain periods of the year. Power and Water has also proposed contingent projects to assist with unlocking large-scale renewable generation. Following feedback on our pace of investment in renewables from our customers and the AER in its draft decision, we are investigating how we can delay investment or invest over longer periods to gather learnings from other jurisdictions while lowering the cost impact on customers and ensuring the NT is

Strategic priority	Stakeholder feedback	Our response
	• Customers also believe Power and Water should play a key role in providing information about renewable technologies to Territory – either through more information provided on the website or through direct community engagement. We should be seen as a business of trust and education on the electricity networks.	still supported to grow its renewable future. We believe the solution to improving how customers develop their understanding on the future of renewables is to co-design this process with our People's Panels. We intend to investigate this process with our Panel following submission of our Revised Regulatory Proposal. We are also undertaking a website refresh to improve the accessibility of information for our customers and stakeholders.
Uplifting our systems and people	• Investing in internal systems and people is important to ensure Power and Water can better serve its customers. • Customers understand that the investment in uplifting capabilities through our Technology and Future Networks expenditure has linkages with other investments within the business. For example, investment in the OT uplift project will also have flow-on effects to the future networks program. • Customers also want Power and Water to be accessible within the community and through different communication channels such as via phone, on the website or at local events. However, panellists preference face-to-face where possible.	We appreciate our customers' support and understanding of our ICT investments, and their enablement of our renewable energy projects. We will continue to provide face-to-face support as an option to our customers and investigate pathways with our People's Panels to improve visibility of Power and Water within the community. We commenced a trial of pop-up shops within the local community of Alice Springs in September 2023 which will be extended to Katherine in February 2024, Tennant Creek in May 2024 and Darwin in August 2024. This provides another platform for customers to ask questions and provide direct feedback.
Managing health of network	• Customers understood the change in approach to address replacement by investing in improving internal planning and visibility capabilities. Many panellists wanted to be kept informed of how this investment continues to	The People's Panel will continue to be educated and uplifted on Power and Water operations, including our future investment plans. We understand that customers are seeking Power and Water to provide more accessible information on the Power and

Strategic priority	Stakeholder feedback	Our response
	develop following AER feedback. • Power and Water should be ensuring there is continuous investment and oversight into Information Communication Technology (ICT) systems to ensure the health and security of the networks.	Water website, therefore our plan is to improve the digital experience for customers and have a dedicated webpage for our Panel. We believe investment in our ICT systems will have a flow-on effect across our network, including getting continuous visibility over the network assets to be able to understand when they require replacement. As part of our Operating Model program, we are looking at improving the consistency of our systems and data to continuously uplift our systems.
Improving utilisation	• While price signals can be beneficial to influence usage of the network, customers believed that it would only be effective if people were informed and communication about these price signals was widely provided. • Customers believed that any changes to prices charged directly to customers will need to consider the impacts on vulnerable customers. • Smart meters should be rolled out at a faster pace than the initial proposal to allow for better retailer choice and enable the unlocking of renewables on the network.	In the NT, over 90% of our energy customers are protected by the Electricity Pricing Order. We have introduced price signals to better manage how customers use the network. We will endeavour to work with our energy partners to provide community education around optimal times to use our network. We will continue to utilise our partnerships and relationships with relevant organisations (such as NTCOSS) and consult with our customers about education and support options for our vulnerable customers. Following feedback from our customers, we are proposing an accelerated smart meter roll-out, which would finalise the replacement of all meters in the NT by 30 June 2029.

1.1.2 Business customers

Our engagement with small-to-medium business customers made clear that they value transparency and simplicity in how energy costs are calculated. Business customers want to be able to understand tariffs and charging parameters to better manage their usage behaviour and reduce their power bills. Small business customers highlighted the challenges around understanding the concepts of energy and the electricity systems – noting they often do not have the time to regularly engage in consultation or be kept informed of major changes. Simple messaging and access to important information as required by businesses is therefore a priority.

Small-to-medium business customers indicated that affordability and reliability of supply are their primary concerns. Most stakeholders were interested in being educated on how they can reduce their usage either through implementing energy efficiency measures or investing in renewable technologies.

Large customers similarly value certainty and clear communication. They told us that Power and Water's investments could have a material impact on how they conduct business and invest in renewables. Large customers demonstrated interest in being further engaged as we refine our forecasts, to ensure our plans align with what they need and expect from the electricity networks.

1.1.3 Energy partners

We have developed strong relationships with our energy partners based on priorities of collaboration, open communication and ensuring affordability for Territorians. As we have advanced through our engagement program, we have identified ways to collaborate on solutions and invite stakeholder involvement through formal processes, such as the Regulatory Investment Test process.

1.2 Engagement on key projects

The People's Panel held in May this year was the first People's Panel for 2023 and fourth engagement session with our representative group of residential customers for the 2024-2029 regulatory period. It was one of the first opportunities to consult on some of the key capex projects and associated opex step changes that we had not been able to engage customers on prior to the January 2023 submission, specifically our:

- Information and communications technology (**ICT**) investment program.
- Future networks program (including DER integration).
- Single site consolidation project.

We have since engaged further on these projects via the August and October People's Panels, as well as in one-on-one meetings with business customers, energy partners, and government stakeholders.

Below is a summary of feedback.

1.2.1.1 ICT investment program

We introduced the three key pillars of our ICT investment program at our May 2023 People's Panel: the migration of infrastructure to the cloud, investment in Power and Water's operational technology, and improvement of cyber security capabilities. These pillars were then revisited at the August and October 2023 Panels.

Most panellists were supportive of investing in some areas of technology now to keep systems up to date and prepare for the future, however, some also expressed that Power and Water should go slow in investing in technology as the market continues to develop. Panellists also showed support for updating systems under the OT program that would both 'benefit customers and also help Power and Water staff with their jobs'.

1.2.1.2 Future networks program

Customers have repeatedly told us they prefer renewable energy and indicated that Power and Water has an important role in facilitating and encouraging the connection of renewable technologies. When revisited at the October 2023 People's Panels, customers were asked for feedback on:

- The DER integration program.
- Projects to accommodate greater volumes of large scale generation in the Darwin-Katherine network.
- The need to increase capabilities of the Future Networks team.

Panellists were supportive of implementing solutions to integrate greater levels of DER, including potentially through implementation of a dynamic operating envelope. Customers told us they want to be able to export back into the grid and were not comfortable with the idea that they may not be able to. However, the Panel suggested Power and Water could take a more measured approach to DER integration, and seek the opportunity to learn from proven solutions or more advanced technology in other jurisdictions. This is consistent with the AER's feedback in the draft decision. One customer stated that Power and Water should 'be a leader within the context of learning from bigger interstate power providers without being unduly held back'.

Panellists supported investment to unlock renewable energy from existing solar farms to customers, forming the view that this low cost and clean form of generation should enable electricity to be supplied at a cheaper cost, as well as providing environmental benefits. Many suggested this requires a resourced Future Networks team to support innovation, continuity and retention of staff, and ultimately deliver a renewable future for Territorians. The Alice Springs Panel suggested incentivising younger, Indigenous apprentices to meet the future network needs.

Similarly, our energy partners were interested in how they can be involved in Power and Water's future networks program, particularly to understand how it will benefit their customers. This included specific focus on the proposed contingent projects to unlock renewable generation in the Darwin and Katherine regions (contingent projects 2a and 2b) and alleviate voltage issues and network constraints through dynamic operating envelopes. Energy partners emphasised the potential for these programs to provide cost savings to customers and that Power and Water should pursue opportunities to deliver these projects efficiently.

1.2.1.3 Single site consolidation project

When the single site consolidation concept was first introduced to customers at the May People's Panel, the panellists showed support for Power and Water investigating the investment in consolidation of most of our corporate staff in Darwin. One customer even stated, "why wouldn't we [Power and Water] do it." The Alice Springs Panel recognised the efficiency benefits of having staff at a single location and expressed a strong preference for Power and Water to own their own premises rather than lease. Similarly, the Darwin Panel understood the benefits of consolidation but needed further information before supporting the project. This included requesting a comparison between leasing costs and buying over the longer term, and being informed about how Power and Water planned to communicate the project and its costs to the public.

In August, when the single site consolidation project was discussed, the Panel suggested that more information was required before it could provide informed feedback to Power and Water. Following this, we went away and developed our single site consolidation project business case, and further clarified the scope and potential benefits of moving a significant portion of our workforce to a purpose-built location at the Ben Hammond Complex. The Panel was particularly interested in the costs and benefits to them.

We tested our single site project again at the October People's Panel sessions. Many panellists expressed support in Power and Water achieving non-economic benefits such as cultural and engagement improvements and the efficiency of having staff at a single location. Customers recognised the potential savings in avoiding lease costs and improving energy efficiency, noting that Power and Water will need to carefully consider how it will explain the costs of the consolidation to the general public.

We engaged with our energy partners through regular meetings. They expressed some support for the single site project and recognised the practicality and potential cultural and efficiency benefits of consolidating Power and Water operations at Ben Hammond. They noted a large property project of this type would require a significant capital investment and encouraged Power and Water to ensure any investment is underpinned by a robust business case and strict cost management.

2. Revenue

2.1 The AER’s draft decision

Constituent component 2: Annual revenue requirement

In accordance with clause 6.12.1(2)(i) of the NT NER, the AER's draft decision is to not approve the annual revenue requirement set out in Power and Water Corporation building block proposal. Our draft decision on Power and Water Corporation’s annual revenue requirement for each year of the 2024–29 regulatory control period is set out in Attachment 1 of the draft decision.

The AER’s draft decision was to allow a total annual revenue requirement of $1,014.0 million ($ nominal unsmoothed) for the 2024-29 period. This is a reduction of $73.2 million (6.7%) from our proposed revenue of $1,087.2 million. The AER’s lower revenue estimate is largely driven by the lower forecast opex and return on capital building blocks.

In its draft decision, the AER noted it used placeholder values for certain revenue building block components such as the rate of return and expected inflation, and would make further updates for these values as part of its final decision.

2.2 Our response

Power and Water’s response:

We accept the AER’s revenue calculation methodology, but propose an alternative estimate of our total annual revenue requirement of $1,045.5 million ($ nominal), based on:

- Our revised capex and opex forecasts.
- Actual expenditure and non-financial inputs for 2022-23.
- Updated labour escalators from BIS Oxford (see Attachment 2.6).
- Other minor modelling updates.

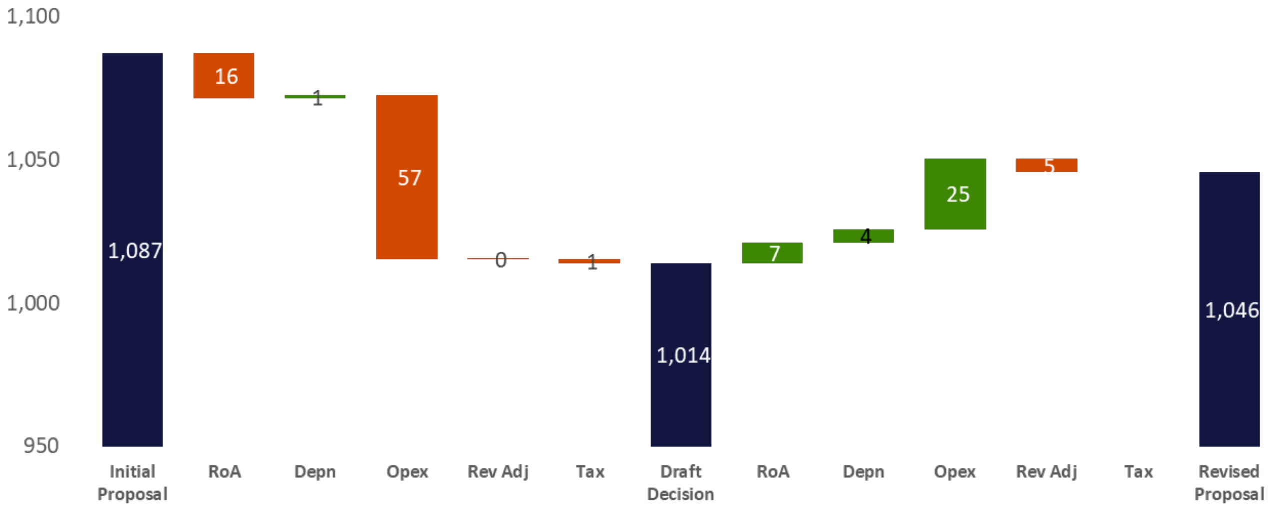
The total annual revenue requirement is the calculation of revenue Power and Water can recover over the regulatory period for the provision of standard control services. It is built up using a number of revenue building blocks as expanded on below.

We accept the AER’s calculation method, but have modified the unsmoothed revenue requirement as shown in Table 2.1 and Figure 2.1.

Table 2.1: SCS unsmoothed building block adjustments ($ million, nominal)

Building block	Initial proposal	Draft decision	Revised proposal
Return on capital	428.4	412.6	419.7
Regulatory depreciation	204.9	206.0	210.5
Opex	453.4	396.3	421.2
Revenue adjustments	-0.7	-0.9	-5.9
Tax	1.1	-	-
Annual revenue requirement (unsmoothed)	**1,087.2**	**1,014.0**	**1,045.5**
Annual expected revenue (smoothed)	**1,091.1**	**1,016.4**	**1,048.4**

Figure 2.1: Waterfall of SCS unsmoothed building block movements from initial proposal to the AER's draft decision and our revised proposal ($ million, nominal)



The following sections summarise our revenue building block adjustments. Further detail on changes to the various revenue and expenditure models that reflect this revised proposal is provided in Attachment 2.5.

2.2.1 Return on capital

Our revised return on capital reflects the AER's allowed rate of return parameters as per its draft decision. We have adopted the latest information on the expected inflation rate.

However, our revised return on capital forecast is based on our revised capex forecast for 2024-29, which is $7.1 million (nominal) higher than the AER's draft decision, but $8.7 million (nominal) lower than our initial proposal. Further discussion on our revised capex forecast is provided in section 3.

Table 2.2: SCS return on capital forecast ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Initial proposal	72.5	78.8	85.5	$91.7	100.0	**428.4**
Draft decision	71.3	77.0	83.0	$88.7	92.6	**412.6**
Revised proposal	**72.1**	**77.8**	**83.8**	**$89.1**	**96.9**	**419.7**

2.2.2 Regulatory depreciation

The regulatory depreciation forecast is impacted by the opening regulated asset base (**RAB**) calculation. We accept the AER's method for calculating the RAB, which we have updated to incorporate 2022-23 actuals.

The revised RAB calculation is provided in the revised standard control services roll-forward model in Attachment 2.2. Consequently, we have updated the depreciation forecast to incorporate 2022-23 actuals, asset disposals, capital contributions and estimated 2023-24 capex. We have accepted the AER's changes to capitalised overheads (as per the AER's model) and have adopted the latest information on the expected inflation rate.

We are also changing the standard life that applies to the capitalised leases for those properties that will be relinquished due to the single site consolidation project. The standard lives for these leases will be reduced from 10 years to five years. Refer to section 3.2.3 for details of our revised single site consolidation project forecast.

Our revised regulatory depreciation forecast also reflects our revised capex forecast for 2024-29, which is discussed in section 3.

The revised regulatory depreciation calculation is presented below.

Table 2.3: SCS depreciation forecast ($ million, nominal)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Initial proposal	34.6	36.0	39.0	45.4	49.6	**204.9**
Draft decision	35.8	36.8	39.5	45.0	48.9	**206.0**
Revised proposal	**36.0**	**37.3**	**40.2**	**46.3**	**50.7**	**210.5**

2.2.3 Opex

Our revised opex building block calculation is based on our revised opex forecast for the period, which re-incorporates some of the opex step changes excluded by the AER in its draft decision. We have retained 2021-22 as the opex base year and the trend growth parameters as calculated by the AER, updated for actual 2022-23 customer numbers and line length parameters.

The revised opex forecast is $22.8 million (or $24.9 million in nominal dollars) higher than the AER's draft decision, but $28.1 million (or $32.2 million in nominal dollars) lower than our initial proposal. The revised opex forecast is summarised in Table 2.4 and is described in more detail in section 5.

Table 2.4: SCS opex forecast ($ million, nominal)[12]

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Initial proposal	84.0	87.4	90.0	94.5	97.6	**453.4**
Draft decision	74.0	76.8	79.3	81.8	84.4	**396.3**
Revised proposal	**78.0**	**81.2**	**84.0**	**87.5**	**90.4**	**421.2**

2.2.4 Revenue adjustments

We have accepted the AER's draft decision on revenue adjustments, which are $0.2 million (nominal) lower than our initial proposal. The slight difference is due to updated forecast penalties under the capital expenditure sharing scheme (**CESS**) and demand management innovation allowance that follow automatically from changes to the expenditure and other inputs to the revenue proposal.

2.2.5 Tax

We have recalculated the tax allowance using the AER's methodology, which consistent with the AER's draft decision – projects a zero tax expense for the 2024-29 period.

12 This table shows the opex building block in nominal terms. This is to align with how the other revenue items are presented in this chapter. The values here will differ from the opex presented in chapter 5, which are shown in real $2024.

3. Capital expenditure

3.1 The AER's draft decision

Constituent component 4: Forecast capex

In accordance with clause 6.12.1(3)(ii) of the NT NER and acting in accordance with clause 6.5.7(d) of the NT NER, the AER's draft decision is to not accept Power and Water Corporation's proposed total forecast capital expenditure of $568.0 million ($2023–24). Our draft decision therefore includes an alternative estimate of Power and Water Corporation's total forecast capex for the 2024–29 regulatory control period of $432.8 million ($2023–24).

The AER's draft decision substituted our proposed capex of $568.0 million with its forecast of $432.8 million. The AER accepted our business as usual capex forecasts, including our augmentation, replacement and connections, and fleet capex forecasts. The AER also accepted our forecast capex on cyber security, subject to Power and Water providing further information to substantiate the $11.4 million it approved as a placeholder.

The AER's $135.2 million forecast capex reduction mostly relates to three projects[13]:

- **DER integration**: The AER removed the majority of costs ($12.1 million) associated with managing voltage issues caused by distributed energy resources. It only allowed $1.1 million of capex associated with installer outreach programs to manage compliance with inverter standards. The AER's draft decision highlighted that alternative, lower-cost options beyond those included in the supporting business case should be considered, and further detailed analysis of hosting capacity is required prior to its approval of investment in more dynamic management options.
- **OT capability uplift**: The AER removed $21.6 million of costs associated with this program of work as it considered the program was not fully required for the 2024-29 period. The AER felt the information provided in support of the program had not yet demonstrated gaps in safety, reliability or compliance that are not already addressed by business as usual expenditures.
- **Single site consolidation**: The AER removed $84.3 million of costs (net of an increase in capitalised leases) associated with this project due to a lack of supporting information on the scope of the project and options considered. The Consumer Challenge Panel also noted that it had not observed any engagement with customers or stakeholders on this project.

Our response to the AER's the draft decision on our proposed capex program of work is provided in the following section.

13 The remaining $17.3 million of capex adjustments relate to modelling adjustments to account for inflation, real cost escalation assumptions, and updates to 2022-23 capitalised overheads (i.e., replacing estimated expenditure with actual).

3.2 Our response

Power and Water's response:

We propose a revised net capex forecast of $538.2 million which includes:

- Each of the capex categories supported by the AER in its draft decision.
- A revised $3.7 million of forecast capex to better integrate DER, which reflects a modified program from that included in the initial proposal.
- A revised $15.8 million OT capability uplift program, supported by more information on the need for and benefits of the program.
- $76.1 million for the single site consolidation project, which reflects a modified project at a lower cost compared to the initial proposal, and is supported by an NPV positive business case.
- An additional $15.7 million in network and corporate overheads reflecting the 2022-23 actuals and inclusion of the revised forecasts.
- A number of minor consequential changes (e.g. updated inflation rates and capitalised overheads).

Our initial regulatory proposal included $568.0 million of capital investment in standard control services over the 2024-29 period. This capex forecast comprised:

- $176.6 million to replace and refresh network assets.
- $33.2 million to augment the network to meet compliance, reliability and demand requirements.
- $7.0 million to connect new customers.
- $13.2 million to manage issues on the low voltage network resulting from the uncontrollable volumes of electricity being exported from rooftop solar.
- $70.7 million to maintain ICT assets and increase our IT and OT capability.
- $129.4 million in property, plant and fleet assets to support the provision of network services.
- $144.7 million in capitalised overhead costs.

This forecast was a significant increase in the work program from the current regulatory period (2019-24), but reflected our view on what we needed to do to manage the network in line with good industry practice. It also reflected our view at the time of what we needed to do in the context of the ongoing nationwide transition to renewable energy, and what we heard from our customers were their priorities.

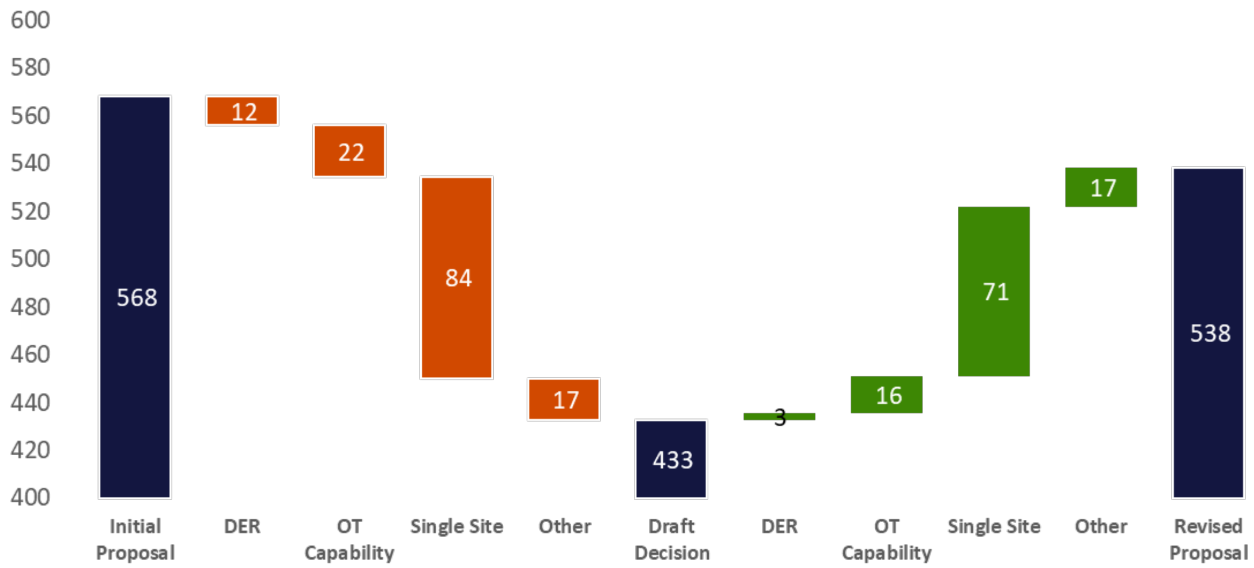
The AER approved the majority of our capex program, including all network asset replacement, network augmentation, fleet, and expenditure to connect new customers. The main point of difference being some items of non-network expenditure and DER-related investments, which we concede were not fully formulated at the time of the initial regulatory submission.

We have continued to engage with our customers and key stakeholders to review and validate our plans. We have given particular focus to key projects and programs that are new for Power and Water and/or the Northern Territory, including those projects on which there was insufficient time prior to our January 2023 submission to fully engage with customers.

This has led us to develop a modified capex forecast for the 2024-29 period. Our modified forecast includes the estimates for network asset replacement, augmentation, fleet, ICT, and customer connections as approved by the AER, plus revised estimates for the proposed DER integration, OT capability uplift, and single site consolidation projects that were excluded in the draft decision.

Our revised total net capex forecast is $538.2 million. Figure 3.1 shows the change in our capex forecast, driven predominantly by re-inclusion of DER integration, OT capability uplift, and single site consolidation projects, albeit at lower amounts.

Figure 3.1: Waterfall of SCS capex changes, initial proposal, draft decision, revised proposal, $ million real 2024



The key capex adjustments are discussed in the following sections.

3.2.1 Future Networks – DER integration

What is the challenge?

The isolated nature of our networks, coupled with limited network redundancy and the relatively small number of major loads and synchronous generators connected to them, means it does not take a huge influx of rooftop solar photovoltaic (**PV**) generation to place our power system at risk. As discussed in more detail below (and in Attachment 3.1), we are already experiencing significant over-voltage issues across the distribution system.

To date, we have been able to manage the network to accommodate increasing levels of PV connections. Where voltage issues in our three networks have arisen, we have undertaken traditional voltage control methods (such as transformer tap changing and network augmentation) as mitigation. We have also begun to look at inverter compliance and other less invasive and capital-intensive voltage management solutions. However, as the power system becomes more complex and the number of PV connections increase, we have exhausted our available low-cost methods and face imposing static export limits to curtail the output of future connected solar PV.

Network analysis undertaken since our initial proposal highlights that we are already experiencing an increase in local network constraints leading to declining power quality, specifically non-compliance with voltage standards. Based on current PV connection rates, we expect the extent of this non-compliance will worsen and will also contribute to security risks at times of minimum load. To ensure the network can continue to accommodate the ongoing uptake of rooftop solar, static export limits will be required.

Solar curtailment can result in reduced clean energy consumption and ultimately higher bills to consumers in the NT. It also slows down the transition to renewables and net zero targets. If rooftop solar curtailment is implemented, it will undermine customer's investments in DER and go against the customer feedback provided to us that they want the network to be able to facilitate distribution of more renewable energy, not less.

Other distribution network service providers are responding to the same issues as those faced by Power and Water with several Australian states already initiating solar management programs. In the NT, our low level of system demand means our system is particularly difficult to balance. It is therefore vital we invest in our skills and capability to provide a more efficient approach to enabling small-scale DER on the network, which is the focus of this project.

The advantage of adopting dynamic management of solar export is that it allows maximum use of low-cost renewable energy, rather than applying static limits to mitigate the identified local network issues. This option also provides the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system. Dynamic management of solar PV also provides an immediate mitigation to the risks of minimum system demand. The NT is a small system and does not have sufficient load to balance the solar being exported by rooftop systems. We need to respond to the high quantities of solar being generated and exported into the grid to maintain and ensure grid stability. Dynamic management allows us to do this.

The AER's position

In forming its draft decision, the AER assessed our analysis, options and quantifiable benefits consistent with the AER's published DER Integration Expenditure Guidance Note[14]. At the time of submitting our initial proposal, we did not have sufficient information available, or the tools to assess the magnitude of the voltage challenge.

The AER highlighted that the necessary voltage studies and network analysis required to inform the scale and scope of the DER-related voltage problem had not been completed. Put simply, we had not provided evidence to substantiate the issues that need to be resolved.

We agree with the AER on this matter. To ensure we are implementing the most appropriate solutions, it is vital we have the data and insight to inform our investment decisions. That is why we have continued to study how our network is behaving and develop a more robust investment case.

How big is the problem today?

Since developing the initial Dynamic Operating Envelope (**DOE**) business case (submitted in January 2023), we have partnered with GridQube to better understand the limitations of our LV network. Preliminary analysis undertaken to date has given us a view of the state of our network at the individual meter level for

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14 AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022, available at: https://www.aer.gov.au/system/files/Final%20DER%20integration%20expenditure%20guidance%20note%20-%20June%202022.pdf

all connections where advanced metering is installed. The study shows we already have significant over-voltage compliance[15] issues in Katherine and Alice Springs.

While these DER-related voltage issues are not unique to the Territory, our challenge is subtly different to interconnected networks like those that make up the National Electricity Market (**NEM**). We operate three small volume, standalone, geographically isolated networks, with fewer large-consumption customers than most other Australian networks. This means we have fewer opportunities to absorb excess solar generation and help balance load and manage voltage in the network. Curtailment of solar energy, including to manage voltage within technical limits, results in increases to customer bills.

Added to this, in the near to medium term we need to understand how the uptake in electric vehicles (**EVs**) and standalone batteries will be used, and adapt to the changes in consumption, load, and voltages in the network. We have sought to estimate this impact, but we do not expect a huge increase in EVs and standalone batteries to materialise in the 2024-29 period. We will, however, look to improve our forecasts and understanding of the impact of these technologies over the next five years, building on our capabilities, network information and performance data, and achieve greater visibility of our assets and customer connected assets through system investment and trials.

Will increasing inverter compliance solve the problem?

In its draft decision, the AER supports our proposed installer outreach program, which is designed to increase compliance with contemporary inverter standards for new installations. This program is the only capital or operating expenditure the AER has included in the draft revenue determination to facilitate the integration of DER in the Territory at this stage.

The AER is of the view that the installer outreach program, coupled with lowering the static export limits, should reduce export curtailments. Furthermore, the AER highlighted that, based on its sensitivity analysis, this approach would reduce the benefits of avoided curtailment such that the initial business case no longer has a positive NPV. In its draft decision, the AER states:

> *We undertook our own sensitivity analysis to consider how improvements in inverter compliance would impact the economic justification for the proposed investment. If we assume that the rate of inverter non-compliance improves from 30% to 20% and apply a static export limit of 2.6kW (in line with PWC's sensitivity analysis), avoided export curtailment benefits decrease by around 37% and the overall net present value becomes negative.*
>
> *…*
>
> *Overall, this makes the proposed investment option less attractive than the base case scenario.*
>
> *…*
>
> *Considering the potential benefits of improving inverter compliance, we do not accept PWC's forecast capex of $13.2 million and instead provide an alternative capex forecast of $1.1 million to enable PWC to commence its installer outreach programs, which combined with ongoing compliance activities (opex) will result in improved inverter compliance and minimise*

15 Australian Standard 60038 requires that electricity is supplied within an allowable voltage range of 207 to 253 volts. At times when over-voltage issues occur, customer may experience visible fluctuations in supply, failure of appliances and curtailed solar exports (this is because AS4777.3 requires solar inverters to shut down automatically if voltage is outside the allowable range).

reductions to its static export limits. We consider this is a more prudent and efficient option than what has been proposed by PWC.

In its revised proposal, PWC should consider a scenario which includes voltage management activities, improvements in network visibility and accounts for improvements in PV inverter compliance. [16]

Our view is that an inverter compliance program alone will not solve the problem. While an increase in inverter compliance will help ease uncontrollable over voltages, by itself it will also increase the problem of voltage-induced curtailment of customer systems. Working with installers to help ensure new inverters meet the AS4777.3 requirements should reduce the instances of new installation non-compliances, however, it does not address existing installation non-compliances[17]. Fixing existing non-compliance for post-2016 installations is time-consuming and expensive, as it requires sending out technicians and is subject to customer cooperation. Pre-2016 installations generally need inverter replacement to make them grid friendly.

Our revised proposal

We understand the AER's concerns around the cost and prudence of the dynamic operating envelopes (**DOE**) solution that was initially proposed. Responding to these concerns we revisited our initial proposal, considering more recent results from our modelling and analysis about the performance of our network and the practicability of potential solutions.

We have done the following:

- Undertaken additional system studies to help target our investment program, with a focus to identify those investments that we will benefit from earlier in our DER integration journey, and those we can potentially delay (noting should we need them sooner we will need to re-prioritise our work program through the next regulatory period due to the potential impact on our ability to maintain security and reliability of supply for our customers).
- Reviewed the insights gained from progress from the Alice Springs Future Grid project, which was not available at the time of our initial proposal. The scope included deployment of a virtual power plant (**VPP**) program using similar technology solutions, and in many ways provides the proof of concept for parts of the proposed DER integration project. The Alice Spring project and engagement with the Alice Springs community has allowed us to make a more informed estimate of the required investment and resources for a broader DER management solution.
- Talked to stakeholders about their views on managing the impact of increasing DER, including implementing dynamic operating envelopes, their effectiveness, and the preferred pace of implementation. Stakeholders suggested Power and Water should continue to pursue dynamic operating envelopes and other forms of DER integration investment, but should consider adopting a more measured approach and ensure the technical solution and pace of change is appropriate for the NT. One customer stated that Power and Water should 'be a leader within the context of learning from bigger interstate power providers without being unduly held back'.

This has resulted in a revised program of work, supported by the business case provided in Attachment 3.1. Without a more sophisticated response to integrating DER into the Power and Water network, the

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16 AER, Attachment 5 Capital expenditure | Draft Decision - Power and Water Corporation Distribution determination 2024–29, page 27.

17 We have also considered whether a customer focussed non-compliant inverter rectification program could be effective or efficient, and have determined the cost of the program coupled by the slow rate at which we could expect rectification would be ineffective and inefficient.

PowerWater

tightening of static export limits on residential and commercial and industrial connections will result in curtailing solar export year-round not just during minimum demand events; and uneconomic investments in the network are also likely.

The revised program provides a minimum level of core infrastructure to enable dynamic management of solar PV. It will provide a base level of capability to manage immediate compliance related risks and allow us to better understand the hosting capacity and voltage performance of our network. This will establish a solid foundation on which we can build greater dynamic DER management capabilities as and when required.

The proposed investment is required in all future scenarios that we have considered for the management of DER in the Territory, and is consistent with prudent and efficient DER management options undertaken in other jurisdictions.

The revised program will see us invest in the following:

- **State estimation and constraints engine**: To use engineering data from meters and constraint functions to derive DOEs at a feeder level.
- **Agent fees to communicate with inverters**: To implement the flexible export limits, a third-party trader observes the limit and communicates it to consumer devices, requiring third party agent fees.
- **Power and Water's ICT capabilities**: Internal ICT resources will be required to provide a significant amount of new enabling services and modify existing services.
- **Supporting activities**: A range of supporting activities are required to realise the benefits of the DOE investment, including hosting forums with customers to understand their expectations and preferences, ensuring that inverters connected to our network are compliant, and undertaking development of targeted trials.

We have included separate provision for the design, development, procurement and testing for deployment of a communications upgrade to IEE2030.5, being an internet based communication protocol. This development allows us to move away from third party service providers to an open protocol specifically designed for DER in the subsequent regulatory period. IEEE 2030.5, and its underlying data model, is the standard to represent and manage DERs across the utility and non-utility ecosystem in a coordinated way.

This capital works program is supported by the operating expenditures discussed in section 5.2.3.1.

More information on the impact of the increasing number and capacity of customer assets on the performance and operation of the network, options considered and revised forecast expenditures are provided in Attachment 3.1.

Meeting the NT NER test for inclusion in our forecast capex

This project meets the requirements of rule 6.5.7(a) of the NT NER as it is:

- Required to manage expected demand in the network.
- Required to comply with our obligations to provide safe, reliable and secure standard control services.
- Supported by a business case that follows the requirements of the AER's guidance on DER projects, including in relation to the valuation of the benefits of the reduced curtailment of DER.

Implementing our revised proposal

We have updated our capex forecast to reflect a modified DER integration program with a revised capex forecast of $3.7 million. This is supported by a revised opex forecast as discussed in section 5.2.3.1.

Our revised forecast is provided in the following table.

Table 3.1: Future networks – DER integration revised capex forecast, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	0.1	0.1	1.0	1.5	1.0	3.7
Allocation to SCS	0.1	0.1	1.0	1.5	1.0	3.7

3.2.2 Operational Technology capability uplift

What is the challenge?

Our OT is a secure computing environment that helps monitor, operate and control transmission network assets and some distribution network assets. It is essentially the suite of control room tools we use to keep the network functioning securely and to respond to issues.

Power and Water's primary OT system, the Energy Management System (**EMS**), is limited in its capabilities, particularly to distribution system management. The EMS was designed as a transmission network management tool with wider system control functions and does not provide distribution management functions or visibility. This means we rely on manual processes to manage the distribution system.

We are currently the only Australian electricity utility still using pin boards to manage the operational status of the distribution network. We do not have any standard distribution supervisory control and data acquisition (**SCADA**) system, and we do not have an outage management system (**OMS**) or distribution management system (**DMS**) – tools utilised by most other Australian distribution utilities. We accept that the NT network is smaller in scale and therefore may not yet require an OT solution as sophisticated as some of our peers, however, our current OT capabilities are no longer commensurate with the sophistication of our power system.

Over the past decade the network has grown and become more complex. The volume of intermittent renewable power sources – both in front of and behind the meter – have increased. The network has to accommodate two-way flows, and customers continue to want to connect new loads, new generation, and new distributed energy resources.

Until recently, manual processes have sufficed and we have been innovative in the use of our EMS since its implementation in 2008 to provide some basic status indication of critical switching. However, the requirements of a modern distribution system have stretched beyond the limits of what we can do with the EMS.

The biggest limitation of our current OT is visibility. The lack of visibility (i.e. how the network is performing and where new assets are being deployed) exposes the network to very high safety risks. For example, if a protection system fails on a long distribution line, our current manual processes may not pick this issue up very quickly, increasing the potential for long duration outages.

Under its licence obligations and the provision of the NT NER, Power and Water is required to operate under a safety management and mitigation plan, which reflects good industry practice in relation to the safety management of the electricity infrastructure owned or operated by Power and Water. This applies to both the regulated and non-regulated networks.

To meet these obligations, Power and Water is required to have an accurate record of the type, location and status of its network for planning, operation and maintenance purposes. This includes a Geographic Information System (**GIS**), and complimentary distribution system operation tools to ensure that information is available to assist operational decision making and timely and accurate information to customers. Historically, the accuracy of these functions has been low risk and highly predictable, meaning our systems could also be simple. This is increasingly not the case, and will only become more dynamic and unpredictable with changes to power flows and system strength, and to varying degrees in different parts of the network.

Our current GIS will be three years past vendor support by the end of the next regulatory period. It needs to be upgraded to allow us to meet our obligations. We are therefore using the end-of-life GIS upgrade as the platform and catalyst to uplift our associated OT.

The AER's position

As acknowledged by the AER in its draft decision[18], we currently have limited OT capability on our distribution networks and our processes remain largely manual. However, the AER was concerned we had not provided sufficient evidence to allow it to determine whether our proposed program to remove these manual processes and associated risk was prudent, and that the proposed solution was efficient or deliverable.

We accept this criticism. When the January 2023 submission was developed, the OT project design was in development and the full scope of the drivers, requirements, and overlap with other technology projects had not been fully formulated. We flagged this in May 2023 and as acknowledged by the AER in its draft decision, advised that we were proposing to develop a revised business case and expenditure proposal for our OT uplift.

Our revised proposal

Rather than making the substantial shift towards an advanced distribution management system (**ADMS**) as contemplated in the initial proposal, we have pared back our OT capability uplift program to deliver the highest priority OT upgrades during 2024-29 and adopt a more conservative and responsible approach to bringing our systems up to standard. Our immediate focus will be on upgrading the GIS.

Our revised proposal has been prepared in accordance with our OT roadmap. We will progress the highest priority issues associated with obsolescence risk, inconsistent quality and robustness of operational data, and OT operating practices that are no longer fit for purpose. This approach to progressively uplift our OT capability is consistent with feedback from customers, who have told us they support investment in OT where it will improve service, but advised a more cautious approach to adopting technology, whereby Power and Water draws on experiences in other jurisdictions.

The scope of our revised proposal for 2024-29 is broken down into three sub-categories of expenditure:

1. **Mitigate obsolescence risk in critical operational systems** through upgrading of the GIS to a supported version.

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18 P19, Attachment 5, Capital Expenditure, Draft Decision, AER September 2023.

2. **Address inconsistent quality and robustness of operational data** by rectifying issues with data and allowing multiple platforms to operate off the same accurate and complete data set to maintain the safety and reliability of our network.
3. **Updating / upgrading OT operating practices that are not fit for purpose.** Power and Water is the only Australian electricity utility still using pin boards to manage the operational status of the network and the only utility without a DMS/OMS. These limitations restrict our ability to deliver on targets for network development, maintaining reliability standards and technical and safety compliance. It also inhibits our ability to support the NT Governments' renewable energy and decarbonisation targets.

Forecast capex for the revised program is estimated at $15.8 million, with an associated opex step change component of $3.9 million (discussed in section 5.2.3.2). This program has effectively halved since our January 2023 forecast.

We are conscious of the relative size of our networks compared to other jurisdictions and the need to ensure the scale of any system we install represents value for customers. We are also conscious of what can realistically be achieved over one regulatory period, hence we have adopted a more conservative OT uplift program for 2025-29, with a view to building on this in future regulatory periods as network and customer needs evolve.

This revised proposal reflects a prudent, efficient and deliverable level of investment, commensurate with good industry practice and the relative sophistication of our network.

Our proposed OT capability uplift project will:

- Provide a contemporary unified network model and supported GIS application.
- Achieve a single asset source view, through development of the common information model (**CIM**).
- Allow us to address immediate visibility risks (through the GIS), while affording us data and time to inform the most practicable and efficient pathway to uplift our OT over the longer term (rather than making a higher cost and potentially high risk OT shift).
- Improve our ability to manage the network model and network state, including management of switching and permitting processes.
- Allow us to better manage outages and delivery of restoration information to customers and regulators, and enables further opportunity for workforce efficiency in the future.
- Represent a deliverable work program, and migration/evolution plan for future investments.

Further information on the revised OT capability uplift program is provided in the business case in Attachment 3.2, the Operational Technology Roadmap in Attachment 3.3 and cost benefit analysis in Attachment 3.4.

Meeting the NT NER test for inclusion in our forecast capex

This project meets the requirements of rule 6.5.7(a) of the NT NER as it is:

- Required to comply with our obligations to provide safe, reliable and secure standard control services.
- Supported by a business case that substantiates the proposed costs as those a prudent operator would require to achieve the capital expenditure objectives.

Implementing our revised proposal

We have updated our capex forecast to reflect a modified OT uplift program with a revised capex forecast of $17.4 million. This is supported by a revised opex forecast as discussed in section 5.2.3.1.

Our revised forecast is provided in the following table.

Table 3.2: Summary of revised OT capability uplift forecast capex 2024-29, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	3.5	4.1	3.4	3.8	2.6	17.4
Allocation to SCS	3.1	3.7	3.1	3.5	2.4	15.8

3.2.3 Single site consolidation

What is the challenge?

The Power and Water workforce is spread across several buildings in Darwin. Just over half of our Darwin-based staff (356) are located in Stuart Park in the Ben Hammond Complex, which Power and Water owns. A further 334 staff are spread across two leased buildings in Darwin – Mitchell Centre and Jacana House. While this separation of staff across three sites has been manageable, it does pose challenges and inefficiencies in work practices, interoperability, communication, and culture. The dispersed nature of our Darwin staff is also inconsistent with our aims to improve the quality of service we can provide customers and to reduce our accommodation emissions footprint.

In 2022-23, in line with our refreshed 2023-29 Strategic Plan, we conducted a review of current leasing and accommodation arrangements, with a view to deciding whether it would be more prudent and efficient to conclude the Mitchell Centre and Jacana House leases and seek alternative accommodation.

In our initial proposal, we included $89.8 million for property costs to redevelop the Ben Hammond Complex.[19] The project was at its very early planning stage when we submitted the initial proposal in January 2023, therefore limited options analysis and detailed scoping had been conducted at that time. We signalled that the project was critical for enhancing our operations and will bring multiple benefits both in terms of productivity and cultural improvements, as well as long term cost savings. However, the full business case and cost benefit analysis was not available.

The AER's position

The AER did not accept the business case for this project in its draft decision. This was primarily because, at that point in time, we hadn't adequately demonstrated the project need or benefits.

The AER acknowledged that we would need additional costs to maintain staff accommodation at Mitchell Street for an additional five years. In its draft decision, the AER included an additional $5.5 million for capital expenditure associated with the lease extension, extending the lease term back to ten years.

The AER also noted we had not engaged with customers regarding the project before submitting the initial regulatory proposal.

[19] This was partially offset by the removal of costs associated with the Mitchell Street building lease costs.

The AER acknowledged that, at the time of the initial proposal the single site consolidation project was still at a conceptual design, clearly articulating what it expects from us to include the project in the capex forecast:

> *To effectively assess whether the proposed single site consolidation project reasonably reflects PWC's capex requirements, we require PWC to provide further information to support the proposal. This includes a detailed evaluation of the options, including a cost benefit analysis and cost and delivery planning advice.* [20]

Our revised proposal

Since our initial proposal, we have worked to refine the single site consolidation project.

We remain certain that the co-location of our staff at a single location will:

- Provide secure, purpose-built offices and amenities to enable the effective pursuit of our strategic objectives and operational needs.
- Ensure ongoing compliance with diverse legislative and regulatory requirements, including those related to construction codes, workplace safety and critical infrastructure security.
- Help tackle the aging condition of our property infrastructure.
- Help us adapt to the evolving operational demands of various business units tied to our properties, both owned and leased.
- Leverage property locations to maximise value, boost interoperability, engagement, productivity and responsiveness during core and non-core activities.

The drivers of the project have not changed. However, we have worked to develop a design concept[21] for the new site and engaged relevant subject matter experts to help us better understand the potential options, and likely costs and benefits of the project.

We have developed a business case (see Attachment 3.5) that shows that our preferred option, reflected in our capex forecast, results in an overall net benefit and is NPV positive.

A cost benefit analysis shows the project will deliver a number of direct benefits over the life of the new complex, including savings[22] of $67 million in property lease costs, $36 million in travel costs and $10 million in general operating expenditure (e.g. electricity use and repairs and maintenance). The analysis shows there is also around $90 million of indirect benefits attributed to productivity gains, and a significant boost to the NT economy, with the total benefits ranging from $270 to $380 million largely driven by construction activities.

Additional, less tangible benefits associated with the project include:

- **Strengthened safety, security and compliance**: The move to a new building enables us to modernise our infrastructure, guaranteeing that our facilities not only meet modern, industry-standard safety standards but also provide enhanced security outcomes consistent with our operational role as the provider of essential services in the Territory.

20 Attachment 5 Capital expenditure | Draft Decision - Power and Water Corporation Distribution determination 2024–29, AER, page 13

21 The design concept supports a P25 estimate of the cost.

22 In NPV terms

- **Advancing our renewables commitment**: Power and Water is taking proactive steps to actively support and further the NT Government's renewable energy targets. The project integrates solar generation and energy-efficient infrastructure into the project's design and construction. This project shows our commitment to environmental responsibility, aligns with the overarching renewables strategy, and provides tangible benefits in terms of sustainability and the corporation’s clean energy transition.
- **Operational efficiency and interoperability**: The consolidation of our staff into one location enhances operational efficiency and fosters enhanced interoperability among teams. By co-locating diverse functions, we would be able to streamline workflows and communication, subsequently boosting the overall performance of the corporation.

Ultimately, this consolidation would enhance our ability to deliver value to our customers – by concentrating our efforts and resources, we can respond more effectively to their needs and deliver improved services and solutions.

Further information on the revised single site consolidation project is provided in the business case in Attachment 3.5.

Engagement on the single site consolidation project

We shared our revised single site consolidation plans with key stakeholders including our residential customers through People’s Panels in May, August and October 2023, and business customers through direct engagement in June and July 2023.

Stakeholders were generally supportive of this project however sought more information, including how it would benefit customers outside the Darwin-Katherine network. However, there was overwhelming understanding that this project will have a profound benefit to the operations of Power and Water, resulting in a better culture and quality of service.

We have also received support for the project from the NT Government (see Attachments 3.6 and 3.7).

We will continue to engage with the NT Government and our suppliers and contractors to understand the impact of any changes in the economic and political environment that may help facilitate (or otherwise) this project. We will continue to engage with stakeholders through the course of the project through planning and into implementation.

More information on stakeholder engagement is provided in Attachment 1.1.

Meeting the NT NER test for inclusion in our forecast capex

This project meets the requirements of rule 6.5.7(a) of the NT NER as it:

- Provides the best overall NPV in consideration of the costs, benefits and risk of the various options.
- Is supported by a business case that substantiates the proposed costs as those a prudent operator would require to achieve the capital expenditure objectives.

Implementing our revised proposal

We have updated our capex forecasts and associated building blocks to:

- Remove the AER’s $5.5 million for the extension of the Mitchell Street lease.
- Shorten the life of the Mitchell Street lease to 4.5 years.
- Include $76.1 million of forecast single site consolidation capex to be recovered through Standard Control Services (**SCS**).

3.2.4 Cyber security

In its draft decision the AER accepted our proposed cyber security program as prudent and included our forecast capex of $11.4 million as a placeholder. However, the AER requested additional information to demonstrate that our forecast reflected that of a prudent and efficient operator, specifically requiring:

- *description of the proposed actions to address each of the maturity/capability gaps it identified between its current level of cyber maturity and the level required to achieve SP–2 maturity across each of the 11 domains under the AESCSF framework*
- *linking each of the above proposed actions to the respective individual costs required to undertake these actions*
- *detail for the individual costs inputs related to each proposed action, the basis for these costs (including relevant inputs, calculations, assumptions and sources) and set out how they were estimated, such as the number of labour-days or license fee*
- *demonstrating the efficiency of each cost input, e.g. through market testing and detailing all assumptions or other independent expert reports.*

Information to satisfy these requirements is provided in Attachment 3.8. The cyber security capex forecast remains unchanged from our initial proposal at $11.4 million.

3.2.5 Capitalised overheads

We have updated the capex forecast model to incorporate actual capitalised overheads for 2022-23, consistent with changes made throughout the revised proposal (e.g., using actual capex for 2022-23 to roll forward the RAB). Applying the approach adopted by the AER in its draft decision has increased forecast capitalised overheads over the 2024–29 period.

Our revised forecast is provided in the following table.

Table 3.3: Capitalised overheads, revised capex forecast, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Capitalised overheads	**28.0**	**27.3**	**23.6**	**33.8**	**33.9**	**146.6**

4. Contingent projects

4.1 The AER's draft decision

Constituent component 5: Determination of contingent projects

In accordance with clause 6.12.1(4A)(i) of the NT NER, the AER's draft decision is that the following projects are contingent projects for the purpose of this revenue determination for Power and Water Corporation:

- Shared transmission works to transport generation from a Renewable Energy Hub in Darwin-Katherine ($120.8 million)
- Holtze-Kowandi land development ($60.8 million)
- Middle Arm commercial development ($69.1 million)
- Wishart commercial development ($45.6 million).

The AER's draft decision is that Power and Water Corporation's proposed Unlocking existing large scale renewable generation in Darwin-Katherine ($45.7 million) project is not a contingent project for the purposes of the revenue determination for Power and Water Corporation.

Constituent component 6: Forecast capex for contingent projects

In accordance with clause 6.12.1(4A)(ii) of the NT NER, the AER's draft decision is that it is satisfied that the capital expenditure for the contingent projects as described in Power and Water Corporation's revenue proposal, and as determined to be contingent projects by the AER, reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

Constituent component 7: Trigger events for contingent projects

In accordance with clause 6A.12.1(4A)(iii) of the NT NER, the AER's draft decision on the trigger events for the four contingent projects is set out in Attachment 5 of this draft decision and includes amendments to the triggers proposed by Power and Water Corporation.

The AER's draft decision accepted four of our five proposed contingent projects at a total indicative cost of $296.3 million.

The AER did not accept the proposed contingent project to unlock existing large scale renewable generation in Darwin-Katherine, as it did not consider the project to be *reasonably required to maintain the quality, reliability and security of supply, or to meet or manage the expected demand for distribution services over the 2024-29 period.*[23] The AER considered that Power and Water had not demonstrated a sufficient need for the contingent project, and therefore could not approve it under the NT NER.

In preparing its draft decision, the AER worked with us to develop more specific trigger events for each of the four accepted projects, which it has included in the draft decision.

Our response to the AER's draft decision on our proposed contingent projects is provided in the following section.

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23 As per the requirements of clause 6.6A.1(b)(1) of the NT NER.

4.2 Our response

Power and Water's response:

We accept the proposed trigger events for the four contingent projects the AER accepted in the draft decision.

We maintain that the proposed contingent project associated with allowing existing large scale renewable generation capacity connected to the Darwin-Katherine transmission line (**DKTL**) [24] to export existing and expected new renewable energy is required for the 2024-29 period, and have provided further information to better articulate and justify the need for the project.

Since our initial proposal, our system studies have identified that more work needs to be done to address the system strength issues posed by the transition to renewables and the changing generation mix in the NT.

Our initial proposal was based on the premise that the proposed investment to 'unlock' the full capacity of renewables connected to the DKTL (potential installation of a synchronous condenser and/or battery storage systems) would also address future system strength issues likely to arise across the network in the near term. However, the recent studies indicate addressing the system strength issues on the DKTL would not provide an adequate solution to maintain security of supply in the broader Darwin area. Additional synchronous condensers or other network solutions at further locations would also be required.

Therefore, the originally proposed Unlocking existing large scale renewables on the DKTL contingent project would not address system security issues in the Darwin area. Additional investment will be required.

Added to this, the retirement of at least one of the four Frame 6 synchronous generators is likely to be brought forward to 2024, increasing the pace of change in the NT's generation mix and increasing the likelihood and urgency of investing in system strength.

Given these developments, and to better articulate the need for the proposed contingent project, we have separated the original project into two discrete components:

1. **Unlocking large scale renewables on the DKTL**: As per the initial proposal, investment in the order of ~$50 million is required to enable large scale solar to increase export from facilities connected to the DKTL without compromising system security.
2. **Managing network voltage and system strength with an increasing proportion of inverter-based generation**: As synchronous generation leaves the power system and the proportion of inverter-based generation increases, investment is required to maintain adequate system strength and regulate voltage across the Darwin region. This will likely include additional synchronous condensers and/or battery storage systems in the order of ~$100 million.

In our recent engagement with customers, we presented our revised suite of future network related projects, including increasing large scale renewable generation through the contingent proposed projects aimed at relieving constraints that limit dispatch. We received the following feedback:

[24] The DKTL is a single circuit 132kV transmission line that connects from Channel Island Power Station to Katherine. It supplies the townships of Manton, Batchelor and Pine Creek.

- Customers understood that there are network challenges that need to be resolved to enable dispatch of large scale renewables in the Darwin and Katherine regions.
- Panellists supported investment to unlock renewable energy from existing solar farms to customers, forming the view that this low cost and clean form of generation should enable electricity to be supplied at a cheaper cost, as well as providing environmental benefits.

An overview that further explains and substantiates these two contingent project components is provided in Attachment 4.1. We have included specific trigger events, consistent with the AER's draft decision on other contingent projects. Any investment will be subject to further analysis and Transmission Regulatory Investment Test (**RIT-T**) challenge before progressing.

5. Operating expenditure

5.1 The AER's draft decision

Constituent component 8: Forecast opex

In accordance with clause 6.12.1(4)(ii) of the NT NER and acting in accordance with 6.5.6(d) of the NT NER, the AER's draft decision is to not accept Power and Water Corporation's proposed total forecast operating expenditure, inclusive of debt raising costs, of $415.3 million ($2023–24). Our draft decision therefore includes an alternative estimate of Power and Water Corporation's total forecast opex for the 2024–29 regulatory control period of $364.4 million ($2023–24) including debt raising costs and exclusive of DMIAM.

In its draft decision, the AER included an alternative opex estimate of $364.4 million. This is $50.9 million or 12.3% lower than the forecast in our initial proposal. The key drivers of the AER's alternative estimate are:

- A reduction of $5.3 million in base year opex to account for:
  - The removal of the DMIA, the expenditure for which should not be included in the opex forecast as it is accounted for elsewhere in the revenue modelling, resulting in a $2.0 million reduction.
  - Removing movements in provisions, resulting in a $0.3 million reduction.
  - The latest inflation forecasts.
- A reduction of $46.7 million due to the removal of five of our six proposed step changes.

These reductions are partially offset by an increase of $1.0 million in trend growth and $0.1 million in debt raising costs.

Our response to the AER's draft decision on our proposed opex forecast is provided in the following section.

5.2 Our response

Power and Water's response:

We propose a revised opex forecast of $387.2 million which includes:

- The AER's adjusted base opex of $361.4 million reflecting our $72.3 million 2021-22 actual opex.
- Trend growth parameters as calculated by the AER, updated for the actual 2022-23 customer numbers and line length parameters, and an updated labour escalation forecast from BIS Oxford.
- A revised cyber security step change supported by historical actual costs, and vendor estimates to demonstrate the efficiency of the forecast, modified slightly to $5.0 million to correct a transcription error.
- Reintroduction of the cloud migration step change supported by historical actual costs, and vendor estimates to demonstrate the efficiency of the forecast, reduced to $3.3 million including revision of the affected systems and timing of the migration to the cloud.

- Reintroduction of the $3.9 million step change associated with the OT capability uplift program, supported by more information on the need for and benefits of the program.
- Reintroduction of a step change to better integrate DER in our network, reduced to $4.9 million to account for the significantly reduced scope of the overall works program.
- Reintroduction of the $4.9 million step change related to the increase in our insurance premiums as estimated by our independent insurance broker.

The initial regulatory proposal included $415.3 million of operating and debt raising costs over the 2024-29 period. This opex forecast included:

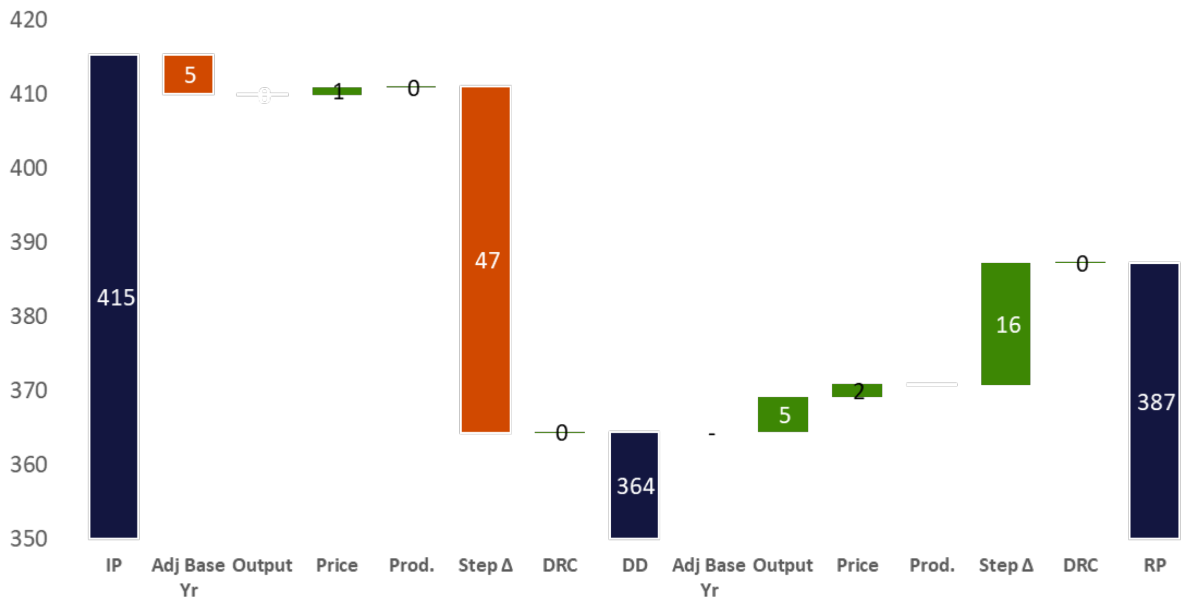
- $366.7 million of base opex reflective of our revealed costs in 2021-22.
- Price, output and productivity (trend) growth of -$7.0 million.
- A $4.4 million increase reflecting the need to increase our cyber security capability to SP-2.
- A $6.0 million increase to meet our regulatory obligations.
- A $4.0 million increase to migrate critical ICT assets to the cloud where on-premises solutions are no longer offered by the provider.
- $18.8 million of operating costs associated with the OT capability uplift program.
- $14.1 million of operating costs associated with our future network program.
- A $4.9 million increase in our insurance premiums.
- $3.3 million in debt raising costs.

Since submitting the initial regulatory proposal, we have continued to review and modify our capital investment program, which in turn has reduced our forecast opex for the period. We have extended the timeframe over which our DER integration program (part of our Future Networks Strategy) will be delivered, and we have pared back our OT capability program. These changes alone have reduced our opex forecast by around $24.1 million, almost halving our forecast opex step changes.

Since the initial submission we have sought customer feedback on these step changes through People's Panels and targeted stakeholder engagement sessions. A summary of these engagements is provided in Attachment 1.1.

Our revised total opex forecast is $387.2 million. Figure 5.1 shows the change in our opex forecast from the draft decision, driven predominantly by re-inclusion of a number of step changes.

Figure 5.1: Change in forecast SCS opex from the initial revenue proposal (IP) to the draft decision (DD) and the revised revenue proposal (RP) by component, $ million real 2024



Note: 'IP' is the initial regulatory proposal, 'DD' is the AER's draft decision, 'RP' is PWC's revised regulatory proposal, 'Adj Base Yr' is the impact of updates to the base year, 'Output' picks up updates to the output forecasts and weights, 'Price' is the impact of changes in labour escalation, 'Prod' picks up changes in productivity, 'Step Δ' picks up changes to the step change forecast, while 'DRC' picks up changes in debt raising costs.

The key opex adjustments are discussed in the following sections.

5.2.1 Base year opex

In its draft decision, the AER accepted our use of the 2021-22 actual opex for the purposes of establishing the basis of our forecast opex for the 2024-29 period. We accept the changes the AER has made to our base opex.

5.2.2 Trend

We accept the AER's draft determination as it relates to calculating the price, output and productivity growth rates applied to our opex forecast. This includes the AER's proposed method of determining labour price growth by averaging two different wage price index forecasts.

We have updated a number of input parameters as follows:

- We have actual customer numbers and line lengths for 2022-23 and have therefore replaced the placeholder estimate with these actuals and rebased our forecasts from those actual values. This has resulted in an increase in our forecast opex of $4.7 million.
- We have updated the BIS Oxford labour escalator forecast (see Attachment 2.6) to reflect more recent information. This has increased forecast opex by $1.7 million.

We have also applied the updated growth rates to our revised opex forecast, which is $22.8 million higher than the draft decision (including growth). The results in a net increase in trend growth of $6.3 million.

5.2.3 Step changes

We have considered the AER's comments on the step changes and have modified our step change forecast significantly in this revised proposal. Specifically, we have:

- Revised our Future Networks and OT capability uplift programs which has resulted in reduced expenditure in the next regulatory period.
- Provided additional evidence to support the inclusion of cyber security, cloud migration and insurance step changes, with some minor modifications to the forecasts.
- Accepted the AER's decision on our proposed regulatory obligations step change.

Our key changes in response to the draft decision on our proposed step changes are discussed in the following sections, and in the opex step change model included at Attachment 5.4.

5.2.3.1 Future Networks – DER integration

We do not accept the AER's draft decision to reduce the Future Networks step change from $14.1 million to $1.1 million. The AER excluded all project costs associated with DER integration (previously referred to as the DOE program) with the exception of the installer outreach program. The AER highlighted that at the time of our initial proposal we had not adequately demonstrated the merits of the various components of the Future Networks opex step change, or that these costs could not be absorbed by the business.

As discussed in section 3.2.1, we have revised the scope of the 2024-29 program of work. Our revised step change is supported by the DER integration business case (provided at Attachment 3.1), which addresses the feedback provided by the AER, including a detailed cost estimate. Our proposed Future Networks step change has reduced from $14.1 million in the initial proposal to $4.9 million in this revised proposal.

We do not propose to implement the full customer wide dynamic operating envelope solution during the next regulatory period. The revised DER integration program provides a minimum level of core infrastructure to enable dynamic management of solar PV. It will provide a base level of capability to manage immediate compliance related risks and better understand the hosting capacity and voltage performance of our network.

We will instead focus on uplifting visibility of DER impact, improving inverter compliance and targeted DER integration, as well as customer and installer outreach programs. We have included provision for stakeholder engagement around the patterns of behaviour for DER and EV charging associated with the EV charging trial.

In addition to the $1.1 million of opex associated with our consumer engagement and installer outreach program accepted by the AER in its draft decision, our revised Future Networks step change includes opex associated with:

- Software licensing and maintenance and support costs associated with the network state estimator and constraints engine.
- Maintenance and support for the development and deployment of a communications upgrade to IEEE 2030.5 communication protocol.
- Making improvements to the DER Register.

This results in a revised opex step change of $5.5 million, with the allocation to Standard Control Services (**SCS**) being $4.9 million. Following further review and discussion with stakeholders, we have removed any components of the Future Network step change that are not related to the DER integration project.

More information on each of these components is included in the business case provided in Attachment 3.1.

Our revised forecast is provided in the following table.

Table 5.1: Future networks, DER integration step change, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	0.4	0.4	1.1	1.8	1.8	**5.5**
Allocation to SCS	0.4	0.4	1.0	1.6	1.6	**4.9**

5.2.3.2 OT capability uplift

We do not accept the AER's draft decision to remove the OT capability step change. The AER excluded all project costs associated with our OT capability uplift. At the time of the initial proposal we had not provided sufficient information to demonstrate the merits of the various components of the proposed step change.

The AER stated:

> *We have not included this step change in our alternative estimate, as PWC has indicated it is revaluating the business case on which this step change is based and will provide updated information in its revised proposal.*
>
> ..
>
> *In developing its revised business case, we ask PWC to clarify the drivers of, and need for, any OT capability uplift expenditure, the options considered to meet any gaps in current capabilities, and to provide supporting information including a detailed cost estimate for the project.*

As discussed in section 3.2.2, we have revised our OT capability uplift capex project, scaling back the proposed full ADMS solution to a more conservative and deliverable operational technology uplift – focusing mainly on upgrading the GIS and improving both our data, and distribution operation processes. As a result, the associated opex has reduced significantly, from $18.8 million to $3.9 million.

Our revised OT capability uplift step change is supported by a business case which addresses the feedback provided by the AER, including a detailed cost estimate. The opex associated with the OT program includes:

- GIS licencing cost; production and user licence for ArcFM web, ArcFM editor and associated database costs.
- Data cleansing and migration costs associated with GIS upgrade.
- Data corrections to address known gaps identified with elements of the GIS data that need to be refined so it can genuinely be a source of truth for other dependent systems. This will require resources to improve the quality of this data for migration into the GIS (both before and after the upgrade).

- Support and maintenance costs for base DMS functionality, including an estimate of the associated licence cost.

We have included the costs associated with the ongoing data governance and data maintenance activities in our business case, however propose to absorb these costs into our normal business activities. Accordingly, we have not included these costs in the proposed opex step change. This results in a revised opex step change of $3.9 million.

More information on each of these components is included in Attachments 3.2 to 3.4.

Our revised forecast is provided in the following table.

Table 5.2: OT capability uplift step change, $ million real 2024

	2024-25	2025-26	2026-27	2027-2	2028-29	Total
Total	0.6	1.1	0.7	0.8	0.8	**3.9**
Allocation to SCS	0.6	1.1	0.7	0.8	0.8	**3.9**

5.2.3.3 Insurance premiums

In our initial proposal we included an insurance step change of $12.2 million, of which $4.9 million was allocated to SCS, reflective of recent changes to market conditions that had seen the cost of insurance for electricity network service providers increase significantly. At the time of the initial proposal, we had not received an estimate from our insurance broker for the next regulatory period. As a placeholder, we estimated the impact based on recent increases experienced by other distribution network service providers in Australia.

The AER did not include an amount for an insurance cost increase as they did not have sufficient information to assess our proposed forecast. The AER stated:

> *Consistent with our standard approach for assessing this type of step change, we requested that PWC provide an independent forecast (e.g. an insurance broker's quote or a consultant's report) of the expected changes in its insurance premiums out to the end of the next regulatory control period. PWC notified us that this could not be provided in time for the draft decision,*[84] *but advised that it will provide an updated forecast for this step change with the requested supporting documentation in its revised proposal.*

Since the initial proposal, we engaged our insurance brokers, Marsh, to provide an independent estimate underpinning our insurance premium step change. It is provided as Attachment 5.1.

We have updated our step change based on the independent estimate, and which totals $4.9 million when allocated to SCS. Our revised forecast is provided in the following table.

Table 5.3: Revised insurance step change, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	1.7	2.1	2.4	2.6	2.9	**11.6**
Allocation to SCS	0.7	0.9	1.0	1.1	1.2	**4.9**

5.2.3.4 Cyber security

In our initial proposal we included a cyber security step change of $9.0 million, of which $4.4 million was allocated to SCS. This was to complement the capex project designed to increase our cyber security resilience to achieve security profile two (SP-2)[25] by 2028 – a requirement of the *Security of Critical Infrastructure Act 2028 (Cth)* and associated subsidiary legislation.

The project scope was based on a detailed gap analysis, and the forecast was based on a combination of vendor, consultant and subject matter expert advice.

In its draft decision, the AER noted the need for a cyber security uplift and included a placeholder amount reflective of our forecast of $4.4 million subject to us providing additional information demonstrating the efficiency of our forecast. Specifically, the AER requested the following information:

- *a description of the proposed actions to address the maturity / capability gaps identified between its current level of cyber maturity and the level required to achieve SP–2 maturity across each of the eleven domains under the AESCSF framework*
- *linking / mapping of each of the above proposed actions to the respective individual costs required to undertake the actions*
- *details of the costs related to each proposed action, including the basis for these cost[s] (e.g. relevant inputs, calculations, assumptions and sources) and how they were estimated, such as the number of labour-days or license fee*
- *information which demonstrates the efficiency of cost inputs, e.g. through market testing or other independent expert reports.*[26]

We have provided further evidence to show the prudence and efficiency of the cyber security project as a whole in Attachment 3.8.

Since the initial proposal, we have found a transcription error related to the cyber security forecast. The value in our opex step changes model, and therefore all consequential forecasts were inconsistent with the forecast in our business case submitted as part of the proposal. The business case supported a forecast of $10.0 million, of which $5.0 million was allocated to SCS. However, the initial regulatory proposal and associated step change model showed the incorrect SCS forecast of $4.4 million. This has increased the forecast step change allocated to SCS by $0.6 million.

We have reflected the correct forecast, aligned with the business case provided at the time of our initial regulatory proposal, as shown in Table 5.4.

Table 5.4: ICT cyber security step change, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	2.0	2.0	2.0	2.0	2.0	**10.0**
Allocation to SCS	1.0	1.0	1.0	1.0	1.0	**5.0**

25 As defined in the Australian Energy Sector Cyber Security Framework.

26 Attachment 6 Operating expenditure | Draft Decision – Power and Water - Electricity Distribution Determination 2024–29, AER, page 23

5.2.3.5 Cloud migration – Meter to Cash

In our initial proposal we included a step change of $8.0 million to establish a small cloud footprint, of which $4.0 million was allocated to SCS. This is required as some of our critical business applications are only being offered as cloud-based applications. Some other applications are or will soon become uneconomic or unavailable as our preferred, on-premises instances.

In its draft decision, the AER accepted the need to maintain vendor support for critical software solutions and agreed that a step change of some amount may be required. However, the AER was not satisfied that we adequately demonstrated the prudence and efficiency of the step change. The AER requested further information to support the inclusion of an uplift in its final decision.

The AER stated

> *We consider it prudent for PWC to maintain vendor supported software solutions for any necessary IT capabilities, and agree that a step change of some amount may be required to fund the migration of the identified IT capabilities to the cloud. However, we have not included this step change in our alternative estimate as we consider the proposed cloud solutions have not been satisfactorily demonstrated to be prudent and efficient. We seek further information from PWC in its revised proposal to inform our assessment of these costs for the final decision.*

Since our initial proposal we have new information from our procurement process for the Meter to Cash project. We have revised our forecast to reflect the outcome of a competitive tender process for the provision of Azure Managed Services, and published costs for all other components of our cloud presence to support the project. This has reduced the forecast step change by $0.7 million after allocation to Standard Control Services.

Our revised opex step change is based on maintaining a minimum cloud footprint, consistent with adoption of contemporary systems that replaced existing on-premise solutions, namely the Retail Management System. The Retail Management System was a legacy, obsolete and out of date system that did not meet our compliance obligations. The selection of the solutions formed the basis of our Meter to Cash project.

We have provided further evidence to show the prudence and efficiency of the cloud migration costs in Attachment 5.2.

Our revised forecast is provided in Table 5.5.

Table 5.5: ICT cloud migration step change, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Total	1.3	1.3	1.3	1.3	1.3	**6.6**
Allocation to SCS	0.7	0.7	0.7	0.7	0.7	**3.3**

6. Pass through events

6.1 The AER's draft decision

Constituent decision 19: Nominated pass through events

In accordance with clause 6.12.1(14) of the NT NER the AER's draft decision is to apply the following nominated pass through events to Power and Water Corporation for the 2024–29 regulatory control period in accordance with clause 6.5.10:

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

The definitions of these events have, and our reasons for this decision, are set out in Attachment 15.

The AER did not approve our proposed new confidential cost pass through event.

6.2 Our response

Power and Water's response:

We do not accept the AER's draft decision to reject our proposed confidential cost pass through event. Information supporting the retention of this event is provided in Confidential Attachment 6.1.

In response to Territory Generation's submission on our initial proposal, we propose to include a new cost pass through event to allow us to recover potential future network support services costs (as non-network alternatives), for which we are not currently paying for. More information is provided as Attachment 6.2.

6.2.1 Confidential pass through event

Further information to support our confidential cost pass through event is provided in Confidential Attachment 6.1.

6.2.2 Network support pass through event

Requirement for a new cost pass through event

We have added a nominated pass through event to allow Power and Water to recover costs if it is required to pay for voltage management, network support or system strength services (known as essential system services) during the next regulatory period. This matter was raised by Territory Generation in its public submission on our regulatory proposal.[27]

[27] Available at: https://www.aer.gov.au/system/files/Territory%20Generation%20-%20Submission%20-%202024-29%20Electricity%20Determination%20-%20PWC%20-%20May%202023.pdf

Territory Generation highlighted that it currently provides a number of services through its generation assets, that are typically the responsibility of the network operator, which Power and Water currently does not incur costs for. These essential system services are:

- Network support through the provision of capacity / N-1 of the 132kV line to Katherine.
- Provision of voltage management.
- Provision of inertia and system strength through out of merit dispatch.

Electricity market reforms to legislate the responsibility for procurement of these services and the costs associated with them, are still underway in the NT. As the network operator, it is reasonably likely that we will become responsible for provision of these services.

We expect to incur costs for provision of these services in the next regulatory period. It is not clear whether the change would qualify as a regulatory change event. This is because we are already accountable for a number of services being provided by third parties like Territory Generation, meaning there would not necessarily need to be a change to legislation in order for us to be required to pay for these services. There is also a question around the timing of this change.

As the generation mix in the NT power system changes, a network solution may not be the most efficient method to address changing needs. A better outcome for customers could be a network support service solution and these should be provided by the network operator. A nominated cost pass through mechanism to enable this as an option is therefore a prudent inclusion in the regulatory determination.

The basis for procuring non-network alternatives to maintain network reliability, referred to as 'network support', is well established in Australia. The AER describes network support as:[28]

> *Network support provides a direct benefit to transmission customers and end users, as it can defer the need for transmission augmentation, and hence results in lower transmission charges, while maintaining the reliability of the network. However, the amount of network support required by a TNSP in any given year is dependent on factors that are outside the control of the TNSP such as weather conditions, demand levels, and electricity usage patterns.*

NER provisions exist for NEM Transmission Network Services Providers (**TNSPs**) where the cost increases (or decreases) are beyond their control. In such circumstances, it is unreasonable for TNSPs to bear the risk (or benefit) arising from changes in costs. As these provisions have not yet been activated in the NT NER, it is uncertain whether Power and Water would be able to recover these costs.

Accordingly, we propose that a new nominated pass through event is included to provide Power and Water with reasonable certainty to recover the cost of network support payments.

Our revised proposal

We have included a new nominated cost pass through event in response to Territory Generation's submission, to provide us with a reasonable opportunity to recover the costs associated with third-party provision of network support services. This cost pass through event is defined as:

> *A **network support event** occurs if:*
>
> *Network support payments, as defined in Chapter 10 of the NT NER, are made by Power and Water Corporation in its role as the Transmission Network Service Provider.*

[28] AER, Guideline for network support pass through

This event is based on the definitions of network support services and network support payments in Chapter 10 (Glossary) of the NT NER. We have applied the definitions to Power and Water in its role as the TNSP although we are regulated as if the business is solely a DNSP under section 6 of the NT NER.

We expect this cost pass though event to be retained into the future as a way to manage these variable costs that are difficult to forecast. The retention of this pass through is consistent with provisions in the NER that applies to Transmission Network Service Providers[29], and included in the NT NER but not yet enforced.

Meeting the NT NER requirements as a cost pass through event

As part of the AER's assessment of additional pass through events, it must assess them against the NER considerations for a nominated cost pass through event set out in clause 6.5.10(b)) of the NT NER. These considerations are set out in Table 6.1.

Table 6.1: Summary of assessment against the NT NER requirements

NT NER consideration (6.5.10(b))	Assessment of the event against rule considerations
Whether the event proposed is an event covered by a category of pass through events specified in the Rules clause 6.6.1(a1)(1) to (4)	No
Whether the nature or type of event can be clearly identified at the time the determination is made for the service provider	Yes, the event can be clearly identified as per the proposed definition
Whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event	No, these costs reflect the most efficient solution to ensure we are compliant with network design criteria under the NT Network Technical Code and Planning Criteria. These costs are incurred as an alternative to more costly network augmentation solutions
Whether the relevant service provider could insure against the event, having regard to: • the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or • whether the event can be self-insured on the basis that: – it is possible to calculate the self-insurance premium; and – the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services	It would not be possible for us to insure or self-insure against this event as these costs reflect business as usual operations for a Transmission Network Service Provider such as Power and Water

29 More information is provided in the AER's Procedural Guideline for preparing a transmission network support pass through application, available at: https://www.aer.gov.au/system/files/Guideline%20-%20final.pdf

NT NER consideration (6.5.10(b))	Assessment of the event against rule considerations
Any other matter the AER considers relevant and which the AER has notified network service providers is a nominated pass through event consideration	The NER and the AER's guideline for preparing network support pass through applications includes similar provisions for the recovery of costs associated with network support payments. This is an enduring pass through event for Transmission Network Service Providers that we are looking to replicate in our role as the Transmission Network Service Provider in the NT

Further information on our network support nominated pass through event is provided in Attachment 6.2.

7. Tariffs

7.1 The AER's draft decision

Constituent component 21: Tariff structure statement

In accordance with clause 6.12.1(14A) of the NT NER, the AER's draft decision is to not approve the tariff structure statement (**TSS**) proposed by Power and Water Corporation. The reasons for our draft decision are set out in Attachment 19.

The AER's draft decision accepted most elements of Power and Water's 2024-29 TSS. Key elements of our initial proposal approved by the AER are:

- Tariff assignment and new time-of-use tariff structures for low voltage (**LV**) customers.
- The tariff assignment and tariff structure for high voltage (**HV**) customers with smart meters consuming less than 10 GWh per annum.
- A seasonal component to the demand charges for large businesses consuming above 750 MWh and those connected to the HV network.
- Refining and shortening of Power and Water's peak demand window to 3pm – 9pm on weekdays (from the current 12pm – 9pm).

The AER did not accept the proposed changes to the super user tariff, Tariff 7. The AER required a cost reflective charging parameter be included in the super user tariff to reflect the LRMC of providing the service.

The AER was concerned that Tariff 7 as initially proposed, could result in other network users cross subsidising the forward looking costs of our proposed super users. The AER also considered that as the largest consumers of electricity, super users are capable of understanding and responding to cost reflective price signals.

The AER also encouraged us (along with other distribution network service providers) to consider:

- Developing a controlled load tariff for EV chargers.
- Grid-scale battery research and lessons learnt from other distributors' grid-scale battery tariffs, with a view to proposing tariff trials during 2024-29 and grid-scale battery tariffs for the 2029-34 TSS.
- Refinements to the LRMC approach for the 2029-34 TSS with regard to our approach to replacement capex and the length of its forecasting horizon.

These tariff trial and research recommendations require no changes to our 2024-29 TSS and were already contemplated in our Tariff Structure Explanatory Statement for that period.

7.2 Our response

Power and Water's response:

We accept in principle the AER's proposed changes to the TSS regarding Tariff 7. We have adopted a slightly different approach to that proposed by the AER to achieve the same outcome. It involves removing Tariff 7 and adding the super users into the approved Tariff 6, which already has a demand charging component that reflects LRMC.

We welcome the AER's draft approval of our initial TSS proposal elements relating to:

- Our compliance with the TSS content requirements.
- Our proposed customer tariff assignments.
- Splitting Tariff 3 and moving these customers from demand tariffs to time of use (**TOU**) energy tariffs with a shorter peak.
- Changing the eligibility for Tariff 5 and Tariff 6 and refining their demand charge periods for seasonality and a shorter 3pm – 9pm peak period.
- Our Export Tariff Transition Strategy, which proposed to not introduce two-way pricing for the 2024–29 regulatory period, but to first progress our dynamic operating envelope capability then collaborate with retailers on trials.
- Our approach to estimating LRMC.

We have retained these approaches in our revised TSS, with consequential adjustments to our customer tariff assignments for the AER's rejection of our proposed Tariff 7.

Our initial TSS proposed to separate our HV tariff class customers into two tariffs:

- Tariff 6 for HV customers consuming 0-10,000 MWh pa, which the draft decision accepts.
- Tariff 7 for HV customers consuming above 10,000 MWh pa, which the draft decision does not accept.

We proposed introducing a super users tariff (Tariff 7) with a flat anytime energy tariff for our 13 largest users. This proposal sought to recognise that the marginal cost of capacity provision to our HV-connected super users are accounted for in their individual network connection charges and corresponding connection agreements.

The AER's draft decision considered the proposed anytime tariff is not compliant with the pricing principles because it is not based on LRMC. The AER considered that we had not sufficiently established there are no shared network assets upstream impacted by these customers, or that the customers have already fully paid for their capacity through connection charges.

Our revised TSS proposal does not propose a Tariff 7. We propose to instead adopt the approved Tariff 6 as a single tariff applicable to all customers in our HV tariff class. Our reasoning for this is that:

- Adding an LRMC charging parameter to Tariff 7 would involve adding demand charges that replicate the Tariff 6 structure.
- Having two HV tariffs with identical structures:
  - would not achieve our original intent of Tariff 7; and

– would not support the NT NER rule 6.18.3(d)(2) requirement that our HV tariff class be constituted with regard to the need to avoid unnecessary transaction costs, because there would be no gain from the transaction costs of establishing a second identically structured tariff within that HV tariff class.

- Our largest retail customer, Jacana, submitted to the AER on our initial TSS proposal stating that '*As there are only a handful of customers that would fall into the super user tariff category, Jacana Energy is of the view that creating new tariff structures and potentially new contracts only for these customers will be inefficient*.'[30]
- No other stakeholders submitted in support of introducing Tariff 7.

7.2.1 Tariff trials and research recommendations

We appreciate the AER's guidance on tariff trials and research. This accords with our intent for the 2024-29 TSS period.

We recognise that tariff trials and building on lessons from other network's tariff trials will be essential to us successfully designing and testing future NT network charges that address the needs of both our future network and our customers.

We also acknowledge that tariff trials cannot proceed for most of our customers under the current Electricity Pricing Order due to the prescribed retail pricing for our customers who consume >750MWh per year.

In the 2024-29 TSS period we therefore propose to collaborate with NT retailers and the NT Government to design targeted trials that can:

- Inform our future network tariff design; and
- Provide evidence to support the NTG considering reform to the Electricity Pricing Order.

Tariff trials would also help us in understanding:

- Whether customers will adapt their export scale, pace and timing due to export pricing or rebate signals.
- Whether differing prices for static versus dynamic customer connection or device controls are warranted, and the scope for these to encourage controlled load solutions that benefit both network costs and customer bill outcomes.
- How pricing for the behaviours of grid-scale batteries that can either drive up or help avoid our costs and help encourage efficient deployment of these batteries across our networks.

[30] Jacana, Review of AER Issues Paper: PWC Electricity Distribution Determination 1 July 2024 – 30 June 2029 Jacana Energy Responses, p.10.

8. Metering

8.1 The AER's draft determination

Alternative control services: Metering

The AER's draft decision was to:

- Remove the costs associated with the single site consolidation project.
- Include alternate smoothed revenue of $70.1 million ($ nominal).
- Set metering prices to recover revenue components consistent with its draft decision.

The AER also encouraged us to maintain or possibly increase the current installation rate of smart meters. Accelerating the roll out would be consistent with the pace of change in other Australian jurisdictions and the recent metering review by the Australian Energy Market Commission (**AEMC**). The AER recommended we engage with stakeholders on the price impact of a program acceleration.

8.2 Our response

Power and Water's response:

We have made two key changes to our metering capex forecast:

- We have revised the single site consolidation project (as discussed in section 3.2.3) and updated the allocation to forecast metering capex accordingly.
- In line with the AER's recommendation and feedback from customers and stakeholders, we have also revised our capex forecast to maintain our current installation rates of smart meters (~11,000 per annum) with a view to complete the smart meter replacement program by the end of the 2024-29 regulatory period.

8.2.1 Revised metering replacement program

In line with the AER's recommendation, we have looked into the possibility of accelerating the smart metering roll out by maintaining the replacement rates achieved in 2022 and 2023. We consider this is a practicable solution and expect to be able to achieve an estimated 11,000 replacements per year throughout the 2024-29 regulatory period.

This accelerated program will allow placement of orders for suitable meters[31] in sufficient volumes and with sufficient lead times to maintain the stock levels at an efficient cost. The accelerated program will also allow us to maintain the current volume of appropriately skilled staff and contractors replacing meters across Darwin, Katherine, Tennant Creek and Alice Springs.[32]

[31] We will continue to monitor equipment failure rates to ensure we are using the mix of equipment that proves to be most resilient in our harsh range of climates.

[32] The legacy issues with existing metering installations are understood by staff and contractors and solutions and work practices to manage them have been developed and are in use in the current replacement program.

We engaged on this matter in our People's Panels as well as through individual engagement with energy partners. In our discussions we indicated an accelerated roll out would increase the daily charge for single phase residential customers from 34 cents per day as reflected in the AER's draft decision (based on the roll out included in our initial proposal) to 36 cents per day under the accelerated roll out.

The People's Panels expressed strong support to pursue this faster speed of smart meter roll out. One participant queried whether Power and Water should invest even faster. Similarly, our energy partners were supportive of the benefits it would provide to them and agreed that we should maintain the accelerated rate achieved in 2022 and 2023.

Table 8.1 shows the revised meter replacement capex associated with an accelerated smart meter roll out.

Table 8.1: Accelerated smart meter roll out, $ million real 2024

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Initial meter replacement capex	4.9	4.7	7.6	7.6	7.5	**32.3**
Draft decision meter replacement capex	4.9	4.7	7.6	7.6	7.5	**32.2**
Revised meter replacement capex	11.5	11.6	11.7	11.8	8.1	**54.6**

Note: this includes expenditure on electronic meters, metering communications and dedicated CTs and VTs

8.2.2 Revenue and prices

We have updated revenue and prices for the revised capex forecast. Table 8.2 summarises the revised costs and compares them to those in the initial regulatory proposal and draft decision. Smoothed revenue and prices have increased from the draft decision due to our revised proposal to accelerate the smart meter roll out, as well as updates to forecast labour escalation and non-network expenditure and to 2022-23 capital expenditure.

Table 8.2: Forecast metering revenue and prices, $ nominal

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Smoothed revenue ($ million)						
Initial regulatory proposal	11.9	13.0	14.1	15.4	16.7	**71.1**
Draft decision	13.0	13.5	14.0	14.5	15.0	**70.1**
Revised regulatory proposal	14.1	14.6	15.1	15.7	16.2	**75.7**
Prices ($ per meter)						
Initial regulatory proposal						
1 Phase Meters (including Prepayment)	113.4	122.4	132.1	142.6	153.9	
3 Phase Meters	150.2	162.1	175.0	188.9	203.9	
LV CT	599.4	647.0	698.4	753.8	813.7	

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
HV	2,068.1	2,232.3	2,409.5	2,600.8	2,807.3	
Draft decision						
1 Phase Meters (including Prepayment)	124.0	127.4	131.0	134.7	138.5	
3 Phase Meters	164.3	168.8	173.6	178.4	183.4	
LV CT	655.5	673.8	692.7	712.1	732.0	
HV	2,261.5	2,324.8	2,389.9	2,456.8	2,525.6	
Revised regulatory proposal						
1 Phase Meters (including Prepayment)	131.1	134.8	138.5	142.4	146.4	
3 Phase Meters	173.7	178.5	183.5	188.7	194.0	
LV CT	693.1	712.5	732.4	752.9	774.0	
HV	2,391.2	2,458.1	2,527.0	2,597.7	2,670.4	

9. Ancillary services

9.1 The AER's draft decision

Ancillary services: Fee-based and quoted services

In its draft decision, the AER:

- Adjusted our proposed X factor to account for its decision on labour price growth factors.
- Replaced four of our seven labour rates with maximum labour rate benchmark rates.
- Replaced our overhead rate of 83.08% with its benchmark rate of 61%.
- Adjusted prices consistent with these decisions and updated inflation.
- Adopted a 6% margin to apply to quoted services as part of the form of control formula for those services.

The AER's draft decision has reduced our proposed prices by an average of 13.2% over all services offered. The AER notes that the adjusted fee-based services benchmark well against similar services provided by other distribution network services providers. The AER therefore considers its draft decision will allow us to recover at least our efficient costs in providing fee-based services.

9.2 Our response

Power and Water's response:

We accept the AER's draft decision on fee-based and quoted services, and reduced fees for three of our fee-based metering services even lower than the draft decision.

Our initial proposal included three fee-based metering services, which each incorporated cost components for meter assets and communications equipment. In our revised proposal, we have adopted the AER's draft decision as the starting point but have then removed the meter assets and communications equipment components from these services. This is because we propose to classify these capital costs as Alternative Control Services (**ACS**) metering capex and add it to the ACS metering RAB. These costs will therefore be recovered over the life of the asset via meter charges and should therefore not feature in the service fee.

Our revised prices for the three fee-based services only includes the labour component of the service charge. The changes in fees are summarised in Table 9.1.

Table 9.1: Fee-based meter replacement charges, $ real 2024

Service	Service category	Initial proposal	Draft decision	Revised proposal
Exchange or replace meter – three phase	Meter Servicing (Fee based)	1,184.99	1,068.26	436.36
Exchange or replace meter – single phase	Meter Servicing (Fee based)	796.33	720.51	376.28
Install modem on smart ready meter	Meter Servicing (Fee based)	483.73	438.83	316.19

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