Revised Revenue Proposal 2023–2028

2 December 2022

ElectraNet

Contents

Welcome to ElectraNet's Revised Revenue Proposal

This is ElectraNet's response to the Australian Energy Regulator's Draft Decision on our Revenue Proposal for the period from 1 July 2023 to 30 June 2028.

Our Revenue Proposal was designed to address the challenges we face as the power system continues to transform in coming years. Since our Revenue Proposal was prepared, change in our operating environment has continued at pace.

South Australia is the first gigawatt scale power system in the world to experience periods of 100% Variable Renewable Energy. These periods will become more frequent and longer in duration. To support this, we need to uplift our capabilities to plan and operate the transmission network to maintain secure and reliable supply for customers.

We have also seen significant change in economic conditions in recent months, driving up interest rates and inflation.

We share customer concerns over the rising costs of living. Electricity costs are a part of this and we are committed to keeping our costs as low as possible, exploring innovations and playing a broader role in enabling the transition to cleaner energy.

Our focus is to manage the increasing challenges of the energy transformation while maintaining the safety and reliability of South Australia's electricity transmission network. We are very mindful of getting the balance right between risk, cost and performance of the network.

We proposed a capital program that continues the downward trend in underlying capital expenditure. Our capital expenditure will be significantly lower than it has been at any time in the last fifteen years.[1]

Our operating costs continue to be impacted by external cost pressures such as insurance, cyber security requirements and the increasing complexity of our network operating environment. These continue to drive up our operating costs.

In its Draft Decision the AER accepted the majority of our Revenue Proposal, noting that our forecasting methods are prudent, in line with applicable AER guidelines, and are based on estimates of the likely realistic costs of relevant projects and programs.[2] It also concluded that our historical expenditure, both capital and operating, was efficient.

The AER accepted our capital expenditure forecast. In relation to operating expenditure, the AER accepted most of our proposal, though it made changes to some of the step changes we proposed.

For the most part we accept the AER's Draft Decision in this Revised Revenue Proposal.

This Revised Revenue Proposal sets out our detailed response to the AER's Draft Decision. Among other things, we have:

- adjusted forecasts for movements in inputs such as inflation
- provided further information in support of some of the step changes the AER did not accept, including increasing cyber security requirements
- addressed the increasing need for inertia services in South Australia identified by AEMO
- addressed the capability uplift required to manage the network with 100% renewables.

I thank our customers and stakeholders and especially our newly reconstituted Consumer Advisory Panel for their support and input to this Revised Revenue Proposal.

There can be no energy transition without transmission and ElectraNet will continue to play its part in safely delivering South Australia's energy future.

Simon Emms
Chief Executive

1 AER Draft Decision, Attachment 5, p.6
2 AER Draft Decision, Attachment 5, p.7

Reliability and affordability remain ElectraNet's key priorities

Our Revised Revenue Proposal balances reliable and affordable electricity supply in a rapidly changing power system

Capital Expenditure
($m FY23)

AER Draft Decision	Revised Proposal
696	749

As accepted by the AER and adjusted for inflation

Operating Expenditure
($m FY23)

AER Draft Decision	Revised Proposal
633	701

External factors continue to drive up operating costs

Revenue
($m FY23, smoothed)

AER Draft Decision	Revised Proposal
1,937	1,970

Revenue requirement reflects the other updates shown here

Opening RAB
($m FY23)

AER Draft Decision	Revised Proposal
3,817	3,860

Adjusted for changes in inflation and expenditure timing

Rate of Return
(Nominal vanilla WACC)

AER Draft Decision	Revised Proposal
5.56%	5.56%

AER Draft Decision placeholder

Customer Price Impact FY24 (P_0) ($FY23)

AER Draft Decision	Revised Proposal
9.6%	10.3%

We share customer concerns over the rising costs of living. We are spending the minimum necessary to maintain reliable and secure services in the face of significant increases in interest rates, inflation and operating costs. We are committed to keeping our costs as low as possible, exploring innovations and playing a broader role in enabling the transition to cleaner energy.

All figures in this Revised Revenue Proposal are presented in real terms ($FY23) unless indicated otherwise

How we are responding to the AER's Draft Decision

The AER accepted the majority of our Revenue Proposal in its Draft Decision. Accordingly, we have accepted most elements of the Draft Decision. We have responded to a small number of outstanding issues in this Revised Revenue Proposal as follows.

Component	AER **Draft Decision**	ElectraNet **Our Response**
Maximum Allowed Revenue	The Australian Energy Regulator's (AER) Draft Decision produced a Maximum Allowed Revenue (MAR) that is 15% higher than we proposed, increasing from $1,836m to $2,118m ($nom) on a smoothed basis. This increase is largely due to the impact of rising inflation and interest rates.	We have responded to and applied the AER's Draft Decision in relation to each of the revenue building blocks that determine the MAR as outlined below. This produces a revised MAR of $2,179m ($nom) on a smoothed basis. (Chapter 6)
Regulatory Asset Base	The AER accepted our proposed Regulatory Asset Base (RAB) values with adjustments for higher expected inflation and changes in forecast depreciation and other minor inputs. This increased the opening RAB from $3,593m to $3,817m ($nom).	We **accept** the AER's Draft Decision on the RAB. As required, we have updated the RAB value for 2021-22 actual capital expenditure, the latest forecast expenditure for 2022-23 and updated inflation for these years. This produces a revised opening RAB of $3,860m ($nom). (Chapter 6)
Rate of Return	The AER accepted our proposed approach to calculating the rate of return and accepted our nominated averaging periods. It applied its 2018 Rate of Return Instrument to determine a placeholder estimate of 5.56% compared with our proposal of 4.29%, reflecting the impact of rising interest rates. It will apply its forthcoming Rate of Return Instrument in its Final Decision.	We **accept** the AER's Draft Decision on the rate of return. For simplicity we have maintained the AER's placeholder estimate of 5.56% while recognising this figure will be updated by the AER in its Final Decision. (Chapter 6)
Regulatory Depreciation	The AER accepted our approach to regulatory depreciation, with some minor adjustments. The depreciation forecast was reduced from $367m to $274m ($nom) reflecting the impact of increased RAB indexation due to higher inflation.	We **accept** the AER's Draft Decision on regulatory depreciation. Updated for inflation and opening RAB movements this produces a reduced depreciation forecast of $228m ($nom). (Chapter 6)
Capital expenditure	The AER accepted our proposed capital expenditure forecast of $696m ($FY23).	We **accept** the AER's Draft Decision on forecast capital expenditure. Adjusted for inflation and real wage escalation, this results in a forecast of $749m ($FY23). (Chapter 3)
Contingent projects	The AER accepted two of our three contingent projects, with minor amendments to trigger events.	We **accept** the AER's Draft Decision on contingent projects. (Chapter 3)
Operating expenditure	The AER accepted the majority of our proposed operating expenditure forecast. It applied reductions to a number of step changes and applied updated inflation and real wage escalation estimates. These offsetting movements resulted in a reduction in our proposed forecast from $642m to $633m ($FY23), or a net reduction of 7.4% on a like for like basis if inflation is held constant.	We **do not accept** the AER's Draft Decision on forecast operating expenditure. We have applied various adjustments and updates including: • updated insurance forecast based on latest annual cost information • revised estimate for the cost of cyber security compliance, reflecting increasing requirements • revised estimate for the rule change step change including increased capability requirements, increased transmission licence fees and the development of Renewable Energy Zone (REZ) Design Reports • inclusion of a network support allowance to fund inertia support services we are providing to the Australian Energy Market Operator (AEMO) in 2023-24 and 2024-25 We have also adjusted the forecast for inflation and real wage escalation. This produces a revised forecast of $701m ($FY23) (Chapter 4)

Component	AER Draft Decision	ElectraNet Our Response
Corporate income tax	The AER accepted and updated our corporate tax allowance, resulting in an increase from zero to $5.2m ($nom).	We **accept** the AER's Draft Decision on corporate tax. Updated for expenditure and revenue movements this results in a revised tax allowance of $0m ($nom). (Chapter 6)
Efficiency Benefit Sharing Scheme	The AER accepted our Efficiency Benefit Sharing Scheme (EBSS) forecast with minor updates and adjustments. This resulted in an increased penalty outcome, rising from -$5m to -$11m ($FY23).	We **accept** the AER's Draft Decision on the EBSS. Adjusted for our current expenditure profile this results in a revised penalty outcome of - $14.2m ($FY23). (Chapter 6)
Capital Expenditure Sharing Scheme	The AER did not accept our proposed approach and applied a capital expenditure deferral adjustment under the Capital Expenditure Sharing Scheme (CESS). This results in a penalty outcome of -$8.8m ($FY23).	We **do not accept** the AER's Draft Decision on the CESS. We have updated the CESS forecast to remove the capital expenditure deferral adjustment. This results in a penalty outcome of -$2.7m ($FY23). (Chapter 5)
Service Target Performance Incentive Scheme	The AER accepted our Service Target Performance Incentive Scheme (STPIS) proposal, with some minor adjustments to the Market Impact Component target. Our Network Capability Incentive Parameter Action Plan (NCIPAP) was accepted.	We **accept** the AER's Draft Decision on the STPIS and NCIPAP. (Chapter 6)
Demand Management Innovation Allowance Mechanism	The AER accepted our Demand Management Innovation Allowance Mechanism (DMIAM) proposal.	We **accept** the AER's Draft Decision on the DMIAM and will work with our Consumer Advisory Panel (CAP) to implement it. (Chapter 6)
Pricing Methodology	The AER approved our proposed Pricing Methodology with minor updates.	We **accept** the AER's Draft Decision on our Pricing Methodology. (Chapter 6)
Pass through events	The AER approved most of our nominated cost pass through events, with minor amendments. It did not accept our nominated cost pass through event for REZ Design Reports.	We **accept** the AER's Draft Decision on our nominated cost pass through events with one amendment to address the risk of a cyber insurance event. We have included REZ Design Reports in our operating expenditure forecast. (Chapter 6)

Chapter 1

What has changed since our Revenue Proposal?

Our environment has changed substantially

There have been substantial changes in ElectraNet's operating environment in the year or more since the Revenue Proposal was prepared. These include changes in economic conditions, and increasing change and growing complexity of the power system.

Revenue Proposal (Jan 2022)		Revised Revenue Proposal (Dec 2022)
RBA indicating no interest rate rise during 2024 RBA cash rate sitting at 0.10%	Interest rates	7 interest rate rises to date RBA cash rate now 2.85%
Inflation forecast averaging about 2.5% in FY23 and FY24 Longer term outlook – RBA expects underlying inflation to pick up further, but only gradually	Inflation	Inflation is now at 6-8% in FY23 and FY24 Longer term outlook – RBA expects inflation will peak later this year and then decline gradually
Cyber security legislation in Commonwealth Parliament	Cyber Security	Cyber security legislation passed with Rules to follow and industry standard to be lifted
Insurance markets tight, driving up costs	Insurance	Insurance markets tighten further as disaster events continue
AEMO foreshadows need to manage 100% instantaneous renewables	Transition Accelerates	National emissions target of 43% by 2030 driving more rapid change in the power system AEMO has identified systems and capability uplift required to operate securely with 100% renewables
ElectraNet contracting inertia network services for AEMO for FY23	Inertia	ElectraNet contracting a higher volume of inertia network services for AEMO for FY24 and FY25

Economic conditions have changed materially

Significant changes in economic and market conditions have had a major impact on network costs and broader power prices.

2.85%

Interest rates

6.3%

Inflation for 2022-23 (RBA forecast)

Rising interest rates and inflation

When our Revenue Proposal was lodged, the Reserve Bank of Australia (RBA) cash rate was 0.10 per cent and the RBA was forecasting inflation would remain at or below its target rate of 2.5 per cent.

Since then, economic conditions have changed significantly, with the cash rate rising to 2.85 per cent and inflation now at the highest level in 40 years.

The AER updated its Draft Decision for these movements as a standard part of the determination process. We have maintained and updated these values as follows:

- The regulated rate of return remains at 5.56% and will be updated by the AER in its Final Decision.
- Actual inflation is maintained at 6.1 per cent for 2021-22 and forecast inflation is adjusted from 6.2 to 6.3 per cent for 2022-23 based on the latest RBA forecasts. These values are used to convert expenditure forecasts to real 2023 terms.
- Expected inflation for the coming regulatory period has been updated from 3.0 to 3.37 per cent using the AER's 'glide path' method. This value is used to convert the RAB and revenue building blocks to nominal terms.

The affordability challenge

The cost of living for Australians has increased substantially, driven by housing, petrol and grocery prices. Electricity bills are having an impact as well. In the 2022 Budget, the Australian Government announced that it expects electricity bills to increase by 56% in the next two years.

ElectraNet acknowledges the increasing cost of living and that this is a major issue for South Australians. We are committed to playing our part by ensuring that the money we spend on South Australia's electricity transmission network is spent efficiently and is in the long term interests of consumers.

While transmission costs are only about 11% of the average household electricity bill, we will keep searching for innovative solutions to keep costs as low as possible. Our CAP has challenged us to drive down costs while maintaining reliability and we remain committed to this.

Transmission costs are about

11%

of household electricity bills


ElectraNet

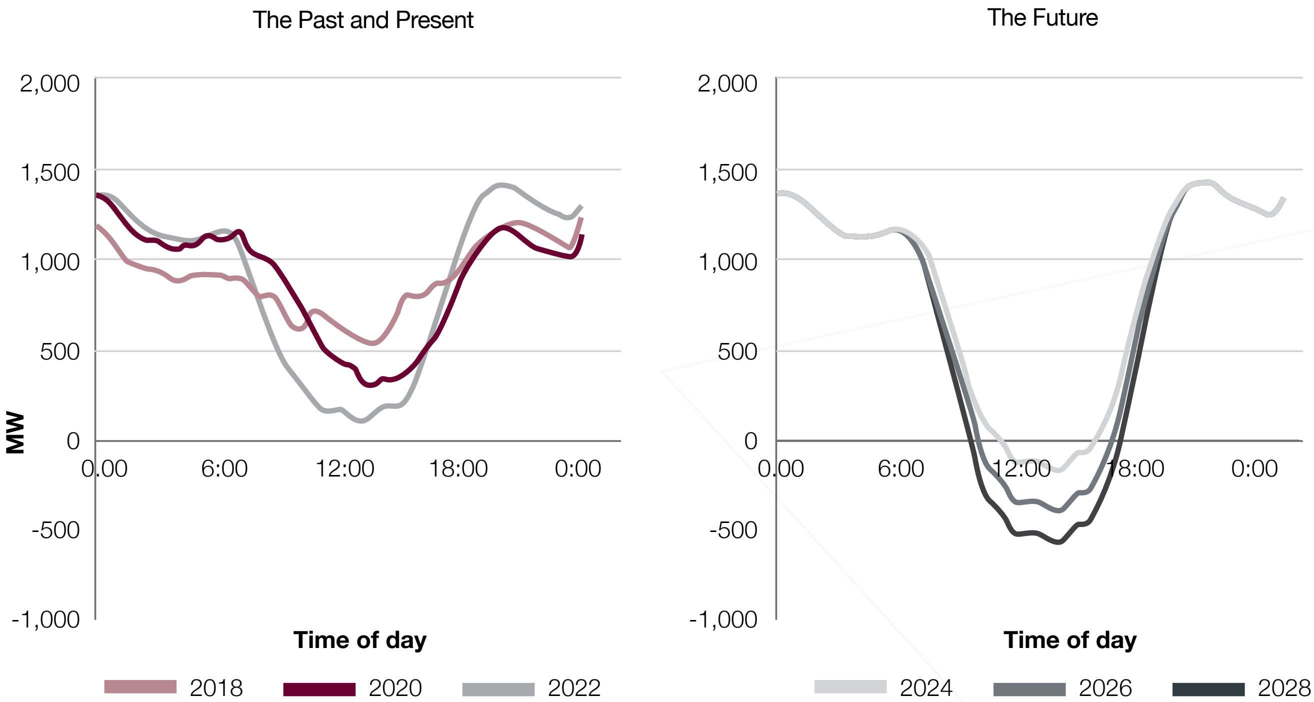
The complexity of the power system is increasing rapidly

South Australia continues to be at the forefront of changes sweeping power systems worldwide. In November 2021, distributed solar PV and non-scheduled wind and solar generation supplied enough electricity to meet the State's entire electricity demand in what was likely a first for a gigawatt scale network anywhere in the world.

AEMO data shows minimum demand in South Australia has fallen steadily in recent years and forecasts show this will continue to fall sharply during the coming regulatory period, given increasing penetration of distributed solar PV.

South Australia has reached periods of zero demand on the network, a first for a power system of our size. Increasingly lower demand levels and more rapidly changing daily demand present new challenges to be managed.

Figure 1: South Australian operational demand-minimum day



ElectraNet analysis of AEMO data

The increasing rate of change of power flows on the network is also increasing complexity.

In our Revenue Proposal we foreshadowed that increases in system complexity and planning obligations would drive up our operating costs.

Since our Revenue Proposal was prepared greater industry-wide clarity has been developed on what is needed to manage the rapidly changing power system securely and efficiently.

Increasing Capability Requirements

Dec 2021

AEMO releases initial NEM engineering roadmap identifying effort needed to operate with 100% Variable Renewable Energy. [3]

Jun 2022

AEMO releases Operations Technology Roadmap identifying the capability needed to maintain reliability, security and resilience while enabling the transformative change of the NEM.[4]

Jul 2022

The ISP highlights a need for network service providers to increase their capability to operate the power system securely with an increasing level of Variable Renewable Energy.

Dec 2022

AEMO releases its Engineering Roadmap to 100 percent Renewables providing further details on the systems and capability uplift network service providers must implement to enable reliable and secure operation.[5]

We are working closely with AEMO and other stakeholders to develop the uplift required to operate the NEM securely with 100% renewables, and are seeking to progress the systems and capability uplift required to protect the power system and customers from the risk of major disturbances in an increasingly complex operating environment.

We engaged international power system experts PowerRunner to evaluate the systems and capability uplift needed. Their report, which is in Attachment 1, highlights a need to increase our capability in network and asset monitoring and situational awareness, operational processes, and power system modelling.

Specifically, additional capability is required in network planning, outage management, protection adequacy, integrated power system management, dynamic monitoring, alarm analytics, asset condition monitoring, system disturbance analysis and control room operations.

This requirement is driven by the rapid change and growing complexity of the power system and is unrelated to the growth factors built into the AER's operating expenditure forecast.

> **"To ensure the NEM power system can operate securely with such high penetration of inverter-based resources, the system operator and network service providers will need to uplift their capabilities in operational systems, processes, real time monitoring and power system modelling. AEMO has developed a strategic roadmap for this uplift[4]."**

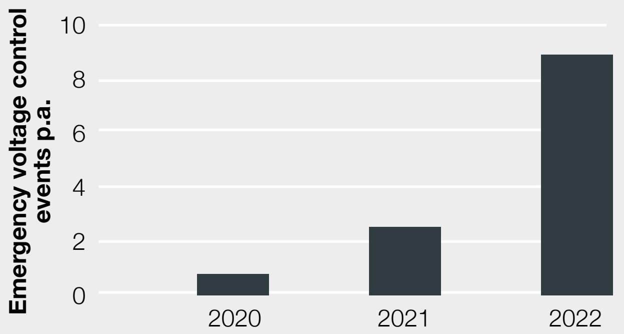
3 See https://aemo.com.au/initiatives/major-programs/engineering-framework.

4 See https://aemo.com.au/initiatives/major-programs/operations-technology-roadmap.

5 See https://www.aemo.com.au/initiatives/major-programs/engineering-framework

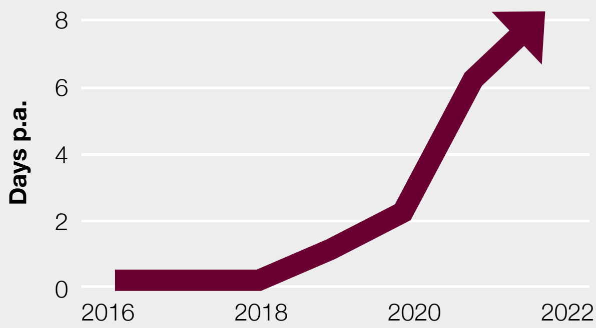
We are seeing warning signs of increased risk of system disturbances, with examples including:

Voltage control



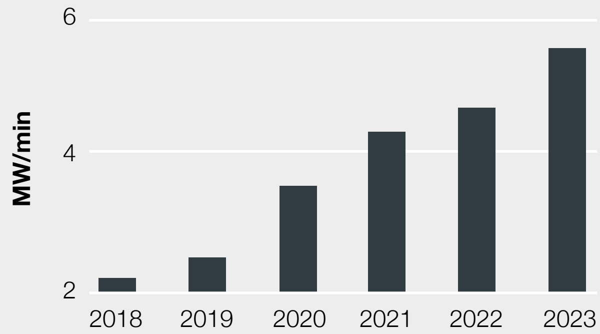
Falling system demand is resulting in an ongoing increase in the use of emergency voltage control measures.

System demand below 500MW



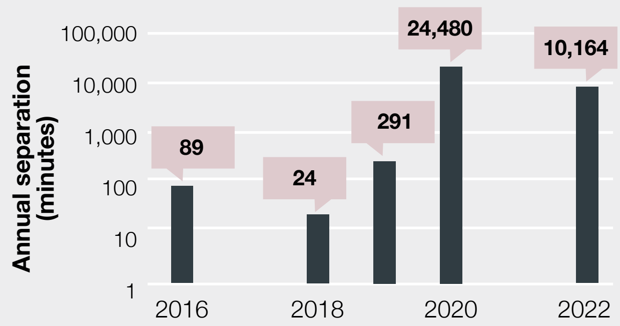
As demand falls to very low levels for longer, the power system is increasingly vulnerable and challenging to operate.

Rate of change of system demand



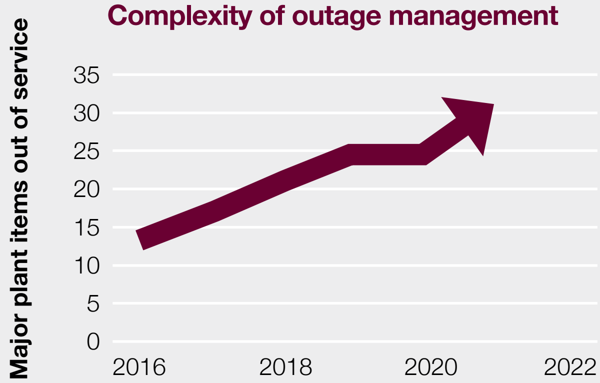
The increasing rate of change in daily system demand results in more challenging operating conditions, increasing the need for operator intervention and real time analysis.

Separation events



Recent separation events demonstrate the increasing challenges of maintaining system security with high levels of variable renewable energy.

Complexity of outage management



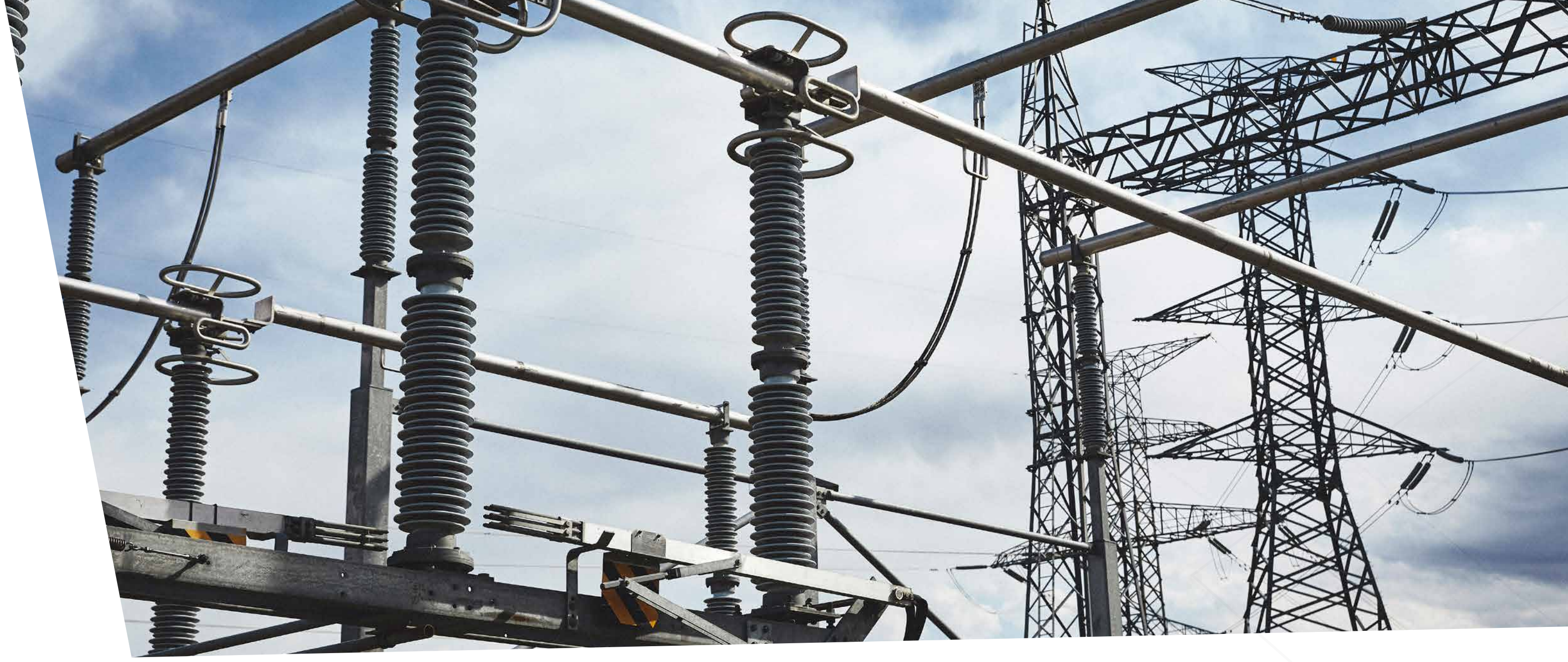
Major plant out of service at any given time has increased. This increases the complexity and scale of contingency analysis and system security assessments required to coordinate outages securely.

Voltage disturbance event

On 23 June 2022 widespread voltage oscillations were observed throughout South Australia. Many customers noticed their lights flickering and dimming.

These voltage oscillations were caused by a renewable generation source in Port Augusta.

This event is an example of a system disturbance that could have cascaded to a widespread customer loss of supply.



These examples highlight the need for a greater level of planning and operational preparedness for responding to the risks of a rapidly changing power system.

Uncertainty and complexity are increasing the risk of more frequent system disturbances that if not understood and managed can cascade to load shedding and system blackouts. Power system blackouts typically start with an initial disturbance followed by subsequent cascading events.

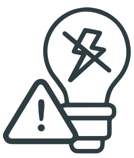
A systems and capability uplift is required to manage this increased risk of system disturbances.

We have included a modest operating expenditure step change in this Revised Revenue Proposal to address this requirement.

While the probability of a widespread power system failure remains relatively low, the impact of such an event is very high. If a system disturbance resulted in South Australia's average demand of 1700 MW[6] being lost and took eight hours to restore, the cost to South Australians would be $460m using the AER's standard value of customer reliability[7] of $34,000/MWh. This amount is unlikely to capture the full cost of broader economy-wide impacts of such a power system failure, which means the true cost would likely be higher.

Other changes since our Revenue Proposal that we have addressed in this Revised Revenue Proposal include:

- AEMO's 2022 ISP requires us to undertake preliminary activities in relation to two Renewable Energy Zones (REZ) in South Australia with indications we will likely be asked to prepare 4-6 REZ Design Reports in the coming regulatory period.
- We have also been advised of an increase in our annual transmission license fees by the South Australian Government, reflecting the growing administrative costs of an increasingly complex power system.



The consequence to consumers of increased risk of system disturbances is that, if not properly managed, they can cascade into a customer loss of supply or system wide blackout.

6 This includes the component of underlying demand supplied by rooftop solar PV and small non-scheduled generation https://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

7 AER, Value of Customer Reliability, December 2021 update, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update

Chapter 2

Consumer engagement

Consumer engagement has shaped our Revised Revenue Proposal

ElectraNet's CAP was first established in 2015. It formed the cornerstone of consumer engagement throughout the current regulatory period and in the preparation of our January 2022 Revenue Proposal. The CAP identified the priority issues for engagement with us to provide input and feedback as we worked through our response to the AER's Draft Decision. The outcomes of this engagement are summarised as follows.

A full record of the proceedings and outcomes of the CAP meetings is available on ElectraNet's website.[8]

	Key issue	What we heard	How we have responded
1	**Price impact / Contingent Projects** Higher interest rates and inflation have increased required revenue beyond AER Draft Decision expenditure cuts	• ElectraNet should consider options to mitigate the impact for customers such as: ○ Innovations to reduce capital expenditure costs without reducing the quality of supply ○ Whether a more rigorous target can be set on operating expenditure productivity ○ Is there a transition possibility where the full rate of return impact is not applied up front but is delayed? • ElectraNet should consider regional businesses' sensitivity to reliable supply – consistency of supply can be more important than price relief. • While related, the impact of contingent projects needs to be considered separately. • It is important for ElectraNet to acknowledge and reflect a really clear understanding of the impact increased revenue will have on customers. This needs to be addressed in the Revised Revenue Proposal as it is a really tough issue for many consumers. • The CAP will look for ElectraNet to take leadership in exploring potential for innovation in ways that drive down cost without losing reliability in years to come – what might be possible to maintain reliability and reduce costs? There is not necessarily a straight line relationship between cost and reliability – it can be bent. • The DMIAM is worth exploring. • ElectraNet should be open to raising affordability concerns with the South Australian Government and AER to explore actions to reduce the adverse impacts of increasing power costs for customers. • It is important to bear in mind that the transmission component of residential power bills is ~11% compared with Federal Budget projection of 56% bill increases. Other elements are driving up costs. • Further deferral of capital expenditure might create further risk and cost so needs to be carefully considered.	• We share customer concerns over the rising costs of living. Electricity costs are a part of this and we are committed to keeping our costs as low as possible, exploring innovations and playing a broader role in enabling the transition to cleaner energy. • ElectraNet reduced its capital expenditure forecast by $100m from Preliminary Revenue Proposal level and does not consider further reductions in expenditure programs to be in the long term interests of consumers. Reducing capital expenditure below the current level would lead to unacceptable risk in the short to medium term (safety, fire, supply interruption). Material new capital expenditure requirements have already arisen since ElectraNet's Revenue Proposal that will need to be absorbed within the AER capital expenditure allowance. • ElectraNet will continue to pursue capital expenditure and operating expenditure efficiencies wherever possible, incentivised by the EBSS and CESS, and will pursue innovations through the NCIPAP and DMIAM measures. • The Rate of Return is set by the AER under the Rules, with the relevant instrument to be updated in early 2023. There is no scope for ElectraNet to vary from this or influence prevailing market rates.

8 https://www.electranet.com.au/our-approach/community/consumer-advisory-panel/

<table>
<tr><th></th><th>Key issue</th><th>What we heard</th><th>How we have responded</th></tr>
<tr><td>2</td><td>Capital Expenditure Sharing Scheme
Some SA-NSW interconnector project capital expenditure was delayed into next regulatory period
ElectraNet reprioritised previously deferred capital projects to ‘fill the gap’ left by this deferral
ElectraNet’s reprioritisation means that there is no windfall gain from the PEC capital expenditure deferral
ElectraNet strongly believes that AER Guideline criteria for making a capital expenditure deferral adjustment have not been met</td><td>Given timing there was limited opportunity for engagement on this topic with the previous CAP.
The CAP sought and obtained additional information to enable it to identify next steps for engagement, including ElectraNet’s letter of May 2022 on which its consulted with the previous CAP and further response to the AER of Aug 2022 on this issue.
The CAP understands the delay of Project EnergyConnect (PEC) but doesn't want ElectraNet to obtain a windfall gain. ElectraNet said it brought projects back so that there is no CESS gain, nor loss.
The information provided was helpful, though the tables were not as clear as they could have been. However, on balance the CAP accepts that the relevant projects were considered by the CAP in the previous reset process.
The key question is whether the projects brought back are legitimate under CESS rules and if so, ElectraNet should not carry much of a CESS penalty or gain.
A penalty of ~$2-3m that results with no deferral adjustment looks like the right outcome to the CAP.</td><td>ElectraNet agrees no windfall gain should occur under the CESS due to the deferral of Project EnergyConnect.
No windfall gain will occur as ElectraNet has efficiently reprioritised its capital program by bringing forward previously deferred expenditure to offset the deferral.
The bulk of these projects (over 80%) were presented in our Revenue Proposal for the current period and have been scrutinised previously by customers.
There is therefore no need for a deferral adjustment, which would only impose a windfall penalty on ElectraNet (of over $20m).
The risk for customers is that imposing a windfall penalty would discourage network businesses from efficiently prioritising their capital programs in future. It would also leave a revenue shortfall for ElectraNet, putting pressure on expenditure elsewhere and increasing risk.
The removal of the deferral adjustment leaves ElectraNet a small underlying penalty ($2.7m).
It is in the long term interests of consumers that the signals sent to ElectraNet and other Transmission Network Service Providers (TNSP) drive efficient investment decisions.
ElectraNet has addressed the AER’s concern that consumers did not have an opportunity to scrutinise the projects brought forward, showing that the majority of the delayed projects brought back had been considered by the CAP in the previous process five years ago.</td></tr>
<tr><td>3</td><td>Insurance costs
The AER cut ElectraNet's proposed step change by ~$15m over the regulatory period
This cut will be reduced in Final Decision once ElectraNet’s higher FY23 insurance costs are considered
NOTE: under the cost pass through mechanism if insurance costs exceed forecasts materially the extra can be ‘passed through’ to customers.</td><td>Insurance was subject to detailed consumer scrutiny by the previous CAP. This built a shared understanding of the risk balance.
The AER's Draft Decision focused on the prudent cost, so the CAP is comfortable with the AER and ElectraNet coming to an outcome.
The CAP sought and obtained information on the costs of insurance to date in the current regulatory period relative to the 1% pass through threshold.
The CAP has been through risk sharing and other aspects a year ago and needn’t review again.
It’s about getting the right level of coverage and doing so at the best possible price. CAP members face similar challenges in relation to insurance.</td><td>ElectraNet recently submitted a cost pass through application for FY23, providing the missing information about current year costs and restoring the majority of the original forecast.
ElectraNet has not expanded its insurance cover or increased the forecast based on the latest information.
ElectraNet does not agree in principle with the ‘scale factor’ reduction made by the AER (of around $7m) but has accepted this in the Revised Revenue Proposal.</td></tr>
</table>

	Key issue	What we heard	How we have responded
4	**Cyber step change** • ElectraNet proposed an operating expenditure increase to fund cost of improving cyber security • The AER's advisor considered cost increase excessive	• Cyber security was subject to consumer scrutiny by the previous CAP. • It is important to the CAP that the forecasts on cyber security are commensurate with other networks. The key issue is what is prudent. • The CAP asked whether ElectraNet is taking adequate action or only the bare minimum? • The CAP asked whether the AER is looking at cybersecurity from a 'whole of economy' perspective, given the impact of loss of supply to businesses across the economy. • ElectraNet should update the CAP regularly in managing cyber security given the dynamic environment. • It was important to the CAP to have updated information in advance of the Revised Revenue Proposal to allow the opportunity for the CAP to engage and consider this issue in its submission.	• ElectraNet has learned that AEMO shortly plans to increase the compliance level for industry target Security Profile 3 (SP3) in the release of version 2 of the AESCSF. • ElectraNet has revisited its cost analysis to reflect the cost implications of the higher SP3 requirements. • ElectraNet will provide further cost information to the CAP as it becomes available. • Separately, the AER did not accept pass through for cyber related costs if insurance becomes unavailable or is exhausted. ElectraNet has responded to this.
5	**Renewable Energy Zones** • The CAP has expressed an interest in learning about the future planning of the network, particularly REZs • ElectraNet proposed a pass through for the costs of preparing REZ Design Reports • The AER did not accept this pass through event, which was not subject to a 1% materiality threshold	• The CAP needs to understand the network's capacity to accommodate REZs. This includes the pace of change, and emissions reporting by businesses. • The CAP asked where is SA is sitting from a national perspective. • The CAP was keen to engage with the CAP on the development of REZs during its ongoing planning cycle. • It is important that REZ development is on the agenda for CAP in the next phase. The CAP also noted the interrelationship with land compensation issues. • The CAP queried whether the existence of REZ means that TNSPs will focus less on other places, thus limiting access to network in other areas? How do REZs interact with other works, infrastructure and planning programs? This was identified as an issue for ongoing CAP engagement.	• The development of REZs will occur as required by AEMO's ISP. These projects automatically become contingent projects if required and do not need to be addressed in the Revised Revenue Proposal. ElectraNet plans to engage with the CAP on these developments during the course of its annual planning cycle. It is also undertaking a REZ development study for the SA Government, outcomes of which will inform this engagement in 2023. • ElectraNet also provided its 2022 Transmission Annual Planning Report to the CAP. • ElectraNet has included the expected cost of preparing REZ Design Reports (which are intended to address questions such as those above) in the revised operating expenditure forecast.
6	**Inertia Services** • ElectraNet is tendering for inertia services required by AEMO in 2023-24 and 2024-25 • Under network support pass through arrangements, costs will either be recovered at the time with a small true-up in arrears, or fully recovered in arrears • Placeholder cost estimate is $6.7m pa based on historical outcomes	• The CAP recommended that ElectraNet submit an estimate of expected cost upfront and have smaller variations later. • Price certainty and stability are important to consumers and it's better to create budget / cost clarity for consumers than not to. • The impact of synchronous condensers on inertia was discussed given that they are recent, noting they have reduced the requirement for inertia and associated costs to consumers. • It is difficult for CAP to know whether the cost is the right number. The CAP's role is limited to ensuring process / governance is reasonable. The CAP sees it as AER's role to review numbers in more detail e.g. by reference to experience elsewhere.	• The tender process for inertia services resulted in lower unit rates for inertia support services. • However, the length of time we expect this service to be required has increased. • The forecast has been settled on this basis. The expected costs will be recovered as incurred though a Network Support allowance as per the guidance from the CAP.

We continue to improve our engagement approach

We have identified and implemented several improvements to our consumer engagement approach in conjunction with the CAP. These include re-establishing our CAP with a broader membership and revised Terms of Reference supported by an Independent Facilitator. Importantly we have also established a framework to engage with the CAP through our annual planning cycle.

Improvement Opportunity	How we are responding
Independent Facilitator and engagement culture Reinstate an Independent Facilitator to support the CAP and contribute to the broader engagement culture of ElectraNet and the CAP.	We have appointed an Independent Facilitator to work with a reappointed and expanded CAP, and support its ongoing development. The Independent Facilitator is also engaging with ElectraNet's Executive and supporting the ongoing development of ElectraNet's engagement culture.
Engagement of the CAP in the annual planning process Involve the CAP in twice-yearly considerations of the development of network and asset plans, including the Transmission Annual Planning Report.	ElectraNet has established a new Asset Management Strategic Planning Framework that documents the timetable and approach for involving the CAP in its annual planning cycle as highlighted in the graphic opposite. This engagement with the CAP is scheduled to commence in the first quarter of 2023 (following the Revised Revenue Proposal).
Develop measurable success criteria Satisfaction that engagement is effective is important and measures should separately assess process versus outcome, noting aspects of engagement are subjective.	A CAP survey instrument is being developed to gauge the ongoing effectiveness of CAP meetings. The new Terms of Reference of the CAP also include a commitment to the development of Key Success Indicators.
Induction and Training Support Provide training for Members with minimal/ no experience in understanding network proposals or network business operations to get the most from their unique experiences and expertise.	ElectraNet has held an initial round of induction sessions for both new and reappointed CAP Members, and will continue to work with members on providing ongoing training and support.
Face to face meetings Meetings should be held in person as much as possible for greater collaboration opportunities.	CAP meetings will be held in person wherever possible, with provision for remote attendance for regional members and those unable to attend in person. Opportunities for additional informal interaction are also being increased.
Meeting Preparation Meeting presentations and supporting information to be provided to participants well in advance of meetings.	ElectraNet is endeavouring to provide meeting agendas and material with more notice, within the time constraints of the revenue determination timetable. This remains a work in progress.
Early Engagement on Revenue Proposal Greater involvement of the CAP (or a CAP Working Group) earlier during the development of the next Preliminary Revenue Proposal.	ElectraNet is committed to engaging with the CAP in the annual business planning cycle and will continue this in the lead up to the next Revenue Proposal. This also enables greater information sharing and ongoing involvement in network direction and strategy.
Regional Engagement Include face-to-face engagement in regional South Australia, particularly once COVID limitations have receded.	We look forward to working with the CAP, particularly Members based in the regions, to explore opportunities for more direct engagement with regional South Australians.
Coordination with SA Power Networks Consider stronger engagement with SA Power Networks and potentially a series of joint workshops and developing/utilising a single set of demand forecasts and other relevant analysis.	ElectraNet continues to engage closely with SA Power Networks at a working level through the joint planning process and at an executive level through joint Steering Committees which meet on a regular basis. A joint meeting of representatives of the consumer panels of ElectraNet and SA Power Networks is also being planned for 2023.

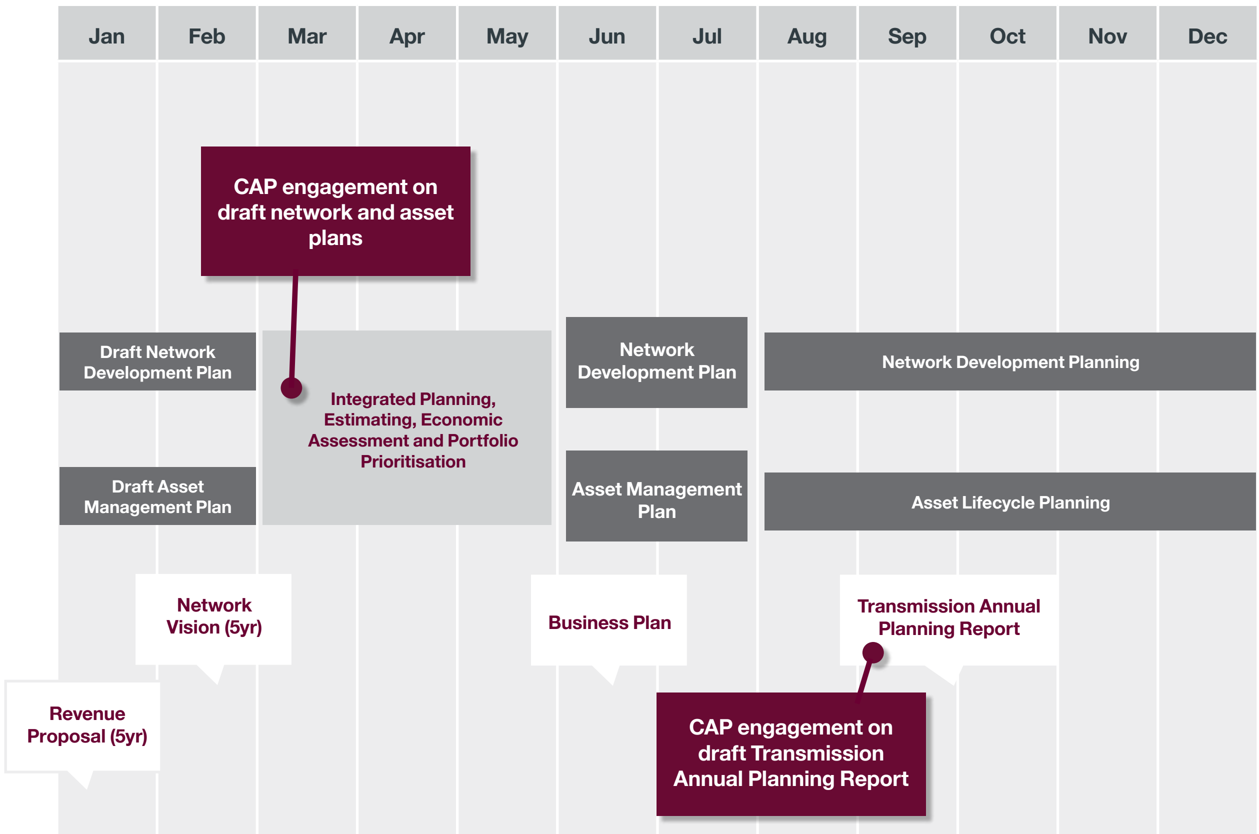
Ongoing engagement will strengthen ElectraNet's annual planning process

ElectraNet will engage with the CAP, on behalf of consumers, as a routine part of our annual planning cycle. This will focus on the two annual milestones depicted in the figure below.

Firstly we will engage in the development of our network and asset plans. Secondly we will engage on the draft outputs of the planning process in response to changing priorities and other changes.

This will provide consumer input to our planning and decision making, and ongoing scrutiny of the outcomes of our investment programs.

Figure 3: ElectraNet annual planning cycle



Chapter 3

Capital expenditure

Our capital expenditure program is reducing substantially and remains focussed on managing risk and maintaining service reliability

Revenue Proposal

Our Revenue Proposal included a capital expenditure forecast of $696m. This represented a 47 per cent reduction in capital expenditure from the current regulatory period, or 18 per cent if the effect of ISP projects is excluded. Our proposed capital expenditure is focussed mainly on asset replacement, with targeted investments in improving physical, system and cyber security of the network.

AER Draft Decision

In its Draft Decision the AER accepted our capital expenditure forecast.

The AER also found our capital expenditure during the current regulatory period to be efficient, and rolled this into our RAB without adjustment.

It also concluded that our forecasting method is prudent. More specifically, that it:

> **accords with [the AER's] 2019 Industry Practice application note for asset replacement planning in terms of the application of risk-based cost-benefit analysis, the identification of projects, and the relevant identification of the consequences of asset failure in terms of network safety, reliability and security. In this regard, it is consistent with good industry practice, prudent and based on estimates of the likely realistic costs of relevant projects and programs.**[9]

Additionally, the AER accepted two of our three proposed contingent projects. It concluded that the third, the interconnector upgrade, should be considered through AEMO's ISP process.

Revised Revenue Proposal

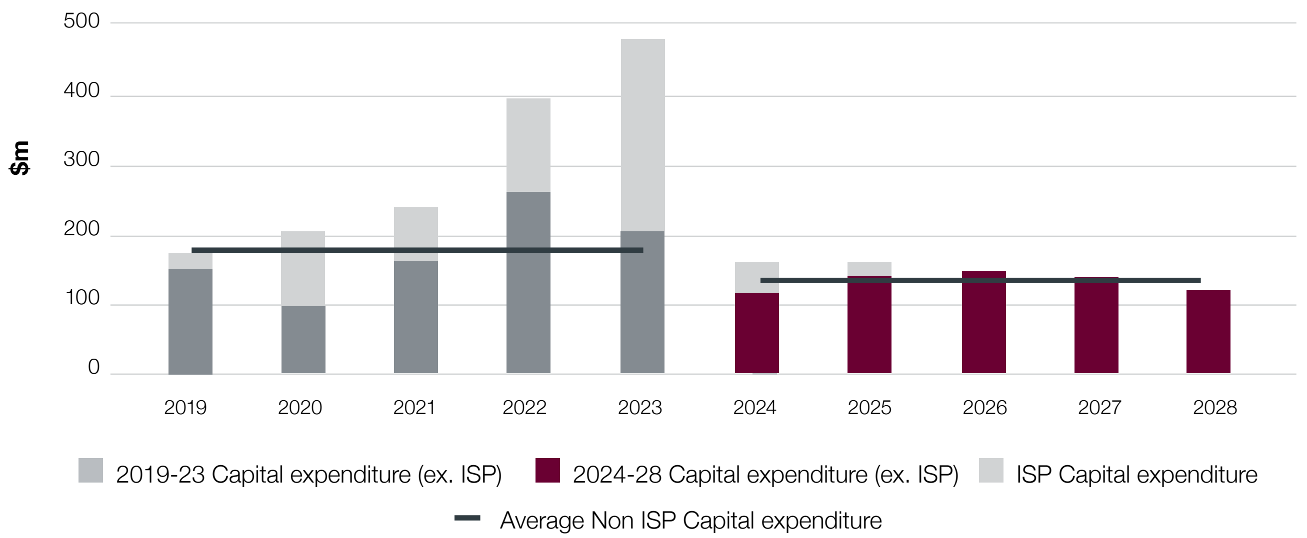
We **accept** the AER's Draft Decision, adjusted for inflation.

During customer engagement on this Revised Revenue Proposal, the CAP noted that increases in the Rate of Return have driven forecast revenue above the level anticipated in our Revenue Proposal. In light of these changes the CAP encouraged us to revisit our capital expenditure forecast and other activities to identify potential opportunities for reducing the price pressure on consumers. This is discussed further in chapter 2 above.

We have carefully considered this feedback and believe that our capital expenditure forecast represents an appropriate balance between cost to our customers and the benefits they will receive through maintaining service reliability. We made significant reductions to our capital expenditure forecast and are concerned that further reductions would deliver minimal price relief while increasing risk to unacceptable levels.

We will continue to work with the CAP to balance cost and reliability in the long term interests of consumers.

Figure 4: Revised capital expenditure forecast



9 AER Draft Decision, Attachment 5, p.7

Our revised capital expenditure forecast is $749m as set out in Table 3.1. This has been adjusted for inflation and real wage escalation. The underlying forecast accepted by the AER remains unchanged.

Table 3.1: Capital expenditure by category ($m)

	Forecast	Description
Augmentation	63	No demand driven investment following completion of Project Energy Connect
Connection	0	
Easements/ Land	7	Minor Strategic land acquisition
Replacement	353	Most of our capital program is focused on ongoing programs to refurbish and replace aging assets
Refurbishment	72	
Security/ Compliance	181	Investment requirements to maintain physical, cyber, and power system security and network safety.
Information Technology	47	Investments to maintain capability and harness modern technology to meet future needs.
Inventory/ Spares	13	Ongoing requirements to maintain spares
Facilities	13	Ongoing requirements to maintain facilities
TOTAL	**749**	

We **accept** the AER's Draft Decision on our contingent projects.

Real wage escalation

In our Revenue Proposal we provided forecasts of real wage growth obtained from BIS Oxford Economics (Attachment 2). We applied the AER's long standing approach of taking the average of real wage growth forecasts submitted by regulated networks and forecasts prepared for the AER, noting at the time that the AER's updated forecasts were not available. In the Draft Decision the AER has incorporated its updated forecasts. These were applied to the operating expenditure forecast but not to capital expenditure.

We have also obtained updated forecasts from BIS Oxford Economics, which are reflected in the table below, with detailed calculations in the accompanying operating expenditure model.

Table 3.2: Real wage escalation (%)

	2023-24	2024-25	2025-26	2026-27	2027-28
Draft Decision	0.8	1.3	1.3	0.6	0.5
Revised Revenue Proposal	**0.9**	**1.4**	**1.2**	**0.5**	**0.3**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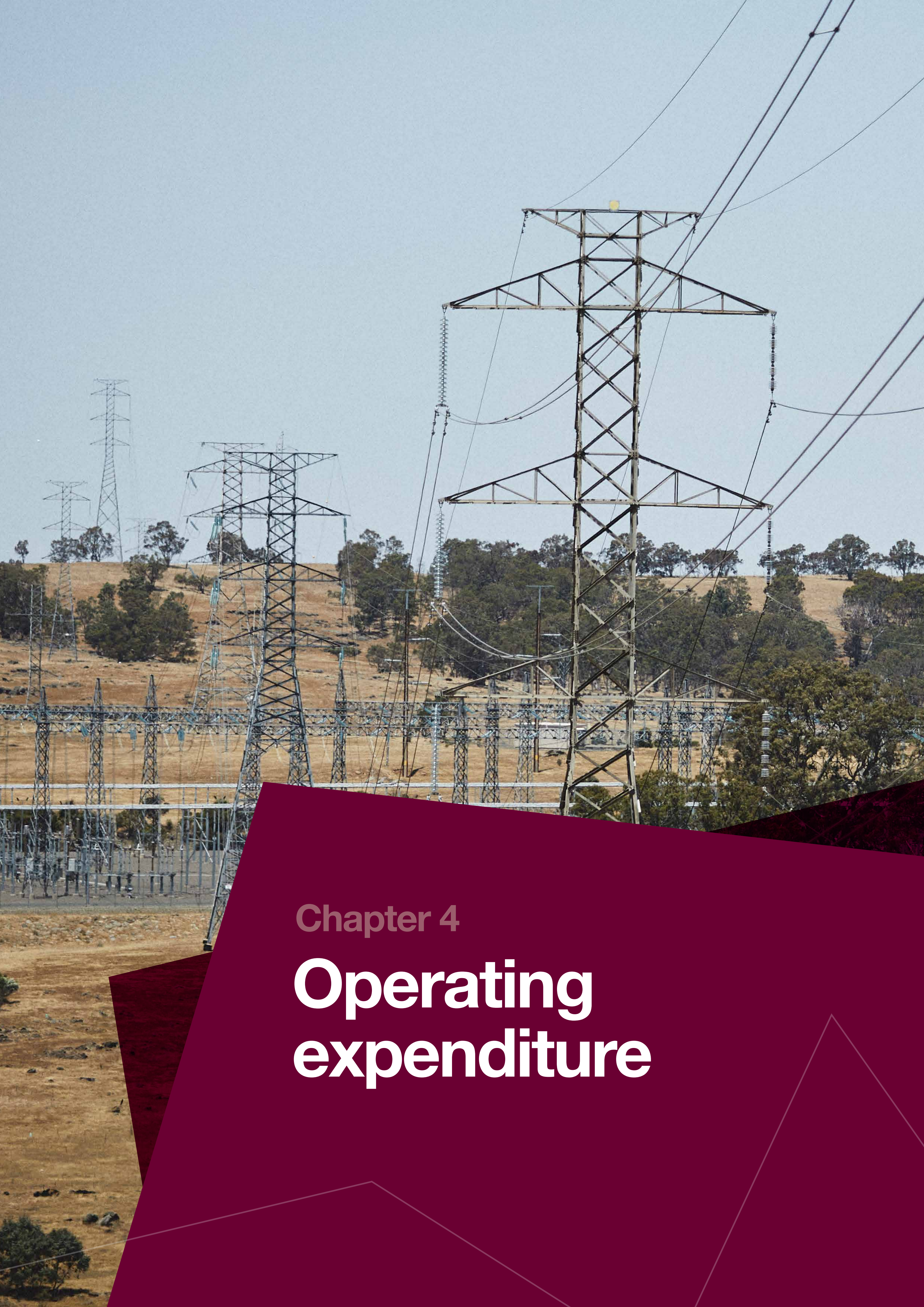


Chapter 4

Operating expenditure

Our operating expenditure program is focused on managing the network efficiently in an increasingly complex and challenging environment

Revenue Proposal

Our Revenue Proposal included an operating expenditure forecast of $642m.[10]

While our underlying operating expenditure is relatively stable, total operating expenditure is forecast to increase driven by externally imposed costs, the majority of which are captured in a number of step changes.

In addition, accounting treatment changes require us to report intangible assets as operating expenditure, resulting in a net transfer of $46m from our capital expenditure forecast.

AER Draft Decision

In its Draft Decision the AER accepted our underlying operating expenditure forecast with minor adjustments. It accepted our proposed transfer of capital expenditure to operating expenditure due to the accounting treatment of intangible assets.

ElectraNet proposed four step changes. In relation to these, the AER:

- Accepted the rationale and need for our proposed cyber security and insurance step changes, but did not fully accept the proposed amounts and applied a different methodology to calculating the insurance step change
- Did not accept our proposed step changes for the cost of migrating to cloud computing or the impact of increasing system complexity reflected through recent rule changes.

Revised Revenue Proposal

We **accept** the majority of the AER's Draft Decision in respect of operating expenditure, with the following adjustments and updates.

We **accept** the AER's decision that our treatment of accounting changes results in forecast operating expenditure that is prudent and efficient.[11] As was clear in materials accompanying our Revenue Proposal, that was prepared in 2021 terms and escalated to 2023 terms using inflation forecasts that are now out of date. We have updated those forecasts in our Revised Revenue Proposal.

We **accept** the AER's decision not to include our proposed cloud computing step change. We will seek to absorb these costs, resulting in a saving to consumers of $9m.

We **accept** the changes in methodology applicable to the insurance step change and have updated the AER's placeholder forecast of actual insurance cost in 2022-23. This is discussed further below.

We **accept** the AER's decision that it is prudent for ElectraNet to achieve cyber security level SP-3, but do not accept its decision in relation to the cost of doing so. In particular, we understand that AEMO intends to increase SP-3 cyber security requirements for transmission. We have updated our step change to reflect our best estimate of the cost of meeting this increased standard. This is discussed further below.

We **do not accept** the removal of the rule change step change. We have included the cost of additional capability uplift requirements that have been identified, together with the expected cost of REZ Design Reports and increased transmission licence fees. This is discussed further below.

We have adjusted the forecast for the latest inflation and real wage forecasts.

We have also included the expected costs of inertia network services we are required to provide for 2023-24 and 2024-25 as a network support allowance as was foreshadowed in our Revenue Proposal. This is discussed further below.

10 As amended through post lodgement clarifications and updates
11 AER Draft Decision, attachment 6, p.17

Our revised operating expenditure forecast is shown in Figure 5 below.

Figure 5: Revised operating expenditure forecast

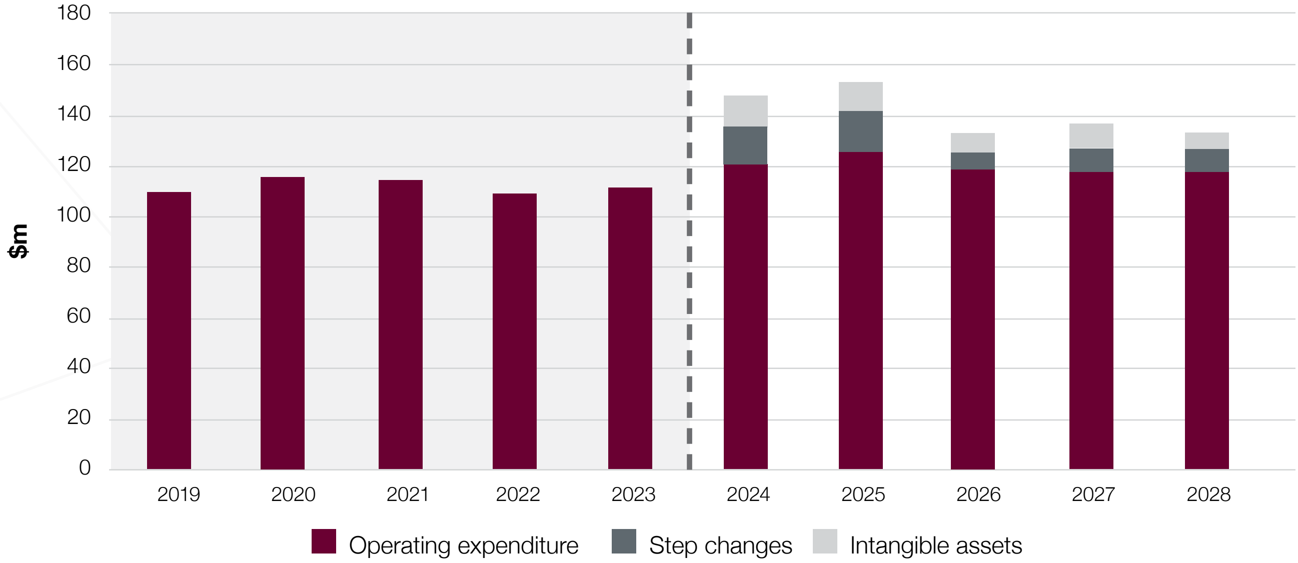


Table 4.1 below summarises the step changes and network support allowance reflected in this Revised Revenue Proposal.

Table 4.1: Revised operating expenditure forecast ($m)

	Draft Decision	Revised Revenue Proposal
Base operating expenditure	**513.3**	**540.4**
Output growth	29.3	30.9
Price growth	10.8	11.4
Productivity growth	-7.8	-8.2
Total trend	**32.3**	**34.1**
Intangible assets	45.6	48.7
Insurance	14.3	6.0
Cyber Security	18.0	24.6
Cloud Migration	0.0	0.0
Rule Change	0.0	21.4
Total step changes	**77.9**	**100.6**
Network support allowance	0.0	16.3
Total operating expenditure ex DRC	**623.5**	**691.5**
Debt raising costs	9.5	9.6
Total	**633.0**	**701.1**

Insurance costs

In its Draft Decision the AER reduced our insurance step change to reflect:

- its preference that the step change be calculated by reference not to the base year used in operating expenditure forecast, but to our actual insurance costs in 2022-23 as the final year of our current regulatory period, which were not known at the time of the Draft Decision.
- its view that growth in our insurance costs should be captured by the rate of change formula which is part of the AER base-base-step-trend operating expenditure forecast methodology.

The CAP accepts the AER will assess the efficient cost of obtaining insurance, noting the current environment of rising costs. Some CAP members noted that they face similar challenges in relation to insurance for their own organisations and acknowledged and highlighted the need for appropriate insurance. From the CAP's perspective the objective is to ensure that ElectraNet's revenue reflects the right level of coverage obtained at the best possible price.

In the Revised Revenue Proposal we have updated our insurance costs for 2022-23 and applied the AER's forecasting approach. Consistent with the Draft Decision this produces an insurance forecast with a higher base component and smaller step change component.

While our original insurance forecast, as accepted by the AER's expert adviser, indicates that insurance costs will grow substantially faster than suggested by the growth factor in the AER base-step-trend forecast methodology we accept the removal of the growth component of the forecast by the AER. This reduces the forecast by $7m.

Cyber security step change

Cyber threats face all Australian businesses, including those responsible for nationally significant infrastructure. The AESCSF has been developed to address these risks in our sector. Its purpose is to enable participants to assess, evaluate, prioritise and improve their cyber security capability and maturity.[12]

In the Revenue Proposal we proposed that:

- It is prudent to increase our cyber security to reach SP-3 during the coming regulatory period
- An operating expenditure step change of $24.3m, quantified for ElectraNet by Deloitte, would be required to achieve this.

The AER took advice from EMCa in relation to ElectraNet's proposal and concluded that:

- It is prudent for ElectraNet to increase its cyber security to SP-3
- The amount ElectraNet proposed as a step change was more than necessary to achieve this.[13]

Cyber security was a key issue of interest to the CAP. Members noted the potential widespread impacts of major power system outages on businesses across the economy. They were keen to ensure that ElectraNet does more than the 'bare minimum' and takes adequate and prudent steps to protect the network from cyber risk, commensurate with action being taken by other networks.

This is an ongoing, and growing, challenge as has been clearly illustrated by recent attacks on Optus and Medibank. Reflecting the changing nature of this challenge, AEMO, the Department of Industry, Science, Energy and Resources, and the energy industry have been collaborating on a review of the AESCSF. That review is expected to be finalised in December 2022. AEMO is expected to increase the number of requirements captured by SP-3 by 45%. The increase in complexity of these activities, in particular in the architecture, risk management and supply chain security domains is substantial.

Accordingly, ElectraNet engaged Deloitte to revisit its analysis of the cost of achieving SP-3 during the coming regulatory period. Table 4.2 shows our expectation of the cost of achieving SP-3 based on Deloitte's preliminary work. We will provide the AER with Deloitte's finalised report (Attachment 3) as soon as it is available and, in so doing, will update our cyber security forecast, if

Table 4.2: Cyber Security step change ($m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Draft Decision	6.8	6.8	1.1	1.1	2.2	18.0
Revised Revenue Proposal	9.5	7.9	2.1	2.1	3.0	24.6

Cyber threats face all Australian businesses, and must be guarded against, especially by those responsible for nationally significant infrastructure.

12 AEMO, Australian Government, Department of Industry, Science, Energy and Resources, "Australian Energy Sector Cyber Security Framework (AESCAF) Framework Overview 2022 program – minor refresh", 19 April 2022, p.1 available from www.aemo.gov.au

13 In the Revenue Proposal the proposed step change was $25.9m. However, ElectraNet subsequently decided to bring forward expenditure worth $1.6m to 2022-23 so this value was removed from the proposed step change.

Rule change step change

In our Revenue Proposal we foreshadowed that increases in system complexity and planning obligations would drive up our operating costs. The AER acknowledged this in its Draft Decision, but was not satisfied that the impact would be material or that we had provided sufficient detail in relation to the likely costs.

The complexity of our operating environment continues to increase based on the rapidly changing power system, and growing understanding of the risks, challenges and capabilities needed to address these, as discussed in Chapter 2.

ElectraNet engaged international power system experts PowerRunner to work with us to develop the systems and capability uplift needed. PowerRunner, whose report is Attachment 1 to this Revised Revenue Proposal highlights a need to increase our capability in the following areas.

Table 4.3: Capability uplift requirements

Capability	Function	Description	FTE
Planning	**Network planning**	Increased rate of change on the network and the potential for demand to fall to very low levels throughout the year requires much more detailed 'what if' analysis to underpin network management plans and to manage the risk of high impact low probability events.	6-8
	Outage management	With demand and generation being more volatile and the network more constrained during the year, much more detailed analysis of the system is needed to allow network equipment to be taken offline for maintenance and project work.	
	General Power System Risk Review	AEMO's annual General Power System Risk Review requires additional input, analysis and information from TNSPs.	
	Protection adequacy	The continued growth of inverter-based technologies on the power system increases the need for regular review of protection schemes to ensure they operate as intended to protect against power system disturbances.	
	System strength management	The recent Efficient Management of System Strength Rule includes new obligations for forward looking planning and provision of system strength services by TNSPs.	
Situational Awareness	**Dynamic monitoring**	Analysis of Phasor Measurement Unit data for improved situational awareness and early detection of network risk conditions to support operational decision making.	5-7
	Alarm analytics	In a more complex power system, network alarms will occur more frequently and in increasingly complex combinations. Improved alarm analytics is needed to help identify and diagnose problems as they emerge.	
	Asset condition monitoring	An uplift is required in real-time monitoring, modelling, and analysis of network critical asset information, including predictive analytics.	
	System disturbance analysis	More needs to be done to investigate, analyse and learn from system disturbances given reduced 'safety margins' in a highly variable renewable system.	
Network Operations	**Control Room**	The increasing complexity and variability of system operations and risk of system disturbances places greater demands on Transmission System Operators in the control room requiring deployment of additional resources.	8-11
	Operations Systems Development	As the network and therefore the tools used to manage it become increasingly complex, additional SCADA engineers are required to support the tools for voltage and contingency analysis, situational awareness and control room information systems.	
Total			**19-26**

Drawing on PowerRunner's advice ElectraNet has included a capability uplift to the rule change step change based on progressively adding 20 FTE to our planning and operations workforce over the next five years as shown in the table below. The 20 FTE uplift we have adopted is towards the bottom of the range of likely requirements identified by PowerRunner.

Table 4.4: Rule change step change

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
FTE increase	12	16	20	20	20	20
Capability uplift ($m)	2.4	3.2	4	4	4	17.6
Licence fee increase ($m)	0.5	0.5	0.5	0.5	0.5	2.3
REZ design reports ($m)	0.0	0.6	0.0	0.9	0.0	1.5
Total ($m)	**2.9**	**4.3**	**4.5**	**5.4**	**4.5**	**21.4**

In addition to the capability uplift requirements, the South Australian Government has advised ElectraNet that our annual transmission licence fee will be increased from 1 July 2023, as shown in Table 4.4.

The table also shows our forecast cost of preparing REZ design reports.

In AEMO's 2022 ISP it identifies REZs including two for which it requires ElectraNet to undertake preparatory activities. When AEMO determines that the need is approaching it will require ElectraNet to prepare REZ Design Reports. AEMO releases an ISP every two years so there will be two during the coming regulatory period, in 2024 and 2026. We consider it reasonably likely that those two ISPs will 'trigger' two or three REZ design reports each.

In the Revenue Proposal we noted the uncertainty associated with this estimate and proposed that the relevant costs be recovered through a cost pass through event. The AER did not accept this due to our proposal that the materiality threshold normally associated with pass through events should be disregarded in this case.

Therefore, we propose that our best estimate of the likely cost of preparing REZ design reports, which is set out in the table above, be included in the step change.

Table 4.5: Rule change step change ($m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Draft Decision	0	0	0	0	0	0
Revised Revenue Proposal	**2.9**	**4.3**	**4.5**	**5.4**	**4.5**	**21.4**

Inertia network services

Inertia is a critical requirement for a secure power system. A minimum level of inertia, in conjunction with frequency control services, is needed for maintaining power system frequency within limits, both during normal system operation and after disturbance events.

Under the Rules,[14] AEMO must determine and publish the inertia requirements for South Australia. ElectraNet is then responsible for meeting those requirements.

In its 2020 System Strength and Inertia Report, AEMO concluded that there is an inertia shortfall in South Australia until 30 June 2023. The shortfall is equivalent to 200MW of fast frequency response at times when South Australia is 'islanded' or at risk of separation from Victoria. In December 2021 it declared a shortfall equivalent to 360 MW of FFR services from 1 July 2023 until PEC is available. We currently expect the need for the service will cease in July 2025.[15][16]

Given these conclusions, AEMO directed ElectraNet to use reasonable endeavours to make the required inertia network services available.[17]

Our Revenue Proposal noted we were working to respond to the shortfall, and that this could potentially result in additional costs to be reflected in a network support allowance in our Revised Revenue Proposal.

It is now clear that ElectraNet will incur such costs in both 2023-24 and 2024-25 and that consumers will bear the efficient cost of addressing the inertia shortfall under the network support pass through arrangements.

The amount of those costs is uncertain because it varies depending on whether an islanding event actually occurs and on its duration. ElectraNet's analysis of recent relevant data, summarised in Attachment 4, shows that the expected duration of an islanding event exceeds the annual four hour cap applicable to the service contracts.

This is underscored by the recent storm event in which South Australia was islanded from the NEM for approximately a week. Accordingly, the proposed network support allowance is estimated on the expectation that ElectraNet will provide the full four hours of service in both 2023-24 and 2024-25.

Building on previous competitive tendering processes, ElectraNet conducted a rigorous tendering process in September and October 2022 to secure the required services at the lowest cost to electricity customers. The 2022 process yielded tender offers at approximately half of the unit cost from the previous year.

Based on the tenders received, ElectraNet has concluded that the expected cost of providing the relevant services in 2023-24 and 2024-25 is approximately $8m per annum. Details of the cost calculation and the tender process are provided in Attachment 4. If the duration of islanding events differs from the expected duration of four hours, the cost will be trued up accordingly, so consumers only pay the actual cost incurred in providing the services.

An alternative approach would be to recover some or all of the inertia service costs in arrears through the network support pass through process.

ElectraNet engaged with the CAP on the approach that would best suit consumers. What we heard is that consumers value cost transparency and price stability. Therefore, the CAP preferred including a best estimate of the annual inertia costs upfront with relatively small 'true up' adjustments to follow. This approach also ensures that consumers are not paying for inertia support services after service provision has ceased.

Accordingly, ElectraNet proposes a network support allowance for the expected cost of these services as per Table 4.6.

Table 4.6: Inertia network service network support allowance ($m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Draft Decision	N/A	N/A	N/A	N/A	N/A	N/A
Revised Revenue Proposal	**8.2**	**8.2**	**-**	**-**	**-**	**16.3**

14 Clauses 5.20.B.2(a) and (c)

15 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/system-security-reports.pdf?la=en

16 It is possible that the emerging FFR market will resolve this shortfall before July 2025.

17 Several other conditions must also be addressed, as set out in clause 5.20B.4(c).

Robertstown Synchronous Condenser

What is inertia?

Inertia relates to the ability of a power system to withstand changes in generation output and load levels while maintaining stable system frequency.

In a power system with high levels of inertia, frequency changes less rapidly for a change in load or generation than in a system with low levels of inertia.

In a system with low levels of inertia:

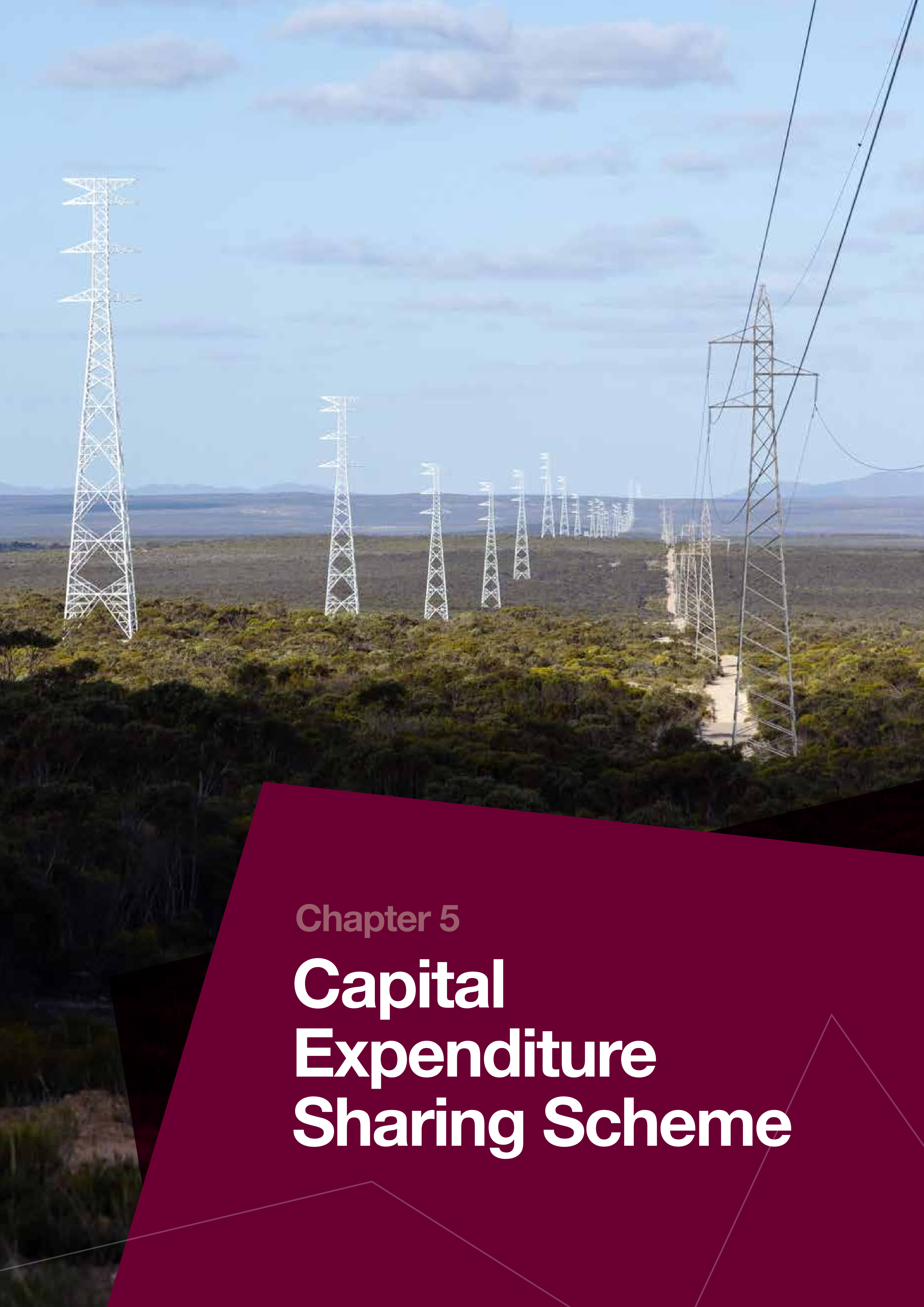
- generators may be unable to remain connected during disturbances on the power system;
- limits (constraints) may be applied to ensure stable operation of the power system, for example reduced power flows between regions.

Inertia is generally provided by large rotating electrical machines that are synchronised to the frequency of the power system, including traditional synchronous generators, motors and synchronous condensers. Inertia can also be substituted to some extent by fast acting frequency control services e.g. batteries.

Inertia is generally measured in megawatt seconds or in megawatts of Fast Frequency Response.

ElectraNet's 2022 tendering process reduced the unit cost of inertia network services by approximately half.

Recent storm events caused South Australia to be islanded from the NEM for an extended period, increasing the volume of inertia network services likely to be called upon in future.



Chapter 5

Capital Expenditure Sharing Scheme

We have responded efficiently to the Capital Expenditure Sharing Scheme by reprioritising our capital program in response to changing needs

Revenue Proposal

The CESS incentivises efficient capital expenditure delivery by rewarding underspend and penalising overspend against the AER capital expenditure allowance. Our Revenue Proposal applied the CESS to our capital expenditure in the current regulatory period.

The Revenue Proposal included a capital expenditure deferral adjustment for delays in PEC but highlighted that this adjustment was not strictly required, nor was it consistent with the requirements of the CESS, as none of the AER criteria for making such an adjustment were met.

We submitted that the appropriateness of this adjustment under the CESS should be reconsidered.

Accordingly, we engaged with the CAP on this and wrote to the AER and stakeholders in an open letter on 9 May 2022 providing updated calculations applying the CESS without a capital expenditure deferral adjustment.

AER Draft Decision

In its Draft Decision the AER did not accept our position and applied the CESS with a capital expenditure deferral adjustment. In considering the relevant criteria under its guideline, the AER formed the view that:

- The amount of capital expenditure deferred into the coming regulatory period is material
- The underspend in capital expenditure in the current regulatory period is material
- Total capital expenditure in the coming regulatory period has materially increased

The AER also expressed concern that ElectraNet has reallocated capital expenditure on projects that have not been consulted on with consumers or assessed by the AER.

Under the regulatory framework the AER sets an efficient capital expenditure allowance, but does not approve individual projects. TNSPs must manage and reprioritise changing capital requirements against this allowance.

Revised Revenue Proposal

We **do not accept** the AER's Draft Decision.

The CAP has maintained a consistent view that the deferral of Project EnergyConnect should not result in a CESS windfall gain or penalty.

We agree. No windfall gain will occur with the capital expenditure deferral adjustment removed because:

- We have efficiently reprioritised our capital program within the AER capital expenditure allowance by bringing forward previously deferred expenditure to offset the deferral of Project EnergyConnect.
- The bulk of these projects (over 80%) were presented in our Revenue Proposal for the current regulatory period and were scrutinised by the CAP and the AER in the previous revenue reset process five years ago. The projects brought forward are therefore part of a well considered and prudent capital expenditure program.
- There is therefore no need for a deferral adjustment, which would only impose a windfall penalty on ElectraNet (of over $20m).
- The risk for customers is that imposing a windfall penalty would discourage network businesses from efficiently prioritising their capital programs in future. It would also leave a revenue shortfall for ElectraNet, putting pressure on expenditure elsewhere and increasing risk.
- It is in the interests of customers that the signals sent to TNSPs drive efficient investment decisions.
- The application of the CESS without the deferral adjustment leaves ElectraNet a small underlying penalty of $2.7m.

Having reviewed the relevant information, the CAP accepts that the majority of capital expenditure brought forward was consulted on with consumer representatives and the AER in the previous revenue determination. This addresses the key concern of the AER in its Draft Decision.

The CAP concluded that the small penalty that results when the PEC deferral adjustment is removed (of $2-3m) is the right outcome.

The AER has accepted throughout that our capital expenditure program is prudent and efficient. It has accepted our forecast in full for the coming regulatory period. It has also accepted all capital expenditure incurred in the current regulatory period in determining the opening RAB and found our capital expenditure in the ex post ‘look back’ review period to be consistent with the capital expenditure criteria and objectives. This assessment supports the prudency and efficiency of both our forecasting, and the delivery of the capital program through effective prioritisation and management.

We have also obtained expert advice from Incenta Economic Consulting (Attachment 5). This advice concludes that the CESS should be applied without a capital expenditure deferral adjustment, consistent with the intent of the CESS and the AER’s previous guidance.

Accordingly, we have applied the CESS to our capital expenditure without a capital expenditure deferral adjustment in this Revised Revenue Proposal. This results in a small penalty of $2.7m.

Further background is provided as follows.

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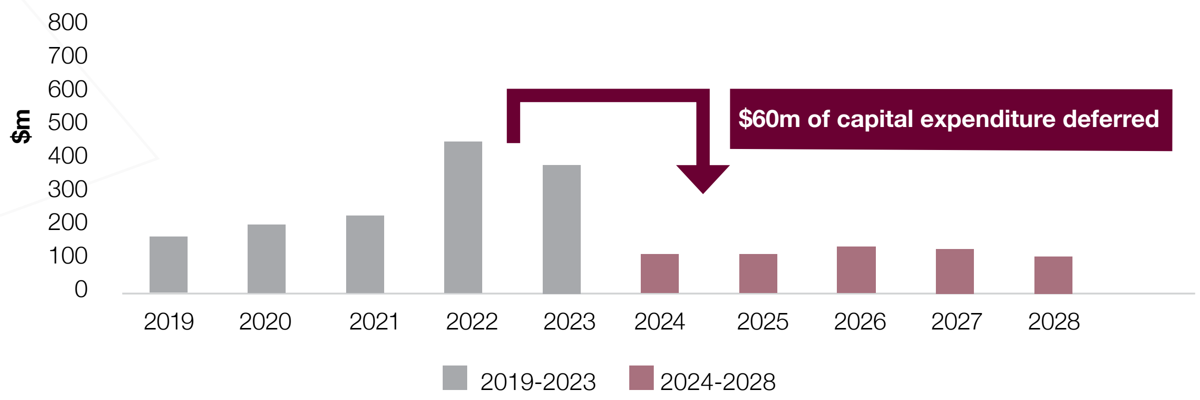
Projects deferred due to capital constraints

In the current regulatory period capital project costs have risen above the levels expected in our revenue determination. Rather than overspend the AER approved capital expenditure allowance, which would have 'locked in' lasting higher electricity prices, we reviewed and reprioritised our capital program by deferring lower priority projects into the next regulatory period.

The effect of this is shown below, as reflected in the capital expenditure forecast published at the time of the Preliminary Revenue Proposal in July 2021.

This represented the efficient reprioritisation of the capital program in the interests of customers and consistent with the incentives of the CESS.

Figure 6: Preliminary Revenue Proposal - July 2021



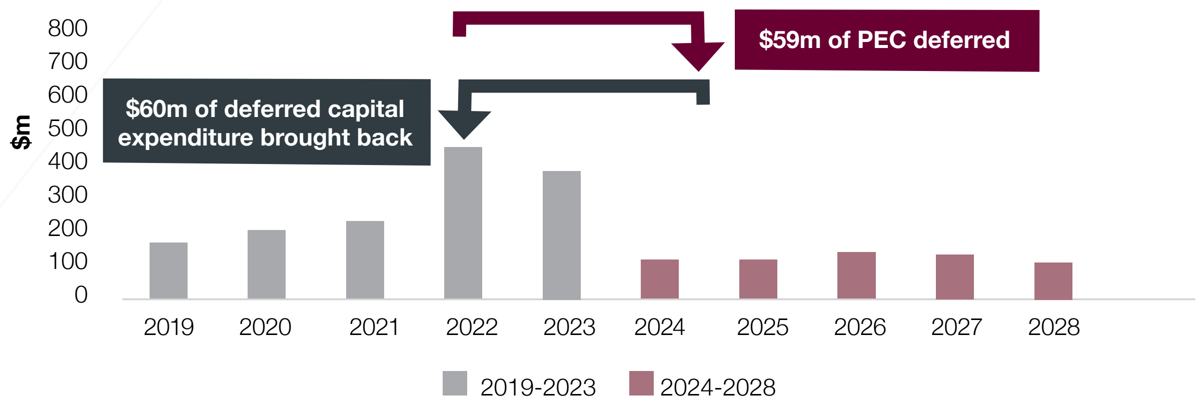
Delay in Project EnergyConnect offset by 'bringing back' deferred projects

By late 2021 the scheduled completion of the South Australian component of PEC was deferred by several months, resulting in the deferral of approximately $60m of expenditure into the 2024-28 regulatory period.

Given this, we reprioritised our capital program by bringing back projects previously deferred due to capital constraints. The majority of these projects had been scrutinised previously by the CAP and the AER and form part of a well considered and prudent capital expenditure program, albeit they were deferred as discussed above.

The effect of this is shown below, as reflected in the capital expenditure forecast contained in the Revenue Proposal submitted in January 2022.

Figure 7: Revenue Proposal - January 2022



These offsetting movements in our capital program mean that:

- ElectraNet receives no windfall gain from any underspend
- Customers are not required to fund the same capital expenditure twice
- The capital expenditure allowance for the coming regulatory period is lower than it would have been if the projects were not brought back.

Whether it is appropriate to apply a CESS deferral in these circumstances

The conditions requiring a capital expenditure deferral adjustment have not been met based on the criteria set out in the AER's guideline[18] as follows:

Table 5.1. Conditions requiring a capital expenditure deferral adjustment under the CESS

Condition	Met?	Explanation
The amount of deferred capital expenditure is material	No	The net amount of capital expenditure deferred is not material, because an offsetting adjustment was made
The underspend in the current period is material	No	There is a slight overspend (less than one per cent) in the current regulatory period.
The total capital expenditure in the forthcoming period is materially higher than it is likely to have been without the deferral	No	There is no material increase in capital expenditure in the forthcoming regulatory period due to the offsetting capital expenditure movement

As noted earlier, the CAP has concluded that ElectraNet's proposed treatment, involving no capital expenditure deferral adjustment, is the right outcome.

Expert advice from Incenta Economic Consulting, in Attachment 5, concludes that the CESS should be applied without a capital expenditure deferral adjustment in the current circumstances, consistent with the intent of the CESS and the AER's previous guidance.

We have therefore applied the CESS to our capital expenditure without a capital expenditure deferral adjustment, resulting in a small penalty of $2.7m.

18 AER, "Better Regulation | Capital Expenditure Incentive Guideline", p 9.

Chapter 6

Revenue Building Blocks

We continue to follow established approaches to determine our revenue 'building blocks'

We are following the AER's standard approaches to the remaining revenue building blocks. This chapter covers the following parameters needed to complete our Revised Revenue Proposal.

- Regulated asset base
- Rate of return
- Corporate income tax
- Regulatory depreciation
- Maximum allowed revenue and X factors
- Incentive arrangements
- Average price path

Our revenue building blocks are summarised as follows:

Table 6.1: Revenue requirement, 1 July 2023 to 30 June 2028 ($m nominal)

	Revenue Proposal	AER Draft Decision	Revised Revenue Proposal
Return on capital	809	1,169	1,195
Return of capital	367	274	228
Operating expenditure	673	692	774
Taxation allowance	0	5	0
Revenue adjustments	-12	-19	-17
Total revenue requirement	**1,837**	**2,121**	**2,179**

The key components are discussed further in the following sections.

Regulated Asset Base

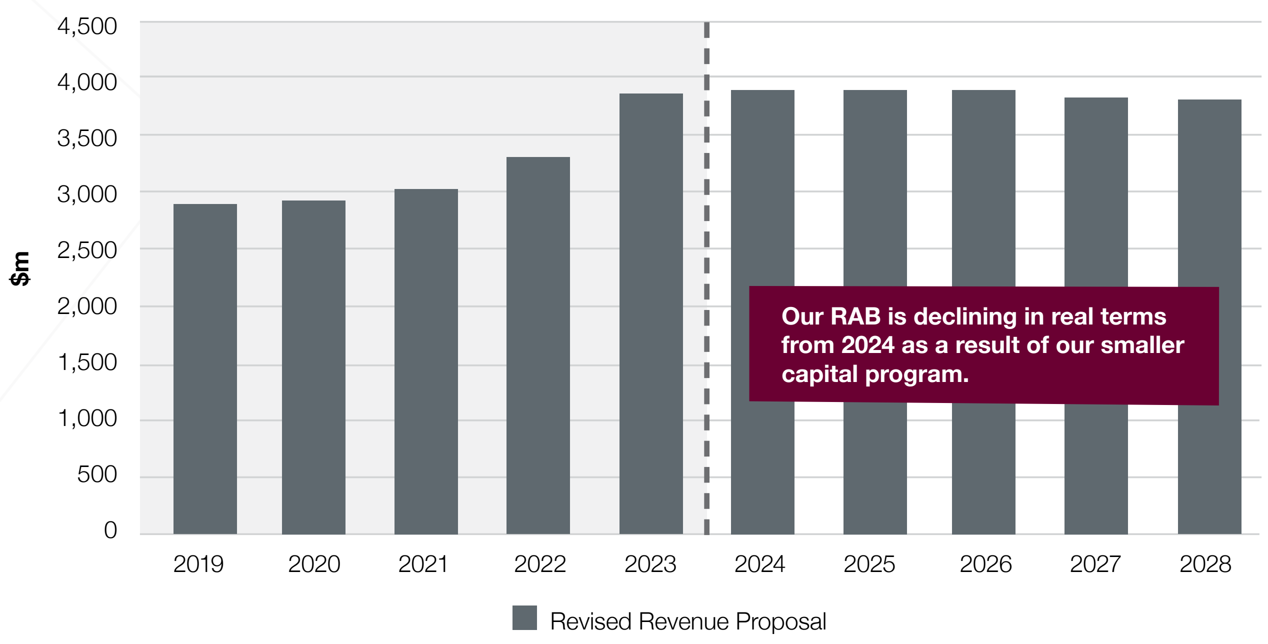
In its Draft Decision the AER accepted our opening RAB which we have updated for inflation.

Our proposed opening RAB is $3,860.1m as summarised in Table 6.2. Our forecast RAB is shown in Figure 8.

Table 6.2: Asset base roll-forward from 1 July 2023 to 30 June 2028 ($m nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23
Opening RAB	2,560.2	2,659.2	2,763.6	2,872.8	3,212.0
Capital expenditure as incurred	159.8	181.9	216.6	379.4	511.6
Straight line depreciation	-106.4	-126.5	-131.2	-140.6	-139.0
Inflation adjustment	45.7	48.9	23.8	100.5	257.0
Closing RAB	2,659.2	2,763.6	2,872.8	3,212.0	3,841.6
Adjust for difference in 2018 actual capital expenditure (and disposals)					17.3
Adjust for return on difference in 2018 actual capital expenditure (and disposals)					6.2
Final year asset adjustments					-5.0
Opening RAB at 1 July 2023					3,860.1

Figure 8: Actual / Forecast Closing RAB



Rate of return

In its Draft Decision the AER accepted our approach on the rate of return, including our proposed averaging period.

We **accept** the AER's Draft Decision.

We have applied the AER's placeholder rate of return of 5.56% in this Revised Revenue Proposal. The AER will update this in its Final Decision to reflect its forthcoming Rate of Return Instrument and latest market information.

Corporate income tax

In our Revenue Proposal we proposed a tax allowance of $0, calculated using the AER's standard methodology in the Post Tax Revenue Model. In its Draft Decision, the AER applied the same methodology, and updated the forecast to $5.2 million largely due to a higher Rate of Return.

We **accept** the AER's Draft Decision.

In this revised proposal we calculate the Net Tax allowance to be $0 as shown in Table 6.3 based on updated expenditure and revenue movements.

Table 6.3: Net Tax Allowance ($m nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Draft Decision	0	0	0	1.6	3.6	5.2
Revised Revenue Proposal	**0**	**0**	**0**	**0**	**0**	**0**

Regulatory depreciation

In our Revenue Proposal we proposed a regulatory depreciation allowance of $366.5 million calculated using the AER's standard methodology in the Post Tax Revenue Model. In the Draft Decision, the AER applied the same methodology, and updated the forecast to $274.3 million due to increased inflation, which reduces Regulatory Depreciation.

We **accept** the AER's approach to regulatory depreciation. In this Revised Proposal we calculate Regulatory Depreciation to be $228 million as shown in Table 6.4. The change from the Draft Decision is due to further inflation updates discussed elsewhere in this Revised Revenue Proposal.

Table 6.4 Regulatory Depreciation ($ nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Draft Decision	44	56	56	61	57	274
Revised Revenue Proposal	**32**	**46**	**46**	**57**	**47**	**228**

Maximum allowed revenue and X factors

We applied the AER's approach from its Draft Decision to convert the annual building block revenue requirement into a MAR.

Table 6.5 below shows the annual building block revenue requirement, the MAR, the X factors, and the total revenue cap for the forthcoming regulatory period.

Table 6.5: Smoothed revenue requirement ($m nominal)

		2023-24	2024-25	2025-26	2026-27	2027-28	Total
Annual building block revenue requirement (Unsmoothed)	**Draft Decision**	378	419	427	448	449	2,121
	Revised Revenue Proposal	**390**	**435**	**437**	**464**	**454**	**2,180**
Annual expected MAR (Smoothed)	**Draft Decision**	399	411	423	436	449	2,118
	Revised Revenue Proposal	**407**	**421**	**435**	**450**	**465**	**2,179**
X Factor	**Draft Decision**	-8.5%	0%	0%	0%	0%	
	Revised Revenue Proposal	**-9.3%**	**0%**	**0%**	**0%**	**0%**	

Incentive arrangements

We set out below how we have responded to and applied the AER's Draft Decision on the relevant incentive arrangements.

Table 6.6: Revenue adjustments for incentive arrangements ($m)

		2023-24	2024-25	2025-26	2026-27	2027-28	Total
EBSS	Draft Decision	-8.2	0.7	3.4	0	-7.0	-11.0
	Revised Revenue Proposal	**-8.2**	**0.7**	**3.4**	**0.0**	**-10.1**	**-14.2**
CESS	Draft Decision	-1.8	-1.8	-1.8	-1.8	-1.8	-8.8
	Revised Revenue Proposal	**-0.5**	**-0.5**	**-0.5**	**-0.5**	**-0.5**	**-2.7**
DMIAM	Draft Decision	0.4	0.4	0.4	0.4	0.4	2.2
	Revised Revenue Proposal	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**2.2**
Total	Draft Decision	-9.5	-0.6	2.1	-1.3	-8.3	-17.6
	Revised Revenue Proposal	**-8.3**	**0.6**	**3.3**	**-0.1**	**-10.2**	**-14.7**

Service Target Performance Incentive Scheme

We **accept** the AER's Draft Decision in relation to the STPIS.

In its Draft Decision the AER accepted our proposed Service Component parameters, and updated them for more recent (2021) data

In relation to the Market Impact Component (MIC) the AER referred to its revenue determination for AusNet Services, which was published as ElectraNet's proposal was being lodged. In that decision the AER made various clarifications relating to the way AusNet Services (Transmission) should treat 'counts' for the Market Impact component of the STPIS. For example, the AER said that:

> **where semi-dispatched renewable generators make offers to the NEM in excess of their nominated export level their output levels will appear as being constrained by a planned outage. [The AER considers] that constraints arising from renewable generators not modifying their bids into the market while knowingly aware that a planned network outage is in place should not be counted, because this is outside the control of the TNSPs**

Given this, the AER asked ElectraNet to revisit the data we submitted in support of our proposed MIC parameters to implement the approach clarified above.

We agree that TNSPs should not be penalised by renewable generators modifying their bids when they are, or ought to be, aware that a planned outage will make those bids impossible to deliver.

However, when we sought to action the AER's request we identified important practical differences in the way constraint equations are written for the South Australian and Victorian transmission networks, which make it difficult, if not impossible to implement the AER's request.

For this reason the AER's Draft Decision was made based on the 'unadjusted data'.

In summary the 'AusNet clarification' is applicable to circumstances in which there is a single generator on the left hand side of a constraint equation. We understand this is common practice in Victoria, but in South Australia there are often, and increasingly, multiple generators and batteries on the left hand side of constraint equations.

We have therefore concluded that this adjustment is not applicable to our circumstances. Accordingly we accept the unadjusted value determined by the AER in its Draft Decision.

More broadly, we consider that the notion of using historical outcomes to establish future performance targets in the MIC is flawed in the current context of material changes in network and market operation. The energy transformation means that historical data are not meaningful as predictors of future performance in the MIC. While we accept that the AER's Draft Decision on this matter is an accurate reflection of the Rules and the relevant guideline, we consider that, in its current form, the MIC is no longer fit for purpose.

It can be expected that in the coming regulatory period ElectraNet will incur significant performance penalties with no benefits to consumers.

As ElectraNet and other TNSPs have previously suggested to the AER, the MIC needs to be reformed because historical performance has lost its relevance to target setting.

NCIPAP

We **accept** the AER's Draft Decision on the NCIPAP.

In its Draft Decision the AER accepted our NCIPAP.

The Network Capability Component of the STPIS was designed to improve the capability of the transmission network for the benefit of electricity customers. It gives TNSPs an incentive to review the capability of the transmission network and find low-cost improvements that would provide greatest benefit to customers. When these improvements are made, generation is less likely to be constrained by network limits, which leads to more efficient dispatch and puts downward pressure on wholesale electricity prices.

Our NCIPAP comprises four projects that we expect to deliver reductions in the wholesale price of electricity in coming years by removing constraints and allowing more efficient generation dispatch.

We will also seek to identify further projects to include in the plan in the coming period.

EBSS

We have **accepted** and applied the AER's Draft Decision on the EBSS.

The EBSS gives ElectraNet an incentive to pursue operating expenditure efficiencies.

ElectraNet's proposal was that the EBSS carryover amount should be -$5.3 million.[19]

The AER's Draft Decision is to include an EBSS carryover amount of -$11.0 million. The reduction is due to inflation and the impact of ElectraNet's 2022 insurance cost pass through, which was applied after the Revenue Proposal was submitted.

ElectraNet's Revised Proposal is that the EBSS carryover amount should be -$14.2 million as shown in the accompanying EBSS model, reflecting updates to our expenditure profile.

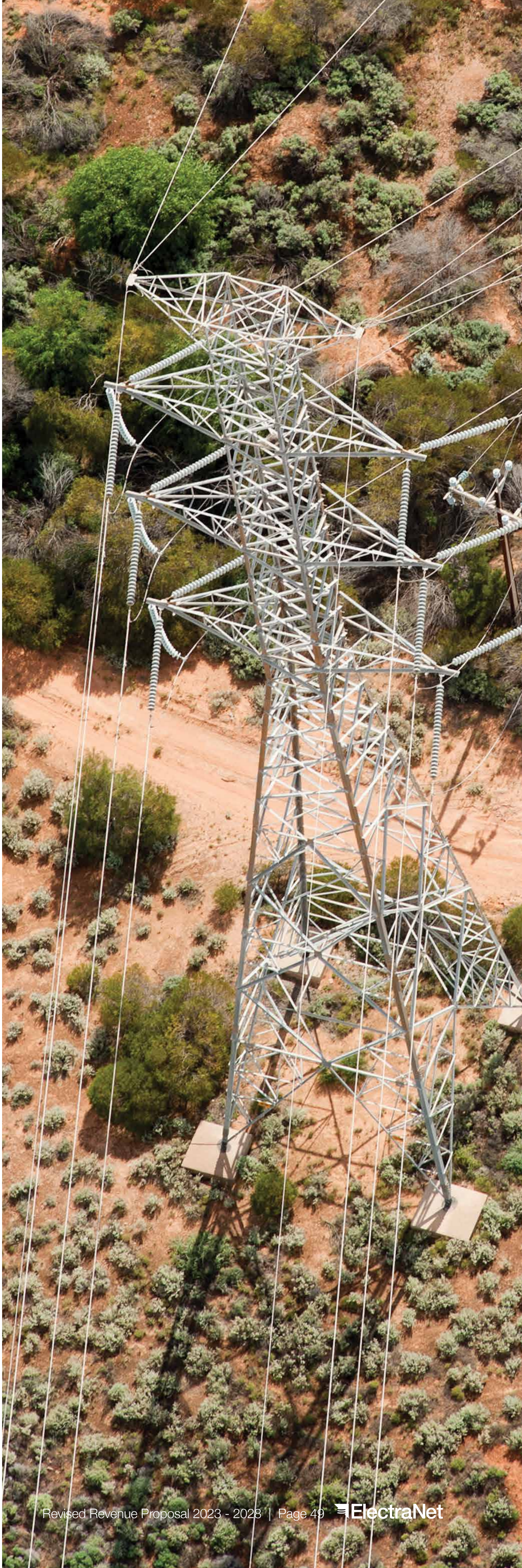
DMIAM

We **accept** the AER's decision to apply the DMIAM in the next regulatory period.

We see the DMIAM as a useful enhancement to our ongoing efforts to find the most efficient means of providing a safe, secure and reliable electricity supply to our customers.

We will work with our CAP to implement the DMIAM in the coming regulatory period.

19 As amended through post lodgement clarifications and updates.

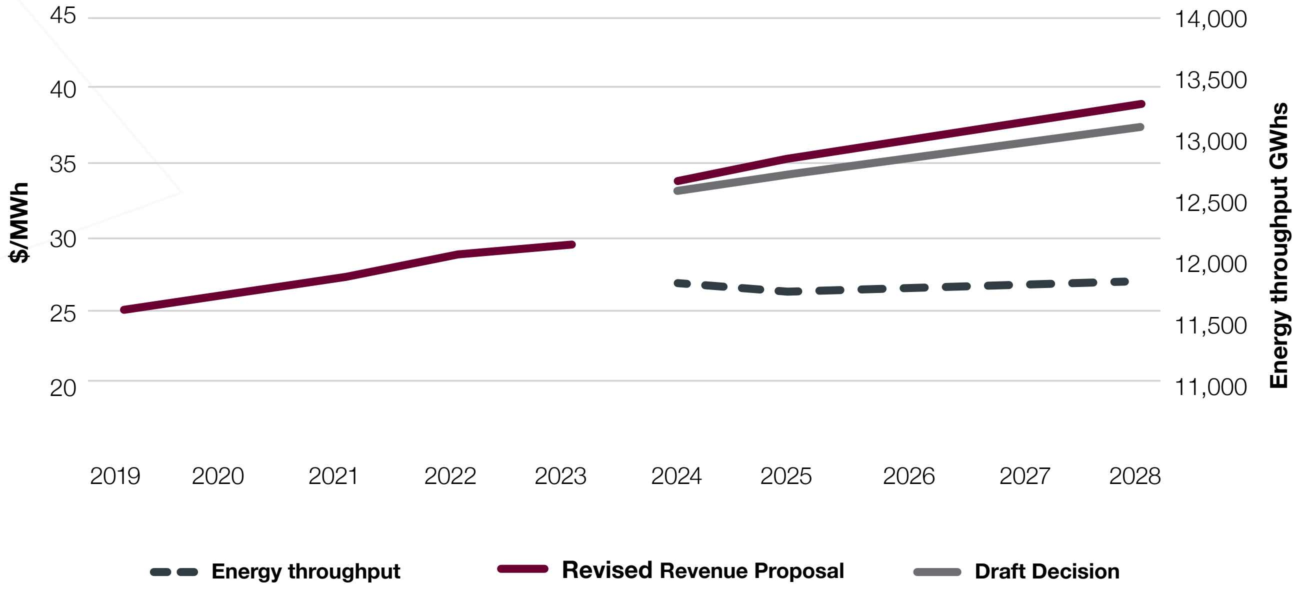


Average price path

We determine our annual transmission charges based on revenues approved by the AER and our approved Pricing Methodology, which is attached. The effect of our Revised Revenue Proposal on average transmission charges can be approximated by taking the MAR and dividing it by forecast delivered energy in South Australia, which we have obtained from AEMO's ISP (step change scenario).

Figure 9 below shows the average price path resulting from this Revised Revenue Proposal during the next regulatory period compared with the average price between 2018-19 and 2022-23.

Figure 9: Average price path ($/MWh nominal)



We estimate that the increase in our transmission charges in the first year of the forthcoming regulatory period would add approximately $28 to the average residential customer's annual electricity bill and approximately $70 to the average small business customer's bill (in nominal terms).

We have identified two contingent projects in our Revised Revenue Proposal, and also noted that further contingent projects may arise during the forthcoming regulatory period if identified as being required by AEMO's ISP or as a system strength project in accordance with the Rules. Such projects are subject to separate consultation and approval by the AER and are only approved if determined to be in the long term interests of electricity customers, such that their cost is more than outweighed by benefits.

If one or more of these projects proceeds, our revenue requirements will increase from the amounts presented in this Revised Revenue Proposal.

If both accepted contingent projects were to proceed mid period at the middle of their cost range, we estimate the indicative revenue impact to be approximately $15m equivalent to a price impact of 0.5%.

Cost pass through

In its Draft Decision the AER:

- Accepted (with some amendments) four of ElectraNet's nominated cost pass through events – covering terrorism, natural disaster, insurance coverage and insurer's credit risk events;
- Did not accept ElectraNet's REZ Design Report pass through event or system strength services pass through event.

In this Revised Revenue Proposal, we **accept** the AER's:

- amendments to the terrorism, natural disaster, and insurer's credit risk events
- decision regarding the system strength event
- decision regarding the REZ Design Report event.[20]

We **do not accept** the AER's decision to exclude cyber attack costs from the insurance coverage event, although we accept the other amendments to that event.

ElectraNet proposed that cyber attack costs be included explicitly in the definition of an 'insurance coverage event'. This would ensure that ElectraNet has a means to recover its efficient costs arising from cyber attack where they exceed the limit of prudent insurance coverage, or in the event that insurance cannot be obtained in future.

The AER declined this proposal on the basis that it is important for ElectraNet to have an incentive to mitigate the costs that might arise from a cyber attack.

ElectraNet accepts that it is efficient for risk to be borne by whoever is best placed to manage it to the extent that it can be managed. We do not agree, however, that it is efficient for our exposure to these costs to be unlimited or that providing a cost pass through event for recovery of costs that cannot be covered by a prudent level of insurance, diminishes our incentive to manage cyber security risks.

Indeed, the very existence of the insurance coverage event demonstrates that there is a limit to the efficient extent to which risk should be borne by a network operator.

Insofar as incentives are concerned, ElectraNet is required to comply with the Security of Critical Infrastructure Act and to meet applicable standards under the AESCSF. These, and other legislative and regulatory obligations relating to cyber security provide a substantial incentive to ensure that we take prudent measures to protect South Australia's electricity transmission network.

Including cyber attack costs in the insurance coverage event would ensure that ElectraNet has a means of recovering cyber attack costs incurred efficiently in excess of prudent insurance limits. This will not diminish ElectraNet's incentive to protect South Australia's electricity transmission network against cyber attacks any more than the natural disaster event diminishes our incentive to protect the network against bushfire.

Pricing Methodology

We **accept** the AER's Draft Decision in relation to our Pricing Methodology. Attachment 6 is an updated version which contains the minor edits identified in the Draft Decision.

[20] *We have included our best estimate of our likely REZ design report preparation costs in our updated rule change step change.*

Mount Gambier, South Australia

Chapter 7

Benefits and Risks

What are the key benefits and risks for electricity customers?

The key benefits and risks to our customers remain as they were in the Revenue Proposal and are

Benefits

The principal benefits of our Revised Revenue Proposal from a customer perspective are reflected in our asset management objectives. In summary, the capital and operating expenditure requirements described above, and therefore the revenue we have proposed, will allow us to deliver the following:

Safety of People

Ensure the safety of staff, contractors, and the public.

Protect the environment

Ensure the environmental impact of network operations are minimised.

Affordability and reliability

Reduce the overall cost of electricity to customers by removing network constraints, operating the network, and delivering our capital and maintenance works as efficiently as possible, while maintaining safety and reliability.

Power system security and resilience

Ensure the network is resilient and operates within acceptable parameters in the face of electrical, physical, or cyber disruption, and continues to enable the transition to a low carbon emissions future.

Risks

There are two key risk areas for customers in relation to this Revised Revenue Proposal.

Risk 1 Our actual revenue requirement may exceed that forecast in this Revised Revenue Proposal

The National Electricity Rules place a substantial onus on us to identify an efficient revenue requirement and they limit the circumstances in which this may be changed. Therefore, most of the revenue risk is with ElectraNet. However, there are some circumstances in which our revenue, and therefore the transmission prices our customers pay, might increase. These include:

Additional services

We are required to respond to a shortfall in inertia support services in South Australia declared by AEMO. This will result in additional service costs being passed to customers in the coming regulatory period.

The true-up process under the Rules ensures customers will only fund the actual costs incurred.

Increases in interest rates or other financial market changes

Our rate of return is expected to be reset each year to reflect prevailing conditions in financial markets. This is important to ensure our investors are fairly compensated for their investment, and therefore to ensure that future investment is possible. While Australia has enjoyed an extended period of low interest rates and benign financial markets as these conditions change the cost we incur in financing our business will increase as will the prices our customers pay.

Cost pass through events

Each of the nominated pass through events relate to risks that our customers bear. For instance, if we were to fall victim to a terror event our customers may experience electricity supply disruptions.

While treating these issues as pass through events places the risk on our customers, this is preferable to the alternative because, this way, customers will only bear the cost of these risks if they occur. Given the uncertainties inherent with them, this is more efficient than providing an upfront allowance in our building block costs.

Contingent and actionable ISP projects

The power system is changing rapidly as Australia transitions to a low emissions future. This means that there is significant uncertainty about the size and timing of some projects. This uncertainty is dealt with through the contingent project mechanism and, in more recent years, through the actionable ISP mechanism. Either of these might lead to increases in our capital expenditure, our RAB and, therefore, transmission prices. If they do, though, it will be because the AER, AEMO and others have determined that the relevant projects are in the long term interests of electricity customers, so their cost will be more than outweighed by other benefits.

Risk 2 Our Revenue may be insufficient to adequately manage the network

Risk of underinvestment

Our customers benefit when we invest in the network, thus ensuring an ongoing safe, secure and reliable electricity supply. By the same token there is a risk associated with under investment. Deferring investment would allow for lower prices right now, but, as was pointed out by Energy Consumers Australia during our engagement process, this just transfers the cost to future years. Too little investment creates risks to supply reliability, security and affordability in the short term and also increases the amount of investment required in future.

Given the importance of transmission services, the consequences of under investment tend to outweigh the risk of over investment.


ElectraNet

Next steps

We welcome your feedback on our Revised Revenue Proposal, either directly to us or through the AER's consultation process as it considers our Revised Revenue Proposal.

How to get in touch with us:

consultation@electranet.com.au

1800 890 376

electranet.com.au

We look forward to your feedback.

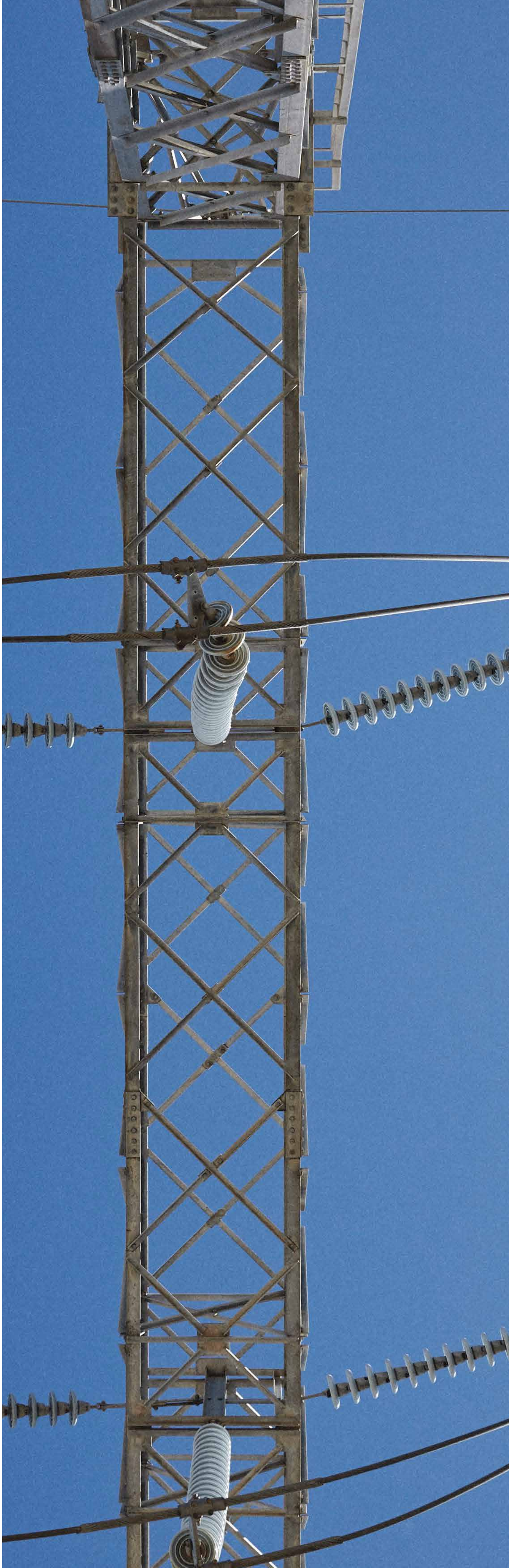
The expected timeframes for the remaining steps of the revenue determination process are as follows:

Milestone	Timing
Submissions due	**20 Jan 2023**
AER issues Final Decision	**April 2023**

Further information

Further information can be found in the following attachments and supporting models that accompany this Revised Revenue Proposal:

Attachment 1	PowerRunner Report - Operating at 100% Renewable Energy
Attachment 2	BIS Oxford economics - Real Wage Escalation
Attachment 3	Deloitte Report - Cyber Security Costs
Attachment 4	Inertia Network Services
Attachment 5	Incenta Economic Consulting Report - CESS
Attachment 6	Pricing Methodology



ElectraNet