2023-28 Revised Revenue Proposal

December 2022

Transgrid

People. Power. Possibilities.

Transgrid

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Acknowledgement of Country

In the spirit of reconciliation Transgrid acknowledges the Traditional Custodians of the lands where we work, the lands we travel through and the places in which we live.

We pay respects to the people and the Elders, past, present and emerging and celebrate the diversity of Aboriginal peoples and their ongoing cultures and connections to the lands and waters of NSW and ACT.

A message from our CEO

I am pleased to present Transgrid's Revised Revenue Proposal for the 2023-28 regulatory period, which responds to the Australian Energy Regulator's September 2022 Draft Decision.

We welcome the Australian Energy Regulator's engagement on its Draft Decision and are confident this proposal captures the feedback of our many stakeholders as well as the macro and micro-environmental factors influencing our response to key Government commitments on accelerating the transition to clean energy, enhancing system security and minimising consumer impacts.

As this Revised Regulatory Proposal outlines, the long-term needs and priorities of our customers and communities, are paramount in our planning. This revised proposal responds to the Australian Energy Market Operator's updated Integrated System Plan, as well as expert reports, new consumer research and the valuable feedback of our customers and other stakeholders. Most importantly, our proposals have been shaped by the extensive work of Transgrid's Advisory Council, which has a new composition to strengthen its customer focus.

The positions and proposals in this document are made on the premise that the 2023-28 regulatory period will be one of profound change in the Australian energy market as our nation accelerates the transition to net zero emissions while also competing on a global scale for critical supply chain capacity and resource needs as system security hits crisis levels around the world.

Since the submission of our initial Revenue Proposal in January 2022, we have also seen significant policy changes at both the State and Commonwealth levels with commitments to a true transformation of the National Electricity Market from fossil fuels to firmed renewables, and calls for levels of investment in generation, storage, transmission and system services that exceed all previous commitments combined. This will require significant upfront and ongoing investment from our securityholders, and we welcome the strong leadership of the Commonwealth Government in committing to support this investment through its Rewiring the Nation Policy.

Australia is dramatically shifting its energy mix, and Transgrid is on the frontline of making the rapid and profound changes required to make this happen.
As frequently stated by the Commonwealth Energy Minister, 'there is no transition without transmission'. To meet the Government's 2030 target of cutting emissions by 43 per cent, renewable electricity production must become 82 per cent of our electricity supply and it must be connected to the grid.

Already, as part of the Australian Energy Market Operator's Integrated System Plan, Transgrid is delivering vital upgrades and expansions to NSW's interconnectors with Queensland, Victoria and South Australia. This work will enable low-cost renewables to enter the market, delivering both environmental benefits and savings to our customers. Subject to regulatory approvals, we will also deliver the Victoria to New South Wales Interconnector West, HumeLink, other Integrated System Plan projects and the NSW Renewable Energy Zones.

With acceleration front-of-mind, we are working to integrate HumeLink, EnergyConnect and Victoria to New South Wales Interconnector West into a single program, to bring forward delivery, leverage supply chain savings and accelerate the realisation of long-term consumer bill relief.

A message from our CEO (continued)

As we work with our regulators and governments on the delivery of Australia's green grid, our priority is our customers. This revised proposal is designed to maintain a robust transmission network that will be resilient to support the connection of a rapidly changing mix and location of energy resources, while continuing to provide strong security, reliability and safety performance. To this end, it responds to the Australian and State governments' enhanced cyber-security protection requirements and includes opportunities to strengthen our network resilience by replacing ageing assets with climate-adaptive alternatives, where the opportunity arises.

New customer research conducted for this revised proposal confirms that the five priority customer outcomes identified in our initial Revenue Proposal remain valid for the 2023-28 period:

- **Affordability** – Since our initial Revenue Proposal, we have identified further capex and opex savings over the 2023-28 period of more than $1,560 million through efficiencies, technology and innovation.
- **Safety, security and reliability** – All three are being challenged by the operational complexity of the rapid energy transformation and the growing threat of cyber risks. In response, our proposal largely maintains our initial expenditure forecasts and provides additional evidence to their prudence and necessity.
- **Serving rapid, localised demand growth** – We are committed to meeting residential and business customers' needs as new development across Sydney and regional NSW drives demand growth. Our revised proposal includes new projects to meet load growth and address major constraints while managing system security and reliability.
- **Supporting the energy transition** – We are already delivering projects in accordance with the Australian Energy Market Operator's Integrated System Plan and the NSW Electricity Infrastructure Roadmap. This proposal includes new projects to facilitate the energy transition and lower emissions.
- **Supporting technology and innovation** – Where possible, this revised proposal makes use of non-network components that harness innovative technologies to either replace or defer network investment and drive down costs to customers, further supporting affordability.

We are grateful to our Transgrid Advisory Council, customers, and other stakeholders for actively participating in this Revised Revenue Proposal. We believe our revised forecast revenue and price path is a prudent response that will meet our customers' needs and maintain the reliability, security and safety of our transmission network, while supporting the energy transition.

Brett Redman
Chief Executive Officer
December 2022

A snapshot of the key positions in our Revised Revenue Proposal

Our Revised Revenue Proposal reflects

Positions of the Transgrid Advisory Council (TAC) on key issues, consulted on through our co-designed post-lodgement engagement activities. Our revised operating expenditure (opex) and capital expenditure (capex) forecasts and the resultant revenues and prices reflect the TAC's positions.

Updates our total 2023-28 forecast

- **Capex** from $1,368.5 million (excluding pre-approved forecast capex for EnergyConnect (otherwise known as Project EnergyConnect or PEC) to **$1,644.7 million**.
  We have provided additional information, including expert reports, to explain why our revised capex forecast is prudent and efficient in accordance with the National Electricity Rules (Rules or NER) requirements.
- **Opex** from $1,015.0 million to **$1,186.9 million** (including debt raising costs) and presents further information to justify our new and revised step changes, which are driven by our regulatory obligations.

Accepts the Australian Energy Regulator's (AER's) Draft Decision on

1. **Regulatory Asset Base (RAB) and depreciation**
   We have adopted the AER's adjustments and have updated our RAB to reflect our actual 2021-22 capex and our revised forecast capex.
2. **Rate of return** of 5.77 per cent annum estimated using its 2018 Rate of Return Instrument (RoRI) as a placeholder value. The AER has indicated that, in its Final Decision on our 2023-28 Revenue Proposal Determination (Final Decision), it will update the rate of return to reflect its Final 2022 RoRI, which is expected to be published in February 2023.
3. **Debt raising costs** and applied the revised benchmark cost to the updated debt component of our projected RAB.
4. **Forecast inflation** of 3.0 per cent, noting that the AER is expected to update this to reflect the Reserve Bank of Australia's (RBA's) February 2023 Statement on Monetary Policy in its Final Decision.
5. **Estimated cost of corporate income tax**, which largely accepts our opening Tax Asset Base (TAB) and the inputs and approaches in our initial Revenue Proposal.
   We have adopted the specific changes that the AER made, updating where necessary for actual 2021-22 capex and our revised 2023-28 capex forecast and changes to the other building blocks discussed throughout this Revised Revenue Proposal.
6. **Efficiency Benefit Sharing Scheme** (EBSS) carryover amount for 2018-22. We have updated the calculation of the carryover amount for our actual 2021-22 opex.
7. **Capital Expenditure Sharing Scheme** (CESS) carryover amount for the 2018-23 period. We also accept the AER's Draft Decision to apply the CESS in the 2023-28 period to our business-as-usual capex but we are seeking to exclude EnergyConnect and other Actionable Integrated System Plan (ISP) projects approved by the AER in the 2023-28 period from the application of the CESS. This is a departure from our initial Revenue Proposal, consistent with our ongoing discussions with the AER about our financeability concerns for ISP projects.
8. **Service Target Performance Incentive Scheme** (STPIS) targets on the basis that the AER will update the STPIS targets to reflect actual 2022-23 data when it becomes available.
9. **Demand Management Innovation Allowance Mechanism** (DMIAM) allowance.
10. **Nominated cost pass through events**. Based on feedback from our TAC, we have included an additional nominated pass through event to address the risk we face if we are not able to secure non-network services to meet our regulatory obligations, reflecting our TAC's preferred approach to managing this risk.
11. **Some aspects on contingent projects** but does not accept others. Where we have not accepted the AER's Draft Decision we have provided additional information to address the AER's concerns in its Draft Decision and consulted with the TAC.
12. **Shared asset revenue**, which is consistent with our initial Revenue Proposal.
13. **AER's approval of our Pricing Methodology**. We have proposed further amendments to include charging arrangements for system strength services, in accordance with a recent change to the NER and the AER's updated transmission pricing guidelines.

Executive Summary

This is Transgrid's Revised Revenue Proposal for the 2023-28 regulatory period. It responds to the September 2022 Draft Decision by the AER on our initial Revenue Proposal and supporting documentation, which we submitted on 31 January 2022. We also provided further information in response to information requests from the AER between 1 February and 31 August 2022.

This Revised Revenue Proposal reflects the valuable feedback received from our customers and other stakeholders since submitting our initial Revenue Proposal. We continued to engage actively with our customer representatives through the Phase 2 (post-lodgement) period. We listened to the feedback on our Phase 1 (pre-lodgement) engagement and made significant changes to respond to this, including reviewing the composition of the TAC to strengthen its customer focus. Through six deep dive workshops, we empowered the TAC to shape this Revised Revenue Proposal. We have also sought the TAC's views and feedback on external changes, including recent announcements and developments beyond our control, that have emerged since we submitted our initial Revenue Proposal. The positions in this Revised Revenue Proposal are fully in line with the TAC's feedback.

We also retested the end-customer research that we undertook in our pre-lodgement engagement to ensure this Revised Revenue Proposal continues to deliver on our customers' priorities and preferences. This is important given the rapid and significant changes to the electricity market over the last 12 months.

Our post-lodgement customer research confirms that the five priority customer outcomes identified in our initial Revenue Proposal remain valid for the 2023-28 period.

Customer outcomes

This Revised Revenue Proposal continues to prioritise the following five customer outcomes, which will guide our activities in the 2023-28 period as we lead the energy transition:

1. Affordability
2. Safety, security and reliability
3. Serving rapid localised demand growth
4. Supporting the energy transition, and
5. Supporting technology and innovation.

Affordability

Affordability is our customers' highest priority because electricity is central to Australians' quality of life and economic prosperity. We are committed to doing everything we can to provide our services at the lowest possible cost to ensure customers have an affordable supply of energy. Based on this proposal, from 30 June 2023 to 30 June 2028 (i.e., by 2027-28 from the 2022-23 level), we expect the transmission component of indicative customer bills to increase, in nominal terms (i.e., $ Nominal), for:

- residential customers in NSW by $27.56 per annum and in the ACT by $21.64 per annum, and
- small business customers in NSW by $59.08 per annum and in the ACT by $33.29 per annum.[1]

[1] Using the AER approach to estimate the bill impacts for residential and small business customers.

Table E-1 shows that the cost of our transmission services comprises 6 to 7 per cent of indicative residential household and small business bills in NSW and ACT. Our costs represent the smallest component of the total retail bill that customers pay. The other bill components include generation, distribution and retail costs as well as environmental policies.

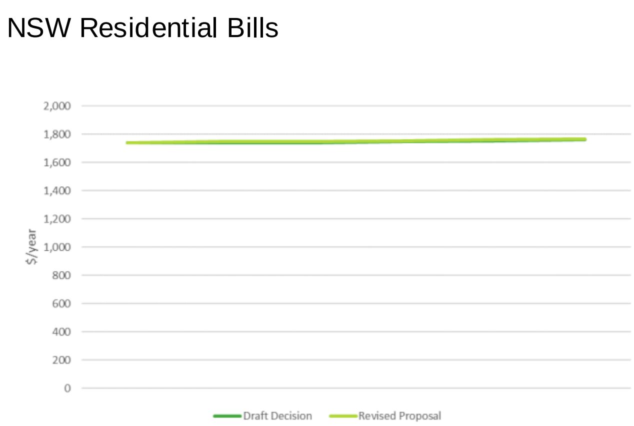
Table E-1 Indicative breakdown of total retail bill - residential and small business customers

Electricity Supply chain	Proportion of total bill %	
	Residential	Small business
Generation	36	34
Transmission	7	6
Distribution	25	24
Retail and other	23	26
Environmental policies	8	9

Source: ACIL Allen, Transgrid TUOS as a proportion of residential and small business electricity bills, 23 November 2022. Note: the proportion of total bill % is assumed to apply to typical annual bills for 2022-23.

Analysis by Frontier Economics indicates that, notwithstanding the increase in our costs over the 2023-28 period, transmission services are expected to remain on average below 7 per cent of the total indicative customer bill over that period.

Figure E-1 Indicative household bills ($, Nominal)



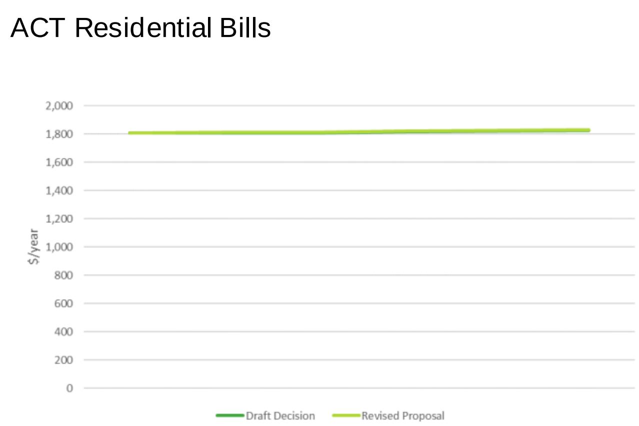
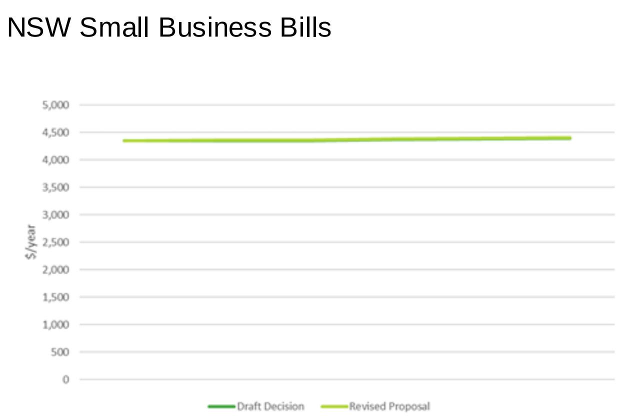
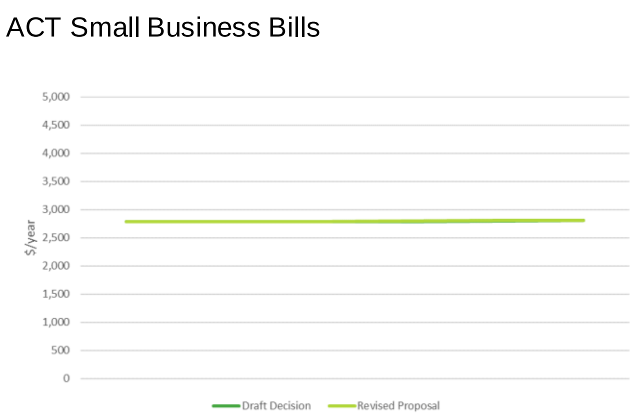


Figure E-2 Indicative small business bills ($, Nominal)





In preparing this Revised Revenue Proposal, we have left no stone unturned to identify costs that could be removed or reduced to drive our customers' dollars further. We have carefully scrutinised our revised expenditure forecasts to identify cost savings through efficiencies, technology and innovation.

Since our initial Revenue Proposal, we have identified cost savings of **$1,560.4 million**.

In support of these cost savings, we have:

- only included $21.1 million[2] for network investments arising from recently completed Regulatory Investment Tests for Transmission (RIT-Ts). This is $720.8 million less than the indicative capex of $741.9 million in our initial Revenue Proposal and is due to the efficient use of non-network solutions.[3] The TAC strongly supports the use of innovative non-network solutions to place downward pressure on electricity prices.
- in line with feedback from our TAC, accepted the AER's Draft Decision to:
  - remove contingent projects totalling $528.0 million[4]
  - remove four Augmentation capex (Augex) projects totalling $25.9 million, for which there is uncertainty regarding the forecast load growth or net economic benefits[5]
  - reduce our Replacement capex (Repex) projects for secondary systems, transformer renewals and palisade gates by $15.1 million
  - remove two property and fleet sustainability measures totalling $3.8 million. We remain committed to the investments and will self-fund these initiatives.[6]
  - reduce our insurance premium opex step change by $16.1 million from $30.0 million to $13.8 million, and
  - remove our ISP preparatory activity step change of $2.9 million and fund this through our base year allowance.
- also updated our base year opex to reflect our 2021-22 audited opex of $203.0 million.[7] This reflects a $49.5 million saving from the opex allowance for that year, which results in a total saving of $247.7 million to our customers in the 2023-28 period (compared to our base year allowance). These savings are due to the operational efficiencies we have achieved in the 2018-23 period, including upgrading our processes and systems, changing our operating model, adapting our labour force, and improving our planning and our scheduling of work.

2 This comprises $11.8 million for Managing line 86 (Repex) and $9.3 million for Maintain reliable supply to North West Slopes.
3 Network support costs paid to proponents of non-network solutions are recovered through our opex costs, under pass through provisions in the Rules.
4 Market benefits driven projects comprising $275.8 million for 'improving capacity of Southern NSW lines for renewables' and $252.2 million for 'strategic easement acquisition for supply to Sydney from the south'.
5 This comprises $8.4 million for supply to far west NSW and $17.5 million for managing multiple contingencies in Sydney north west area, Bayswater to Sydney area and north west NSW area.
6 Comprising $1.4 million for electric vehicles replacements and $2.5 million for installing solar PV and LED at the depots.
7 As reported in our 2021-22 RINs and converted to Real $2022-23.

- not included a real increase in materials costs in our expenditure forecasts, although we expect that the high inflationary environment will continue and the cost of materials will increase at a rate faster than CPI,[8] and
- ensured our costs are efficient compared to our peers, as demonstrated by the independent benchmarking and analysis that we have commissioned from HoustonKemp and GHD.

Safety, security and reliability

Our core responsibility is to ensure that electricity is delivered safely, securely and reliably to homes and businesses in NSW and the ACT. This is being challenged by the operational complexity arising from the rapid transformation of the energy system as more variable large-scale renewable generation connects to the National Electricity Market (NEM) and ageing coal-fired generation retires.[9] It is also challenged by the growing threat and costs of responding to evolving cyber risks.

Our initial Revenue Proposal explained that we will maintain a safe, secure, reliable and resilient network in the 2023-28 period by:

- renewing and replacing ageing, obsolete and deteriorated network assets to maintain the long-term condition of our electricity network
- replacing assets with more resilient alternatives, where it is efficient, so that our network can withstand more frequent, intense and longer climate-driven extreme weather events
- aligning with the Australian and NSW Governments' new cyber and physical security requirements. This will enable us to respond to growing and evolving cyber risks and continue to securely operate our network to keep our load and customer data safe, and
- rolling out new Information and Communication Technology (ICT) platforms and continuing to refresh or replace legacy applications and systems at the end of their lives.

The AER's Draft Decision reduced three aspects of our initial expenditure forecast required to deliver these outcomes:

- Replacement capex (Repex)
- Non-network ICT capex, and
- Cyber and critical infrastructure security opex step change.

We do not consider the AER's alternative forecasts are sufficient to enable us to deliver these outcomes, nor are they supported by our end-customer research, which found that residential and small business customers prioritise a reliable, safe and affordable electricity supply. This research found that 89 per cent of residential customers and 84 per cent of small business customers want us to maintain the current level of reliability. The TAC considers that, given the technical nature of these expenditure categories, we should resolve the efficient level of expenditure directly with the AER. On this basis, we have largely maintained our initial expenditure forecasts and provided additional evidence, including expert reports, to explain why

8 AEMO, Draft 2022 Integrated System Plan (ISP), December 2021, p. 15. This acknowledges that the acceleration in global infrastructure and energy investment over the next two decades will significantly increase demand for expertise, materials, and equipment, putting pressure on costs for transmission projects.

9 2GW of large scale solar and wind capacity was added to the NEM in 2020, and a further 8GW of large scale solar and wind generation is currently under construction. The pipeline is even larger – 300 generation and storage projects, totalling 55,000 MW – see https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf and https://aemo.com.au/newsroom/media-release/aemo-updates-2020-esoo.

they are prudent and efficient in accordance with the NER and will result in better outcomes for our customers than the AER's alternative forecasts.

Serving rapid localised demand growth

We are committed to meeting residential and business customers' needs as new developments across Sydney and regional NSW drive demand growth. We welcome the AER's Draft Decision which approved projects that will allow us to serve strong maximum demand growth in regions such as western Sydney (Western Sydney Priority Growth area and Supply to Sydney West), north west Sydney (Vineyard area) and central west NSW (Beryl area). The AER also approved 'supply to Strathnairn', which will enable us to respond to demand growth in the ACT. The strong demand growth across our network is due to new residential, commercial, transport and data centre developments in western Sydney and the ACT and the development of mining and industrial precincts in regional NSW.

This Revised Revenue Proposal also includes projects, which will enable us to:

- meet load growth from new residential and commercial developments in southern NSW and the ACT (Jerrabomberra area),[10] and
- address a major mining spot load in central west NSW (Panaroma area), which is constrained by Essential Energy's distribution network.

The TAC supports the inclusion of these projects in this Revised Revenue Proposal. Our end-customer research also found that our residential and business customers' highest priorities are affordability and meeting demand growth.

Supporting the energy transition

The 2023-28 regulatory period will be one of profound change in the Australian energy market as Australia transitions towards net zero emissions. The transition to renewables is happening faster than previously expected as governments commit to decarbonisation,[11] technology advances and renewable energy costs fall. The NSW[12] and ACT[13] Governments have set targets of net zero emissions by 2050, with the NSW Government also recently committing to reduce emissions by up to 50 per cent below 2005 levels by 2030.[14] The ACT Government has also committed to reducing emissions by 50 to 60 per cent below 1990 levels,[15] including phasing out fossil fuel gas by 2045 by electrifying Canberra over the next two decades using 100% renewable electricity.[16]

The Albanese Government is also actively supporting the energy transition through its Rewiring the Nation fund. Rewiring the Nation will provide $20 billion of low-cost finance for transmission investment to modernise the grid and implement AEMO's ISP.

Our transmission network is at the heart of the NEM and is vital to achieving NSW and ACT's net-zero emissions targets, by connecting geographically and technologically diverse, low-cost generation to deliver renewable energy to customers.

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[10] Maintain voltage in Alpine area.
[11] Meet the 1.5°C global warming target in the Paris Agreement.
[12] NSW Government - Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020-2030.
[13] The targets set under the Climate Change and Greenhouse Gas Reduction Act 2010.
[14] Meet the 1.5°C global warming target in the Paris Agreement. See: https://www.nsw.gov.au/media-releases/nsw-set-to-halve-emissions-by-2030.
[15] ACT Government, ACT Climate Change Strategy 2019-25, 2019, p. 1.
[16] ACT Government, Powering Canberra: Our Pathway to Electrification, August 2022.

We welcome the AER's Draft Decision, which approved programs that will support the energy transition in the 2023-28 period by:

- relieving network congestion to enable additional generation from low-cost and low-emission sources,[17] and
- installing voltage control devices in southern NSW, north west NSW and Greater Sydney to maintain voltage levels within prescribed limits as minimum demand falls due to the increased uptake of household solar photovoltaic (PV) generation.

These programs are essential as network congestion and constraints prevent prospective renewable generation projects.

We have also included new expenditure in this Revised Revenue Proposal to facilitate the energy transition in the 2023-28 period, including:

- our System Security Roadmap project to upgrade our control rooms and operations, planning and asset management functions. This will ensure we have the right technology, tools, people and skills needed to securely operate our network with the increasing levels of renewables. AEMO's NEM Engineering Framework Initial Roadmap[18] forecasts that in the 2023-28 period, the NEM could reach up to 100 per cent instantaneous renewables at times
- installation, as required by AEMO, of Phasor Measurement Unit (PMU) real-time monitoring devices to enable us and AEMO to better understand system conditions and maintain power system security
- investment to respond to the Network Support and Control Ancillary Services (NSCAS) shortfall in the Coleambally region. AEMO declared the shortfall based on its forecasts that minimum demand in NSW will rapidly decline over the next 10 years due to ongoing growth in distributed solar PV generation, and
- strategic benefit payments to private land holders that will host EnergyConnect infrastructure on their land.

The TAC supports these investments and our end-customer research also found that customers strongly support the energy transition and investment that lowers emissions. The research found that one in two customers believe the electricity industry should prioritise investment to facilitate the transition to renewable energy in the next three years.

As explained in our initial Revenue Proposal, we will deliver projects in accordance with AEMO's ISPs and the NSW Electricity Infrastructure Roadmap, as they are required, which will facilitate the uptake of new low-cost renewable generation. By delivering these projects we will be demonstrating our commitment to the energy transition. We will adhere to the NER automatic contingent project provisions for Actionable ISP projects and the NSW Electricity Infrastructure Investment (EII) Regulations for Priority Transmission Infrastructure Projects (PTIPs), including Renewable Energy Zones (REZs) and other projects under the NSW Electricity Infrastructure Roadmap. The costs of these projects are therefore not included in our expenditure forecasts in this Revised Revenue Proposal and customers will only pay for these projects if, after public consultation, AEMO and the NSW Government determine that they are needed and their costs have been assessed as prudent and efficient by the AER.

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[17] This comprises increase capacity for generation in the Molong to Parkes and Wagga North areas and increase capacity of 132 kV busbars at Wagga Substation.

[18] AEMO, NEM Engineering Framework Initial Roadmap, December 2021, p. 6.

Supporting technology and innovation

Our customers have told us they support investment in innovation to improve affordability and address climate change. We have partnered with the TAC in relation to our approach to the treatment of the preferred options under recently completed RIT-Ts for:

- improving stability in south west NSW
- maintaining reliable supply to the North West Slopes area stage 1, and
- maintaining reliable supply to Bathurst, Orange and Parkes stage 1.

In collaboration with the TAC, we have decided to rely on the non-network component of the preferred solutions to the greatest extent possible. These solutions reflect innovative technologies that either replace or defer network investment and drive down costs to customers, thereby supporting affordability. The TAC strongly supports the efficient use of non-network solutions, noting that technological innovation is critical to achieving affordability.

As requested by the TAC, we have also included a new nominated pass through event to address the risk we face if we are not able to secure non-network services to meet our regulatory obligations. Our end-customer research found that supporting cost reductions through technology and innovation is most important among residential and small business customers.

Responding to the AER's Draft Decision

We welcome and accept much of the AER's Draft Decision, which will enable us to deliver on our customers' five priority outcomes in the 2023-28 regulatory period.

In summary, we accept the AER's Draft Decision on:

- the RAB and depreciation
- the estimated rate of return, debt raising costs and forecast inflation
- corporate income tax
- incentives schemes including:
  - the EBSS and CESS carryover amounts
  - the DMIAM allowance, and
  - the STPIS targets.
- nominated cost pass through events
- shared asset revenue, and
- our pricing methodology.

As explained above, we are seeking changes to three areas of expenditure. This Revised Revenue Proposal provides additional information, including expert reports, to assist the AER to reconsider its draft positions on these matters:

1. Forecast Repex
2. Forecast Non-network ICT capex, and
3. Cyber and critical infrastructure security opex step change.

Forecast Repex

Repex is the largest component of our 2023-28 forecast capex and is needed to deliver a safe, reliable and resilient network as our assets age, condition-related issues increase and extreme climate events become more prevalent. Our transmission network:

- serves more end customers and delivers more energy than any other transmission network in the NEM
- comprises assets that are, on average, older than those of other transmission networks, and
- comprises relatively more assets than any other transmission network.[19]

HoustonKemp's independent benchmarking analysis shows that the AER's Draft Decision would result in a total Repex forecast materially below our current levels of Repex and at the lower end of the historical range since 2009. This would not be in our customers' long term interests noting that:

- the AER's alternative forecast does not reflect the costs required to address the safety risks on our network. We have a duty to protect the public and our field crews, and our commitment to safety cannot be compromised, and
- our customers prefer a sustainable level of expenditure, which does not accrue problems for future customers. They also expect us to maintain our existing performance standards and build a safe and reliable network for the future.

Benchmarking analysis undertaken by GHD reinforces HoustonKemp's findings, noting that:

- the energy transition is increasing the importance of network performance to maintain customer outcomes, and
- the higher volume and relative older age of our assets means that comparatively more assets are due for replacement or refurbishment in the 2023-28 period compared to other transmission networks.

We have updated our business cases to identify the most cost-effective network options and provided additional evidence to address the issues raised by the AER in its Draft Decision, including in relation to our duty of care.

Forecast Non-network ICT capex

Our forecast Non-network ICT capex is needed to enable us to deploy new technology and continue to refresh or replace legacy applications and systems at the end of their lives. The energy transition is creating new demands on our operating systems and processes as the complexity of our network increases. To respond to these challenges efficiently, we need to enhance our data analytics and reporting capability and modernise our IT platforms.

Our workforce is also growing rapidly to support the significant new investments we are undertaking to deliver AEMO's Actionable ISP projects. We need to provide the necessary ICT equipment and platforms to enable our growing workforce, which is critical to support the energy transition.

Independent benchmarking from HoustonKemp supports the efficiency of our proposed expenditure, noting that:

- we benchmark well against other transmission network service providers (TNSPs) for the metrics most relevant to ICT, including ICT totex per employee, user and device, and

[19] Based on GHD's analysis.

- on a per unit basis, our ICT capex will continue to decline over the 2023-28 period and is expected to fall by more than 20 per cent from the current 2018-23 period.

We have adopted the AER's top-down benchmarking approach to determine our revised ICT capex forecast and provided further information and supporting documents to address the concerns raised by the AER in its Draft Decision.[20]

Cyber and critical infrastructure security opex step change

Our cyber and critical infrastructure security opex step change is needed to enhance our cyber and physical security capability to meet the Australian and NSW Governments' new requirements and manage the rapidly evolving cyber risk. Recent and ongoing events, such as data breaches, ransomware and fraud are increasing. In Australia, a cyber-attack occurs every 7 minutes[21] and there is a cyber-attack on Australia's critical infrastructure every 32 minutes.

The failure of our critical infrastructure would have a profound impact on our customers and Australia's economic activity. We rely on core operational technology (OT) and ICT systems to safely and securely operate our network. We are working harder than ever to protect our network from cyber and physical attacks.

We maintain 24x7 monitoring over our physical and cyber assets to ensure we can rapidly respond to protect data privacy and continue to keep our network operating safely and securely. Our critical infrastructure's 'attack surface' is much bigger than that of electricity generators and retailers. The significant new investments we are undertaking to deliver AEMO's Actionable ISP projects will further expand the attack surface, requiring a broader control coverage. The recent security breaches at Optus and Medibank reinforce the importance of focusing our attention on cyber risks and ensuring that effective measures are in place to mitigate them.

Deloitte has independently reviewed our cyber and critical infrastructure security step change and sets out its professional opinion as follows:

> *Our concluding opinion is that any reduction to Transgrid's Cyber OPEX funding will constrain it from adequately delivering a holistic program of cyber maturity uplift and risk reduction initiatives, and ongoing maintenance/operation of capabilities (both current and uplifted) necessary to achieve AESCSF SP-3. Moreover, the number of cyber developments since the original funding request and the likelihood of additional factors in the 2023-28 period (not least the volatility of cyber as a strategic threat) mean there is a high probability that additional cyber funding will be reasonably required within the 2023-28 regulatory period.*
>
> *In drawing these conclusions we note that Transgrid is rated as a 'high' criticality market entity according to the AESCSF Electricity Criticality Assessment (E-CAT), due to the high potential of critical impact to wider Australian society (and other critical infrastructure entities) from a sustained core systems failure. This elevates the significance of the adequacy of cyber capability and risk management at Transgrid compared to other market participants.*

Deloitte also cautions that the external cyber threat landscape is likely to continue escalating to 2028. As a prudent operator, we must continue to invest in our security capability to ensure we have the appropriate systems and processes in place to defend against cyber and physical attacks.

[20] Updated for our actual 2021-22 and revised 2022-23 estimated costs.
[21] The Australian Cyber Security Centre (ACSC) Annual Cyber Threat Report 2021-22, Executive Summary.

Our revised forecast opex

Our initial opex forecast of $1,015.0 million was determined using the AER's preferred base-step-trend method and included step changes to address externally driven costs that we will incur in the 2023-28 period, for:

- insurance premiums
- cyber and critical infrastructure security (discussed above), and
- ISP preparatory activity.

Our revised opex forecast of $1,186.9 million[22] is $171.9 million or 16.9 per cent higher than our initial forecast and $148.3 million or 14.3 per cent higher than the AER's Draft Decision of $1,038.5 million.

Our Revised Revenue Proposal:

- accepts the AER's Draft Decision to adopt 2021-22 as the base year and we have updated it to reflect our 2021-22 audited opex.[23] This results in substantial savings of $247.7 million for our customers in the 2023-28 period (compared to our base year allowance)[24]
- revises the labour escalation forecast to combine a new forecast from BIS Oxford with that from KPMG, adopted by the AER and adds a superannuation adjustment
- accepts the methodological approach in the AER's Draft Decision to reduce our insurance premium step change and reject our ISP preparatory activity step change
- for the reasons set out above, maintains our initial critical infrastructure security step change costs, which relate only to the Security of Critical Infrastructure Act 2018 (SOCI Act) pillar 1 'cyber' and pillar 2 'physical and natural hazards'. Further, we have increased our initial costs to address the new requirements for the additional elements of the SOCI Act, being pillar 3 'personnel', pillar 4 'supply chain' and the overarching critical infrastructure risk management plan, which were published on 15 December 2021. Given this timing, we were unable to incorporate the costs of these additional requirements in our initial Revenue Proposal and committed to revisit them in our Revised Revenue Proposal, and
- includes two additional step changes totalling $78.7 million, which are driven by new information and developments outside our control:
  - $47.6 million for our System Security Roadmap, which is focused on ensuring that we have the right people and skills to securely operate our network as the energy transition accelerates, and
  - $31.0 million for payments to compensate EnergyConnect private landholders under the NSW Government's strategic benefit payment scheme. This scheme recognises that Actionable ISP projects and the NSW Government's PTIPs are required to transform our electricity system into one that is cheaper, cleaner and more reliable.

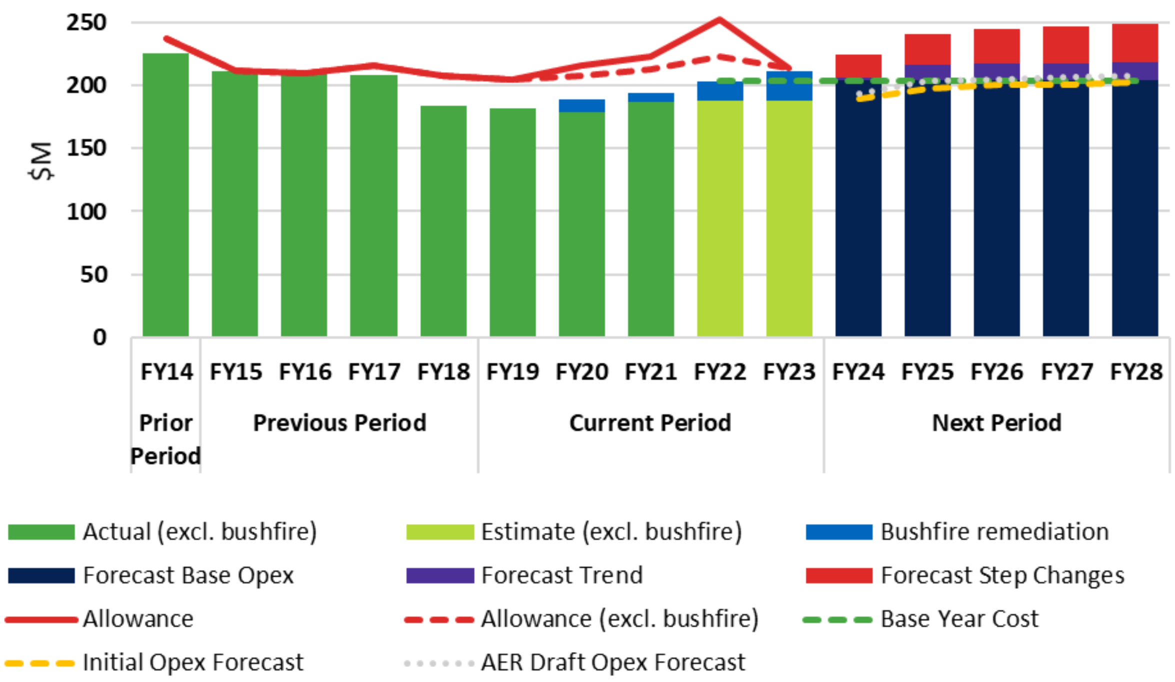
Our revised opex forecast reflects the prudent and efficient expenditure we require to continue to provide safe and reliable electricity supply and to comply with new regulatory requirements. As such, our revised

[22] Including debt raising cost of $25.7 million.
[23] In our initial Revenue Proposal, our estimated 2021-22 opex base was $223.5 million (Real 2022-23) including SaaS costs. Our actual audited 2021-22 opex base is $203.0 million (excluding SaaS) or $220.5 (including SaaS).
[24] This is a $49.5 million saving from the AER's opex allowance for that year (where our actual 2021-22 Opex is $203.0 million compared to the AER's allowance of $252.5 million) calculated over the 5-year regulatory period (49.5 X 5 = 247.7).

opex forecast will ensure we can deliver the services that our customers expect while also promoting affordability and supporting the transition to renewable technology.

Figure E-3 compares our revised opex for the 2023-28 period with our initial Revenue Proposal and the AER's Draft Decision.

Figure E-3 Forecast opex 2023-28 ($M, Real 2022-23)



Our revised forecast capex

To deliver on affordability, which is our customers' highest priority, our initial Revenue Proposal kept our 2023-28 total capex forecast broadly in line with our expected capex for the current 2018-23 period. Our initial forecast capex balanced the objective of keeping our prices as low as possible with the need to:

- deliver a safe and reliable network as our network ages and condition-related issues increase
- strengthen network climate resilience
- meet our new cyber and physical security requirements
- support the energy transition
- meet growth in localised demand
- replace assets in accordance with our duty of care obligations, and
- deploy new ICT technology and continue to refresh or replace legacy applications and systems at the end of their lives.

Our revised total capex forecast of $1,644.7 million (excluding pre-approved capex)[25] is $276.2 million or 20.2 per cent higher than our initial forecast of $1,368.5 million and $424.1 or 34.7 per cent higher than the AER's Draft Decision of $1,220.6 million.

We understand the AER and the TAC's concerns regarding our ability to deliver our proposed 2023-28 business-as-usual (BAU) works program, given:

- the current industry wide demand for labour and materials as the energy market transitions, and
- the additional demands in delivering AEMO's Actionable ISP projects and the NSW Government's PTIPs, under its Electricity Infrastructure Roadmap.

While we acknowledge these concerns, we believed they are misplaced. To demonstrate this, we have prepared a Deliverability Plan, which explains that we are aware of, and prepared for, the coming resource challenges. The Plan sets out the structural and operational changes we have made to de-risk the deliverability of our 2023-28 capex program from the concurrent delivery of AEMO's ISP projects and the NSW Government's PTIPs. This includes establishing two separate delivery units, each with their own sourcing strategies, capital planning and delivery processes.

We have also updated the unit rates underpinning our Repex and Augex forecasts from 2020-21 to 2021-22, which are the latest available and reflect the high and unexpected inflation over the 12 months ending June 2022. The impact of inflation is an international phenomenon that is beyond our control. Our 2021-22 unit rates reflect the latest available market pricing and therefore provide the appropriate starting point for determining our future capex requirements.

To balance affordability with the need to ensure a sustainable level of capex, to maintain existing performance and build a safe and reliable network for the future, we carefully scrutinised our initial capex forecasts to identify costs that could be removed or reduced to drive our customers' dollars further. We have:

- reduced our initial capex forecast by accepting the AER's feedback where we believe it will result in better outcomes for our customers. This includes removing four Augex projects totalling $25.9 million, relying on non-network solutions to the greatest extent possible[26] and removing two property and fleet sustainability measures [27]
- for the reasons explained above, largely maintained our original scope for our forecast Repex. After carefully reviewing the issues raised in the AER's Draft Decision, and undertaking extensive new analysis, we have formed the view that subject to some refinement based on the AER's Draft Decision and feedback from the TAC, our original scope is more efficient for customers. Our customers have told us that they expect us to maintain our strong performance and high levels of safety and reliability in the 2023-28 period
- for the reasons explained above, largely maintained our non-network ICT capex forecast based on the AER's top-down forecasting approach updated to reflect our actual 2021-22 and revised 2022-23 estimated costs. This shows that our initial bottom-up forecast is efficient and necessary to enable us to deploy new technology and continue to refresh or replace legacy applications and systems at the end of their lives, and

[25] Pre-approved forecast capex relates to capex approved by the AER in the 2018-23 period for EnergyConnect Contingent Project Application (CPA) that we expect to incur in the 2023-28 period.

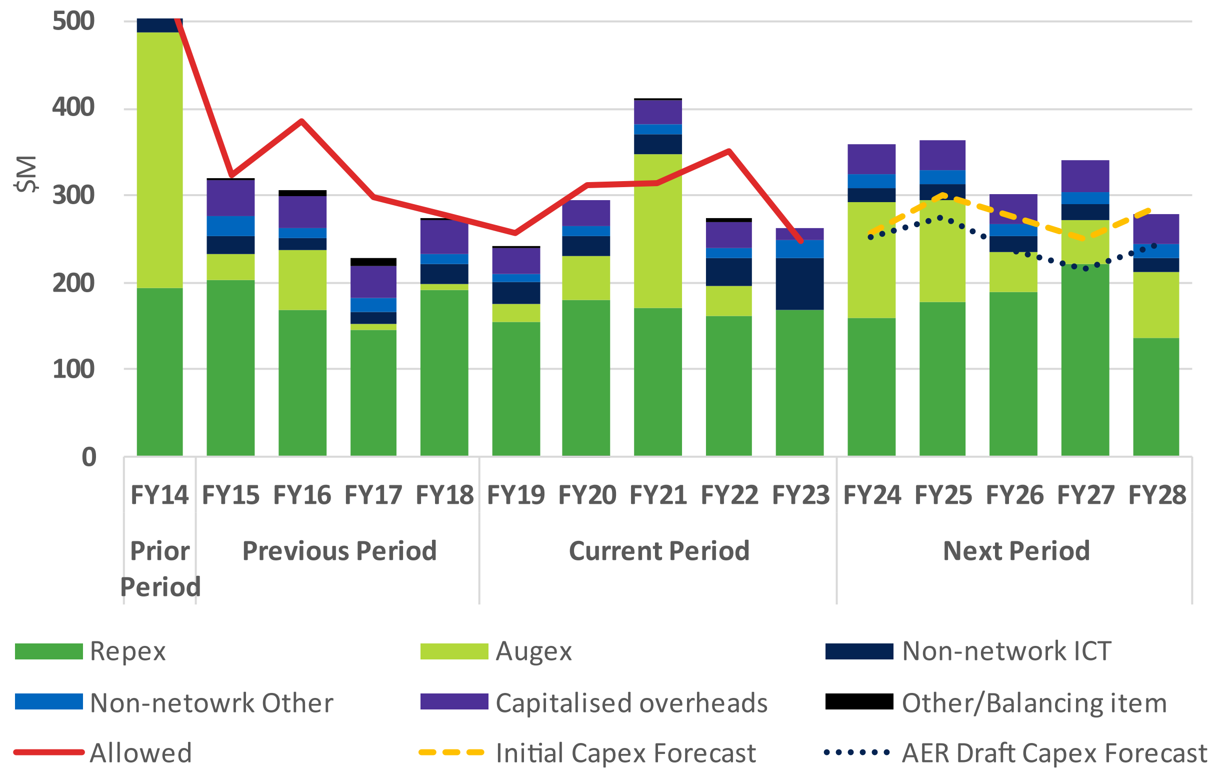
[26] Network support costs paid to proponents of non-network solutions are recovered through our opex costs, under pass through provisions in the Rules.

[27] Comprising $1.4 million for electric vehicles replacements and $2.5 million for installing solar PV and LED at the depots.

- updated our initial capex forecasts to include additional capex to enable us to respond to new information and developments outside our control, which have emerged since submitting our initial Revenue Proposal. This includes our System Security Roadmap project in response to the accelerated energy transition, AEMO's directions to install PMUs and address an NSCAS gap and a new customer connection request from Essential Energy.

Figure E-4 compares our revised forecast capex for the 2023-28 period with our initial Revenue Proposal and the AER's Draft Decision. To aid comparison, we have excluded our expenditure of $1,453.6 million on AEMO's Actionable ISP Projects approved by the AER as contingent projects for the 2018-23 regulatory period (i.e., HumeLink Stage 1 (Early Works), EnergyConnect, the Queensland – New South Wales Interconnector (QNI) Minor upgrade and the Victoria – New South Wales interconnector (VNI) Minor upgrade).

Figure E-4 Forecast capex 2023-28, excluding pre-approved forecast capex, ISP Projects and NSW Electricity Infrastructure Roadmap project



Our revised forecast revenue and price path

Our forecast revenue will fund our expenditure program to meet our customers' needs and maintain the reliability, security and safety of our transmission network, while supporting the energy transition. As a customer-driven response to the AER's Draft Decision, our Revised Revenue Proposal and the resultant revenues and price paths are in line with the TAC's feedback, noting that our post-lodgement engagement empowered the TAC to shape how we should respond to key elements of the AER's Draft Decision.

Table E-2 compares our revised Annual Building Block Revenue Requirement (ABBRR) (unsmoothed revenue) and Maximum Allowed Revenue (MAR) (smoothed revenue) with our initial Revenue Proposal and the AER's Draft Decision.

Table E-2 Forecast revenue – Revised Proposal compared to our initial Revenue Proposal and AER's draft Decision ($M, Real 2022-23)

Building block	Total 2018-23[2]	Initial Revenue Proposal[1]	AER's Draft Decision	Revised Revenue Proposal
Return on capital (2023-28 rate of return)[1]	2,410.4	2,067.6	2,676.6	2,709.2
Depreciation	642.1	743.3	525.2	557.1
Opex	1,082.8	1,015.0	1,038.5	1,184.8
Revenue adjustments	51.4	33.5	15.3	(31.6)
Corporate income tax	194.5	65.7	96.4	99.4
ABBRR (unsmoothed revenue)	**4,381.1**	**3,925.1**	**4,352.0**	**4,519.0**
MAR (smoothed revenue)	**4,379.2**	**3,921.6**	**4,349.1**	**4,512.3**

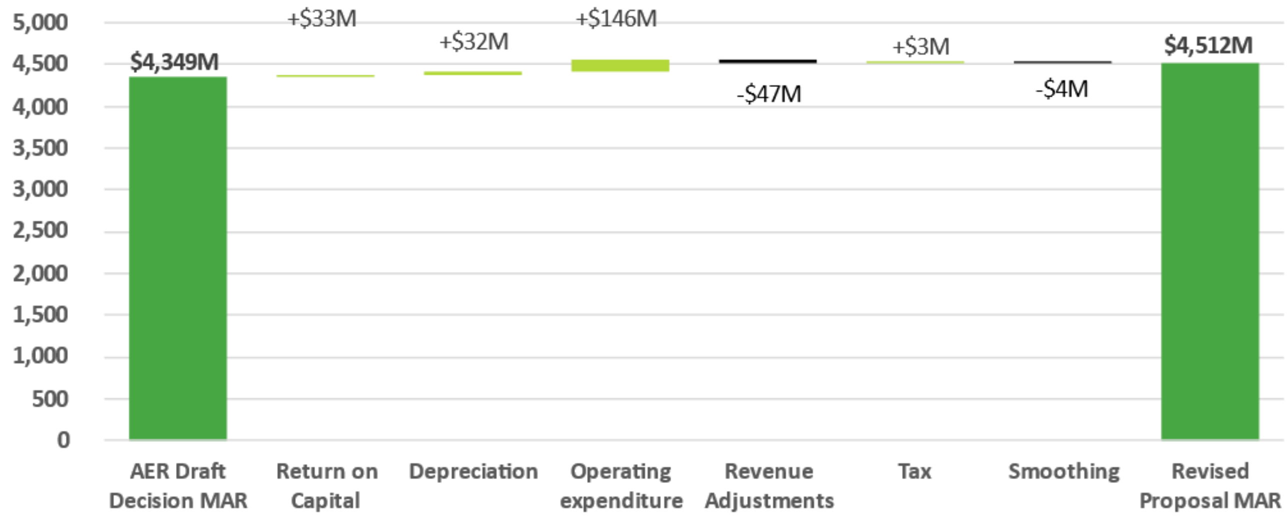
Notes: 1. The estimated rate of return in our initial Revenue Proposal was 4.70 per cent, calculated using the latest market data at the time and AER's binding 2018 RoRI. The AER's Draft Decision RoRI is 5.77 per cent (for the first year of the 2023—28 period), which we have adopted in this Revised Revenue Proposal, is based on the 2018 RoRI and reflects an increase in corporate and government bond yields. 2. Allowed revenue for the 2018-23 period includes the HumeLink allowance.

Figure E-5 compares the key changes between the AER's Draft Decision and our 2023-28 revised MAR (smoothed revenue). The key drivers of the increase in our revised MAR compared to the AER's Draft Decision are:

- higher forecast capex that is increasing our opening RAB, which in turn increases the return on capital and depreciation, and
- higher opex due to the additional step changes discussed above.

These increases are partially offset by decreases in the revenue adjustments, which reflect updates to the incentive mechanisms for 2021-22 to reflect actual expenditure and the further deferral of pre-approved capex for EnergyConnect into the 2023-28 period.

Figure E-5 Changes in our MAR – AER's 2023-28 Draft Decision and our 2023-28 Revised Revenue Proposal



As noted above, our expenditure forecasts do not include the costs of:

- the projects in AEMO's ISP, except those that have already been approved in the current 2018-23 period

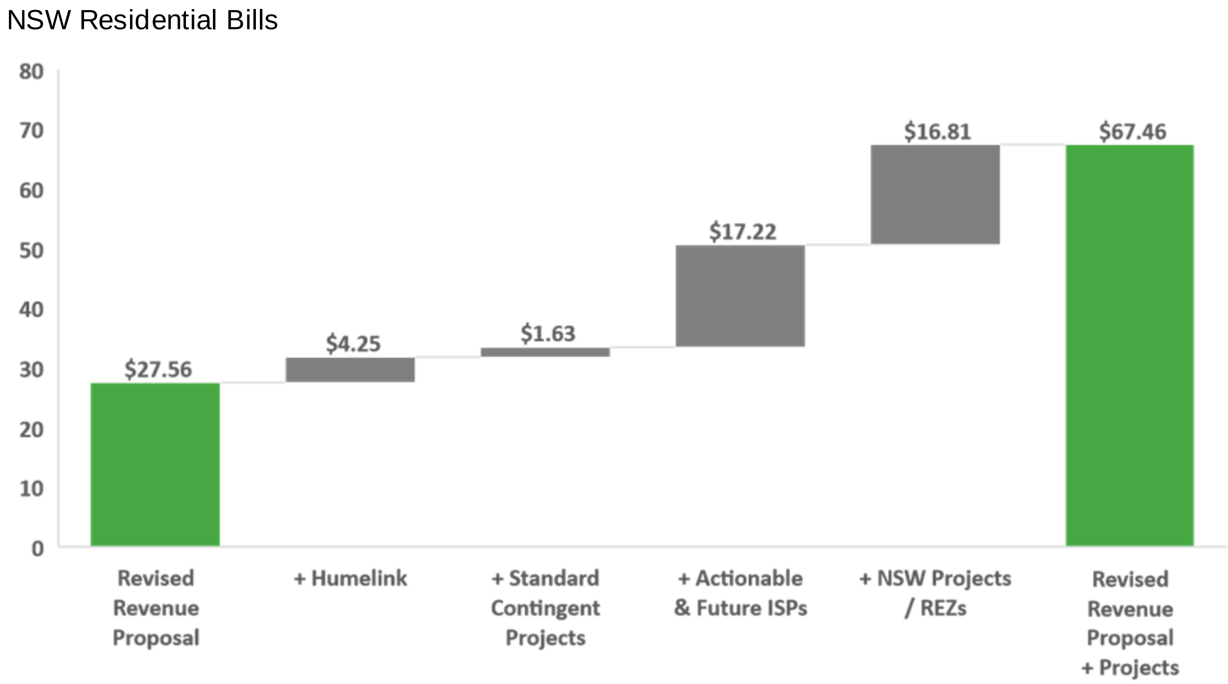
- the NSW Government's PTIPs, including REZs that are regulated under the NSW EII Regulations, or
- contingent projects, discussed in Chapter 10.

Customers will only pay for these projects if, after public consultation under the NER for Actionable ISP projects or the NSW EII Regulations for PTIPs, AEMO and the NSW Government determine that they are needed and their costs have been assessed as prudent and efficient by the AER.

Figure E-6 and Figure E-7 show that, should all these projects proceed in the 2023-28 period, we expect transmission costs to increase in nominal terms (i.e., $Nominal) over the period 30 June 2023 to 30 June 2028, for:

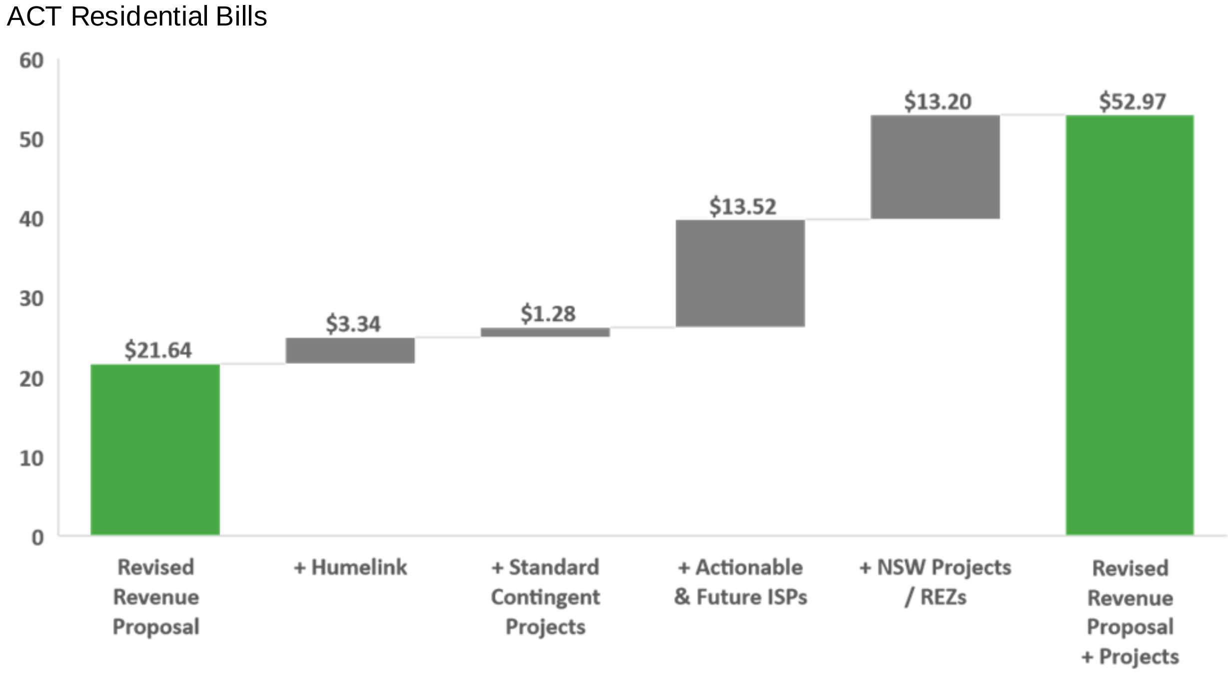
- residential customers in NSW by $67.46 per annum and in the ACT by $52.97 per annum, and
- small business customer in NSW by $144.63 per annum and in the ACT by $64.62 per annum. [28]

Figure E-6 Residential bill impact – 2022-23 to 2027-28 – transmission component ($ / year, Nominal) [29]



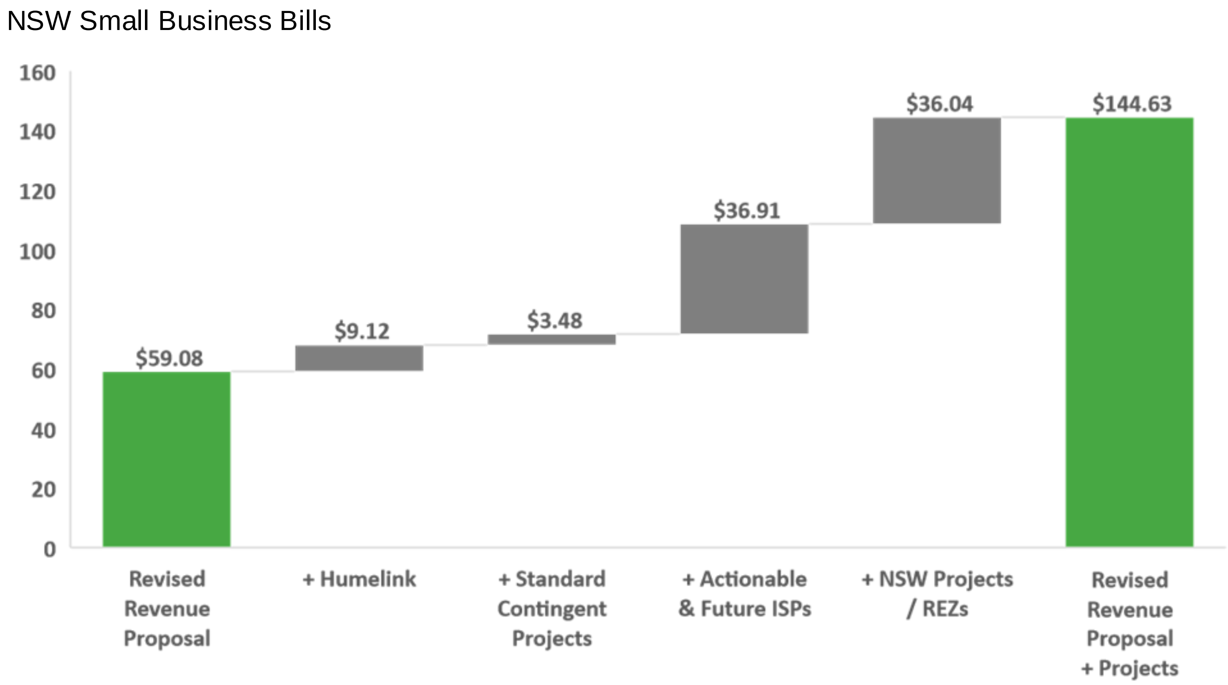
[28] By 2027-28. We have used the same approach as that adopted by the AER to estimate the bill impacts for residential and small business customers.

[29] Capex for ISP projects is projected to be incurred earlier than for NSW REZ projects. As a consequence, the ISP projects would impact revenue and prices sooner.

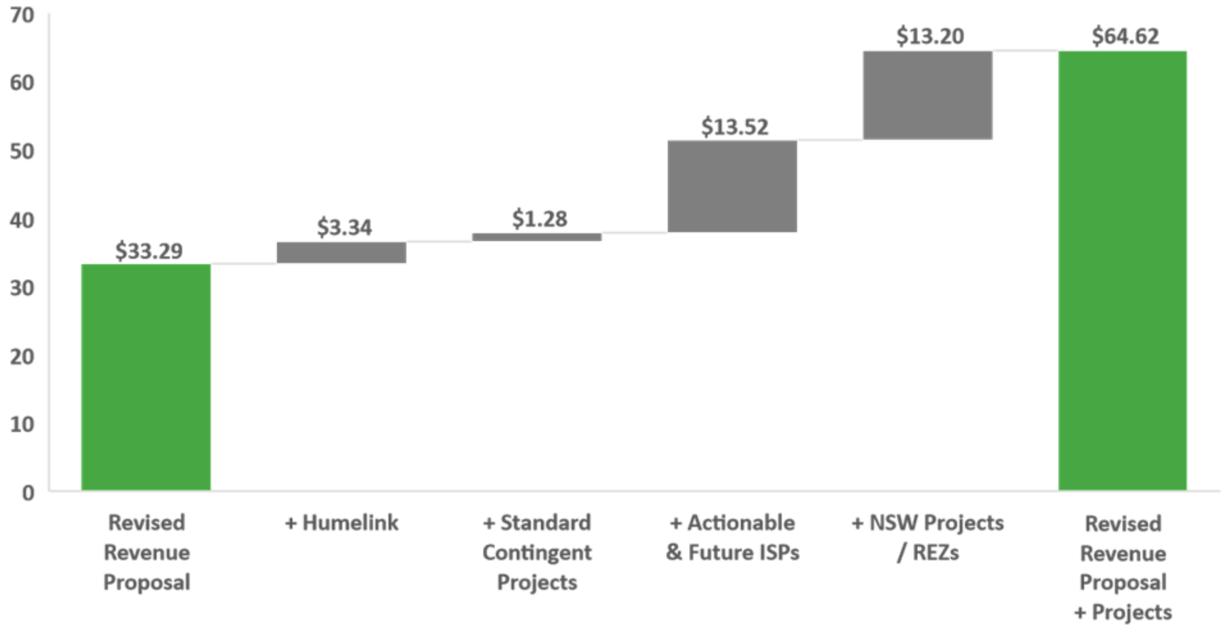


Notes: 1. The values do not sum exactly due to the impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for residential customers. 4. NSW Framework projects comprise $717 million for Central West REZ, $2,125 million for New England REZ, $251 million for Hunter region REZ, $251 million for Illawarra REZ, $1,106 million for South Western REZ, $982 million for Sydney Ring North (Hunter Transmission Project), and $107 million for Waratah Super Battery (brownfield transmission works only). All projects are expected to have a small brownfield component, costs TBD. 5. ISP projects comprise $3,701 million for HumeLink (Stage 1 and 2), $663 million for VNI West, and $169 million for QNI Connect.

Figure E-7 Small business bill impact – 2022-23 to 2027-28 – transmission component ($ / year, Nominal)



ACT Small Business Bills



Notes: 1. The values do not sum exactly due to the impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for small business customers.

Who we are

Transgrid operates and manages the high voltage electricity transmission network in NSW and the ACT, connecting generators, distributors and major end users. Our network is the backbone of the National Electricity Market, enabling energy trading between Australia's three largest states along the east coast and supporting the competitive wholesale electricity market.

Our assets and network performance

End use customers
About 4 million
NSW and ACT

Total network length
High voltage transmission line and underground cable

12,969 km
of overhead transmission line up to 500kV

106km
of underground cables up to 330kV

1,023 km 500kV	5,494 km 330kV
681 km 220kV	5,711 km 132kV
61 km below 132kV	

Transmission line structures

37,315 structures

15,693 steel lattice tower and pole structures

12,608 Wood pole structures

9,014 Concrete pole structures

Transmission substations

95 substations

208 power transformers

1,511 circuit breakers

5,777 instrument transformers

Communications infrastructure

4,200 km Optical fibre

85 Telecommunication sites

Peak demand
12,530 MW

Maximum system demand[1]
12,004 MW
At end 2021-22

Annual energy
68,200 GWh
At end 2021-22

Network reliability
99.99999%
At end 2021-22

Our values

Safety
We put safety first

Integrity
We act with integrity

Achievement
We make a difference

Service
We deliver for our customers and communities

Our Five Focus Areas

Affordability

Safety, security and reliability

Energy transition

Rapid localised demand growth

Technology and innovation

Our network

1

About us and this Revised Revenue Proposal

1. About us and this Revised Revenue Proposal

1.1. About us

Transgrid operates the high voltage transmission network in NSW and the ACT, which services about 4 million customers. Our transmission network supplies higher peak loads and transmits more energy annually than any other transmission network in Australia. This Revised Revenue Proposal explains our expenditure, revenues and transmission prices for the next regulatory period, which commences on 1 July 2023 and ends on 30 June 2028.

1.2. Basis for this Revised Revenue Proposal

We have prepared our Revised Revenue Proposal in accordance with clause 6A.12.3 of the NER. This Revised Revenue Proposal only revises our initial Revenue Proposal to address:

- matters raised by the AER's Draft Decision or its reasons for it, and
- external changes, including recent announcements and developments that are beyond our control and have emerged since we submitted our initial Revenue Proposal.

This means that the positions in our initial Revenue Proposal stand, except where they are replaced in this Revised Revenue Proposal. As such, this Revised Revenue Proposal needs to be read together with our initial Revenue Proposal to gain a complete view of our positions.

This Revised Revenue Proposal details the revenues we require to deliver outcomes that our customers have told us they value most: an affordable, safe, secure, reliable and sustainable energy supply. The development of this Revised Revenue Proposal has benefited from customer and other stakeholder consultation, as explained throughout this document, including discussions with the AER about its Draft Decision. At a high level, this Revised Revenue Proposal:

- reflects a TAC-driven response to the AER's Draft Decision. The positions in this Revised Revenue Proposal are fully in line with the TAC's feedback.
- accepts the AER's feedback where we believe it will result in better outcomes for our customers and provides further justification and support for those projects and programs where we do not accept the AER's proposed expenditure reductions or deferrals
- reflects the latest available information for market variables, including unit rates, labour costs, interest rates and expected inflation
- is supported by updated business cases for a number of specific projects and programs in response to the AER's Draft Decision, and
- is supported by expert reports and validation, including in relation to our demand forecasts underpinning key Augex projects.

We have adopted the 'Accept, Update, Maintain and New additional expenditure' approach in our Revised Revenue Proposal as follows:

- **Accept:** We accept the AER's Draft Decision on the basis that the AER has either accepted our forecast in our initial Revenue Proposal or proposed a substituted forecast that is acceptable to us, having regard to our customers' needs, the TAC's feedback and our regulatory obligations.

- **Update:** Based on feedback from the AER, we are updating the forecast capex set out in our initial Revenue Proposal to either change the project scope (e.g., where an alternative option is acceptable) or vary the forecast costs. We have also updated our unit rates from 2020-21 to 2021-22, which are the latest available and reflect the high and unexpected inflation over the 12 months ending June 2022.
- **Maintain:** We maintain the forecast capex set out in our initial Revenue Proposal was prudent and efficient and are re-submitting our business cases with additional evidence to explain why the proposed expenditure is prudent and efficient in accordance with the Rules requirements.
- **New additional expenditure:** We have updated our initial forecast capex to include new additional expenditure that is driven by new information and developments outside our control since our initial Revenue Proposal in January 2022. The key drivers of our new additional expenditure include our System Security Roadmap project, in response to the accelerated energy transition and AEMO's directions to install PMUs and address an NSCAS gap, a new customer connection request from Essential Energy, the network investments required by the recently completed RIT-T and payments to compensate private landholders under the NSW Government's strategic benefit payment scheme.

1.3. Structure of this Revised Revenue Proposal

This Revised Revenue Proposal is structured as follows:

- Chapter 2 details how we re-engaged with our customers in our Phase 2 (post-lodgement) engagement to guide the development of this Revised Revenue Proposal
- Chapter 3 details our revised opex forecast
- Chapter 4 details our revised capex forecast
- Chapter 5 details our revised RAB and our depreciation forecast
- Chapter 6 details our revised estimated rate of return, forecast inflation, and debt and equity raising costs
- Chapter 7 details our revised estimated cost of corporate income tax
- Chapter 8 details our revised proposals on the application of the AER's expenditure and service standard incentive schemes
- Chapter 9 details our revised proposals on our nominated cost pass through events
- Chapter 10 details our revised proposed contingent projects
- Chapter 11 details our revised shared asset revenue forecast
- Chapter 12 details our revised MAR and X-factors and price path forecasts
- Chapter 13 details our revised pricing methodology for the 2023-28 period

1.4. How to provide feedback

We welcome the views of customers and other stakeholders on this Revised Revenue Proposal. Please share your feedback with us by:

- Email at: revenue.reset@transgrid.com.au
- Phone on: 02 9284 3431

The AER's review process and the next steps are shown in the figure below. This Revised Revenue Proposal will be submitted by 2 December 2022 to enable the AER to make a Final Decision by 30 April 2023. The new regulatory period will commence on 1 July 2023.

Figure 1-1: AER's review process and next steps

The AER will invite submissions on our Revised Revenue Proposal until 20 January 2023. We will continue to engage with our customers and other stakeholders on our Revised Revenue Proposal up to and after this date, including through the TAC.

1.5. Conventions

In this Revised Revenue Proposal, unless otherwise specified:

- historical and forecast expenditure is presented in end-year (to 30 June) real 2022-23 dollars
- all dollars for regulatory years:
  - > up to and including 2021-22 are actuals
  - > 2022-23 are estimates, and
  - > 2023-24 onwards are forecasts.
- negative figures are presented in brackets, and
- our revenue building-blocks from the post-tax revenue model (PTRM) are presented in end-year (to 30 June) nominal dollars.

Totals presented in tables may not add due to rounding.

All figures and tables have been prepared from material sourced by us, unless otherwise specified.

1.6. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
2023-28 Revised Revenue Proposal Document Register
2023-28 Revised Revenue Proposal Confidentiality Claims

2

Re-engaging with customers

2. Re-engaging with customers

Key messages:

- Stakeholder engagement is an integral part of our business. Our BAU engagement activities include working with a diverse group of stakeholders on a range of strategic, project and operational matters.
- In preparing our initial Revenue Proposal, we undertook specific pre-lodgement engagement, in addition to our BAU engagement, to understand the priorities and preferences of our customers and stakeholders.
- Our stakeholders have criticised our pre-lodgement engagement, noting that our engagement could have started sooner, did not involve sufficient partnering with stakeholders, and did not balance customer and non-customer voices.
- We accept these criticisms and have made a concerted effort to address them through our post-lodgement engagement. For example, we:
  - acted swiftly to change the composition of the TAC to better reflect our customers' views
  - co-designed a new engagement plan for the development of this Revised Revenue Proposal
  - empowered the TAC through six independently facilitated deep dive sessions, and
  - listened, at all levels of our organisation, to the views and feedback from the TAC, noting that members of our Board and Executive Leadership Team attended the deep dive sessions.
- Our post-lodgement activities have focused on understanding the TAC's views and feedback on:
  - new additional expenditure in response to information and developments outside our control since our initial Revenue Proposal, and
  - our response to the AER's Draft Decision, noting that the TAC has shaped our response.
- We have also retested our independent customer research, which has confirmed that the five focus areas identified in our initial Revenue Proposal remain valid.
- We are grateful to the TAC for its continued efforts and invaluable feedback in our post-lodgement engagement. We are confident the TAC's commitment and feedback will deliver better outcomes for our customers.

2.1. Pre-lodgement engagement approach

Engaging with our customers is integral to our business. We seek views and feedback from a diverse group of stakeholders on strategic, project and operational matters as part of our BAU engagement, which covers a wide range of issues, including major projects and policy changes. The feedback we receive through our BAU engagement provides us with a good understanding of the priorities and preferences of our customers and other stakeholders. We explained our BAU engagement in our initial Revenue Proposal and have not repeated it in this Revised Revenue Proposal.

To inform the development of our initial Revenue Proposal, we undertook specific pre-lodgement engagement, which occurred up to our initial Revenue Proposal submission on 31 January 2022. While our BAU engagement was not formally part of our pre-lodgement engagement, it provided essential background information and learnings which informed that process. Our pre-lodgement engagement involved:

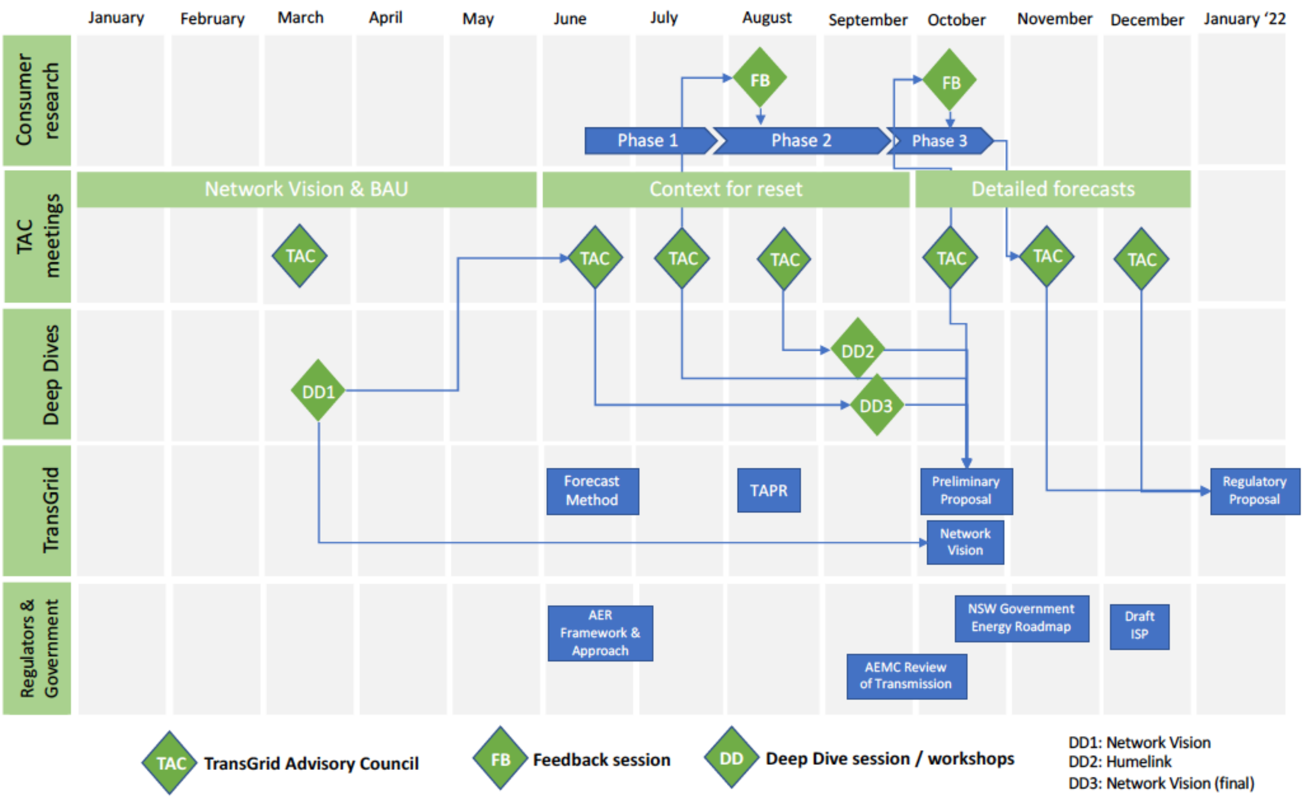
- monthly meetings with our TAC, some of which were targeted deep dive workshops[30]
- independent customer research led by Forethought
- the publication of our Preliminary Revenue Proposal, which set out our draft positions and sought feedback from all interested stakeholders, and
- a series of six 90-minute focus groups[31] to seek customers' views on specific proposed expenditures in our Preliminary Revenue Proposal.

The TAC played a key role in our pre-lodgement engagement activities. Since it was established in 2016, the TAC has been central to our customer engagement activities, providing ongoing support and advice to our business on policy issues, regulatory strategy, customer perspectives and industry insights.

Figure 2-1 summarises the full range of engagement activities we undertook during 2021 as we worked with the TAC and other stakeholders to develop our initial Revenue Proposal. It shows the meetings and deep dive sessions conducted with the TAC, in addition to our other engagement activities and key industry developments, such as the NSW Government Energy Roadmap and AEMO's draft 2022 ISP.

Chapter 2 of our initial Revenue Proposal provides further details of our pre-lodgement engagement activities.

Figure 2-1: Overview of our engagement activities in 2021.



[30] These workshops were open to a broader range of stakeholders than our TAC, such as generators and battery owners / providers.

[31] Comprised of six customers per group.

2.2. Listening and responding to stakeholder feedback

We acknowledge that our pre-lodgement engagement has been criticised by our stakeholders and the AER's Consumer Challenge Panel (CCP). We accept these criticisms, which include that our engagement:

- could have started sooner, at least 18 months before the submission date
- fell short of partnering with stakeholders to develop the initial Revenue Proposal
- did not balance customer voices against non-customer voices
- did not match the engagement standard we achieved on Powering Sydney's Future project, which reflected a greater level of co-design and collaboration, and
- did not distinguish between customers' and non-customer representatives' positions and views.

On 12 October 2022, the AER held a public forum on its Draft Decision on our 2023-28 Revenue Proposal, which it published on 30 September 2022. In this public forum, we received feedback that in preparing our Revised Revenue Proposal we should:

- be transparent about the opportunities for the TAC to influence our revised positions and proposals
- develop and reflect 'a stakeholder-driven response' to the AER's Draft Decision
- demonstrate how customers have materially changed our proposals and positions, and
- demonstrate how we have improved our efficiency and fully embraced innovation and technology to reduce our costs and place downward pressure on electricity prices. This is critical to demonstrating that we 'respect our customers' dollars' as electricity affordability concerns escalate.

We fully embraced the challenges outlined above and took immediate action to enhance our post-lodgement engagement process. Specifically, we:

- acted swiftly to change the composition of the TAC to ensure it has a stronger customer focus
- co-designed a timetable and process with the TAC that focused on deep dive sessions, which were independently facilitated and recorded by KPMG
- agreed an engagement plan for the development of this Revised Revenue Proposal, and
- empowered the TAC to drive the engagement agenda, including the topics for discussion and the number of meetings for each deep dive session.

We did not wait for the publication of the AER's Draft Decision or the public forum before initiating a number of these changes. This point was acknowledged by the AER in its Issues Paper published in March 2022[32] in which it acknowledged the steps that we had taken at that time to respond to the stakeholder feedback received. In its Draft Decision, the AER also noted the improvements to our engagement process that were already underway, which it found encouraging:[33]

> *More recently in this review, we are encouraged by the positive steps that Transgrid has undertaken in response to the constructive feedback provided by stakeholders, including co-*

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[33] AER, Draft Decision - Overview, Transgrid electricity transmission revenue proposal, 1 July 2023 to 30 June 2028, September 2022, p.2 and p.11.

designing workshop topics with stakeholders to help inform the revised proposal and rebalancing the TAC's membership.

[…]

Transgrid has since responded with a monthly series of independently-facilitated stakeholder meetings, based on deep-dive topics co-designed with its TAC, to inform its upcoming revised proposal. Transgrid also revised its TAC membership in response to stakeholder feedback. Stakeholders have welcomed Transgrid's improved engagement approach.

We welcome the AER's feedback on the early response we made to stakeholder feedback on our pre-lodgement engagement.

2.3. Our post-lodgement engagement activity

Our post-lodgement engagement involved active and authentic consultation through deep dive sessions with the TAC, which empowered the TAC to shape our response to the AER's Draft Decision in this Revised Revenue Proposal. We also refreshed our end customer research to ensure that our understanding of our customers' preferences and priorities remains up to date.

2.3.1. TAC deep dives

In accordance with the stakeholder feedback we received, the objective for these deep dive sessions was to consult on key changes since our initial Revenue Proposal and develop a TAC driven response to the AER's Draft Decision. We made every effort to achieve this by:

- empowering the TAC to set the agenda for the deep dive sessions, including the number of meetings required for each session. We expanded our four originally planned deep dive sessions to six sessions in response to the TAC's request to discuss specific topics in greater detail
- co-designing a process that transparently identified 'in scope' and 'out of scope' topics
- resourcing our response with members of our Board and our Executive Leadership Team, in addition to subject matter experts who attended each of the deep dive meetings
- providing information papers ahead of each deep dive workshop to facilitate informed discussions
- balancing perspectives by ensuring sufficient customer advocates were in attendance at each deep dive session
- recording deep dive sessions and distinguishing between the views provided by customers and other stakeholders. We also sought confirmation that we had correctly captured their feedback
- offering one-on-one meetings with TAC members as required as well as additional resources to support the TAC's participation
- ensuring that we continued to engage with customer groups and other stakeholders that may not have been fully represented on the TAC, and
- providing a detailed summary of the AER's Draft Decision and asking for the TAC's views and feedback on how we should respond to the Draft Decision. This moved our engagement to the 'empower' end of the International Association of Public Participation (IAP2) Spectrum.

In accordance with this approach, Deep Dive 1 was dedicated to co-designing the agenda and timelines for the subsequent sessions. The TAC was asked to:

- prioritise proposed topics through an online voting tool, and
- propose any additional topics that had not been captured in the proposed list.

To ensure a wide representation of views, stakeholders who were unable to attend Deep Dive 1 workshop were also given an opportunity to vote and provide feedback.

KPMG facilitated six deep dive sessions and documented stakeholders' views. This assisted to maximise the value from the deep dive sessions and ensure that the views expressed by stakeholders were captured comprehensively and accurately.

Table 2-1 sets out the deep dive sessions, the topics discussed and the meeting dates. It illustrates the extent of the activities undertaken to capture and reflect the TAC's views this Revised Revenue Proposal. While most deep dive sessions involved one timetabled meeting, the TAC requested six meetings in relation to deep dive 6. We committed the necessary resources to these meetings and prepared supporting material, recorded the TAC's views and responded to requests from some TAC members for bilateral meetings.

Table 2-1: Summary of deep dive sessions, engagement topics and meeting dates

Session	Engagement topics	Meeting dates
Deep Dive 1	• Content and purpose of the deep dive workshops • Feedback on initial Revenue Proposal • Engagement approach • Market-driven changes • Updates to Transgrid's 2023-28 expenditure forecasts • Prioritisation of topics • Next steps for collaboration	6 July 2022
Deep Dive 2	• Engagement approach, including Transgrid's response to feedback from Deep Dive 1 • RIT-T scenarios and assumptions for non-ISP projects, including scenario development, demand forecast, VCR, discount rates and network option costs • System Security Roadmap project • Next steps	15 August 2022
Deep Dive 3	• Engagement approach, including Transgrid's response to feedback from Deep Dive 2 • End-customer survey • Non-ISP RIT-Ts • Improving stability in south-western NSW • Next steps	6 September 2022

Session	Engagement topics	Meeting dates
Deep Dive 4	• Engagement approach • The AER's assessment process for demand-driven projects • Unit rates • AEMO directives • Repex forecasting method and outcomes • Indicative revenue and price impact from all investment in the 2023-28 period • Next steps	12 September 2022
Deep Dive 5	• Engagement approach, including Transgrid's response to feedback from Deep Dives 3 and 4 • System Security Roadmap • Critical Infrastructure Security • Strategic Benefit Payments to landholders • Indicative revenue and price impact from all investment in the 2023-28 period • Next steps	26 September 2022
Deep Dive 6	• Engagement approach, including Transgrid's response to feedback from Deep Dive 5 • AER's Draft Decision and our proposed response: - Opex - New additional opex - Repex - Augex - Non-network ICT capex - Non-network other capex - New additional capex - Recently completed RIT-Ts - Contingent projects – existing - Contingent projects – additional - STPIS - Next steps	A series of 6 meetings: • 18 October • 19 October • 20 October • 25 October • 31 October • 14 November

While we accept the criticisms from stakeholders on our pre-lodgement engagement, the extent of our post-lodgement engagement activities reflect a concerted effort to partner with customers and capture their views on:

- matters that have changed since our initial Revenue Proposal in response to external factors, and

- our response to the AER's Draft Decision.

KPMG's deep dive reports and final report on our engagement with the TAC through the deep dive sessions are provided as Attachments to this Revised Revenue Proposal.

2.3.2. End customer research and leveraging DNSP engagement

A significant role of the transmission network is to provide the services that NSW distributors require to meet the needs of their customers. Ultimately, therefore, the transmission network serves both residential and business customers connected to the distribution network. As such, we pay close attention to the customer research that the NSW distribution networks undertake. For example, Ausgrid's research recently concluded that communities want it to do more than deliver safe, reliable and affordable energy services, they also want Ausgrid to focus on four priorities:[34]

- Building network resilience to reduce climate and cyber risks
- Delivering net zero
- Providing a better customer experience, and
- Facilitating an affordable energy transition.

While we pay close attention to this type of research, we also recognise that customers' experience with their distributors and the opportunities for service enhancements are different to those at the transmission level. We therefore undertook our own research to ensure that we have understood customers' priorities and preferences for the services we provide. As noted above, we undertook independent customer research led by Forethought to inform our initial Revenue Proposal. This found that customers prioritise the following outcomes:

- Affordability
- Safety, security and reliability
- Serving rapid localised demand growth
- Supporting the energy transition, and
- Supporting technology and innovation.

Since our initial Revenue Proposal, significant changes have occurred in the broader economic and energy market environment that could change our customers' priorities and preferences. In particular, the recent increases in inflation and interest rates are likely to heighten cost of living concerns, while issues regarding cyber security breaches and the increased frequency of climate-related events may also drive a change in customers' priorities.

As part of our post-lodgement engagement, we therefore engaged KPMG to test whether there were any changes to our customers' views on the key focus areas that informed our initial Revenue Proposal. KPMG targeted 1,375 residential and small-medium business customers across NSW and ACT and demographic indicators. The survey results confirm that:

- cost of living is top of mind for most customers
- residential and business customers consider that all five focus areas identified in our initial Revenue Proposal are important, but would give most weight to affordability, demand growth and safety, and

[34] Ausgrid, Our Draft Plan for 2024-29, September 2022, p.28.

- the priorities identified in our pre-lodgement independent customer research remain valid.

KPMG's customer survey report is provided as an Attachment to this Revised Revenue Proposal.

The findings of this survey are consistent with the priorities identified by the NSW DNSPs in their recent extensive customer research, particularly that affordability, reliability and safety are customers' top priorities.[35]

Our decision to retest the survey further illustrates our commitment to ensure that this Revised Revenue Proposal reflects customers' priorities. The survey results were factored into the TAC's position on the key issues arising from the AER's Draft Decision, which are discussed next.

2.4. TAC feedback in shaping this Revised Revenue Proposal

Table 2-2 and Table 2-3 provide a high-level summary of the TAC's positions on:

- the AER's Draft Decision and how we should respond where a TAC-driven response could be adopted and
- additional expenditure driven by new information and developments outside our control since our initial Revenue Proposal.

In responding to the AER's Draft Decision, we explained that we cannot accept the AER's position if doing so would be inconsistent with meeting our compliance obligations. For all other matters, we empowered the TAC to shape the positions in our Revised Revenue Proposal. This Revised Revenue Proposal fully reflects the views and preferences of the TAC.

Further information on TAC's feedback and how it has shaped this Revised Revenue Proposal is discussed in detail in the relevant Chapters of this document.

We are grateful to the TAC members for their continued efforts in the consultation process and the invaluable feedback provided.

Table 2-2: Summary of TAC-driven response to the AER's Draft Decision

Element	What we heard	Discussed in this Revised Revenue Proposal
Opex step changes	• Cyber security and critical infrastructure – resolve efficient level of opex with AER given the technical nature of the investment. • ISP preparatory activities and insurance – accept AER's Draft Decision to reduce opex.	Chapter 3
2021-22 unit rates	• Increased costs are unavoidable - 'it is what it is' • Provide independent review of annual update process.	Chapter 4
Repex	• Resolve efficient level of Repex with AER given the technical nature of the investment.	Chapter 4
Augex	• Remove projects that are uncertain to proceed.	Chapter 4

[35] Ausgrid, Draft Revenue Proposal, September 2022, Endeavour Energy, Preliminary Proposal, April 2022, and Essential Energy, How engagement informed our draft proposal, September 2022.

Element	What we heard	Discussed in this Revised Revenue Proposal
Non-network ICT	• Resolve efficient level of ICT capex with AER given the technical nature of the investment.	Chapter 4
Non-network Other	• Remove sustainability initiatives for LED lighting and electric vehicles.	Chapter 4
STPIS	• Adopt AER's Draft Decision on performance targets, caps and floors for the service and market impact components.	Chapter 8
Contingent Projects	• Remove contingent projects that are market benefits rather than reliability driven.	Chapter 10

Table 2-3: Summary of TAC- driven response to new additional expenditure requirements

Topic	Key issues and summary of the TAC's positions	Discussed in this Revised Revenue Proposal
1. NSW strategic benefit payments scheme (SBPS)	Support in-principle, subject to being a pass-through cost and confirmation of who is paying for this cost.	Chapter 3
2. System Security Roadmap	• Support investment in-principle subject to: > further testing and justifying the assumptions > confirming no duplication or overlap with investment by other NSPs and AEMO > providing a plain English overview for customers. • Resolve efficient level of expenditure with the AER given the technical nature of the investment.	Chapters 3 and 4
3. AEMO directives	• Beyond Transgrid's control – 'it is what it is'.	Chapter 4
4. New connections	• Beyond Transgrid's control – 'it is what it is'.	Chapter 4
5. Recently completed RIT-Ts	• Support non-network solutions to reduce network capex • Support a nominated pass through event as a backstop to mitigate risk of non-network solution failure	Chapter 4

2.5. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
2023-28 Revenue Proposal Phase 2 Engagement Plan

Name
KPMG – Deep Dive Workshop 1 Stakeholder Engagement Report
KPMG – Deep Dive Workshop 2 Stakeholder Engagement Report
KPMG – Deep Dive Workshop 3 Stakeholder Engagement Report
KPMG – Deep Dive Workshop 4 Stakeholder Engagement Report
KPMG – Deep Dive Workshop 5 Stakeholder Engagement Report
KPMG – Deep Dive Workshop 6 Stakeholder Engagement Report
KPMG – End Customer Survey Final Report
KPMG - Post-lodgement Stakeholder Engagement Report

3

Revised opex forecast

Transgrid

3. Revised opex forecast

Key messages:

- The AER has accepted our proposal to use the base-step-trend method to forecast our opex over the 2023-28 period. However, the AER has changed key components of this approach, including to:
  - increase our base opex from $176.9 million to $186.9 million, predominately due to updated inflation inputs for 2021-22 and 2022-23
  - adopt a higher labour escalation forecast and add a superannuation adjustment
  - reduce our proposed step changes from $57.8 million by $30.1 million to $27.7 million, and
  - adopt a higher inflation forecast, which increased the forecast opex by $51.4 million.
- These changes resulted in the AER determining a substitute opex allowance of $1,038.5 million, which is 2.3 per cent higher than our initial opex forecast of $1,015.0 million (including debt raising costs).
- In this Revised Revenue Proposal, we have:
  - Updated our base opex to $195.2 million to reflect our 2021-22 audited opex and removed SaaS costs as requested by the AER. This results in substantial cost savings of $247.7 million for customers in the next period (compared to our base year allowance). These savings are more than we expected in our initial Revenue Proposal
  - revised the labour escalation forecasts to combine a new forecast from BIS Oxford Economics (BISOE) with that from KPMG, adopted by the AER, and added a superannuation adjustment
  - accepted the methodological approach in the AER's Draft Decision to reduce our insurance premium step change and reject our ISP preparatory activity step change
  - retained and updated the costs for cyber and physical security step change, and
  - added two new step changes totalling $78.7 million, which are driven by:
    - recent changes in our regulatory obligations under the NSW Government's Strategic Benefit Payments Scheme, and
    - changes in our operating environment as a result of the acceleration in the energy transition (System Security Roadmap)
- Our revised opex forecast of $1,186.9 million for the 2023-28 period is $148.3 million or 14.3 per cent higher than the AER's Draft Decision of $1,038.5 million. We consider that this revised forecast reflects the efficient costs of meeting our current and expected regulatory obligations and the service outcomes required by our customers.

3.1. Initial Revenue Proposal

As explained in our initial Revenue Proposal, we used a base-step-trend approach to forecast our opex for the 2023-28 regulatory period, except for our debt raising costs and network support costs. The base-step-trend approach involves a forecast developed at an aggregate level, rather than for each of the opex categories detailed in the AER's Economic Benchmarking Regulatory Information Notice (RIN).

The four steps in the base-step-trend approach are:

- Step 1 – nominate the efficient revealed cost base year (base opex). This includes applying adjustments to remove non-recurrent expenditure from the base year
- Step 2 – apply the rate of change adjustment, which comprises three elements:
  > real price changes in labour and non-labour inputs
  > growth in output, and
  > productivity improvements
- Step 3 – add or subtract step changes, and
- Step 4 – add specific forecasts for any other costs that were not included in steps 1–3.

Based on this approach, we estimated an initial opex forecast of $1,015.0 million (including debt raising costs), which is $11.5 million, or 1.2 per cent higher than our actual opex for the 2018-23 regulatory period (excluding debt raising costs), due to the:

- forecast growth in our network from delivering major ISP projects
- externally driven step changes including:
  > insurance premiums - $30 million
  > cyber and critical infrastructure security - $25 million
  > ISP preparatory activities - $2.9 million

3.2. What we heard from our customers

As discussed in Chapter 2, we have actively engaged with the TAC on our revised opex forecast through our co-designed post-lodgement engagement deep dives. We empowered the TAC to shape how we should respond to the AER's Draft Decision and sought its views and feedback on the new additional opex that is driven by new information and developments outside our control since our initial Revenue Proposal. Table 3-1 summarises what we heard from the TAC and how we have responded in this Revised Revenue Proposal. Further detail is provided in the remainder of this Chapter.

Table 3-1 Forecast opex – what we heard from the TAC and how we have responded

Element	What we heard	How we have responded
Network support costs	Transgrid should rely on network support solutions to the greatest extent possible, where this would reduce overall costs (opex and capex).	We will: • rely on network support solutions to the greatest extent possible, as discussed in Section 3.6.2 • rely on the network support cost pass through arrangement to recover the costs of non-network services, and • seek confirmation from the AER that the level of these costs is prudent and efficient prior to incurring them.
Insurance premium step change	The TAC supports the AER's Draft Decision to reduce the step change.	• We have accepted the AER's Draft Decision.

Element	What we heard	How we have responded
ISP preparatory activities	The TAC supports the AER's Draft Decision to reject this step change.	• We have accepted the AER's Draft Decision.
Cyber and physical security step change	The TAC: • supports this investment in principle, subject to confirmation that the timing is optimal and quantum of proposed costs are efficient and match the scale of the risk, and • considers that the AER should determine the efficient level of expenditure given the technical nature of the requirements.	• We commissioned an independent review by Deloitte of the nature and scope of our proposed activities as well as the timing and associated costs. Deloitte concludes that these are reasonable and in line with industry norms.
New additional opex		
System security roadmap	The TAC is generally supportive of this investment subject to Transgrid: • demonstrating that there is no overlap and/or duplication with other NSPs and AEMO • undertaking additional sensitivity testing to confirm the need for the investment, and • explaining how customers will benefit from the investment. The TAC considers that the AER should determine the efficient level of expenditure.	• We provided the TAC with a plain English overview of the drivers for the investment and the expected outcomes for customers. • We also set out how we are working with AEMO and other NSPs to ensure a coordinated, streamlined and efficient approach that avoids any overlap in investment to keep costs as low as possible.
Strategic Benefit Payments	The TAC supports paying landowners for hosting ISP projects on their land. However, it considers that Transgrid should clearly identify this is a pass-through cost and note who is paying for this cost.	We have calculated the payments to landholders in accordance with NSW Government's Strategic Benefit Payments scheme.

3.3. The AER's Draft Decision and our response

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

The AER did not accept our initial total 2023-28 opex forecast of $1,015.0 million and determined a substitute estimate which is 2.5 per cent lower than our initial opex forecast when inflation is treated on a like-for-like basis with our initial Revenue Proposal.

Table 3-2 overviews the key components of our revised opex forecast for the 2023-28 period compared to our initial opex forecast and the AER's Draft Decision. This shows that the AER's substitute estimate of $1,038.5 million is 2.3 per cent higher than our initial opex forecast largely due to:

- the impact of the updated inflation inputs for 2021-22 and 2022-23, and
- the AER adopting a higher labour escalation forecast and adding a superannuation adjustment.

Table 3-2: Forecast 2023-28 opex – our initial forecast the AER's Draft Decision and our revised forecast

	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
2021-22 base opex	871.7	1,018.4	1,018.5
Adjustment to 2022-23	13.0	(83.8)	(42.5)
Rate of change	**46.8**	**52.8**	**56.4**
Output growth	47.0	45.9	47.9
Price growth	12.9	20.9	23.0
Productivity growth	(13.1)	(13.9)	(14.5)
Step changes	**57.8**	**27.7**	**128.7**
Insurance premiums	30.0	13.8	13.8
Cyber and critical infrastructure security	25.0	13.9	36.3
ISP preparatory activity	2.9	-	-
NSW Government's Strategic Benefit Payments to landholders			31.0
System Security Roadmap			47.6
Total excl. debt raising costs	**989.3**	**1,015.1**	**1,161.2**
Debt raising costs	25.7	23.4	25.7
Total incl. debt raising costs	**1,015.0**	**1,038.5**	**1,186.9**

The remainder of this chapter explains and justifies each component of this forecast.

3.4. Base year

Our initial Revenue Proposal used our 2021-22 board approved budget opex for the base year, as actual data was not available at that time. We chose 2021-22 as the base year because it represents a realistic expectation of the efficient and sustainable on-going opex that will provide our prescribed transmission services in the 2023-28 regulatory period. We made the following adjustments to our base year opex consistent with the AER's preferred approach and its recent transmission determinations, removing:

- movements in provisions

- costs for bushfire remediation incurred in 2021-22, which are not expected to be recurring costs[36]
- network support costs, and
- the non-recurrent component of SaaS costs, which were one-off costs relating to our 'Digital Core' initiative to replace our previous enterprise resource planning system, Ellipse, which is approaching end of life.

The AER has:

- accepted our 2021-22 proposed base year, noting that our multilateral partial factor productivity (MPFP) benchmarking over the 2006-20 period shows that our opex is efficient
- agreed that we should update our base year to reflect our 2021-22 audited actual opex in our Revised Revenue Proposal, which the AER will also use in its Final Decision, and
- determined total base opex of $934.6 million for the 2023-28 period, which is $49.9 million or 5.6 per cent higher than our proposed base opex, solely due to updated inflation values. While some of the adjustments in its alternative estimate are different to those in our initial Revenue Proposal, they have the same net impact on forecast opex when inflation is kept constant.[37]

We have accepted the AER's Draft Decision and updated the base to reflect our 2021-22 audited opex of $203.0 million.[38] This reflects a $49.5 million saving from the opex allowance for that year, which is a total saving of $247.7 million over five-year regulatory period. These savings are more than we expected in our initial Revenue Proposal because:

- based on updated advice from the AER, we have removed SaaS costs and have continued to capitalise these in the 2018-23 period.[39] In accordance with recent changes to accounting standards, these costs will be expensed, rather than capitalised, in the 2023-28 period, and
- our actual 2021-22 bushfire remediation costs are lower than initially forecast.[40]

As explained in our initial Revenue Proposal, these savings (compared to our base year allowance) reflect the operational efficiencies we have achieved in the 2018-23 period, including by upgrading our process and systems, changing our operating model, adapting our labour force, and improving how we plan and schedule work.

Table 3-3 compares the opex base year adjustments applied in our initial Revenue Proposal, the AER's Draft Decision and our Revised Revenue Proposal. There are three main drivers for the differences shown.

[36] Should we face such costs again, we will seek to recover these using the pass-through provisions under the NER

[37] The adjustments made by the AER were: (1) remove SaaS costs from reported opex and instead add a positive adjustment to base opex reflect what is expected over the 2023-28 period; (2) add lease payments to reported opex and then remove them as a base year adjustment; and (3) add the change in bushfire allowance from FY22 to FY23 to base opex and then remove it as a non-recurrent efficiency gain.

[38] As reported in our FY22 RINs and converted to Real $2022-23

[39] In April 2021, the International Financial Reporting Interpretations Committee (IFRIC) published guidance clarifying that these costs should be expensed rather than capitalised. In preparing our initial Revenue Proposal, we consulted with the AER on this change to accounting standards and the AER advised us that we should apply this change in the 2018-23 regulatory period.

[40] In our initial Revenue Proposal, we estimated 2021-22 base year opex of $223.5 million (Real 2022-23), including SaaS costs. Our actual audited 2021-22 opex base is $203.0 million excluding SaaS costs and $220.5 million including SaaS costs. We have also deferred some bushfire remediation expenditure from the 2021-22 regulatory year to the 2022-23 regulatory year due to impacts of Covid and wet weather. We intend to spend our entire bushfire remediation allowance to complete our bushfire remediation works by 2022-23, subject to wet weather and available outage windows.

- **Inflation** – The AER's Draft Decision and this Revised Revenue Proposal reflect actual inflation values for 2021-22 and the Reserve Bank of Australia's August 2022 forecast for the year to June 2023. Our initial Revenue Proposal reflects earlier estimates for both years.
- **Treatment of SaaS costs** – Our initial Revenue Proposal and the AER's Draft Decision includes SaaS costs in the estimated 2021-22 opex. These costs are then removed to determine base year opex. In contrast, our actual 2021-22 opex does not include SaaS costs.
- **Treatment of bushfire remediation costs** – Our initial Revenue Proposal removed bushfire remediation costs from our 2021-22 opex estimate. In its Draft Decision, the AER left those costs in base opex and instead removed them (implicitly) by adjusting for the change in the opex allowance between 2021-22 and 2022-23 (which included the bushfire remediation cost allowance reducing to zero). This Revised Revenue Proposal retains the approach in the AER's Draft Decision.

Table 3-3: Opex base year adjustments ($M, Real 2022-23)

Base year expenditure adjustment	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
FY22 opex budget / actuals	223.5[1]	235.9	203.0
Less movements in provisions	(5.0)	(5.3)	0.8
Less budgeted cost for bushfire remediation	(22.4)	-	-
Less budgeted network support costs	(1.6)	(1.6)	(1.3)
Less Digital Core (SaaS) costs	(20.2)	(26.4)	-
Add leases		1.1	1.1
Proposed base year opex	**174.3[2]**	**203.7**	**203.7**

Notes: 1. 2021-22 budgeted opex does not include debt raising costs or yet-to-be capitalised operating expenditure associated with the Network Capability Incentive Parameter Action Plan, which will similarly not be included in the level of 'total opex' reported in the RIN. 2. The proposed base year opex of $174.3 million (Real 2022-23) included in our initial Revenue Proposal matches that in HoustonKemp's report[41].

3.5. Rate of change

The rate of change is applied to our base year opex for each year of the 2023-28 regulatory period. The rate of change captures the year-on-year change in efficient expenditure due to forecast changes in output levels, prices and productivity and therefore comprises three components: output, price and productivity.

The AER's Draft Decision includes a rate of change allowance of $52.8 million over the 2023-28 period, which is $6.1 million or 13 per cent higher than our initial Revenue Proposal of $46.8 million. The higher annual average growth is due to the AER:

- reflecting real labour cost escalation based on an average of our forecast from BISOE and a forecast from KPMG, adopted by the AER, and
- incorporating the superannuation guarantee increases.

Each of these components of the rate of change are discussed below.

[41] HoustonKemp, Efficiency of Transgrid's base year operating expenditure, December 2021.

Rate of change – Output

The output growth factor is the expected change in network output over the 2023-28 regulatory period. We applied the output change measures and respective weightings that are detailed in the AER's 2021 Annual Benchmarking Report for TNSPs.[42] The four output growth measures are:

- energy throughput
- ratcheted maximum demand
- customer numbers, and
- circuit line length.

This Revised Revenue Proposal accepts the AER's Draft Decision, subject to updating the data. Table 3-4 shows our updated annual output growth factors for the 2023-28 regulatory period, as well as the total output growth. The last two years of the current regulatory period are shown for completeness.

Table 3-4: 2023-28 opex - updated output growth forecast

Output measure (%)	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
Energy throughput	(0.3)	0.1	(0.5)	0.0	-	0.4	0.7
Ratcheted maximum demand	-	-	-	-	-	0.8	1.2
Customer numbers	1.4	1.3	1.3	1.3	1.3	1.3	1.3
Circuit line length	-	0.2	2.2	7.7	-	-	-
Total output growth	**0.1**	**0.2**	**1.2**	**4.2**	**0.1**	**0.4**	**0.5**

Rate of change – Prices

Our base year opex reflects the current prices of our cost inputs. Real changes in input costs capture real changes in labour and materials costs over the 2023-28 period.

We commissioned BISOE to forecast real labour escalators for the 2023-28 period[43] and did not include a real increase in materials costs in our expenditure forecasts.

The AER accepted our proposal to incorporate forecast real escalation for labour costs in our opex forecast and not for materials. However, the AER adopted an alternative forecast from KPMG.

We have updated our labour cost escalators based on the latest available information. We have retained the historically accepted approach of averaging KPMG's forecast and a new updated forecast prepared by BISOE to reflect more recent information since our initial Revenue Proposal. We consider that an average of two independent forecasts provides a better estimate than relying on one, provided they both measure the labour costs that are likely to apply to us – which in our view they do.

Table 3-5 shows the two forecasts and the simple average of them over the 2023-28 regulatory period. The BISOE forecast is provided as an Attachment to this Revised Revenue Proposal.

[42] AER, Annual Benchmarking Report – Electricity transmission network service providers, November 2021.
[43] BISOE, Labour escalation forecast to 20-27/28 – prepared by BIS Oxford Economics for Transgrid, December 2021.

Table 3-5: 2023-28 opex - updated forecast real labour price growth 2023-28

Real labour price growth (%)	2023-24	2024-25	2025-26	2026-27	2027-28	Average
BISOE	0.83	0.97	0.91	0.52	0.18	0.68
KPMG	0.16	1.10	0.85	0.47	0.48	0.61
Average	0.49	1.03	0.88	0.49	0.33	0.65
Superannuation guarantee	0.50	0.50	0.50	-	-	0.30
Price rate of change	0.99	1.53	1.38	0.49	0.33	0.95

Rate of change – Productivity

The productivity growth factor reflects forecast productivity improvements. Consistent with the AER's preferred methodology, our initial Revenue Proposal included a forecast opex productivity improvement of 0.5 per cent per annum.

The AER accepted our productivity forecast.

We have accepted the AER's Draft Decision and retained a forecast productivity improvement of 0.5 per cent per annum in this Revised Revenue Proposal.

3.6. Specific or category costs

Our initial Revenue Proposal included two category specific forecasts: debt raising costs and network support costs. These costs are treated as 'category specific' forecasts because they are more appropriately forecast using a bespoke methodology.

3.6.1. Debt raising costs

The AER accepted our forecasting approach for debt raising costs and network support costs but did not accept the forecast amount. While we have accepted the AER's assumptions in its Draft Decision, the higher RAB proposed in this Revised Revenue Proposal has increased our debt raising costs as shown in Table 3-6.

Table 3-6: Opex – debt raising costs - our initial forecast, the AER's Draft Decision and our revised forecast ($M, Real 2022-23)

Category costs	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
Debt raising costs	25.7	23.4	25.7

3.6.2. Network support costs

Our initial Revenue Proposal explained that we were actively exploring network support options in a number of areas, to defer or supplement network investment. Our initial Revenue Proposal included a value of zero for network support costs in the 2023-28 regulatory period and explained that we would use network support cost pass through provisions under the Rules to recover these costs should they arise during the period.

As explained in Section 4.10.1.4, we have recently completed the RIT-T for several major Augex projects. As part of the RIT-T consultation process, we have identified opportunities to adopt innovative technologies to provide non-network solutions. This has substantially reduced our Augex forecasts for the 2023-28 regulatory period. We are currently progressing commercial negotiations with non-network service providers. These negotiations are not expected to conclude until after the AER makes its Final Decision in April 2023.

We will rely on the network support cost pass through arrangements under the NER clause 6A.7.2 to recover the costs of non-network services. The actual level of network support payments passed through to customers will be determined by the amount that we are required to pay under the commercial contracts with non-network proponents. We will seek confirmation from the AER that the level of these costs is prudent and efficient prior to these costs being incurred.

3.7. Step changes

Our initial Revenue Proposal included three step changes totalling $57.8 million for the 2023-28 period, for insurance premiums, cyber and critical infrastructure security, and ISP preparatory activities.

In its Draft Decision, the AER reduced our step changes for insurance premiums and cyber and critical infrastructure security and rejected our step change for ISP preparatory activities. This is shown in Table 3-7.

Table 3-7 2023-28 step changes – AER's Draft Decision and our initial Revenue Proposal

	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Insurance premiums	30.0	13.8	(16.1)	(54)
Cyber and critical infrastructure security	25.0	13.9	(11.1)	(44)
ISP preparatory activities	2.9	0.0	(2.9)	(100)
Total	57.8	27.7	(30.1)	(52)

This Revised Revenue Proposal accepts some aspects of the AER's Draft Decision on our step changes but does not accept others:

We accept the AER's draft decision to:

- reduce our insurance premium step change of $30.0 million by $16.1 million or 53.8 per cent to $13.8 million. While the AER accepted AON's forecast for the 2023-28 period, it:
  - > removed costs associated with network growth or scale to avoid double counting, and
  - > used 2022-23 as the base year, rather than our proposed 2021-22 base (which is used to forecast other expenditure categories). Given that our 2022-23 insurance costs are higher than our 2021-22 costs, this reduces the step change amount.
- reject our ISP preparatory activity step change of $2.9 million. In line with feedback from our TAC, we accept the AER's Draft Decision. We remain committed to undertaking these activities and will fund these through the recurrent base year allowance.

We do not accept the AER's alternative estimate of $13.9 million for cyber and critical infrastructure security. The AER reduced our initial forecast of $25.0 million by $11.1 million or 44.4 per cent because it considers:

- our 2021-22 base year opex is higher than our average expenditure over the 2018-23 period and that this higher amount (i.e., the increment) should be deducted from our base opex. The AER therefore deducted $9.8 million to avoid double counting this amount
- we have had sufficient time to achieve Security Profile-2 (SP-2) in the 2018-23 period. The AER has therefore deducted $2.4 million (Real 2020-21) for activities that it considers we should have undertaken in the 2018-23 period, and
- that we have not provided sufficient evidence to support our physical security external assurance activities of $1.0 million (Real 2020-21)

Our response to the AER's Draft Decision on this step change is discussed in Section 3.7.1.

We have added two new step changes to address recent changes in our regulatory obligations and our operating environment:

- NSW Government's Strategic Benefit Payments to landholders – $31.0 million. This is discussed in Section 3.7.2, and
- System Security Roadmap – $47.6 million. This is discussed in Section 3.7.3

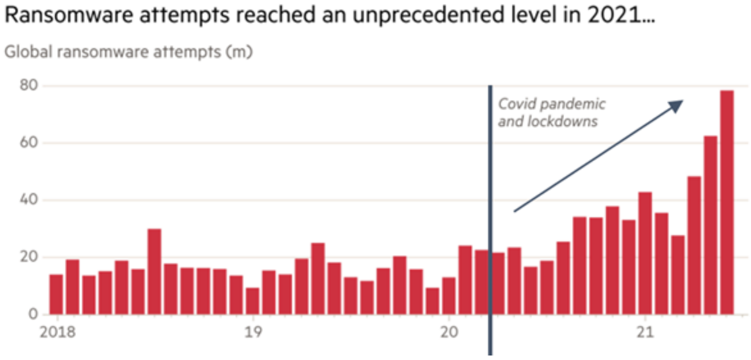
3.7.1. Cyber and critical infrastructure security costs

This Revised Revenue Proposal maintains our initial critical infrastructure security step change costs, which relate only to the SOCI Act pillar 1 'cyber' and pillar 2 'physical and natural hazards'. We have increased our initial costs to address the new requirements for the additional elements of the SOCI Act, being pillar 3 'personnel', pillar 4 'supply chain' and the overarching critical infrastructure risk management plan, which were published on 15 December 2021. Given this timing, we were unable to incorporate the costs of these additional requirements in our initial Revenue Proposal and committed to revisit them in our Revised Revenue Proposal.

Our network operates in a rapidly deteriorating cyber security environment. Since 2020, we have experienced a significant increase in global cyber activity, particularly in ransomware events during the COVID pandemic as shown in Figure 3-1. The Australian Cyber Security Centre (ACSC) recently reported that Australian Government and organisations experience a cyber-attack every 7 minutes, an increase of nearly 13 per cent from the previous year.[44] The Parliamentary Joint Committee on Intelligence and Security has also reported that every 32 minutes there is a cyber-attack on Australia's critical infrastructure. Detected cyber events in our network are growing significantly, with 8 billion events logged in September 2022 alone, and attacks only increasing.

[44] ACSC Annual Cyber Threat Report 2021-22, Executive Summary.

Figure 3-1: Ransomware attempts since 2018



Within the last 12 months, ransomware has caused extended 'organisational paralysis' exceeding five weeks duration in other Australian energy organisations (e.g., CS Energy). It is becoming increasingly difficult to mitigate cyber threats:

- as criminal and nation-state activity from well-resourced countries like Russia and North Korea increases, and
- nearly all major incidents show that cyber threats encompass other aspects, such as supply-chain compromise, physical compromise and human mistakes or coercion.

Our critical infrastructure 'attack surface' (i.e., points of entry) is challenging to protect and much bigger than that of generators and retailers. It includes:

- a wide geography of 12,969 km of high-voltage transmission network
- 17 tier 1 and 78 tier 2 substations
- 85 radio repeater stations, and
- 4,200 km of optical cable.

Our investment in AEMO's Actionable ISP projects to support the energy transition will further expand the attack surface of the network and introduce more IP-based devices, which will in turn require a broader control coverage. EnergyConnect alone, which is currently under construction, will add almost 1,400 km of transmission line to our high-voltage network. HumeLink and VNI West will increase this even further.

Given the vast and increasing geographic scale of our operations, the benefit of robust and maturing physical security controls and the need for external assurance, activities to validate our controls and identify gaps are critical. We have seen direct evidence of rising cyber risks through the significant growth of detected cyber events in our network. To date, this increasing malicious cyber activity has been managed through the existing investments in cyber capabilities and risk mitigations. However, as threat actors and our vulnerabilities change, our cyber sophistication and capabilities need to evolve and expand.

The growing cyber threat has the potential to impact the stability and safety of our transmission network, as well as the confidentiality of load and customer data that is covered by licence conditions. Our current risk management framework and controls must be regularly re-evaluated to validate whether they remain sufficient in the context of growing threats.

We must continue to invest in cyber and physical security to manage the evolving cyber risks. [redacted]

3.7.1.1. Our initial Revenue Proposal

Our initial Revenue Proposal includes an opex step change of $25.0 million to enable us to comply with the Australian and State Governments' enhanced cyber and physical security obligations under the:

- *Energy Legislation Amendment Act 2021* (NSW),[45] which was assented to in November 2021. This introduces obligations for managing cyber security risks and responding to cyber security incidents, and
- SOCI Act, which introduces obligations on a range of sectors (including electricity) to ensure the physical and electronic security of Australia's critical infrastructure. The SOCI Act was amended in 2021 and 2022 by the:
  > Security Legislation Amendment (Critical Infrastructure) Act 2021,[46] and
  > Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (SLACIP Bill)[47]

The enhanced legislative framework comprises four pillars that seek to manage national security risks of sabotage, espionage and coercion posed by foreign involvement in Australia's critical infrastructure:

- Pillar 1 – cyber
- Pillar 2 – physical and natural hazards
- Pillar 3 – personnel, and
- Pillar 4 – supply chain.

These pillars are held together by a critical infrastructure risk management plan that aims to minimise and mitigate the effects of a hazard being realised.

In 2018, AEMO, in conjunction with industry and government stakeholders, developed the Australian Energy Sector Cyber Security Framework (AESCSF), which provides a standardised approach for energy market participants to assess their state of cyber security and capability to inform potential actions to become more resilient in the face of a cyber-attack. The AESCSF has two measures of cyber security capability and maturity:

- Maturity Index Levels (MIL) 0 to 3, and
- Security Profiles (SP) levels 0 to 3.

We have been reporting our cyber security maturity in accordance with the AESCSF since 2018.

Under the enhanced cyber and physical security legislative framework we must increase our security profile. Achieving SP-3 in accordance with the AESCSF will ensure that:

- our network is protected against cyber and physical infrastructure threats, and
- we maintain the security and reliability of our network expected by our stakeholders and other customers.

At the time of submitting our initial Revenue Proposal to the AER in January 2022:

- the enhanced legislative framework was available in draft only. This meant that there was significant uncertainty around the requirements for the personnel and supply chain pillars (i.e., pillars 3 and 4).

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[45] NSW Government, *Energy Legislation Amendment Act 2021,* November 2021.
[46] Australian Government, *Security Legislation Amendment (Critical Infrastructure) Act 2021*, December 2021.
[47] Australian Government, Security Legislation Amendment (Critical Infrastructure Protection) Act 2022, April 2022.

Given this uncertainty, our initial step change included only the incremental costs (above our 2021-22 base year) for the cyber and physical and natural hazards pillars (i.e., pillars 1 and 2)

- our AESCSF cyber security maturity assessments were based on our self-assessments. We had not commissioned an external assessment or review of our cyber security maturity
- based on our 2020-21 AESCSF self-assessment, which was the most recently available, we anticipated that we would achieve SP-1 by 2021-22 and commence some SP2 and SP3 activities in 2021-22. The forecast cost for these activities was $1.5 million and we deducted this cost from our step change to avoid any double counting, and
- our step change included incremental costs to achieve SP-3 in the 2023-28 period. Our intention was (and remains) to achieve SP-2 by January 2025 and SP-3 (the highest classification) by 2027. This will ensure that we achieve the highest standard in cyber security practice, which is paramount given the criticality of our transmission network to the electricity supply across the NEM.

Based on the above, we determined that the unavoidable annual increase in our opex over the period 2021-22 to 2027-28 to achieve SP-3 was $26.5 million. As noted above, we deducted $1.5 million for activities related to SP-2 and SP-3 that we expected to incur in 2021-22 to avoid any double counting. Table 3-8 shows how we determined our initial step change of $25.0 million.

Table 3-8: Initial critical infrastructure security step change

Category	Total incremental opex to achieve SP-3[1] 2021-22 to 2027-28	*Less* Incremental opex to achieve SP-3 2021-22 only	Incremental opex to achieve SP-3 2023-24 to 2027-28
ICT	19.1	(0.5)	18.6
OT	3.6	(0.1)	3.5
Physical	3.7	(0.9)	2.8
Total	**26.5**	**(1.5)**	**25.0**

Notes: we anticipated that we would achieve SP-1 before the end of the 2018-23 period, which would enable us to progress towards SP-3 in 2021-22. These activities were forecast to cost $1.5 million. We deducted these from our step change to avoid any double counting of costs in our 2021-22 base year.

3.7.1.2. Changes since submitting our initial Revenue Proposal

Since submitting our initial Revenue Proposal in January 2022, a number of changes have occured, including in:

- April 2022, when the SLACIP Bill was enacted, confirming the legislative requirements to increase our security profile under all four pillars of the enhanced legislative framework. In line with AEMO's expectations, we will increase our security profile to SP-3, and
- May 2022, when we commissioned our first external review (independent verification)[48] of our cyber security maturity for our 2021-22 AESCSF annual assessment to AEMO.[49] This found that our maturity to SP-1 was not as advanced as our 2020-21 self-assessment. In particular, it found that we were only 95 per cent of SP-1 and that we now intended to reach SP-1 by January 2023, in line with the

48 We commissioned Secolve Pty Ltd an external consultancy specialising in OT/IT Security to provide an independent and unbiased view of our AESCSF maturity.

49 We submitted our 2021-22 AESCSF to AEMO on 30 June 2022.

enterprise security strategy portfolio rollout and our regulatory obligation under the SOCI Act. We provided the independent verification of our cyber security maturity to the AER and its consultants.

Based on the final legislation and our 2021-22 independent AESCSF assessment, we:

- reviewed the activities and associated forecast costs for pillars 1 and 2 that we included in our initial Revenue Proposal, confirming that these remain unchanged, and
- identified activities required to address pillars 3 and 4, as well as the overarching risk management plan for inclusion in our Revised Revenue Proposal.

3.7.1.3. The AER's draft decision and our response

The AER's Draft Decision reduced our initial step change of $25.0 million by $11.1 million or 44 per cent to $13.9 million. The AER's consultant, Energy Market Consulting associates (EMCa) concluded that for:

- ICT and OT cyber security – the AER agreed that we should achieve a AESCSF maturity level of SP-1, SP-2 and ultimately, SP-3 as soon as practicable. The AER and its consultants also found the following to be reasonable:
  > our 'gap analysis' (and corresponding opex step change estimate) between our self-assessed maturity level in early 2021 and SP-3
  > our initiative development principles, strategy and activities, and
  > our associated cost estimates.
- physical security – we selected the appropriate option based on addressing the gaps between our current practices and the Positive Security Obligations arising from the SLACIP Bill 2022. The option appropriately focusses on critical sites.

However, EMCa also found that for:

- ICT, OT and physical security – our 2021-22 base year opex is higher than our average expenditure over the 2018-23 period and we have not deducted this higher amount (i.e., the increment) from our base. As a result, EMCa considers that our step change double-counts the higher than average expenditure in our base year. EMCa has reduced the step change accordingly to remove the incremental expenditure in our base year
- ICT cyber security – according to EMCa, we slowed our progress towards achieving SP-2 (and therefore SP-3) and had sufficient time since our last AESCSF self-assessment to implement the activities necessary to achieve SP-2 by the end of the current 2028-23 regulatory period. EMCa concluded that:

  In summary, we consider that Transgrid has provided a compelling case for it to target achievement of the AESCSF SP-3 maturity level. However, Transgrid has provided no business-related reason for having slowed its security enhancement program in the remainder of the current RCP, deferring it from this period and planning to ramp it again from the beginning of the next RCP. We conclude that Transgrid should have continued its program throughout the current RCP at a rate sufficient to achieve SP-2 by June 2023, or possibly sooner.

- physical security – we selected the appropriate option to address our new obligations at a cost of $1.8 million, reflecting Option PS2 in our business case. We also included additional external assurance activities of $1.0 million, taking our total step change proposal for physical security to $2.8 million. EMCa found that these costs for external assurance activities were not justified and reduced our forecast opex of $2.8 million by $1.0 million to $1.8 million, which aligns with the cost component in our business case.

Table 3-9 AER's draft decision - 2023-28 critical infrastructure step change ($M, Real 2022-23)

Category	Initial Revenue Proposal	AER base year adjustment	AER – adjustment for 'slowing down' in 2018-23	AER – removal of assurance costs	AER's Draft Decision
ICT	18.6	(4.3)	(2.5)		11.8
OT	3.5	(2.9)			0.6
Physical	2.8	(1.2)		(1.0)	0.6
Total	25.0	(8.4)	(2.5)	(1.0)	13.9

We do not accept the AER's reduction of these costs, noting that our forecast opex in the 2023-28 period to achieve SP-3 is consistent with practical implementation timeframes for security uplifts in the industry. We do not agree that the amount proposed by the AER in its Draft Decision is sufficient to enable us to uplift our security from SP-1 at the end of the current regulatory period to achieve SP3 and meet our new legislative requirements in the 2023-28 period.

In relation to our security obligations and costs, we note that:

- all of the ICT and OT related expenditure that we incurred in the current 2018-23 period was required to achieve SP-1 by 2022-23. As per our external 2021-22 AESCSF assessment, which we provided to the AER and its consultants, we will only achieve SP-1 in the last year of the current regulatory period. We have therefore not undertaken any SP-2 or SP-3 activities in the current 2018-23 period
- our 2022-23 costs for SP-1 reflect the ongoing costs to maintain compliance with SP-1 in each year of the 2023-28 period. The forecast opex associated with SP-2 and SP-3 is incremental to these costs, and
- our initial step change relates only to SP-2 and SP-3 activities for pillars 1 and 2.

We engaged Deloitte to independently review and verify our cyber and physical security step change. Deloitte's independent opinion, which is provided as an Attachment to this Revised Revenue Proposal confirms that:

- our cyber and physical security activities and initiatives in the current 2018-23 period are prudent and the associated costs are reasonable
- our opex step change and our proposed timeframes to achieve SP-2 and SP-3 over the 2023-28 period are comparable with Australian energy industry norms and Deloitte's own experience of AESCSF cyber uplift programs for other market participants of similar size and position as many of the areas of cyber and physical security uplift require an increase in recurring opex to sustain maturity
- The basis for the AER's Draft Decision reductions largely hinge on us achieving most of the SP-2 by June 2023 or sooner. However, this is not realistic becuase:
  - our starting position is materially lower than we initially self-assessed in January 2021. This has increased the scope of work that must be undertaken to achieve SP-1, SP-2 and SP-3.

> [redacted] which caused resources to be reprioritised to address the root cause(s), and

> achieving SP-2 requires a considerable uplift compared to our current position, which goes beyond just technology implementation. Like other NSPs, we have non-financial constraints as to how swiftly we can transform. Deloitte notes that finite capacity to run concurrent organisational and technology change is the key reason that AESCSF uplift programs are running slower than planned in other TNSPs and DNSPs.

Deloitte explains that EMCa has understated the effort required to achieve SP-2, describing EMCa's target date of June 2023 as unrealistic. Specifically, Deloitte explains that the challenges arising from SP-2 are significant:

> *..the shift to the concept of Security Profiles threshold requires a more sequential approach because an organisation can only achieve a given Security Profile if it achieves the required maturity level in every domain of the framework. While this may seem straightforward, it increases the complexity (time, cost and effort) required to progress from one Security Profile to the next.*

> *[…]*

> *Achieving SP-2 requires a considerable amount of uplift from the current position, which goes beyond just technology implementation. In common with other TNSPs and Distribution Network Service Providers (DNSPs), Transgrid has non-financial constraints as to how swiftly it can transform across 11 AESCSF domains in parallel, such as capacity for organisational change, regulatory conditions, and the bandwidth of (and access to) key staff and subject matter experts to support transformation workstreams.*

EMCa's suggestion that we have chosen to delay our implementation of SP-1 and SP-2 is incorrect. In part, this reflects an understatement of the implementation challenges, as noted above. In addition, EMCa's position also fails to account for the progress made by other NEM organisations in achieving these milestones. As Deloitte explains, few organisations have achieved SP-1 or SP-2:

> *Only 21 (approximately 15%) of the 139 entities that have made submissions to the AEMO AESCSF Portal have achieved SP-1. Furthermore, only 1 of the 139 entities has achieved SP-2, with another 7 being close (approximately 5%). It is not understood which of these entities has had their maturity level validated independently, nor how many are TNSPs.*

Given these observations, it is not reasonable to conclude that we have delayed the implementation of these important measures to address cyber risk.

In examining all the available information, Deloitte sets out its professional opinion as follows:

> *Our* concluding *opinion is that any reduction to Transgrid's Cyber OPEX funding will constrain it from adequately delivering a holistic program of cyber maturity uplift and risk reduction initiatives, and ongoing maintenance/ operation of capabilities (both current and uplifted) necessary to achieve AESCSF SP-3. Moreover, the number of cyber developments since the original funding request and the likelihood of additional factors in the 2023-28 period (not least the volatility of cyber as a strategic threat) mean there is a high probability that additional cyber funding will be required within the 2023-28 regulatory period.*
>
> *In drawing* these *conclusions we note that Transgrid is rated as a "high" criticality market entity according to the AESCSF Electricity Criticality Assessment (E-CAT), due to the high potential of critical impact to wider Australian society (and other critical infrastructure entities) from a sustained*

core systems failure. This elevates the significance of the adequacy of cyber capability and risk management at Transgrid compared to other market participants.

This Revised Revenue Proposal therefore:

- maintains the SP-2 and SP-3 opex forecast in our initial Revenue Proposal of $25.0 million for pillars 1 'cyber' and 2 'physical and natural hazards'. We have increased this by $1.5 million to $26.5 million for the SP-2 and SP-3 activities that we expected to undertake in 2021-22, but that will in fact be undertaken in the 2023-28 period, and
- includes unavoidable annual increases in our opex for pillar 3 'personnel' and pillar 4 'supply chain' as well as for the overarching risk management plan. Further detail is contained in the business case for this investment, which is provided as an Attachment to this Revised Revenue Proposal.

Table 3-10 details the unavoidable annual increases in our opex associated with meeting all four pillars of the Australian Government's new cyber and physical security obligations, as well as developing the overarching risk management framework to achieve SP-3.

Table 3-10: Critical infrastructure security costs – opex step change ($M, Real 2022-23)

Initiative	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial step change (pillars 1 and 2)[1]	5.6	5.1	5.6	5.1	5.6	**26.8**
Pillar 3 - personnel	0.7	0.4	0.4	0.4	0.4	**2.3**
Pillar 4 - supply chain	0.6	0.5	0.5	0.5	0.5	**2.4**
Risk management framework	1.0	1.0	1.0	1.0	1.0	**4.8**
Total	**7.8**	**6.9**	**7.4**	**6.9**	**7.4**	**36.3**

Note: 1. This includes $1.5 million that we initially deducted for SP-2 activities that we anticipated would be undertaken in 2021-22 but that have not eventuated in the current period.

3.7.2. Strategic Benefit Payments to EnergyConnect landholders

The NSW Government is committed to transform NSW's electricity system into one that is cheaper, cleaner and more reliable. To facilitate the timely delivery of the ISP investments needed to transform the energy system, the NSW Government has introduced a Strategic Benefit Payments (SBP) scheme to compensate private land holders impacted by these projects.[50]

The proposed SBP scheme will provide additional compensation to private landowners in NSW who sell their land for the transmission easements required to enable the construction of Actionable ISP Projects, such as EnergyConnect, HumeLink and VNI West. These payments:

- acknowledge the critical role these landowners have in hosting the new energy infrastructure that will power NSW into the future, and
- ensure that these landholders share directly in the benefits of this significant economic investment.

These payments comprise annual payments for a period of 20 years and are separate and in addition to compensation under the *Land Acquisition (Just Terms Compensation) Act 1991* (Just Terms Act).

The SBP scheme will apply to major transmission projects including:

[50] NSW Government, Strategic Benefit Payments Scheme, October 2022. This requires that annual payments for a given line are calculated, in $ Real 2022, as eligible line length KMs x $200,000 / 20 years.

- Actionable ISP Projects, which are regulated under the NER, including EnergyConnect, HumeLink and VNI West, and
- NSW Government PTIPs, which are regulated under the NSW EII Regulations. These projects include the Central-West Orana REZ Transmission Project and Hunter Transmission Project.

The opex step change in this Revised Revenue Proposal only includes the costs for payments to private landholders for EnergyConnect. Payments required for other projects will be included as part of our future contingent project applications.

Table 3-10 sets out the unavoidable annual increases in our opex associated with Strategic Benefit Payments to EnergyConnect landholders for the 2023-28 period.[51]

Table 3-11: Strategic benefit payments to EnergyConnect landholders – opex step change ($M, Real 2022-23)

Step change	2023-24	2024-25	2025-26	2026-27	2027-28	Total
EnergyConnect Strategic Benefit Payments	1.7	7.3	7.3	7.3	7.3	31.0

Strategic Benefit Payments to Landowners

We are proposing $31.0 million to fund the NSW Government's SBP for landowners hosting EnergyConnect transmission assets. Under the SBP scheme, private landowners hosting new high voltage transmission projects critical to the energy transformation will be paid $200,000 per kilometre of transmission lines hosted, in annual instalments over 20 years, linked to CPI.

These payments will be in addition to the 'just terms' compensation paid to these landowners for transmission easements on their land, ensuring that they share directly in the benefits of these new transmission projects.

The SBP scheme will apply to private landowners hosting new transmission projects that are required for the energy transition under AEMO's ISP and the NSW Government's Electricity Infrastructure Roadmap. The payment will not apply to public land (including council land), minor operational projects or minor interest holders.

The payments will make a significant difference to landowners with planned infrastructure on their properties. Once EnergyConnect is commissioned, we will make these annual payments to private landowners.

Our Revised Revenue Proposal therefore includes the future Strategy Benefits Payments for EnergyConnect in 2023-28 as an opex step change, as the contingent project application for

51 Under the NSW SBPS, payment commence once the line is energised. For EnergyConnect, the payments commence in 2023-24 following practical completion on 28 July 2023 for the Buronga – SA Border and Buronga – Red Cliffs sections.

EnergyConnect has already been approved. The opex associated with payments for future projects, such as HumeLink and VNI West, will be included in their contingent project applications.

3.7.3. System Security Roadmap

In our initial Revenue Proposal, we explained that AEMO's NEM Engineering Framework Initial Roadmap, published in December 2021, identified that urgent and significant investment is required to address the energy transition and the increase in instantaneous renewables:[52]

> *urgent and extensive industry collaboration and effort is needed to engineer the power system to meet* these *new conditions in a timely and orderly manner, with positive consumer outcomes at the heart of all decision-making.*

Due to the timing of AEMO's announcement in December 2021, our initial Revenue Proposal did not include the costs of readying our network for 100 per cent renewables. Rather, our initial Revenue Proposal explained that we would include the costs in our Revised Revenue Proposal subject to:

- undertaking further work to determine the scope and the associated cost of the investment required to facilitate an orderly transition towards this future state, and
- consulting with the TAC and other customers on the scope and associated costs of this work.

In February 2022, Origin Energy advised AEMO that it will close the Eraring Power Station – Australia's largest coal-fired power station – seven years earlier than previously planned. This represented a major acceleration in NSW's electricity transformation.

In its 2022 ISP published in June 2022, AEMO reconfirmed the need for urgent and significant investment in our network to maintain the secure operation of the NEM as it transitions to 100 per cent renewables:[53]

> *Uplifts are needed in in real time monitoring, power system modelling, and control room technologies by AEMO and Network Service Providers, to ensure operational staff have the tools to maintain secure operation of the NEM power system as it transitions to significant penetrations of inverter-based resources including Distributed Energy Resources. AEMO has developed a strategic roadmap for this uplift.*

Since submitting our initial Revenue Proposal, we have commissioned independent power system expert, PowerRunner, to advise us on the nature and scope of investments required to enable us to continue to plan, maintain and operate securely as we transition towards higher penetrations of renewables. This is informed by PowerRunner's assessment of our capability gap and global best practice. As explained in Chapter 4, based on the outcomes of this assessment, we have included the following operational technology capital projects:

- Situation Awareness Operational Technology tools, and
- Digital Twin technologies.

We will also incur unavoidable annual increases in our opex as a result of:

[52] AEMO, NEM Engineering Framework Initial Roadmap, December 2021, p. 6.
[53] AEMO, 2022 ISP, June 2022, p. 58

- ongoing annual licensing and maintenance costs. These costs are required to operate and maintain the new Digital Twin and Situation Awareness Operational Technology tools, including annual vendor software maintenance costs and application support, and
- capacity uplift involving additional staff, skills sets and training. Forty-six additional staff are required to plan, operate and maintain an increasingly complex network and maintain secure grid operations throughout the 2023-28 period. The additional staff will have new skillsets that are required to support the increasing requirements and complexity of network planning, asset monitoring and system operations.

We discussed the drivers, scope and expected outcomes from this project with the TAC at our System Security Roadmap (SSR) Working Group, Energy Transition Working Group (ETWG) workshops and Revenue Reset deep dives. The TAC raised concerns about the input risk assumptions and requested:

- further sensitivity testing of the investment
- a plain English explanation of why this investment is in the long-term interest of customers, and
- evidence that our approach is coordinated with the broader industry to ensure that customers will only be paying once for this investment.

We are grateful for the TAC's feedback and acknowledge that the TAC has raised important issues that required further analysis and revisions. Further details of how we have responded to the TAC's feedback on these matters are discussed in Section 4.10.1.1.

Table 3-12 overviews the nature of additional required roles.

Table 3-12: Additional staff requirements

Function	Additional staff and skill set
System Operations (15 additional FTEs in 2027-28)	Control room operators, control room trainer, outage planning function, operations analysis, operations manager, asset monitoring (including asset condition monitoring, CCTV/Security, procurement of easements), SCADA connections and uplift in personnel training
System Planning (17 additional FTEs in 2027-28)	Connection studies, developing limit equations for thermal retirements, subsystem planning, power system modelling, non-network options, new technology assessment, system strength, 100 per cent renewable studies and uplift in personnel training
Asset Management (additional 14 FTEs in 2027-28)	Digital infrastructure capacity, asset standards for new technology, transmission line capacity, outage impact analysis, asset data and systems capability, analyst, substation capacity and uplift in personnel training
Total 46 additional FTEs per annum by 2027-28	

Table 3-13 details the additional full-time staff (FTEs) required in each year of the next regulatory period, showing that the number of additional FTEs increases steadily over the period from 30 in 2023-24 to 46 by the end of the period. The number of additional FTEs will remain at the 2027-28 level for each year beyond that date.

Table 3-13: Expected increase in staff required over the 2023-28 period

	2023-24	2024-25	2025-26	2026-27	2027-28
FTE increase from FY22 base year	29	35	39	45	46

Table 3-14 details the unavoidable annual increases in our opex associated with this project from the capacity uplift (i.e., additional staff) and ongoing annual Operating Technology licensing and maintenance costs.

Table 3-14: System security roadmap opex step change ($M, Real 2022-23)

Initiative	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Additional FTEs	6.8	8.2	9.0	10.3	10.5	44.9
Annual licensing & maintenance	-	-	0.7	1.0	1.0	2.7
Total	**6.6**	**8.2**	**9.8**	**11.3**	**11.5**	**47.6**

3.8. Our revised opex forecast

Table 3-15 details our revised base-step-trend forecast opex over the 2023-28 regulatory period, which is a summation of the above components.

Table 3-15: Updated 2023-28 opex forecast ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
2021-22 base opex	203.7	203.7	203.7	203.7	203.7	1,018.5
Adjustment to 2022-23	(8.5)	(8.5)	(8.5)	(8.5)	(8.5)	(42.5)
Output growth	2.3	10.7	10.9	11.5	12.5	47.9
Price growth	1.4	3.5	5.4	6.1	6.6	23.0
Productivity growth	(1.0)	(2.0)	(2.9)	(3.9)	(4.8)	(14.5)
Step changes	17.3	24.4	27.3	29.1	30.6	128.8
Total excluding debt raising costs	**215.3**	**231.8**	**235.8**	**238.1**	**240.1**	**1,161.2**
Debt raising costs	5.0	5.2	5.2	5.2	5.1	25.7
Total including debt raising costs	**220.2**	**237.0**	**241.1**	**243.3**	**245.2**	**1,186.9**

3.9. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
BIS Oxford Economics – Labour Escalation Forecasts to 2027-28
Deloitte – Transgrid Cyber and Physical Security AER Pricing Review Opinion Letter
Enhanced Supply Chain, Personnel and Risk Management Plan Business Case
PowerRunner – System Security Roadmap technical report
CutlerMerz – System Security Roadmap assurance report
OER-N2761 System Security Roadmap Technology and Human Resource uplift

4

Revised capex forecast

Transgrid

4. Revised capex forecast

Key messages:

- In this Revised Revenue Proposal, we are proposing total capex for the 2023-28 period of $1,644.7 million (excluding pre-approved forecast capex), reflecting a $276.2 million or 20.2 per cent increase from our Revenue Proposal. This compares with the AER's Draft Decision of $1,220.6 million.
- In its Draft Decision, the AER explained that we:
  > did not provide sufficient justification for some aspects of our initial capex forecast
  > should update our business cases to address the AER's concerns, and
  > have not demonstrated our ability to deliver our BAU 2023-28 capital works program.
- In preparing this Revised Revenue Proposal, we have:
  - empowered the TAC to shape how we should respond to the AER's Draft Decision and sought its views and feedback on new additional capex in response to developments outside our control since our initial Revenue Proposal. Our revised capex forecast is in line with the TAC's feedback
  - developed a Deliverability Plan, which explains that we are aware of, and prepared for, the resource challenges in the 2023-28 period. The Plan sets out the structural and operational changes we have made to de-risk the deliverability of our 2023-28 capex program from AEMO's ISP projects
  - updated the unit rates underpinning our Repex and Augex forecasts from 2020-21 to 2021-22, which are the latest available and reflect the high and unexpected inflation over the 12 months ending June 2022. Our 2021-22 unit rates reflect current market pricing and therefore provide the appropriate starting point for determining our future capex requirements
  - largely maintained our original scope for Repex. After carefully reviewing the issues raised in the AER's Draft Decision, and undertaking extensive new analysis, we have formed the view that, subject to some refinement, our original scope is more efficient for customers. Where possible, we have revised down parts of our forecast to respond to matters raised by the AER
  - updated our Augex forecast in line with the AER's Draft Decision and feedback from the TAC by removing four projects for which there is uncertainty regarding the forecast load growth or net economic benefits. We have reinstated and increased our forecast for our 'Maintain Voltage in Alpine area' project based on updated load forecasts from Essential Energy
  - updated our initial capex forecast to include additional capex for recent development outside our control including:
    > our System Security Roadmap project, in response to the accelerated energy transition
    > AEMO's directions to install PMUs and address an NSCAS gap
    > a new customer connection request from Essential Energy, and
    > network investments required by our recently completed RIT-T
- largely maintained our Non-network ICT capex forecast based on the AER's top-down forecasting approach updated to reflect our actual 2021-22 and revised 2022-23 estimated costs. This shows that our initial bottom-up forecast is efficient and necessary to enable us to deploy new technology and continue to refresh or replace legacy applications and systems at the end of their lives.

4.1. Overview of our revised capex forecast

Our revised forecast capex of $1,644.7 million (excluding pre-approved capex) is $276.2 million or 20.2 per cent higher than our initial forecast of $1,368.5 million and $424.1 million or 34.7 per cent higher than the AER's Draft Decision of $1,220.6 million.

Table 4-1 compares our revised capex for the 2023-28 period to our Initial Revenue Proposal and the AER's Draft Decision. Our 2023-28 revised forecast capex comprises pre-approved and new forecast capex.

Table 4-1: 2023-28 capex – our initial forecast the AER's Draft Decision and our revised forecast capex ($M, Real 2022-23)

Capex category	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
Repex	797.6	675.9	883.7
Augex	253.6	240.3	422.8
Non-network ICT	86.9	77.4	88.0
Non-network Other[1]	71.4	75.6	75.9
Capitalised overheads	159.0	151.4	174.3
Total (excluding pre-approved capex)	**1,368.5**	**1,220.6**	**1,644.7**
Pre-approved EnergyConnect capex	532.8	530.7	989.3
Pre-approved HumeLink capex	0.0	0.0	69.8
Asset disposals	(22.0)	(22.0)	(27.4)
Total (including pre-approved capex)	**1,879.4**	**1,729.3**	**2,676.4**

4.2. Pre-approved capex

Pre-approved forecast capex relates to capex approved by the AER in the 2018-23 period for EnergyConnect Contingent Project Applications (CPA) that we expect to incur in the 2023-28 period.

Our initial Revenue Proposal explained that project delays mean that the delivery date for EnergyConnect is anticipated to be 2024-25 and that, as a result, we expect to spend $532.8 million of the total approved capex of $2,008.0 million[54] (pre-approved forecast capex) in the 2023-28 period. Based on the latest information, we understand that supply chain issues mean that we now expect to spend $989.3 million of the pre-approved 2018-23 capex in the 2023-28 period. This is largely due to:

- delays in detailed design impacting the construction start date
- global factors such as shipping and supply chain bottlenecks, impacting the procurement of long lead items, and
- the timing of seasonal studies and compulsory acquisition requirements delaying the Environmental Impact Statement processes and approvals, as well as the acquisition of property and easements.

Notwithstanding this change to the timing of undertaking capex, we are committed to delivering this project in line with the total approved capex allowance of $2,154.4 million and are not seeking any additional capex for EnergyConnect in this Revised Revenue Proposal.

54 Excluding equity raising costs.

We will add this pre-approved capex for EnergyConnect to our forecast for the first two years (i.e., 2023-24 and 2024-25) of the 2023-28 regulatory period.

The AER approved our HumeLink Stage 1 CPA in August 2022 with a total allowance of $306.1 million, of which we estimate $69.8 million will be incurred in the 2023-28 period. In line with feedback from the AER, our actual and forecast capex in this Revised Revenue Proposal does not include pre-approved capex for HumeLink Stage 1. We understand, however, that the AER will add this pre-approved capex to its Final Decision.

4.3. What we heard from our customers

As discussed in Chapter 2, we have actively engaged with the TAC on our revised capex forecast through our co-designed post-lodgement engagement deep dives. We empowered the TAC to shape how we should respond to the AER's Draft Decision and sought members' views and feedback on the new additional capex that is driven by new information and developments outside our control since our initial Revenue Proposal.

The TAC's response to the AER's Draft Decision and how we have responded is discussed in the remainder of this Chapter. In summary, the TAC considers on:

- Unit rates underpinning Repex and Augex – We should provide an independent review of the process for updating the unit rates from 2020-21 to 2021-22.
- Repex – We should resolve our differences on the efficient level of Repex directly with the AER given the technical nature of the expenditure, drivers and associated issues.
- Augex – We should exclude projects where demand uncertainty still remains.
- ICT – We should resolve differences on the efficient level of ICT directly with the AER.
- Non-network other – We should exclude sustainability initiatives for LED lighting and electric vehicles.

The TAC's feedback seeks to balance affordability, which is our customers' highest priority, with the need to ensure a sustainable level of capex, so as to not accrue problems for future customers, maintain existing performance and build a safe and reliable network for the future. As discussed in the remainder of this Chapter, our revised capex forecast has, where possible, taken on more risk by removing some projects and anticipates potential savings that may be obtained through non-network solutions.

Table 4-2 summarises what we heard from the TAC and other customers on our new additional capex since our initial Revenue Proposal and how we have responded in this Revised Revenue Proposal.

Table 4-2: Summary of feedback on new additional capex

Issues	What we heard	How we responded
System Security Roadmap	The TAC acknowledges that key assumptions underpinning the business case require further justification and sensitivity testing, including the: • risk of major system outages, which is assumed to be a 13 per cent likelihood of a NSW System Black event by 2030,[55] and	We have undertaken further sensitivity analysis for this investment, which confirms that, even if the likelihood of a system black out is as low as a 1.8 per cent increase (i.e., an increase from 2 per cent in 2021-22 to 3.8 per cent in 2029-30), it would still deliver a positive net benefit.

[55] This assumption is in the base case. A customer advocate considered that this seemed high.

Issues	What we heard	How we responded
	• level of risk mitigation achieved by the proposed 60 per cent uplift in capability and capacity.	We provided this analysis to the TAC at Deep Dive 5 workshop on 26 September 2022.
AEMO Directives	The TAC acknowledges that meeting AEMO's directive to maintain network reliability and security is beyond Transgrid's control. While Transgrid needs to respond to directives, Transgrid should demonstrate that it is 'respecting customers' dollars' and driving efficient delivery.	We have included the costs of responding to AEMO's directives in our revised Augex forecast. To ensure the costs in our Revised Revenue Proposal are as low as possible, we undertook a feasibility study to identify the most efficient approach to meet AEMO's directive. This study found that we can comply with AEMO's PMU Directives at a materially lower cost than estimated by AEMO. We have reflected this lower cost in our revised forecast capex.
Recently completed RIT-Ts	A number of stakeholders made the following points: • the inputs, assumptions and scenarios used in our non-ISP RIT-Ts should be agreed upfront with the TAC • Transgrid should provide more transparency in relation to confidential demand forecasts, and • Transgrid should, to the greatest extent possible, rely on the non-network component of the preferred solutions by: - adopting technological innovation in the provision of services (i.e., non-network solutions), and - deferring the later stages of solutions until it is clear that they are needed.	We have: • jointly, with the TAC, developed a term sheet with our default positions on the scenarios, inputs and assumptions for non-ISP RIT-Ts. We will periodically review this with the TAC • sought independent review and verification of demand forecasts for non-ISP RIT-Ts where spot loads are subject to confidentiality • sought to extend our use of non-network solutions where feasible • included a contingent project to manage uncertain future demand (for North West Slopes), and • as a result, only included $21.1 million in our capex forecast for recently completed RIT-Ts (compared to an indicative cost of $741.9 million in our initial Revenue Proposal). This comprises $11.8 million for 'managing risk on line 86' (Repex) and $9.3 million (Augex) to 'maintain reliable supply to North West Slopes'.

4.4. Our initial capex forecast

In our initial Revenue Proposal submitted on 31 January 2022, we forecast total capex of $1,368.5 million (excluding pre-approved forecast capex) for the 2023-28 regulatory period. This is $198.5 million or 12.7 per cent lower than our estimated capex of $1,567.1 million for the current 2018-23 period.

Our initial Revenue Proposal explained that our capex forecast is required to deliver a safe, secure and reliable service while supporting the energy transition. In particular, our initial capex forecast reflected our key operational challenges and the priorities identified by our customers, including:

- our ageing assets, which require replacement due to their condition, deterioration and obsolescence, the impact of climate-related extreme weather events and new cyber and physical security obligations. These challenges impact our network's safety, security and reliability
- pockets of strong maximum demand growth in some regions from mining and industrial precincts in regional NSW, urban development and data centres, and
- increased operational complexity of our network from large-scale variable renewable generation connecting to the NEM as part of the energy transition. This includes more widespread network congestion and decreasing minimum demand due to increased solar PV generation.

In terms of the drivers of each sub-category of our initial capex forecast capex:

- Repex is driven by the need to deliver a safe and reliable network as our network ages and condition-related issues increase. We will also:
  > invest to enhance our cyber and physical security capability and respond to the changing generation mix, and
  > focus on climate change and network resilience to maintain our network safety, reliability and security during extreme climate events.
- Augex (excluding capex on ISP projects) is driven by the need to:
  > address rapid localised load growth and spot loads in certain regions, including central west NSW, western Sydney, and north-west Sydney which, if not addressed, will lead to the network in those areas not complying with NER voltage stability and thermal limits and IPART's reliability standards, and
  > maintain compliance with voltage stability, which is being impacted by decreasing minimum demand as household solar PV generation increases.
- Non-network ICT capex will enable us to deploy new technology and continue to refresh or replace legacy applications and systems at end of life as our workforce grows to support the energy transition through our investment in AEMOs ISP projects and the NSW Government's PTIPs, and
- Non-network other capex is driven by the need to continue to provide safe, compliant and productive offices and depots to support the increase in our network operations activity and invest to maintain the suitability and safety of our fleet, plant and equipment.

We explained in our initial Revenue Proposal that we would:

- undertake further work to respond to changes arising from market variables and conditions, including the energy transition, which is occurring urgently to ensure low-carbon and low-cost energy, and
- incorporate, as appropriate, the network investment identified through the RIT-Ts that were underway at the time we submitted our initial Revenue Proposal but that were expected to be finalised by July 2022.

Our initial Revenue Proposal also explained the processes, inputs and methodologies we used to develop our forecast capex. These explanations have not been repeated in detail in this Revised Revenue Proposal, except where necessary to explain our revised capex forecast. Where the AER accepted programs from our initial Revenue Proposal, or where we have accepted the AER's Draft Decision, no further documentation has been submitted for these programs in this Revised Revenue Proposal.

4.5. The AER's Draft Decision

The AER did not accept our initial 2023-28 forecast capex of $1,368.5 million (excluding pre-approved forecast capex) as it was not satisfied that it reasonably reflected the capex criteria. The AER's substitute estimate of $1,220.6 million is 10.8 per cent below our initial forecast capex and is 22.1 per cent below our 2018-23 estimated capex. When inflation is treated on a like-for-like basis with our initial Revenue Proposal the AER's reductions are more significant – approximately 16.2 per cent compared to our initial Revenue Proposal.

The AER formed the view that we did not provide sufficient evidence to satisfy it of the prudency and efficiency of our forecast capex. The primary reasons for the AER's Draft Decision were:

- Repex – the AER considers that:
  - > several of our risk assumptions are overstated and not supported by historical observations. When adjusted, lower-cost options are likely to be more efficient, and
  - > we should update our business cases and models to reflect the latest economic indicators including the discount rate and cost escalators.
- Augex – the AER considers that:
  - > our focus on delivering AEMO's Actionable ISP projects and the NSW Government PTIPs means that we are likely to defer investment, especially economic benefit projects to the 2028-33 period
  - > the demand forecasts for several projects are uncertain and project timing is sensitive to changes in demand. The AER has rejected projects with uncertain demand, and
  - > the investment needed will be met by non-network rather than network solutions.
- Non-network ICT capex – the AER considers that our forecast capex should be in line with trend over the period 2009 to 2023, and
- Non-network other – the AER considers that our property and fleet sustainability initiatives are not consistent with the NER capex objectives.

Table 4-3: Comparison of our 2023-28 capex our initial forecast and the AER's draft decision ($M, Real 2022-23)

Capex category	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Repex	797.6	675.9	(121.6)	(15.3%)
Augex	253.6	240.3	(13.3)	(5.3%)
Non-network ICT	86.9	77.4	(9.5)	(11.0%)
Non-network Other[1]	71.4	75.6	4.2	5.9%
Capitalised overheads	159.0	151.4	(7.6)	(4.8%)
Total (excluding pre-approved capex)	**1,368.5**	**1,220.6**	**(147.9)**	**(10.8%)**
Pre-approved EnergyConnect capex	532.8	530.7	(2.2)	(0.4%)
Asset disposals	(22.0)	(22.0)	0	-

Capex category	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Total (including pre-approved capex)	**1,879.4**	**1,729.3**	**(150.1)**	**(8.0%)**

4.6. Our approach to responding to the AER's Draft Decision

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

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

As explained in Chapter 1, we have responded to the AER's draft decision for each category of capex using the following approach:

- **Accept** the AER's draft decision where we believe it will result in better outcomes for our customers
- **Update** the forecast capex set out in our initial Revenue Proposal to either incorporate:
  > the AER's feedback, including updating our business cases to reflect the latest economic indicators, including the discount rate and cost escalators, and

  > changes to either the project scope (e.g., where an alternative option is acceptable) or vary the forecast costs.
- **Maintain** our initial capex forecast set out in our initial Revenue Proposal and provide additional evidence to further justify and support the needs and costs, and
- **Include new additional expenditure** where we have updated our initial forecast capex for new additional expenditure that is driven by new information and developments outside our control since our initial Revenue Proposal. This is discussed in Section 4.10.1.

The remainder of this chapter explains the issues raised in the AER's Draft Decision, the feedback we have received from the TAC and our response to the following elements of our 2023-28 forecast capex:

- Section 4.7 – our capex forecasting approach and business cases for Repex and Augex
- Section 4.8 – real material costs escalators and our updated 2021-22 unit rates for Repex and Augex
- Section 4.9 – our forecast Repex
- Section 4.10 – our forecast Augex
- Section 4.11 – our forecast Non-network ICT capex, and
- Section 4.12 – our forecast Non-network other capex.

4.7. Forecasting approach and business cases

Our initial Revenue Proposal explained the processes, inputs and methodologies that we used to develop our forecast capex for the 2023-28 period. These explanations have not been repeated in detail in this Revised Revenue Proposal, except where necessary to explain our revised capex forecasts.

We welcome the recognition in the AER's Draft Decision that our capex governance, management frameworks and forecasting methods are reasonable. The Draft Decision acknowledges the improvements we have made since our 2018-23 revenue determination in response to the AER's feedback on our forecasting method and capital governance framework, processes and inputs, and found that our:

- governance and asset management system are effective
- use of risk-based options analysis and a top-down challenge to forecast our Repex is reasonable
- asset management strategy is consistent with good industry practice
- approach to estimating demand forecasts is rigorous, and
- capex forecasting methods identified prudent projects and reasonable cost estimates.

The AER, however, identified several areas of concern with our business cases for network capex (for Augex and Repex) and requested that we update them to reflect the latest economic indicators, including the discount rate and cost escalators.

In preparing this Revised Revenue Proposal, we have considered the AER's feedback. We engaged HoustonKemp to assist us in relation to specific aspects of this feedback, including the use of terminal values, weights for high and low scenarios and discount rates. We also sought advice from the University of Melbourne in relation to our bushfire consequence modelling.

Table 4-4 summarises the AER's feedback and how we have responded, including the advice received from HoustonKemp and the University of Melbourne, which is provided in full in Attachments to this Revised Revenue Proposal. We have also updated certain business cases in response to the AER's Draft Decision to address specific feedback or concerns relating to particular projects or programs. Further information on this updated analysis is provided in the relevant sections of this Chapter.

Table 4-4: AER's Draft Decision feedback on our business cases and how we have responded

What we heard	How we have responded
The terminal value is not applied appropriately	HoustonKemp has reviewed: • our terminal value approach and confirmed that it is correctly applied and that we are required to match costs to benefits within the analysis period, and • a sample of business cases and found the payback timing, which does not rely on the terminal value, occurs well within the analysis period, indicating that the present value of benefits exceeds the present value of capital investment.
The low and high benefit scenarios weights are too high	HoustonKemp has reviewed and confirmed that our approach to applying weighted scenarios is appropriate because the: • scenarios are constructed and weighted to inform the robustness of the preferred option, which provides a high degree of assurance that the preferred option is the right option in terms of stakeholder outcomes, and • weighting is unlikely to be material in the identification of the preferred option. This view is confirmed by specific analysis of several business cases.

What we heard	How we have responded
	We have sought the TAC's views on the scenario weightings used in our non-ISP RIT-Ts. We have agreed our approach to future scenario weightings and reflected these weightings in our RIT-T Term Sheet.
Including varying discount rates in the weighted scenarios is not appropriate	HoustonKemp has reviewed and confirmed that our approach to varying the discount rate across scenarios is appropriate because: • discount rates should vary to reflect different opportunity costs of employing capital resources in a particular project under each scenario • our approach is consistent with that used by other TNSPs, including Powerlink, ElectraNet and AusNet in their RIT-T assessments,[56] and • the discount rates used in each scenario are unlikely to change the weighted scenario rankings and therefore will not affect the identification of the preferred option. This view is confirmed by specific analysis of several business cases.
Models should be updated with the latest economic indicators (such as discount rate and cost escalators)	We used a discount rate of 4.8 per cent in our business cases based on AEMO's draft 2021 Input Assumptions and Scenarios Report (IASR). This was the latest available at the time of preparing our business cases for our initial Revenue Proposal. AEMO's final 2021 IASR used a 5.5 per cent assumption. HoustonKemp has reviewed the use of discount rates and considers that it is reasonable to retain the 4.8 per cent discount rate because: • the business case scenario analysis and weighted outcome use a range of discount rates in the low and high benefits scenarios, and • this range already accounts for differences from the central 4.8 per cent discount rate assumption. We have, however, applied the latest discount rate where we have updated specific business cases in response to the AER's Draft Decision.
Including reputational risk in our Repex business cases is not aligned with the AER industry practice note	Our 'reputational risk' category only captures the direct financial consequence[57] relating to: • direct media coverage costs of managing the incident • customer consultation following an event, and • customer contacts following an event. Our 'reputational risk' category is therefore aligned with the 'Financial' risk category in the AER's industry practice note, which states that the direct financial consequence for this category may include: • business disruption, and • media liaison and community engagement. While our naming convention arises from alignment with our internal risk management framework, the approach is aligned with the AER industry practice note. This view is supported by Aurecon's technical assurance

56 Powerlink RIT-T – Addressing the secondary systems condition risk in the Gladstone South area, July 2020, ElectraNet RIT-T – Managing the risk of Protection Relay Failure, December 2019, AusNet RIT-T – Maintaining supply reliability in the Shepparton and Goulburn-Murry area, October 2021.

57 Refer to our Network Asser Criticality Framework, Appendix B.

What we heard	How we have responded
	report, which was provided to the AER in response to an information request.[58] Aurecon's report found that our Repex proposal is aligned with good industry practice, including the AER industry practice note. We also note that 'reputational risk' forms only a very minor part of our quantified risk and is not the main driver of forecast Repex. Nevertheless, to ensure that we have addressed the Draft Decision and stakeholders' concerns, we have removed the reputational risk costs where we have updated specific business cases.
Our bushfire assumptions lead to bushfire risks that are not supported by observed history.	Climate change means that past bushfire experience is not a reliable predictor of future bushfire risk. The University of Melbourne, which undertook our bushfire consequence modelling, has reviewed and confirmed that our modelling: • [redacted] • [redacted]

4.8. Real material costs and unit rates

As noted above, the AER sought information on how we are addressing updated data on our cost escalators.

4.8.1. Material cost escalators

Our initial Revenue Proposal did not include a real increase in materials costs in our expenditure forecasts. We explained, however, that we were concerned about real increases in materials costs, noting that Infrastructure Australia and AEMO forecast significant increases in demand for expertise, materials, and equipment, which would increase costs for transmission projects.[59,60] We indicated that we would revisit this matter in our Revised Revenue Proposal, subject to consulting with our customers and other stakeholders.

The AER and its consultant, EMCa, also expressed concern about the material increases in costs arising from current market conditions and the impact of these cost increases on our business cases:[61]

> *There is considerable generation and transmission development in Australia, and also significant investment in government and private sector infrastructure projects underway and planned. The impact of this demand for labour/skilled resources, materials, plant and equipment is already being experienced in some industry sectors in Australia.*
>
> *We remain concerned that Transgrid has not taken sufficient regard to the current market conditions in preparing its cost forecast, and that it is reasonable to expect that its projects will be subject to material increases in costs and to deliverability constraints, which may impact option selection, timing and the viability of some projects. It is standard practice to allow for assumed 'real*

[58] Information Request #015 – Aurecon - Repex 2023-28 Revenue Proposal Technical Assurance Report, 13 January 2022.
[59] AEMO, Draft 2022 Integrated System Plan, December 2021, p.15.
[60] Infrastructure Australia: Market capacity for electricity generation and transmission projects, October 2021 report.
[61] AER, Draft Decision - Transgrid Transmission Determination 2023-28 – Attachment 5 Capital Expenditure, p.17.

cost escalation', where applicable, in providing a regulatory submission. This allows the regulator to consider the basis for such escalation and to provide a response in its Draft Determination.

Consistent with the AER's preferred approach, we have maintained the approach in our initial Revenue Proposal of not applying any real materials cost escalators in the 2023-28 period. However, to address our and the AER's concerns about real increases in materials costs we have:

- updated our unit rates to reflect the latest market pricing and observed cost movements for materials over the 12 months ending June 2022. This is discussed in Section 4.8.2.
- updated our business cases to determine the impact of this increase on the preferred option. The outcome for each updated business case is discussed in Sections 4.9 and 4.10.

4.8.2. Unit rates

Our initial Revenue Proposal used 2020-21 unit rates from our MTWO[62] cost estimation database to estimate network capex, noting that these were the latest available rates at the time.

Over the 12 months ending June 2022, CPI increased by 6.1 per cent, the highest year-ended CPI inflation since the early 1990s.[63] The Australian Bureau of Statistics (ABS) July 2022 Producer Price Indexes (PPI) finds that heavy and civil engineering construction prices rose 9.0 per cent over the same period.[64] The PPI is representative of the type of work we undertake to deliver network capex.

As part of our annual MTWO cost estimate database update, we have updated our unit rates from 2020-21 to 2021-22 to capture the latest market pricing and observed cost movements using data sources including:

- actual contract and tender price observations for equipment and construction works that occurred in 2021-22
- actual labour rates for 2022
- Rawlinsons (Australian Construction Handbook) for 2022
- commodity price change observations from BISOE and Macromonitor (where actual 2022 rates were unavailable, e.g., as the item was not purchased/constructed in 2021-22), and
- CPI where none of the above items were applicable.

Our 2021-22 unit rates are significantly higher than our 2020-21 unit rates, reflecting that Australia has recently entered a period of high and unexpected inflation, with large increases in producer and consumer prices. As a result, our input costs, including materials, labour and freight have increased. These cost increases have been driven by a range of factors beyond our control, including:

- supply chain disruptions resulting in materials shortages
- the war in Ukraine driving up fuel costs, and
- labour shortages.

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[62] MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built on a bespoke vertical cloud infrastructure supplied by Microsoft Azure, MTWO allows users to integrate and digitalise all project delivery processes in a complete end-to-end solution. More than 100 enterprise-wide modules are built into MTWO, with everything from 5D BIM virtualisation to scheduling, procurement, bidding and tendering on offer. RIB's iTWO cx project management software is also available as part of the MTWO solution.
[63] Reserve Bank of Australia, Statement on Monetary Policy, August 2022, p. 43.
[64] https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/producer-price-indexes-australia/latest-release.

We consider that it is more appropriate to use our 2021-22 unit rates to forecast our Augex and Repex rather than our 2020-21 unit rates because they:

- reflect the high and unexpected inflation over the 12 months to June 2022, which is driven by a range of factors beyond our control, and
- are more recent and therefore provide the best available information for the purpose of forecasting our future capex requirements, noting that rates will not return to the previous year's levels.

This Revised Revenue Proposal therefore updates our Augex and Repex forecasts using the 2021-22 unit rates. This has resulted in an 8.4 per cent increase in the Augex and Repex project costs (all else equal), which is closely aligned with the ABS reported PPI increase of 9.0 per cent.[65] The increase in our unit rates is consistent with EMCa's observations regarding the extent of generation and transmission development in Australia.

We engaged GHD to undertake an independent review of our approach to updating our unit rates. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, confirms that our 2021-22 update:

- leverages the best available sources of unit rates and appropriately applies these to each cost category
- uses credible sources of escalation factors, and
- represents a robust calculation approach.

4.9. Repex

Our initial Repex forecast was $797.6 million, which is 4.4 per cent below our estimated 2018-23 Repex of $834.6 million. The AER reduced our initial forecast Repex by $121.6 million to $675.9 million, which is 15.3 per cent below our initial forecast and 19.0 per cent below our 2018-23 estimate. The key reason for the AER's Draft Decision is that it considers several of our risk assumptions are overstated and are not supported by historical observations. According to the AER's Draft Decision, when these assumptions are adjusted, lower-cost options are likely to be more efficient. These risk assumptions include:

- applying a disproportionality factor of six for environmental risk, including the non-safety related component of bushfire risk
- applying a disproportionality factor of six for safety risk associated with substation equipment, and
- including reputational risk in cost-benefit assessments.

The AER has also requested that we update our business cases and models to reflect the latest economic indicators, including the discount rate and cost escalators.

We are deeply concerned with the AER's substitute Repex allowance, which is insufficient to enable us to maintain a safe, reliable network that is fit for the future as our network ages and condition-related issues continue to grow. The AER's substitute Repex allowance would also leave us poorly equipped to address the frequent extreme climate-driven natural hazard events, which have significant customer impacts. As a consequence, the AER's substitute forecast will not satisfy the capex objectives in the NER.

[65] The ABS PPI only measures the construction portion of costs whereas our cost database update applies to all resources used in our cost estimates.

Feedback from the TAC

We have discussed our concerns about the AER's Draft Decision with the TAC. The TAC acknowledged that technical knowledge and analysis is required to determine the efficient level of Repex for the 2023-28 period. On this basis, the TAC suggested that:

- we should resolve our differences on the efficient level of Repex directly with the AER through the determination process, and
- it would be helpful for the TAC if we could host a joint workshop in which both Transgrid and the AER each explain and justify their respective positions and the reasons for the differences between them. The TAC agreed that this workshop could be held following the submission of our Revised Revenue Proposal.

Our revised Repex forecast is $883.7 million for the 2023-28 period, which is $86.1 million or 10.8 per cent higher than our initial forecast. The key driver of this increase is the impact of updating our unit rates from 2020-21 to 2021-22 to reflect the latest market pricing and observed cost movements, as explained in the previous Section 4.8. In preparing our revised Repex forecast, we have addressed the specific concerns raised by the AER and its consultant, EMCa.

Table 4-5 compares our initial and revised 2023-28 Repex forecasts, by category of capex, with the AER's Draft Decision.

Table 4-5: Comparison of our 2023-28 initial, the AER's draft decision and our revised Repex forecast ($M, Real 2022-23)

Repex	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
Transmission lines	334.5	285.3	381.2
Digital infrastructure	263.4	224.1	282.5
Substations	199.7	166.6	220.0
Total	**797.6**	**675.9**	**883.7**

To substantiate our revised Repex forecast:

- Section 4.9.1 overviews the outcomes of the AER's top-down assessment of our initial Repex forecast and how we have responded in this Revised Revenue Proposal, and
- Section 4.9.2 overviews the AER's bottom-up assessment for each sub-category of Repex and sets out our detailed responses, which focus on the affordability concerns raised by the TAC. This approach has led us to accept the AER's Draft Decision, unless the substitute allowance would create unacceptable risks in relation to meeting our compliance obligations or maintaining the safety and reliability of the network.

4.9.1. The AER's top down assessment and our response

The Draft Decision explains that the AER has assessed our Repex using both a top-down and a bottom-up approach. Based on its top-down assessment, the AER considers that:

- on average, our assets, are the second youngest of all TNSPs
- our assets have the lowest average outage rate among TNSPs over the last five years, and
- our average outage rate has improved substantially in recent years.

The AER therefore concludes that we require less capex to maintain our network performance in 2023-28 compared to 2018-23 given the improvement in our network performance over time:

> *Transgrid's forecast capex is more than required for it to maintain its network over the 2023–28. Top-down testing of Transgrid's network performance revealed that its network performance is improving, suggesting forecast capex lower than actual/estimated capex in the current period may be sufficient for Transgrid to maintain its network.*

We engaged GHD and HoustonKemp to undertake independent benchmarking analysis to assess the overall efficiency of our Repex over time and compared to other TNSPs. The outcome of this analysis is explained below and does not support the AER's findings. In summary, it finds that:

- we are maintaining, rather than improving, our network performance
- our assets are on average older than other TNSPs' assets and are estimated to have a relatively low residual service life
- historical levels of Repex need to at least be maintained once the age of assets is considered and the severity of market impact from unplanned outages has been increasing despite relatively constant network performance, and
- the AER's Draft Decision would result in a total Repex forecast that is materially below our current levels of Repex and at the lower end of the historical range since 2009, reducing our Repex by all partial performance indicators (PPI) metrics[66] used in the AER's benchmarking for TNSPs relative to the current 2018-23 regulatory period.

GHD's benchmarking analysis

GHD's benchmarking analysis relied on the Economic Benchmarking RIN data that is compiled by the AER. Using this data, GHD made the following observations regarding the characteristics of our network:

- it is the second longest network after Powerlink and has relatively more assets than any other TNSP
- its assets are on average older than other networks' assets, which contrasts with the AER's findings in its Draft Decision. GHD found that '*Transgrid has a relatively old network, with a relatively low estimated residual service life across the various categories of transmission network assets'*
- the relatively older age of our assets suggests that more assets will be due for replacement or refurbishment in the 2023-28 period than in the 2018-23 period
- it has more transmission infrastructure at higher voltage levels (≥330 kV) compared with other TNSPs, which is more expensive to replace and refurbish, and
- it services the highest number of distribution customers with a significantly higher maximum demand and energy delivered compared with Powerlink and other TNSPs.

The key findings from GHD's analysis in terms of asset age are:

- Transmission towers – GHD expects our Repex to be higher than other TNSPs because we have relatively more assets than any other TNSP and are responsible for approximately 39 per cent of the transmission tower assets constructed between 1950 and 1970 in the NEM. GHD also expects our Repex to increase over the 2023-28 period as our older assets become due for replacement or refurbishment.

[66] Each PPI connects the quantity of a single input with each unit of output produced by a TNSP.

- Substations – GHD notes that the average age (as a proxy for condition) of our substation switchyards is in line with other TNSPs and the distribution of assets by installation date also appears similar. However, we have relatively more assets reflecting the larger size of the network, a higher amount of energy consumption and a greater number of connections.
- Digital infrastructure – GHD explains that our Repex for digital infrastructure is driven by functionality, accuracy and technology obsolescence. The efficient replacement lifecycle of digital infrastructure tends to be significantly shorter than network assets such as transmission line and substation assets.

GHD notes that we have legislative requirements to comply with safety (WHS[67] and ENSMS[68]), reliability (licence conditions[69]) and environmental (EPA[70] and POEO[71]) obligations. As a consequence, GHD explains that Repex relating to mitigating bushfire, worker and public safety risks may be driven by life cycle risks, events or incidents rather than asset age. GHD found that recent Revenue Proposals from ElectraNet and Ausnet show significant variation in this type of expenditure over time. It follows that the AER should not draw inferences regarding the need for this expenditure from an analysis of asset age.

In relation to network performance, GHD considered the potential for higher or lower Repex compared to historical levels based on a comprehensive assessment using:

- lagging indicators, where a customer impact or network safety event was actually caused by an asset failure, and
- leading indicators, where an asset fault or failure occurred that did not cause a customer outage or network safety event.

In relation to these performance measures, GHD concluded that:

- lagging indices of annual unserved energy and non-process outages leading to >5 system minimum losses have remained constant or slightly reduced over the period going back to 2003. In the most recent 10-year period, from 2011 onwards, these indices have been flat. It is noted that these metrics may be weak indicators of Repex requirements as the response times to outages are heavily influenced by opex
- the leading index of outages of transmission lines and cables have remained constant. Given this is the largest contributor to Repex, it is a strong indicator that the historic expenditure levels have been appropriate to maintain performance
- other leading indices that consider smaller Repex contributors – transformers and reactive plant – indicate slightly improved outcomes over the period, and
- the lagging index of unplanned outage market impact shows that, despite the relatively constant network performance noted above, the severity of outages as measured by market impacts has been increasing.

Contrary to the AER's Draft Decision, GHD concluded that its analysis of leading and lagging indicators show mixed results rather than improved performance, as stated by the AER's Draft Decision. In particular, GHD states:

[67] Work Health and Safety Act 2011, Work Health and Safety Regulation 2017 and supporting industry (ENA) codes, guidelines and rules.
[68] NSW Electricity Supply (Safety and Network Management) Regulation 2014.
[69] NSW Electricity Transmission Reliability and Performance Standard 2017 under Electricity Supply Act 1997.
[70] Environmental Planning and Assessment Act 1979.
[71] Protection of the Environment Operations (POEO) Act 1997.

> *In conclusion, once the age of assets is considered, the data considered in GHD's analysis suggests an increasing role for network management, meaning that historical levels of Repex would need to be at least maintained.*

In relation to cost benchmarking, GHD's analysis for each of the AER's benchmarking metrics indicates that our Repex forecast compares favourably with that of our peers:

- Per end user (i.e., number of distribution customers) – Our Repex is substantially less than comparator TNSPs and will continue to be lower than other TNSPs based on our revised Repex forecast.
- Based on length or size of the network – Our Repex has been relatively consistent and is around average compared to other TNSPs.
- Based on consumption – Our Repex is relatively low compared to other jurisdictions in terms of energy delivered and maximum demand.

GHD's benchmarking report concludes that:

> *Comparisons of Repex based on customer numbers, energy delivered and maximum demand show Transgrid's historical expenditure is the lowest of the TNSPs. Transgrid's revised Repex forecast brings it into line with the historic expenditure rates of other TNSPs with regards to these metrics, while the AER's draft decision would reduce Transgrid's ratios further.*

A copy of GHD's report is provided as an Attachment to this Revised Revenue Proposal.

HoustonKemp benchmarking analysis

HoustonKemp has assessed the efficiency of our overall Repex based on metrics that are consistent with the AER's benchmarking PPIs for TNSPs, by comparing it to:

- non-coincident summated maximum demand
- transmission network circuit length
- energy throughput, and
- the number of end users.

HoustonKemp's analysis considers our Repex performance over time, including relative to other TNSPs, and the level of Repex approved by the AER in its recent determination for Powerlink, because this is the AER's most recent TNSP determination. HoustonKemp's analysis shows that the AER's Draft Decision would:

- result in a total Repex forecast that is materially below our current levels of Repex in the 2023-28 regulatory period and at the lower end of the historical range since 2009
- reduce our Repex by all 'PPI-style' metrics, relative to the current 2018-23 regulatory period and for:
  - some metrics (including Repex per end user and Repex per circuit length), resulting in forecast Repex at our lowest levels on these metrics in real terms since 2009, and
  - for the other metrics (including Repex per GWh and Repex per maximum demand), resulting in levels approximately consistent with Transgrid's second-lowest levels for these metrics since 2010.
- result in a significantly lower Repex per MW and Repex per GWh delivered than those implied by the AER's recent allowance for Powerlink.

4.9.2. The AER's bottom-up assessment and our response

Sections 4.9.2.1 to 4.9.2.3 provide details of our initial Revenue Proposal, the AER's Draft Decision and our Revised Proposal for each sub-category of Repex. In some categories, we largely accept the AER's decision. In other areas, we have more substantial differences.

Table 4-6 compares our revised 2023-28 Repex forecast with our initial Revenue Proposal and the AER's Draft Decision.

Table 4-6: AER's reductions by category of Repex, $M Real 2022-23

Repex category	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
Transmission lines	334.5	285.3	381.2
Tower climbing deterrents	17.1	6.7	18.3
Low spans	30.3	14.5	33.8
Asbestos paint removal	29.8	21.0	32.2
Line 11 tower replacement	56.4	31.4	61.5
Line 94U refurbishment	18.3	17.2	20.2
Other projects and programs (inflation impact only)	182.5	194.4	215.2
Digital Infrastructure	263.4	224.1	282.5
Secondary system renewals	145.4	106.1	162.4
Palisade gate remediation	7.9	4.9	4.6
Other projects and programs (inflation impact only)	110.1	113.0	115.6
Substations	199.7	166.6	220.0
Transformer renewals	64.4	26.6	58.3
Circuit breakers	36.9	31.2	36.9
Other projects and programs (inflation impact only)	98.3	108.9	124.7

4.9.2.1. Transmission lines

Table 4-7 details our revised transmission line Repex forecast, as well as the AER's Draft Decision and our initial Revenue Proposal. It shows that the AER has reduced our initial forecast from $334.5 million by $49.2 million or 14.7 per cent to $285.3 million over the 2023-28 regulatory period. We have now revised our transmission line Repex forecast to $381.2 million.

Table 4-7: Transmission line Repex 2023-28

Repex	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	48.8	59.6	86.0	54.5	85.7	334.5
AER's Draft Decision	52.5	52.6	79.8	43.3	57.1	285.3
Revised Revenue Proposal	53.4	65.8	101.7	104.2	56.0	381.2

Table 4-8 shows the breakdown for 2023-28 for the five sub-categories that comprise transmission line Repex, being replacement or refurbishment of transmission towers, transmission poles, insulators, conductors and cables.

Table 4-8: Transmission line Repex by sub-category 2023-28

	Initial Revenue Proposal	AER's Draft Decision	Revised Revenue Proposal
Transmission poles	76.9	79.6	97.8
Transmission towers	181.7	135.8	198.0
Insulators	38.9	30.4	42.4
Overhead conductors	30.7	32.7	36.0
Underground cables	6.4	6.8	6.9
Transmission lines total	334.5	285.3	381.2

Managing risk on line 86 – Tamworth to Armidale (New additional expenditure)

Our initial Revenue Proposal explained that managing the risk of deteriorating wood pole condition on Line 86 (Tamworth to Armidale) is a key project in the 2023-28 period and is critical to maintain safety, reliability and security of our network.

We did not include the cost of this project (and three other Augex projects, which are discussed in Section 4.10.1.4) in our initial capex forecast because, at the time of submitting our initial Revenue Proposal these projects were undergoing RIT-Ts, which we expected to be completed by July 2022. We explained that we would include the costs of the preferred network option as appropriate in our capex forecast in our Revised Revenue Proposal. This approach ensured that the preferred option for each project was consulted on through the RIT-T process and that only efficient network costs were included in our forecasts.

To provide transparency on the potential cost impact of these projects, we included the indicative costs (revenue and price impacts) of the most likely network option for each project in our initial Revenue Proposal. The indicative cost for this project was $331.1 million.

On 29 July 2022, the RIT-T for this project concluded, which identified that the preferred solution to address wood pole condition issues was the targeted replacement of the 31 highest risk wood poles in the 2023-28 period. The forecast capex for this option is $11.8 million, which is significantly less than the indicative cost of $331.1 million for replacing Line 86 with a higher capacity line which, at the time of our initial Revenue Proposal, was expected to be preferred. The RIT-T can be found here.

The significant reduction in the capex for this project since our initial Revenue Proposal reflects that through the RIT-T, we found that replacing Line 86 with a higher capacity line would not deliver net benefits. We therefore developed a solution based on the latest asset condition data to focus only on replacing the highest risk wood poles, like-for-like and in-situ with concrete or steel poles. The RIT-T determined this to be lowest cost of the credible options assessed. This reflects our commitment to affordability, keeping our prices as low as possible.

The AER's Draft Decision confirmed that the targeted replacement of the highest risk wood poles project is prudent but questioned the efficiency of the forecast capex.

In response to the AER's Draft Decision, we engaged GHD to independently verify the costs by developing a comparative estimate for the project. GHD concluded that our forecast capex for the project was within a reasonable margin of its comparative estimate and consistent with that which would be incurred by a prudent and efficient business. GHD's estimate is 12 per cent lower than our estimate for this project, which is very closely aligned given the early stage of the project.

For the reasons outlined above and consistent with the RIT-T, we have included new additional expenditure of $11.8 million in this Revised Revenue Proposal for this project as detailed in Table 4-9.

Table 4-9: Revised forecast for Managing risk on line 86

Managing risk on Line 86	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	-	-	-	-	-	-
AER's Draft Decision	-	-	-	-	-	-
Revised Revenue Proposal	-	-	0.1	0.4	11.3	11.8

Transmission tower climbing deterrents (Public safety enhancements)

Our initial Revenue Proposal includes forecast capex of $17.1 million to:

- upgrade 2,494 medium- to high-risk steel tower climbing deterrents that are ineffective or non-compliant, and
- replace 239 climbing deterrents in poor condition and require remediation to remain effective.

This program of work will improve the effectiveness of our climbing deterrents to prevent unauthorised access to our steel towers and therefore reduce public safety risk.

Industry guidelines illustrate a suitable typical climbing deterrent.[72] Our current standard design for this asset is consistent with the guidelines and designs used by other NSPs across the industry, both in Australia and overseas. Our initial Revenue Proposal, explained that we identified:

- 3,577 transmission line tower climbing deterrents as ineffective and not complying with the current industry guidelines[73] and our own internal standards to manage public safety risk, and
- 239 transmission line tower climbing deterrents in poor condition and requiring remediation to remain effective.

Of the 3,577 climbing deterrents identified as ineffective or non-compliant, we identified which of these are high, medium, low or very low risk and classified 2,494 as medium to high risk, and 1,083 as very low to low risk.

While the cost benefit analysis for upgrading 2,494 medium to high-risk climbing deterrents did not provide a positive net present value (NPV), we recognised the limitations in this type of quantified analysis which arises because:[74]

- we rely on assumptions regarding public behaviour, and
- tower climbing incident data is not comprehensive in that it does not capture all incidents.

[72] ENA Document 015:2006.
[73] ENA Document 015:2006.
[74] Transgrid - OER-N2425 Rev 0 TL Public Safety Compliance - 1 Nov 2021 – PUBLIC.

In light of this, good practice controls are needed to achieve similar safety outcomes. Our climbing deterrent upgrades reflect 'duty of care' As Low As Reasonably Practicable (ALARP) principles where risks cannot be fully quantified. This is assessed using the following process consistent with AS 5577:

- where reasonably practicable the hazard has been eliminated, or where this is not reasonably practicable all risk good industry practise treatment options have been considered
- a risk treatment option has not been implemented only if the cost in doing so is grossly proportionate to the benefit gained, and
- opportunity for further safety improvement has been assessed.

In its Draft Decision, the AER reduced our initial capex forecast of $17.1 million by $10.4 million or 60.7 per cent to $6.7 million based on its quantitative cost benefit assessment, which reduced the scope of the program to include the high-risk portion only.

We do not accept the AER's Draft Decision because we have a duty of care to ensure that climbing deterrents prevent access to dangerous high voltage zones. Advice from King & Wood Mallesons (KWM) lawyers, provided as an Attachment to this Revised Revenue Proposal, [redacted]

[redacted]

[redacted]

[redacted]

In the 2018-23 period, the number of climbing deterrent by-pass incidents increased as a result of both self-harm and fun-seeking activities, including by children who posted videos online by-passing the climbing deterrents on our towers.

In response to the increase in these incidents, we reviewed the effectiveness of our climbing deterrent. The review found that some of our existing key controls are ineffective because:

- the barbed wire does not cover the entire tower perimeter
- there is no climbing deterrent infill around the tower legs, allowing it to be easily passed, and
- existing barbed wire is not fixed and can be easily moved.

We therefore initiated a program of public safety enhancements to address the effectiveness of our climbing deterrents. Our program, which will be implemented over three regulatory periods (2018-23 to 2028-33) includes:

- 152 climbing deterrent upgrades and repairs in the current 2018-23 period
- 2,733 climbing deterrent upgrades and repairs in the upcoming 2023-28 period, consistent with our initial Revenue Proposal, and
- 1,083 climbing deterrent upgrades in the 2028-33 period.

We engaged GHD to independently review our business case in light of the AER's Draft Decision. GHD's assessment, provided as an Attachment to this Revised Revenue Proposal, confirms that:

- the use of climbing deterrent barriers is a key control across the industry and the design standard is established in the ENA Document 015:2006
- we have a duty to eliminate or minimise the risks to health and safety So Far As Is Reasonably Practicable (SFAIRP), considering what is reasonably expected from a societal perspective, which is difficult to reflect in a NPV calculation, and
- the use of NPV to assess ALARP may not reflect what could reasonably be expected from a societal perspective when considering SFAIRP to establish the scope of work.

GHD's assessment also explains that ElectraNet's 2023-28 Revenue Proposal included a similar climbing deterrent enhancement program in its security and compliance capex and it did not undertake a quantitative NPV assessment stating:

> *Unlike other projects a standard NPV analysis is not well suited to this project due to the lack of reliable data concerning the frequency with which tower climbing is attempted.*

GHD agrees with ElectraNet that a cost-benefit analysis is not suitable in this situation when considering SFAIRP and Good Electricity Industry Practice and notes that the AER's draft decision for ElectraNet[75] has accepted ElectraNet's total capex forecast, including the proposed security and compliance capex.

GHD concludes that, in light of our duty of care to address the non-compliant climbing deterrents, our business case and approach is reasonable.

On KWM and GHD's advice, we have maintained our initial scope of work and updated our business case for the latest available 2021-22 unit rates and discount rate of 5.5 per cent. Our revised forecast for transmission tower climbing deterrents is $18.3 million as detailed in Table 4-10 below.

Table 4-10: Revised forecast for transmission tower climbing deterrents

Transmission tower climbing deterrents	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	6.3	3.0	3.9	3.9	-	17.1
AER's Draft Decision	6.7	-	-	-	-	6.7
Revised Revenue Proposal	6.8	3.2	4.2	4.2	-	18.3

Transmission line low spans – 330kV and 132kV

Our initial Revenue Proposal includes forecast capex of $30.3 million to address low ground clearances on certain steel tower transmission lines with legacy low conductor ground clearances. These programs manage both public and worker safety risks.

We identified 28 transmission lines that breach the minimum clearance requirements both under the relevant legacy design standard as well as the current standard AS/NZS 7000.

The low clearance is a function of utilisation. The higher the utilisation, the higher the probability of low clearances occurring. Some low clearances exist under normal 'everyday' conditions; whereas, others only exist under 'contingency' conditions, such as where another transmission line is switched off thereby increasing the utilisation of the transmission line with low clearances.

75 AER, Draft Decision ElectraNet Transmission Determination 2023 to 2028 Attachment 5 – Capital expenditure, September 2022, p.12.

We used the expected utilisation of each of the 28 transmission lines to prioritise which of them require remediation in the 2023-28 period. Our initial Revenue Proposal included low clearance remediation on 13 lines of which:

- nine are expected to breach clearance heights under normal 'everyday' conditions, and
- four are expected to breach clearance heights only under 'contingency' conditions.

These 13 lines were selected for remediation in the 2023-28 period because they all have a utilisation of more than 80 per cent during 'contingency' conditions, which means they have a higher probability of low spans occurring. We have determined our low spans program based on 'duty of care' ALARP principles, consistent with AS 5577.

The two business cases for these projects confirmed a positive NPV outcome and include a disproportionality factor on the value of statistical life as part of demonstrating ALARP. These business cases are:

- Transgrid - OER-N2609 Rev 0 Main Grid Low Spans - 9 Nov 2021 - PUBLIC
- Transgrid - OER-N2616 Rev 0 132kV TLs Low Spans - 10 Nov 2021 - PUBLIC

The utilisation of our transmission lines has been changing with the shifting generation mix and associated power flows on the network. Where utilisation has increased, the risk associated with legacy low conductor ground clearances has also increased. To meet our 'duty of care' we plan to alter the structure or their insulator arrangements to increase ground clearances and meet the minimum clearance requirements. This will mitigate public and worker safety risk and ensure compliance with design standards.

The AER reduced our initial capex forecast of $30.3 million by $15.8 million or 52.1 per cent to $14.5 million.

The AER's Draft Decision found that the relevant Australian Standard, AS/NZS 7000, which specifies minimum clearance requirements, should be applied to 'normal' or 'N' operating conditions only and not to 'contingency' or 'N-1' operating conditions. The AER has therefore reduced the scope of this program to address low ground clearances under 'normal' operating conditions.

We do not accept the AER's Draft Decision because it fails to recognise our duty to ensure the health and safety of our workers, sub-contractors and the public. Advice from KWM lawyers, provided as an Attachment to this Revised Revenue Proposal, [redacted]

We have experienced recent incidents involving third parties breaching safe clearances, which in some cases has resulted in serious electric shock injuries. While the spans complied with clearance requirements in these cases, low spans increase public safety risk. We have been proactively addressing this issue over the current 2018-23 period and previous regulatory periods and propose to continue this program in the 2023-28 period.

We engaged GHD to independently assess our business cases and the relevant Australian Standard (AS/NZS 7000). GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, confirms that:

- our analysis, which has been conducted at the maximum design temperature, is consistent with Section 2.4 of AS/NZS 7000. This states the overhead line shall be designed for the maximum operating temperature of the line (and its conductors)

- 'N-1' operating conditions, are within the maximum operating temperature of the line. AS/NZS 7000 clearance requirements apply to the maximum operating temperature and therefore encompass and apply to the N-1 operating conditions, and
- 'N-1' operating conditions in our business cases have only been used to determine prioritisation of remediation activities to select the 13 lines we will remediate in the 2023-28 period, which is considered reasonable. As described above, these 13 lines were selected as they all have a utilisation of more than 80 per cent during 'contingency' conditions.

Based on GHD's advice we consider that the AER has misinterpreted the Australian Standard. We have therefore maintained our initial scope for this program and updated our business case for the latest available 2021-22 unit rates and discount rate of 5.5 per cent.

Our revised forecast for transmission line low spans is $33.8 million as detailed in Table 4-11 below.

Table 4-11: Revised forecast for transmission line low spans

Transmission line low spans	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	0.2	9.5	16.5	4.1	-	30.3
AER's Draft Decision	0.0	2.0	9.7	2.8	-	14.5
Revised Revenue Proposal	0.2	10.5	18.5	4.6	-	33.8

Transmission tower asbestos paint remediation

Our initial Revenue Proposal includes forecast capex of $29.8 million to address a legacy issue with asbestos containing paint on 1,604 of our transmission line steel towers.[76] As the paint has been in place for decades, it has deteriorated resulting in flaking. This presents a safety risk to workers who need to perform work on or near the towers, as well as to the general public.

We engaged expert consultant, GHD, to sample, assess and test the paint for asbestos, and prioritise remediation. We classified the towers with asbestos paint into very high, high, medium and low risk. In the current 2018-23 period we are remediating the very high- and high-risk towers. In the 2023-28 period we are proposing to remove asbestos paint from:

- 1,072 medium-risk towers, and
- 532 low-risk towers.

Our business cases assessed two options to remediate the remaining asbestos paint:

- Option 1 – Remediate only the medium-risk towers in the 2023-28 period.
- Option 2 – Remediate the medium- and low-risk towers in the 2023-28 period.

Option 2 is preferred on the basis that it meets our worker and public health and safety obligations, protects our workforce from harm and has a slightly higher NPV outcome than Option 1.

The AER reduced our initial capex forecast of $29.8 million to remediate 1,604 structures with asbestos paint that are rated as medium and low risk by $8.8 million or 29.6 per cent to $21.0 million.

[76] Transgrid, OER-1164 Rev 0 Asbestos Paint on Towers in Various Loc – 1 Nov 2021.

The AER's Draft Decision commented that our proposal is not consistent with a 2019 GHD report, that we commissioned, which recommended remediating only the medium-risk structures and maintaining all low-risk structures in good condition. Based on this report, the AER has only accepted the medium-risk structures with an allowance to inspect, rather than remediate, the low-risk structures.

We do not accept the AER's Draft Decision due to our duty of care to our workers, subcontractors and the public. Advice from KWM lawyers, provided as an Attachment to this Revised Revenue Proposal, [redacted] We are currently addressing this requirement by remediating asbestos paint on 1,185 very high- and high-risk structures the 2018-23 period. We propose to continue with the 1,604 medium- and low-risk structures in the 2023-28 regulatory period.

We also engaged GHD to assess our business cases in the context of its 2019 report, which the AER refers to in its Draft Decision. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, finds that:

- the recommendations in its 2019 report to maintain all low-risk structures in good condition, considered the accessibility of towers from a public access perspective only, and not the exposure to workers
- our interpretation of GHD's 2019 report, as reflected in our business case, better reflects the potential exposure to workers from inspection cycle and preventative and reactive maintenance activities, which GHD considers prudent, and
- our business case analysis and preferred option to remediate the medium and low-risk structures, aligns with the AER's Asset Replacement Planning Note with a positive NPV indicating proportionality when assessing ALARP.

Based on KWM and GHD's advice, we have maintained the scope of our initial Revenue Proposal. Our revised forecast for transmission tower asbestos paint remediation is $32.2 million as detailed in Table 4-12 below.

Table 4-12: Revised forecast for transmission tower asbestos paint remediation

Transmission tower asbestos paint remediation	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	5.8	5.8	5.8	5.8	6.7	29.8
AER's Draft Decision	6.9	6.9	6.9	0.1	0.1	21.0
Revised Revenue Proposal	6.2	6.2	6.2	6.3	7.2	32.2

Transmission line 11 – Sydney South to Dapto

Our initial Revenue Proposal includes forecast capex of $56.4 million to address condition issues on Line 11 by replacing suspension structures and the conductor between Sydney South and Dapto. Being near to the coast, the majority of this transmission line is in a high corrosion area, with towers, conductors, insulators and attachment fittings all subject to corrosion.

Corrosion increases the risk of a critical element of the transmission line failing, creating the potential for a conductor-drop event. This transmission line crosses major motorways, public spaces and bushland on the urban fringe. The safety and bushfire consequences of a failure event could be catastrophic and presents one of the highest risks on our network. Our business case includes an economic and risk assessment supported by:

- detailed visual and ultra-high-resolution condition assessment data
- field sampling and lab testing of key components, and
- bushfire propagation modelling and mobile phone based human movement data to assess the likely consequences of a failure.

We assessed three options in our business case to address the increasing risk on this line:

- Option 1 – Replace 55 steel suspension towers identified with priority condition issues and refurbish the remaining components with condition issues.
- Option 2 – Replace 127 steel suspension towers and refurbish the remaining components with condition issues.
- Option 3 – Replace 127 steel suspension towers, refurbish the remaining components with condition issues and replace the conductor.

Option 3 was selected because it provides the highest net benefit and will mitigate the bushfire and public safety risks to the community.

The AER reduced our initial capex forecast of $56.4 million by $25.0 million or 44.4 per cent to $31.4 million. The AER reduced our forecast because it considers:

- a disproportionality factor of 'six' for environmental risk is overstated
- we did not adequately explore credible options, and
- that if our risk model is adjusted, then none of our options are economically viable.

The AER's Draft Decision formed its own credible option to target high-risk towers and most of the conductors as the basis for its alternate estimate.

We have considered the AER's Draft Decision and updated our business case to address its feedback by:

- considering a new credible option, which targets the high-risk towers and the conductors
- adjusting the disproportionality factor for the non-safety (property damage) component of our environmental (bushfire) risk from 'six' to 'one'[77]
- removing reputational risk costs[78]
- updating our costs to the latest 2021-22 unit rates, and
- updating the discount rate from 4.8 per cent to 5.5 per cent

Our assessment confirms that all of the assessed options remain economically viable even after adjusting the disproportionality factor in our risk models. We are therefore concerned that the AER may have misinterpreted or misapplied our risk models in undertaking its assessment.

Our updated business case for Line 11 demonstrates that the new credible option (targeting high-risk towers and the conductors) is the preferred option. However, it is equal (within 0.3 per cent) ranked (on an

[77] We have adjusted the disproportionality factor applied to non-safety related bushfire risk to 'one' for the purpose of demonstrating it does not impact the economic viability of our business cases.
[78] While we believe our use of 'reputational risk' is consistent with the AER's industry practice note, we have removed it in our business case update to demonstrate that it does not impact on the business case outcome.

NPV basis) with our initially preferred option to replace all towers and the conductor. This updated business case finds that the optimal commissioning year for the new preferred option is 2027-28. This is sooner than the completion date for our initially preferred option which was phased to commence in the 2023-28 period and finish in the 2028-33 period. Our new preferred option, which has a smaller scope, can be completed in the 2023-28 period meaning that the expenditure requirements in 2023-28 remain similar to our initial Revenue Proposal for this project but the cost in the 2028-33 period will be lower.

GHD has reviewed our updated Line 11 business case and its Report, which is provided as an Attachment to this Revised Revenue Proposal, and confirms that it addresses the AER's Draft Decision by:

- developing a new targeted option, and
- reducing the environmental risk disproportionality factor.

GHD concludes that the project provides positive net benefits after these adjustments.

We do not accept the AER's Draft Decision on the basis that:

- our updated business case confirms that the optimal project timing for the preferred solution is 2027-28, and given the smaller project scope we can meet the timing, and
- GHD's advice that our updated business case provides positive net benefits to customers.

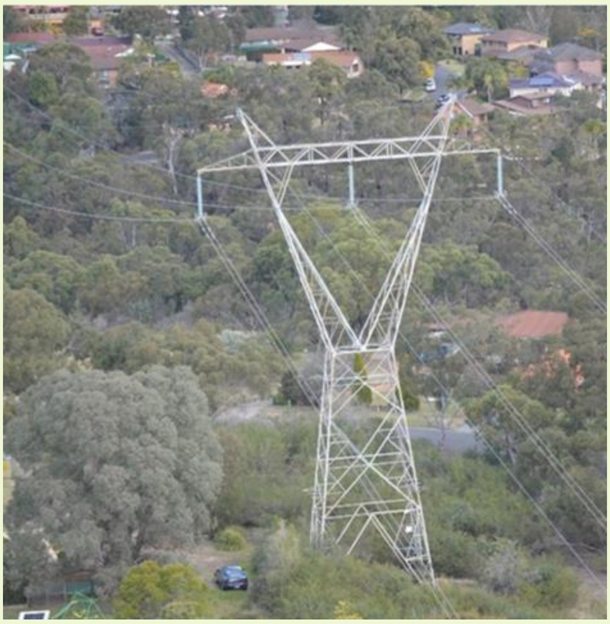
Our revised forecast for Line 11 remains similar to our initial Revenue Proposal at $61.5 million as detailed in Table 4-13 below.

Table 4-13: Revised forecast for transmission line 11

Transmission line 11 – Sydney South to Dapto	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	-	0.6	1.0	1.7	53.1	56.4
AER's Draft Decision	-	0.3	0.6	1.0	29.6	31.4
Revised Revenue Proposal	-	0.6	6.1	45.5	9.2	61.5

Replacement to avoid bushfire risk

We are proposing to invest $61.5 million to replace 60-year-old, corroded towers and the conductor on transmission line 11, which links Dapto to Sydney South substation – a key link between generation in Southern NSW and the Sydney load centre. This investment will address condition issues on the transmission line, avoiding the risk of a failed component sparking a fire in this bushfire danger zone. This part of Southern Sydney and the Illawarra has a history of severe bushfires.



Line 11 runs through coastal areas, where towers, conductors, insulators and attachment fittings are at greater risk of corrosion. It only takes one failing component to cause a disaster. In 2018, in California, a failed transmission attachment fitting sparked a fire that destroyed 18,804 structures and resulted in 85 fatalities. Damages attributed to the network operator ran into billions of dollars.

The transmission line crosses major motorways, public spaces and bushland on the urban fringe, making it one of the highest bushfire risks on our network. The safety and bushfire consequences if the aging and degraded transmission line fails could be catastrophic.

Based on a comprehensive economic and risk assessment, we have identified the highest risk towers and a conductor that need to be replaced to ensure the safety of the community. The assessment is supported by detailed condition assessment data, including field sampling and lab testing of components. We also used bushfire propagation modelling and mobile phone based human movement data to assess the likely consequences of a failure.

An independent review by engineering consultancy, GHD, agreed that replacing the highest risk towers and the conductor as proposed will deliver the highest benefits to the community

Transmission line 94U – Parkes to Forbes

Our initial Revenue Proposal includes forecast capex of $18.3 million to replace end of life wood poles on our transmission line 94U between Parkes and Forbes. Inspections have identified that the wood poles along the line are exhibiting condition issues and are reaching end of life. This transmission line has also been affected by the recent flooding in the region which may accelerate the deterioration of these wood poles. The resulting potential for structural collapse or conductor drop presents a bushfire and public safety risk.

Our business case includes an economic and risk assessment which considered two options:

- Option 1 – Replace the 38 wood poles to address the known ground line degradation issues.
- Option 2 – Replace all 138 wood poles to address all condition issues across the transmission line.

Option 2 was selected because it provides the highest net benefit and will mitigate the bushfire and public safety risks to the community.

The AER's Draft Decision reduced our initial capex forecast of $18.3 million by $1.1 million or 5.9 per cent to $17.2 million. The AER reduced our forecast replacing our unit rate with a lower unit rate because it considers that:

- our wood pole replacement unit rate is too high relative to recent years, and
- we did not justify our unit rate or quantify any efficiency of scale impacts that would reduce the cost of the project.

In response to the AER's feedback, we engaged GHD to review our unit rates and independently assess the costs by comparing our unit rates against similar recently completed projects. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, concludes that:

- our unit rate is within a reasonable range of the internal and external benchmark projects it has considered, and
- our forecast capex for the project is consistent with costs that would be incurred by a prudent and efficient business and in line with GHD's comparative estimate of $20.8 million.

GHD has also reviewed our actual costs[79] for wood pole replacement works, which was completed in May 2021. This involved the replacement of 141 wood poles on a nearby transmission line (Line 94K – Wellington to Parkes), which is adjacent to 94U. Line 94K is a good comparator because it was originally built at the same time, to the same specification and in the same locality as Line 94U. GHD confirms that our proposed unit rates for Line 94U align with our actual unit rates for Line 94K.

We have updated our business case for Line 94U to show that it remains economically justified when we address the AER's feedback by:

- adjusting the disproportionality factor for the non-safety (property damage) component of our environmental (bushfire) risk from 'six' to 'one'[80]
- removing reputational risk costs[81]
- updating our costs to the latest 2021-22 unit rates, and
- updating the discount rate from 4.8 per cent to 5.5 per cent.

Our revised forecast for Line 94U is $20.2 million as detailed in Table 4-14 below. This aligns with GHD's independent comparator estimate of $20.8 million for the project.

Table 4-14: Revised forecast for Line 94U

Transmission line 94U – Parkes to Wellington	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	-	-	0.3	17.2	0.8	18.3
AER's Draft Decision	-	-	0.3	16.1	0.8	17.2

79 These costs are based on construction works performed by a contractor part of our construction services panel.
80 We have adjusted the disproportionality factor applied to non-safety related bushfire risk to 'one' for the purpose of demonstrating it does not impact the economic viability of our business cases.
81 While we believe our use of 'reputational risk' is consistent with the AER's industry practice note, we have removed it in our business case update to demonstrate that it does not impact the business case outcome.

Transmission line 94U – Parkes to Wellington	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Revised Revenue Proposal	-	-	0.4	18.9	0.9	20.2

4.9.2.2. Digital infrastructure

Secondary systems renewals

Our initial Repex forecast included a forecast capex of $145.4 million for secondary system replacements at 24 substation sites to manage the risk of asset failure and obsolescence. This comprises:

- complete sitewide replacements and technological upgrades at eight sites, and
- targeted asset replacement at 16 sites.

The secondary systems that are targeted for replacement are subject to lifecycle risks, including:

- technical obsolescence (i.e., no longer manufactured) as they are replaced with new technology
- no longer supported by manufacturers, including ongoing software and patching upgrades, which increases IT security risk, and
- diminishing spares and cannibalisation of existing systems where renewal programs are active.

The risk of failure for these assets increases over time, leading to extended outage increases, particularly where sitewide technological upgrades have not occurred. Sitewide renewals and technological upgrades also offer operational benefits, which we have captured in our business cases for these projects.

The AER's Draft Decision reduced our initial capex forecast of $145.4 million by $39.3 million or 27.0 per cent to $106.1 million by rejecting eight secondary system replacement projects at:

- Lower Tumut and Kemps Creek substations, where sitewide renewals were proposed, and
- Vales Point, Gunnedah, Nambucca, Eraring, Forbes and Buronga substations, where targeted asset replacements were proposed.

The AER's Draft Decision rejected these eight sites on the basis that it considers the risks and benefits in our business cases are overstated because:

- our disproportionality factor of 'six' for safety in relation to substation assets and environmental risk is overstated
- our operational benefits are overstated for sitewide renewals and are unlikely to be realised, and
- if our risk model is adjusted, then none of our options are economically viable.

We engaged GHD to independently review our proposed investment in response to the AER's Draft Decision and given the critical nature of these assets to the operation of our network. GHD's report, provided as an Attachment to this Revised Revenue Proposal, finds that the operating benefits arising from our proposed technological upgrade represent a reasonable estimate of the benefits which include:

- reduced call out costs, which has been observed following completed sitewide renewals
- reduced routine maintenance requirements, and
- reduced defect rates.

We have considered the AER's Draft Decision and updated our business cases to address its feedback by:

- adjusting the safety risk disproportionality factor from 'six' to 'three' and the environmental risk disproportionality factor from 'six' to 'one'
- removing reputational risk
- reducing operational benefits by 25 per cent to demonstrate the effect if these are reduced, noting that GHD found our original estimate of these benefits to be reasonable
- updating our costs to the latest 2021-22 unit rates, and
- updating the discount rate from 4.8 per cent to 5.5 per cent.

GHD also reviewed our revised business cases and scenario analysis and concluded that our revised business cases are reasonable.

Table 4-15 summarises the outcomes of our assessment for each of the eight business cases rejected by the AER. This shows that six sites remain justified. The details of the update for each site are discussed in the relevant business cases, which are provided as Attachments to this Revised Revenue Proposal.

Table 4-15: Outcome of secondary systems renewal business case updates

Secondary systems renewal site	Initial Revenue Proposal preferred solution	Revised Revenue Proposal preferred solution
Lower Tumut	Full site renewal	Full site renewal
Kemps Creek	Full site renewal	Targeted asset replacement
Vales Point	Targeted asset replacement	Base case (Do nothing)
Gunnedah	Targeted asset replacement	Targeted asset replacement
Nambucca	Targeted asset replacement	Full site renewal
Eraring	Targeted asset replacement	Base case (Do nothing)
Forbes	Targeted asset replacement	Targeted asset replacement
Buronga	Targeted asset replacement	Targeted asset replacement

Our revised forecast for secondary system renewals is $162.4 million as detailed in Table 4-16 below. This includes the 16 sites that the AER accepted in the Draft Decision as well as six sites that remain justified following updates to their business cases.

Table 4-16: Revised forecast for secondary system renewals

Secondary systems renewals	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	21.0	40.4	32.2	35.4	16.4	145.4
AER's Draft Decision	16.7	29.0	16.6	29.6	14.2	106.1
Revised Revenue Proposal	23.5	39.7	32.3	48.1	18.8	162.4

Network property and security - Palisade gate remediation

Our initial Repex forecast included a program to replace two types of palisade gates that are typically both installed at each of our substations:

- Manual hinged swing gates – These gates were the cause of a safety incident and the subject of a WorkSafe improvement notice, as explained in further detail below.
- Motorised sliding gates – These gates are experiencing increased failure rates from deterioration and excessive wear and tear, resulting in operational issues where the gates fail to open or close. This can result in safety issues for staff required to manually operate the gate and a risk to public safety if the gate fails to close, leaving the site open.

Palisade gates are used at substation sites to enable workers' access. The rate of failure of these gates has been increasing and has resulted in a several 'safety and security' incidents. This program of work will manage the safety and operational risks associated with palisade gates by replacing them with modern fit-for-purpose alternatives.

In 2019, an incident occurred at our Orange 132kV substation, where a side access gate that was part of the palisade fence broke off its hinges and fell onto a worker accessing the site, resulting in serious injury. The investigation that followed revealed a design flaw in the hinges of these gates and WorkSafe issued us an improvement notice regarding the use of "3m or larger hinged palisade type gates".

The AER's Draft Decision reduced our initial capex forecast of $7.9 million by $3.0 million or 38.1 per cent to $4.9 million by reducing the scope of our proposed program by 38 per cent.

In this Revised Revenue Proposal, we have decided to accept the AER's Draft Decision, which reduces scope of work to replace only on the highest-risk manual swing gates. However, we are not confident that the AER's allowance will be adequate given the identified issues and the on-going risks.

Our revised forecast for palisade gates remediation is $4.6 million as detailed in Table 4-17 below.

Table 4-17: Revised forecast for palisade gates remediation

Palisade gate remediation	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	4.0	4.0	-	-	-	7.9
AER's Draft Decision	2.5	2.5	-	-	-	4.9
Revised Revenue Proposal	2.3	2.3	-	-	-	4.6

4.9.2.3. Substations

Transformer renewals

Power transformers play a vital role in the network by changing and controlling the voltage and current supplied to customers at points throughout the network. The performance of power transformers is one of the most significant drivers of overall network reliability.

We apply a health index methodology to identify those transformers with the highest risk of failure. The output is an effective age, which is then modelled to an individual probability of failure, which in turn is combined with the consequence (criticality) values for each transformer to determine the optimum intervention strategy.

Our initial Revenue Proposal explained that 10 power transformers will require intervention in the 2023-28 period, with replacement rather than refurbishment being the optimum strategy. This is due to the effective age of the transformers as well as emerging issues related to oil, corrosion and certain types of bushings. In all cases, the replacement option provides a higher NPV than refurbishment.[82]

The AER's Draft Decision reduced our initial capex forecast of $64.4 million for transformer renewals by $37.8 million or 58.7 per cent to $26.6 million based on a top down approach, which assumes that 70 per cent of transformers can be refurbished and only 30 per cent will require replacement because:

- this is consistent with our historical practices of refurbishing rather than replacing transformers
- our condition reports indicate that, subject to minor refurbishment work, most transformers can be returned to service
- our health index uses the transformer manufacturing year, rather than the commissioning year and has a high weighting for age
- we overstate unserved energy by using a 10-week repair time following a transformer failure, and
- the probability and consequence of failure risks are overstated and not supported by evidence.

We have carefully considered whether the AER's alternative suggestion would be more efficient for customers, noting our commitment to leave no stone unturned to reduce costs to customers to ensure our services are provided at the lowest possible costs to address affordability concerns.

We have therefore undertaken deeper analysis of the need to replace rather than refurbish these assets. This has confirmed that:

- the identified option maximises net benefits to customers, consistent with the requirements of the RIT-T
- the nature and scope of the issues associated with the transformers that we are proposing to replace in the 2023-28 period are in fact more extensive than those being addressed through refurbishment in the current 2018-23 period. Therefore, refurbishment will not provide the same level of benefit or life extension for transformers in the 2023-28 period
- the transformers that are in fact being replaced, rather than refurbished, in the 2018-23 period exhibit similar condition issues to those we are proposing to replace in the 2023-28 period, reinforcing that our approach to transformer replacements has remained consistent across regulatory periods
- the assets we are proposing to replace will exceed their effective age in the 2023-28 period, and all but one will exceed their natural transformer age expected life, and
- refurbishing rather than replacing the identified transformers in the 2023-28 period will increase our risk exposure because future replacement needs are increasing. This is because a large proportion of transformers were commissioned in the early 1980s and will therefore be beyond their natural or effective asset lives by the end of the 2023-28 period.

We engaged GHD to independently review our business cases in light of the AER's Draft Decision and the critical role that transformers play in relation to network reliability. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, concludes that:

- consistent with CIGRE's Transformer Reliability Survey 2015, given our average effective transformer age of 55 years, replacement rather than refurbishment options are appropriate. GHD also concludes

[82] See OERs N2404, N2421, N2422, N2423 and N2424.

that, compared with other TNSPs such as Powerlink, we are on average replacing our transformers later in their life

- our asset management strategy for the 2023-28 regulatory period has not changed from the 2018-23 period, and our decision to replace or refurbish transformers is based on net benefits consistent with the AER's Asset Replacement Planning Practice Note
- our proposed number of transformer replacements in the 2023-28 regulatory period is consistent with our long-term average annual transformer replacement quantity
- a small number of our transformers will be replaced in a new location within the substation due to the impacts on reliability during construction, which is a common approach among other transmission and distribution businesses and consistent with our own historical practices
- our probability of failure is based on event data, the calculation of unserved energy is based on industry practice and the assumption of a 10-week replacement period is reasonable based on a risk assessment of spares availability and spares conditions, and
- the analysis detailed in our business cases is supported by actual event data and industry practice.

We have also updated our business case to determine whether they remain economically justified when the inputs are adjusted based on feedback from the AER, by:

- adjusting the disproportionality factor for environmental risk from 'six' to 'one'
- removing reputational risk costs[83]
- updating the Value of Customer Reliability to align with our Network Asset Criticality Framework
- explaining how, where applicable, we have considered in-situ replacement
- explaining the technical limitations associated with the refurbishment of the transformer
- assessing the impact of using commissioning rather than manufacturing date in the health index
- updating our costs to the latest 2021-22 unit rates, and
- updating the discount rate from 4.8 per cent to 5.5 per cent

Table 4-18, which summarises the outcomes of the updated business cases shows that we now propose to:

- refurbish, rather than replace, the Regentville transformer on the basis that its past service history makes it the most suitable candidate for refurbishment, and
- defer the Tenterfield transformer replacement.

We consider that the reduced scope of work in this Revised Revenue Proposal addresses the issues raised by the AER. We are, however, also seeking to include two new spare transformers to replace the 330kV spares that were used in two recent catastrophic events on:

- 18 June 2022 at Dapto 330/132kV substation, and
- 9 October 2022 at Marulan 330/132kV substation.

Currently, we have no 330/132kV transformer spares available, because we used both of our spares in these events. We must therefore procure new spare transformers to ensure these are available in the event

[83] While we believe our use of 'reputational risk' is consistent with the AER's industry practice note we have removed it in our business case update to demonstrate that it does not impact on the business case outcome.

of future catastrophic failure events similar to those that recently occurred. We are placing orders for these new spare transformers now. However, the 18-24 month order lead time means that we will incur costs in the 2023-28 period for these items.

The details of the update for each site are discussed in the specific business case.

Table 4-18: Outcome of transformer renewal business case updates

Transformer renewal site	Initial revenue proposal preferred solution	Revised revenue proposal preferred solution
Molong No.1	Replace	Replace
Tamworth No.1 and No.2	Replace	Replace
Yass No.3	Replace	Replace
Tenterfield	Replace	Deferred to 2028-33 period
Murray No.1 and No.2	Replace	Replace
Regentville	Replace	Refurbish
Inverell	Replace	Replace
Panorama	Replace	Replace
New 330/132kV spare transformer	N/A	New spare required to replace catastrophically failed transformer at Dapto on 18 June 2022
New 330/132kV spare transformer	N/A	New spare required to replace catastrophically failed transformer at Marulan on 9 October 2022

Our revised forecast for transformer renewals is $58.3 million, with the two new 330/132kV spare transformers added to our substation capital spares forecast, as detailed in Table 4-19 below.

Table 4-19: Revised forecast for transformer renewals and substation capital spares ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transformer renewals						
Initial Revenue Proposal	3.0	11.8	22.7	17.8	9.1	64.4
AER's Draft Decision	1.2	4.9	9.4	7.4	3.7	26.6
Revised Revenue Proposal	3.4	12.4	17.9	16.2	8.5	58.3
Substations capital spares						
Initial Revenue Proposal	1.2	1.2	1.2	1.2	1.2	5.8
AER's Draft Decision	1.2	1.2	1.2	1.2	1.2	6.2

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Revised Revenue Proposal		14.9	1.3	1.4	1.3	18.9

Transformer renewals

We are proposing to invest $58.3 million to replace or refurbish nine transformers which are at increased risk of catastrophic failure in 2023-28. These transformers are required to meet IPART's reliability obligations and are essential to keeping the grid running safely and efficiently.

Transformers are expensive, large and complex plant with an expected lifespan of 45 years. They are routinely monitored and maintained to minimise the risk of failure. When the assets' condition begins to deteriorate, we make every effort to refurbish or replace them prior to failure. The average effective age of the transformers we will replace or refurbish in 2023-28 is 54 years (in 2022), which is well above the expected life for a transmission level transformer.

We know that the consequences of catastrophic transformer failures can be severe. We have recently experienced two catastrophic 330kV transformer failures, at Dapto substation in June 2022 and Marulan substation in October 2022. Both resulted in large fires as each transformer holds up to 100,000 litres of oil and carries a large amount of energy. These fires burn for up to two weeks before being completely extinguished. Only after this can we safely commence clean-up and restoration activities.

Our sites are designed to mitigate the initial impact of catastrophic failures consistent with good industry practices and to meet our reliability obligations. However, there is an increased risk of loss of electricity supply to our customers until we can mobilise and replace the failed transformer with a strategic spare, which takes significant resources and around 10 weeks.

The Dapto and Marulan transformer failures have depleted our 330kV strategic spares. We no longer have any spare 330kV transformers should another transformer fail. While we are placing orders for spare transformers, the procurement lead time is 18-24 months, so their cost will fall into the 2023-28 period. We have added these costs to this Revised Revenue Proposal in response to these failures.

Our proposed investment in transformer spares is necessary for a safe, reliable energy supply.

Left: Dapto transformer failure June 2022.

Right: Spare 330kV transformer to be relocated to failure site.

Circuit breakers

Circuit breakers are essential for clearing electrical faults from the transmission network and enabling safe access to the network.

Our initial Revenue Proposal proposed replacing 137 three-phase circuit breakers to manage the increased risk of failure on these assets. We determined the need for replacement using our health index methodology, which feeds into our quantified risk methodology. This asset risk is then assessed in a cost-benefit analysis. The circuit breakers with an optimal replacement timing in the 2023-28 period were included our initial capex forecast.

Our asset failure risk for circuit breakers includes a component for environmental consequences that may result following catastrophic failure. This environmental risk captures bushfire risk and the loss of SF6 gas. Our environmental consequence for loss of SF6 gas included a disproportionality factor of 'three'.

The AER's Draft Decision reduced our initial capex forecast of $36.9 million for circuit breaker replacements by $5.8 million or 15.7 per cent to $31.2 million by reducing the disproportionality factor for environmental risk from 'six' to 'one' and removing reputational risk costs. These changes reduce our proposed replacement scope from 130 to 108 circuit breakers

Based on the AER's Draft Decision, we have performed further analysis to test if the AER's proposed changes to our input assumptions results in different business case outcomes. We have therefore updated our business cases by:

- adjusting the disproportionality factor for environmental risk from 'six' to 'one'
- removing reputational risk
- updating our costs to the latest 2021-22 unit rates, and
- updating the discount rate from 4.8 per cent to 5.5 per cent.

This analysis reduces our initial Revenue Proposal to 122 circuit breakers in the 2023-28 regulatory period. We consider the reduced scope in this Revised Revenue Proposal addresses the issues raised by the AER.

Our revised forecast for 122 circuit breaker replacements is $36.9 million as detailed in Table 4-20 below.

Table 4-20: Revised forecast for circuit breaker replacements

Circuit breaker replacements	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	8.3	7.6	3.8	8.4	8.8	36.9
AER's Draft Decision	7.0	6.4	3.2	7.1	7.4	31.2
Revised Revenue Proposal	8.3	7.6	3.8	8.4	8.8	36.9

4.10. Augex

Our initial Augex forecast of $253.6 million for the 2023-28 regulatory period, excluding pre-approved EnergyConnect capex, will maintain a reliable, safe and resilient network that supports the changing energy system. Our initial Augex forecast is $104.0 or 29.1 per cent lower than our expected 2018-23 Augex, excluding capex on ISP projects. This compares with the AER's Draft Decision of $240.3 million, which is $117.3 million or 32.8 per cent below our estimated 2018-23 Augex.

The AER undertook a detailed review of our Augex by each of the five sub-categories:

1. major projects
2. strategic property
3. base Augex (excluding major projects)
4. connections, and
5. pre-approved capex for EnergyConnect.

Table 4-21 compares our initial Revenue Proposal with the AER's Draft Decision for each sub-category of Augex. It shows that the AER reduced our 2023-28 forecast Augex of $253.6 million (excluding pre-approved capex for EnergyConnect) by $13.3 million or 5.3 per cent to $240.3 million. Table 4-22 shows the AER's Draft Decision removes five projects valued at $28.1 million from our Base Augex and that this reduction is partially offset by the updated inflation applied by the AER to the projects that it accepted.

Table 4-21: Augex – our initial Revenue Proposal and the AER's Draft Decision ($M Real, 2022-23)

Augex	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Major Projects	71.9	76.6	4.7	6.6%
Strategic Property	17.3	18.4	1.1	6.5%
Base Augex (excluding major projects)	161.6	142.2	(19.4)	(12.0%)
Compliance	36.9	37.0	0.1	0.4%
Demand	85.2	81.7	(3.4)	(4.0%)
Economic Benefits	39.6	23.5	(16.1)	(40.7%)
Connections	2.9	3.0	0.2	6.4%
Total Augex (excluding pre-approved EnergyConnect and NCIPAP)	**253.6**	**240.3**	**(13.3)**	**(5.3%)**
Pre-approved EnergyConnect	532.8	530.7	(2.2)	(0.4)
Total including pre-approved EnergyConnect	**786.5**	**771.0**	**(15.5)**	**(2.0)**
NCIPAP	16.2	17.2	1.1	6.5%

The AER's Draft Decision rejected five projects from our Base Augex based on its concerns that our initial Revenue Proposal did not:

- adequately demonstrate that the large spot loads (e.g., mines) that drive some projects will eventuate, noting that future spot loads, particularly the timing, are uncertain
- adequately consider the potential for non-network solutions to defer or avoid the proposed augmentation, and

- demonstrate our ability to deliver our proposed Augex projects, especially given our large capex program to deliver AEMO's ISP and the NSW Government's PTIP projects to support the energy transition and our previous deferral of Augex projects.

Table 4-22 shows the projects removed by the AER under each of the three categories that comprise base Augex being, compliance projects, demand projects, and economic benefit projects.

Table 4-22 Base Augex - our initial Revenue Proposal and the AER's Draft Decision ($M Real, 2022-23)

Base Augex	Initial Revenue Proposal	AER's Draft Decision
Compliance projects		
Maintain Voltage in Alpine area	2.1	0.0
Demand projects		
Supply to far west NSW	8.4	0.0
Economic Benefits projects		
Manage multiple contingencies in Sydney north west area	10.1	0.0
Manage multiple contingencies at Bayswater to Sydney area	4.7	0.0
Manage multiple contingencies at north west NSW area	2.7	0.0
Total	**28.1**	**0.0**

Feedback from the TAC on the AER's Draft Decision

We have reviewed the AER's findings and, in October 2022, sought feedback from the TAC on the AER's Draft Decision and how we should respond in our Revised Revenue Proposal. The feedback from the TAC is summarised below.

Demand uncertainty

Overall, the TAC supported the AER's Draft Decision to exclude projects where demand uncertainty still remains. The TAC also noted that:

- new technologies may become available in the future, which supports removing the projects now, and
- delaying these projects will support a clearer value proposition in the future should these projects be required later.

Delivering our 2023-28 capital works program

Overall, the TAC and the CCP acknowledged and shared the AER's concerns regarding our ability to deliver our capital works program in this Revised Revenue Proposal given our commitment to deliver Major Projects required for the energy transition.

The CCP also commented that deliverability is an industry-wide issue given the shortage of people and materials required to deliver the major infrastructure projects underway across the country.

We understand the basis of this commentary but believe it is ill-founded. To address these concerns, we have prepared a 2023-28 Deliverability Plan, provided as an Attachment to this Revised Revenue Proposal, which demonstrates our ability to prudently and efficiently deliver our proposed 2023-28 works program in this Revised Revenue Proposal, while also delivering AEMO's Actionable ISP projects and the

NSW Government's PTIP projects that are required to support the energy transition. The Plan explains that we are aware of and prepared for the resource challenges facing the industry. We have responded to these challenges by making various structural and operational changes to de-risk the deliverability of our BAU Repex and Augex capital works program including:

- implementing a new operating structure to mitigate deliverability risks. We have established two separate delivery units (Delivery Business Unit and Major Projects Business Unit), each with their own separate sourcing strategies, capital planning processes, resourcing and contractor pools
- establishing new contracting strategies to overcome supply constraints. We are now using:
  - different tiers of contractors for the two different work streams
  - lock-in contracts for contractors, equipment and materials
  - key panels to support long supply leads and early procurement
  - direct purchase of key and long lead time equipment, and
  - risk mitigation actions to achieve an equitable risk allocation that contractors are willing to accept.
- introducing stronger project governance. We have reviewed and made changes to our project governance to ensure it is fit for purpose in the current environment. We have made key changes, including improving the overall robustness of our audits and introducing multiple points of delivery accountability.

While we agree that in the 2023-28 regulatory period we will deliver investment of a previously unseen scale, in terms of our 2023-28 BAU forecast capex:

- our Repex is in line with what was delivered in 2018-23, and
- our Augex is lower than the 2018-23 period.

We also note that, even before introducing the new operating structure and other associated changes, we delivered several major projects (including Queensland-NSW Interconnector (QNI) Minor and Victoria-NSW Interconnector (VNI) Minor projects, Powering Sydney's Future, and Stockdill) on top of our BAU capital works program in the 2018-2023 period. These projects were delivered on time and in line with the overall budget. This demonstrates that, even if our BAU Contingent Projects (discussed in Chapter 9) were to eventuate, we have capacity to deliver these as well as our forecast Repex and Augex programs.

Our 2023-28 Deliverability Plan acknowledges the deliverability risk faced by the broader industry as it transitions to a renewable future. The Plan demonstrates how the above changes will enable us to secure the resource and supply requirements to continue to deliver our proposed capex projects on time and within budget. Given our many years of experience and well-established processes, backed by appropriate levels of planning and preparation, we are well positioned to mitigate the deliverability risk facing the broader industry. We are ready to deliver the future grid, with our Major Projects Business Unit, while continuing to maintain the safety, security and reliability of the existing network, with our Delivery Business Unit.

The AER's Draft Decision and our response

On the basis of the TAC's feedback, we have accepted the AER's Draft Decision for all Augex projects other than the 'Maintain Voltage in Alpine area' project. As discussed below, this is because Essential Energy has updated its load forecast which has confirmed that the project is required by 2027-28. The TAC was supportive of our approach, subject to providing it with documents that demonstrate that the updated load forecasts from Essential Energy support the investment proceeding in the 2023-28 period.

Maintain Voltage in Alpine area

Essential Energy has updated its load forecast and has confirmed that it now expects load growth to occur sooner than initially forecast. This updated load forecast is published in our 2022 TAPR.

This updated load data now indicates that, to meet the optimal timing, this project is required by 2027-28 to meet expected future demand growth in the Alpine area of NSW supplied from Munyang and Cooma Bulk Supply Points. The latest demand forecasts from Essential Energy show that load growth from new residential and commercial developments in the South Jerrabomberra area will result in voltages at Munyang and Cooma falling below the allowable levels required to maintain compliance with NER S5.1.4 under critical contingency conditions from 2025-26.

Based on the updated load data, the timing of this project is earlier than the 2029-30 timing in our initial Revenue Proposal. In light of this, and consistent with the feedback from the TAC, we have included the full project cost of $25.7 million in our Revised Revenue Proposal rather than $2.1 million associated with the development costs (per our initial Revenue Proposal).[84] As requested by the TAC, we commissioned GHD to undertake an independent review of our demand forecast. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, confirms that our revised load forecast and analysis is realistic and that the solution should be implemented within the 2023-2028 regulatory period.

Our revised forecast for Maintain Voltage in Alpine area is $25.7 million as detailed in Table 4-23 below.

Table 4-23: Revised forecast for Maintain Voltage in Alpine area

Maintain Voltage in Alpine area	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Initial Revenue Proposal	-	-	-	0.3	1.8	2.1
AER's Draft Decision	-	-	-	-	-	-
Revised Revenue Proposal	-	0.3	2.1	17.0	6.3	25.7

4.10.1. New additional Augex

In our initial Revenue Proposal, we explained that we intend to include new additional capex in our Revised Revenue Proposal, which is:

- driven by external obligations and developments in our operating environment since our initial Revenue Proposal (as per our consultation with the TAC), and
- necessary to address network solutions required by recently completed RIT-T that were underway at the time we submitted our initial Revenue Proposal.

Table 4-24: New additional Augex

New additional capex	External driver	Forecast 2023-28 capex
System Security Roadmap	• AEMO's Engineering Framework Initial Roadmap	88.2

[84] The bulk of the work for this project will be undertaken in the 2028-33 period given the 2029-30 anticipated commissioning date

New additional capex	External driver	Forecast 2023-28 capex
	• 2022 ISP published in July 2022	
AEMO NSCAS gap and PMUs	• AEMO declared Coleambally region NSCAS gap • AEMO has issued a notice to install PMU devices	16.1
New customer connection	• Essential Energy requested connection of new mining (Supply to Panorama area – McPhillamy's mine connection) load through the joint planning process	15.3
Recently completed RIT-Ts	• Outcomes of RIT-Ts	9.3
Total new additional capex[85]		**128.8**

We consulted with the TAC on each of these through our Revenue Reset deep dives. In relation to System Security, we also met with the TAC in our SSR and ETWG workshops. Each of these matters and the TAC's feedback is discussed in Sections 4.10.1.1 to 4.10.1.4.

4.10.1.1. System Security Roadmap

What is our System Security Roadmap?

A complex energy system needs modern tools and skills

Big power outages happen when grid operators cannot correct small issues quickly.

- Grid control rooms must ensure that the power system operates securely, within a complex technical envelope.
- Disturbance can push the system outside the envelope and control room operators must respond immediately to ensure continued secure operation and prevent cascading failures and outages.
- Less coal and more renewables make it harder for grid operators to manage the network.
- The power system is getting bigger and more complex as we transition to renewables and as coal generation retires. By 2030, only two coal generators are expected to remain in NSW, with hundreds of wind and solar generators, and millions of rooftop solar systems together providing 29GW of additional power.
- NSW is adding renewable energy to the grid faster than almost anywhere in the world.
- The growth in renewables is causing supply and demand to fluctuate more widely with the weather making the grid more complex and difficult to control. When a cloud rolls over the sun, everything changes! In some months, 40,000 alarms are going off in Transgrid's control rooms.
- This means that grid operators have to keep track of vast volumes of rapidly changing data, overwhelming their current capacity to make informed decisions.

What happens when grid controllers don't have enough information?

- International experience has demonstrated that major blackouts can prevail:

85 This does not include $11.8 million for Managing risk on line 86 – Tamworth to Armidale, which is discussed as part of Repex

> California's 24-hour blackout in 2011 and the UK's national blackout in 2019 cascaded from minor events to blackouts in part due to a lack of analytics and situational awareness in control rooms.

> The US-Canada Power System Outage Task Force found that common factors in every major outage in the US and Canada between 1965 and 2003 included:

    - the inability of system operators to visualise events on the system
    - failure to ensure the system operation was within safe limits, and
    - ineffective communication and inadequate training of operating personnel.

- We can't blame the operators for these blackouts. They were trying to respond to a rapidly escalating situation they couldn't see.
- It's like using a paper map to navigate how to get to safety, versus having Google maps telling you where you are and exactly what's happening ahead of you – in real time.

We need vital planning, asset management and operations capabilities.

- Planning is essential to ready the grid for new renewable generators and the new infrastructure and services required to maintain system security as coal generation retires.
- Adding new and novel technologies, like grid batteries, requires more detailed and complex network and planning studies to maintain system security.
- We need to run multiple forecasts and system simulations across different time horizons, factoring in different demand and supply conditions. We will not have the level of modelling capability required to run these studies and scenarios effectively without an uplift in capacity and training.
- As the transmission network gets bigger, assets age, renewable connections increase and novel equipment is added, managing the operation of our network and the health of our assets becomes even more complex, requiring an uplift in capacity and training.

We propose to invest in new tools, training and more people to ensure we can continue to operate our network in an increasingly complex, modern power system

- We propose to invest $135.8 million (capex and opex) in the 2023-28 period to upgrade our control rooms and operations, planning and asset management functions to ensure we have the right technology, tools, people and skills needed to securely run a grid that is seeing increasing levels of renewable penetration, and possibly up to 100 per cent renewable energy at times in the coming five years.
- Our proposed investment will mitigate the growing risk that power system complexity will result in system security incidents.

Our proposed investment will deliver net benefits of $819.2 million over 10 years

- Our proposed investment will provide insurance against the increasing risk to energy customers of growing power system outages. Even if the amount of benefits is only one fifth of those calculated by experts, the investment will have more than paid for itself.
- As our network expands and becomes more complex, the new tools and skills will help us to perform more power system and planning studies better and faster, including modelling future outage scenarios as our transmission network expands, helping connect new renewables quicker.

We are committed to a coordinated and efficient whole of industry approach.

- We are collaborating with AEMO and our fellow Australian NSPs to ensure a coordinated, streamlined and efficient approach to delivering these tools and systems that avoids duplication and overlap to keep costs as low as possible
- We will continue collaborating across the industry, working to ensure the entire system can visualise and manage power flows without doubling up costs or capabilities.
- Our priority is to share learnings, standardise data and line up interfaces to support whole-of-system integration and communication, and prevent duplication or redundancy. The ability to share data is critical. For example, we will share with AEMO data from the high-precision current and voltage measurement devices we are installing in our network

The System Security Roadmap project has helped define both the Operational Technology and internal capacity uplift required to maintain the secure operation of our network as the NEM transitions to periods of up to 100 per cent renewables.

As discussed in our initial Revenue Proposal, we explained that AEMO's NEM Engineering Framework Initial Roadmap, published in December 2021, identified that urgent and significant investment is required to address the energy transition and the increase in instantaneous penetration of renewables:[86]

> *urgent and extensive industry collaboration and effort is needed to engineer the power system to meet these new conditions in a timely and orderly manner, with positive consumer outcomes at the heart of all decision-making.*

Due to the timing of AEMO's announcement in December 2021, our initial Revenue Proposal did not include the costs of readying our network for 100 per cent renewables.

In its 2022 ISP published in June 2022, AEMO reconfirmed the need for urgent and significant investment in our network to maintain the secure operation of the NEM as it transitions to 100 per cent renewables:[87]

> *Uplifts are needed in in real time monitoring, power system modelling, and control room technologies by AEMO and Network Service Providers, to ensure operational staff have the tools to maintain secure operation of the NEM power system as it transitions to significant penetrations of inverter-based resources including Distributed Energy Resources. AEMO has developed a strategic roadmap for this uplift*

As discussed in Chapter 3, since submitting our initial Revenue Proposal, we have commissioned independent power system expert, PowerRunner, to advise us on the nature and scope of investments required to enable us to continue to plan, maintain and operate securely as we transition towards higher penetrations of renewable. PowerRunner's assessment:

- quantified the emerging system complexity and risks and assessed the expected risk of power system events and unserved energy in NSW if left unmitigated
- reviewed our existing capabilities and capacity to identify the changes required so that we can effectively plan, manage and operate the NSW power system, and
- identified the nature and scope of the tools, systems, people and processes required to uplift our capabilities and capacity so that we can continue to meet our obligations under the NER, including the

[86] AEMO, NEM Engineering Framework Initial Roadmap, December 2021, p. 6.
[87] AEMO, 2022 Integrated System Plan (ISP), June 2022, p. 58.

associated with investment. PowerRunner's assessment considered the options and associated costs and benefits of the potential changes.

PowerRunner found that, based on our existing capabilities and capacities, we:

- would be unable to manage the power system securely for this future state, and
- are not capable of being scaled to manage the future power system securely.

We discussed the drivers, scope and expected outcome from this project with the TAC at our SSR working group, ETWG workshops and Revenue Reset deep dives. In these sessions, the TAC:

- raised concerns about the input risk assumptions used in the business case, noting that the 13 per cent likelihood in the 'do nothing' base case of a NSW black system event in 2030 appears high and that the level of mitigation achieved by the proposed capability and capacity uplift (60%) may be too low.
- asked us to test the sensitivity of the project's viability with changes to:
  - system security event likelihood
  - level of risk mitigation achieved by uplift in Transgrid capabilities and capacity, and
  - confirm edge-case project viability
- queried why this investment is in the long-term interest of consumers and asked us to develop a plain English narrative to address this issue, noting the highly technical nature of the investment
- raised concerns about the potential overlap with investments undertaken by other NSPs and AEMO, and asked us to demonstrate that we have a coordinated approach with the broader industry to ensure that customers will only be paying once for this investment, and
- noted that, if this is a business development opportunity for Transgrid, then it should be funded by Transgrid's equity holders and not funded by customers.

We are grateful for the TAC's feedback and acknowledge that the TAC has raised important issues that require further analysis and revision. In response to this feedback, we:

- tested the sensitivity of the investment in conjunction with PowerRunner and updated the business case to incorporate these outcomes. Our updated analysis confirmed that:
  - typically, system operators globally use qualitative rather than quantitative analysis to assess system operability risks arising from the energy transition. These published qualitative assessments highlight the growing system reliability and security risks, and mitigation measures, and
  - the investment is still expected to deliver positive net benefits even when the risk escalation is six times lower than initially assessed by PowerRunner.
- provided the TAC with a plain English overview of the drivers for the investment and the expected outcomes for customers, including why these are in their long-term interest. We also set out how we are working with AEMO and other NSPs to ensure a coordinated, streamlined and efficient approach that avoids any overlap in investment to keep costs as low as possible.

We propose the following two projects in the 2023-28 period to uplift our technology and ensure our compliance with our obligations under Chapters 4 and 5 of the NER, including the requirement to operate the transmission network in a secure operating state, and to plan, design and operate the transmission network in accordance with defined power system standards:

- **Digital twin** – This is a modelled representation of the physical system used to simulate planning and modelling. When used in combination with sensor data, it improves our ability to diagnose operational issues, understand system health and improve system efficiency. A digital twin will enable us to test and learn how new technologies might operate in the field. It will also enable us to analyse data from new SCADA and Phasor Measurement Unit (PMU) sensors (installed under AEMO's notice discussed in Section 4.10.1.2) to improve forecasts and better understand system conditions.
- **Situational awareness and real time decision support** – This investment will provide our network operators with better visibility of system conditions in real time and near real time, so that they can make informed decision and respond effectively to system events as they are occurring. This is a critical requirement for us to maintain system security, anticipate events and respond appropriately before and after system events occur.

Our updated business case, PowerRunner's report and an independent assurance review from CutlerMerz are provided as Attachments to this Revised Revenue Proposal.

The suite of new digital tools, as recommended by PowerRunner, is summarised in Table 4-25.

Table 4-25: Summary of PowerRunner recommendations for Operational Technology uplift

Initiative	Function
Digital Twin – Modelled Representation of Physical System	
Data Governance & Calculation Platform	Structuring and consolidating disparate data as a single source of truth
Asset Registration	Customer and asset registration interface, process and workflow management application which populates downstream systems
Single Network Management Model	Central source of power system data and tool for network models – digital twin
Situational Awareness and Real-Time Decision Support	
Alarm Analytics	Root cause detection tool to distil large quantities of information into manageable insights to support real time decision making
Advanced Forecasting	Artificial intelligence and machine learning-based forecasting for substations and key nodes
Advanced Neural Net State Estimation	Increased visibility of network conditions hour/day/week look ahead - load flow analysis
Visualisation & Operations Decision Support	Providing actionable information to control room operators and asset management
Asset Health Decision Support	Support decision making on asset health and near real time asset condition analysis

Table 4-26 sets out our capex forecast as estimated by PowerRunner for the 2023-28 period.

Table 4-26: System Security roadmap - forecast capex ($M, Real 2022-23)

Initiative	FY24	FY25	FY26	FY27	FY28	Total
Digital Twin						
Single Network Model Management	12.3	6.5	3.9	2.1	0.1	24.9
Asset Registration	4.6	1.3	1.3	1.2	-	8.4
Data Governance and Calculation Platform	10.7	2.7	-	-	-	13.4
Situational Awareness						
Alarm Analytics	4.5	0.3	0.0	-	-	4.9
Forecasting	5.7	0.3	-	-	-	6.0
Advanced Neural Net State Estimation	9.9	2.3	0.1	-	-	12.3
Visualisation and Operational Decision Support	5.4	2.8	1.0	-	-	9.2
Asset Health Decision Support	5.8	2.0	-	-	-	7.8
Support across all applications	1.4	-	-	-	-	1.4
Total Capex	60.2	18.2	6.3	3.3	0.1	88.2

In addition to the capex requirements, we will also incur unavoidable annual increases in our opex as a result of ongoing annual licensing and maintenance costs and the capacity uplift involving additional staff, skills sets and training. The opex step change for these costs is discussed in Chapter 3.

4.10.1.2. AEMO requirements

Since submitting our initial Revenue Proposal, AEMO has:

- declared an immediate Network Support and Control Ancillary Services (NSCAS) gap in the Coleambally region, and
- issued us with a notice under NER 4.11.1(d) and (e) to install PMU real-time monitoring devices for power quality to help maintain power system security.

We discussed with the TAC in our Revenue Reset deep dives:

- how we are proposing to respond to these requirements, including the nature, scope and timing of our proposed investments in the 2023-28 period, and
- the associated forecast costs that we intend to include in this Revised Revenue Proposal to address these requirements, noting that our forecast capex for installing PMUs is lower than the cost included by AEMO in its cost-benefit assessment.

The TAC supported our adoption of a lower forecast capex for PMUs compared to AEMO's cost estimate and queried whether a RIT-T was required for the PMUs.

Our response to AEMO's requirements and the associated costs included in this Revised Revenue Proposal are discussed below.

Immediate NSCAS gap in the Coleambally region

AEMO forecasts that minimum demand in NSW will rapidly decline over the next 10 years due to ongoing growth in distributed solar PV generation.[88] In south-west NSW, growth in small to large scale embedded generation connecting to Essential Energy's network is forecast to continue, driving declining minimum demand in this region.

The south-west NSW region is supplied by four 132 kV transmission lines, which form a link between Wagga Wagga and Darlington Point, via Deniliquin, Coleambally and Finley. Our power system studies show that declining minimum demand means that the electricity transmission system in these areas is at risk of exceeding allowable voltage levels during times of low demand and, in particular, when nearby solar farms are unable to provide reactive power support.

In addition to the excessive voltage issues that we have identified, AEMO has declared an immediate NSCAS gap of 2 MVAr absorbing reactive power in the Coleambally region overnight, when nearby solar farms are not available.[89]

We are required to manage the risk of system voltages exceeding their allowable limits set out in the NER[90] and procure services to meet the NSCAS gap declared by AEMO.[91]

In June 2022, we commenced a RIT-T examining various options to address the excess voltage levels to ensure compliance with the requirements of the NER and received no submissions in response to the PSCR (the first stage of the RIT-T process). The preferred option identified in the RIT-T PSCR involves installing two 11 MVAr 66 kV reactors at Deniliquin at a cost of $8.1 million, which we have included in our revised 2023-28 Augex forecast. We expect to release the Project Assessment Conclusion Report (PACR) in December 2022 confirming this as the preferred solution.

Table 4-27 details the new additional capex we have included in this Revised Revenue Proposal for responding to the NSCAS gap in Coleambally region.

Table 4-27: New additional capex for responding to the NSCAS gap in Coleambally region ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
NSCAS gap in Coleambally region	1.8	5.7	0.6	-	-	8.1

Installation of PMU real time monitoring devices

In June 2022, AEMO issued us with a notice under NER 4.11.1(d) and (e) requiring us to, by:[92]

- 31 December 2023, upgrade, modify or replace remote monitoring equipment (the existing PMUs at [redacted]) so that they comply (if they do not currently comply) with specifications provided by AEMO to remotely monitor the performance of Transgrid's transmission system at those locations

88 AEMO, 2021 Electricity Statement of Opportunities, August 2021.
89 AEMO, 2021 System Security Reports, December 2021.
90 Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage. We expect a non-compliance with this requirement will occur without remedial action.
91 AEMO, 2021 System Security Reports, December 2021, Section 3.4.
92 On 27 June 2022, we received a letter from AEMO with a notice under clauses 4.11.1(d) and (e) of the NER. This letter is provided as an attachment to this Revised Revenue Proposal.

- 31 December 2023, install remote monitoring equipment (PMUs complying with specifications provided by AEMO) to replace the existing Qualitrol high-speed monitoring (HSM) devices and remotely monitor the performance of Transgrid's transmission system at a number of locations[93]
- 31 December 2024, install remote monitoring equipment (PMUs complying with specifications provided by AEMO) to remotely monitor the performance of Transgrid's transmission system at a number of locations,[94] and
- 31 December 2025, install remote monitoring equipment (PMUs complying with specifications provided by AEMO) to remotely monitor the performance of Transgrid's transmission system at a number of locations.[95]

AEMO is required to consider the NEO in carrying out its functions, including prior to issuing a clause 4.11.1(d) notice requiring the PMU investment. This requires AEMO to undertake a cost benefit analysis to determine that the proposed investment it is requiring TNSPs to undertake is efficient and promotes the efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to: price, quality, safety, reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

In August 2022, AEMO provided us a cost benefit analysis for the installation of the PMUs in NSW. This included an estimated cost range of $17.7 million to $21.6 million to install the PMUs.

To ensure the costs in our Revised Revenue Proposal are as low as possible, we undertook a feasibility study to identify the most efficient approach to meet AEMO's directive. Our feasibility study confirms that we can install the PMUs and meet the requirements in AEMO's notice at a materially lower cost than the $17.7 million to $21.6 million estimated by AEMO. We have reflected this lower cost in our revised forecast capex.

On 18 August, we wrote to the AER requesting confirmation that, given AEMO's cost benefit analysis, we are not required to undertake a RIT-T. On 26 September, the AER confirmed that we are not required to undertake a RIT-T for this investment.

Table 4-28 details the new additional capex we have included in this Revised Revenue Proposal for installing PMU real-time monitoring devices.

Table 4-28: New additional capex for installing PMU real time monitoring devices

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AEMO – PMU devices	3.8	2.8	1.4	-	-	8.0

4.10.1.3. New customer connection request

In March 2022, Essential Energy notified us that the McPhillamy's gold mine in Central-West NSW had submitted an application to connect to its network. While the mine will be connected to Essential Energy's distribution network, the mine will draw load from our upstream Panorama 132kV substation.

In July 2022, we received an updated request from Essential Energy with a higher demand forecast for the mine.

93 [redacted]

94 [redacted]

95 [redacted]

The mine is currently planning to connect to the existing electricity network through Essential Energy's distribution network and is expected to significantly increase demand at our Panorama substation from 2024 onwards, with load expected to grow from 25 MVA in 2024 to 35 MVA by 2029.

Under NER we are required to:[96]

- perform joint planning with Essential Energy, and
- respond to Essential Energy's connection request to manage the demand in the area.

This load increase will cause voltage compliance issues if connected at 66kV at our existing Panorama substation and require upgrades within Essential Energy's network. We are currently conducting a RIT-T on this proposed need. Our assessment has shown that the preferred and lowest cost solution to connect the load is to establish a new 132kV switching station and connection point along our Panorama to Orange North (Line 948) transmission line.

We have engaged GHD to review the demand and the processes we have undertaken in relation to this connection request. GHD's report, which is provided as an Attachment to this Revised Revenue Proposal, concludes that our load forecast and timing assumptions are reasonable and our business case identifies the most cost-effective network options.

Table 4-29 details the new additional Augex we have included in this Revised Revenue Proposal for responding to this customer connection request in the Panorama area.

Table 4-29: New additional capex for customer connection request in Panorama area

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
New customer connection request – Panorama area	4.4	10.7	0.2	-	-	**15.3**

4.10.1.4. Recently completed RIT-Ts

At the time of submitting our initial Revenue Proposal in January 2022, there was uncertainty regarding three Augex projects (as well as one Repex project), as they were undergoing RIT-Ts that were expected to be completed by July 2022. We explained that we would include the costs of the preferred network option identified in the RIT-T as appropriate in our capex forecast in our Revised Revenue Proposal. This approach ensured that the preferred option for each project was consulted on through the RIT-T process and that only efficient network costs were included in our forecasts.[97]

To provide transparency to our customers, we included the indicative costs (revenue and price impacts) of the then most likely network option for each project in our initial Revenue Proposal. The total indicative cost of these projects was $741.9 million and comprised:

- Managing risk on Line 86 (Tamworth – Armidale) – $331.1 million (this is a Repex project and is listed here for completeness. This was originally envisaged as an Augex project however the preferred solution under the RIT-T is a Repex project, discussed in Section 4.9.2.1.)
- Improving stability in south western NSW – $127.1 million

[96] NER clause 5.14 requires us to undertake joint planning and NER clause 5.2.3 requires us to manage the demand in the area.

[97] In deciding whether or not it is satisfied that our capital expenditure forecast meets the *capital expenditure criteria* in NER clause 6A.6.7(c), one of the *capital expenditure factors* the AER must have regard to is any relevant Project Assessment Conclusions Report published as part of a RIT-T application (NER 6A.6.7(e)(13)).

- Maintaining reliable supply to the North West Slopes area – $166.3 million, and
- Maintaining reliable supply to Bathurst, Orange and Parkes (BOP) Stage 1 – $117.4 million.

In presenting these indicative costs, we recognised that the preferred option, which was ultimately identified through the RIT-T process, could be a network, non-network or a combination of a network and non-network solution. In advance of completing the RIT-Ts, it was not possible to identify the preferred option and the associated capex (and opex).

We have now completed these RIT-Ts and published PACRs identifying the preferred option for each project. The RIT-T processes enabled us to engage with a range of potential non-network providers, with a focus on the extent to which we are able to drive down costs to customers through adopting non-network solutions and innovative technologies that either replace or defer the need for network investment. Table 4-30 shows that:

- the preferred option identified in the RIT-Ts for both south western NSW and North West Slopes involves a combined network and non-network solution, with the non-network component allowing the deferral of the network component, and
- in the case of 'maintaining reliable supply to BOP Stage 1', there are two equal top-ranked options, one comprising a combined network and non-network solution and the other involving a solely non-network solution.

On 26 July 2022, the Public Interest Advocacy Centre (PIAC) raised a dispute under clause 5.16B NER with the AER in relation to the RIT-T PACRs for maintaining reliable supply to the North West Slopes area and maintaining reliable supply to Bathurst Orange and Parkes areas. PIAC believes that we may have incorrectly applied the RIT-T for these projects. In particular, PIAC is concerned that the:

- scenarios used to assess the costs and market benefits for each credible option are not reasonable, or have not been reasonably weighted, because the assumptions and inputs relating to network capital costs, demand forecasts, VCR and discount rates are incorrect, implausible or outside of what can be assumed with reasonable confidence.
- use of these incorrect or implausible assumptions, and the unreasonable weighting of the scenarios, may have materially influenced timing of investment, ranking of the credible options and basis for any investment.

The AER is currently assessing the dispute and has advised that it will make a decision on our compliance with the RIT–T and NER by 29 November 2022.

The AER's Draft Decision provides feedback on three of the four projects:

- Managing Line 86 – The AER supports the de-scoped option identified in the RIT-T but has queried the efficiency of our forecast capex. This is discussed in Section 4.9.2.1.
- Improving stability in south west NSW – The AER supports the network support arrangements, but does not support the construction of the network solution, noting that:
  - the majority of benefits occur in the early years of the project and therefore further consideration should be given to extending both the BESS network support agreement and the existing special protection scheme
  - it is not clear why the RIT-T attributes the benefits occurring prior to the new transmission line being commissioned to the network project, and

> a more rigorous assessment of options, assumptions and benefits is likely to find that the network project does not have a positive net market benefit.

- Maintaining reliable supply to the North West Slopes area – The AER supports the BESS component of the solution and the installation of a new third transformer at Narrabri ($9.3 million) but does not support the transmission line upgrade component (of which $35.3 million may be required in the 2023-28 period). The AER's concern relates to the uncertainty around the load from the Narrabri Gas Project, which remains uncommitted, as well as uncertainty around other developments in the area.
- Maintain reliable supply to BOP Stage 1 - The AER has not yet reviewed this project.

In light of the AER's feedback, and our commitment to leave no stone unturned to drive our costs as low as possible, we have undertaken further work to identify additional opportunities to drive down our costs. In collaboration with the TAC, we have decided to rely on the non-network component of the preferred solutions to the greatest extent possible. These solutions reflect innovative technologies that either replace or defer network investment, placing downward pressure on our costs. This is critical to supporting affordability, which is our customers' highest priority. The efficient use non-network solutions would reduce the indicative capex of $741.9 million in our initial Revenue Proposal by $732.6 million to $9.3 million[98] for network investments.[99]

In the following projects, this would involve:

- Improving stability in south west NSW – We intend to extend the term of network support from the BESS from three years (as assumed in the RIT-T) for as long as possible to defer the network investment component to beyond the 2023-28 period.[100] This requires AEMO to confirm that, it is able to increase the voltage stability limits on the 330kV line to an agreed acceptable threshold.[101]
- Maintaining reliable supply to the North West Slopes – Consistent with the AER's Draft Decision, we intend to rely on network support from BESS at the Gunnedah 132 kV substation and the installation of a new transformer at our Narrabri substation ($9.3 million). As discussed in Chapters 9 and 10, we have included a nominated pass through event and contingent project to address the risk that no non-network proponents are able to commit to provide the service in the required timeframe. We have also included upgrading the existing transmission lines in the area ($132.8 million)[102] as a stage 2 contingent project because its timing is uncertain and dependent on future demand growth in the area becoming committed (in particular the Narrabri Gas Project).[103] This approach ensures our customers only pay for this investment if and when it is needed. It is also consistent with the feedback in the AER's Draft Decision.
- Maintain reliable supply to Bathurst, Orange and Parkes areas Stage 1 – We intend to rely solely on a non-network solution comprising BESS at Parkes and Panorama and the installation of static

[98] $9.3 million for Maintain reliable supply to North West Slopes. This does not include $11.8 million for Managing line 86 (Repex).
[99] We have updated the RIT-Ts to reflect our latest 2021-22 unit rates. HoustonKemp has updated its NPV analysis underpinning the RIT-Ts to incorporate our latest 2021-22 unit rates and has confirmed that this update does not change the RIT-T NPV outcomes. HoustonKemp's analysis is provided as an Attachment to this Revised Revenue proposal.
[100] Additional analysis has confirmed that this is the preferred option subject to the BESS proponent agreeing to a long term network support contract Refer to attachment: HoustonKemp - Improving stability in south west NSW analysis update - November 2022.
[101] Subject to successful commissioning and testing of performance standards. The current limit is 300 MW and we expect that it would need to increase to at least 420 MW in the easterly direction. This relief provided by the BESS may no longer be adequate if future network or generation changes occur, such as additional generation connecting in the area.
[102] Of which it is expected that $35.3 million may be required in the 2023-28 period.
[103] In the event that we are unable to conclude a network support contract with a BESS, part of Stage 2 of this project (rebuilding the existing Line 969) would instead be progressed, as a contingent project.

synchronous compensators (STATCOMs) at Parkes and Panorama (provided as a non-network solution). As discussed in Chapters 9 and 10, we have included a nominated pass through event and contingent project to address the risk that no non-network proponents are able to commit to provide the service in the required timeframe. We note that, depending on outturn future demand, this project may also require a second stage over the long term, which is also included as a contingent project.[104]

Table 4-30, shows that, based on this approach, we have included only $9.3 million in Augex in our Revised Revenue Proposal. As noted above, this is a saving of $732.6 million compared to the indicative capex of $741.9 million in our initial Revenue Proposal, due to the efficient use of non-network solutions.

As discussed in Chapter 3, we will rely on the network support cost pass through arrangement under the NER clause 6A.7.2 to recover the costs of non-network services. The actual level of network support payments passed through to customers will be determined by the amount that we are required to pay under the commercial contracts with non-network proponents. We will seek confirmation from the AER that the level of these costs is prudent and efficient prior to these costs being incurred.

Table 4-30: Recently completed RIT-Ts ($M Real, 2022-23)

Recently completed RIT-Ts	RIT-T outcome	Technological innovation to reduce capex	RIT-T Base capex (2023-28) (based on FY22 unit rates)	Capex after Innovative delivery
Repex - Network solution only				
Managing risk on line 86 (Repex)	Targeted replacement of the 31 highest risk wood poles in the 2023-28 period	Use of BESS as a Virtual Transmission Line was assessed in the RIT-T. The nature of the RIT-T preferred solution means there is no scope for technological innovation	11.8	N/A
Total Repex			**11.8**	**N/A**
Augex - combined network and non-network solutions				
Improving stability in south west NSW	Combined solution: • interim BESS (3-year terms), and • network solution (330 kV Darlington Point to Dinawan transmission line ($192.6 million).	Keep network costs as low as possible by increasing term of BESS (from 3 to more than 6 years), to defer network investment to beyond the 2023-28 period.	**192.6**	**0**
Maintain reliable supply to the North West Slopes area	Combined solution: • BESS at the Gunnedah 132 kV substation and • network investment including:	• Same as RIT-T, in that a BESS component is used to defer the timing of network investment. • We have included the network component as	**44.6**	**9.3**

[104] Stage 2 involves a new 132 kV line between Wellington and Parkes.

Recently completed RIT-Ts	RIT-T outcome	Technological innovation to reduce capex	RIT-T Base capex (2023-28) (based on FY22 unit rates)	Capex after Innovative delivery
	> a new transformer ($9.3 million) at our Narrabri substation, and > depending on load, rebuild and upgrade the existing lines[105] ($132.8 million, of which $35.3 million may be in 2023-28 period)	a as a nominated pass through and a contingent project noting risk associated with the new BESS technology. • Consistent with the AER's Draft Decision, our revised proposal treats the later upgrading of the existing lines in the area ($132.8 million) as a separate stage 2 contingent project, which would be triggered by future load growth.		
Maintain reliable supply to BOP Stage 1	Two equal top ranked solutions: • a solely non-network solution (BESS and STATCOM), and • a non-network solution (BESS) supported by network investment (i.e., synchronous condenser, which has an expected cost of $46.6 million, of which $44.4 million may be in the 2023-28 period)	• Keep network costs as low as possible by relying solely on the non-network solution (BESS and STATCOM) (i.e., no network syncon). • The risk with this solution is that it depends on successful negotiations with the non-network provider. • We have included the network component as a as a nominated pass through and a contingent project noting risk associated with the new BESS technology.	**44.4**	**0**
Total Augex			**281.5**	**9.3**

[105] Rebuilding the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA.

4.11. Non-network ICT capex

Our initial Non-network ICT capex forecast was $86.9 million for the 2023-28 regulatory period, which is $21.8 million or 25.1 per cent lower than our expected 2018-23 ICT capex (excluding SaaS). Our 2023-28 ICT capex forecast will enable us to deploy new technology and continue to refresh or replace legacy applications and systems at the end of their lives.

The AER's Draft Decision reduced our forecast by $9.5 million or 11.0 per cent to $77.4 million. The AER's reduction reflects its concerns that:

- our 2023-28 ICT forecast may not be indicative of efficient capex-opex trade-offs with the transition to cloud-based computing
- although the majority of our forecast capex is recurrent, it is an order of magnitude above our recurrent expenditure in the current regulatory period
- we have not adequately demonstrated how we have prioritised our ICT portfolio, and
- we have not demonstrated how we have reflected 'cashable' benefits from our 2018-23 capex in our 2023-28 forecast

We are deeply concerned with the AER's substitute ICT allowance, which is insufficient to enable us to:

- refresh or replace legacy applications and systems which are at the end of life
- enhance our data analytics and reporting capability
- continue our transition to cloud-based platforms
- modernise our IT platforms to align with the changing requirements of our network and technology trends, and
- meet our obligations under new cyber security legislation.

As a consequence, the AER's substitute forecast will not satisfy the capex objectives in the NER and will hinder improvements in service delivery through new or more efficient systems, which lower the overall cost of existing service.

Feedback from the TAC

We discussed our concerns about the AER's Draft Decision with the TAC. The TAC acknowledged that technical understanding and analysis is required to determine the efficient level of ICT for the 2023-28 period. On this basis, the TAC suggested that:

- we should resolve our differences on the efficient level of ICT directly with the AER through the determination process
- our proposed approach to provide information to address the AER's concerns is reasonable
- we should consider whether there is any scope to further extend the life of our assets to extract as much value as possible and drive customers' dollars further, and
- it would be helpful for the TAC if we could host a joint workshop in which both Transgrid and the AER each explain and justify their respective positions and the reasons for the differences between them. The TAC agreed that this workshop could be held following the submission of our Revised Revenue Proposal.

The AER's Draft Decision and our response

The AER has assessed our ICT capex forecast using both a bottom-up and top-down approach.

Based on its bottom-up assessment, the AER and its consultant, EMCa, acknowledge that we have identified adequate needs for taking action across the eight proposed packages of work. However, they consider that:

- we have not adequately demonstrated how we have prioritised our investment, noting that a prudent TNSP would have undertaken some of our proposed investments in the current period rather than waiting until the next period, and
- in some cases, we have not adequately considered alternative options to our proposed investments or that some investments could be self-funded from the benefits they provide.

Based on its top-down assessment, the AER determined an alternative ICT forecast of $77.4 million. This is calculated by multiplying the annual average capex over the period 2009-23 of $14.6 million by five years and then applying the AER's Draft Decision inflation and real cost escalation values.

We agree with the AER that using our annual average capex from 2009 is a practical method for estimating efficient long-run costs because it:

- includes multiple refresh cycles for infrastructure and applications, including 'non-recurrent' cycles that occur less frequently than every five years but maintain, rather than add, capability, and
- smooths the transition from capex to opex that comes with migration to the cloud.

This Revised Revenue Proposal therefore adopts the AER's top-down approach to determine our revised ICT capex forecast, updated for our final audited 2021-22 capex and an updated 2021-22 capex estimate.[106]

This results in an annual average capex over the 2009-23 period of $17.2 million and a total revised ICT capex forecast of $86.2 million for the 2023-28 period.

This is in line with our initial capex forecast of $86.9 million, determined based on a bottom-up build of the investment required across our proposed eight packages of work. As explained above, the AER and its consultant, EMCa, also acknowledge that investment is required across these eight work packages.

Reducing our total 2023-28 ICT capex below this value would be neither prudent nor efficient. The AER's consultation paper on ICT expenditure assessment identifies that, over time, ICT expenditure has increased as a trend while total capex and opex has decreased. This is because ICT enables improvements in service delivery through new or more efficient systems, which in turn lowers the overall cost of existing services.

Our actual 2021-22 ICT capex and revised 2022-23 estimate

Table 4-31 details the 2018-23 ICT actual/estimated capex included in our initial Revenue Proposal with and without SaaS,[107] which shows a difference of $36.9 million between our:

- initial 2018-23 actual/estimated ICT capex, excluding SaaS,[108] and

[106] Our 2018-23 capex in our initial Revenue Proposal was based on our actual costs for 2018-19 to 2020-21 and our estimated costs for 2021-22 and 2022-23.

[107] Based on the AER's updated guidance we have excluded SaaS for regulatory years 2018-19 to 2020-21. Prior to 2018-19, we did not incur any SaaS costs.

[108] This includes actual capex for 2018-19 to 2020-21 and estimated capex for 2020-21 and 2021-22.

- updated 2018-23 actual/estimated ICT capex, excluding SaaS.[109]

This increase is due to our actual 2021-22 capex and latest estimated 2022-23 capex both being higher than the estimates values we anticipated at the time of our initial Revenue Proposal.

Table 4-31 - Actual and estimated ICT capex for 2018-23

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
initial 2018-23 actual/estimated ICT capex (including SaaS)	20.7	19.5	19.8	4.2	0.2	64.5
initial 2018-23 actual/estimated ICT capex (excluding SaaS)[110]	19.0	9.8	4.9	4.2	0.2	38.2
updated 2018-23 actual/estimated ICT capex (excluding SaaS)	19.0	9.8	4.9	13.0	28.3	75.0
Difference – initial & updated 2018-23 actual/estimated ICT capex excluding SaaS	0	0	0	8.8	28.1	36.9

The key drivers of the increase in our actual 2021-22 and latest 2022-23 estimated ICT capex are:

- unexpected changes in our Digital Core initiative
- projects that were initially planned for completion in 2021-22 but have extended into 2022-23 with additional resource requirements, in particular:
  - Labour Costing TAA and Payroll
  - Bentley EDMS Replacement
  - Securing Cloud Services, and
  - Worker Safety Authorisation and Training.
- emerging projects that were not originally planned to require capex in 2021-22 and 2022-23, in particular:
  - Data Governance and Ownership
  - firewall improvements
  - Microsoft office improvements, and
  - Data Hub.

These changes are set out in Table 4-32 and Table 4-33.

Table 4-32 details the projects in our initial 2018-23 actual/estimated ICT capex for 2021-22 and 2022-23.

[109] This includes actual capex for 2018-19 to 2021-22 (sourced from our Category Analysis RIN) and estimated capex for 2021-22 based on our latest board approved budget.
[110] Provided to the AER in our response to its Information Request 033 (IR033).

Table 4-32: ICT capex projects which have changed - forecast in our initial Revenue Proposal (excluding SaaS)

Project name	2021-22	2022-23	Comment
Labour Costing TAA and Payroll	0.4	0.2	
Digital Core	3.8	-	Originally expected a completion date of December 2022
Bentley EDMS Replacement	-	-	Expected to incur SaaS opex only
Securing Cloud Services	-	-	Expected to incur SaaS opex only
Worker Safety Authorisation and Training	-	-	Expected to incur SaaS opex only
Adjustment	0.1	-	Adjustment to allow for a pipeline project
Total	**4.3**	**0.2**	

Table 4-33 details the projects included in our updated 2018-23 actual/estimated ICT capex for 2021-22 and 2022-23.

Table 4-33: ICT capex projects which have changed in 2018-23 - updated estimate in our Revised Revenue Proposal (excluding SaaS)

Project name	2021-22	2022-23	Comment
Projects in our initial 2018-23 actual/estimated ICT capex			
Labour Costing TAA and Payroll	2.1	2.8	Cost increase since initial Revenue Proposal
Digital Core	7.4	13.4	Completion now expected late 2023
Bentley EDMS Replacement	0.0	-	Minor capex required to complete project which rounds to $0.0m
Securing Cloud Services	0.3	-	Capex incurred to complete project
Worker Safety Authorisation and Training	0.2	0.0	Capex incurred to complete project
Sub-total	**10.0**	**16.3**	
New emerging projects			
CVM Rebuild	0.4	0.2	
Data Governance and Ownership Program	1.4	3.2	
Evoko Panel Replacement	-	0.0	
Firewall Replacement	1.1	0.0	
Data Hub	-	4.5	
Hardware Replacement	-	0.3	
Microsoft 365 Implementation	-	3.6	
Subtotal	2.9	11.8	
Total	**13.0**	**28.1**	

Table 4-32 and Table 4-33 show that the majority of the increase in our updated 2018-23 actual/estimated ICT capex is due to unexpected changes in our Digital Core initiative, which is replacing our existing Ellipse Enterprise Resourcing Planning (ERP) system. This will shortly no longer be supported by the service provider, ABB. We are therefore replacing Ellipse with a modular SaaS-based ERP solution stack with three integrated platforms for assets, finance and delivery.

At the time of submitting our initial Revenue Proposal, we expected to have completed implementing our Digital Core initiative by December 2022. However, the timing of this project has been delayed by around six months and is now expected to be completed by late 2023. The key reasons for the delay are:

- COVID-19 lockdowns resulting in key resources not being available as planned (especially offshore) which has impacted the continuity and available resources for this project
- system integration scope increasing, including complexities arising from integrating across the various SaaS platforms, which requires additional time and resources, and
- increased complexity in data migration across the existing and new platforms.

For these same reasons, we now expect the total costs of the project to the end of 2022-23 to be $78.4 million (capex, $Nominal) which is higher than our initial forecast of $39.7 million (capex, $Nominal).

Updated ICT infrastructure user count

We have also updated our ICT infrastructure user count for the 2023-28 period to reflect the very significant network investment that we are required to undertake in that period to support the decarbonisation of the Australian economy. We are a key player in the required build-out of Australia's transmission network and are expected to undertake Actionable and Future ISP projects, totalling $4.5 billion (Real 2022-23)[111] over our next 2023-28 regulatory period alone for:

- HumeLink
- VNI West, and
- QNI connect.

This is in addition to capex of $2.5 billion approved by the AER in the current 2018-23 regulatory period for EnergyConnect (PEC), VNI Minor and QNI Minor, attesting to the scale of the investment required across the entire NEM over the next few decades.[112]

We have refreshed our user count forecast for the 2023-28 period and expect a higher growth rate compared to our initial Revenue Proposal. The effort to on-board and provide equipment for new starters (both employees and contract staff) is a contributing factor to our increasing capex requirement.

Table 4-34 summarises our ICT user count actual and forecast for the period. Our user count is growing rapidly. We are on-boarding an additional 200 staff by December 2022 and are on target to have more than 1,900 users by the end of 2022-23, increasing to more than 2,500 users by the end of 2027-28.

Our initial Revenue Proposal did not consider either the accelerated delivery or the expected additional number of users, who require devices and software and also place additional demand on legacy end of life networks.

[111] This comprises $3,701 million for HumeLink (Stage 1 and 2), $663 million for VNI West, and $169 million for QNI Connect.

[112] This comprises $2,154.4 million for PEC, $257.9 million for QNI and $53.3 million for VNI, including capitalised overheads.

Table 4-34 - ICT user count – actual users to 2021-22 and our initial and revised forecast for 2022-23 to 2027-28

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
Initial Revenue Proposal							
User numbers[1]	1,586	1,551	1,449	1,413	1,409	1,405	1,401
Employees[2]	1,260	1,225	1,123	1,087	1,083	1,079	1,075
Devices[1]	2,427	2,373	2,217	2,162	2,156	2,150	2,144
Revised Revenue Proposal							
User numbers[3]	1,678	1,911	2,036	2,160	2,284	2,409	2,533
Employees[4]	1,192	1,537	1,637	1,737	1,837	1,937	2,037
Devices[5,6]	2,882	3,000	3,195	3,390	3,586	3,781	3,976

Notes: 1. The device and user numbers are from the 2023-28 Reset RIN. 2. Based on our Reset RIN and IR#014. 3. Users = Employees, contractors and partners 4. Employees are permanent staff only 5. Devices include laptops, desktops, iPads and mobile phones 6. Device numbers for the 2023-28 period have been calculated based on the number of employees (i.e., staff and contract staff), the assumed breakdown replacements and asset lives based on our asset management framework.

Long-term trends and benchmarking

ICT expenditure has been consistently increasing over time across the NEM as identified in the AER's consultation paper on ICT expenditure assessment. Our experience is consistent with this trend.

Increases in ICT capex over time can be expected despite the move to cloud-based solutions. In particular, for ICT capex, it is becoming increasingly more complex and expensive to maintain existing ICT capability due to the increase in:

- project implementation costs associated with transitioning from traditional on-premise to cloud-based solutions. The progressive shift to cloud solutions across the industry and broader ICT landscape has increased the demand for the services and skills required to implement these projects. This has increased the cost of labour resources, which is treated as capex during the project implementation phase. ICT labour remuneration benchmarking by Pacific Talent Partners, which we commissioned in April 2022, demonstrates that benchmark labour costs have increased significantly
- the number of ICT users, which in turn places upward pressure on the need to replace legacy ICT systems
- the quantity of inputs required to deliver modern ICT applications (i.e., commodity services, such as storage and processing, as well as labour) as new systems become increasingly complex and integrated
- ICT totex requirements as we transition to cloud-based solutions, noting that analysis from Gartner supports this finding,[113] and
- cyber security expenditure across the industry as the digital operating environment becomes increasingly complex and hostile.

Our ICT costs are efficient compared to our peers, as demonstrated by the AER's consultant, EMCa, who state:

> *We have developed a benchmark comprising ICT totex per user from available RIN data, as shown in Figure 6.3. Overall, Transgrid benchmarks well against its peers – particularly against AusNet*

[113] Gartner, March 2021, [Proactively Manage the Impact of SaaS on Opex and Capex Budgets.]()

(Transmission) and ElectraNet – despite Transgrid's totex per user trending up over the current RCP and at an increasing rate during the next RCP.[114]

HoustonKemp has also assessed the efficiency of our ICT totex and capex using our 2018-23 actual/estimated ICT capex. HoustonKemp's analysis, provided as an Attachment to this Revised Revenue Proposal, shows that we benchmark well against other TNSPs for the metrics most relevant to ICT, including in terms of:

- ICT totex per employee – We are the lowest cost provider.
- ICT totex per user – We are the second lowest cost provider.
- ICT totex per device – We are the second lowest cost provider.

Other TNSPs in general have upwards trending ICT expenditure, consistent with our forecast.

HoustonKemp also found that, despite our increase in ICT totex forecast for the 2023-28 period, on a trend basis, when our revised forecast for employee numbers, user numbers and the number of devices are taken into account, our ICT expenditure is declining over time, in particular:

- ICT totex per device is expected to decrease by 2 per cent per year, and
- ICT totex per user is expected to decrease by 0.3 per cent per year.

HoustonKemp also considered the trend in our proposed ICT capex (excluding SaaS), which on a per unit basis is expected to fall over 2023-28, continuing the declining trend since 2009.

4.12. Non-network other

Our initial non-network other capex, which relates to fleet, plant and equipment and property forecast was $71.4 million. The AER's Draft Decision reduced this amount by $2.6 million by disallowing the two programs outlined in Table 4-35, which it considers 'go beyond the requirements of the capex objectives'. The AER also commented that we did not provide evidence of customer support and willingness to pay for these programs. This reduction is, however, offset by inflation, which leads to a $4.2 million or 5.9 per cent net increase to our initial capex forecast from $71.4 million to $75.6 million.

Table 4-35 summarises the AER's Draft Decision in relation to non-network other capex.

Table 4-35 -: AER's Draft Decision to disallow Non-network other capex

Non-network Other Removed	Initial Revenue Proposal	AER's Draft Decision	AER's reasons for Draft Decision
Property	22.8	21.5	Disallow $1.3 million for our sustainability initiative to install solar PV systems and LED lighting
Fleet – passenger vehicles	3.9	2.6	Disallow $1.3 million associated with transitioning our car fleet from petrol/diesel to electric vehicles (EV)
Total for disallowed programs	**26.7**	**24.1**	

[114] EMCa report to AER on aspects of Transgrid RP 2023-28 FINAL v3 (to AER 300822), p. 71 (emphasis added).

Non-network Other Removed	Initial Revenue Proposal	AER's Draft Decision	AER's reasons for Draft Decision
Other projects and programs	44.7	51.5	Higher actual and forecast inflation for 2021-22 and 2022-23 increased the Real$2023 value
Total	**71.4**	**75.6**	

Feedback from the TAC

We acknowledge the AER's feedback that we did not obtain sufficient evidence of customer support for these projects. We therefore asked the TAC for its views on these proposed projects and customers' willingness to pay for them. We received mixed feedback from the TAC including:

- we should ensure that our program considers optimal replacement timing and how to optimise what Transgrid is replacing, and
- to address our customers' affordability priority, we should consider whether there is any scope to further extend the life of our assets to extract as much value as possible and drive customers' dollars further.

The AER's Draft Decision and our response

We have accepted the AER's Draft Decision for Non-network other capex, noting our commitment to ensure our services are provided at the lowest possible costs to address affordability concerns. We have updated the fleet passenger vehicle capex forecast to reflect our actual cost inputs for diesel/petrol passenger vehicles of:

- $45,000 unit cost per diesel/petrol passenger vehicle, and
- a three-year replacement cycle for diesel/petrol passenger vehicles, compared to a four-year replacement cycle, which we used for our electric vehicle forecast.[115] This resulted in an additional six vehicles requiring replacement in the 2023-28 regulatory period.

Our revised forecast for non-network other is detailed in Table 4-36.

Table 4-36: Revised forecast for non-network other capex

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Fleet	9.6	10.3	10.0	10.6	10.3	**50.8**
Property	5.5	5.6	4.0	4.7	5.4	**25.2**
Non-network other	15.1	15.9	14.0	15.3	15.7	**75.9**

4.13. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
2023-28 Deliverability Plan

[115] Electric vehicles have a longer life cycle due to factors such as having fewer moving parts to wear out and their higher upfront cost.

Name
GHD – 2021-22 Unit Rates Update Review
GHD – Repex benchmark comparison
GHD – Line 86 Capex Independent Assessment
GHD – Anti-climb Barriers Duty of Care Demonstration
GHD – 330kV Low Spans Duty of Care Demonstration
GHD – 132kV Low Spans Duty of Care Demonstration
GHD – Asbestos Paint on Towers Duty of Care Demonstration
GHD – Line 11 Tower Replacement Option Assessment
GHD – Line 94U Refurbishment Cost Benchmarking Assessment
GHD – Secondary Systems Review for 2023-28 Revenue Proposal
GHD – Transformer Review for 2023-28 Revenue Proposal
GHD – Supply to Panorama Area Independent Demand Forecast Review
GHD – Maintain Voltage in Alpine Area Demand Forecast Independent Review
GHD – Maintain Voltage in Beryl Area Demand Forecast Independent Review
GHD – Maintaining Reliable Supply to Bathurst, Orange and Parkes Area Independent Demand Forecast Review
GHD – Bathurst, Orange and Parkes Area Stage 2 Independent Demand Forecast Review
GHD – Maintaining Reliable Supply to North West Slopes Area Independent Demand Forecast Review
KWM – Work Health and Safety and Public Liability Legal Advice
University of Melbourne – Bushfire consequence modelling
HoustonKemp – Repex and Augex business cases review
HoustonKemp – Repex metrics review
HoustonKemp – Unit rate update for four recently completed RIT-Ts
HoustonKemp – Improving stability in south west NSW analysis update
HoustonKemp – Transgrid's ICT Expenditure Review
PowerRunner – System Security Roadmap technical report
CutlerMerz – System Security Roadmap assurance report
OER-N2761 System Security Roadmap Technology and Human Resource uplift
Gartner – Proactively Manage the Impact of SaaS on Opex and Capex
Pacific Talent Partners – Remuneration Benchmarking Report Digital & Technology
AEMO - PMU NER 4.11.1(d) notice
AEMO - PMU NER 4.11.1(d) and (e) notice
AEMO - PMU Notice Attachment 1 NSW PMU Specification
AEMO - PMU Cost Benefit Analysis for NSW region

5

RAB and Depreciation

5. RAB and Depreciation

Key messages:

- The AER's Draft Decision largely accepted the approaches and inputs we used to establish our opening Regulatory Asset Base (RAB) at 1 July 2023 and forecast depreciation over the 2023-28 regulatory period. The AER made a number of minor adjustments and updates to:
  - use CPI of 3.5 per cent for 2021-22 based on the latest actual CPI
  - use the RBA's latest Statement on Monetary Policy to determine a CPI forecast of 7.8 per cent
  - update the nominal WACC input for 2022-23 for the latest return on debt update
  - amend the proposed treatment of leases and SaaS for 2021-22 and 2022-23.
  - update the standard lives for 'equity raising costs' and the new 'Leasehold Land and Property' asset classes
- We have adopted these changes in this Revised Revenue Proposal, updating where necessary for:
  - actual expenditure in 2021-22
  - our revised 2023-28 forecast capex, discussed in Chapter 4**,** and
  - actual and forecast inflation discussed in Chapter 6
- In this Revised Revenue Proposal, our updated forecast RAB is expected to increase from an opening RAB of $8,812.6 million (nominal) at 1 July 2023 to a closing RAB of $11,025.1 million (nominal) as at 30 June 2028.

5.1. The AER's Draft Decision

As explained in our initial Revenue Proposal, we adopted standard regulatory approaches to determining our forecast RAB and depreciation for the 2023-28 regulatory period. Specifically, our initial Revenue Proposal explained that our approach applied the NER requirements and the AER's Roll Forward Model (RFM) and Post-tax Revenue Model (PTRM) to derive:

- an opening RAB as at 1 July 2023 of $8,713.0 million (nominal)
- forecast straight line depreciation using our standard asset lives, with the addition of one new asset class for Leasehold Land and Property, and
- our forecast RAB value for each year of the 2023-28 period, reflecting our forecast capex and depreciation.

We also explained that our RAB value has increased significantly since the start of the 2018-23 period, largely due to major investments in projects, such as Powering Sydney's Future and projects included in AEMO's ISP, namely EnergyConnect, VNI Minor and QNI Minor.

In its Draft Decision, the AER accepted our approach to forecasting the RAB and depreciation for the 2023-28 regulatory period. The AER also accepted our proposed standard asset lives, with the exception of Leasehold Land and Property and Equity raising costs asset classes, which the AER amended as follows:

- for Leasehold Land and Property, the AER adopted five years, following our submission of further information, instead of our original proposal of 10 years, and
- for 'Equity raising costs', the AER adopted a standard asset life of 37.3 years compared to our proposal of 15.9 years.

The AER's Draft Decision also made the following amendments to our opening RAB:

- removed capex relating to leases for 2021-22 and 2022-23 from the RFM
- reinstated capex relating to Software as a Service (SaaS) for 2021-22 and 2022-23
- updated the estimated inflation for the 2021-22 inflation with actual CPI of 3.5 per cent published by the ABS
- updated the nominal WACC input for 2022-23 following the most recent return on debt update, and
- updated as incurred and as commissioned equity raising costs in 2018-19 and the forecast depreciation input for the years 2019-20 to 2022-23.
- In relation to the reclassification of expenditure for leases and SaaS, the AER's Draft Decision explained that, although our approach reflected changes in accounting standards, the AER's preference is to maintain the capitalisation treatment for the 2018-23 period, consistent with the basis approved in the 2018-23 determination.

In addition to updating the opening RAB, the forecast RAB over the 2023-28 regulatory period was also amended to reflect:

- a reduction in our forecast capex of $150.1 million or 7.9 per cent
- a higher inflation forecast of 3.0 per cent per annum compared to our forecast of 2.35 per cent per annum, and
- an increase in forecast straight-line depreciation of $119.8 million or 6.7 per cent.

As explained below, we accept the AER's Draft Decision subject to updating input data to reflect updated information, including our revised capex forecasts, which are detailed in Chapter 4 of this Revised Revenue Proposal.

5.2. What we heard from our customers

The calculation of the RAB and depreciation reflects the combined effect of:

- previous investment decisions
- our forecast capex over the 2023-28 regulatory period
- the expected life of our assets, and
- external factors, such as inflation, which are outside our control.

Our customers typically do not have strong views in relation to the technical process of forecasting the RAB and depreciation. However, affordability considerations suggest that customers generally want us to avoid accelerated depreciation as this puts upward pressure on prices in the short term. On this basis, we have maintained our previously approved standard asset lives in our initial Revenue Proposal.

Affordability considerations are also central to our capex plans, which are an important input to our forecast RAB and depreciation over the 2023-28 regulatory period. As explained in Chapter 4, we have given careful consideration to customers' views in formulating our revised capex forecasts, having regard to the matters raised in the AER's Draft Decision. While customers have not provided direct feedback on our revised forecast RAB and depreciation, our revised forecasts indirectly reflect the feed back we have received, particularly in relation to our capex plans.

5.3. Revised opening RAB as at 1 July 2023

Table 5-1 sets out our revised opening RAB as at 1 July 2023 by applying the standard regulatory approach as explained in our initial Revenue Proposal, which the AER accepted in its Draft Decision. The opening RAB has been amended to reflect:

- the AER's proposed adjustments in its Draft Decision, including those relating to the treatment of lease and SaaS expenditure, and
- our updated estimates of our actual and forecast capex for the last two years of the 2018-23 period.

Table 5-1: Revised opening RAB at 1 July 2023 ($M, nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23
Opening value (1 July)	6,371.2	6,463.9	6,638.7	7,201.1	7,646.3
Actual and forecast indexation	113.7	119.0	57.1	251.9	596.4
Net-capex[1]	235.0	330.9	795.2	484.7	882.6
Forecast straight line depreciation	(256.0)	(275.1)	(290.0)	(291.5)	(316.7)
Adjustments	-	-	-	-	4.0
Closing value	**6,463.9**	**6,638.7**	**7,201.1**	**7,646.3**	**8,812.6**

Notes: 1. Net capex is gross capex less any asset disposals and capital contributions.

As shown Table 5-1, our revised opening RAB as at 1 July 2023 is $8,812.6 million (nominal) compared to the AER's Draft Decision of $9,228.7 million (nominal).

5.4. Revised forecast RAB for the 2023-2028 regulatory period

Our approach to forecasting the RAB for the 2023-28 regulatory period is consistent with the AER's Draft Decision and our initial Revenue Proposal. We have:

- forecast the RAB values in accordance with the NER and the AER's PTRM
- ensured that only actual and estimated capex attributable to the provision of prescribed transmission services in accordance with our cost allocation methodology has been included, and
- excluded any forecast capex relating to Contingent or ISP Projects that have not been approved by the AER, as customers will only pay for these projects if, and when, the AER has conducted its assessment of the prudent and efficient costs in accordance with the relevant NER provisions.

We have updated our approach to reflect:

- the revised opening RAB, as explained in Section 5.3
- our revised capex forecasts as detailed in Chapter 4
- further deferral of EnergyConnect capex into the 2023-28 period, which is discussed in Chapter 4, and
- our updated forecast inflation, which reflects the AER's preferred forecasting methodology and is discussed in Chapter 6.

Table 5-2 presents our revised RAB forecast for the 2023-28 regulatory period. It shows that our forecast RAB is expected to increase from an opening RAB of $8,812.6 million (nominal) as at 1 July 2023 to a closing RAB of $11,025.1 million (nominal) as at 30 June 2028.

Table 5-2: Revised RAB roll-forward over the 2023–28 period ($M, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28
Opening value (1 July)	8,812.6	9,913.4	10,426.5	10,629.1	10,851.3
Forecast indexation	264.3	297.3	312.7	318.8	325.5
Net-capex[1]	1,192.4	602.5	328.1	381.9	321.3
Forecast straight line depreciation	(355.9)	(386.7)	(438.3)	(478.5)	(473.0)
Closing value	**9,913.4**	**10,426.5**	**10,629.1**	**10,851.3**	**11,025.1**

Notes: 1. Net capex is gross capex less any asset disposals and capital contributions.

As shown in Table 5-2, our revised closing RAB as at 30 June 2028 is $11,025.1 million (nominal) compared to the AER's Draft Decision of $10,532.2 million (nominal). The difference between these RAB values principally reflects the impact of our revised capex forecasts, which are higher than the AER's Draft Decision for the reasons explained in Chapter 4.

5.5. Revised regulatory depreciation

The AER's Draft Decision accepted our straight-line approach to regulatory depreciation and our proposed asset lives, with the exception of changes to the proposed asset lives for Leasehold Land and Property and Equity raising costs asset classes. We accept the AER's Draft Decision in relation to these changes. Table 5-3 presents our revised forecast regulatory depreciation for the 2023-28 regulatory period, which reflects:

- our updated opening RAB
- our revised capex forecasts for the 2023-28 regulatory period, and
- updated forecast inflation.

Table 5-3: Revised forecast regulatory depreciation over the 2023-28 regulatory period

	2023-24	2024-25	2025-26	2026-27	2027-28
Forecast straight line depreciation ($M, nominal)	355.9	386.7	438.3	478.5	473.0
Less forecast indexation ($M, nominal)	(264.3)	(297.3)	(312.7)	(318.8)	(325.5)
Regulatory depreciation ($M, nominal)	91.6	89.4	125.6	159.7	147.5
Regulatory depreciation ($M, Real 2022-23)	88.9	84.2	114.9	141.9	127.2

The AER's Draft Decision accepted our proposed approach to use forecast depreciation to roll forward the RAB to the start of the regulatory period commencing on 1 July 2028. This approach is consistent with the 2018-23 regulatory period and reflects the approach set out in the AER's Framework and Approach Paper. We have reflected this in our Revised Revenue Proposal.

5.6. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
Roll-forward model
Depreciation model
Post-tax revenue model
Cost Allocation Methodology

6

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

Transgrid

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

Key messages:

- Our initial Revenue Proposal used the AER's binding 2018 RoRI and recent observable market data to estimate a rate of return of 4.7 per cent for the 2023-28 regulatory period. We estimated forecast inflation of 2.3 per cent using the method included in the AER's PTRM.
- The AER's Draft Decision updated our estimated rate of return and inflation to reflect the latest market data and proposed an updated benchmark cost for estimating debt raising costs.
- In this Revised Revenue Proposal, we have adopted the AER's WACC parameters as placeholder values, noting we expect the AER's Final Decision to reflect its final 2022 RoRI, which is expected to be published in February 2023. The AER's Final Decision will also use the latest market data during the confidential averaging periods for the risk-free rate and return on debt, which the AER has accepted.
- In relation to inflation, we have retained the AER's estimate in its Draft Decision, noting that the AER is expected to update this to reflect the RBA's February 2023 Statement on Monetary Policy in its Final Decision.
- We have accepted the AER's Draft Decision on debt raising costs and applied the revised benchmark cost to the updated debt component of our projected RAB.
- Based on projected cash flows, we maintain our earlier view that no allowance is required for equity raising costs for the 2023-28 regulatory period. The AER's Draft Decision accepted our proposal.

6.1. The AER's Draft Decision

Our initial Revenue Proposal and the AER's Draft Decision used the 2018 RoRI to calculate the rate of return and the AER's preferred methodology to estimate inflation.

Table 6-1 compares the AER's Draft Decision on the weighted average cost of capital (WACC) and inflation with our initial Revenue Proposal. The far right-hand column also shows the illustrative WACC if the AER had used the draft 2022 RoRI instead of the 2018 RoRI while retaining the same placeholder averaging period. The increase in the AER's Draft Decision WACC and inflation estimates compared to our initial Revenue Proposal reflects the impact of increasing inflation and interest rates.

Table 6-1: AER's Draft Decision on the WACC

	Initial Revenue Proposal	AER's Draft Decision	AER's Draft Decision, if draft 2022 RoRI was applied
Nominal risk free rate	1.72%	3.82%	3.54%
Market risk premium	6.1%	6.1%	6.8%
Equity beta	0.6	0.6	0.6
Return on equity (nominal post–tax)	5.38%	7.48%	7.62%
Return on debt (nominal pre–tax)	4.25%	4.63%	4.63%
Gearing	60%	60%	60%
Nominal vanilla WACC	4.70%	5.77%	5.83%
Expected inflation	2.35%	3.00%	3.00%

We accept the AER's approach to estimating the WACC, inflation, and debt and equity raising costs. We have updated these estimates to reflect the latest information and market data, but otherwise accept the AER's Draft Decision.

6.2. Rate of return

Under the NER, our return on capital allowance is calculated by multiplying the WACC and the value of our opening RAB in each year of the regulatory period.

As explained in our initial Revenue Proposal, we were required to use the prevailing 2018 RoRI when calculating our return on capital allowance. The AER is currently reviewing the 2018 RoRI and is expected to publish its 2022 RoRI in February 2023. In its Final Decision, the AER will estimate the WACC on its 2022 RoRI and the latest market data measured over the approved confidential averaging periods for the risk-free rate and return on debt.

This Revised Revenue Proposal adopts the AER's Draft Decision WACC as a placeholder, noting that this will be updated in the AER's Final Decision. Table 6-2 applies the WACC in the AER's Draft Decision to our updated opening RAB in each year of the 2023-28 period. The calculation of these RAB values is explained in Section 5.4.

Table 6-2: Revised forecast return on capital ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Opening RAB	8,556.0	9,344.4	9,541.9	9,444.0	9,360.7	
Rate of return (%)	5.77	5.76	5.84	5.91	6.00	
Return on capital	494.0	538.3	557.2	557.9	561.7	**2,709.2**

6.3. Inflation forecast

Our initial Revenue Proposal explained that forecast inflation is used to calculate the regulatory depreciation building block and to convert real dollar values to nominal dollar values. Our approach to estimating inflation reflected the AER's preferred methodology, which is the geometric mean of:

- two years of forecast inflation published by the RBA in its most recent Statement on Monetary Policy,[116] and
- three years transitioning to the midpoint of the RBA's inflation target of 2.5 per cent in the final year.

Table 6-3 shows that this Revised Revenue Proposal retains the AER's Draft Decision forecast inflation of 3.0 per cent per annum. The AER is expected to update this to reflect the RBA's February 2023 Statement on Monetary Policy in its Final Decision.

[116] Consistent with the AER's Draft Decision, we have continued to use the August 2022 Statement on Monetary Policy. Our expectation is that the AER will use the February 2023 Statement on Monetary Policy when it makes its Final Decision.

Table 6-3: Revised inflation forecast

	2023-24	2024-25	2025-26	2026-27	2027-28
	RBA forecast		Linear transition		
Inflation forecast (%)	3.50	3.25	3.00	2.75	2.50
Geometric average1	3.00				

Notes: 1. The geometric average is calculated by adding one to each inflation forecasts and multiplying them together to get a 5 year inflation projection, and then converting that projection back to a compound annual growth rate.

Our PTRM model, which is provided as an Attachment to this Revised Revenue Proposal, sets out the detailed calculations of forecast inflation.

6.4. Debt and equity raising costs

Debt and equity raising costs reflect the costs we incur when raising debt and equity capital from external investors. This includes agency, placement, arrangement, legal, credit rating and registration fees, and roadshow costs. In our initial Revenue Proposal, we set out the following proposal for debt and equity raising costs:

- for debt raising costs, we applied a rate of 9.51 basis points per annum (bppa) to the debt component of our forecast RAB, using 60 per cent gearing, in accordance with advice from Frontier Economics, and
- for equity raising costs, we did not propose any allowance as the application of the AER's methodology did not indicate that any costs would be incurred during the 2023-28 regulatory period.

In its Draft Decision:

- for debt raising costs, the AER updated the benchmark debt raising cost, using Bloomberg data to inform the 'arrangement fee' component of debt raising costs and Chairmont's updated estimates for the remaining components of debt raising costs. The AER's Draft Decision adopted an updated debt raising cost of 8.28 bppa, and
- for equity raising costs, the AER confirmed our assessment that no equity raising costs are warranted for the 2023-28 regulatory period.[117]

In this Revised Revenue Proposal, we have accepted the AER's Draft Decision and applied the 8.28 bppa to the debt component (applying a 60 per cent gearing) of our updated forecast RAB, as shown in Table 6-4.

[117] Given potential changes to projected cash flows, we understand that the AER will re-assess whether an equity raising cost allowance is needed when making its Final Decision.

Table 6-4: Revised debt raising and equity raising costs ($M nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Debt raising costs	4.4	4.8	4.9	4.8	4.8	**23.7**
Equity raising costs	0.3	-	-	-	-	**-**

6.5. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
Post-tax revenue model

7

Estimated cost of corporate income tax

7. Estimated cost of corporate income tax

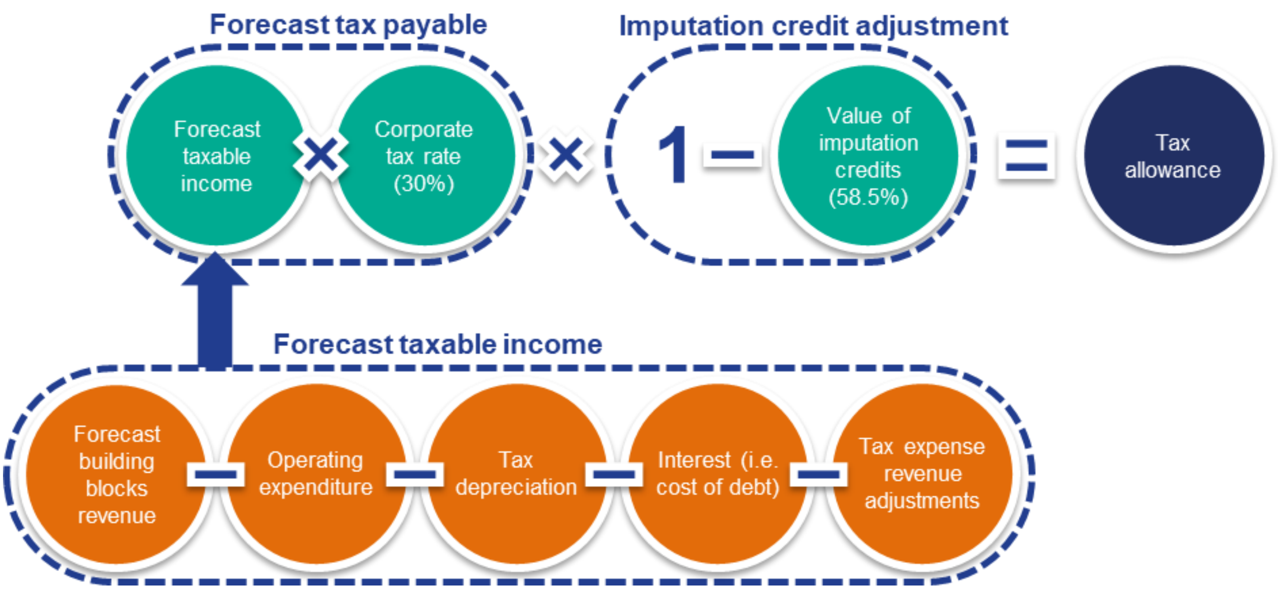
Key messages:

- Our initial Revenue Proposal adopted the AER's latest approach to estimating corporate income tax, including the outcomes of the AER's 2018 Review of the regulatory tax approach.
- The AER's Draft Decision accepted our approach to estimating corporate income tax, subject to making some minor adjustments to our opening tax asset base (TAB). The AER has updated the tax allowance calculations to reflect the proposed amendments in its Draft Decision to our expenditure forecasts and revenue requirements.
- The AER's Draft Decision made minor adjustments to our standard and remaining asset tax lives, including a revision to our proposed approach to Leasehold Land and Property, which is a new asset class.
- We have adopted the AER's changes to estimating corporate income changes in this Revised Revenue Proposal, updating where necessary for actual expenditure in 2021-22, revised expenditure forecasts for 2023-23 and changes to the other building blocks (discussed throughout this Revised Revenue Proposal). We have accepted the AER's Draft Decision on our standard and remaining asset lives.
- Our forecast tax allowance for the 2023-28 period is $99.4 million ($M, Real 2022-23) compared to the AER's Draft Decision of $96.4 million ($M, Real 2022-23).

7.1. The AER's Draft Decision

Figure 7-1, which is reproduced from our initial Revenue Proposal, shows how the tax allowance is calculated.

Figure 7-1: How the tax allowance is calculated



In its Draft Decision, the AER accepted our approach to calculating the tax allowance, which includes the following elements:

- the AER's 2018 Review of the regulatory tax approach, which provides for the immediate expensing of capex and applying the diminishing value method for tax depreciation, in accordance with the tax law
- our standard tax asset lives for each asset class, with the exception of Leasehold Land and Property asset class for capitalised leases as explained in Section 5.1
- the weighted average remaining lives (WARL) method to calculate the remaining lives for our assets in each asset class in the TAB
- the statutory income tax rate of 30.0 per cent, and
- an imputed value for imputation credits of 0.585, in accordance with the AER's 2018 RoRI.

While the AER's Draft Decision accepted our approach to estimating the tax allowance, the AER made an adjustment to our opening TAB to reverse the following two reclassifications in our initial Revenue Proposal:

- SaaS expenditure for the final two years of the 2018-23 period as opex, which was previously treated as capex, and
- lease costs for the final two years of the 2018-23 period as capex, which was previously treated as opex.

As explained in Section 5.1, the AER's Draft Decision reversed these proposed changes so that the capitalisation approach is consistent with its determination for the 2018-23 regulatory period.

The AER's Draft Decision estimated a tax allowance of $96.4 million ($M, Real 2022-23) over the 2023-28 regulatory period compared to $65.7 million in our initial Revenue Proposal. This increase reflects the impact of the higher return on equity, which leads to increases in our taxable revenue and, therefore, the cost of corporate income tax.

7.2. Forecast income tax allowance

This Revised Revenue Proposal maintains our approach to estimating the tax allowance, which the AER accepted in its Draft Decision, and accepts the AER's proposed changes to the reclassification of SaaS and lease expenditure.

We have updated the tax allowance for the 2023-28 regulatory period to reflect our revised expenditure plans and revenue requirements in this Revised Revenue Proposal. Table 7-1 sets out our revised tax allowance for the 2023-28 period calculated using the AER's PTRM.

Table 7-1: Revised forecast tax allowance ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Building blocks revenue	835.7	876.4	915.5	951.1	940.2	**4,519.0**
(–) Operating expenditure	(219.7)	(236.6)	(240.7)	(243.0)	(244.9)	**(1,184.8)**
(–) Tax depreciation	(198.3)	(222.7)	(292.8)	(282.3)	(246.5)	**(1,242.6)**
(–) Interest (i.e., cost of debt)	(237.9)	(258.6)	(271.6)	(275.3)	(281.6)	**(1,324.9)**
(–) Tax expense revenue adjustments	(12.3)	2.8	12.7	11.9	16.5	**31.6**

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Taxable income	167.6	161.3	123.0	162.5	183.8	**798.2**
(x) Corporate tax rate (%)	30.00%	30.00%	30.00%	30.00%	30.00%	**30.00%**
Tax payable	50.3	48.4	36.9	48.8	55.1	**239.5**
(–) Value of imputation credits (58.5%)	(29.4)	(28.3)	(21.6)	(28.5)	(32.3)	**(140.1)**
Estimated cost of corporate income tax	**20.9**	**20.1**	**15.3**	**20.2**	**22.9**	**99.4**

7.3. Forecast tax depreciation

As shown in Figure 7-1, forecast tax depreciation is an input to calculating our taxable income. The calculation of tax depreciation depends on:

- the value of the TAB at the commencement of the 2023-28 regulatory period (1 July 2023)
- the forecast regulatory TAB for the 2023–28 period, and
- standard and remaining tax lives.

In this Revised Revenue Proposal, we have updated the opening TAB at 1 July 2023 to reflect the AER's Draft Decision and our latest estimates of our actual and forecast capex for the last two years of the 2018–23 period, as shown in Table 7-2.

Table 7-2: Revised opening TAB at 1 July 2023 ($M, nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Opening TAB (1 July)	3,911.6	4,045.3	4,102.2	4,142.4	4,417.7	5,031.4
Gross capex	274.4	211.1	203.9	445.7	786.8	
Asset disposals	(4.2)	(2.2)	(3.8)	(9.4)	(5.3)	
Immediate expensing of capex	-	-	-	-	-	
Depreciation	(136.5)	(152.1)	(159.8)	(161.1)	(171.9)	
Final year asset adjustments	-	-	-	-	4.2	
Closing value	**4,045.3**	**4,102.2**	**4,142.4**	**4,417.7**	**5,031.4**	

The AER's Draft Decision accepted our standard and remaining tax lives in our initial Revenue Proposal, subject to minor adjustments and revisions to the tax asset lives for capitalised leases. We accept the standard and remaining tax lives AER's Draft Decision, which are reproduced in Table 7-3.

Table 7-3: Revised tax asset lives

Asset type	Standard tax lives in years as at 1 July 2023	Remaining tax lives in years as at 1 July 2023
Transmission Lines	50.0	48.5
Underground Cables	45.0	45.0
Substations	40.0	38.8
Secondary Systems	15.0	13.7
Communications (short life)	10.0	8.8
Business IT	4.0	3.7
Minor Plant, Motor Vehicles & Mobile Plant	8.0	6.3
Transmission Line Life Extension	35.0	33.8
Land and Easements	n/a	n/a
Synchronous condensers	30.0	-
Leasehold Land and Property	5.0	11.6
Buildings – capital works	40.0	-
In-house software	5.0	-
Equity raising costs	5.0	6.7

Our updated forecast TAB for the 2023-28 period is set out in Table 7-4. A key input to the forecast TAB is the forecast capex, which is discussed in Chapter 4.

Table 7-4: TAB roll-forward over the 2023–28 period ($M, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28
Opening value	5,031.4	5,235.2	6,296.7	6,396.4	6,314.9
Gross capex	413.7	1,303.6	425.6	242.3	677.6
Asset disposals	-	-	-	-	-
Immediate expensing of capex	(5.6)	(5.8)	(6.0)	(6.2)	(6.4)
Depreciation	(204.2)	(236.3)	(320.0)	(317.7)	(285.7)
Adjustments	-	-	-	-	-
Closing value	**5,235.2**	**6,296.7**	**6,396.4**	**6,314.9**	**6,700.3**

7.4. Supporting documentation

The following document supports this Chapter and accompanies our Revised Revenue Proposal.

Name
Post-tax revenue model

8

Incentive Schemes

Transgrid

8. Incentive Schemes

Key messages:

- Our initial Revenue Proposal explained that we support the application of the AER's incentive schemes, which encourage improved customer outcomes.
- The AER's Draft Decision accepted our proposed approach in relation to the:
  - Efficiency Benefit Sharing Scheme (EBSS)
  - Capital Expenditure Sharing Scheme (CESS)
  - Demand Management Innovation Allowance Mechanism (DMIAM), and
  - Service Target Performance Incentive Scheme (STPIS), while making changes to update our performance parameters to reflect the latest available historical data.
- The AER accepted four of our six proposed NCIPAP projects.
- In this Revised Revenue Proposal, we accept the AER's proposed changes with the exception of:
  - the STPIS Service Component 'Average outage duration' parameter, where we have corrected the calculation, and
  - NCIPAP projects, where we have revised our business cases to address the concerns.
- We have updated the incentive amounts that apply in relation to the 2018-23 regulatory period, in accordance with the latest available information.
- In relation to the CESS, we propose that it should not apply to ISP projects given the significant impact of inflation on our ability to manage outturn costs.

8.1. The AER's Draft Decision

The AER's Draft Decision noted that it is currently reviewing and refining its incentive schemes and guidelines to ensure they remain relevant and fit for purpose. Depending on the outcome of this review, it is possible that the incentive schemes for the 2023-28 regulatory period may change. Subject to this caveat, the AER's Draft Decision accepted our proposed application of the following incentive schemes for the 2023-28 regulatory period:

- EBSS (Version 2), which provides a continuous incentive throughout the regulatory period to pursue opex efficiency improvements and share these with our customers.[118]
- CESS (Version 1), which provides an incentive to undertake efficient capex during a regulatory control period.
- STPIS (Version 5), which provides incentives to improve three service components, the:
  - service component (SC)
  - market impact component (MIC), and
  - network capability component (NCC).
- DMIAM, which is a demand management scheme that applies to TNSPs.

[118] Although the AER accepted our application of the EBSS and CESS to the 2018–23 period, it did adjust some of the inputs including SaaS costs and capitalised lease costs.

In relation to the detailed application of these schemes, the AER's Draft Decision accepted our proposed approach to the EBSS and CESS.[118] The AER also accepted four of the six proposed priority projects as part of our NCIPAP, which have been endorsed by AEMO and will deliver benefits to the market and customers. The Draft Decision also accepted our DMIAM, subject to a modest reduction in the allowance.

In relation to the performance targets, caps and floors for the STPIS, the AER's Draft Decision:

- proposed alternative targets, caps and floors as a result of incorporating our latest 2021 network performance data for the SC parameters and MIC, and
- explained that the AER's recent MIC penalty exclusion clarification, which applies to semi-scheduled renewable energy generation, does not extend to scheduled and non-scheduled renewable energy generation.

The AER's Draft Decision did not accept our proposal to reduce (i.e., tighten) the 'large loss of supply events system minutes measure' from 0.25 to 0.15 minutes. Our initial Revenue Proposal explained that this change would increase our target from zero to one event for the 2023-28 regulatory period, thereby providing an incentive to improve performance (i.e., achieve zero in any year). The AER's Draft Decision means that we no longer have an incentive to improve our performance on this parameter, but are still subject to a penalty if an event occurs.

8.2. What we heard from our customers

Our customers recognise the importance of delivering better outcomes for customers by providing network companies with incentives to achieve cost efficiencies and service performance improvements. Customers expect networks to continually improve business practices and to innovate, especially in the context of the rapid energy transition that is directly affecting customers and their role in the energy market.

We discussed the AER's draft decision on our STPIS, SC and MIC with the TAC. Overall, the TAC:

- explained that while customers have diverse views on reliability, in general they do not want to pay for improved reliability through the SC. On this basis, the TAC does not support tightening the targets for system minutes measure from 0.25 to 0.15. The TAC also considers that it would be reasonable to reduce the penalty so that the incentive is symmetrical and noted that this would be considered as part of the AER future STPIS review, and
- considers that generator behaviour may be addressed through other processes, including the future STPIS review, and therefore the MIC exclusion clarification does not need to cover scheduled and non-scheduled renewable energy generators.

This Revised Revenue Proposal fully aligns with the views of the TAC.

8.3. Efficiency Benefit Sharing Scheme (EBSS)

The AER's Draft Decision accepted our proposal to apply version 2 of the EBSS in the 2023-28 regulatory period. We accept the AER's Draft Decision, noting that the scheme is to be reviewed by the AER. Our updated opex allowance and exclusions are shown in Table 8-1.

Table 8-1: Proposed EBSS targets ($M, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Opex	219.7	236.6	240.7	243.0	244.9	1,184.8

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Adjustments						
Debt raising costs	(4.4)	(4.8)	(4.9)	(4.8)	(4.8)	(23.7)
Network support costs	-	-	-	-	-	-
Expensed NCIPAP	-	-	-	-	-	-
capitalised opex that has been excluded from the RAB	-	-	-	-	-	-
movements in provisions	-	-	-	-	-	-
EBSS target	**215.3**	**231.8**	**235.8**	**238.1**	**240.1**	**1,161.2**

In our initial Revenue Proposal, we raised concerns regarding the EBSS's weakened incentive properties as a result of the recent decline in the WACC. We expect the AER will examine this issue as part of its current incentive schemes review. Our view is that the EBSS should be amended to restore the original design intention that efficiency gains (and losses) should be shared 70/30 in favour of customers.

In relation to the application of the EBSS for the 2018-23 regulatory period, this Revised Revenue Proposal has updated the carryover amounts to reflect our latest opex data. This updated calculation shows that:

- our total opex will be around 11.8 per cent below the AER's allowance for the 2018-23 regulatory period, and
- our 2021-22 base year is approximately $49.5 million below the AER's opex allowance.

Table 8-2 shows that the updated opex information produces a negative EBSS carryover of $23.9 million compared to the AER's Draft Decision of $19.3 million ($M, Real 2022-23). Customers benefit from the EBSS because the efficiency savings we have achieved are reflected in a lower opex allowance for the 2023-28 regulatory period.

Table 8-2: Proposed EBSS carryovers ($M, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
EBSS Carryover	13.5	(1.5)	(11.2)	(10.2)	(14.6)	(23.9)

The detailed calculations that support this carryover amount are presented in our EBSS model, which is provided as an attachment to this Revised Revenue Proposal.

8.4. Capital Expenditure Sharing Scheme (CESS)

Our initial Revenue Proposal supported the continued application of version 1 of the CESS as proposed in the AER's Framework and Approach, which encourages us to pursue capex efficiency improvements and share these with customers. The CESS sharing ratio means that we retain 30 per cent of the cumulative underspend (or overspend) and customers receive 70 per cent. The CESS also encourages more efficient substitution between capex and opex.

The AER's Draft Decision accepted our initial Revenue Proposal, subject to any amendments that arise from the AER's incentive review, which is currently underway.

This Revised Revenue Proposal accepts the AER's Draft Decision to apply the CESS to our business-as-usual capex. However, we are seeking to exclude EnergyConnect and other ISP projects approved by the AER in the 2023-28 period from the application of the CESS. This departure from our initial Revenue Proposal is consistent with our:

- ongoing discussions with the AER in the context of our financeability concerns for Major Projects, and
- submission to the AER on its Position Paper – Options for the Capital Expenditure Sharing Scheme (CESS position paper), dated 9 September 2022.

Our proposed exclusion of EnergyConnect and other Major Projects from the CESS is discussed in Section 8.4.1.

In this Revised Revenue Proposal, we have updated the CESS calculations to reflect our latest estimates of capex over the 2018-23 regulatory period. Table 8-3 sets out our carryover for the 2023-28 period. Table 8-3 shows that we are forecasting a negative CESS carryover amount of $1.8 million compared to the Draft Decision of $2.0 million. This includes the repayment of the financing costs that we received an allowance for but did not incur for EnergyConnect in the 2018-23 period, due to the project being partially deferred to the 2023-28 period.

Table 8-3: Proposed CESS carryovers ($M, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
CESS Carryover from 2018–23	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(2.9)
CESS Carryover true up for 2017-18	0.2	0.2	0.2	0.2	0.2	1.1
Total	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**	**(1.8)**

The detailed calculations that support this carryover amount are presented in our CESS model, which is provided as an Attachment to this Revised Revenue Proposal.

8.4.1. Exclusion of EnergyConnect and other ISP Projects from the CESS

We have discussed with the AER our concerns that in relation to EnergyConnect there have been considerable and unexpected changes in actual inflation since May 2021 when the AER published its Determination for EnergyConnect. Specifically the:

- headline CPI increased by 1.8 per cent[119] in the June quarter and by 6.1 per cent over the 12 months ending June 2022, the highest year-ended CPI inflation since the early 1990s[120]
- inputs Producer Price Index (PPI) for the manufacturing sector increased by 17.7 per cent over the 12 months to the end of June 2022,[121] and
- outputs PPI for heavy and civil engineering construction increased by 9.0 per cent over the 12 months to the end of June 2022.[122]

119 Or 1.7 per cent seasonally adjusted.

120 Reserve Bank of Australia, Statement on Monetary Policy, August 2022, p. 43.

121 ABS, 6427.0 Producer Price Indexes, Australia, Table 13. Input to the Manufacturing industries, division and selected industries, index numbers and percentage changes, June 2022.

122 ABS, 6427.0 Producer Price Indexes, Australia, Table 17. Output of the Construction industries, subdivision and class index numbers, June 2022.

The recent unexpected inflation and large increases in producer and consumer prices are resulting in significant increases in our input costs, including materials, labour and freight. These cost increases have been driven by a range of factors beyond our control, including:

- supply chain disruptions resulting in materials shortages
- the war in Ukraine driving up fuel costs, and
- labour shortages.

There is also considerable uncertainty in relation to the construction cost inflation outlook over the medium term.

We consider therefore that the CESS should be suspended temporarily for the duration of the 2023-28 period for EnergyConnect given the:

- unprecedented uncertainty over how long the existing inflationary pressures faced by major construction projects, including EnergyConnect, will last. As the AER has acknowledged recently, capital expenditure related to transmission projects is generally difficult to forecast because it is less recurrent and involves "more project 'lumpiness' with significant major projects including new interconnectors". The uncertainty over the current inflationary pressures compounds the difficulties associated with forecasting the capital expenditures related to EnergyConnect[123]
- fact that these inflationary pressures could not have been anticipated and are largely driven by supply-side factors that are beyond our control, and
- scale of EnergyConnect means that any resulting CESS penalties could have a material adverse impact on cash flows and financeability in future regulatory control periods.

This final point is because, under the current regulatory framework, if our costs increase above the AER's allowance for this project, we would need to fund the gap in financing the investment for the remainder of the period and would be penalised under the CESS for any overspend, even when the higher levels of expenditure are efficient. This means that we may not have a reasonable opportunity to recover the efficient costs of delivering the project. Also, if we significantly overspend our total capex allowance, we could be penalised through the ex-post capex review process by having actual capex incurred excluded from the RAB.

The incremental nature of the capex related to EnergyConnect means that it is easily separable from target capital expenditure used to implement the CESS.

We also consider that other ISP projects approved by the AER in the 2023-28 period should also be excluded from the CESS for the 2023-28 period in light of the overall risk associated with delivering them under the current regulatory framework. There is currently no provision in the NER for adjusting the capex allowance approved by the AER for a Major ISP Project to deal with unforeseeable and unquantifiable costs in a way that is fair to all market participants, including customers and NSPs. Despite our best efforts, we know that there will be unforeseeable and unquantifiable costs that will arise in the delivery of these projects, given that:

- their scale requires billions of dollars to deliver them
- the size and nature (greenfield characteristics) of these projects makes them difficult to forecast
- we are being directed to undertake these projects in accordance with AEMO's ISPs

[123] AER, Review of incentives schemes: Options for the Capital Expenditure Sharing Scheme, Position Paper, August 2022, p. 9.

- we are in an inflationary environment, which means that costs are increasing and we have no control over this, and
- the delivery timeframes and construction market are very tight, increasing the risk of rising costs in the delivery phase.

Our Attachment on the CESS application in the 2023-28 period provides further information to support the rationale for not applying the CESS to ISP projects.

8.5. Service Target Performance Incentive Scheme (STPIS)

The STPIS provides a financial incentive for us to maintain or improve service performance, maximise network availability and address network constraints to dispatch the lowest cost generation. The STPIS is important to counter balance our expenditure incentives, including the EBSS and CESS.

The STPIS (version 5) has three components, the:

1. Service component (SC) – This provides a reward or penalty of +/- 1.25 per cent of the MAR for the relevant calendar year to improve network reliability by focussing on unplanned network outages and prompt restoration in the event of unplanned outages that cause supply interruptions. It also encourages us to identify and address potential network reliability issues.

2. Market incentive component (MIC) – This provides a reward or penalty of up to +/- 1 per cent of the MAR for the relevant calendar year to minimise the impact of transmission outages that can impact the spot price and wholesale market outcomes. Performance is measured based on the number of five-minute dispatch intervals (DIs) constrained when an outage constraint binds with a marginal value greater than $10/MWh.

3. Network capability component (NCC) – This provides pro-rata incentive payments of up to 1.5 per cent of MAR for completion of low-cost one-off opex or capex projects that improve network capability at times when it is most needed and provide value for money to customers. As required under version 5 of the STPIS, we provided a Network Capability Incentive Parameter Action Plan (NCIPAP) as an attachment to our initial Revenue Proposal, which has been endorsed by AEMO.

8.5.1. Initial Revenue Proposal

Service Component

In our initial Revenue Proposal, we proposed:

- values of caps, targets and collars calculated in line with STPIS version 5 based on the historical five-year data 2016 to 2020 in accordance with the AER's Regulatory Information Notice requirements
- targets using the arithmetic mean of the five years of performance data
- caps and floors using probability distribution fitting on the performance data, and
- an alternate target for the large loss of supply event frequency parameter target. Our strong outperformance to date will see us reach the performance frontier in the 2023-28 regulatory period, where our target would reduce to zero events. This would mean we no longer have an incentive to improve our performance.

To ensure this parameter continues to provide an incentive to improve reliability, we proposed to reduce (i.e., tighten) system minutes from 0.25 to 0.15 minutes. This would increase our target from zero to one event in the 2023-28 period, providing an incentive if we have zero events in any given year.

Market Impact Component

In our initial Revenue Proposal, we calculated indicative MIC performance values for the 2023-28 regulatory period in accordance with STPIS version 5, which is consistent with the approach used to calculate the values for the 2018-23 period:

- seven years of performance data ranging from calendar years 2014 to 2020 were used to determine the target, in accordance with the AER's Regulatory Information Notice requirements
- an interim unplanned outage event limit was calculated using 2011 to 2017 performance data. This interim unplanned outage limit was used to determine the adjusted performance counts for the 2014 to 2017 calendar years. The unplanned outage event limit published in the 2018-23 regulatory period determination was used for 2018 to 2020
- an average of the medial five years of adjusted performance counts within the 2014 to 2020 window was used to determine the performance target, with the lowest (2014) and highest (2020) performance counts excluded from the calculation
- the cap was set to zero and the collar was to be twice the performance target, and
- the unplanned outage event limit was calculated by multiplying the performance target by 0.17.

Our MIC performance target proposal applied the force majeure events exclusion clarification provided by the AER in Ausnet's 2022-27 transmission determination[124] for semi-scheduled generation. It was observed that semi-scheduled generators often do not modify their bidding behaviour when a known planned network outage constraint is in place and AEMO has placed a dispatch limit on the generator. This can then be recorded as a binding system constraint, which is uncontrollable by the TNSP. The clarification provided by the AER allows the exclusion of these binding constraints from the MIC penalty where semi-schedule generation do not modify their bids into the market during planned outages.

We also applied this exclusion to scheduled and non-scheduled generation where these generators were observed to have undertaken the same bidding behaviour, offering capacity in excess of the output constraints set by AEMO during planned network outages. We excluded these penalties in line with the same principles that the AER applied to semi-scheduled generators.

Network Capability Component

In our initial Revenue Proposal, we included our AEMO endorsed NCIPAP, which will continue delivering material benefits through the NCC for our customers in the 2023-28 regulatory period. This included six projects with a total cost of $16.2 million.

8.5.2. The AER's draft decision and how we have responded

Service component

The AER's draft decision:

[124] AER – Final Decision – AusNet services transmission 2022-27, Attachment 10 – Service Target Performance Incentive Scheme, January 2022, pp.10-17 - 10-18.

- calculated the SC caps, targets and floors consistent with those in our initial Revenue Proposal, but using the latest available historical five-year data for 2017 to 2021. This 2021 data only became available after we prepared our initial Revenue Proposal, and
- did not accept our proposed alternate target setting for the loss of supply events (y) system minutes parameter.

We consulted the TAC about whether our alternate target for the large loss of supply event frequency parameter should be re-proposed in our Revised Revenue Proposal to provide us with a continued incentive to improve performance. The TAC's primary concern is affordability and cost of living pressures on customers. To give effect to the TAC's position, we have accepted the AER's draft decision for the loss of supply events (y) system minutes parameter, meaning that we will not receive an incentive payment for any further improvement in loss of supply events performance.

Our Revised Revenue Proposal accepts the AER's draft decision for the SC parameters, except for the "Average outage duration" parameter. We consider that the AER has incorrectly calculated the data for this parameter and have therefore proposed a revised cap, target and floor.[125]

Table 8-4 details our revised SC caps, targets, floors, best fit distribution and corresponding weighting based on the AER's Draft Decision and our calculation of the "Average outage duration" parameter.

Table 8-4: SC proposed performance parameters

Service component (+/- 1.25% MAR)	Cap	Target	Floor	Distribution	Weighting (% MAR)
Unplanned outage circuit event rate (+/- 0.75% MAR)					
Lines event rate – fault	8.80%	14.29%	21.84%	LogLogistic	0.2
Transformer event rate – fault	5.87%	9.66%	14.98%	LogLogistic	0.2
Reactive plant event rate - fault	6.81%	12.14%	18.72%	Gamma	0.1
Lines event rate – forced	3.76%	8.68%	15.24%	Gamma	0.1
Transformer event rate – forced	5.05%	9.87%	17.45%	Pearson5	0.1
Reactive plant event rate - forced	6.88%	9.82%	13.68%	Pearson5	0.05
Loss of supply events frequency (+/-0.3% MAR)					
Loss of supply events > 0.05 (x) system minutes	0	1	3	Poisson	0.15
Loss of supply events > 0.25 (y) system minutes	0	0	1	Poisson	0.15
Average outage duration (+/- 0.2% MAR)					
Average outage duration	34	62	107	Pearson5	0.2
Proper operation of equipment (+/- 0% MAR)					

[125] The AER's Draft Decision has used the two-year rolling average value for CYs 2020 and 2021 of 72.24 minutes, instead of the actual CY 2021 annual value from our STPIS submission of 99.58 minutes.

Service component (+/- 1.25% MAR)	Cap	Target	Floor	Distribution	Weighting (% MAR)
Failure of protection system	7	13	19	Poisson	0
Material failure of supervisory control and data acquisition (SCADA) system	0	0	0	N/A	0
Incorrect operational isolation of primary or secondary equipment	2	5	9	Poisson	0

Market Impact Component

The AER's draft decision:

- calculated the MIC performance data consistent with our initial Revenue Proposal, but using the latest available historical five-year data for 2017 to 2021. This 2021 data only became available after we prepared our initial Revenue Proposal, and
- did not accept our proposal to extend the force majeure exclusions clarification to scheduled and non-scheduled generators as the current exclusion clarification is targeted at semi-scheduled generators.

We consulted the TAC about whether the exclusion clarification should be re-proposed in our Revised Revenue Proposal. The TAC considered that generator behaviour could be addressed outside of the incentive scheme, but that this was ultimately an issue for the AER to consider. We have therefore accepted the AER's draft decision of the MIC performance parameters shown in Table 8-5.

Table 8-5: Proposed performance parameters

Parameter	Proposed dispatch interval count
Cap	0
Target	6,476
Collar	12,952
Unplanned outage event limit	1,101
Dollar per dispatch interval	1,455.7

While we accept the Draft Decision, we also reiterate our concerns regarding the effectiveness of the MIC scheme. As noted in our initial Revenue Proposal, we strongly consider that the AER should undertake a review to develop an alternative method for calculating the MIC target, which should be applied in our 2023-28 regulatory period.

Network Capability Component

The AER's draft decision has accepted four of our six proposed NCIPAP projects. The AER did not accept two projects on the basis that the benefits may be overstated and may not deliver material benefits to customers. The two projects not accepted in the AER's draft decision are:

- Darlington Point 330/220 kV transformer tripping scheme ($0.3 million), and
- Yass 330/132 kV transformer dynamic ratings ($1.7 million)

The AER's Draft Decision considered that these projects would only deliver market benefits under N-1 contingency conditions. The AER's adjustment reduces the market benefits of the projects.

We have updated the business cases for these two projects to address the concerns raised in the AER's Draft Decision and have re-submitted these as attachments to this Revised Revenue Proposal. Specifically, we have included additional information explaining that market benefits will be delivered throughout the year as a result of avoiding pre-contingent generation curtailment, which would be imposed in accordance with network operational and generation dispatch principles.

Table 8-6 lists our re-proposed NCIPAP projects, which were previous approved by AEMO and are unchanged from our initial Revenue Proposal.

Table 8-6: Re-proposed NCIPAP projects 2023-28 ($M, Real 2022-23)

Proposed NCIPAP project	Estimated cost ($ Million)
Increase capacity for generation between Darlington Point and Wagga	4.4
Darlington Point 330/220 kV transformer tripping scheme	0.3
Increase capacity for generation X5 voltage stability constraints	6.2
94T line dynamic ratings.	0.4
Yass 330/132 kV transformer dynamic ratings	1.7
Maintain capacity during Climate Change – install dynamic line ratings on multiple lines	6.0
Total	19.0

8.6. Demand Management Innovation Allowance Mechanism (DMIAM)

The DMIAM provides TNSPs with research and development funding to trial new demand management solutions that have the potential to reduce long-term network costs by reducing ongoing or peak demand. Our initial Revenue Proposal explained that we estimate an allowance of $4.1 million ($M, Real 2022-23) under the AER's DMIAM for the 2023-28 regulatory period based on:

- $200,000 fixed allowance for the costs of independent assessment, plus
- 0.1 per cent of our total ABBRR (unsmoothed revenue) for the 2023-28 regulatory period.

In its Draft Decision, the AER accepted our approach to setting the DMIAM. In this Revised Revenue Proposal, we have updated the allowance to reflect the revised annual revenue requirement as shown in Table 8-7.

Table 8-7: DMIAM allowance ($M, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Allowance	0.9	0.9	0.9	0.9	0.9	4.7

Demand-response resource pool

Through our Phase 2 TAC engagement, a customer advocate suggested that we establish a pool of demand-response resources across our network. The rationale is that proactively establishing services ahead of time would overcome barriers for non-network solutions to participate in RIT-T processes, increasing their efficient deployment to meet emerging network needs. This could reduce, defer or avoid network capex and lower customer energy bills.

We estimate that building a demand-response resource pool would require $15.2 million of opex in the 2023-28 regulatory period. This would build on the trials and research conducted through the DMIAM. Creating capability at a network-level scale would involve:

- competitive procurement of 30-50 MW of demand-response in NSW, for example, via a demand response auction program, similar to that used in California
- contracting with demand-response providers to establish the pool of resources, such as smart electric vehicle charging providers, DER aggregators or industrial customers with load flexibility. Payments would cover setup costs, testing and ongoing resource availability, and
- establishing a Distributed Energy Resource Management system to coordinate and operate demand-response resources across the network.

This initiative would create a meaningful demand-response capability, which could be called on at times of network stress. It would also establish the processes, commercial relationships and structures needed to quickly and cost-effectively scale the deployment of demand-response resources.

Noting the primary importance of energy affordability, we have elected not to include this expenditure in our proposal for the 2023-28 regulatory period. However, we welcome the AER's assessment of this initiative and inclusion of it in our Final Revenue Determination if AER deems it worthwhile.

We welcome the AER's response to this proposal.

8.7. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal.

Name
Efficiency Benefit Sharing Scheme Model
Capital Expenditure Sharing Scheme Model
Suspension of CESS for Project EnergyConnect
OER-N2176 Rev 3 Uprating DNT 330-132kV Transformers
OER-N2471 Rev 2 Increase Capacity in Yass Transformers

9

Cost pass through events

Transgrid

9. Cost pass through events

Key messages

- Our initial Revenue Proposal included the following nominated pass through events:
  - an insurance coverage event
  - an insurer's credit risk default event
  - a natural disaster event, and
  - a terrorism event.
- The AER's Draft Decision accepted our insurance coverage event definition, subject to making a number of changes to clarify its scope and to ensure consistency with recent determinations.
- The AER's Draft Decision accepted our proposed definitions for the insurer's credit risk default event, natural disaster event and terrorism event, noting that they are consistent with the AER's recent determinations. The AER proposed to rename the 'insurer's credit risk default event'.
- In this Revised Revenue Proposal, we accept the AER's definitions for our proposed nominated pass through events.
- We propose a new additional nominated pass through event to address the risk we face if we are not able to secure non-network services to meet our regulatory obligations, reflecting our TAC's preferred approach to managing this risk.

9.1. The AER's Draft Decision

Our initial Revenue Proposal explained that the NER allows TNSPs to recover or 'pass through' the actual costs arising from high impact, low probability events, such as bushfires. In the absence of pass through provisions, an allowance for these high impact, low probability events would need to be included in a TNSP's revenue requirement. From an efficiency and equity perspective, it is strongly preferable to address the risk of these high impact, low probability events by allowing the actual costs of an event to be passed through to customers.

In our initial Revenue Proposal, we proposed the following nominated cost pass through events in addition to the pass through events that are specified in the NER:

- an insurance coverage event
- an insurer's credit risk default event
- a natural disaster event, and
- a terrorism event.

For each of these events, our initial Revenue Proposal proposed definitions that were largely consistent with the currently applicable definitions and recent AER decisions. The AER's Draft Decision accepted our nominated pass through events, subject to making the following changes to the insurance coverage event:

- broaden the meaning of 'changed circumstances' by referring to 'insurance market' instead of 'insurance liability market' and adding 'including liability insurance' to reflect that the scope of the insurance coverage event is broader than liability insurance
- make an amendment to clarify that the AER may have regard to its final guidance note on the insurance coverage pass in assessing a pass through application, and

- make changes consistent with recent determinations to clarify that:
  - Transgrid will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of Transgrid in relation to any aspect of Transgrid's network or business, and
  - Transgrid will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of Transgrid in relation to any aspect of Transgrid 's network or business.
- The AER's Draft Decision also changed the name of the proposed 'insurer's credit risk default' event to 'insurer's credit risk' event to ensure consistency with recent determinations.

9.2. Nominated pass through events

This Revised Revenue Proposal accepts the AER's Draft Decision on nominated pass through events for the 2023-28 regulatory period. They are:

Event	Definition
Insurance Coverage Event	An insurance coverage event occurs if: 1. Transgrid: a. makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies, or b. would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances, and 2. Transgrid incurs costs: a. beyond a relevant policy limit for that policy or set of insurance policies, or b. that are unrecoverable under that policy or set of insurance policies due to changed circumstances, and 3. The costs referred to in paragraph 2 above materially increase the costs to Transgrid in providing prescribed transmission services. For the purpose of this insurance coverage event: a. 'changed circumstances' means movements in the relevant insurance market, including liability insurance, that are beyond the control of Transgrid, where those movements mean that it is no longer possible for Transgrid to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies. b. 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had: i. the limit not been exhausted, or ii. those costs not been unrecoverable due to changed circumstances. c. A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the

Event	Definition
	regulatory control period or a previous regulatory control period in which Transgrid was regulated; and d. Transgrid will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of Transgrid in relation to any aspect of Transgrid's network or business; and e. Transgrid will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of Transgrid in relation to any aspect of Transgrid's network or business. *Note: For the avoidance of doubt, in assessing an insurance coverage event through application under rule 6A.7.3(j), the AER will have regard to:* i. the relevant insurance policy or set of insurance policies for the event ii. the level of insurance that an efficient and prudent NSP would obtain, or would have sought to obtain, in respect of the event iii. any information provided by Transgrid to the AER about Transgrid's actions and processes, and iv. any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.
Insurer's Credit Risk Event	An insurer's credit risk event occurs if an insurer of Transgrid becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Transgrid: a. is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy, or b. incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer. *Note: In assessing an insurer credit risk event pass through application, the AER will have regard to, among other things:* i. Transgrid's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation, and ii. in the event that a claim would have been covered by the insolvent insurer's policy, whether Transgrid had reasonable opportunity to insure the risk with a different provider.
Natural Disaster Event	Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2023–28 regulatory control period that changes the costs to Transgrid in providing prescribed transmission services, provided the cyclone, fire, flood, earthquake or other event was: a. a consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or b. not a consequence of any other act or omission of the service provider.

Event	Definition
	Note: In assessing a natural disaster event pass through application, the AER will have regard to, among other things: i. whether Transgrid has insurance against the event, and ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event
Terrorism Event	Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: a. from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and changes the costs to Transgrid in providing direct control services. *Note: In assessing a terrorism event pass through application, the AER will have regard to, among other things:* i. whether Transgrid has insurance against the event ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

New additional nominated pass through event

We are also proposing a new additional nominated pass through event to address the risk we face in not being able to secure non-network services to meet our regulatory obligations. As discussed in Chapters 4 and 10, the RIT-Ts for the following projects identified that non-network options form part of the preferred solutions for managing reliable supply to the:

- Bathurst Orange Parkes area, and
- North West Slopes area.

We are committed to engaging with potential non-network providers to successfully conclude network support agreements in line with the RIT-T outcomes. However, until the conclusion of the procurement process, there remains a risk that non-network proponents are not able to provide the required service in the time required to meet our obligations under the NER. If this occurs, we would need to undertake network investment, in line with the next ranked option in the relevant RIT-T, in order to meet our NER obligations.

The TAC recognises that relying on innovative non-network solutions increases our risks in relation to meeting our regulatory obligations for these projects and is supportive of us efficiently managing this risk. On this basis, this Revised Regulatory Proposal includes:

- contingent projects consistent with our discussion with the AER staff, who have indicated that these arrangements are the most appropriate mechanism under the Rules to address this risk. This is discussed in Chapter 10, and
- a new nominated pass through, as an alternative to the contingent projects, consistent with the TAC's strong preference to rely on the cost pass-through provisions under the NER to manage this risk.

We propose that a **non-network option event** for a RIT-T project is defined as one or more of the following:

(i) the non-network solution identified in the associated RIT-T being found not to be technically feasible, and/or

(ii) no non-network proponent being able to provide the required service in time to meet the requirements of Schedule 5.1.4 of the National Electricity Rules.

Where a 'RIT-T project' refers to the Managing Reliable Supply to the Bathurst Orange Parkes area project and the Managing Reliable Supply to the North West Slopes area project.

In relation to the nominated pass through considerations in the Rules:

- this event is not covered by any of the categories of pass through event in clause 6A.7.3(a1)(1) to(4)
- the nature of the event can be clearly identified at the time the determination is made, as evidenced by the proposed definition
- Transgrid could not reasonably prevent an event of this type from occurring, as whether a NNO is technically feasible and/or able to provide the service within the required timeframe is outside of Transgrid's direct control, and
- Transgrid cannot insure against this event.

This cost pass through event would be triggered where we either:

- receive no compliant responses in our procurement process for non-network services for these RIT-T projects, or
- receive notification from either AEMO or a NNO that the NNO option is unable to provide the required service within the timeframe required to avoid an expected breach of the requirements of Schedule 5.1.4 of the Rules.

10

Contingent Projects

10. Contingent Projects

Key messages

- Our initial Revenue Proposal included:
  - eight standard contingent projects
  - four contingent projects for those projects that were undergoing a RIT-T at the time of our initial Revenue Proposal.
- The AER's Draft Decision:
  - accepted only one of the eight standard contingent projects, being to 'manage increased fault levels in Southern NSW', and
  - did not accept the four projects that were undergoing a RIT-T.
- In this Revised Revenue Proposal, we have
  - accepted the AER's draft decision on 'manage increased fault levels in Southern NSW'
  - removed four contingent projects that are market benefits driven
  - reproposed three contingent projects required to meet a future reliability compliance requirement and updated their triggers based on the AER's feedback, and
  - proposed four new contingent projects:
    - > one relating to our 'System Security Roadmap'
    - > two relating to recently completed RIT-Ts for which we are relying to on non-network solutions. We have included contingent projects to address the risk we face if we are not able to secure non-network services to meet our regulatory obligations, and
    - > one relating to potential future demand in the Narrabri area.

10.1. Our initial Revenue Proposal

Our initial Revenue Proposal explained that in the 2023-28 regulatory period our network will be challenged by:

- pockets of strong maximum demand growth in some regions from mining developments and industrial precincts in regional NSW, urban development and data centres, and
- increased operational complexity from the rapid change in the mix and location of generation as ageing coal-fired generation retires and large-scale variable renewable generation connects to the NEM.

Given these operational challenges, the need, timing and cost of a number of projects was uncertain at the time of submitting our initial Revenue Proposal. We therefore proposed to treat these projects as contingent projects so that customers only pay for them if and when they proceed. Our initial Revenue Proposal included two categories of contingent projects:

- Standard contingent projects – we identified eight projects under the NER to address:
  - > quality, reliability and security of supply in response to:
    - > system inertia and strength requirements
    - > increased fault levels, and
    - > expected demand growth

  - provide market benefits in response to:
    - expected new generation connection.

- Projects undergoing a RIT-T and where the outcome of the RIT-T process will be known prior to us submitting our Revised Revenue Proposal to the AER. There were four of these projects and we explained that we would include the preferred option identified through the RIT-Ts in our Revised Revenue Proposal.

10.2. The AER's Draft Decision

Standard contingent projects

The AER's Draft Decision accepted only one of the eight standard contingent projects that we proposed, being to 'manage increased fault levels in Southern NSW', on the basis that the project may be required to maintain the quality, reliability and security of supply or meet demand in the 2023-28 period. The AER rejected the other seven contingent projects because:

- the event in the trigger is unlikely to occur during the 2023-28 period and therefore the trigger is not probable
- there is no clear link between the trigger occurring and the need for additional capex, and
- the trigger does not relate to a specific location but rather a wider area (where some assets may or may not require augmentation) or general demand uncertainty.

The AER explained that we can use the defined cost pass through events in the NER[126] for system inertia and system strength related projects where these meet the NER requirements.

We accept the AER's view that we provided limited information to demonstrate the likelihood of the projects occurring in the 2023-28 period and welcome its constructive advice in relation to specificity of the triggers. We have carefully considered the issues raised by the AER and whether the AER's Draft Decision would be more efficient for customers. We suggest only including contingent projects required to meet a future reliability compliance requirement and removing those that are market benefits driven. This will best balance the objective of delivering capex savings to customers with the need to deliver a safe and reliable network and meet growth in localised demand.

We believe it is in the long-term interest of consumers to include projects to maintain the future quality, reliability and security of supply or meet demand, noting that these projects will only proceed if:

- it is determined through the RIT-T process that each project would deliver a net economic benefit or is required to meet a reliability requirement and the specified trigger events occur, and
- the AER determines, based on its own careful scrutiny in accordance with the NER requirements, that the proposed expenditure is prudent and efficient.

This will ensure that the projects will only proceed if they are in our customers' interests. Our customers will not face any additional costs unless a project is shown to deliver net benefits, or is required to meet a reliability requirement, and the AER has assessed the projects' costs as prudent and efficient.

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[126] The NER clause 6A.7.3(6) and (7) provide defined pass through events for an 'inertial shortfall event' and a 'fault level shortfall event'.

Projects undergoing RIT-Ts

The AER's Draft Decision does not accept the four projects that were undergoing a RIT-T at the time of our initial Revenue Proposal as contingent projects. The AER considers that these projects do not satisfy the requirements of a contingent project and encourages us to:

- consult with our customers on these projects if we include them in our Revised Revenue Proposal, and
- address the issues raised by its consultant, EMCa.

Feedback from the TAC

We acknowledge that the AER has raised important issues on our proposed contingent projects. We sought feedback from the TAC on the AER's Draft Decision and our proposed response is to:

- for standard contingent projects:
  - accept the AER's draft decision for 'market benefits' driven projects, and
  - maintain projects that are required to meet a future reliability compliance requirement.
- for projects with recently completed RIT-Ts that have identified the preferred option as including both network and non-network components:
  - rely on the non-network component of the preferred solutions to the greatest extent possible, and
  - include later stages of the preferred option which would be required to meet potential increases in demand as contingent projects, to ensure that our customers only pay for this investment if and when it is needed.

Our TAC recognises that by seeking to address our regulatory obligations by using innovative non-network solutions introduces risks. We have heard different views from the AER and the TAC on the appropriate mechanism to address this risk:

- the AER has indicated that it considers the contingent project arrangements would be the most appropriate mechanism under the NER, and
- the TAC's strong preference is to rely on a new additional nominated pass through event.

This Revised Revenue Proposal includes a new nominated pass through event for the AER's consideration, as an alternative to the contingent projects proposed in this section.

10.3. Our Response to the AER's Draft Decision

10.3.1. Standard Contingent Project

Table 10-1 summarises our response to the AER's Draft Decision on the eight standard contingent projects. In this Revised Revenue Proposal:

- for five projects, we have accepted the AER's Draft Decision, and
- for three projects that the AER rejected, we have maintained our position from our initial Revenue Proposal and addressed the AER's feedback, including on the triggers and demand uncertainty. In particular, we have provided independent reports from GHD on the likelihood of the forecast levels of demand occurring.

Table 10-1: Standard Contingent Projects – Our Revised Proposal

Proposed contingent project	AER's Draft Decision	Our Revised Proposal consistent with TAC feedback
1. Manage increased fault levels in Southern NSW	Accept	• Accept AER's Draft Decision including its changes to the trigger events
2. Meeting NSW system inertia requirement	Reject	• Accept AER's Draft Decision and rely on pass through provisions
3. Meeting NSW system strength requirement	Reject	• Accept AER's Draft Decision and rely on pass through provisions
4. Supply to Bathurst, Orange and Parkes Stage 2	Reject	• Maintain because needed to meet externally imposed obligations on voltage management (i.e., Schedule 5.1.4 of the NER). • Updated triggers to address AER concerns. • GHD's independent review of the demand forecasts for this project supports that the trigger event is likely to occur.
5. Improve capacity of Southern NSW lines for renewables	Reject	• Accept AER's Draft Decision because this is a market benefits driven project
6. Supply to ACT network capability	Reject	• Maintain because needed to meet externally imposed obligations on voltage management (i.e., Schedule S5.1a.4 of the NER) • Updated triggers to address AER concerns.
7. Moree Special Activation Precinct	Reject	• Maintain because needed to meet externally imposed obligations for special contingency events stipulated by the Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 1) Clause 4.1.1 (1)(d) • Updated triggers to address AER concerns. • GHD's independent review of the demand forecasts for this project supports that the trigger event is likely to occur
8. Strategic easement acquisition for supply to Sydney from the south	Reject	• Accept AER's Draft Decision because this is a market benefits driven project

Table 10-2 sets out the updated triggers for the four standard contingent projects included in this Revised Revenue Proposal and Table 10-3 sets out the associated indicative costs and expected completion dates.

Table 10-2: Standard Contingent Projects – Revised Revenue Proposal triggers

Proposed contingent project	Reason for project and proposed triggers events
1. Manage increased fault levels in southern NSW	(b) Transgrid Board commitment to proceed with the HumeLink project, subject to the AER amending the revenue determination pursuant to the Rules (c) Issue of a joint notification to AEMO under 5.3.7(g) of the Rules that a connection agreement for Snowy 2.0 has been entered, including relevant technical details of the proposed plant and connection (d) The AER accepts that Transgrid has completed a RIT-T that demonstrates the proposed network investment is the most efficient option to ensure fault current ratings of equipment at Lower Tumut, Upper Tumut, Wagga 330kV and Murray are not exceeded, and (e) Transgrid Board commitment to proceed with the 'Manage increased fault levels in Southern NSW' project, subject to the AER amending the revenue determination pursuant to the Rules.
2. Supply to Bathurst, Orange and Parkes Stage 2	**Reason for the contingent project:** The RIT-T found that a new 132 kV line between Wellington and Parkes forms part of preferred option, irrespective of whether a non-network solution is able to be implemented as part of Stage 1 of this project. However, the date at which this new line is required depends on future demand forecasts and, specifically, when certain spot loads expand or request to connect around Orange and/or Parkes. We have included a contingent project in light of the uncertain timing of the potential spot load developments. GHD has reviewed the Stage 2 demand forecasts. Its report, provided as an Attachment to this Revised Revenue Proposal, finds that the demand forecasts: • are a probable outcome in the 2023-28 period • would result in the trigger event occurring in 2023-28, and • would require augmentation to be initiated. **Updated triggers:** (a) One or more of the following: (i) Total forecast demand in the Orange area exceeds 360 MW, or (ii) Total forecast demand in the Parkes area exceeds 120 MW, and (b) Successful completion of a RIT-T that demonstrates action is needed to comply with our regulatory requirements and that increasing capacity of the network in the Bathurst, Orange and Parkes areas is the option or part of the option that maximises net economic benefits.
3. Supply to ACT network capability	**Reason for the contingent project:** We have regulatory requirements to restore supply to Canberra for special contingency events stipulated by the Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 1)

Proposed contingent project	Reason for project and proposed triggers events
	Clause 4.1.1 (1)(d) and expect that our ability to meet these will be compromised due to demand growth if action is not taken. We have included a contingent project in light of the uncertain timing of the potential load developments associated with the ACT Government's pathway to electrification and transition away from fossil fuels. **Updated triggers:** (c) Combined demand forecast of the load supplied between Canberra, Stockdill and Williamsdale exceeds 890 MW within five years, and (d) Successful completion of a RIT–T that demonstrates that action is needed to comply with our regulatory requirements and that transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.
4. Moree Special Activation Precinct	**Reason for the contingent project** The NSW Government is preparing a plan to develop the Moree area to provide a new business hub (the Moree Special Activation Precinct (SAP)), specialising in agribusiness, logistics and food processing. Initial joint planning discussions with Essential Energy have identified a future requirement to augment the transmission network to accommodate the resulting increase in load. Given the loss of the 9U2 line between Moree and Inverell when the Moree Solar Farm is not generating, the voltage at Moree can drop to below 0.9 per unit, breaching the system standard voltage requirement of NER Schedule S5.1a.4 Power Frequency Voltage. We have included a contingent project in light of the uncertainty regarding the timing of this load development. GHD has reviewed the Moree SAP forecasts and found that, under all load forecast scenarios, there is a requirement to trigger the contingent project. GHD's review is provided as an Attachment to this Revised Revenue Proposal. **Updated triggers:** (e) Total demand forecast in the Moree area exceeds 42 MW, and (f) Successful completion of a RIT–T that demonstrates action is needed to comply with our regulatory requirements and that transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.

Table 10-3 sets out the associated indicative total project costs as well as the expected costs for the 2023-28 period for these four projects.

Table 10-3: Standard Contingent Projects – indicative project cost and timing ($M, Real 2022-23)

Proposed contingent project	Indicative total project cost	Expected commencement date	Expected completion date
1. Manage increased fault levels in Southern NSW	54.3	2023/24	2026/27

Proposed contingent project	Indicative total project cost	Expected commencement date	Expected completion date
2. Supply to Bathurst, Orange and Parkes Stage 2	145.9	2023/24	2030/31
3. Supply to ACT network capability	100.4	2025/26	2028/29
4. Moree Special Activation Precinct	45.3	2026/27	2027/28
Total	**345.9**		

10.3.2. New additional contingent projects

This Revised Revenue Proposal includes four new contingent projects.

One of these relates to our 'System Security Roadmap'. We are undertaking power system studies to identify needs and options to maintain system security as NSW's coal generators retire. While some needs have been identified, we anticipate that further system security issues will emerge as coal generators withdraw. We have included a contingent project given the uncertainty about:

- when the power system security concerns will arise, noting that they are driven primarily by the retirement of coal plants, and
- the nature and scope of investment that will be required to address these concerns.

The other three projects relate to recently completed RIT-Ts. Our approach to the treatment of the preferred options under these RIT-Ts is discussed in Section 4.10.1.4. This explains that in collaboration with the TAC, we have decided to rely on the non-network component of the preferred solutions to the greatest extent possible. These solutions reflect innovative technologies that either replace or defer network investment, placing downward pressure on our costs.[127] The approach for each project is re-capped below:[128]

- **Improving stability in south west NSW** – We are seeking to extend the term of network support from the BESS from three years for as long as possible, to defer network investment to beyond the 2023-28 period. We will require confirmation from AEMO that, subject to successful commissioning and testing of performance standards, it will consider increasing the voltage stability limits on the 330kV line to an agreed acceptable threshold.[129] Given that this project is not driven by regulatory obligations, we have not included a contingent project for this project in this Revised Revenue Proposal.[130]
- **Maintaining reliable supply to the North West Slopes area stage 1** – Consistent with the AER's Draft Decision, we intend to initially rely on network support from BESS at the Gunnedah 132 kV substation and install a new transformer at our Narrabri substation ($9.3 million). We are currently

127 We note that network support costs paid to proponents of non-network solutions are recovered through our opex costs, under pass through provisions in the Rules.

128 As noted above, the TAC has expressed a strong preference for the risks associated with presumptively relying on non-network solutions to be managed through a cost pass through rather than as contingent projects. We have included both approaches in this Revised Proposal for the AER's consideration as to the most appropriate mechanism to adopt to manage this risk.

129 The current limit would need to increase by 120 MW (i.e., from 300 MW to at least 420 MW) in the easterly direction.

130 The technology risk relates to the effectiveness of the BESS operating in 'Virtual Machine Mode' which must be confirmed through the commissioning and testing process with AEMO each time a network change occurs.

progressing competitive procurement and commercial negotiations with non-network proponents for network support contracts. In the event that there is no non-network proponent able to commit to having the BESS (or other technology) in place to provide network support by a date that meets the requirements under Schedule 5.1.4 of the Rules, we would need to progress with a network-only solution to enable us to continue to meet our regulatory obligations. This would in effect be the same investment proposed for Stage 2, brought forward.

- **Maintaining reliable supply to the North West Slopes area Stage 2** – We have included upgrading the existing transmission lines in the area ($132.8 million)[131] as Stage 2 of this project and have proposed this as a contingent project because its timing is uncertain and part of this investment is dependent on future demand growth in the area becoming committed (in particular the Narrabri Gas Project).
- **Maintain reliable supply to Bathurst, Orange and Parkes areas Stage 1** – We intend to rely solely on a non-network solution comprising BESS at Parkes and Panorama and the installation of static synchronous compensators (STATCOMs) at Parkes and Panorama (as a non-network solution). Given the need to still finalise a network support agreement, we have included the alternative network investment (i.e., a synchronous condenser) that could be coupled with a non-network BESS, as a contingent project for the upcoming regulatory period. We have also included a fully-network option as a contingent project in case the non-network solutions are found not to be technically feasible, or if we are unable to conclude network support agreements in time to meet our regulatory obligations, although we are working hard to avoid this outcome.

Table 10-4: New contingent project triggers

New Contingent Project	Proposed Trigger Events
1. Supply to Bathurst, Orange and Parkes Stage 1	(a) One or more of the following: (i) No non-network proponent~~s~~ being able to commit to having the BESS (or other technology) in place to provide network support by a date that meets the requirements under Schedule 5.1.4 of the NER, and/or (ii) The non-network options not being able to form a complete solution and needing to be coupled with a synchronous condenser. (b) One the following: (i) The AER accepting that the option with the most efficient cost includes a network component (i.e., a 25 MVAr synchronous condenser at Parkes), or (ii) None of the non-network solutions being able to form part of the solution and the AER accepting: (A) Our application for an exemption under clause 5.16.4(z3) from having to reapply the RIT-T, and (B) Updated analysis from Transgrid that demonstrates Option 3 (the preferred solely network option) is the highest ranked option under the RIT-T and that there has not been a material change in circumstance, or

[131] Of which it is expected that c.$42 million may be required in the 2023-28 period.

New Contingent Project	Proposed Trigger Events
	(C) Updated analysis from Transgrid that demonstrates an alternative option would be the highest ranked option under the RIT-T.
2. Maintaining reliable supply to the North West Slopes area Stage 1	(a) None of the non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that ensures that the RIT-T preferred option continues to be considered as the top-ranked option under the RIT-T, and (b) All of the following: (i) The AER accepting Transgrid's application for an exemption under clause 5.16.4(z3) from having to reapply the RIT-T, and (ii) The AER accepting updated analysis from Transgrid that demonstrates that Option 3A (the preferred solely network option) is the highest ranked option under the RIT-T and that there has not been a material change in circumstance, or (iii) The AER accepting updated analysis from Transgrid that demonstrates an alternative option would be the highest ranked option under the RIT-T.
3. Maintaining reliable supply to the North West Slopes area Stage 2	(a) One or more of the following: (i) The summated maximum demand forecast for Narrabri and Gunnedah areas exceeds 120 MW within the next six years, or (ii) Commitment of the Narrabri Gas Project.
4. Maintaining power system security in NSW (System Security Roadmap)	(a) One or more of the following: (i) The announcement of the planned retirement of over 500MW of synchronous generation capacity in the NSW Hunter, Central Coast and Central West regions in the following seven years, as recorded in AEMO's Generation Information page, or (ii) AEMO projects in its most likely ISP scenario that more than 500MW of synchronous generation capacity in the NSW Hunter, Central Coast and Central West regions are expected to be retired or mothballed in the following seven years, or (iii) In the following seven years, the minimum number of NSW Hunter, Central Coast and Central West coal units online for more than 1 per cent of the time in each financial year is projected to fall below six units. (b) Successful completion of a RIT–T that demonstrates transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.

Table 10-5 sets out the associated indicative total project costs as well as the expected costs for the 2023-28 period for these five projects.

Table 10-5: New contingent project indicative cost and timing ($M, Real 2022-23)

Proposed contingent project	Expected scope of works	Indicative total project cost	Expected start date	Expected finish date
Supply to Bathurst, Orange and Parkes Stage 1	Panorama 132 kV SVC (30 MVA) and/or synchronous condenser at Parkes 132 kV (2 x 25 MVA)	98.4	2023/24	2026/27
Maintaining reliable supply to the North West Slopes area Stage 1 (if no BESS) [132]	Rebuilding existing line 969 Upgrading Line 9UH	132.8	2023/24	2027/28
Maintaining reliable supply to the North West Slopes area Stage 2	Rebuilding existing line 969 Upgrading Line 9UH	132.8	2025/26	2029/30
Maintaining power system security in NSW (System Security Roadmap)	Dynamic reactive power devices (e.g., synchronous condenser and/or SVC)	107.8	2023/24	2028/29
Total		**471.9**		

10.4. Supporting documentation

The following documents support this Chapter and accompany our Revised Revenue Proposal

Name
Contingent Projects Overview
GHD – Maintain Voltage in Beryl Area Demand Forecast Independent Review
GHD – Maintaining Reliable Supply to Bathurst, Orange and Parkes Area Independent Demand Forecast Review
GHD – Bathurst, Orange and Parkes Area Stage 2 Independent Demand Forecast Review
GHD – Maintaining Reliable Supply to North West Slopes Area Independent Demand Forecast Review
GHD – Moree SAP Contingent Project Independent Demand Forecast Review
HoustonKemp – Unit rate update for four recently completed RIT-Ts

[132] Note that the investment under this Stage 1 is the same as that under the separate Stage 2 North West Slopes contingent project, but it would occur earlier if the BESS component of the RIT-T preferred option is not able to be progressed.

11

Shared Assets

11. Shared Assets

Key messages

- Our initial Revenue Proposal included $10.6 million ($M, Real 2022-23) of forecast shared asset revenue adjustment over the 2023-28 regulatory period.
- The AER adopted this forecast in its Draft Decision, without any change.
- In this Revised Revenue Proposal, we have retained that forecast as it remains a reasonable reflection of the shared asset revenue we expect to receive over the 2023-28 regulatory period.

11.1. The AER's Draft Decision

In its Draft Decision, the AER accepted our proposed forecast for shared asset revenue of $106.2 million ($M, Real 2022-23) over the 2023-28 regulatory period.

In making its decision, the AER considered that our forecast was reasonable as it was comparable to the unregulated revenues from shared assets that we had earned historically. As that forecast exceeded 1 per cent of its projected MAR, the AER considered that it met the materially threshold set out in the Shared Asset Guideline. Consistent with our initial Revenue Proposal and that guideline, the AER then reduced our building block revenue by 10 per cent of the forecast shared asset revenue, i.e., $10.6 million ($M, Real 2022-23).

11.2. Forecast shared asset revenue

This Revised Revenue Proposal retains the shared asset revenue forecast of $106.2 million ($M, Real 2022-23). As this continues to exceed 1 per cent of our forecast MAR, we have also retained the shared asset revenue adjustment of $10.6 million ($M, Real 2022-23). These amounts are set out in Table 11-1 below.

Table 11-1: Shared asset revenue forecast ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Shared asset revenue	17.9	19.1	20.5	23.0	25.7	106.2
Revenue adjustment	1.8	1.9	2.0	2.3	2.6	10.6

11.3. Supporting documentation

The following document supports this Chapter and accompanies our Revised Revenue Proposal.

Name
Post-tax revenue model

12

MAR, X factors and price path

Transgrid

2023-28 Revised Revenue Proposal

12. MAR, X factors and price path

Key messages:

- In this Revised Revenue Proposal, we are proposing total MAR for the 2023-28 period of $4,512.3 million (Real 2022-23). This compares to the AER's Draft Decision of $4,349.1 million (Real 2022-23) and reflects updates to our revised expenditure forecasts.
- In its Draft Decision, the AER:
  - updated the PTRM to version 5.1, which was published after we submitted our initial Revenue Proposal
  - updated rate of return, inflation, debt raising cost, and asset base inputs
  - updated the capex and opex forecasts
  - adopted an alternative X-factor profile to accommodate the impact of the HumeLink contingent project decision.
- We have largely retained these updates in this Revised Revenue Proposal, starting with the models used by the AER in its Draft Decision. Our only updates are to incorporate actual 2021-22 outcomes and our revised capex and opex proposals as discussed in Chapters 3 and 4. This will see energy bills for:
  - residential customers in NSW, rise from $1,740.4 per year in 2022-23 to $1,767.9 in 2027-28 (Nominal), an increase of $27.6 per year
  - residential customers in ACT, rise from $1,807.0 per year in 2022-23 to $1,828.6 in 2027-28 (Nominal), an increase of $21.6 per year
  - small business customers in NSW, rise from $4,347.7 per year in 2022-23 to $4,406.7 in 2027-28 (Nominal), an increase of $59.1 per year, and
  - small business customers in ACT, rise from $2,780.0 per year in 2022-23 to $2,813.3 in 2027-28 (Nominal), an increase of $33.3 per year.

12.1. The AER's Draft Decision

The AER's Draft Decision adopted a forecast MAR of $4,349.1 million (Real 2022-23) over the 2023-28 period. This was $427.5 million (Real 2022-23) higher than our initial Revenue Proposal of $3,921.6 million (Real 2022-23).

Table 12-1 compares, by building block, the AER's Draft Decision to our initial Revenue Proposal. It highlights that the increase in MAR was driven by significant increases in the return on capital and operating expenditure building blocks. These increases result from the higher rate of return and inflation inputs adopted by the AER due to changes in market information.

Table 12-1: AER's Draft Decision on Building block and MAR forecasts, five year total ($M, Real 2022-23)

	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Return on capital	2,067.6	2,676.6	609.1	29.5%
Return of capital (depreciation)	743.3	525.2	(218.1)	(29.3%)
Operating expenditure	1,015.0	1,038.5	23.5	2.3%

	Initial Revenue Proposal	AER's Draft Decision	Difference $	Difference %
Revenue adjustments	33.5	15.3	(18.2)	(54.4%)
Taxation	65.7	96.4	30.7	46.7%
ABBRR (unsmoothed revenue)	**3,925.1**	**4,352.0**	**426.9**	**10.9%**
MAR (smoothed revenue)	**3,921.6**	**4,349.1**	**427.5**	**10.9%**

The AER made some minor updates to the modelling used to generate the building blocks and MAR revenue, including to adopt a more recent version of the PTRM. We accept these updates and have incorporated them into this Revised Revenue Proposal. [133]

12.2. MAR and X-factors

This Revised Revenue Proposal forecasts total MAR of $4,512.3 million (Real 2022-23) over the 2023-28 period. This forecast and the building blocks that underpin it are shown in Table 12-2.

We have started with the models, including the PTRM, adopted by the AER in its Draft Decision. Our only changes are to update for actual 2021-22 outcomes, revised 2022-23 estimates and revised 2023-28 expenditure forecasts.

Consistent with the AER's Draft Decision, we have targeted 2023-24 MAR revenue to be close to the 2022-23 revenue estimate in nominal terms. We have then targeted a lower MAR in 2024-25 in anticipation of the HumeLink contingent project revenue, adopting common X factors for 2025-26, 2026-27 and 2027-28.

Table 12-2: Building block and MAR forecasts ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Return on capital	494.0	538.3	557.2	557.9	561.7	**2,709.2**
Return of capital (depreciation)	88.9	84.2	114.9	141.9	127.2	**557.1**
Operating expenditure	219.7	236.6	240.7	243.0	244.9	**1,184.8**
Revenue adjustments	12.3	(2.8)	(12.7)	(11.9)	(16.5)	**(31.6)**
Taxation	20.9	20.1	15.3	20.2	22.9	**99.4**
ABBRR (unsmoothed revenue)	835.7	876.4	915.5	951.1	940.2	**4,519.0**
X factors	(1.3%)	2.7%	(1.3%)	(1.3%)	(1.3%)	N/A
MAR (smoothed revenue)	909.0	884.1	895.1	906.4	917.7	**4,512.3**

[133] As per the AER's Draft Decision, we have not included HumeLink expenditure or allowed revenues in our Revised Revenue Proposal. Similar to that decision, we have adopted a revenue profile whereby a common X factor is adopted for all years, except for 2023-24 where the X factor is 4% higher than the common X factor. This profile creates a 'dip' in that year in anticipation of HumeLink revenue being added from that year.

12.3. Price path

Retaining the approach used by the AER in its Draft Decision to calculate customer bill impacts, we estimate that indicative NSW bills will increase from:

- $1,740.4 million in 2022-23 to $1,767.9 million in 2027-28 (Nominal) for residential customers, and
- $4,347.7 million to $4,406.7 million for small business customers.

These NSW bill increases are shown in Figure 12-1 and Figure 12-2, respectively, along with equivalent increases for the ACT. These charts also compare the bill impacts to those in the AER's Draft Decision.

Figure 12-1: Indicative residential bills ($/year, Real 2022-23)

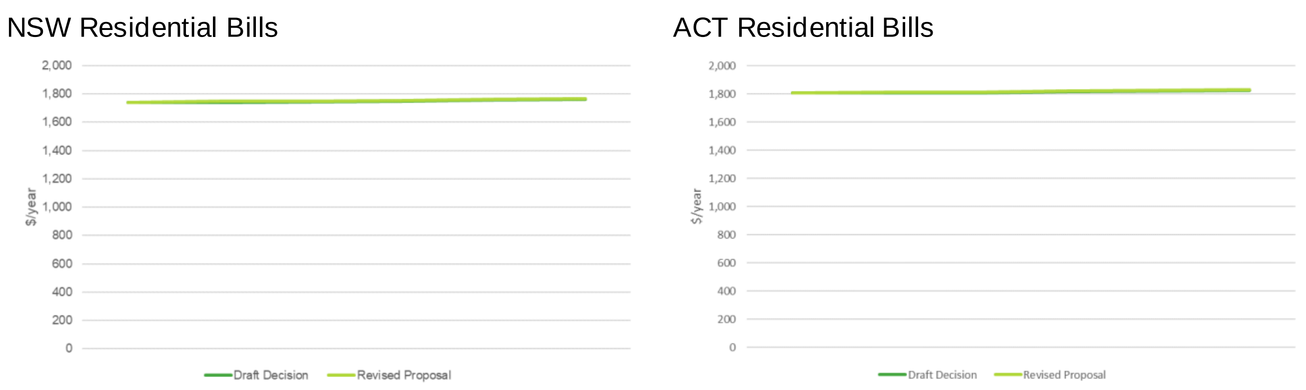
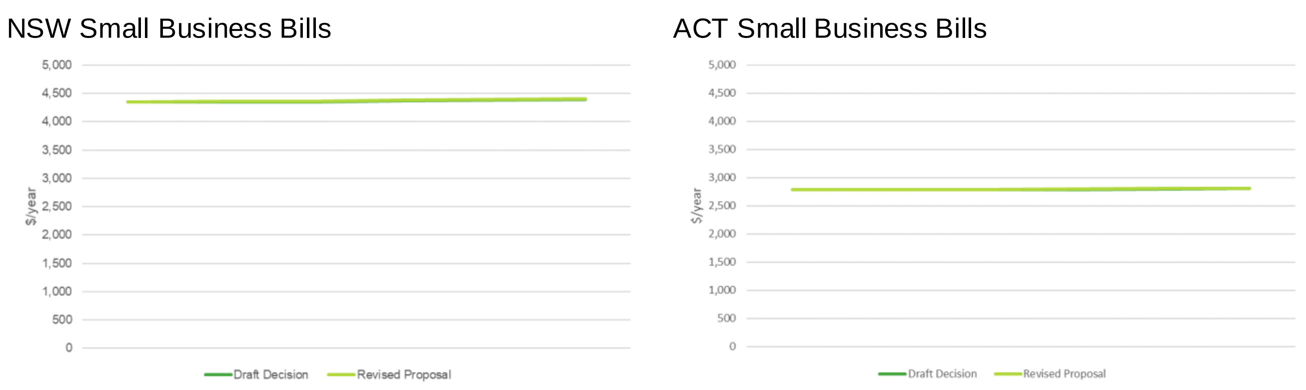


Figure 12-2: Indicative small business bills ($/year, Real 2022-23)



12.4. Supporting documentation

The following document supports this Chapter and accompanies our Revised Revenue Proposal.

Name
Post-tax revenue model

13

Pricing Methodology

2023-28 Revised Revenue Proposal

Transgrid

13. Pricing Methodology

Key messages:

- Our initial Revenue Proposal proposed minor amendments to the current pricing methodology to incorporate a recent Rule change relating to the recovery of costs arising from AEMO's National Transmission Planner function and to clarify two minor issues.
- The AER's Draft Decision approved our proposed pricing methodology, noting that it complies with the Rules' requirements and the AER's pricing methodology guidelines. The AER also noted that no submissions were received in relation to our proposed pricing methodology.
- In this Revised Revenue Proposal, we have:
  - proposed additional amendments to address a further Rule change relating to the introduction of System Strength Charging. We have worked closely with the AER to develop these proposed changes to ensure that they comply with the Rules requirements and the AER's amended pricing methodology guidelines, which were published in August 2022, and
  - made a minor amendment to our proposed pricing methodology to recognise that we are able to recover the costs of AEMO's Participant fees for the 2023-28 regulatory period, in accordance with the AEMC's Rule determination published in October 2022.

13.1. The AER's Draft Decision

The AER's Draft Decision noted that we proposed the following amendments to the current pricing methodology to address the following matters:

- a Rule change that allows for the recovery of AEMO's costs in undertaking its National Transmission Planner function
- clarification of the charging arrangements for dedicated connection assets, and
- clarification regarding the calculation of non-locational charges for a connection point.

The AER reviewed the proposed changes and accepted each of them, noting that the proposed methodology complies with the NER and the AER's pricing methodology guidelines. The AER also noted that the CCP submitted that it had no comments on the proposed pricing methodology and no other submissions were received on the proposed pricing methodology.

The AER's Draft Decision therefore approved our proposed pricing methodology.

13.2. System Strength Charging

This Revised Revenue Proposal includes further changes to our proposed pricing methodology to include System Strength Charges. The reasons for proposing these changes and the scope are explained below.

13.2.1. Rules requirements

The AEMC's Efficient Management of System Strength on the Power System Rule 2021 introduced new arrangements for system strength charging. This Rule established arrangements to coordinate the supply and demand of efficient levels of system strength services. In the context of the current energy transformation, the efficient level of system strength is an emerging challenge as large synchronous generating units are replaced by inverter-based generation.

The Rule introduces new planning obligations on transmission networks to meet a system strength standard specified by AEMO. The new system strength standard must be met by a subset of TNSPs, known as system strength service providers (SSSPs). Transgrid is the SSSP for the NSW region. The SSSPs must determine what services they need to procure to meet the standard. These services may include building new network infrastructure, such as synchronous condensers, or contracting with existing synchronous generators.

The NER introduces a new way of charging for system strength, giving generators and large loads a choice of paying to use the system strength services offered by the SSSP or providing their own system strength (self-remediate). By applying a location-specific system strength charge, the connecting party is incentivised to consider self-remediation or to locate in a part of the grid where it would face a lower system strength charge.

In developing its final Rule, the AEMC concluded that the AER should have the flexibility to determine how the system strength charge should be calculated. Following extensive industry consultation, the AER concluded that the system strength charge should reflect long-run average costs (LRAC).

13.2.2. Proposed system strength charging arrangements

We have worked with the other TNSPs to develop a common approach to setting a system strength unit price (SSUP) for each system strength node. As part of this joint work, the TNSPs also engaged with the AER to discuss specific aspects of the system strength pricing methodology, having regard to the AER's pricing methodology guidelines, which were amended in August 2022, and the Rules requirements.

We acknowledge and appreciate the constructive approach adopted by the AER, which accords with the requirements of clause 11.143.5(f) of the Rules. This provision explicitly requires the AER and TNSPs to cooperate to ensure that the proposed system strength pricing methodology is capable of being approved by 31 January 2023. The Rules require each TNSP to submit amendments to its current approved pricing methodology by 30 November 2022. This amendment is required because the system strength charging period applies from the second year of a regulatory period to the end of the first year of the following regulatory period. Therefore, in order to provide for system strength charges from 1 July 2023 to 30 June 2024, it is necessary to amend the current approved pricing methodology.

We must also submit a revised proposed pricing methodology with our Revised Revenue Proposal that provides for the system strength charging period which commences on 1 July 2024. We have therefore amended our proposed pricing methodology, which we submitted with our initial Revenue Proposal, to include the system strength charging arrangements that will apply from 1 July 2024. Our proposed system strength methodology is unchanged from our submission on 30 November 2022.

In preparing the proposed system strength pricing methodology, we are particularly conscious of the limited information that will be available in setting SSUPs for the first system strength charging period. As explained in our revised proposed pricing methodology, there is:

- limited historical data that could inform our forecast revenue from system strength charges, and
- no information available regarding the likelihood that connection applicants will elect to pay the system strength charge in relation to a proposed connection or alteration.

While we expect the current paucity of information to improve over time, it is important to highlight the practical challenges in setting SSUPs.

A further related issue is the uncertain future costs of providing system strength services. It is reasonable to expect that the costs of providing system strength services will decline over time. While batteries may ultimately provide a lower cost alternative to network solutions, such as synchronous condensers, the task of providing system strength services as specified by AEMO must be met by the SSSPs. In some cases, synchronous condensers may be the lowest cost option to address AEMO's specified requirements, despite the prospect of cheaper solutions becoming available in future periods.

The prospect of technological change and lower future costs of providing system strength services create a challenge in setting SSUPs. In particular, there are two competing objectives, to:

- recover the actual costs of providing system strength services from the connecting parties, and
- avoid connecting parties from self-remediating in circumstances where the SSSP could provide the system strength services at a lower price.

As detailed in our revised proposed pricing methodology and the numerical examples, the proposed approach in setting SSUPs requires the SSSP to consider both its actual costs of providing system strength services and the future costs of providing those services. As discussed with the AER, this pragmatic approach to setting SSUPs is consistent with the requirements of the NER and the AER's reasoning in selecting LRAC as the preferred pricing methodology, which is that it:

- results in stable pricing across system strength charging periods. This in turn would support investor confidence and more optimal location decisions, and
- allocates more of the costs of providing system strength transmission services to the parties that require those services. This in turn reduces the costs to be recovered from customers via prices for prescribed common transmission services.

We also note that a draft determination has been published in relation to the National Electricity Amendment (Operational Security Mechanism) Rule 2022. The interface between this Rule and the system strength charging arrangements has not yet been settled. To recognise the possible implications of the final Rule for the system strength charging arrangements, our revised proposed pricing methodology notes that the capital and operating costs of providing system strength capacity at a system strength node will have regard to the National Electricity Amendment (Operational Security Mechanism) Rule 2022.

13.3. AEMO's Participant fee Rule change

On 20 October 2022, the AEMC made a final determination in response to a Rule change request from Energy Networks Australia (ENA). The ENA's Rule change request concerned the arrangements for recovering AEMO's Participant fees (excluding AEMO's National Transmission Planner (NTP) fees), which will be charged to the TNSPs for the first time from 1 July 2023. The Rule change request sought amendments to allow TNSPs to recover AEMO's actual Participant fees (excluding AEMO's NTP fees), noting that equivalent arrangements were already in place relation to the recovery of AEMO's NTP fees.

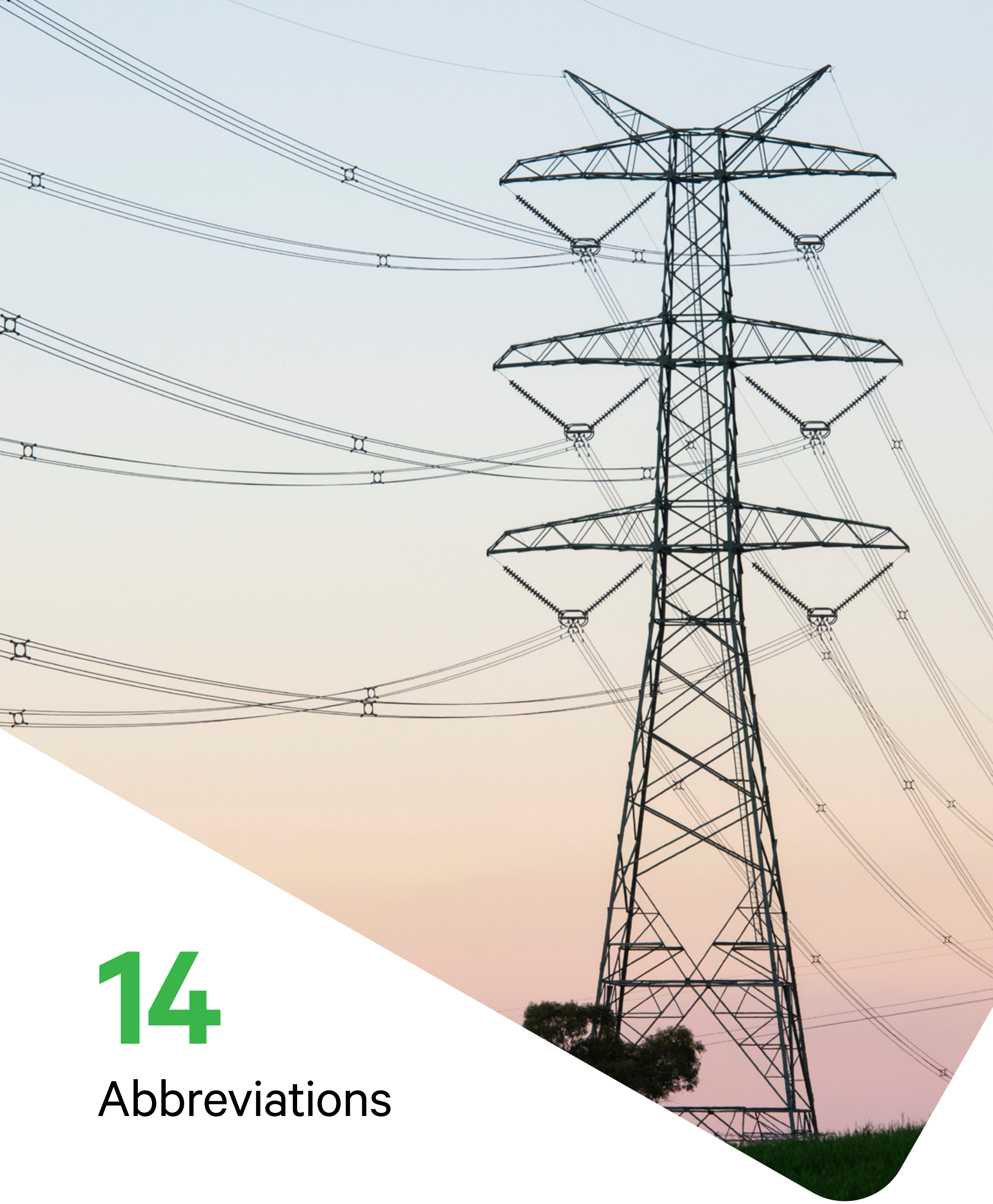
For the 2023-28 regulatory period, the AEMC concluded that transitional arrangements should be put in place to give effect to the ENA's proposed Rule change. For subsequent regulatory periods, however, the AEMC concluded that cost recovery should be achieved by requiring each TNSP to forecast AEMO's participant fees (excluding AEMO's NTP fees) over the regulatory period.

In accordance with the AEMC's transitional provisions in clause 11.153 of the Rules, we have therefore amended our proposed pricing methodology for the 2023-28 regulatory period to allow for the recovery of AEMO's actual participant fees (excluding NTP fees). This change is given effect through an adjustment to the calculation of the non-locational component of our charges set out in clause 6A.23.3(e).

13.4. Supporting documentation

The following document supports this Chapter and accompanies our Revised Revenue Proposal.

Name
2023-28 Revised Pricing Methodology



14

Abbreviations

14. Abbreviations

The following abbreviations are used in this Revenue Proposal.

Acronym/Abbreviation	Meaning
2018-23 regulatory period or period	The regulatory control period commencing 1 July 2023 and ending 30 June 2028
$Real 2022-23	These are dollar terms as at 30 June 2023
$Nominal	These are nominal dollars of the day
2018-23 approved contingent projects	EnergyConnect, QNI Minor and VNI Minor
AARR	Annual Aggregate Revenue Requirement
ABBRR	Annual Building Block Revenue Requirement
ABS	Australian Bureau of Statistics
ACSC	Australian Cyber Security Centre
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
ALARP	As Low As Reasonably Practicable
ANU	Australian National University
ASRR	Annual Service Revenue Requirement
Augex	Augmentation capex
BESS	Battery Energy Storage Systems
BISOE	BIS Oxford Economics
BOP	Bathurst, Orange and Parkes
BSP	Bulk Supply Point
CAM	Cost Allocation Methodology
capex	Capital expenditure
CBs	Circuit Breakers
CCP	AER's Consumer Challenge Panel
CDN	Corporate Data Network
CESS	Capital Expenditure Sharing Scheme
CI Act	Critical Infrastructure Act 2018
CPA	Contingent Project Application
CTs	Current transformers

Acronym/Abbreviation	Meaning
DMIAM	Demand management innovation allowance mechanism
DNSP	Distribution network service providers
E-CAT	The AESCSF Electricity Criticality Assessment
EBSS	Efficiency benefit sharing scheme
EII Regulations	NSW Electricity Infrastructure Investment Regulations
EMCa	AER's consultant, Energy Market Consulting associates
ENA	Energy Networks Australia
EPA	Environmental Planning and Assessment Act 1979
ERP	Enterprise Resourcing Planning
ETWG	Energy Transition Working Group
EV	Electric vehicles
FTE	Full-Time Employee
IAP2 Spectrum	International Association of Public Participation Spectrum
IASR	Input Assumptions and Scenarios Report
IBR	Inverter based resources
ICT	Information and communication technology
IFRIC	International Financial Reporting Interpretations Committee
ISP	Integrated System Plan
Km	Kilometre
KWM	King & Wood Mallesons lawyers
M	Million
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
MPFP	Multilateral Partial Factor Productivity
MWh	Megawatt hour
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NER or Rules	National Electricity Rules
Non-network other capex	Property, fleet, plant and equipment
NPV	Net Present Value
NSCAS	Network Support and Control Ancillary Services

Acronym/Abbreviation	Meaning
NSP	Network Service Provider
NSW Electricity Infrastructure Roadmap	NSW Government's Electricity Infrastructure Roadmap
NTP	National Transmission Planner
opex	Operating expenditure
OT	Operational technology
PACR	Project Assessment Conclusion Report
PIAC	Public Interest Advocacy Centre
PMU	Phasor Measurement Unit
POEO	Protection of the Environment Operations Act 1997
PPI	Producer Price Indexes
PPM	Project and Portfolio Management
Pre-approved forecast capex	AER approved capex for EnergyConnect
PSF	Powering Sydney's Future
PTIP	Priority Transmission Infrastructure Project
PTRM	Post tax revenue model
PV	photovoltaic
QNI Minor	Queensland to New South Wales Interconnector Minor
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement capex
REZs	Renewable Energy Zones
RFM	Roll forward model
RFS	Rural fire service
RIN	Regulatory Information Notice
RIT-Ts	Regulatory Investment Tests for Transmission
RoRI	Rate of Return Instrument
SaaS	Software as a Service
SBPS	NSW Strategic Benefit Payments Scheme
SC	Service Component
SFAIRP	So Far As Is Reasonably Practicable
SSR	System Security Roadmap Working Group
SSSP	System Strength Service Provider
SSUP	System Strength Unit Price

Acronym/Abbreviation	Meaning
STATCOMs	static synchronous compensators
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TAC	Transgrid Advisory Council
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
totex	Total Expenditures
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
VNI Minor	Victoria to New South Wales Interconnector Minor
VPPs	Virtual Power Plants
VTs	Voltage Transformers
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Lives
WHS	Workplace Health and Safety
WPI	Wage Price Index

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