A.1 2026-31 Revenue Proposal Overview

Enabling Central-West Orana Renewable Energy Zone Network Infrastructure Project (non-contestable)

July 2025

Official

Contents

Acknowledgement of Country

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

We pay respect to the people and Elders past and present, and celebrate the diversity of Aboriginal and Torres Strait Islander peoples and their ongoing connections to the lands and waters of NSW and the ACT.

Pokolbin, NSW

Artwork: Yura. Gili. Nanga. the indigenous interpretation of Power. People. Possibilities

About us and this Revenue Proposal

Who we are

Transgrid operates the high voltage transmission network in New South Wales (NSW) and the Australian Capital Territory (ACT), which services about four million customers. Our transmission network supplies higher peak loads and transmits more energy annually than any other transmission network in Australia. In providing our prescribed transmission services to our customers, we must comply with the National Electricity Rules (NER or Rules).

We are also a network operator for the purposes of the EII Act[1] and provide NSW non-contestable services under the EII Act and EII Regulation (EII services). We provide these EII services, relying on, amongst other things, our transmission operator's licence issued under the *Electricity Supply Act 1995* (NSW).

Our role in the NSW Government's Electricity Infrastructure Roadmap

The NSW Government's Electricity Infrastructure Roadmap (Roadmap) sets out the State's 20-year plan to transform the electricity system into one that provides affordable, clean and reliable energy for all consumers. It aims to coordinate investment in transmission, generation, storage and firming infrastructure as ageing coal-fired generation plants retire.[2]

Renewable Energy Zones (REZs) are designed to coordinate development in energy-rich regions, connecting multiple generators in one area. These zones are a crucial part of the Roadmap, marking a significant change in how energy is produced and distributed. By integrating large-scale renewable projects like solar and wind farms with the essential transmission infrastructure, REZs ensure the delivery of affordable, reliable, and clean energy. Additionally, they provide socio-economic benefits to communities throughout NSW.

Under the Roadmap, new transmission infrastructure to support the first NSW REZ, the Central-West Orana (CWO) REZ, is being delivered by a consortium comprised of Acciona, Cobra and Endeavour Energy (ACEREZ). Transgrid has been authorised to undertake works to augment our existing shared network on a non-contestable basis to connect the CWO REZ to the shared transmission network. As NSW's incumbent transmission network service provider, it is not feasible to source these services from another party.[3]

We are pleased to present our Revenue Proposal for delivering the non-contestable Enabling CWO REZ Network Infrastructure Project (referred to herein as the 'Enabling CWO RNIP' or 'Project') for the regulatory period commencing 1 July 2026 and ending 30 June 2031 (the 2026-31 regulatory period).

This marks our inaugural Revenue Proposal for a REZ Network Infrastructure Project (RNIP). In preparing this proposal, we have worked collaboratively with the NSW Government, the Australian Energy Regulator (AER) and our Transgrid Advisory Council (TAC).

1 EII Act, Dictionary, definition of 'network operator'.
2 NSW Government, Electricity Infrastructure Roadmap, n.d.
3 AEMO Services, Statement of Reasons - Enabling, June 2024, p. 11.

The Enabling CWO REZ Network Infrastructure Project

The Project is being delivered under the NSW electricity infrastructure investment framework

The *Electricity Infrastructure Investment Act 2020* (EII Act) and *Electricity Infrastructure Investment Regulation 2021* (EII Regulation) enables a framework for the delivery of the Roadmap. Under this framework, the Minister can declare a REZ and appoint an Infrastructure Planner to assess and recommend network infrastructure projects required for the REZ. The Consumer Trustee appointed under the EII Act, AEMO Services, must then consider these recommendations and either authorise the project or recommend the Minister to direct the project be carried out.[4]

On 5 November 2021, the NSW Minister for Energy and Environment declared the CWO REZ as a REZ under section 19(1) of the EII Act and appointed the Energy Corporation of New South Wales (EnergyCo) as Infrastructure Planner.[5] EnergyCo evaluated a range of network infrastructure options against the following criteria:

- consistency with the REZ declaration, Network Infrastructure Strategy and Infrastructure Investment Objectives
- safety, reliability and security performance
- affordability for NSW electricity customers
- community support.[6]

EnergyCo then made a recommendation to the Consumer Trustee on the infrastructure projects required for the CWO REZ. On 4 June 2024, the Consumer Trustee authorised two RNIPs in the CWO REZ, on the recommendation of EnergyCo:

- the Main CWO RNIP to be carried out by ACEREZ, and
- the Enabling CWO RNIP to be carried out by Transgrid.[7]

The Enabling CWO RNIP involves the construction and operation of new network infrastructure to connect the contestably-procured Main CWO RNIP to the existing NSW transmission network and augment the capacity of the existing network.

The scope of the Project aligns with our Consumer Trustee Authorisation

The scope we are required to deliver is set out under our Consumer Trustee Authorisation[8] and our Project Deed with EnergyCo and includes:

- a new 330kV single circuit transmission line between Bayswater and Liddell substations
- upgrade works to Bayswater substation to accommodate new transmission line, including secondary works
- modifications at Liddell substation to accommodate new transmission line

[4] EII Act, ss 24, 30-31.
[5] The CWO REZ declaration was subsequently amended on 15 December 2023 and 19 April 2024.
[6] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, p. 37.
[7] AEMO Services, Statement of Reasons, June 2024, p. 4.
[8] AEMO Services, Statement of Reasons, June 2024, p. 10.

- a new 330kV single circuit transmission line between Mt Piper and Wallerawang substations
- augmentation of Mt Piper substation, adding additional feeder bays, upgrading existing high voltage equipment and secondary systems
- augmentation of Wallerawang substation, reinstating redundant generator feeder bay, upgrading existing high voltage and secondary systems
- Barigan Creek Switching Station (BCSS) cut in works involving Lines 5A3 and 5A5 and connection to Wollar, Bayswater and Mt Piper substations and including remote ends secondary system upgrade works at Bayswater, Mt Piper and Wollar substations
- facilitation of ACEREZ's new 500kV transmission line overcrossing Transgrid's existing 330kV Line 79 including design reviews, outage management and construction supervision
- four line transpositions to enable transfer of generation from CWO REZ to the NSW transmission network[9].

Under the Project Deed, we are also required to acquire, commission and energise BCSS. BCSS will initially be constructed and pre-commissioned by ACEREZ and will then be transferred to Transgrid, to be commissioned and used in connection with the control and operation of the Enabling CWO RNIP. BCSS will fall under our Consumer Trustee Authorisation only once the Consumer Trustee (as an authorisation provider) approves the transfer and the asset has been transferred to Transgrid.[10] As such, it is not included in the proposed expenditure outlined in this Revenue Proposal. It will be addressed via an adjustment mechanism, triggered at the time of acquisition.[11]

Future works, including two line transpositions, to support the CWO REZ have been identified and will likely be undertaken at a later stage. Studies are also currently underway to determine whether a Special Protection Scheme is required. The delivery model for any future works is currently being determined. These works are not covered by this Revenue Proposal.

The technical scope of the Project has been independently verified by GHD as appropriate to meet the requirements set out in the Project Deed and Consumer Trustee Authorisation.

The Project will create significant benefits and is in the long-term interests of NSW electricity consumers

The CWO RNIPs (inclusive of both the main and enabling works) are key to delivering on the Roadmap and are the first RNIPs to be authorised under the EII Act. The Australian Energy Market Operator (AEMO)'s 2024 Integrated System Plan (2024 ISP) also identifies CWO REZ network infrastructure as an anticipated project, confirming that work should progress to deliver this infrastructure to schedule.[12]

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[9] Changes, modifications or additions to the network infrastructure described in the Consumer Trustee Authorisation is permitted if made in accordance with the Project Deed and provided that following the relevant change, modification or addition, the Project remains consistent with the description in the Authorisation. Refer to Clause 5(f)(2) of Transgrid's Consumer Trustee Authorisation for further detail.

[10] EII Regulation, cl. 21.

[11] The development of BCSS is currently authorised under ACEREZ's Consumer Trustee Authorisation. If approved by the Consumer Trustee, the sale and transfer of the asset to Transgrid will result in BCSS being considered an asset authorised under Transgrid's Consumer Trustee Authorisation. See clause 6 of our Consumer Trustee Authorisation and clause 21 of the EII Regulation for further information.

[12] AEMO, 2024 ISP, June 2024, p. 60.

Together, these projects are intended to deliver an additional 4.5 GW of network transfer capacity to enable new renewable generation and storage to connect to the electricity network in NSW. The projects are critical to the affordability, reliability, security and sustainability of electricity supply in NSW, given the expected closure of Eraring Power Station in August 2027.[13]

EnergyCo assessed the costs of the CWO REZ against the expected benefits and determined that the REZ is expected to create net financial benefits for all NSW electricity consumers that are more than $3 billion greater than the costs in real terms, compared to a scenario where it is not built.[14]

As identified by EnergyCo, the CWO REZ will improve energy security and reliability and generate significant long-term financial benefits for NSW electricity consumers, while supporting legislated emissions reduction targets of 50% by 2030 and 70% by 2035. The REZ will also generate significant economic benefits for the CWO region and NSW, attracting private investment in electricity generation and storage projects to the region. Specifically, the CWO REZ will:[15]

- initially unlock at least 4.5 GW of new network capacity, allowing for the connection of approximately 7.15 GW of new renewable generation projects[16] and additional storage projects.
- include centralised system strength infrastructure and meet the N-1 planning standard and N-1 Secure operating standard, contributing to the security and reliability of electricity supply.
- enable up to $20 billion in private investment in the CWO region by 2030, and support around 5000 jobs during peak construction.
- benefit local communities, through the provision of funding for the delivery of community projects and the creation of job opportunities.

As part of its Consumer Trustee Authorisation process, AEMO Services conducted a cost benefit analysis in order to independently satisfy itself that the recommended network infrastructure is in the long-term financial interests- of NSW electricity consumers. Overall, the Consumer Trustee has concluded that NSW electricity consumers are likely to be worse off if the Main and Enabling CWO RNIPs do not proceed.[17]

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[13] NSW Department of Environment and Heritage, NSW Government secures 2-year extension to Eraring Power Station to manage reliability and price risks, media release, 23 May 2024.
[14] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, p. 4.
[15] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, pp. 16-25.
[16] NSW Government, Multibillion-dollar renewables investment by private sector to power 2.7 million NSW homes, media release, 8 May 2025.
[17] AEMO Services, Statement of Reasons, June 2024, p. 15.

Our Revenue Proposal for the 2026-31 regulatory period

Our Revenue Proposal outlines the forecast capital and operating expenditure for the Project, and the amount proposed to be recovered from the Scheme Financial Vehicle for delivering the Project, for the AER's review and determination. An overview of key considerations that have informed this Revenue Proposal is set out below.

The Project has complex and unique commercial, delivery and operational requirements

Delivery under EII framework
Delivery under new and largely untested commercial and regulatory frameworks, involving complex interfaces, multiple interconnected contractual arrangements and accelerated delivery timeframes

Renewable energy integration
The integration of REZs, and the resultant variable energy generation, requires careful network planning and increases the complexity of real-time network monitoring and operations

New delivery interfaces
The addition of ACEREZ, as a new network operator, introduces further complexity and scope interdependencies, resulting in increased commercial, governance and site coordination, activities and resources for all parties

The complexity of the Project necessitates robust and innovative network planning, sophisticated project coordination, extensive contract obligation management and increased oversight of asset management and real-time network operations

To ensure our role in the energy transition results in the best outcomes for NSW energy consumers, we have undertaken a considered approach to deliver and operate the Project, ensuring prudent and efficient outcomes.
Our approach delivers a fit-for-purpose solution, which optimises consumer outcomes while ensuring a prudent and efficient allocation of costs. Examples of actions we have taken to prioritise prudency and efficiency include:

- selecting a transmission line route that minimises impacts to communities and the environment and reduces biodiversity liabilities
- undertaking an early contractor involvement process that addressed contractor uncertainties and sought to reduce unnecessary contractor margins and achieve cost savings where possible
- employing cost-efficient design solutions where suitable e.g. the use of alternate structures (poles) in access-constrained locations
- utilising EII framework mechanisms, such as revenue adjustments, to reduce contingencies in our base expenditure and ensure customers only incur costs if and when these events occur
- leveraging the scale of our existing maintenance regimes for the existing NSW transmission network to achieve scale efficiencies

Our forecasting approach has been tailored to the Project's specific circumstances and results in costs that are demonstrably prudent and efficient. Our forecast largely relies on market-tested costs and has been validated using internal benchmarking and external validation of costs

The unique delivery challenges of the Enabling CWO RNIP

The Project is the first RNIP to be connected to our existing backbone 500kV transmission network and involves a first-of-its-kind contractual model in NSW. The Enabling CWO RNIP, which will be delivered under the EII Act, has a unique set of commercial and technical delivery challenges including:

- delivery under a new commercial framework, featuring complex and intertwined contractual arrangements including contracts with EnergyCo, ACEREZ (a consortium consisting of three separate entities), our D&C contractor Zinfra and third-party equipment suppliers, requiring dedicated resources to ensure effective implementation and compliance
- a combination of brownfield and greenfield works, each presenting distinct delivery challenges and requiring sufficient oversight to balance resourcing and effectively coordinate between different phases
- complex interface management, particularly in areas where existing infrastructure is modified, or where third-party activities intersect with construction (e.g. ACEREZ's overcrossing of TL79).
- scope interdependencies, technical interfaces and site and program coordination, including with other external bodies to manage outage requirements
- network integration challenges including incorporating new and modified assets that may result in compliance and operational standards risk
- contractual obligations with EnergyCo to deliver the required scope under agreed timelines.

We have taken a thoughtful approach to delivering and operating the Project, focusing on effectively managing these challenges and optimising project outcomes. Drawing from lessons learned from recent and ongoing projects, we have adapted our delivery strategy. For example, for construction management, we are adopting a proactive and informed approach, ensuring we are adequately resourced to provide proper oversight to swiftly address issues on site, particularly around third-party interfaces to prevent any potential delays and associated cost overruns. This is critical to ensure we meet the Government's delivery timeframes.

We have also allocated dedicated resources to manage the suite of new and interlinked commercial arrangements between Transgrid, EnergyCo and ACEREZ. The novelty, scale and interdependencies of these agreements introduce a high degree of commercial and operational complexity, necessitating dedicated commercial oversight to ensure our contractual obligations are fulfilled. Similarly, we require a skilled and experienced team to provide network operations support, noting that the transmission network will become increasingly complex with the introduction of the REZ.

At the same time, we have sought to achieve Project efficiencies, where feasible. This includes:

- selecting a transmission line route that minimises impacts to communities and the environment and reduces biodiversity liabilities
- undertaking an early contractor involvement process that addressed contractor uncertainties and sought to reduce unnecessary contractor margins and achieve cost savings where possible
- employing cost-efficient design solutions where suitable e.g. transmission poles rather than towers
- utilising EII framework mechanisms, such as revenue adjustments, to reduce contingencies in our base expenditure and ensure customers only incur costs if and when these events occur
- leveraging the scale of our existing maintenance regime for the existing NSW transmission network to achieve scale efficiencies.

Overall, we consider that this aligns with the approach a prudent and efficient operator would adopt in these circumstances.

Transgrid's commitment to delivering the Project, and realising the benefits of the CWO REZ, in a prudent, efficient and reasonable manner

In line with the AER's expectations of prudency and efficiency[18], we have prepared our capital and operating expenditure forecasts for the Project to reflect the best course of action and the lowest long-term costs to consumers to achieve the expenditure objectives outlined in EII Chapter 6A, namely:

- to meet or manage the expected demand over the regulatory period
- to comply with all regulatory requirements in the EII Regulation
- to maintain the safety of the Project through the supply of regulated network services.[19]

The forecasts have been developed with reference to the scope of works required under our Consumer Trustee Authorisation and our Project Deed with EnergyCo. These instruments define the required scope, technical specifications and delivery timeframes for the Project.

Our approach to delivering the Project ensures optimal resource utilisation. We have appointed a contractor to assist in the design and construction of the Project, leveraging their experience for skill-specific work. Our internal labour resources provide essential project delivery, management, commercial and technical expertise while the selected team structure, stream objectives and scheduled hours is informed by lessons learned from recently completed and in-progress projects to ensure efficiency. This approach, combined with the use of professional and consulting services where appropriate ensures resources are adequately skilled, optimally utilised and minimises the risk of labour stranding following the completion of the project.

Overall, our capital and operating expenditure forecasts to deliver this scope are prudent, efficient and reasonable.

[18] The AER defines prudent and efficient expenditure as that which reflects the lowest long term costs to consumers for the most appropriate investment or activity required to achieve the expenditure objectives. See AER, Expenditure Forecast Assessment Guidelines, final decision, October 2024.

[19] EII Chapter 6A, cl. 6A.6.6(a) and cl. 6A.6.7(a).

What we did	Why it matters
Ran a market-tested, competitive procurement process for the design and construction of new and upgraded transmission lines and substations, undertaken in accordance with our strict governance and compliance requirements.	Contract prices reflect competitive market outcomes ensuring costs are prudent, efficient and reasonable.[20]
Used external cost estimates, including input from our insurance broker and independent specialists like GHD for biodiversity offsets.	Ensures cost forecasts are reliable, transparent and based on current industry knowledge and expertise.
Applied current rates in accordance with existing supplier agreements and contracts in our estimates.	Reflects reflect prevailing rates in current market conditions.
Relied on past actual costs where appropriate, including **benchmarking against comparable projects**.	Ensures that our costs are reasonable and realistic, taking into account recent market performance.
Engaged GHD and E3 to review and verify all Project costs.	Provides independent assurance – verifying our costs are prudent, efficient and in NSW consumers' long-term interests.

This framework for cost estimation ensures costs are consistent, transparent, robust and can be adequately justified with supporting information. This evidence-based approach to forecasting ensures consumers are paying no more than they should be for the services they will receive.

Our total capex forecast for the 2026-31 period is $437.9 million (including equity raising costs[21]). Our forecast capex and key drivers of this forecast are outlined in the table below.

Breakdown of capex categories and key drivers of cost ($M, real 2025-26)

Cost category	Total	Key drivers of cost
Infrastructure Planner costs	193.5[22]	Facilitates early development activities. Costs have been determined by contractual arrangements with EnergyCo.
Pre-period costs	8.2	Reflects costs incurred prior to the regulatory period to support the Project development. These costs have not otherwise been compensated.

[20] The AER accepts that where a suitable, competitive tender process has occurred, it is reasonable to presume that the contract price reflects prudent and efficient costs. See AER, Expenditure Forecast Assessment Guidelines, final decision, October 2024, p. 7.

[21] Total forecast capex excluding equity raising costs of $1.6 million is $436.3 million.

[22] This equates to $188.1 million (nominal), taking into account our expected spend profile, which aligns with the amount agreed under the Project Deed.

Cost category	Total	Key drivers of cost
Direct costs		
D&C contractor costs	145.0	Supported by a robust and comprehensive early contractor engagement and competitive tender processes, reflecting the market price to deliver the identified scope.
Easement acquisition	[redacted]	Based on legislative obligations for property acquisition and informed by market quotations and historical data relating to previous acquisition processes.
Biodiversity offset costs	[redacted]	Derived from legislative obligations to offset our biodiversity liability and supported by independent cost estimation, where possible, and desktop assessments using prescribed methodologies.
Other construction costs	11.7	Informed by a robust and comprehensive risk identification and allocation approach.
Labour and indirect costs		
Labour costs	41.0	Calculated using expected resource requirements needed to manage the Project, benchmarked against similar projects previously undertaken. We have accounted for the Project's construction and commercial complexity in determining resource requirements.
Indirect costs	20.8	Informed by Project activities required including engineering studies, insurance costs and assurance reviews, and based on current market rates, quotations and recent historical data.
Labour escalation and equity raising costs		
Labour escalation	0.3	The labour escalators for 2026-27 to 2027-28 are as set out in our 2023-28 Revenue Determination. For 2028-29 to 2030-31, the labour escalator is assumed to be equivalent to the average applied in 2026-27 to 2027-28.
Equity raising costs	1.6	Calculated within the Post-Tax Revenue Model (PTRM).
Total capex	**437.9**	

Our total forecast opex for the 2026-31 regulatory period is $28.8 million (including debt raising costs). This has been determined using a bottom-up-build because no base year is available from a preceding regulatory period, which means that we are not able to apply the AER's preferred base-step-trend approach. Our forecast opex and key drivers of this forecast are outlined in the table below.

Breakdown of opex categories and key drivers of cost ($M, real 2025-26)

Cost category	Total	Key drivers of cost
Maintenance costs	1.6	Estimated with reference to the scope of maintenance activities for newly built transmission lines and modifications to existing substations, accounting for opportunities to leverage the existing scale of our maintenance regime.
Operating costs	22.8	Reflecting the additional labour and operational activities necessary to manage the expanded assets, newly created interface with EnergyCo and ACEREZ, adapt operations to support the material increase in renewable energy generation, comply with contractual and regulatory obligations.
Insurance costs	1.3	Estimated premiums for insurance, based on independent report from Lockton Australia.
Vegetation integrity rehabilitation costs	0.7	Required due to our legislative obligations to undertake works to restore and maintain native vegetation within the easement clearance zone for the Project, informed by revealed costs for similar projects.
Strategic Benefit Payments	0.7	Expected compensation amounts under the NSW Strategic Benefit Payments Scheme.
Real input cost escalation	0.8	The labour escalators for 2026-27 and 2027-28 are as set out in our 2023-28 Revenue Determination. For 2028-29 to 2030-31, the labour escalator is assumed to be equivalent to the average applied in 2026-27 and 2027-28
Debt raising costs	0.9	Calculated within the PTRM.
Total opex	**28.8**	

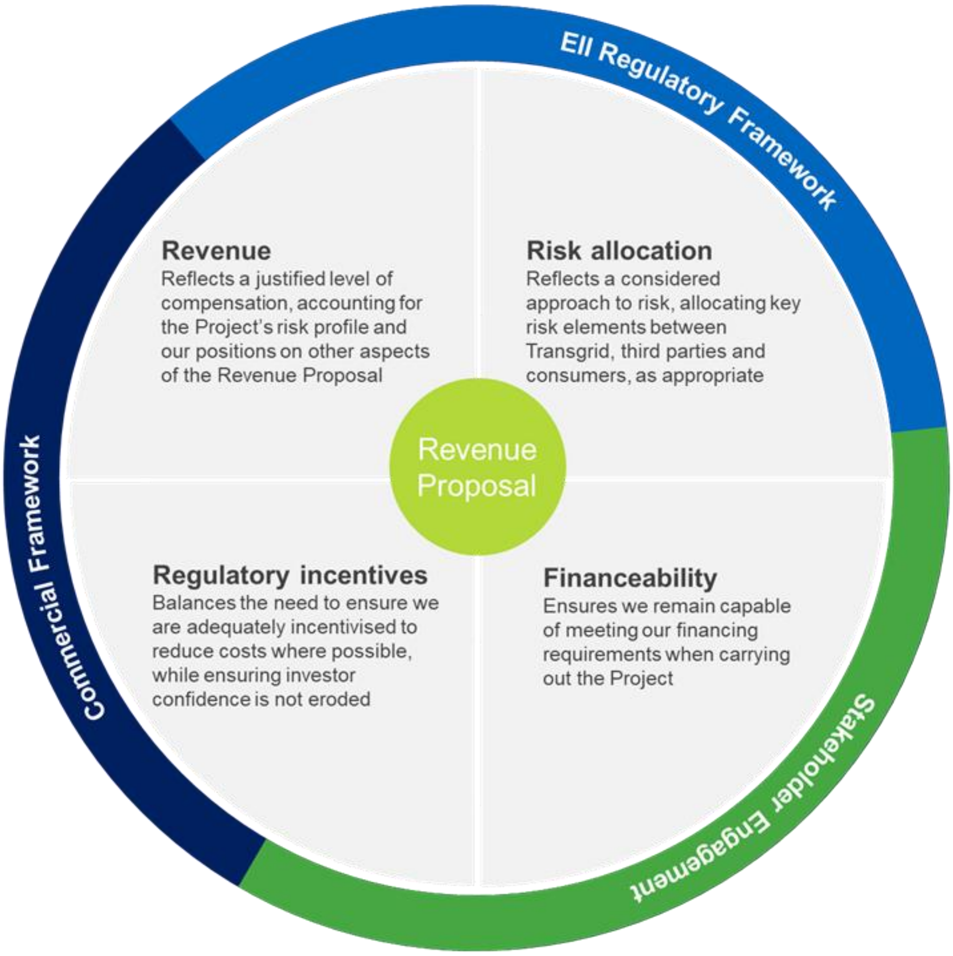
Ensuring we are appropriately incentivised to provide, and are compensated for providing, electricity services prudently and efficiently

Our proposed capital and operating expenditure, and associated revenue requirement, has been developed in the context of the other positions we have adopted in our Revenue Proposal, namely:

- our approach to risk allocation, including the use of adjustment mechanisms for low probability, high impact events
- our position on incentive schemes, including our proposal to apply a Capital Expenditure Sharing Scheme (CESS) that reflects a 30 per cent sharing ratio for overspends and underspends up to 10 per cent of capex and a sharing ratio set to the average of the financing cost for capex that exceeds the 10 per cent cap
- the addition of a 'financeability' asset class to allow for an adjustment to bring forward cashflows to ensure our financeability position is not negatively impacted by the Project.

The interdependencies are outlined in the figure below.

Overview of interlinked Revenue Proposal positions



Overall, we consider that managing our exposure to certain risks via adjustment mechanisms represents the most prudent and efficient means of addressing events that are beyond our control to prevent or mitigate, cannot be effectively insured against, have a low probability of occurrence but are likely to have significant cost impacts, if indeed they do occur. Therefore, we propose various adjustment mechanisms, including:

- automatic adjustments to address annual updates to revenue for actual inflation, annual updates to the return of debt and an update for the return on equity where required
- 'non-automatic' adjustments for various categories of events, including to account for:
    - prescribed pass-through events under EII Chapter 6A
    - nominated pass-through events previously approved in our 2023-28 Revenue Determination and our 2024-29 Waratah Super Battery (WSB) Revenue Determination
    - the transfer of BCSS
    - contractual arrangements under our Project Deed with EnergyCo
    - other events that are beyond our control and where it is not appropriate to include a cost forecast in our base expenditure.

The use of adjustment mechanisms in our Revenue Proposal also informs our calculation of other construction (risk) costs, noting that the presence of revenue adjustments assists in managing risk in certain circumstances.

In respect of CESS, we understand that the AER's incentive schemes are a key feature of incentive regulation and are intended to promote efficient cost and service performance over time. We support incentive regulation where it will be effective, given the particular circumstances of the project.

At a high level, the CESS is designed to provide a constant incentive to undertake efficient capex, removing the incentive for a network operator to defer expenditure to the end of a regulatory period and receiving a financing benefit from this deferral. However, for EII projects, we consider that contractual arrangements between us and EnergyCo appropriately incentivise us to deliver the works within the specified timeframe. This means that even in the absence of CESS, we are appropriately motivated to deliver the Project and undertake the capex in the years we have indicated in our Proposal.

Additionally, we believe that, for high-value, complex and specialised projects, the current inflationary and uncertain environment makes it likely that CESS will introduce asymmetric risk. At higher levels of overspend, a CESS could result in significant additional costs and mean that investors are unwilling to commit to large transmission projects.

Given this, we consider it is inappropriate to apply unmodified CESS to the Project. While we consider that CESS should not apply at all to this Project, we acknowledge that the AER has previously concluded, for WSB, that despite the presence of contractual arrangements with EnergyCo, we may still have opportunities to achieve capex efficiencies and so, should be appropriately incentivised to do so. Taking this into account, we propose a CESS that reflects a 30 per cent sharing ratio for overspends and underspends up to 10 per cent of capex. For capex overspends or underspends that exceed the 10 per cent cap, the sharing ratio should be set to the average of the financing cost or benefit, respectively. This reflects the approach adopted by the AER for the HumeLink Stage 2 Contingent Project Application. We consider these modifications balance the need to appropriately incentivise us to reduce the cost of the Project for consumers, whilst ensuring that investor confidence is not eroded. This results in a reasonable sharing of the benefits and risks between us and consumers.

Overall, for the 2026-31 regulatory period, we propose to:

- apply a modified CESS to the Project, in the manner outlined above
- defer the decision on whether or not to apply the EBSS to the end of the regulatory period, consistent with the decision made for the WSB non-contestable project
- not apply STPIS as this is unable to be applied to non-contestable EII projects in the initial regulatory period.[23]

The EII framework recognises that in order to ensure financeability when delivering EII projects, it may be appropriate for a network operator to include a proposed adjustment to its depreciation schedule to avoid a financeability issue.[24] This allows us to amend the timing of the recovery of depreciation to improve cash flows in the short term while not recovering more revenue from consumers in the long-term. In accordance with the EII framework and applicable AER guidance, we have assessed our financeability position and consider that a financeability adjustment is required.

Our assessment of financeability demonstrates that when incorporating the revenue forecast for the Enabling CWO RNIP, we observe a change in all relevant financeability test metrics but particularly, the

[23] Clause 6A.7.4(e) of EII Chapter 6A.
[24] EII Regulation, cl. 47D(3), EII Chapter 6A, cl. 6A.6

FFO interest coverage ratio. This results in a financeability issue, where our financeability position is lower than the benchmark credit rating at step one and deteriorates further below that position at step two.

As outlined above, we propose an adjustment to our depreciation schedule to accelerate depreciation of $23.7 million (nominal) to ensure our financeability position is not negatively impacted by the Project during the 2026-31 regulatory period.

Our payment schedule appropriately reflects the total revenue we propose to be paid by the Scheme Financial Vehicle for delivering the Project

The total 2026-31 forecast revenue to fund the delivery of the Project, as specified in our Consumer Trustee Authorisation is $165.1 million (nominal). The table below shows the year-by-year breakdown of the forecast in nominal dollars.

Maximum allowed revenue over the 2026-31 regulatory period - Detailed breakdown ($M, Nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on capital	11.4	21.9	30.4	30.9	30.8	125.4
Return of capital	(0.3)	2.9	4.6	1.5	(2.3)	6.4
Operating expenditure	0.8	3.5	8.2	10.3	9.1	31.9
Revenue adjustment	-	-	-	-	-	-
Corporate income tax	0.6	0.6	0.2	-	-	1.5
Maximum allowed revenue	**12.5**	**28.9**	**43.4**	**42.7**	**37.6**	**165.1**
NPV (as at 30 June 2026)						**132.6**

We have calculated the schedule of quarterly payments proposed to be paid by the Scheme Financial Vehicle for delivering the Project based on the forecast maximum allowable revenue (MAR) for the 2026-31 regulatory period. This has been done by converting our MAR into quarterly payments.[25] The table below shows the forecast quarterly payments for the 2026-31 regulatory period. The total revenue differs slightly from the table above due to the impact of the net present value (NPV) conversion.

Forecast quarterly payments for the 2026–31 regulatory period ($M, Nominal)

Year	Quarter 1 (30 September)	Quarter 2 (31 December)	Quarter 3 (31 March)	Quarter 4 (30 June)	Total
2026-27	3.0	3.0	3.1	3.1	12.2
2027-28	6.9	7.0	7.1	7.2	28.2
2028-29	10.3	10.5	10.7	10.8	42.3
2029-30	10.2	10.3	10.5	10.7	41.6
2030-31	9.0	9.1	9.3	9.4	36.7
Total	**39.3**	**39.9**	**40.6**	**41.3**	**161.1**
NPV (as at 30 June 2026)					**132.6**

25 The net present value (NPV) of the schedule of payments matches the NPV of MAR.

Stakeholder engagement

Collaborating with our stakeholders in developing this Revenue Proposal

Throughout the development of this Revenue Proposal, we have engaged with key stakeholders in order to understand their priorities and preferences, keep them informed and to the extent possible, reflect their feedback in the Proposal. The positions in this Revenue Proposal have been developed following detailed consideration of stakeholder preferences in the context of engineering and constructability requirements, environmental impacts and relevant cost implications, to ensure outcomes are prudent and efficient.

Community and other key stakeholders

We listened to community feedback, which played a crucial role in shaping the Project's preferred route

Transgrid Advisory Council (TAC)

We ran five deep-dive workshops with the TAC, and their feedback was considered when developing our approach to risk allocation, adjustment mechanisms, and incentive schemes

AER and EnergyCo

We engaged regularly with both the AER and EnergyCo. Their feedback was considered and reflected in our Revenue Proposal

Community and stakeholder feedback has played a key role in informing Project development, shaping the preferred route for a key portion of the Enabling CWO RNIP, i.e. the Mount Piper to Wallerawang transmission line upgrade.[26] We have also undertaken significant stakeholder engagement to inform our Environmental Impact Statement, working with governments, elected representatives, local Aboriginal land councils, community groups and landowners to establish draft findings and identify proposed mitigations. Landowner engagement has also been a priority for the Project and we have been engaging with impacted landowners on a monthly basis, to facilitate ongoing information sharing and feedback loops.

The TAC has been our primary forum for engagement on key issues relating to this Revenue Proposal. The TAC is the principal regulatory stakeholder engagement forum, with TAC members representing consumer advocates and industry. The engagement approach with the TAC was guided by learnings gained from previous engagement on Revenue Proposals, our principles of engagement, the AER's Better Resets Handbook and the IAP2 Spectrum of Public Participation. The detailed approach, including identifying key areas the TAC could influence, was developed in collaboration with the TAC.

The TAC met from June 2024 to June 2025 for five project-specific 'deep dive' sessions, focused solely on the Enabling CWO RNIP. These sessions provided a forum to seek members' views and positions on the Project and key positions adopted in this Revenue Proposal. The TAC has provided valuable input on a range of topics, most critically on the approach to risk allocation. Where we have received specific

[26] Transgrid, Mount Piper to Wallerawang Transmission Line Upgrade Project Preferred Route Report, December 2023, p.6.

feedback from the TAC, we have carefully considered it and in certain instances, reflected this feedback in our positions.

We also met regularly with the AER and EnergyCo in preparing this Revenue Proposal. AER and EnergyCo feedback has informed the content and structure of this Revenue Proposal and supporting documentation.

The constructive and positive approach adopted by all stakeholders is greatly appreciated, especially considering this is a relatively new revenue-setting process for all parties. We value the input and perspectives received on this Revenue Proposal as we continue our ongoing engagement with the TAC and other stakeholders in the next phase of the Revenue Determination process.

How stakeholder feedback has been considered in this Revenue Proposal

We have received useful feedback throughout our engagement activities and have considered this in developing our Revenue Proposal.

Feedback received from consultation and engagement undertaken to date and how we have responded

Topic	Feedback provided	Our response
Route selection for Mt Piper to Wallerawang	• We engaged with landholders and local community on route options for the Mt Piper to Wallerawang line upgrade. • Overall, a relatively low amount of feedback was received from communities.[27] Common themes included: - anti-renewable energy sentiment - concerns regarding the potential impact to local environment - confusion re responsibility of different projects in the region e.g. EnergyAustralia's Pumped Hydro Project and Battery Energy Storage System.	• We developed and investigated several route options. Following engagement with stakeholders and community, we concluded that various options were not suitable due to feedback from stakeholders, including: - the requirement to clear significant vegetation (with the potential for significant biodiversity impacts). - potential impacts on the Wallerawang township and residential landowners. - potential impacts on operations for businesses, including due to potential outages required during maintenance. - potential impacts on heritage-listed buildings. - The preferred option was chosen as it uses an existing transmission line easement, impacting the smallest number of landowners and minimising impact on the environment.[28]
Risk allocation	• TAC members noted that risk should be allocated to those parties best placed to manage it. • We also heard from TAC members that any proposed risk cost allowance	• We have assessed our Project risks and identified a number of risks that are best managed by Transgrid via prudent risk management controls. For these risks, no additional allowance has been sought.

[27] Transgrid, Consultation Outcomes for the Preferred Route – Mount Piper to Wallerawang Transmission Line Upgrade Project, March 2024, p. 12.
[28] Transgrid, Mount Piper to Wallerawang Transmission Line Upgrade Project – Preferred Route Report, December 2023.

Topic	Feedback provided	Our response
	should not be used to completely de-risk the Project.	• There are a small number of residual risks where it is appropriate for Transgrid to seek a cost allowance. This is because it is more efficient to accept these risks, where the cost of allocating these risks to third parties would likely exceed the expected cost impact if the risk eventuated. This is discussed further in the Other Construction Costs Forecasting Methodology document, provided as an attachment to this Revenue Proposal.
Adjustment mechanisms	• TAC members highlighted their preference to only include adjustment mechanisms that were demonstrably outside of Transgrid's control. • On that basis, some TAC members recommended including an adjustment mechanism in the Revenue Proposal for instances where planned outages were cancelled by AEMO due to the uncontrollable nature of these events. • Similarly, some TAC members considered that biodiversity offset costs should be considered as a pass-through noting that these costs are largely outside of Transgrid's control. • A TAC member noted that it may be more appropriate to treat extended inclement weather as an adjustment mechanism as this relates to events outside of Transgrid's control, namely weather. • TAC indicated that where appropriate, caps on adjustment mechanisms should be applied to ensure Transgrid was still incentivised to reduce costs to the extent possible. • Various TAC members raised the need to demonstrate that there is no duplication of costs between base expenditure, other construction costs and adjustment mechanisms. • A TAC member raised concerns around how costs addressed via adjustment mechanisms for this project interfaced with the maximum capital cost (MCC).	• We have considered a range of project risks and only proposed adjustment mechanisms where we consider the adjustment is contractually required under the Project Deed with EnergyCo, or where a project risk: - is uncontrollable, and cannot be reasonably mitigated or prevented - cannot be effectively insured against (either via commercial or self insurance) - is not accounted for in the base expenditure proposed for the Project or other pass-through events (to avoid double-counting - has the potential to have a significant cost impact - meets the requirements outlined in the nominated pass-through event considerations. • Our Other Construction Costs Methodology, provided as an attachment to this Revenue Proposal outlines in detail how the other construction costs included in addition to the base expenditure are estimated and how there is no duplication of costs, either between the base expenditure or as adjustment mechanisms. • We have included adjustment mechanisms related to AEMO cancellations of planned outages and biodiversity offset costs, noting TAC support. • We have not included an adjustment mechanism for extended inclement weather. This is because there are ways in which we can mitigate the residual costs resulting from such an event (including through appropriate site

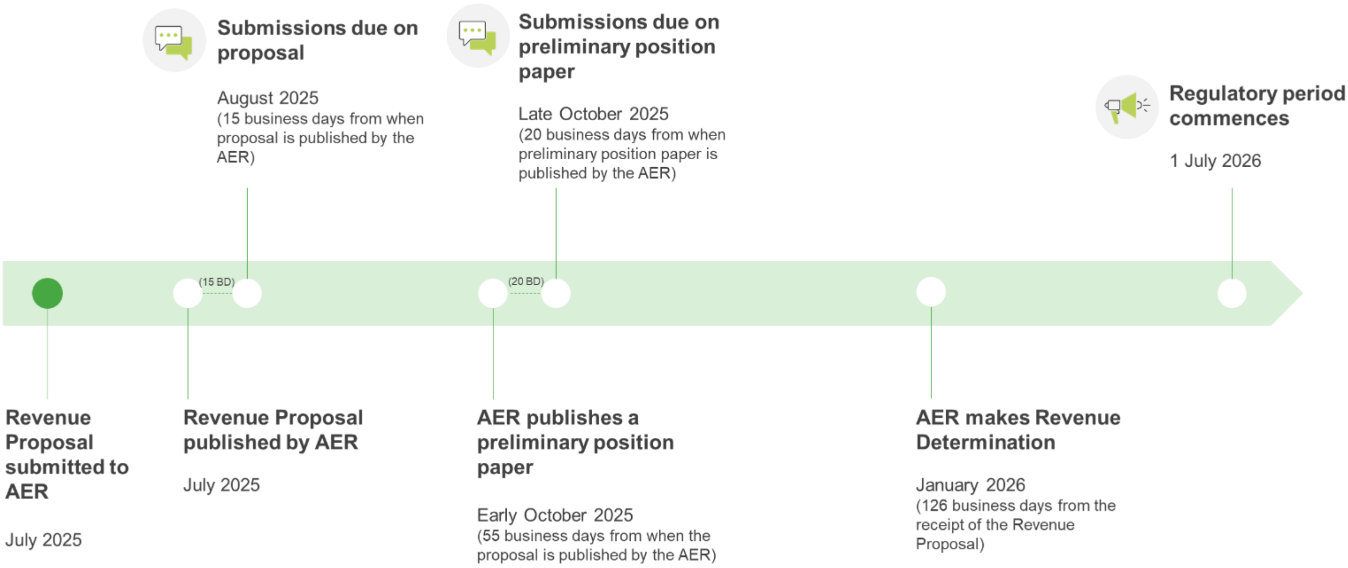
Topic	Feedback provided	Our response
		supervision and management and resourcing reallocation). We therefore think it is more appropriate for this risk to be addressed via an allowance in the base expenditure. This approach ensures that we are appropriately incentivised to mitigate any potential delays, where possible, to ensure we remains within our budgeted allowance. • We have evaluated the potential exposure that consumers may face where an adjustment mechanism is accepted, and proposed caps where we consider it is appropriate to reduce this exposure. • Our approach to adjustment mechanisms is discussed further in Chapter 9 of the Revenue Proposal.
Incentive schemes	• We engaged with our TAC members on the application of incentive schemes for the Revenue Proposal. We heard from TAC members that they considered it appropriate to: - apply an unmodified CESS to the Project - not to apply STPIS to the first regulatory period (in line with the requirements of EII Chapter 6A) - to defer the decision to apply EBSS to the end of the first regulatory period due to a lack of historical operating expenditure to currently inform this decision (similar to the decision made in the Waratah Super Battery non-contestable Revenue Determination).	• We consider that the decision to apply incentive schemes is dependent on the circumstances of the project being considered. This is because for certain projects, elements of capex are not recurrent and can be difficult to forecast. Events outside of our control can also contribute to this uncertainty. In these cases, we consider it more appropriate to modify CESS to reflect these project characteristics. • Noting the above, we have considered the features of the Project, including our contractual arrangements with EnergyCo, our proposed adjustment mechanisms and the underlying justification for our capital expenditure forecasts. This analysis, combined with a consideration of TAC feedback on this issue, has resulted in us proposing to: - apply a modified CESS to the Project - not to apply STPIS to the first regulatory period (in line with the requirements of EII Chapter 6A) - to defer the decision to apply EBSS to the end of the first regulatory period due to a lack of historical operating expenditure to currently inform this decision. • Our position relies on our proposed adjustment mechanisms and capital expenditure forecast being substantially approved by the AER. Where the AER's Determination did not substantially align

Topic	Feedback provided	Our response
		with our Revenue Proposal, we would consider it appropriate to review our position on CESS.
Financeability	We also consulted with our TAC on the application of a financeability adjustment. The TAC raised concerns around the following areas: • assumptions applied with respect to Project EnergyConnect and how different CESS outcomes were being considered • appropriateness of making a financeability application given the size of the Enabling CWO RNIP and uncertainties surrounding the overspends associated with Project EnergyConnect. A TAC member also suggested that we consider engaging with credit rating agencies to better understand the thresholds that might trigger a downgrade.	This feedback has been constructive and informative in a novel process. We have sought to address feedback received from the AER and our TAC by: • adopting base case assumptions that reflect the current regulatory environment and determinations. This is particularly important with regards to the overspend associated with Project EnergyConnect. We have made an assumption that all spend is deemed to be prudent and efficient, subject to a 30 per cent sharing ratio for CESS. We consider this is an appropriate assumption in the absence of an AER determination to the contrary • excluding BCSS from our financeability assessment, and • undertaking sensitivity analysis to inform our financeability request. Our approach including sensitivity analysis undertaken is outlined in further detail below. Regarding the appropriateness of making a financeability application, we consider it is important to get clarification on how the financeability test and associated guideline will be applied going forward. It is beneficial to seek this clarification as early as possible and in respect of a relatively straightforward project RAB. This will ensure that when applying the financeability test to more capital-intensive projects, the focus is on solving financeability issues to minimise impacts on consumers, rather than extensive discussion of applicable assumptions. We also note that the financeability assessment is based on regulated cashflows and factors that reflect credit rating agencies' methodologies and metrics. Further, the framework does not require us to demonstrate the risk of a credit downgrade. Given this, we do not consider it appropriate to engage with credit rating agencies for the purposes of the financeability assessment.

Next steps

The AER's review process and next steps are shown below. This Revenue Proposal will be submitted in July 2025 to enable the AER to make a Revenue Determination in early 2026. The regulatory period will commence on 1 July 2026.

AER's review process and next steps



The AER will invite submissions on our Revenue Proposal for a period of 15 business days from the date it is published. 55 business days after receiving the Revenue Proposal, the AER will publish a preliminary position paper, which will be open for submissions for a further 20 business days. The AER will publish its Revenue Determination and supporting analysis 126 business days from the date of receipt of the Revenue Proposal.