2026-31 Revenue Proposal

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

July 2025

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

Executive Summary

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 aging coal-fired generation plants retire.[1]

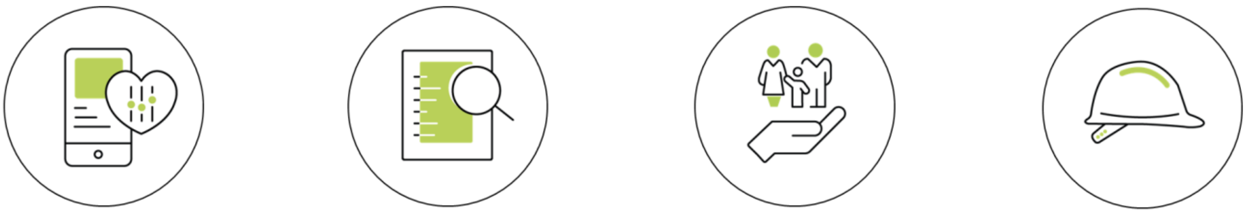
Renewable Energy Zones (REZs) are designed to coordinate development in energy-rich regions, connecting multiple generators in one area. These zones are a crucial part of the Roadmap, marking a significant change in how energy is produced and distributed. By integrating large-scale renewable projects 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 any other party.[2]

We are pleased to present this 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).

We are committed to delivering the Project efficiently, at the lowest sustainable cost to consumers



Fit for purpose
Best outcomes for consumers

Prudent
Optimal technical solution

Efficient
Market tested and externally validated

Reasonable
Utilising network experience to operate

This 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.

[1] NSW Government, Electricity Infrastructure Roadmap, n.d.
[2] AEMO Services, Statement of Reasons – Enabling, June 2024, p. 11.

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 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.[3]

On 5 November 2021, the NSW Minister for Energy and Environment officially declared the CWO REZ as a REZ under section 19(1) of the EII Act and appointed the Energy Corporation of New South Wales

[3] EII Act, ss 24, 30-31.

(EnergyCo) as Infrastructure Planner.[4] 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.[5]

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.[6]

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 we are required to deliver is set out under our Consumer Trustee Authorisation 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
- a new 330kV single circuit transmission line between Mt Piper and Wallerawang substations
- augmentation of Mt Piper substation, adding additional feeder bays and upgrading existing high voltage equipment and secondary systems
- augmentation of Wallerawang substation, reinstating redundant generator feeder bay and 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 the transfer of generation from CWO REZ to the NSW transmission network.

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.[7] As such, it is not included

[4] The CWO REZ declaration was subsequently amended on 15 December 2023 and 19 April 2024.
[5] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, p. 37.
[6] AEMO Services, Statement of Reasons – Main, June 2024, p. 4.
[7] EII Regulation, cl. 21.

in the proposed expenditure outlined in this Revenue Proposal. It will be addressed via an adjustment mechanism, triggered at the time of acquisition.[8]

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 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.[9]

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.[10]

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.[11]

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 per cent by 2030 and 70 per cent 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:[12]

- 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[13] 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.

[8] 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.
[9] AEMO, 2024 ISP, June 2024, p. 60.
[10] 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.
[11] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, p. 4.
[12] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, pp. 16-25.
[13] NSW Government, Multibillion-dollar renewables investment by private sector to power 2.7 million NSW homes, media release, 8 May 2025.

- 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.[14]

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 agreed 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

[14] AEMO Services, Statement of Reasons – Enabling, June 2024, p. 15.

- 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 (i.e. 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 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[15], 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.[16]

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. 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.

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.

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[15] 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.

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

How we ensure our forecasts are prudent, efficient and reasonable

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.[17]
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[18]). 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[19]	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.

[17] 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.
[18] Total forecast capex excluding equity raising costs of $1.6 million is $436.3 million.
[19] 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	0.9	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**	

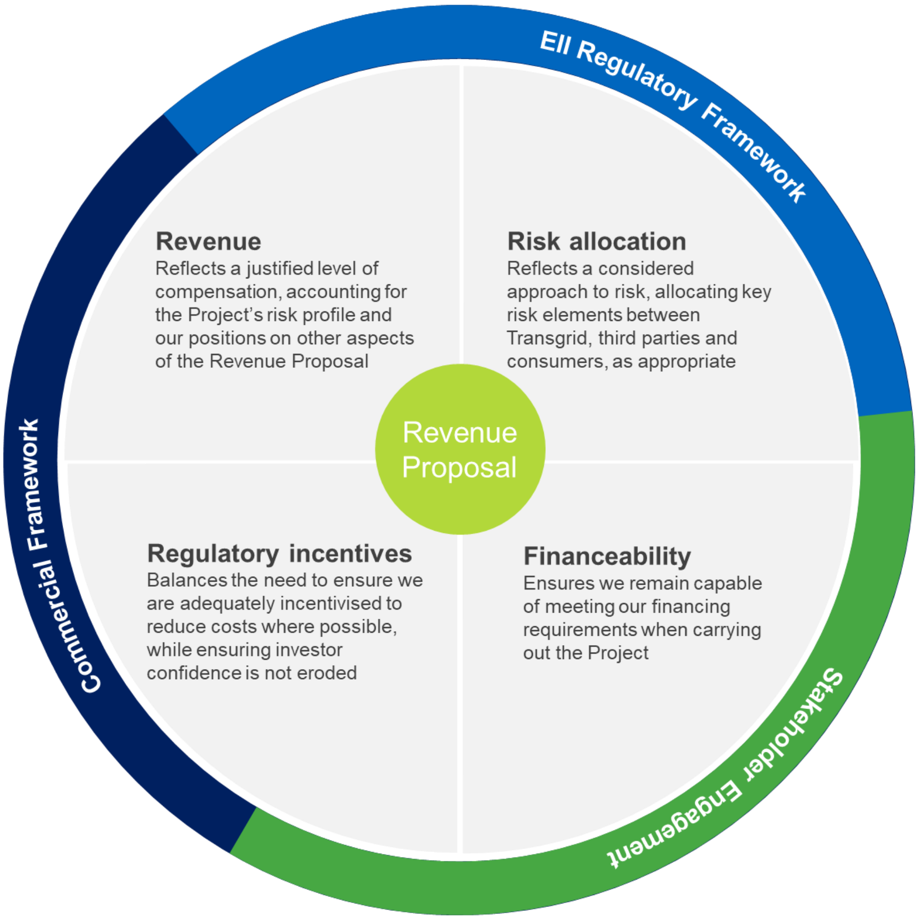
Ensuring we are appropriately incentivised to provide, and are compensated for providing, electricity services prudently and efficiently

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.[20]

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.[21] 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

[20] Clause 6A.7.4(e) of EII Chapter 6A.
[21] 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)[22] 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.[23] 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**

[22] This equates to $22.1 million in real 2025-26 dollars.
[23] The net present value (NPV) of the schedule of payments matches the NPV of MAR.

Collaborating with our stakeholders in developing this Revenue Proposal

Throughout the development of this Revenue Proposal, we have engaged with key stakeholders 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.

How we engage with our stakeholders

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

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

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.

1. Introduction

1.1. About Transgrid

We operate the high voltage transmission network in 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 prescribed transmission services (NER 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[25] 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).

1.2. About this Revenue Proposal

As a network operator under the EII Act, Transgrid can be directed or authorised to carry out REZ network infrastructure projects.[26] A RNIP is defined as a network infrastructure project that:

- forms part of a REZ; and
- consists of network infrastructure of a class prescribed by the EII Regulation.[27]

The CWO REZ was declared a REZ under section 19(1) of the EII Act in November 2021. The CWO REZ project (including both the main and enabling works) classifies as a RNIP, as the project forms part of a REZ and consists of applicable network infrastructure.[28]

On 4 June 2024, AEMO Services acting as Consumer Trustee, authorised Transgrid to develop, construct, own, control and operate the Enabling CWO RNIP in accordance with the terms of our Authorisation and section 31(1)(b) of the EII Act.[29] Separately, we will also acquire and energise BCSS. BCSS will initially be constructed and pre-commissioned by ACEREZ and once approved by the Consumer Trustee (as an authorisation provider), will then be transferred to us, to be commissioned and used in connection with the control and operation of the Enabling CWO RNIP.

This Revenue Proposal relates to the non-contestable CWO RNIP, referred to throughout this proposal as 'Enabling CWO RNIP' or 'the Project'. This is our first Revenue Proposal for the Project, and explains our 2026-31 forecast capex, opex and revenue and the amount we propose to be paid by the Scheme Financial Vehicle (SFV) for delivering the Project during the 2026-31 period.

For clarity, the Revenue Proposal does not include forecast capex, opex or revenue for the acquisition, energisation and operation of BCSS. 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

[25] EII Act, Dictionary, definition of 'network operator'.
[26] EII Act, ss. 31(1)(b), 32(1)(a).
[27] EII Act, Dictionary, definition of 'REZ network infrastructure project'.
[28] NSW Government Gazette No. 569 of Friday 5 November 2021.
[29] AEMO Services, Notice of Authorisation – Enabling CWO REZ Network Infrastructure Project, June 2024.

transferred to us. As such, it will be treated as an adjustment mechanism for the purposes of this Revenue Proposal, to be triggered at the time of acquisition.

1.3. Basis for this Revenue Proposal

The Project is being delivered under the EII framework. As such, this Revenue Proposal complies with requirements under:

- the EII Act
- the EII Regulation
- EII Chapter 6A[30], and
- the AER's Transmission Efficiency Test (TET) and revenue determination guideline for non-contestable network infrastructure projects (non-contestable Guideline).[31]

In particular, this Revenue Proposal:

- establishes the matters outlined in the information notice issued by the AER under section 38(7) of the EII Act
- contains the information and matters specified in Schedule 6A.1 of EII Chapter 6A and section 4 of the Regulatory Information Notice (RIN) for the Project
- has been prepared using the post-tax revenue model (PTRM) referred to in clause 6A.5 of EII Chapter 6A (modified and applied in accordance with the AER's guidance note on amending the PTRM for EII projects[32]), and
- is accompanied by an overview paper which includes the matters outlined in clause 6A.10.1(g) of EII Chapter 6A.[33]

The forecast expenditure in this Revenue Proposal relates only to EII services. These are services provided under the EII Act, are subject to regulation, and include services such as shared transmission network services, network stability services, connection services provided to distribution networks, and connection services provided to generators.

The quality, reliability and security of supply of the EII services we provide are established in our transmission operator's licence, as well as in our contractual agreements with EnergyCo and ACEREZ.

The allocation of costs to these services is in accordance with our Cost Allocation Methodology (CAM).[34] Expenditure has been allocated to capital expenditure and operating expenditure in accordance with our Expenditure Capitalisation Standard. A copy of this standard is provided as an attachment to this Revenue Proposal.[35]

As required under the EII framework, we have also adopted the most recent version of the AER's Rate of Return Instrument (RORI) to determine the rate of return that applies to the Project. At the time of preparing

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[30] AER, Economic regulation of NSW non-contestable revenue determinations under Part 5 of the *EII Act 2020* (EII Chapter 6A), July 2024.
[31] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024.
[32] AER, Guidance note – Amendments to NER PTRM for determinations under the Electricity Infrastructure Investment Act and Regulations, November 2024.
[33] EII Chapter 6A, clause 6A.4.1(b).
[34] Transgrid, Cost Allocation Methodology, May 2023.
[35] Transgrid, Expenditure Capitalisation Standard, November 2021.

this Revenue Proposal, the 2022 RORI was the latest instrument available. We have therefore used the 2022 RORI to calculate our return on capital allowance in this Revenue Proposal.

Noting that EII Chapter 6A substantially replicates Chapter 6A of the NER, we have, where possible, aligned our positions and approaches in this Revenue Proposal with those approved by the AER in its Revenue Determinations (made under the NER) for our prescribed transmission services.[36] For example, we have adopted:

- the decisions in the AER's 2023-28 Revenue Determination for nominated pass through events
- the decision in the AER's 2018-23 and 2023-28 Revenue Determinations for the weighted average cost of capital (WACC) for pre-period capital expenditure (adjusted for inflation)
- labour escalation rates (where applicable)[37]
- standard asset lives, with exceptions for biodiversity offset costs, a financeability asset and equity raising costs.

We have also adopted certain positions approved by the AER in its 2024-29 Revenue Determination (made under the EII Act) for the non-contestable components of the Waratah Super Battery project. This includes:[38]

- the decision to calculate the trailing average portfolio return on debt for EII services separately from NER services
- the decision to account for annual adjustment for inflation, updates to the applicable rate of return, contractor force majeure and unavoidable D&C contract variations as adjustment mechanisms.

1.4. Consistency with the Consumer Trustee's Authorisation and our contractual arrangements

This Revenue Proposal is consistent with the Consumer Trustee's Authorisation and our contractual arrangements relating to the Project. Table 1-1 sets out how this Revenue Proposal is compliant with the relevant sections of the Consumer Trustee's Authorisation.

Table 1-1 Consistency of the Revenue Proposal with the Consumer Trustee's Authorisation

Provisions of Authorisation	Consistency with Revenue Proposal
Clause 5: Enabling CWO REZ Network Infrastructure Project Clause 5 of the Consumer Trustee's Authorisation specifies the authorised Enabling CWO REZ Network Infrastructure Project comprises: • a new 330 kV single circuit transmission line between Bayswater and Liddell substations	This Revenue Proposal relates to the Enabling CWO RNIP. The scope of works, as described in Chapter 2.2 of this Proposal, aligns with the specifications of the Consumer Trustee's Authorisation.

[36] AER, Final Decision Transgrid Transmission Determination (1 July 2023 to 30 June 2028), 28 April 2023.
[37] The labour escalation rates adopted by the AER for the 2023–28 Revenue Determination have been applied. The labour escalators for 2026-27 and 2027-28 are consistent with those set out in our 2023–28 Revenue Determination. As the AER's decision does not extend beyond 2027-28, we have assumed the labour escalator for 2028-29 to 2030-31 to be equivalent to the average applied in 2026-27 to 2027-28.
[38] AER, Final Decision Transgrid Waratah Super Battery (non-contestable) (1 July 2024 to 30 June 2029), December 2023, p. 16.

Provisions of Authorisation	Consistency with Revenue Proposal
• a new 330 kV single circuit transmission line between Mt Piper and Wallerawang substations • BCSS cut in works involving Lines 5A3 and 5A5 and connection to Wollar substation, including remote ends works at Bayswater, Mt Piper and Wollar substations • works to Transgrid's existing 330 kV Line 79 to enable the overcrossing of 500 kV transmission lines to be constructed from Barigan Creek switching station to Merotherie Energy Hub for the Central-West Orana renewable energy zone generally • all ancillary plant, equipment or other assets that will be connected to or used by Transgrid for the purposes of controlling and operating the above network infrastructure • any change, modification or addition to the above network infrastructure: - required for Transgrid to comply with its obligations under the National Electricity (NSW) Law or otherwise at law; or - made in accordance with the Project Deed, provided that following the relevant change, modification or addition, the authorised Enabling CWO REZ Network Infrastructure Project will remain consistent with the description in sections 5(a) to 5(e) of this instrument.[39]	
Clause 6: Transfer of REZ network infrastructure project assets (a) If Transgrid acquires or leases an asset which: - comprises part of an authorised REZ network infrastructure project under another instrument under the Act; and - connects to or will be used by Transgrid in connection with the control or operation of the Enabling CWO RNIP, the relevant asset will be deemed to be authorised under this instrument.[40]	BCSS currently comprises part of the Main CWO RNIP, authorised by the Consumer Trustee under another instrument.[41] Transgrid intends to acquire and energise BCSS (following approval by the Consumer Trustee as authorisation provider), to be used in connection with the control and operation of the Enabling CWO RNIP. Per the Consumer Trustee's Enabling CWO RNIP Authorisation, following Transgrid's acquisition of this asset, it will be deemed to be authorised under the relevant instrument. Noting this, this Revenue Proposal includes the acquisition and energisation of BCSS by Transgrid as a trigger for an adjustment mechanism, allowing for cost recovery of this asset.

[39] See clause 5 of the Consumer Trustee's Enabling CWO RNIP authorisation.
[40] See clause 6 of the Consumer Trustee's Enabling CWO RNIP authorisation.
[41] AEMO Services, Notice of Authorisation – Main CWO REZ Network Infrastructure Project, 4 June 2024.

Under our Consumer Trustee Authorisation, we were required to enter into the Project Deed with EnergyCo by 30 June 2025. We executed the Project Deed and other relevant contractual arrangements in January 2025.

This Revenue Proposal complies with the contractual obligations under the Project Deed. Table 1-2 summarises key requirements under the Project Deed and outlines how they have been addressed.

Table 1-2 Consistency with the Project Deed

Contractual arrangements	Consistency with Revenue Proposal
Clause 3.2(d) states that Transgrid has been appointed as the Network Operator for the Project and intends to receive a revenue determination, separate from the Network Operator of the Main CWO RNIP. Under the Project Deed, the Transmission Network Augmentation (TNA) Project includes the financing, design and construction of the TNA Upgrade Project and the TNA Connection. It also includes all other activities that Transgrid performs or is required to perform as set out in the Project Deed. The TNA Upgrade Project is separately defined under the Deed as Bayswater to Liddell Upgrade Works, Mount Piper to Wallerawang Upgrade Works and Transposition Works. The TNA Connection Project is defined as the Cut-in to BCSS, Commissioning of BCSS Stage 1, Commissioning of BCSS Stage 2, Merotherie Lines Connection, Commissioning of BCSS Stage 3 and Facilitation of TL70 over-crossing.	This Revenue Proposal has been prepared in line with Transgrid's role and responsibilities under the Project Deed. It is prepared distinctly from the Revenue Proposal for the Main CWO RNIP. As noted above, BCSS and associated works (i.e. the BCSS commissioning portions of the TNA Connection Project) are not currently within the scope of Transgrid's Consumer Trustee Authorisation and will only fall within Transgrid's scope following the Consumer Trustee's approval of the transfer and the acquisition and transfer of the asset. Reflecting this, the proposed capex in Chapter 4 covers the works under our Project Deed that are currently authorised under the Consumer Trustee Authorisation. Those works not yet authorised will be addressed via adjustment mechanisms, as outlined in Chapter 9.
Clause 11.1(a) requires Transgrid to use our best endeavours to obtain one or more revenue determinations for the TNA Separable Portions and the adjustment mechanisms required under the Deed (referred to as Determined Service Payments (DSP) Adjustments). DSP refers to the amount determined in a determination to be payable by the Scheme Financial Vehicle to Transgrid in carrying out the TNA Project (or any part of it).	This Revenue Proposal is intended to cover all TNA Separable Portions of the Project. As outlined above, the TNA Upgrade Project and cut-in works are included in base expenditure, while the TNA Connection Project will be treated as an adjustment to this Determination. The Revenue Proposal has been prepared in accordance with relevant regulatory requirements and consistent with the Project Deed. Chapter 15 outlines the proposed quarterly payments over the 2026-31 regulatory period by the SFV to Transgrid, based on Transgrid's proposed prudent, efficient, and reasonable costs. Chapter 9 proposes various adjustment mechanisms, including those specified as DSP Adjustments by EnergyCo under the Project Deed which is a contractual arrangement. These adjustments will result in changes to the proposed initial schedule of payments.

Contractual arrangements	Consistency with Revenue Proposal
Clause 11.1(b) requires Transgrid to provide EnergyCo with an opportunity to comment on the Revenue Proposal and consider relevant feedback.	On 30 May 2025, we provided EnergyCo with an interim draft of our Revenue Proposal for early feedback. On 5 June 2025, EnergyCo provided its comments, which we reviewed and incorporated where applicable. On 19 June 2025, in line with our contractual requirements, we provided the Revenue Proposal to EnergyCo for review. On 3 July 2025, EnergyCo provided its comments, which we reviewed and incorporated where applicable.
Clause 11.2 requires Transgrid to include mechanisms for specific DSP Adjustments as required by the Project Deed, and to seek these adjustments as required.	Chapter 9 proposes adjustment mechanisms that reflect Transgrid's contractual obligations under the Project Deed.
Clause 11.4 sets out the process for EnergyCo to assist with regulatory submissions if requested by Transgrid.	EnergyCo was engaged in the preparation of this Revenue Proposal, and relevant comments were addressed.
Clause 12.2(b) requires Transgrid to include any Reimbursable Costs in our initial Revenue Proposal and any subsequent proposal (as applicable). Transgrid must use best endeavours to obtain regulatory approval of these costs.	This Revenue Proposal includes Infrastructure Planner costs of $193.5 million (real 2025-26), as outlined in Chapter 4. This equates to a nominal amount of $188.1 million (taking into account Transgrid's expected profile of spend), which aligns with the capped amount specified in the Project Deed.
Clause 12.3 states that EnergyCo may direct changes to Reimbursable Costs or payment dates. If this occurs, Transgrid must seek an Adjustment to reflect the change in costs.	Chapter 9 includes an adjustment mechanism to account for potential changes to Infrastructure Planner costs.
Clause 13.4 states that all amounts paid by EnergyCo under the Project Development Deed form part of the Reimbursable Costs.	The Infrastructure Planner costs include payments made by EnergyCo for early project development activities under the Project Development Deed. This is discussed in Chapter 4.
Clause 17.2 requires Transgrid to include in our initial Revenue Proposal: • an adjustment mechanism for the recovery of the BCSS Purchase Price • an adjustment mechanism to adjust the BCSS Purchase Price • In addition, Transgrid may include an adjustment mechanism to cover incremental capital and operating expenditure for BCSS.	Chapter 9 includes BCSS-related adjustment mechanisms that reflect these obligations.

[redacted]

Contractual arrangements	Consistency with Revenue Proposal
[redacted]	
Under Clause 23, EnergyCo may propose a variation before practical completion of a TNA Separable Portion. Clause 23.13 requires Transgrid to seek a DSP Adjustment to reflect variation costs arising from an EnergyCo Variation Request or an EnergyCo directed Variation Order.	No variation requests have been received at the time of submission. Chapter 9 includes an adjustment mechanism for future variations.
Under Clause 24.6, EnergyCo may request an augmentation proposal from Transgrid. Under Clauses 24.7 and 24.8, if EnergyCo accepts the augmentation proposal and the Consumer Trustee authorises the augmentation, Transgrid must submit a Revenue Proposal to the AER.	No augmentation requests in relation to this Revenue Proposal have been received at the time of submission. Any future augmentations will therefore need to be addressed in a separate Revenue Proposal.

1.5. Structure of this Revenue Proposal

This Revenue Proposal is structured as follows:

- Chapter 2 describes the Project
- Chapter 3 sets out our engagement approach, activities and what we have heard from our customers and other stakeholders
- Chapter 4 sets out our forecast capex, including our forecasting methodology
- Chapter 5 sets out our forecast opex, including our forecasting methodology
- Chapter 6 sets out our proposed RAB, depreciation forecast and financeability adjustment
- Chapter 7 sets out our estimated rate of return, forecast inflation, and debt and equity raising costs
- Chapter 8 sets out our estimated cost of corporate income tax
- Chapter 9 sets out our proposed cost pass-through events and adjustment mechanisms
- Chapter 10 sets out our proposed application of the AER's expenditure incentive schemes
- Chapter 11 sets out our forecast maximum allowed revenue
- Chapter 12 sets out our proposed payment schedule
- Chapter 13 sets out other matters, including information on our approach to confidential information and the assurance and certification we have provided, including the key assumptions supporting our expenditure forecasts.

This Revenue Proposal is supported by a number of attachments, models and other supporting documents (illustrated in Figure 1-1 and detailed in Table 1-3). This Revenue Proposal references these attachments, models and other supporting documents and should be read in conjunction with them.

Figure 1-1 Revenue Proposal document structure

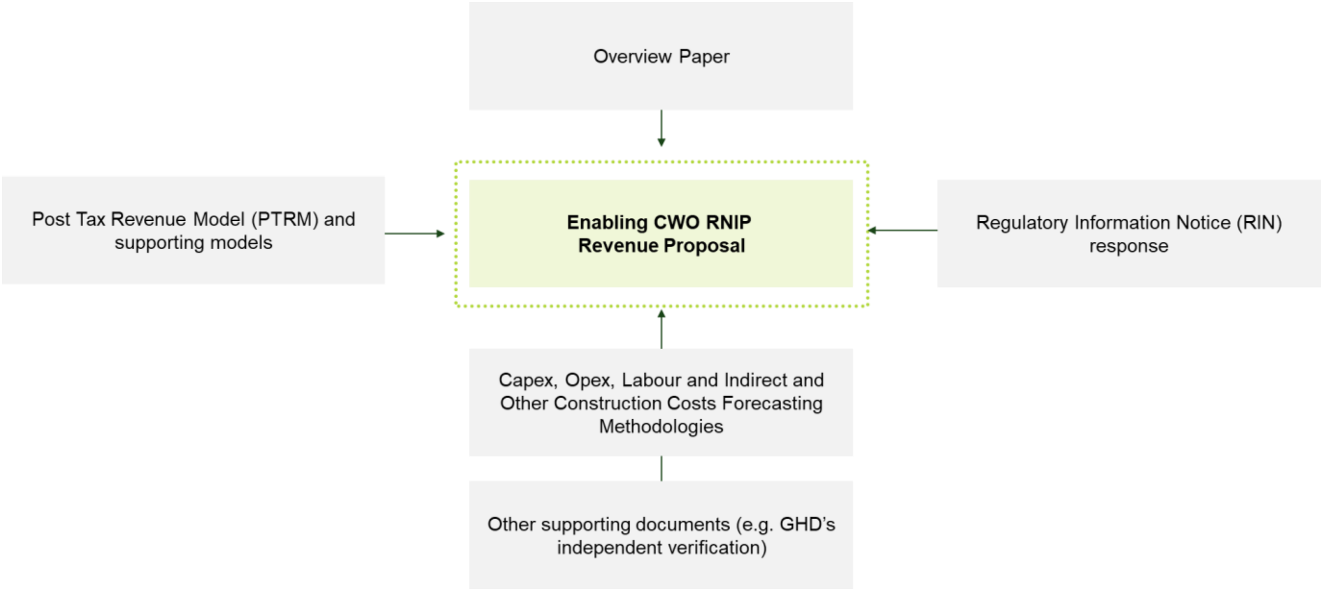


Table 1-3 Supporting documentation

Document / Model number	Document name
Models	
M.1	Capex Forecast Model
M.2	Labour and Overhead Costs Model
M.3	Opex Forecast Model
M.4	Direct Non-Labour Model
M.5	Rate of Return Model
M.6	Post Tax Revenue Model (PTRM) (unadjusted)
M.7	PTRM (adjusted)
M.8	Financeability
M.9	VNI West Stage 1 2018-23 RFM
M.10	VNI West Stage 1 CPA Depreciation
M.11	PTRM Humelink S2 2025-26 RoD
M.12	2023-28 CESS HL S1P1
M.13	2023-28 CESS HL S1P1 (with Actuals)
M.14	2018-23 PTRM Humelink
M.15	2024-29 WSB non-contestable PTRM
M.16	2021-22 Economic Benchmarking
M.17	2022-23 Economic Benchmarking
M.18	2023-24 Economic Benchmarking
M.19	2021-22 Regulatory Accounts
M.20	2022-23 Regulatory Accounts
M.21	2023-24 Regulatory Accounts
M.22	2023-28 Depreciation Tracking Module
M.23	2023-28 RFM
M.24	2028-33 PTRM
M.25	2028-33 CESS Model
M.26	2028-33 Opex Model
M.27	2028-33 EBSS Model
M.28	2024-2029 WSB Depreciation Tracking Module
M.29	2024-29 WSB RFM
M.30	2029-34 WSB non-contestable PTRM
M.31	2029-34 WSB CESS Model
M.32	Inflation Data
Other supporting documentation	

Document / Model number	Document name
A.1	Revenue Proposal Overview
A.2	Document Register
A.3	Regulatory Information Notice Checklist
A.4	Regulatory Information Notice Response
A.5	Statutory Declaration
A.6	Confidentiality Claims
A.7	Key Capex and Opex Assumptions Certification
A.8	Direct Capex Forecasting Methodology
A.9	Labour and Indirect Costs Forecasting Methodology
A.10	Other Construction Costs Forecasting Methodology
A.11	Opex Forecasting Methodology
A.12	RfT Evaluation Plan
A.13	Deliverability Plan
A.14	Community and Stakeholder Engagement Plan
A.15	GHD Independent Verification and Assessment
A.16	E3 Independent Verification and Assessment
A.17	Insurance Report
A.18	Expenditure Capitalisation Standard
A.19	Cost Allocation Methodology
A.20	Nominated Averaging Periods
A.21	Audit Report[42]
A.22	Project Deed
A.23	GHD Biodiversity Cost Estimate Report
A.24	Additional Regulatory Information Notice Response (Pre-period costs)
A.25	Financeability Schedule
A.26	Amending Deed and Umbrella Deed
A.27	Adjustment Letter 19 Feb 2025
A.28	Adjustment Letter 7 Mar 2025
A.29	Amendment Letter – Umbrella Deed
A.30	CEFC Terms Agreement
A.31	CEFC Senior Secured Facility
A.32	Note Trust Deed

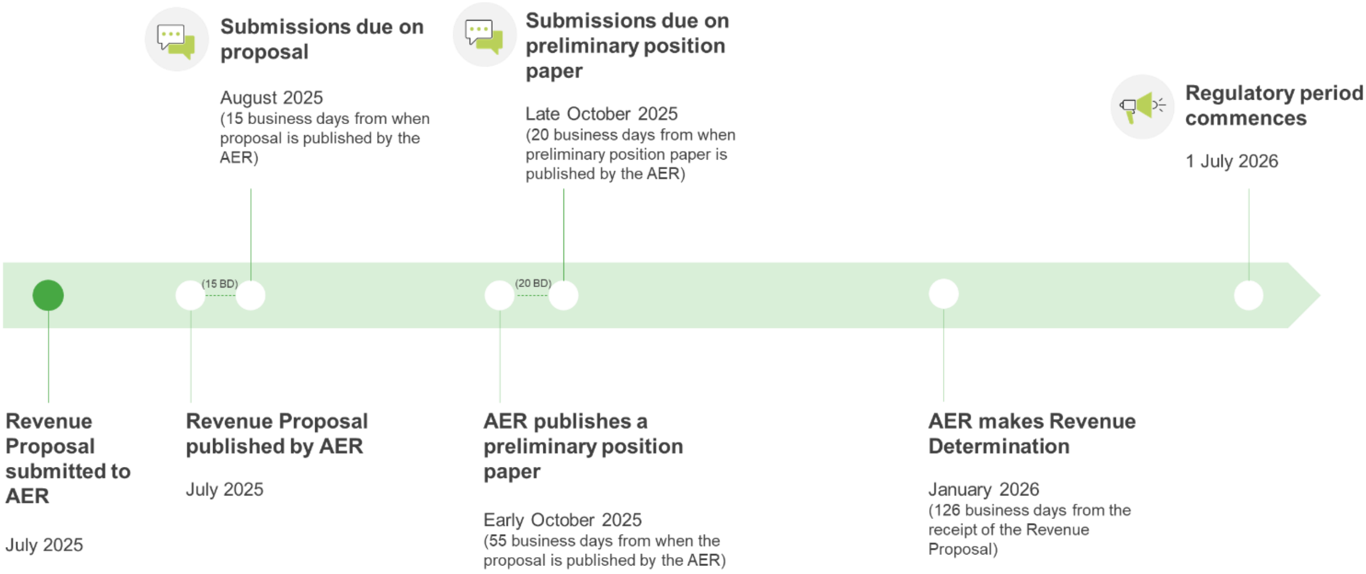
[42] This audit report relates to the audit of the 2021-22 to 2023-24 ‘early project development activity’ costs paid by EnergyCo and required to be repaid by Transgrid under our Project Deed (discussed further in section 4.3). The audit report for pre-period costs incurred in 2020-21 to 2021-22 that have not been paid by EnergyCo (discussed further in section 4.4) will be submitted to the AER by 30 September 2025.

Document / Model number	Document name
A.33	Pricing Supplement
A.34	Concessional Finance Agreement

1.6. Next steps

The AER's review process and next steps are shown in Figure 1-2 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.

Figure 1-2 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. Approximately 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.

1.7. Conventions

In this Revenue Proposal, unless otherwise specified:

- historical and forecast expenditure is presented in end-year (to 30 June) real 2025-26 dollars
- all dollars for regulatory years:
  - up to and including February 2025 are actuals, and
  - March 2025 onwards are forecasts.
- all dollars in tables and charts are presented in millions, unless otherwise stated
- 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. Zero values in tables are included where the specific units used do not allow for a meaningful representation of the costs (i.e. the costs are less than $0.1 million).

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

2. About the Project

2.1. Project description

- The Project is being delivered under the NSW-specific framework for electricity infrastructure development.
- It 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 the scope set out in our Consumer Trustee Authorisation and the requirements outlined in our Project Deed with EnergyCo.

The CWO REZ is approximately 20,000 square kilometres centred by Dubbo and Dunedoo. It will be serviced by new transmission network infrastructure, including transmission lines and energy hubs, which will transfer power generated by solar and wind farms to electricity consumers.

On 5 November 2021, the Minister declared the CWO REZ and appointed EnergyCo as Infrastructure Planner.[43] On 4 June 2024, the Consumer Trustee authorised two RNIPs in the CWO REZ, on the recommendation of EnergyCo as the Infrastructure Planner for the CWO REZ:

- the Main CWO RNIP to be carried out by the ACEREZ, and
- the Enabling CWO RNIP to be carried out by Transgrid.[44]

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.

Transgrid will also acquire and energise BCSS. BCSS will be constructed and pre-commissioned by ACEREZ and will then be transferred to us (subject to the Consumer Trustee's approval of the transfer as an authorisation provider) to be commissioned and used in connection with the control and operation of the Enabling CWO RNIP.

The projects (inclusive of both main and enabling works) are key to delivering on the NSW Government's NSW Electricity Infrastructure Roadmap (the Roadmap) and are the first REZ network infrastructure projects to be authorised under the EII Act. AEMO's 2024 ISP also identifies the CWO REZ network infrastructure as an anticipated project.[45]

Together, these projects are intended to deliver an initial 4.5 GW of network transfer capacity to enable new renewable generation and storage to connect to the electricity network in NSW, with capacity to increase to 6 GW by 2038 if pursued by EnergyCo. 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.

[43] The CWO REZ declaration was subsequently amended on 15 December 2023 and 19 April 2024.
[44] AEMO Services, Statement of Reasons, June 2024, p. 4.
[45] AEMO, 2024 ISP, June 2024, p. 60.

2.2. Scope of Works

Transgrid's scope of works for the Project aligns with the Consumer Trustee's Authorisation and the Project Deed, as agreed with EnergyCo. As discussed in section 1.2, the Project relates to the non-contestable component and at the time of submission, does not include the acquisition, energisation and operation of BCSS. The Project is the first RNIP to be connected to our existing backbone 500kV transmission network and represents a first-of-its-kind contractual model in NSW. We are contractually required to deliver the scope within agreed timeframes.

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 us. As such, it will be treated as an adjustment mechanism for the purposes of this Revenue Proposal, to be triggered at the time of acquisition. For completeness, the scope of the works associated with BCSS is outlined below.

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.

2.2.1. Project scope

The scope of the Project aligns with the Consumer Trustee Authorisation and includes[46]:

- a new 330 kV 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
- a new 330 kV 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
- 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 330 kV 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.

Under the Project Deed, line transpositions are required to enable transfer of generation from CWO REZ to the NSW transmission network.[47] Detailed network planning for the integration of the Main CWO RNIP, in collaboration with ACEREZ, identified the need for these transmission line transpositions on existing Transgrid lines.

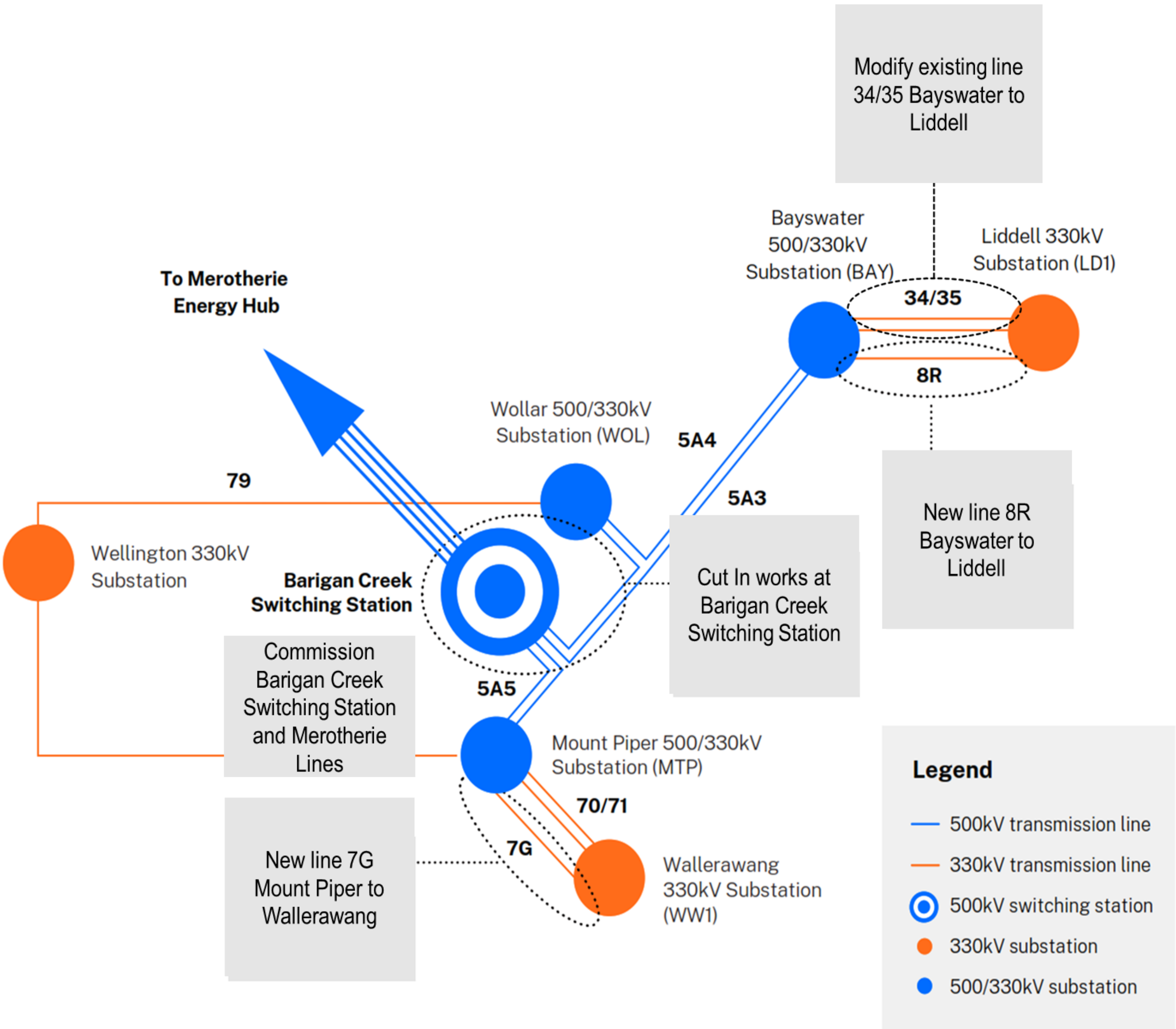
[46] AEMO Services, Statement of Reasons, June 2024, p. 10.
[47] Changes, modifications or additions to the network infrastructure described in the Consumer Trustee Authorisation are permitted if made in accordance with the Project Deed and provided that following the relevant change, modification or 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.

Transposition refers to the process of rearranging the relative positions of the conductors along the length of a three-phase transmission line. This assists in minimising voltage imbalances (in line with our requirements under the NER[48]) and reducing energy losses, which is critical for proper system operation and stability. The following line pairs are being transposed:

- 5A4/5A3 Wollar to Bayswater
- 5P1/5P2 Barigan Creek to Mt Piper.

The key packages of works are illustrated in Figure 2-1. A diagram of the initial transpositions is provided in Figure 2-2. A detailed description of the work packages is provided in the Direct Capex Forecasting Methodology accompanying this Revenue Proposal.

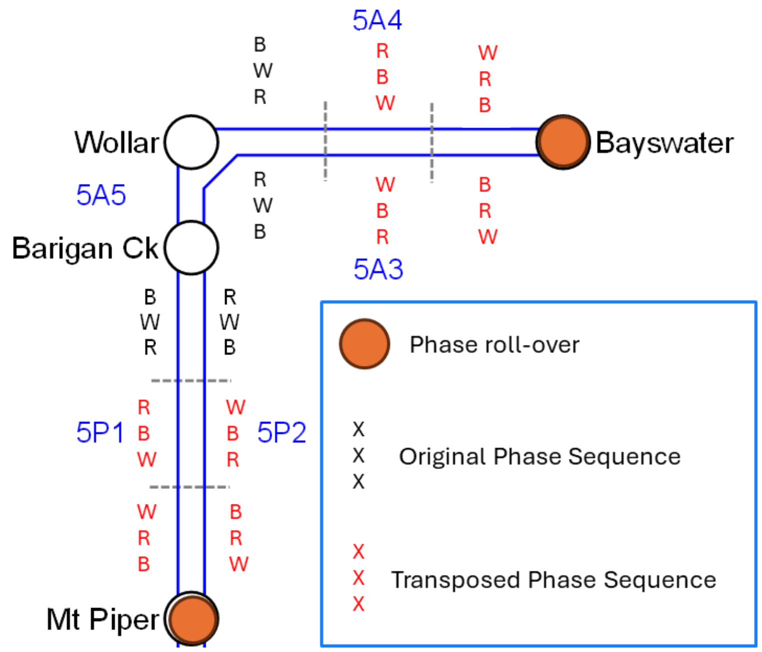
Figure 2-1 Enabling CWO RNIP work packages



Source: Transgrid (adapted from AEMO Services, 2024).

[48] NER, clause S5.1a.

Figure 2-2 Transmission line transpositions



2.2.2. Acquisition and energisation of BCSS

BCSS will be constructed and pre-commissioned by ACEREZ as part of the Main CWO RNIP and is the key connection point from CWO REZ into Transgrid's NSW transmission network. Following construction and pre-commissioning, ACEREZ will direct us to pay EnergyCo the purchase price of BCSS[49] (as EnergyCo is funding the design and construction costs for BCSS) and ACEREZ will then transfer ownership of BCSS to us.

At the time of the transfer and subject to the approval of the transfer by the Consumer Trustee, BCSS will then fall within our Consumer Trustee Authorisation. We will commission the asset into our existing transmission network, to be used in connection with the control and operation of the Enabling CWO RNIP. Relevant works, as specified under the Project Deed, are:

- provision of loop-in-loop-out landing spans to the BCSS gantry structures for line 5A5 (Mt Piper – Wollar).
- connection of line 5A3 (Mt Piper – Bayswater) and line 5A5 (Mt Piper – Wollar) to BCSS
- commissioning and energisation of remaining Merotherie line bays
- commissioning and energisation of Merotherie lines 5M1, 5M2, 5M3 and 5M4
- performing asset acceptance, testing and commissioning to energise BCSS into the NSW transmission network.

Acquisition of BCSS is expected to occur in [redacted] Energisation and commissioning of BCSS will then occur from [redacted]

[49] This includes any purchase price adjustments, as determined by EnergyCo and ACEREZ.

2.2.3. Project timeline

We are contractually required to deliver the scope within agreed timeframes under the Project Deed with EnergyCo, in line with the dates in Table 2-1.

Table 2-1 Project timeline

Work package	Date
BCSS commissioning	[redacted]
BCSS cut-in	
Bayswater to Liddell upgrade works	
Mt Piper to Wallerawang upgrade works	
Merotherie lines connection	
Line transpositions	

To meet these delivery milestones, we have adapted our delivery strategy to ensure timely and efficient execution. In particular, we have:

- engaged early with delivery partners through an Early Contractor Involvement process to address delivery risks and enable timely mobilisation
- utilised separable portions under our D&C contract, eliminating the risk of the contractor claiming a single delay or variation that has a consequential impact on other scopes of work
- adopted a proactive project, construction, and commercial management model to ensure strong oversight, early resolution of site issues, and prompt management of disputes.

These measures are designed to provide the agility and control required to meet the Project's timeframes while maintaining cost and delivery discipline.

2.3. Benefits of the Project

The Project will form an integral part of our existing transmission network once operational and will enable connection of the Main CWO RNIP. Without the Project, the CWO REZ could not proceed and the outcomes and benefits of the CWO REZ would not be delivered.

The successful on-time delivery of the Project is critical to the continued reliable, secure, sustainable and safe supply of electricity in NSW following the anticipated closure of the Eraring Power Station in 2027.

EnergyCo, in its role as Infrastructure Planner, 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.[51]

[50] Note that the transposition construction works are occurring concurrently with the main works, however the phase roll cannot be undertaken for lines 5A3/5A4 and 5P1/5P2 until the BCSS cut-in and commissioning is complete.

[51] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo's network recommendations, May 2024, p. 4.

As part of its Consumer Trustee Authorisation process, AEMO Services also 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 Enabling CWO RNIP does not proceed.[52]

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. 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:

- 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[53] and additional storage projects. This new renewable generation will:
    - improve the sustainability of electricity supply
    - support NSW and Commonwealth legislated renewable energy and emissions reduction targets
    - put downward pressure on wholesale electricity prices in the NEM, resulting in lower costs for NSW electricity consumers.
- 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
- deliver up to $20 billion in private investment in the CWO region by 2030, and support around 5,000 jobs during peak construction.
- benefit local communities, through the provision of funding for the delivery of community projects and the creation of job opportunities.[54]

The successful on-time delivery of the Project is critical to the continued reliable, secure, sustainable and safe supply of electricity in NSW following the anticipated closure of the Eraring Power Station in 2027. The Project will form an integral part of our existing transmission network once operational and will enable connection of the Main CWO RNIP (delivered by ACEREZ) and associated renewable energy generators in the CWO REZ. Without the Project, the Main CWO RNIP could not proceed and the outcomes and benefits of the CWO REZ would not be delivered.

[52] AEMO Services, Statement of Reasons, June 2024, p. 15.
[53] NSW Government, Multibillion-dollar renewables investment by private sector to power 2.7 million NSW homes, media release, 8 May 2025.
[54] EnergyCo, Central-West Orana Renewable Energy Zone Rationale and basis for EnergyCo’s network recommendations, May 2024, pp. 16-25.

3. Consumer and stakeholder engagement

This chapter provides an overview of our engagement approach and activities, what we have heard from our customers and other stakeholders and how we have responded to their feedback in preparing 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 TAC has been our primary forum for engagement on key issues relating to this Revenue Proposal. The TAC has provided valuable input on a range of topics, most critically on the approach to risk allocation.
- 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.

3.1. Our engagement requirements

The AER's non-contestable Guideline sets out its expectations on how we should engage with our customers and stakeholders when preparing our EII Revenue Proposals. The Guideline explains[55]:

- Network Operators should use best endeavours to engage with stakeholders ahead of submitting a Revenue Proposal, including consulting on the nature of the project and proposed costs.
- Where possible, Network Operators should incorporate the findings of this pre-lodgement engagement into their Revenue Proposals, noting that interlinkages with contestable projects and commercially sensitive information may limit the information able to be shared during engagement.
- Where possible, Network Operators should use best endeavours to publish a draft Revenue Proposal for the AER and public comment and reflect consumer views in its Revenue Proposal.
- Network Operators should aim to satisfy principles set out in the AER's Better Resets Handbook.

The Guideline also acknowledges that consultation for EII projects will necessarily be narrower than engagement under the NER, as the Consumer Trustee's Authorisation or Minister's direction will specify most aspects of the project. Additionally, Network Operators are not expected to re-engage with stakeholders on issues that have been previously consulted on by the Infrastructure Planner, Consumer Trustee or Minister.

This guidance has informed our engagement approach for the Project.

3.2. Our engagement approach

Our engagement approach is based on genuine consultation through meaningful and transparent dialogue. As detailed in our Stakeholder Engagement Strategy for the Project, our engagement approach is underpinned by the engagement principles of being genuine, inclusive, accessible, responsive and transparent. We are committed to understanding the priorities and preferences of our customers and other

[55] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, pp. 15-16.

stakeholders, keeping them informed and reflecting their feedback, to the extent possible, in our Revenue Proposal.

Our core engagement objectives for the CWO REZ Revenue Proposal are to:

- provide clear, concise information about the CWO REZ Revenue Proposal to ensure TAC members can provide informed feedback
- understand and address consumer and customer issues, priorities and preferences in relation to the CWO REZ Revenue Proposal
- respond to feedback on the CWO REZ Revenue Proposal and be transparent about the decisions Transgrid makes, and why.

Throughout the development of this Revenue Proposal, we have engaged with various stakeholders. This includes:

- extensive engagement with communities and key stakeholders on potential route options for the Mount Piper to Wallerawang transmission works
- focused engagement with the Transgrid Advisory Council (TAC) to gather insights, perspectives and feedback on areas where it was identified the TAC could provide meaningful input
- pre-lodgement engagement with EnergyCo, noting the interrelationship between the Project and the contestably-procured Main CWO RNIP
- pre-lodgement engagement with the AER to provide project updates, engage on novel regulatory issues and foster open and transparent communication.

Where relevant, we have also had regard to engagement undertaken by EnergyCo in its role as Infrastructure Planner. This includes engagement with local councils, community members, First Nations organisations and renewable energy companies through the planning, design and procurement stages.

We have also considered feedback received from customers and stakeholders in our broader engagement processes under the EII framework and the NER and reflected them in our engagement approach for this Revenue Proposal, where appropriate. In particular, this has included TAC and AER feedback on our engagement approach for the 2023-28 Revenue Proposal and the 2024-29 Revenue Proposal for Waratah Super Battery. Based on this feedback, we made several changes to our engagement approach for the Project to enhance customer outcomes and better meet stakeholder needs and expectations.

To ensure on-time delivery of the Project, we were required to submit this Revenue Proposal within a compressed timeframe. As a result, a draft Revenue Proposal was not able to be published for broader public consultation. However, to ensure stakeholders' views were appropriately considered, the draft was shared with the TAC, the AER, and the Infrastructure Planner ahead of submission. Feedback from these stakeholders was incorporated where appropriate.

3.2.1. Alignment with AER engagement guidance

We consider that our engagement approach for the Project satisfies the relevant principles set out in the AER's Better Resets Handbook, as outlined in Table 3-1. We have also considered the guidance provided in the AER's guidance note on regulation of actionable ISP projects[56], which provides helpful advice on best practice stakeholder consultation.

[56] AER, Guidance note – Regulation of actionable ISP projects, March 2021.

Table 3-1 Alignment with AER's Better Resets Handbook engagement expectations

Relevant AER expectations	Our alignment
Sincerity of engagement: • Genuine commitment from network businesses extending from Board and Executive level to give effect to consumer preferences • Openness to new ideas and a willingness to change • Ongoing engagement with customers about outcomes that matter to them, which allows customers to 'set the agenda' • Ensuring consumer confidence in the engagement process and alleviating concerns consumers may have	• Our Executive General Manager (EGM) of Stakeholder, Regulatory and Corporate Affairs regularly chairs the TAC. • Members of our Executive Leadership Team (ELT) and Board attended and participated in TAC deep dives for the Project, when appropriate. • We consulted with the TAC on the engagement approach and scope of engagement for the Project and adapted our engagement approach based on previous feedback from the TAC and AER. • We engaged with the TAC in June 2024 to ensure that aspects of the Project that they wished to have further information on were discussed, and there were further opportunities to engage on these topics. • We circulated materials in advance of meetings to allow for meaningful discussion of issues. • We 'circled back' to the TAC on how the feedback that had provided during engagement had been considered in the Revenue Proposal. • We surveyed TAC members at the end of each engagement meeting to understand TAC member satisfaction with the engagement process and opportunities to improve. • We were responsive to TAC members' requests for further information and engagement on key issues, including addressing queries in subsequent deep dives and providing written responses to questions where appropriate.
Accessible, clear and transparent engagement: • Set out engagement plans including outlining engagement objectives, engagement issues/topics and the level of participation and influence consumers can expect on the Revenue Proposal.	• We developed a forward-looking engagement plan with TAC input to ensure appropriate coverage of relevant topics. • We presented our proposed engagement objectives prior to commencing engagement discussions. We clearly outlined the proposed level of engagement of the TAC for each topic and the reasons why • We clearly discussed and agreed the areas that the TAC could influence, noting that as an EII project, many aspects of the Project (including scope) are outlined in the Consumer Trustee's Authorisation and therefore outside of Transgrid's control. We also explained and discussed the areas that the TAC could have less impact on. • We provided accurate and unbiased information necessary to ensure stakeholders could meaningfully participate. This included facilitating an AER presentation to the TAC on the Project and areas of influence. We note that due to commercial sensitivities at various stages of engagement, some information remained confidential during earlier engagement sessions. When presenting the draft proposal on 20 June, Transgrid ensured that key information was able to be disclosed to the TAC.

Relevant AER expectations	Our alignment
Consultation on desired outcomes and then inputs: • Customers should guide the development of proposals i.e. be consulted on what they want and how they want businesses to engage	• As outlined above, we clearly discussed the areas that the TAC could influence through the engagement process, noting that as an EII project, many aspects of the Project (including scope) are outlined in the Consumer Trustee's Authorisation and therefore outside of Transgrid's control. • Where possible, we have aligned our positions with stakeholder views and preferences gained through earlier engagement for our 2023-28 Revenue Determination, 2024-29 Revenue Proposal for Waratah Super Battery and HumeLink's Stage 2 Contingent Project Application.
Clearly evidenced impact: • There should be a clear link to the outcomes desired by consumers and how the Proposal gives effect to those outcomes. • Evidence of consumer preferences should be provided.	• We have considered all customer and stakeholder feedback received in the development of our Revenue Proposal. • Where appropriate, we have reflected this feedback in the positions we have put forward in this Revenue Proposal, as outlined in section 3.4.

3.3. Engagement activities

We have engaged with various stakeholders throughout the development of this Revenue Proposal. This includes:

- extensive engagement with communities and key stakeholders on potential route options for the Mount Piper to Wallerawang transmission works
- focused engagement, including pre-lodgement engagement with the TAC to gather insights, perspectives and feedback on areas where it was identified the TAC could provide meaningful input
- pre-lodgement engagement with EnergyCo, noting the interrelationship between the Project and the contestably-procured Main CWO RNIP
- pre-lodgement engagement with the AER to provide project updates, engage on novel regulatory issues and foster open and transparent communication.

3.3.1. Engagement with communities and key stakeholders

We engaged with key stakeholders and community members on potential route options for the Mount Piper to Wallerawang transmission line upgrade. Our engagement activities included:

- media releases
- newspaper advertisements
- letterbox drops
- correspondence with email subscribers
- landowner correspondence and meetings
- engagement with local councils
- engagement with environmental advocacy groups
- engagement with Traditional Owners
- engagement with NSW National Parks and Wildlife Service
- online surveys

- social media releases
- website updates
- community events in Lithgow and Wallerawang.[57]

We will continue to engage with the community throughout the environmental assessment process for the Mount Piper to Wallerawang line upgrade. We expect that the Environmental Impact Statement will be on public display in September 2025.

We also consulted with AGL on the Bayswater to Liddell transmission line upgrade, noting that as the modifications to the network were solely on AGL's land, minimal consultation with other stakeholders was relevant for this portion of the work.

3.3.2. Engagement with the Transgrid Advisory Council

The TAC has been the primary forum for engagement on the development of this Revenue Proposal. This is largely due to the fact that:

- The Consumer Trustee Authorisation for the Project specifies the elements for design, construction and operation.
- Noting that the Main CWO RNIP cannot proceed without the Enabling CWO RNIP, EnergyCo requested an expedited timeframe to determine applicable contractual arrangements, limiting engagement timeframes available.

Given this, the TAC is best suited to provide targeted feedback on the key areas that can be influenced in the time available.

TAC members represent consumer advocates, industry and business. Our TAC meetings are facilitated by our Executive and Leadership team to ensure their views are heard at the most senior level and shared broadly across our business. Our engagement objectives with the TAC for the Project were:

- to provide clear, concise information about the Revenue Proposal to ensure TAC members can provide informed feedback
- to understand and address consumer and customer issues, priorities and preferences in relation to the Revenue Proposal, and
- to respond to feedback on the Revenue Proposal and be transparent about the decisions Transgrid makes, and why.

We have engaged extensively with the TAC, including undertaking Project-specific 'deep dives' to:

- provide background on the Enabling CWO RNIP and broader CWO REZ projects
- outline the purpose and key elements of this Revenue Proposal
- seek TAC feedback on the appropriate engagement approach and elements of the proposal the TAC can influence
- present a proposed engagement program for TAC member feedback
- consult with TAC members on elements of the proposal they have influence over to obtain feedback on alternatives and draft positions
- consult with TAC members on the risk allocation approach and treatment of risk for the Project

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

- consult with TAC members on the costs for the Project
- revert back to the TAC to outline how feedback has been considered in developing this Revenue Proposal
- present the Revenue Proposal for broader feedback and comment prior to submission.

We also facilitated an AER-led presentation to the TAC on how the TAC could add value through its engagement on the Enabling CWO RNIP. We also provided several updates on the Project at quarterly CEO TAC meetings, which were attended by our CEO, Executive and some Board members.

Our deep dive topics are summarised in Table 3-2.

Table 3-2 Deep dive consultation topics

Deep dive	Consultation
Deep Dive #1 (20 June 2024)	Engagement approach and project background
Deep Dive #2 (30 January 2025)	Incentive schemes, risk, adjustment mechanisms, allocation of risk, financeability
Deep Dive #3 (4 March 2025)	Allocation of risk
Deep Dive #4 (15 April 2025)	Project cost estimates, allocation of risk
Deep Dive #5 (20 June 2025)	Circle back on how feedback has been considered in the Revenue Proposal

3.3.3. Pre-lodgement engagement with the AER

We have met with the AER on a regular basis, from September 2024 to June 2025, in preparing this Revenue Proposal. This pre-lodgement engagement has ensured the AER was kept up to date on commercial and project developments throughout the negotiation process. We have also sought the AER's feedback and views on our draft regulatory models and key positions, including on matters that are specific to the EII framework:

- financeability of the project – we met regularly with AER staff to understand the AER's financeability guideline and how it applies to the Project and sought early feedback on our draft financeability modelling
- pre-period costs – we discussed options for how these costs should be presented in the Revenue Proposal and PTRM
- the acquisition and energisation of BCSS – we discussed options for including BCSS in our Revenue Proposal, including how best to reflect this as an adjustment mechanism and the limitations regarding including BCSS in our financeability modelling
- Infrastructure Planner costs – we discussed options for how these costs should be presented in the Revenue Proposal and PTRM
- incentive schemes – we discussed the AER's views on the application or modification of incentive schemes to EII projects including criteria for disapplying CESS and how the AER considers EBSS and STPIS should apply for initial revenue determinations
- adjustment mechanisms – we discussed proposed adjustment mechanisms to understand the AER's views on circumstances where it is appropriate to include an adjustment mechanism.

The AER's feedback on these matters and others has informed the content and structure of this Revenue Proposal and supporting models.

AER staff also attended our TAC meetings to observe first-hand our engagement and hear the views and preferences of TAC members. The AER also established a Consumer Challenge Panel (CCP) for this Revenue Proposal. The member appointed to the CCP was Ms Helen Bartley, who attended four of our TAC 'deep dive' sessions to observe our engagement process.

3.3.4. Pre-lodgement engagement with EnergyCo

We have met regularly with EnergyCo in preparing our Revenue Proposal, noting the interrelationship with the contestable elements of the CWO REZ, and the need to establish contractual arrangements for the delivery of the Project with EnergyCo.

On 30 May 2025, we provided EnergyCo with an interim draft of our Revenue Proposal for early feedback. On 5 June 2025, EnergyCo provided its comments, which we reviewed and incorporated where applicable.

On 19 June 2025, in accordance with the Project Deed, we provided EnergyCo a draft version of our Revenue Proposal. We received EnergyCo's comments on 3 July 2025 and have incorporated them in this document, where appropriate.

3.4. How feedback has been considered in this Revenue Proposal

Table 3-3 sets out the feedback we have received throughout our engagement activities and how we have considered this in developing our Revenue Proposal.

Table 3-3 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.[58] 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.[59]

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

Topic	Feedback provided	Our response
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 should not be used to completely de-risk the Project.	• 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. • 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	• 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

Topic	Feedback provided	Our response
	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).	site 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.
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 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	This feedback has been constructive and informative in a novel process. We have sought

Topic	Feedback provided	Our response
	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.	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. •

4. Forecast capex

This chapter sets out the total 2026-31 regulatory period forecast capex for the Project, which has been developed in accordance with our Expenditure Capitalisation Standard. We have also applied our approved CAM to appropriately allocate costs to EII services.

4.1. Overview

- The total forecast capex for the Project is **$437.9 million**, with the majority of expenditure occurring during 2026-27 and 2027-28.
- The Project involves complex and unique commercial, technical and delivery requirements. It is being delivered under new and relatively untested commercial and regulatory frameworks, involving complex interfaces, multiple interconnected contractual arrangements and agreed delivery timeframes. The integration of REZs increases the complexity of network planning and operations, while the addition of a new network operator, necessitates increased commercial, governance and site coordination.
- Our approach delivers a fit-for-purpose solution, which optimises consumer outcomes whilst ensuring a prudent and efficient allocation of costs. Efficiencies have been achieved through the use of early contractor involvement processes, cost-efficient design alternatives, and optimised resource utilisation.
- The capex forecast is underpinned by a robust and transparent forecasting approach, utilising competitive market pricing, independent cost verification, and benchmarking against other projects to ensure prudency, efficiency, and reasonableness.

We have been engaged by EnergyCo to deliver the Enabling CWO RNIP. The Project involves augmenting the existing transmission network to enable the connection of the Main CWO RNIP, which will be delivered by ACEREZ.

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 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 to ensure we meet the Project's agreed delivery timeframes.

The timely delivery of the Project is critical to maintaining a safe, reliable, secure and sustainable supply of electricity in NSW following the anticipated closure of the Eraring Power Station in 2027. To meet this timeline, EnergyCo has committed funding (up to a capped amount) for early development activities up to 31 December 2026 under the Project Deed. Each month, we submit our actual labour, management and external costs incurred in delivering the milestones agreed with EnergyCo and EnergyCo must then review and pay these amounts.[60] Under the Project Deed, these early development activity costs are one of the reimbursable cost categories, for which we must repay EnergyCo. We refer to reimbursable costs under the Project Deed as Infrastructure Planner costs, for the purposes of this Revenue Proposal.

The EII framework allows us to recover payments required to be made to EnergyCo under the Project Deed in our Revenue Proposal.[61] These payments are not reviewed for efficiency, prudency or reasonableness as part of the AER's Revenue Determination. Instead, the Project Deed stipulates that the early development activity costs must be demonstrably prudent, efficient and reasonable and are subject to review and acceptance by EnergyCo. The AER will then pass these costs through as part of the Revenue Determination.[62] The forecast capex below includes actual Infrastructure Planner costs to 28 February 2025 and an estimate of Infrastructure Planner costs to be paid after this date.

At the time of submitting the Revenue Proposal, the Project's scope does not include the acquisition, energisation and operation of BCSS. BCSS will be covered by our Consumer Trustee Authorisation only after the Consumer Trustee (as an authorisation provider) approves the transfer and the asset is formally transferred to us. As such, costs associated with the purchase, commissioning, operation and management of BCSS are excluded from our capex and opex forecasts for this Revenue Proposal. Instead, these costs are proposed to be recovered via an adjustment to our allowable revenue, following the successful transfer of BCSS (refer to section 9.3 for details).

Noting the above, our total forecast capex for the Project is $437.9 million and comprises:

- $193.5 million[63] (or 44.2 per cent of capex) for Infrastructure Planner costs comprising payments made by EnergyCo to us to undertake early development activities to ensure timely Project delivery, that are contractually required to be reimbursed to EnergyCo
- $8.2 million (or 1.9 per cent of capex) for pre-period costs, covering early development activities prior to the commencement of the Project Development Deed
- $145.0 million (or 33.1 per cent of capex) for tendered works, comprising [redacted] million for the augmentation works and [redacted] million for line transposition works. These works will be delivered by our D&C contractor Zinfra
- [redacted] for acquiring the necessary easements
- [redacted] for acquitting our biodiversity offset liabilities

[60] Under the Project Deed, EnergyCo can request additional information on these costs and may also withhold or set off costs. Where we disagree with the decision to withhold or set off costs, we can refer this decision to dispute resolution.
[61] EII Regulation, cl. 46(1)(b)(ii).
[62] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, section 5.6.
[63] This equates to $188.1 million (nominal) and aligns to the capped amount agreed under the Project Deed.

- $11.7 million (or 2.7 per cent of capex) for other construction costs comprising a prudent and efficient allowance for known Project risks
- $62.1 million (or 14.2 per cent of capex) for our labour and indirect costs, mostly comprising:
  - $41.0 million (or 9.4 per cent of capex) for labour resources, primarily supporting project management, construction management, commercial management, and safety functions
  - $20.8 million (or 4.8 per cent of capex) for non-labour indirect, primarily covering insurance premiums during the construction period and costs associated with professional and consulting services required for biodiversity offsets and environmental planning approval
  - $0.3 million (or 0.1 per cent of capex) for labour escalation
- $1.6 million or 0.4 per cent for equity raising costs.

Table 4-1 sets out our annual and total capex forecast for the 2026-31 regulatory period for the Project.

Table 4-1 Total capex for the Project, including pre-period capex ($M, real 2025-26)

	Pre-period	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Infrastructure Planner costs	152.0	41.5	-	-	-	-	193.5
Pre-period costs	8.2	-	-	-	-	-	8.2
Direct costs							
D&C contractor costs	-	74.2	65.9	4.9	-	-	145.0
Easement acquisition	[redacted]						
Biodiversity offset costs							
Other construction costs	-	4.8	5.0	1.9	-	-	11.7
Labour and indirect costs							
Labour costs	-	12.8	25.1	3.2	-	-	41.0
Indirect costs	-	6.9	12.5	1.4	-	-	20.8
Labour escalation and equity raising costs							
Labour escalation	-	0.1	0.2	0.0	-	-	0.3
Equity raising costs	-	1.6	-	-	-	-	1.6
Total capex (excluding equity raising costs)	160.2	146.4	118.3	11.4	-	-	436.3
Total capex	**160.2**	**148.0**	**118.3**	**11.4**	**-**	**-**	**437.9**

Table 4-2 details the total capex required to deliver the Project by asset class. This include both pre-period costs and Infrastructure Planner costs.

Table 4-2 Total capex by asset class ($M, real 2025-26)[1]

	Pre-period	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Transmission lines	80.2	100.6	79.7	10.7	-	-	271.2
Substations	25.7	25.2	17.4	0.7	-	-	69.0
Secondary systems	10.7	10.8	7.1	-	-	-	28.5
Land and easements	18.6	1.1	-	-	-	-	19.7
Biodiversity offsets – stewardship sites	7.4	2.6	4.2	-	-	-	14.1
Biodiversity offsets – direct payments and other costs	17.7	6.1	10.0	-	-	-	33.8
Equity raising costs	-	1.6	-	-	-	-	1.6
Total capex excluding equity raising costs	160.2	146.4	118.3	11.4	-	-	436.3
Total capex	**160.2**	**148.0**	**118.3**	**11.4**	**-**	**-**	**437.9**

[1] **The asset classes outlined here do not account for the adjustment to the secondary systems capex to reflect the proposed 'financeability' asset class. This adjustment is discussed further in Chapter 6 of the Revenue Proposal.**

Sections 4.2 to 4.7 explain and justify our forecast capex by category. Our detailed approach to forecasting capex is provided in our Direct Capex Forecasting Methodology, Labour and Indirect Capex Forecasting Methodology and Other Construction Costs Forecasting Methodology, which are provided as attachments to this Revenue Proposal.

4.2. Key capex assumptions

Table 4-3 details the key assumptions underpinning our capex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.1(5) of EII Chapter 6A, as discussed in Chapter 13 of this Revenue Proposal.

Table 4-3 Capex key assumptions

Key assumption	
Legislative and regulatory obligations	We have developed this Revenue Proposal taking into account current legislative and regulatory obligations, our transmission operator's licence requirements, the Consumer Trustee's Authorisation for the Project and our contractual arrangements relating to the Project, in particular the Project Deed.

Key assumption	
Project scope	The scope of works for the Project aligns with our Consumer Trustee Authorisation for the Project and the Project Deed, as agreed with EnergyCo.
Project timeline	We are contractually required to deliver the scope within agreed timeframes. To meet these obligations, we have adapted our delivery strategy to ensure timely and efficient delivery.
Unit rates and project costs	The unit rates and project costs that we have applied in developing our capex forecasts are representative of the costs that will be incurred in the regulatory period.
Cost allocation and capitalisation	Our capex forecasts reflect our Expenditure Capitalisation Standard and our CAM, which provide an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services (and between capex and opex).
Cost escalations	The cost escalations that we have applied in developing our capex forecasts are representative of the increased costs that we will incur in the regulatory period.
Inflation	The inflation that we have applied in developing our capex forecasts is representative of the inflation-related costs that we will incur in the regulatory period. This is consistent with the AER-preferred inflation forecasting method.
Adjustment mechanisms	Our capex forecasts reflect the assumption that the AER will approve our nominated pass-through events / revenue adjustments.

4.3. Infrastructure Planner costs

Clause 46(1)(b)(ii) of the EII Regulation allows us to recover costs for any payments required to be made to EnergyCo under contractual arrangements entered into pursuant to the Consumer Trustee Authorisation. The Project Deed was entered into pursuant to clause 7 of our Consumer Trustee Authorisation and therefore, payments made in accordance with the Project Deed are permitted to be recovered by us.

The Project Deed requires us to make payments to EnergyCo for a range of costs EnergyCo may incur in respect of the Project (Infrastructure Planner costs), including:

- costs relating to biodiversity offsets (excluding any biodiversity offsets for which we are responsible for obtaining)
- payments made by EnergyCo for early project development activities

[redacted]

- the costs of variations to be borne by EnergyCo.

Under the Project Deed, EnergyCo must provide us with actual and budgeted Infrastructure Planner costs. These costs must be included in the Revenue Proposal and are payable by us to EnergyCo by [redacted] (or 20 business days after we are notified that such costs are approved by the AER). We supported EnergyCo in the determination of the amount for inclusion in the Revenue Proposal, noting that at the time of submission, actual and expected reimbursable costs only related to early development activities (the costs for which are driven by the activities we intend to undertake in this period). This amount is included in the proposed base expenditure and is detailed in Table 4-4 below.

For clarity, the period in which early development activities will be undertaken extends to 31 December 2026. At the same time, we will begin incurring costs for construction activities from 1 July 2026. Construction activities are not included in the activities that will be paid for by EnergyCo and later reimbursed by us. This means that in 2026-27, costs in our Revenue Proposal will include both Infrastructure Planner costs and construction costs paid by us.

Table 4-4 Summary of Infrastructure Planner costs by activity ($M, real 2025-26)

Capex category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Total
D&C contractor costs	[redacted]						
Equipment							
Easement acquisition							
Biodiversity offset costs							
Other construction costs	-	-	-	-	0.6	4.8	5.4
Labour costs	2.6	3.2	9.1	15.1	19.4	10.0	59.5
Indirect costs	6.1	1.9	3.8	16.3	18.7	5.7	52.5
Total	**8.7**	**5.1**	**12.8**	**39.7**	**85.7**	**41.5**	**193.5**

Table 4-5 summarises Infrastructure Planner costs by asset class.

Table 4-5 Summary of Infrastructure Planner costs by asset class ($M, real 2025-26)[1]

Asset class	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Transmission lines	5.5	3.2	8.1	23.4	34.7	28.5	103.5
Substations	1.4	0.8	2.0	6.7	13.5	7.2	31.6
Secondary systems	0.6	0.3	0.8	3.0	5.3	3.0	13.2
Land and easements	[redacted]						
Biodiversity offsets – stewardship sites							
Biodiversity offsets – direct payments and other costs							
Total	**8.7**	**5.1**	**12.8**	**39.7**	**85.7**	**41.5**	**193.5**

[1] **The asset classes outlined here do not account for the adjustment to the secondary systems capex to reflect the proposed 'financeability' asset class. This adjustment is discussed further in Chapter 6 of the Revenue Proposal.**

As outlined above, Clause 46(1)(b)(ii) of the EII Regulation allows us to recover the costs for any payments required to be made to EnergyCo under contractual arrangements entered into pursuant to the Consumer Trustee Authorisation. The Project Deed stipulates that the early development activity costs must be demonstrably prudent, efficient and reasonable and are subject to review and acceptance by EnergyCo. The AER will then pass these costs through as part of the Revenue Determination.[64]

[64] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, section 5.6.

The actual payments made by us to EnergyCo may be higher or lower than this estimated amount. This could be due to:

- a variance between actual costs incurred and the budgeted amount included in the Revenue Proposal (either higher or lower), and/or
- a cost arising that was not certain or initially foreseen at the time of submission (e.g. [redacted] a contractual variation).

To account for this, the Project Deed requires us to propose an adjustment mechanism to allow for adjustments to the Infrastructure Planner costs. Accordingly, we have proposed an adjustment mechanism to reflect increases or decreases in Infrastructure Planner costs (see Chapter 9 of the Revenue Proposal for further discussion).

4.4. Pre-period costs

We incurred costs in 2020-21 and 2021-22, prior to the commencement of the 2026-31 regulatory period and the execution of the Project Development Deed with EnergyCo. We refer to these costs as pre-period costs. These costs relate to:

- project management, including strategic planning and scheduling
- concept design
- community and stakeholder engagement, and
- land and environment activities, including land access strategy and valuations.

These costs are separate from, and in addition to, costs recovered from EnergyCo and ARENA for related activities. For clarity, these costs have also not been recovered under our NER arrangements. Further detail is provided in the Labour and Indirect Capex Forecasting Methodology document, provided as an attachment to this Revenue Proposal.

Table 4-6 details the pre-period costs of $8.2 million that we have incurred in respect of the above activities.

Table 4-6 Summary of pre-period capex ($M, real 2025-26)

Pre-period costs	2020-21	2021-22	Total
Labour	1.4	1.0	2.4
Indirect	3.3	2.4	5.8
Total	**4.7**	**3.5**	**8.2**

We have included these costs within the opening regulatory asset base to be recovered over subsequent regulatory periods. As the pre-period costs are not directly attributable to a single asset class, as they relate to labour or overhead costs and other indirect costs, we have allocated this expenditure across asset classes in proportion to the total capex for the project.

Table 4-7 provides a summary of pre-period costs by asset class.

Table 4-7 Summary of pre-period costs by asset class ($M, real 2025-26)[1]

	2020-21	2021-22	Total
Transmission Lines	3.0	2.2	5.2
Substations	0.7	0.5	1.3
Secondary systems	0.3	0.2	0.5
Land and easements	0.2	0.1	0.3
Biodiversity offsets – stewardship sites	0.2	0.1	0.3
Biodiversity offsets – direct payments and other costs	0.4	0.3	0.6
Total	**4.7**	**3.5**	**8.2**

[1] **The asset classes outlined here do not account for the adjustment to the secondary systems capex to reflect the proposed 'financeability' asset class. This adjustment is discussed further in Chapter 6 of the Revenue Proposal.**

4.5. Basis for capex forecast

We have developed a capex forecast that is prudent, efficient and reasonable and designed to deliver the Project safely, efficiently, and at the lowest sustainable cost to consumers.

Our total Enabling CWO RNIP capex is $437.9 million, comprising Infrastructure Planner costs[65], direct capex, labour and indirect capex, and equity raising costs (Table 4-1). The Project is anticipated to achieve practical completion date by May 2028, with the majority of expenditure occurring during 2026-27 and 2027-28.

Our capex forecast has been developed to support the timely and cost-effective delivery of the Project, whilst achieving the capital expenditure objectives, outlined in EII Chapter 6A, to:

- meet or manage the expected demand for regulated network services
- comply with all regulatory requirements (as defined in the EII Regulation)
- maintain the safety of the Project through the supply of regulated network services.

Our proposed capex is prudent, efficient and reasonable, and reflects a delivery approach focused on managing the unique and complex challenges of the Project, to optimise outcomes and meet the agreed delivery timeframes.

The scope of works underpinning the forecast is consistent with our Consumer Trustee Authorisation and our contractual obligations under the Project Deed with EnergyCo. These instruments define the required scope, technical specifications and delivery timeframes for the Project. The technical scope of the Project

[65] The Infrastructure Planner costs reflect actual Infrastructure Planner costs to 28 February 2025 and an estimate of Infrastructure Planner costs to be paid after this date. Under the EII framework, we are entitled to recover these costs in our Revenue Determination.

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

To ensure the delivery of the Project results in the best outcomes for consumers, we have prioritised prudent and efficient outcomes when developing our approach to deliver and operate the Project. Our approach has focused on delivering a fit-for-purpose solution, at the lowest sustainable long-term cost to consumers. Examples of actions we have taken to prioritise prudent and efficient outcomes include:

- selecting a transmission line route that minimises impacts on communities and the environment and reduces biodiversity offset liabilities
- undertaking an early contractor involvement process to address key delivery risks and scope uncertainties early in the process, thereby improving cost transparency, reducing unnecessary contractor margins, and achieving cost savings where feasible
- employing cost-efficient design solutions where appropriate – for example, the use of alternate structure types in constrained locations.

Our approach to delivering the Project also 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. For example, our approach to construction management is designed to be proactive and informed, ensuring we are adequately resourced to provide proper oversight to swiftly address issues on site, particularly at third-party interfaces. Similarly, for commercial management, we have established a dedicated team to provide clear oversight and accountability of both upstream and downstream commercial interfaces to ensure compliance with our obligations and to safeguard against avoidable costs, drawing on our experience with the Waratah Super Battery (WSB) project. 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.

Our capex forecasting methodology has been tailored to the Project's specific characteristics and delivery model. It draws heavily on competitively sourced, market-tested costs and has been validated through a combination of internal benchmarking and independent expert verification to ensure our proposed costs are prudent, efficient and reasonable. Specifically, our forecasts reflect:

- the outcome of a robust, market-tested 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. 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.[66] Approximately 49.1 per cent of forecast capex (excluding Infrastructure Planner costs) is based on market prices obtained through competitive tender processes.
- cost estimates for specific cost categories provided by service providers (such as our insurance broker) and independent experts (including GHD, who has estimated our likely biodiversity offset liability for the augmentation works). The use of independent cost estimates ensures reliability and transparency in the cost estimation process.
- estimates that utilise rates provided in existing supplier agreements and contracts, ensuring cost estimates reflect prevailing rates in current market conditions.

[66] AER, Expenditure Forecast Assessment Guidelines, final decision, October 2024, p. 7.

- a reliance on past actual costs where appropriate, including benchmarking against comparable projects to ensure costs are reasonable taking into account recent market performance.
- review and verification of all Project costs by GHD and E3 Advisory. Independent verification utilises established benchmarks and methodologies to review and validate cost estimates, providing additional validation that cost estimates are prudent, reasonable and efficient.

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.

Table 4-8 provides an overview of the approach we have used to forecasting capex, excluding pre-period and Infrastructure Planner costs.[67]

Table 4-8 Total forecast capex for Enabling CWO RNIP by category ($M, real 2025-26)

Category of capex	Capex (excluding IP costs)	Market tested or independently estimated	Basis of capex forecast	Relevant chapter reference
Direct costs				
D&C contractor costs	145.0	Yes[1]	The outcome of a competitive tender process	Chapter 4.5.1
Easement acquisition	[redacted]	No	Certified Practising Valuer advice	Chapter 4.5.3
Biodiversity offset costs		Where possible	Third party estimate for augmentation works and internal desktop assessment for line transposition works	Chapter 4.5.4
Other construction costs	11.7	No	Detailed probabilistic assessment	Chapter 4.5.2
Labour and indirect costs				
Labour costs	41.0	No	Internal resource requirements and market labour rates	Chapter 4.5.5
Indirect costs	20.8	Where possible	Rates from current engagements, available market quotes and recent historical data	Chapter 4.5.5
Labour escalation and equity raising costs				
Labour escalation	0.3	N/A	The labour escalators for 2026-27 and 2027-28 are as set out in our 2023-28 Revenue Determination. For 2028-29, 2029-30 and 2030-31, the labour escalator is assumed to be equivalent to the average applied in 2026-27 and 2027-28.	Chapter 4.5.6

[67] Our capex forecast reflects the capital expenditure objectives, criteria and factors as set out in EII Chapter 6A clauses 6A.6.7(a), 6A.6.7(c) and 6A.6.7(e), respectively.

Category of capex	Capex (excluding IP costs)	Market tested or independently estimated	Basis of capex forecast	Relevant chapter reference
Equity raising costs	1.6	N/A	These costs are calculated in the PTRM.	Chapter 7.8
Total capex (excluding equity raising costs)	234.6	N/A		
Total capex (including equity raising costs	**236.2**			

[1] **The transpositions scope of work under the D&C contract was unable to be included in the RfT process. Refer to Chapter 5 and 6 of the Direct Capex Forecasting Methodology for further discussion.**

Our capex forecast is explained and justified in the following supporting documents:

- Direct Capex Forecasting Methodology – Attachment A.8
- Labour and Indirect Forecasting Methodology – Attachment A.9
- Other Construction Costs Forecasting Methodology – Attachment A.10
- GHD's independent engineering capex verification and assessment – Attachment A.14
- E3's independent verification and assessment of biodiversity offset costs – Attachment A.15.

4.5.1. D&C contractor costs

To ensure we deliver the Project at the lowest sustainable, whole of lifecycle cost to maximise benefits to customers, we undertook a competitive procurement process for the design and construction of substations and transmission line augmentation works.

We engaged contractors in an **ECI process** to collaborate on constructability and design development, assess site conditions, and refine commercial arrangements. This early engagement enabled us to collaboratively assess the constructability of designs, address key project challenges and opportunities and identify opportunities for acceleration of the allocated scope at various stages of the project lifecycle. Further detail is provided in the Direct Capex Forecasting Methodology.

Overall, our procurement process is characterised by three key phases which progressively reduced risk and increased confidence in the award of a suitable contractor to complete the design and construction works.

Figure 4-1 summarises at a high-level the three key stages of the procurement process, ahead of awarding the contract.

Figure 4-1 Transmission line and substations procurement process

Each of these procurement phases is explained in detail in our Direct Capex Forecasting Methodology.

Overall, the tender process identified Zinfra as the preferred tenderer to deliver the augmentation scope of works for the Project. The benefit of a single design and construction (D&C) contract is that it enables efficient management whilst maximising market appetite and minimising the risk to us and consumers of schedule delays and costs overruns. The D&C contract was awarded to Zinfra in March 2025.

We adopted a **fixed-price lump sum D&C contract** with specific limited adjustment items. This approach allows for key risk to be transferred to the contractor and provides cost certainty, reducing the risk of cost overruns in delivery. This model was well-suited as the scope was relatively well defined at the time of tendering and the ECI process provided tenders with sufficient information to provide an informed price. The presence of specific, limited adjustments in the contractual model ensures that the tendered price remains efficient and does not include unwarranted premiums for items which are highly variable and that the contractor has minimal control over.

The D&C contract with Zinfra has been broken down into seven separable portions, with only the first separable portion awarded at the time of submission. These separable portions are:

- **D&C Separable Portion 1** – Detailed design and management plans
- D&C Separable Portion 2 – BCSS cut-in works
- **D&C Separable Portion 3** – Transmission Line Bayswater and Liddell
- **D&C Separable Portion 4** – Substation Works Bayswater and Liddell
- **D&C Separable Portion 5** – Transmission Line Mt Piper and Wallerawang
- **D&C Separable Portion 6** – Substation Works Mt Piper and Wallerawang
- D&C Separable Portion 7 – Transpositions

The line transposition works were only identified as a scope requirement, following detailed network planning for the integration of the Main CWO RNIP into the existing Transgrid network. As this occurred post the commencement of the RfT process, it was not possible to include the transposition scope of work without delaying the award of the remainder of the works and impacting the commissioning date. Following the award of the contract, we asked Zinfra to price the scope of works to complete the initial transmission line transpositions.

The response from Zinfra forms the basis of the cost forecast. We are in the process of awarding the transposition scope of work through a Deed of Amendment to Zinfra's existing contract. The costs estimated by Zinfra has been compared against our internal estimate for the proposed scope which had been independently reviewed by [redacted]. This review by [redacted] (a consultancy firm with expertise in cost estimation of major transmission projects) identified that the estimate was reasonable, given the early stage of development for the project.

The **use of separable portions** eliminates the risk of the contractor claiming a single delay or variation has a consequential impact on other scope of work. Delays to the works will be isolated to separable portions and any potential delay claims are limited, reducing risk exposure to claims and costs.

Table 4-9 sets out our forecast capex for design and construction. The capex forecast reflects the detailed final contract price agreed with Zinfra following the detailed procurement and evaluation process outlined in the Direct Capex Forecasting Methodology, provided as an attachment to this Revenue Proposal. The costs for the initial transmission line transpositions are based on the price provided by Zinfra, following the award of the D&C contract.

Table 4-9 Design and construction capex for the Project for the 2026-31 regulatory period ($M, real 2025-26)[1]

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Transmission lines	[redacted]					
Substations						
Secondary systems						
Transpositions						
Total	**74.2**	**65.9**	**4.9**	**-**	**-**	**145.0**

[1] **The asset classes outlined here do not account for the adjustment to the secondary systems capex to reflect the proposed 'financeability' asset class. This adjustment is discussed further in Chapter 6 of the Revenue Proposal.**

A more detailed breakdown of transmission line, substation, secondary system and transposition capex, and the corresponding scopes of work, is provided in our Direct Capex Forecasting Methodology.

4.5.2. Other construction costs

The Enabling CWO RNIP is the first non-contestable REZ network infrastructure project to be delivered under the NSW EII framework. It presents a unique set of delivery challenges largely driven by the delivery program contractos required under the contractual arrangements with EnergyCo and the novel interfaces and complexities associated with ensuring the successful integration of the Main CWO RNIP into the NSW transmission network.

To reduce Project uncertainty, we have sought to undertake activities that assist in the identification and understanding of risks faced. This has included reducing Project uncertainty by:

- undertaking early development activities, including undertaking geotechnical investigations and environmental activities (such as spring survey and Environmental Impact Statement (EIS) development), and

- engaging multiple contractors in an ECI phase, to allow them to assess constructability of the designs and resourcing, site access and planning approval requirements[68].

Following this, we have comprehensively and transparently identified and assessed the key risks for the Project, including our ability to efficiently manage, prevent or mitigate these risks (including through insurance) and the magnitude and likelihood of the risk.

We consider that there are a range of risks that are best managed by us as part of our usual risk practices / controls when delivering a transmission project of this size and scope. Additionally, we consider that some of these risks are related to unpredictable events that are outside of our control and cannot be reasonably mitigated or prevented. For these risks, it is not appropriate to include an allowance in our proposed base expenditure due to the difficulties in accurately quantifying these costs. For these specific risks, we have proposed adjustment mechanisms (as outlined in Chapter 9 of our Revenue Proposal) in accordance with clause 51 of the EII Regulation and clause 6A.6.9 of EII Chapter 6A.

However, there are also a number of residual risks that will affect the cost of the Project, are not adequately compensated for in the return on capital and cannot be efficiently transferred, avoided or mitigated (or included as adjustment mechanisms). For these risks, we consider it is most appropriate to include an allowance in our base expenditure to adequately address these risks, as provided for under clause 6A.5.4 of EII Chapter 6A. We refer to this risk allowance as 'other construction costs'.

Our forecast other construction costs for the Enabling CWO RNIP is $11.7 million over the 2026-31 regulatory period, representing 2.7 per cent of the total capex.

Table 4-10 Other construction costs ($M, real 2025-26)

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Other construction costs	4.8	5.0	1.9	-	-	11.7

We have adopted a bottom-up approach to the quantification of this allowance, including:

- establishing consequence estimates that represent reasonable estimates of the efficient and prudent costs that may be incurred
- estimating realistic likelihoods of the consequential cost being incurred
- accounting for the presence of any controls or mitigations, and
- accounting for the Project specific contractual risk allocations adopted.

The risk management framework and project risk management procedure are well developed and align with AS ISO31000:2018 Risk Management Guidelines. The key steps in our risk approach involve:

- understanding and establishing the context for the potential risk events that could arise
- identifying expected risks and establish a risk register
- analysing and evaluating potential risks, and mitigate/manage potential risks
- assessing potential cost impacts of risks, to determine appropriate 'other construction costs' allowance.

An integrated Cost and Schedule Quantitative Risk Analysis (QCSRA) probabilistic approach was used in estimating our risk allowance. We have utilised a hybrid approach, combining the top-down Risk Factor

[68] Due to feedback in the ECI phase from multiple contractors, we amended the contracting strategy to award all separable portions to one contractor to improve efficiency and de-risk resourcing.

coupled with the top-down First Principles Risk Analysis (FPRA) technique, which accounts for both inherent uncertainties and contingent risk.[69]

As a result of our analysis, we identified other construction costs that are likely to be incurred to deliver the Project on time and within budget. These other construction costs form part of the overall cost of the Project and reflect the probability-weighted calculation of 'expected costs'.

Throughout this process, we have **engaged extensively with the TAC on the risk allocation** to ensure alignment with consumer interests and regulatory expectations. Consultation with the TAC focused on preferred approaches to risk allocation, including the appropriate balance between upfront allowances and adjustment mechanisms. Feedback from the TAC has informed both the forecast other construction costs and the adjustment mechanisms proposed.

Our approach is explained in further detail in our Direct Capex Forecasting Methodology and Other Construction Costs Forecasting Methodology documents, provided as attachments to this Revenue Proposal.

When forming our position on the application of incentive schemes (such as CESS) and the calculation of our allowance, we have assumed that our proposed adjustment mechanisms are accepted. Where the AER adopts an alternate view of appropriate adjustment mechanisms is appropriate, we will need to also reconsider our positions on these aspects of our Revenue Proposal.

4.5.3. Easement acquisition

[redacted]

Transgrid's property acquisition process is guided by the *Land Acquisition (Just Terms Compensation) Act 1991* (NSW) (JTC Act). Under the JTC Act, acquisition can be by agreement or compulsory acquisition. The acquisition process must be a fair and transparent process with appropriate engagement and negotiation undertaken, before compulsory acquisition can be considered as a last resort.

[redacted]

As the transposition scope of works is in early stages of development, it is difficult to assess with accuracy which costs will be realised prior to 31 December 2026. NSW property acquisition data from 2023-24

[69] Methodology applied based on: Australian Government, Supplementary Guidance Note 3A – Probabilistic contingency estimation, version 2, November 2023 and Risk Engineering Society and Engineers Australia, Contingency Guideline, 2nd edition, February 2019.

indicates that 93.7 per cent of property acquisitions were settled by agreement.[70] Noting this, we currently expect to incur a significant portion of the relevant acquisition costs prior to 31 December 2026. At the time of submission, it is expected that we will continue to negotiate with certain landholders up to the date that a compulsory Property Acquisition Notice is published in the NSW Government Gazette (currently anticipated in late 2026 or early 2027). [redacted]

Where there is a significant timing delay in incurring these costs, we may seek to adjust its revenue to recategorise easement acquisition costs from Infrastructure Planner costs to capital expenditure incurred after 1 January 2027 in the regulatory period (see Chapter 9 for further discussion).

Based on the above assumptions, the total forecast capex for the acquisition of the required easements for the transposition scope of works is [redacted] with [redacted] expected to be incurred prior to 31 December 2026 as an early development activity and [redacted] post 1 January 2027, during the 2026-31 regulatory period. The costs relate to the following activities:

- compensation payments to landholders
- option fees, payable upon execution of an option for easement
- transfer duty on land acquisition costs
- compulsory acquisition costs
- Transgrid's legal costs
- disturbance costs being the payment of fees incurred by landholders for professional advice, such as legal and valuation fees
- statutory fees, valuations and legal costs.

The forecast capex for easements acquisition for the line transposition works is summarised in Table 4-11.

Table 4-11 Forecast easement acquisition capex ($M, real 2025-26)

Activity	Total Project capex
Landholder compensation	[redacted]
Option fees	[redacted]
Legal fees	[redacted]
Landholder disturbance costs	[redacted]
Valuation fees	[redacted]
Minor interest disturbance costs	[redacted]
Compulsory acquisition costs	[redacted]
Other (transfer duty and survey fees)	[redacted]
Total	[redacted]

70 NSW Centre for Property Acquisition, Summary of acquisition – financial year 2023-24, NSW Government.

4.5.4. Biodiversity offset costs

Biodiversity offsets are conservation measures intended to compensate for residual impacts on biodiversity caused by projects, to ensure there is no net loss of biodiversity arising from the activities that occur during and after construction.

We expect to incur biodiversity offset costs related to the augmentation works from Bayswater to Lidell and Mount Piper to Wallerawang, and transmission tower line transpositions for two circuits from Bayswater to Barigan Creek and Barigan Creek to Mt Piper.

The augmentation and transposition scope of works are subject to different environmental approval pathways. This means that a different set of cost assumptions are applicable for each scope of work, particularly with regards to the likelihood of the costs occurring, and when costs are likely to become payable.

Table 4-12 provides a summary of the biodiversity offset costs for the Project over the regulatory period.

Table 4-12 Biodiversity offset costs ($M, real 2025-26)

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Augmentation	[redacted]					
Line transpositions						
Total						

A changing regulatory environment (combined with the required timing for submission of the Revenue Proposal) means our estimates for biodiversity offset costs are currently contingent on several external factors that are not yet confirmed. Changes in these positions could materially affect costs and timing. These factors include:

- The biodiversity offset cost estimate for the Mt Piper to Wallerawang portion of the project depends on utilising offset sites to minimise cost payable. These sites cannot be confirmed prior to submission of the Revenue Proposal.
- Biodiversity offset costs are currently calculated assuming that consent for deferral of offset liability is provided and a full clearing model will apply to the Project. Each of these assumptions may not apply, resulting in changes to the biodiversity offset cost payable.
- Options available for offset acquittal may change, based on the recently introduced *Biodiversity Conservation Amendment (Biodiversity Offset Scheme) Act 2024 (NSW)*.
- Desktop studies were required to inform our estimate for offset costs associated with line transposition works, as site access is not possible until later in 2025.

Given these uncertainties, we consider it is appropriate to 'true up' our biodiversity offset cost forecast at the time the Project's biodiversity offset liability, and relevant cost implications, are known. We have proposed an adjustment mechanism to reflect this. The proposed adjustment, and the relevant factors that necessitate this approach, are outlined further in Chapter 9.4.4.3 of our Revenue Proposal.

4.5.4.1. Biodiversity offset obligations for augmentation works

The Mt Piper to Wallerawang portion of the Project has been declared by the NSW Minister for Planning and Public Spaces as Critical State Significant Infrastructure (CSSI), meaning it is essential for NSW for economic, environmental and social reasons. We also submitted a referral under the *Environment*

Protection and Biodiversity Conservation Act 1999 (Cth) (EPBC Act) for the Project, which has been determined as a 'controlled action' requiring Commonwealth approval.

All CSSI project applications must be accompanied by an Environmental Impact Statement (EIS). The EIS in turn requires a comprehensive assessment of biodiversity impacts from the construction and operation of the Project. The Project's planning approvals, impact mitigations and biodiversity offset obligations are required in accordance with:

- the Environmental Planning and Assessment Act 1979 (NSW) (EP&A Act)
- the Biodiversity Conservation Act 2016 (NSW) (BC Act)
- the EPBC Act

Under the BC Act, we are required to:

- avoid biodiversity impacts in the first instance
- minimise the extent of the biodiversity impacts, where impacts cannot be avoided, and
- offset the residual impacts, once avoidance or minimisation steps are exhausted.

The augmentation works are subject to the NSW Biodiversity Offset Scheme, which requires a Biodiversity Development Assessment Report (BDAR) to be prepared in accordance with the Biodiversity Assessment Method (BAM), including:

- an assessment of the biodiversity values of the land subject to the proposal
- an assessment of the impact of the proposal on the biodiversity values of the land, in accordance with the BAM
- measures that the proponent proposes to take to avoid and minimise the impact of the proposal
- the number and type of biodiversity credits needed to offset residual impacts of the proposal.

We have based our biodiversity offset capex forecast for the augmentation scope of works on an independent cost estimation report prepared by GHD, provided as an attachment to the Revenue Proposal. GHD's cost estimate report includes forecast cape for two scenarios, a 'High Case' and an 'Expected Case'.

We have assumed GHD's Expected Case of [redacted] will apply. Approximately [redacted] of this cost is expected to be incurred during the development phase and will be included in our Infrastructure Planner costs. The remaining [redacted] will be incurred post 31 December 2026 and is included in our base expenditure estimate.

4.5.4.2. Biodiversity offset obligations for line transpositions

The transposition scope of works is separate to the Mt Piper to Wallerawang transmission line works and is therefore not deemed to be CSSI and does not require an EIS. Under the *Electricity Network Assets (Authorised Transactions) Act 2015* (NSW), we are deemed to be an Authorised Network Operator (ANO) and can self-assess and self-determine the environmental impact of the transposition scope of works.

Biodiversity offsets would only be required for the transposition works if they are likely to significantly affect biodiversity values (and are thus required to be assessed under the NSW Biodiversity Offset Scheme). As it has not been possible to conduct field assessments at the time of submission preparation, it is currently not known whether offsets will be required. At present, our expected capex forecast is based on a high-level desktop assessment of conservative biodiversity offset cost scenarios for the transposition works.

Our capex forecast for biodiversity offset costs for the transposition scope of works conservatively assumes:

- the presence of particular plant community types (PCTs) and habitat within each proposal area
- PCTs / habitat are based upon desktop assessments and are subject to the limits of input data sources and interpretation of aerial photography
- the presence of threatened flora species (for those sites where presence is considered likely based upon assumed habitat)
- a significant impact on those threatened species assumed to occur
- acquittal of any offset liability via payment to the Biodiversity Conservation Fund (BCF).

Table 4-13 summarises the results of these desktop assessments.

Table 4-13 Rapid desktop assessment results ($M, real 2025-26)

Site	Ecosystem Credits	Species Credits	Total
[redacted]			
Total	[redacted]		

Greater certainty regarding any requirement for biodiversity offsets resulting from the transposition scope of works will be available later in 2025. For this reason, we have proposed a biodiversity offset costs 'true-up' adjustment mechanism to ensure that consumers pay no more than necessary for biodiversity offsets, given the existing uncertainty around the total quantum of costs payable.

4.5.4.3. E3 review of our biodiversity offset cost estimate

We engaged E3 to undertake an independent verification and assessment of our biodiversity offset capex forecast for both the augmentation and transposition scope of works (noting that GHD has prepared both the biodiversity offset cost estimate for the augmentation works and the independent cost verification report).

E3 considered that the design envelope used to determine the area of disturbed land that may require biodiversity offsets was appropriate for the construction activities and the approach and calculation of the biodiversity offsets was well documented, prudent and efficient. E3's report is provided as an attachment to the Revenue Proposal.

4.5.5. Labour and indirect costs

The total forecast for labour, labour-related and indirect capex is $61.9 million and reflects a bottom-up-build of costs. This forecast reflects the Project's unique delivery environment, which presents a range of technical, commercial, and delivery challenges. These factors directly influence the scope, timing, and scale of labour resource requirements over the 2026-31 regulatory period. Table 4-14 sets out our forecasts based on key categories.

Table 4-14 Labour and indirect costs for the Project ($M, real 2025-26)

Capex Category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Direct labour (internal and outsourced)	**11.5**	**21.9**	**3.2**	**-**	**-**	**36.5**
Project Development	0.4	0.6	-	-	-	0.9
Project Delivery Management	8.8	17.2	1.6	-	-	27.5
Community and stakeholder engagement	0.1	0.1	0.0	-	-	0.2
Land and Environment	0.8	1.1	0.4	-	-	2.2
Other support and corporate roles	1.5	2.9	1.2	-	-	5.7
Direct labour-related	**1.3**	**3.1**	**0.0**	**-**	**-**	**4.5**
Project Development	0.0	0.0	0.0	-	-	0.0
Project Delivery Management	1.1	2.6	0.0	-	-	3.7
Community and stakeholder engagement	0.0	0.0	0.0	-	-	0.0
Land and Environment	0.2	0.4	0.0	-	-	0.6
Other support and corporate roles	0.1	0.1	0.0	-	-	0.2
Indirect	**6.9**	**12.5**	**1.4**	**-**	**-**	**20.8**
Proportion of direct labour and labour-related[1]	5.5	10.7	1.4	-	-	17.6
Non-labour	1.4	1.8	0.0	-	-	3.2
Total	**19.7**	**37.6**	**4.6**	**-**	**-**	**61.9**

[1] **This comprises 30 per cent of total capitalised labour and labour-related costs, allocated from project development, project delivery management, community and stakeholder engagement, land and environment, and other support and corporate roles subcategories.**

The Project involves complex and interlinked contractual arrangements, including six upstream agreements between Transgrid, EnergyCo, and ACEREZ, and one downstream contract with the D&C contractor. These agreements are highly interdependent, meaning any misalignment in scope, schedule, or technical requirements poses significant delivery and compliance risks. This requires increased commercial, governance and site coordination, activities and resources for all parties.

Delivery of the Project also involves both brownfield and greenfield works. This means we must complete augmentation of existing assets before energising BCSS. An additional complexity arises from the parallel delivery streams – i.e. Transgrid and ACEREZ – requiring alignment of technical, commercial, and delivery obligations. During construction and commissioning, activities must be conducted in line with defined access conditions, environmental approvals, and staging requirements. The energisation of BCSS by Transgrid and the commissioning of the Merotherie lines by ACEREZ must be precisely coordinated, followed by a joint defect rectification process that continues post-handover.

As NSW's primary Transmission Network Service Provider, we must also ensure safe and reliable integration of the CWO REZ into the broader transmission network, while enabling the connection of renewable generation.

> 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.

Our forecast of $61.9 million covers labour, labour-related costs (e.g. travel, IT, recruitment), and indirect costs (e.g. consulting and environmental services). It has been developed using a bottom-up approach, supported by supplier quotes, benchmarks, and independently assured by GHD. This aligns with our standard cost estimation methodology applied across other regulated transmission projects.

The following sections summarise key cost drivers. Further detail on our assumptions and forecasting methodology is provided in the Labour and Indirect Capex Forecasting Methodology document, provided as an attachment to this Revenue Proposal.

4.5.5.1. Project Delivery Management – Project management costs

We forecast a total project management cost of $11.3 million over the 2026-31 regulatory period. In line with our standard CAM, 70 per cent of this forecast cost is treated as direct costs ($7.9 million), with the remaining 30 per cent allocated to indirect costs ($3.4 million).

To manage the delivery of the Project, we have established a dedicated Enabling CWO RNIP Project Team. This team is led by a Project Director who holds overall accountability for the successful delivery of the Project. The team structure has been deliberately designed to optimally align with the structure of our upstream agreements and the downstream D&C contract, with clear accountabilities and management lines (e.g. our team is structured around the different separable portions in the upstream Project Deed with EnergyCo, and the downstream D&C contract). The team is also managing the interface with ACEREZ under the Interface Deed.

The forecast reflects the resources required to manage five dispersed work sites, manage and oversee greenfield and brownfield works (including new transmission lines and upgrades to existing assets), and oversee ACEREZ's overcrossing of TL79. Further, ongoing contractor labour constraints have reduced the availability of experienced personnel in the market and, in turn, increased the need for greater supervision by our internal resources in order to deliver this critical work safely and reliably.

We consider the forecast cost reflects the minimum incremental level of labour and support necessary to manage the criticality and tight timelines of this Project. To ensure our forecast is efficient and reasonable, we have benchmarked the level of project management resourcing against comparable projects previously delivered by Transgrid and found our forecast to be consistent with established norms for projects of similar complexity and scope.

4.5.5.2. Project Delivery Management – Construction management costs

We forecast a total construction management cost of $19.3 million, comprised of direct labour and labour-related costs of $13.5 million and $5.8 million of indirect costs.

Construction Management includes the oversight and coordination of the D&C contractor's site-based construction activities to ensure the Project is delivered safely, efficiently, and in accordance with agreed quality standards. This function is critical to ensuring compliance with technical specifications, regulatory obligations, and safety requirements throughout the construction phase. Key factors influencing the level of construction management effort include:

- a high volume of brownfield construction activities, requiring close supervision to avoid unplanned outages and protect existing Transgrid assets
- remote and geographically dispersed worksites, necessitating frequent and lengthy travel to site by staff, which increases overall resourcing requirements
- continuous on-site Transgrid presence, required to promptly resolve issues and prevent delays or cost overruns in contractor delivery
- 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)
- high risk nature of the work under workplace health and safety (WHS) legislation.

To address these challenges, we have adopted a proactive and informed approach to Construction Management, drawing on lessons learned from recently completed and in-progress projects. For example, our labour forecast reflects the need to quickly address issues on site, particularly around third-party interfaces to prevent potential delay claims[71]. This has resulted in a resourcing profile that ensures appropriate oversight is maintained without exceeding prudent expenditure levels.

Our construction management activities include:

- facilitating and reviewing on-site investigations (e.g. geotechnical assessments where tower locations have been finalised and access track investigations) to support final design and construction planning
- conducting ongoing constructability reviews to identify and mitigate delivery risks
- finalising construction related management plans with the D&C contractor before starting construction (e.g. Construction Management Plan, Work Health and Safety Management Plan, Outage Plans and Waste Management Plan)
- coordinating contractor safety inductions, training and onsite construction preparations to ensure compliance with safety and site access requirements
- monitoring and measuring construction works to verify performance and inform commercial contract management, including variation and claim approvals
- facilitation and oversight of ACEREZ's overcrossing of Transgrid's existing TL79 transmission line
- supervision activities for safety, environmental compliance, adherence to construction designs, measuring progress, measuring changes to baseline assumptions, maintaining site records, providing inputs to commercial disputes, facilitating access, site audits and continuous reporting of overall project status

[71] This has occurred on previous projects where property owners have limited access unless there were representatives from the client organisation present. This has resulted in delay to projects and subsequent claims from contractors.

- engagement with local community members, landowners, landholders, ACEREZ and electricity distribution businesses during construction to ensure positive engagement with local communities and reduce the risk of impact to the electricity supply in the areas affected by the projects.

We are also responsible for commissioning all substation works. This includes final commissioning of the line protection schemes and in-service load checks to verify directional protection schemes (or non-directional where line injections are not feasible) following energisation of the line. These works will be carried out by our trained and qualified personnel, who possess the highly specialised skills and expertise required to safely and effectively perform commissioning activities. This ensures the continued safety, reliability, and security of the network.

We have adopted a proactive and informed approach to establishing the construction management team, drawing on lessons learned from recently completed and in-progress projects. For example, our approach to resourcing addresses the need to quickly resolve issues on site, particularly around third-party interfaces to prevent potential delay claims[72].

This results in a resourcing profile that ensures appropriate oversight without exceeding prudent expenditure levels. We have benchmarked the level of team resourcing against similar projects we have delivered and found that overall the level of resourcing for the Project is comparable.

4.5.5.3. Project Delivery Management – Commercial management costs

We forecast a total commercial management cost of $10.9 million, comprised of direct labour and labour-related costs of $7.6 million and $3.3 million of indirect costs.

The commercial management function is responsible for managing, administering and coordinating the suite of commercial arrangements required to deliver the Project. This includes managing upstream agreements with EnergyCo and ACEREZ, and downstream delivery contracts with the D&C contractor and equipment suppliers.

Key responsibilities of the commercial management function include:

- maintaining alignment across all agreements, particularly in relation to key milestones, technical requirements, and change management
- managing commercial communications and formal correspondence with EnergyCo, ACEREZ and the D&C contractor
- leading the resolution of commercial claims, disputes, and variations
- providing commercial input into project reporting, risk management, and stakeholder governance processes.

The complexity and interdependencies of these agreements give rise to material commercial risk. Any misalignment of contractual scope, schedule, or performance obligations between parties can lead to disputes, delivery delays, or financial penalties. This function is therefore essential to ensuring that contractual obligations are met, risks are proactively managed, and changes are coordinated across the contractual arrangements and interfaces.

[72] This has occurred on previous projects where property owners have limited access unless there were representatives from the client organisation present. This has resulted in delays to projects and subsequent claims from contractors.

Given the Project's complex and unique commercial framework, a dedicated commercial contract management team is essential to proactively manage commercial risks, align interdependent upstream and downstream agreements, and avoid potentially costly and lengthy disputes, to provide prudent and efficient outcomes.

4.5.5.4. Other support and corporate costs

The total forecast capex of $8.3 million for other support and corporate labour and labour-related costs relates to project team resources needed for ongoing WHS, regulatory, procurement and legal support throughout the delivery phase of the Project. This is comprised of direct labour and labour-related costs of $5.8 million and $2.5 million of indirect costs.

The resources required for these deliverables have been determined based on a bottom-up assessment of the scope of work. The other support and corporate work program includes:

- safety supervision of the construction works performed by the D&C contractor, which includes continuous onsite presence of Transgrid safety personnel at all worksites to monitor the works. This is critical to ensure the safety of the works and prevent issues to the Transgrid network
- minor ongoing regulatory support during the delivery phase of the Project
- procurement support to assist with the engagement and management of contractors and consultants other than the D&C contractor, and
- internal legal support to assist with the management of legal issues that may arise under upstream agreements with EnergyCo, downstream agreements with the D&C contractor, or in relation to third-party landholders. This allowance relates solely to internal legal resources and is separate from any provision for external legal advice.

4.5.5.5. Non-labour indirect costs

We forecast $3.2 million in non-labour indirect capex for the Project, primarily comprised of insurance premiums ([redacted] and costs associated with biodiversity and planning requirements ($1.4 million).

Insurance premiums are required under the D&C contract and cover the construction period. The forecast is based on estimates provided by our insurance broker, Lockton Australia. Insurance coverage includes Contract Works insurance (to protect the works from damage), and Construction Liability insurance (to cover Transgrid's legal liability to third parties for property damage and/or bodily injury). These insurance costs are non-recurring and relate only to the construction phase. Ongoing operational insurance post-commissioning is separately accounted for in our opex forecast.

The environmental component of the forecast supports compliance with biodiversity and planning requirements. This includes the cost of credit transfer deeds and associated legal services needed to establish biodiversity offset sites. The estimate is informed by subject matter expert advice and costs incurred on similar projects.[redacted]

4.5.6. Labour escalation

Our labour costs were prepared using real 2025-26 dollars. Labour escalation needs to be applied from 2026-27 to ensure costs are representative of the values we will incur in the regulatory period.

Where possible, we have adopted the labour escalators in the AER's 2023-28 Revenue Determination. Given that the AER's determination only includes escalation to 2027-28, we have extrapolated the forecast by setting the 2028-29, 2029-30 and 2030-31 real labour escalators equal to the average of that adopted by the AER for 2026-27 to 2027-28. Table 4-15 sets out the labour escalators used for each year of the regulatory period.

Table 4-15 Real labour escalation forecast for the 2026-31 regulatory period

Component	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Real labour escalation (%)	0.43%	0.30%	0.37%	0.37%	0.37%	N/A
Real labour escalation ($M, Real 2025-26)	0.1	0.2	0.0	-	-	0.3

We adopted the same real labour escalation rates when calculating our forecast opex (Chapter 5).

4.6. Deliverability of the Project

Section 5.4.4 of the AER's Regulatory Information Notice requires us to outline the extent to which the forecast capex can be realistically undertaken during the 2026-31 regulatory period with respect to the ability of Transgrid to:

- obtain finance
- source physical resources (i.e. labour and materials)
- manage and undertake the forecast capex proposal and forecast opex proposal.

The Project is being delivered at the same time as our program of BAU works, EII projects and workstream of contingent and actionable major projects. We recognise that success in delivering the Project is dependent on coordination and optimisation of our workstreams due to pressures from the domestic and international markets competing for equipment, materials and resources.

Transgrid is owned by large global infrastructure investors with long term investment horizons and significant capital to deploy. We have a proven track record of securing the necessary debt and equity funding to support capital growth projects.

Our securityholders have provided a total of $4.7 billion in equity commitments since 2021 to support growth projects including Project EnergyConnect, HumeLink, VNI West CPA1 and other network capital growth.

We also have a proven track record of obtaining debt capital with total debt facilities in excess of $10 billion supported by:

- access to diversified sources of capital across multiple markets and tenors including the bank debt market (with strong banking relationships across domestic and international lenders), Institutional Term Loan market, the Australian Medium Term Note market, US Private Placements and hybrid capital and concessional government loan funding through the Clean Energy Finance Corporation.
- a strong investment grade credit rating at Baa2 by Moody's and BBB by Standard and Poor's.

The Project is the first RNIP to be connected to our existing backbone 500kV transmission network. We have taken a thoughtful approach to delivering and operating the Project, focusing on effectively managing the specific Project challenges and optimising project outcomes. Drawing from lessons learned from recent and ongoing projects, we have adapted our delivery strategy. We are adopting a proactive and informed project, construction and commercial management model, ensuring we are adequately resourced to prevent any potential delays and associated cost overruns. This is critical to ensure we meet the 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.

Where possible, we will leverage our Shared Services Model[11] to utilise existing internal subject matter experts and systems for cost-efficient delivery of these support functions. This approach helps minimise duplication, ensures alignment with corporate processes, and provides flexibility to scale resourcing in response to workload changes over the course of the Project. 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.

We have benchmarked the level of resourcing against similar projects we have delivered and found that overall, the level of resourcing is comparable.

The D&C contractor will procure materials as specified in the D&C contract. We will also directly procure a range of high voltage plant, equipment and secondary systems utilising our existing panel arrangements to reduce the risk of equipment-related delays (due to our greater market power and ability to reprioritise equipment across the network). These items will be provided as free issue items to the D&C contractor for the augmentation and connection works.

To ensure our contractual timelines are met, we have also:

- engaged early with delivery partners through an ECI process to address delivery risks and enable timely mobilisation
- utilised separable portions under the D&C contract, eliminating the risk of the contractor claiming a single delay or variation that has a consequential impact on other scopes of work
- adopted a design strategy where we undertook more of the design work in key areas, ensuring this could be completed in parallel to procurement.
- undertaken to complete the commissioning works of the assets constructed, following experiences on recent projects where external contractors held this responsibility and delays occurred.

Overall, we consider this approach ensures the deliverability of the Project and means the capex forecast and opex forecast can be managed and undertaken within the 2026-31 regulatory period.

4.7. Independent external validation

We engaged GHD to undertake an independent verification and assessment of our capex forecast for the Project. GHD independently verified and assessed:

- whether the scope of the Project is appropriate to meet the requirements of the Consumer Trustee Authorisation and the Project Deed
- whether the capex forecast includes any payments required to be made by us to the Infrastructure Planner under any contractual arrangement
- the accuracy and supportability of the capex forecast at this stage of the Project using a range of assurance techniques. These include validation against tender results, benchmarking against comparative projects, selection testing, recalculation, and alignment with industry practice
- whether capex costs for development and construction for the network infrastructure project are prudent, efficient, and reasonable.

Overall, GHD concluded that our development and construction capex is prudent, efficient and reasonable. GHD's independent review therefore supports the consistency of our forecast capex with that which would be incurred by a prudent, efficient and reasonable network operator.

GHD's report is provided as an attachment to this Revenue Proposal.

5. Forecast opex

This chapter sets out total forecast opex for the Project over the 2026-31 regulatory period. This should be read in conjunction with the Opex Forecasting Methodology, which details our forecasting methodology and is provided as an attachment to this Revenue Proposal.

5.1. Overview

- We are committed to achieving the lowest sustainable whole-of-life costs for the Project, with a total opex forecast of **$28.8 million** for the 2026-31 regulatory period. This includes the minimum labour and support resources required to meet our contractual and regulatory obligations while maintaining delivery standards and operational integrity.
- Our forecast is developed in accordance with our ISO55001-certified Asset Management System and is based on historical performance data and pricing from existing agreements to ensure it is realistic, reasonable, and aligned with internationally-recognised best practice methodologies.
- Due to the Project's complex and unique commercial arrangements, opportunities for commercial efficiency savings are limited at this stage. Nonetheless, we have identified and applied non-commercial operational efficiencies where feasible, and we remain committed to continuous improvement in future determinations.

Operational costs have been built bottom-up utilising a tailored approach to meet the opex objectives under EII Chapter 6A, including:

- meeting or managing the expected demand over the regulatory period
- complying with all regulatory requirements
- maintaining the safety of the Project through the supply of the network services.

In developing our forecast, we also considered our operational and maintenance warranty obligations and specific obligations under our electricity transmission licence.

Our forecast takes into account our contractual and regulatory obligations under the suite of new agreements between EnergyCo, ACEREZ and Transgrid for this Project. These obligations require dedicated resources to ensure effective implementation and compliance. The forecast reflects the minimum level of labour and support necessary to meet these mandatory obligations while maintaining delivery standards and operational integrity.

Our opex forecast for asset management has been prepared in accordance with our Asset Management System, which has been independently certified to comply with the international asset management standard ISO55001. This system underpins a disciplined and structured approach to managing our assets, focusing on optimising performance, managing risk, and delivering value for NSW energy consumers. Compliance with ISO55001 ensures a continuous improvement cycle, reinforcing robust decision-making, transparency, and stakeholder confidence.

Our proposed expenditure forecast draws on historical performance data and pricing from existing agreements to ensure our forecast is both realistic and reasonable. The unique nature of the commercial arrangements, combined with their scale and complexity, means that opportunities for commercial efficiency savings at this stage are limited. However, other non-commercial operational efficiencies have been applied as identified. We are committed to continuous improvement and will apply lessons learned to enhance efficiency in future determinations for this Project.

Based on this approach, our total forecast opex for 2026-31 regulatory period is $28.8 million. This represents the minimum incremental cost required to operate and maintain new and modified assets, while meeting our regulatory and contractual obligations. Table 5-1 provides a breakdown of our incremental opex forecast by category over the regulatory period. The following sections provide key details on our forecasting assumptions, basis of forecast and key drivers, with further explanation included in our Opex Forecasting Methodology.

Table 5-1 Incremental forecast opex for the Project ($M, real 2025-26)

Sub-category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Maintenance costs (excluding labour escalation)	-	0.1	0.5	0.8	0.2	1.6
Operating costs (excluding labour escalation)	0.5	2.5	5.9	7.2	6.6	22.8
Insurance costs	-	0.3	0.3	0.4	0.3	1.3
Vegetation integrity rehabilitation costs	0.1	0.1	0.1	0.1	0.1	0.7
Strategic Benefit Payments	-	0.1	0.2	0.2	0.2	0.7
Real input cost escalation	0.0	0.1	0.2	0.3	0.3	0.9
Total opex excluding debt raising costs	**0.6**	**3.2**	**7.3**	**9.0**	**7.8**	**27.9**
Debt raising costs	0.1	0.2	0.2	0.2	0.2	0.9
Total opex including debt raising costs	**0.7**	**3.3**	**7.5**	**9.2**	**8.0**	**28.8**

5.2. Key opex assumptions

Table 5-2 details the key assumptions underpinning our opex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.2(6) of the EII Chapter 6A, as discussed in Chapter 13 of this Revenue Proposal.

Table 5-2 Opex key assumptions

Key assumptions	
Legislative and regulatory obligations	Our opex forecasts are based on our current legislative and regulatory obligations, our transmission operator's licence requirements, Consumer Trustee Authorisation, and contractual commercial arrangements with the Infrastructure Planner (i.e. EnergyCo) and CWO REZ Network Operator (i.e. ACEREZ).
Bottom-up-build	Our opex forecast reflects a bottom-up build because no base year is available from a preceding regulatory period.
Alignment with capex forecast	Our incremental opex forecast for the Project aligns with our capex forecast, in that opex has been forecast in alignment with our capex assumptions as follows:

Key assumptions	
	• maintenance activities are assumed to begin once capital assets are installed and commissioned • operating costs are assumed to commence upon Project commissioning in 2027-2028, with the exception of regulatory submission activities. These activities are expected to begin in the first year of the regulatory period (i.e. 2026-27), to support annual updates and adjustment mechanisms. • Strategic Benefit Payments assumed to commence once the Project reaches the energisation phase, targeted for February 2028 • operational insurance coverage will commence once the assets are commissioned (with the premium costs incurred prior to the year of coverage), and • debt raising costs are assumed to be incurred when new debt is required to fund capital investment.[73]
Cost allocation and capitalisation	Our opex forecasts reflect our expenditure capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services.
Cost escalations	The cost escalations that we have applied in developing our opex forecasts are representative of the increased costs that we will incur in the next period.[74]
Cost pass throughs and revenue adjustments	The AER will approve our proposed nominated pass through events and revenue adjustments as set in Chapter 10 of this Revenue Proposal.

5.3. Forecasting methodology and basis for opex forecast

- We have adopted a bottom-up-build forecasting method to develop a robust and transparent estimate of the Project's incremental opex over the 2026-31 regulatory period.
- This approach is consistent with AER-accepted practices for other ISP and EII projects and reflects our internal budgeting methodology. Our total opex forecast includes maintenance of new assets, operating costs to meet regulatory and contractual obligations, insurance premiums, vegetation rehabilitation, and landowner payments under the NSW Government's Strategic Benefit Payments Scheme.
- Forecasts are established using unit rates, consistent with existing regulatory approaches (where relevant) and escalation methods, ensuring a prudent and efficient opex estimate.

[73] Debt raising costs are transaction costs incurred each time debt is raised or refinanced as well as the costs of maintaining the debt facility. This reflects benchmark costs, and not actual debt raising costs. The inclusion of debt raising costs as part of opex allowance is in line with the AER's building block approach. Debt raising costs are included in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers such as Transgrid refinancing debt.

[74] 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 and 2027-28.

5.3.1. Bottom-up-build forecasting method

As noted above, we have used a bottom-up-build to forecast incremental opex for the Project over the 2026-31 regulatory period. This is because:

- no base year is available for the Project because this is our initial Revenue Proposal for the Enabling CWO RNIP. This means that we are not able to apply the base-step-trend approach to forecast opex
- it is consistent with the approach used to derive our internal budget for the Project over the regulatory period
- it is consistent with the opex forecasting approach for ISP projects, which would be subject to a Contingent Project Application under the NER. The AER has accepted a bottom-up-build approach to determine forecast opex for these types of projects.

A bottom-up-build approach allows for an accurate estimation of the required incremental opex for the Project. This involves:

- multiplying unit rates by forecast volumes for maintenance activities[75]
- forecasting expected labour requirements and non-labour expenses for operating activities
- identifying the number and cost of internal resources required to meet our contractual obligations, manage our commercial contracts and meet our regulatory requirements
- basing the operational insurance premium costs on the independent expert report from our broker
- calculating strategic benefit payments in accordance with the NSW Government's Scheme
- applying labour escalators as relevant, and
- including an allowance for debt raising costs.

5.3.2. Key opex categories

Our total forecast opex of $28.8 million is comprised of the following key categories:

- **Maintenance costs** – These incremental costs are estimated based on the scope of maintenance activities for the newly built transmission lines and modifications to existing substations. In addition to the main base scope of work, Transgrid interface equipment will be installed at BCSS to allow integration of the REZ into Transgrid's network, and maintenance of this equipment has been included in the opex forecast. The forecast includes routine maintenance and inspections, as well as an allowance for condition-based and defect maintenance. We have leveraged the scale of our maintenance regime for the existing NSW transmission network in developing this forecast.
- **Operating costs** – These costs reflect the additional labour and operational activities necessary to manage the expanded assets, interface with EnergyCo and ACEREZ, comply with contractual obligations and meet our regulatory obligations for the Project. This includes asset management, network planning, network operations, commercial contract management and preparation of regulatory submissions.
- **Insurance costs** – These costs account for the estimated premiums for industrial special risks and operational third-party insurance covering the Project assets once commissioned.
- **Vegetation integrity rehabilitation costs** – These costs cover works to restore and maintain native vegetation to its target condition.

[75] Maintenance unit rates are based on standard job costs comprising two components: labour and material rates. These rates are multiplied by the required labour resources and material volumes to calculate total maintenance costs.

- **Strategic Benefit Payments** – These ongoing payments compensate private landowners impacted by the Project, in line with the NSW Government's Strategic Benefit Payment Scheme.

5.3.3. Basis for opex forecast

Table 5-3 sets out our total forecast opex by component, together with a summary of the basis of the forecast.

Table 5-3 Basis for determining forecast opex, by category ($M, real 2025-26)

Opex category	Value	Basis for forecast expenditure
Maintenance costs (excluding labour escalation)	1.6	Current and proposed maintenance activity unit rates multiplied by projected volumes of maintenance activities
Operating costs (excluding labour escalation)	22.8	Projected labour requirements based on incremental opex activities required to meet regulatory and contractual obligations multiplied by labour rates for each resource type
Insurance costs	1.3	Based on independent report from Lockton Australia
Vegetation integrity rehabilitation costs	0.7	Based on works required within the easement clearance zone for the Project
Strategic Benefit Payments	0.7	Calculated in accordance with NSW Government's Strategic Benefit Payments Scheme
Real input cost escalation	0.9	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 using the same approach in our 2023-28 Revenue Determination, as reflected in the PTRM
Total	**28.8**	

5.4. Key drivers of opex forecast

The total forecast opex of $28.8 million represents the minimum incremental cost required to operate and maintain new and modified assets, while meeting our regulatory and contractual obligations. Developed using a bottom-up-build approach, the draws on actual cost data, and established agreements, frameworks and best practice methodologies. We consider the forecast to be prudent, efficient and reasonable, ensuring operational readiness and long-term network performance at the lowest cost to consumers.

As the first REZ to be connected to the NSW transmission network, the CWO REZ introduces a step-change in operational complexity. It brings new challenges in network planning, asset management, real-time network operations, and commercial management. These changes create obligations not present in our NER transmission projects and require targeted responses to ensure compliance, maintain system stability and enable cost recovery.

Majority of our opex forecast is expected to commence from 2027-28, aligning with the commissioning of the first REZ assets. The following sections summarise the key activities and cost drivers, with further detail provided in the Opex Forecasting Methodology.

5.4.1. Maintenance costs

Over the 2026-31 regulatory period, our total forecast maintenance cost is $1.6 million. Given the newness of the assets, we expect to incur modest costs to cover relatively minor routine inspection, condition based and corrective maintenance activities from 2027-28, the year following when assets are first commissioned.

Key elements of the forecast routine maintenance opex are:

- [redacted] on circuit breakers, instrument transformers and disconnectors installed at the various substations
- [redacted] liability period transmission line inspections for new and modification structures on lines
- [redacted] of automation, communication and metering interface equipment with ACEREZ installed at BCSS (assuming operation by ACEREZ).

These activities are required to meet safety and reliability standards, reflecting only the maintenance necessary to uphold asset performance, meet regulatory and contractual obligations, and ensure long-term network reliability in line with good industry practice and our certified Asset Management System.

5.4.2. Operating costs

Our total forecast operating costs of $22.8 million reflect additional work required to manage the operational, commercial and regulatory complexities of the Project and CWO REZ. These costs include asset management, network planning, network operations, commercial contract management and regulatory activities.

5.4.2.1. Asset management

We forecast total asset management costs of $1.9 million over the 2026-31 regulatory period. This reflects the cost of incorporating new and modified assets in accordance with our Asset Management System and ensuring compliance with our licence and contractual obligations.

A key driver of this forecast is the need to meet our commercial commitments under agreements with ACEREZ, including obligations related to protection and control schemes, operational protocols, data and communication standards, and site access. The forecast also accounts for the preparation, implementation and regular review of asset management plans for both new Transgrid assets and interface assets with ACEREZ. In addition, it covers routine asset management activities such as updating registers, data platforms and maintenance plans, spares management, and ensuring alignment with corporate governance frameworks.

These costs are prudent, consistent with our overall asset management practices and are essential to maintaining integrity of our Asset Management System. They support safe and reliable operation of our network, and ensure ongoing licence compliance.

5.4.2.2. Network planning

We forecast total network planning costs of $2.1 million over the 2026-31 regulatory period. This reflects the additional and ongoing work required to integrate CWO REZ into our broader transmission network planning.

A key driver of this forecast is the need for coordinated joint planning with EnergyCo, as the Infrastructure Planner, to ensure efficient integration. This includes reviewing and incorporating CWO REZ materials into the Transmission Annual Planning Report and ongoing assessment of demand and renewable energy forecasts within CWO REZ into our network planning. This will require regular updates to network models and system analysis tools, system integration studies to assess impacts on stability limits and fault levels, and ongoing monitoring of power quality at REZ interfaces.

5.4.2.3. Network operations

We forecast total network operation costs of $3.9 million over the 2026-31 regulatory period. This reflects the increased complexity of real-time network operation once CWO REZ is integrated into the NSW transmission network.

As such, additional staffing and system enhancements are needed for:

- 24/7 monitoring and response by a team of shift workers and on-call engineers
- increase in system alarms, requiring additional FTEs to monitor and respond
- managing increased complexity due to the variability of renewable generation, necessitating adjustments in system operations, protocols and processes such as:
  - maintenance of customer operating protocols, operating manuals, and High Voltage Operating Diagrams
  - outage management including contingency planning and clash avoidance
  - management of electrical data models for state estimator
  - provision and management of additional SCADA data points for new assets
  - management of changes to data interfaces with new connections

These activities are essential to maintain system stability, ensure reliability, and manage the operational interfaces between the CWO REZ generation and the NSW transmission network.

5.4.2.4. Commercial contract management

We forecast total commercial contract management costs of $7.0 million over the 2026-31 regulatory period to support the new, ongoing and complex commercial contract management activities required for the Project. This reflects the scale and complexity of the commercial framework developed for the Project, which establishes a series of interdependent contractual relationships between Transgrid, EnergyCo and ACEREZ. These arrangements are the first of their kind in NSW and are critical to enabling the coordinated delivery and operation of the REZ into the NSW's transmission network.

The CWO REZ framework includes multiple detailed and interconnected agreements such as the Transgrid Non-Contestable Augmentation Project Deed, Interface Deed, REZ Network Connection Agreement, Line Crossing Deed and Coordination Deed. Managing these agreements requires continuous commercial oversight to ensure we meet our obligations, hold counterparties accountable, manage disputes, and respond to commercial and legal events across multiple contractual interfaces. These are not static or routine functions, rather they are ongoing, resource-intensive responsibilities that are essential to safeguard Transgrid's commercial position.

To develop a robust opex forecast, we undertook a structured assessment of each agreement to identify ongoing contractual obligations and compliance requirements. These were then mapped to relevant internal roles and assessed for the level of effort required to fulfil each responsibility. This approach was informed by our experience with similar commercial frameworks and adjusted for the unique features of the CWO REZ arrangements.

The resulting workload is a substantial and sustained workload that requires specialist commercial expertise. At the core of this function is the delivery and coordination of key commercial obligations across multiple agreements. This includes the provision of connection services and regular updates to the data book under the REZ Network Connection Agreement, management of quarterly and annual charges, and coordination of formal notices for outages and access rights under the Line Crossing Deed. Equally critical is the administration of quarterly payments and charges, which require precise internal calculations, assurance processes, and formal agreement with counterparties.

Beyond routine administration, this commercial function plays a critical role in managing events such as disputes, defaults, force majeure claims, changes in law, and potential termination scenarios. It also encompasses the negotiation and execution of variations, amendments and augmentations to agreements as the Project evolves.

We consider this overlay of commercial stewardship is essential to mitigate risk, uphold contractual integrity and maintain effective partnerships across the REZ. Without it, there is a risk of legal, financial and operational consequences, with costs that could ultimately be passed on to consumers. This forecasted expenditure is therefore necessary to ensure the REZ is operated and managed in a commercially sound and sustainable manner.

5.4.2.5. Regulatory activity costs

We forecast total regulatory activity costs of $4.6 million over the 2026-31 regulatory period to support the regulatory activities necessary for the Project. This forecast reflects the ongoing effort required to ensure that we can recover our prudent, efficient and reasonable costs in accordance with the EII Framework.

Key regulatory responsibilities during this period include the preparation of annual updates and applications relating to any triggered adjustment mechanisms, as well as the development and submission of the 2031-36 Revenue Proposal. These processes require detailed financial modelling, technical analysis, and cross-functional coordination to ensure that cost forecasts are robust, well-justified and clearly communicated to the AER.

To meet these obligations, ongoing labour resources are essential. Specialist expertise in regulatory finance, and commercial arrangements is needed to ensure that submissions accurately reflect the Project’s cost drivers and contractual framework. Without dedicated resources in place, there is a risk that critical inputs may be delayed or incomplete, which could undermine cost recovery, delay regulatory approvals, and adversely affect the delivery and operation of the Project.

5.4.2.6. Other costs

We forecast total other operating costs of $3.3 million over the 2026-31 regulatory period. These costs relate to essential activities required to meet statutory, regulatory and reporting obligations that are not otherwise captured in the preceding categories.

This includes finance function support for annual reporting and administration of Strategic Benefit Payments, along with external audit fees and associated internal resourcing needed to maintain financial compliance. It also includes ongoing minor delivery costs associated with property matters, access track planning and management, and coordination of routine maintenance works.

These costs are necessary to ensure compliance with financial, legal and operational requirements and to support the effective day-to-day functioning of the Project following commissioning. The forecast represents a prudent and efficient allocation of resources aligned with good industry practice.

5.4.3. Insurance costs

We expect to incur incremental operating expenditure for insurance premiums once Project assets are commissioned. Two types of insurance are required for our regulated infrastructure assets:

- **Industrial special risks** – this covers physical loss, destruction or damage to the assets occurring during operation
- **Third-party liability** – this covers Transgrid's legal liability for third party property damage or bodily injury occurring during operation of the assets.

These forms of insurance are prudent as they cover risks that are both material and that we cannot easily (or cost effectively) avoid, and are consistent with standard commercial and regulatory practice for electricity network service providers.

To inform our forecast, we engaged an independent insurance broker to estimate the cost of insurance during the operational phase of the Project. In addition, we forecast a one-off increase of $0.06 million in 2029-30 to prepare insurance coverage for the subsequent regulatory period, consistent with our recent experience.

Based on these inputs, we forecast a total insurance cost of $1.3 million over the 2026-31 regulatory period. This forecast represents a prudent and efficient allocation of cost to ensure adequate protection against operational risks and to maintain regulatory compliance.

5.4.4. Vegetation integrity rehabilitation costs

The Project is required to maintain a target native vegetation condition state (referred as vegetation integrity) on-easement, as defined in the biodiversity impact assessment under the Infrastructure Approval.

While routine operational maintenance activities are designed to avoid and minimise impacts to native vegetation at all times, it is likely to be acknowledged in the approval that routine maintenance activities may temporarily impact native vegetation below the target condition state. As a result, rehabilitation works will be required will be required following each easement maintenance event to restore native vegetation to its approved condition, in line with environmental mitigation measures.

We forecast total vegetation integrity rehabilitation costs of $0.7 million over the 2026-31 regulatory period. This includes delivery by qualified bush regeneration crews, drawing on our recent experience in similar projects requiring vegetation rehabilitation. The forecast also includes internal costs to oversee and verify that the rehabilitation works meet the target vegetation condition as specified in the biodiversity assessment. This includes delivery by qualified bush regeneration crews, drawing on our recent experience in similar projects requiring vegetation rehabilitation. The forecast also includes internal costs to oversee and verify that the rehabilitation works meet the target vegetation condition as specified in the biodiversity assessment.

5.4.5. Strategic Benefit Payments

To support the transformation of NSW's electricity system, the NSW Government has introduced the Strategic Benefit Payments (SBP) Scheme. This scheme provides additional payments to eligible landowners (excluding Public Authority in NSW) who host new high voltage transmission infrastructure on their land, including for projects such as CWO REZ.

The SBP Scheme provides annual payments over a 20-year period, recognising the critical role that landowners play in enabling the development of essential energy infrastructure and ensuring they share in the long-term benefits of this investment.

We forecast total SBP-related opex of $0.7 million over the 2026-31 regulatory period. This includes annual payments to eligible landowners in accordance with the NSW Government's SBP Scheme, commencing once the Project is commissioned (energised). The forecast also includes internal costs associated with administering and processing these payments. This expenditure is considered prudent and efficient, aligned with the NSW Government policy. Further details on the calculation of SBP are provided in the Opex Forecasting Methodology.

6. RAB, depreciation and financeability

This chapter sets out forecast changes in the Project's asset base and the forecast return of capital (depreciation). These are calculated within the PTRM which is provided as an attachment to this Proposal.

6.1. Overview

- Our opening RAB value as at 1 July 2026 is **$167.8 million** (nominal).
- Our regulatory depreciation over the 2026-31 regulatory period is **$6.4 million** (nominal).
- As part of our calculation of regulatory depreciation, 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 over the 2026-31 regulatory period.

Our RAB reflects the value of assets required to deliver the Project. The opening RAB is the capitalised value of capex pre-period costs, which we incurred prior to the start of the 2026-31 regulatory period, adjusted for financing costs.

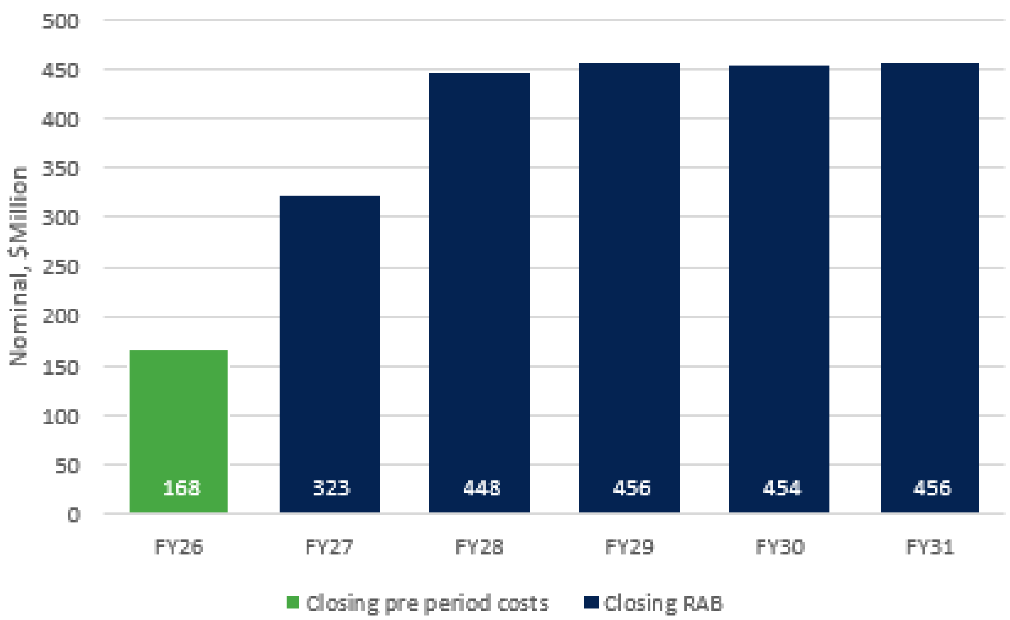
The RAB is projected over the 2026-31 period using forecast inflation, capex, and depreciation. Forecast capex and pre-period costs are allocated to asset classes that reflect the nature of the assets created. That expenditure is depreciated based on the standard economic lives that range from short life assets, such as secondary systems (with a 15-year life) to long life assets such as transmission lines (with a 50-year life). We have used the standard asset lives in the AER's 2023-28 Revenue Determination, with some exceptions. We have added two new asset classes for each category of biodiversity offsets (i.e. stewardship sites and direct payments and other costs), consistent with the HumeLink Stage 2 and VNI West Stage 1 Contingent Project Application (CPA) determinations. We have also added a 'financeability' asset class to allow us to accelerate depreciation over the 2026-31 regulatory period to ensure the Project remains financeable.

The RAB value is used to calculate the revenue required to recover our efficient costs associated with the return on capital and depreciation. We propose that the value of the RAB is calculated (or rolled-forward) over the 2026-31 period, consistent with the EII regulatory framework and PTRM. The RAB value is adjusted each year to reflect:

- increases due to inflation (indexation)
- increases due to new capex net of any contributions from customers or proceeds from any asset sales, and
- removal of straight-line depreciation.

Our opening RAB value in July 2026 is $167.8 million, as shown in Figure 6-1.

Figure 6-1 How the RAB changes over time ($M, Nominal)



6.2. Establishing the opening RAB as at 1 July 2026

Table 6-1 sets out the opening RAB as at 1 July 2026, which is driven by:

- pre-period capex incurred in 2020-21 and 2021-22
- Infrastructure Planner costs incurred from 2021-22 to 2025-26
- inflation and the allowed rate of return.

The opening value as at 1 July 2026 is estimated to be $167.8 million (nominal). This includes a financeability adjustment that reallocates $11.2 million (nominal) from the Secondary Systems asset class into a dedicated financeability asset class. This is discussed further in Chapter 6.5.

Table 6-1 shows the opening RAB by asset class as at 1 July 2026.

Table 6-1 Opening RAB by asset class as at 1 July 2026 ($M, nominal)

Asset class	Pre-period capex	Infrastructure Planner costs	Financing costs	Financeability adjustment	Opening RAB
Transmission lines	5.2	75.0	4.4	-	84.5
Substations	1.3	24.4	1.2	-	26.9
Secondary systems	0.5	10.1	0.5	(11.2)	-
Land and easements	0.3	18.3	0.6	-	19.2

Asset class	Pre-period capex	Infrastructure Planner costs	Financing costs	Financeability adjustment	Opening RAB
Biodiversity offsets – stewardship sites	0.3	7.1	0.2	-	7.6
Biodiversity offsets – direct payments and other costs	0.6	17.1	0.6	-	18.3
Financeability asset class	-	-	-	11.2	11.2
Total RAB	**8.2**	**152.0**[76]	**7.5**	**-**	**167.8**

6.2.1. Pre-period costs

We undertook activities and incurred capex prior to the commencement of the 2026-31 regulatory period. To ensure that we can recover these costs, we have incorporated them into our proposed revenue for the 2026-31 regulatory period. We have achieved this by incorporating this pre-period capex into the opening RAB for the 2026-31 regulatory period. We have also included the financing costs, which cover the time value of money over the period from when we incur the pre-period costs to 30 June 2026. As shown in Table 6-1, the estimated pre-period capex is $8.2 million.

Pre-period costs are discussed further in Chapter 4.4.

6.2.2. Infrastructure Planner costs

Infrastructure Planner costs reflect EnergyCo's expected costs of funding early development activities to 31 December 2026, initially under the Project Development Deed and subsequently under the Project Deed. The Project Deed requires us to reimburse EnergyCo for these amounts. Under the EII framework, we are entitled to recover these costs in our Revenue Determination.

In line with our accounting treatment of these costs, we have recognised the liability that arises to repay EnergyCo at the time that liability accrues and incorporated Infrastructure Planner costs incurred prior to 1 July 2026 into the opening RAB for the 2026-31 regulatory period[77]. We consider that this ensures consistency in the treatment of our RABs across projects, whilst also accounting for the time delay that arises from the initial funding of the costs by us to the reimbursement by EnergyCo e.g. in some cases, costs incurred in 2021-22 were not reimbursed until 2024-25.

We have also included the financing costs, which cover the time value of money over the period from when we accrue the pre-period costs to 30 June 2026.

6.2.3. Financing costs

Pre-period costs were capitalised to the opening RAB, along with associated financing costs. As shown in Table 6-1, these financing costs are estimated to be $7.5 million. These costs have been calculated using the allowed rates of return proposed in Chapter 7.6, assuming that expenditure is incurred in the middle of

[76] This aligns with the amount of early development activity costs expected to be incurred prior to 2026-27. The remainder of the Infrastructure Planner cost amount is expected to be incurred in the first half of 2026-27, as outlined in Table 4.4 above.

[77] The remainder of the Infrastructure Planner costs are recognised as incurred during the period from 1 July 2026 to 31 December 2026.

the year. For instance, capex incurred in the 2021-22 year is adjusted by half a year of the 2021-22 rate of return and one year of the 2022-23 rate of return to determine the closing value as at 30 June 2026.

6.2.4. Depreciation

No depreciation is applied to the pre-period costs or Infrastructure Planner costs when establishing the opening RAB. Once added to the RAB, these costs are then depreciated on an as commissioned basis.

6.3. Forecast RAB over the 2026-31 regulatory period

Table 6-2 sets out our forecast RAB value for each year of the 2026-31 period. We have derived the RAB values using the AER's PTRM, with minimal adjustments. Only actual and estimated capex attributable to the Project has been included in the RAB, in accordance with our CAM.

We have rolled forward the opening RAB value of $167.8 million (nominal) as at 1 July 2026 by:

- adding forecast indexation, which we have calculated based on the AER's December 2020 final decision on the treatment of expected inflation, which is also reflected in the AER's PTRM.[78]
- adding forecast net capex
- deducting straight-line depreciation
- deducting accelerated depreciation of the 'financeability asset'.

Table 6-2 RAB roll forward over the 2026-31 period ($M, Nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening RAB (1 July)	167.8	323.1	447.5	455.5	454.1
Forecast indexation	4.7	9.0	12.4	12.7	12.6
Net capex	155.1	127.3	12.6	-	-
Forecast straight line depreciation	(0.6)	(4.1)	(9.1)	(10.0)	(10.3)
Accelerated depreciation	(3.8)	(7.8)	(8.0)	(4.1)	-
Closing RAB	**323.1**	**447.5**	**455.5**	**454.1**	**456.4**

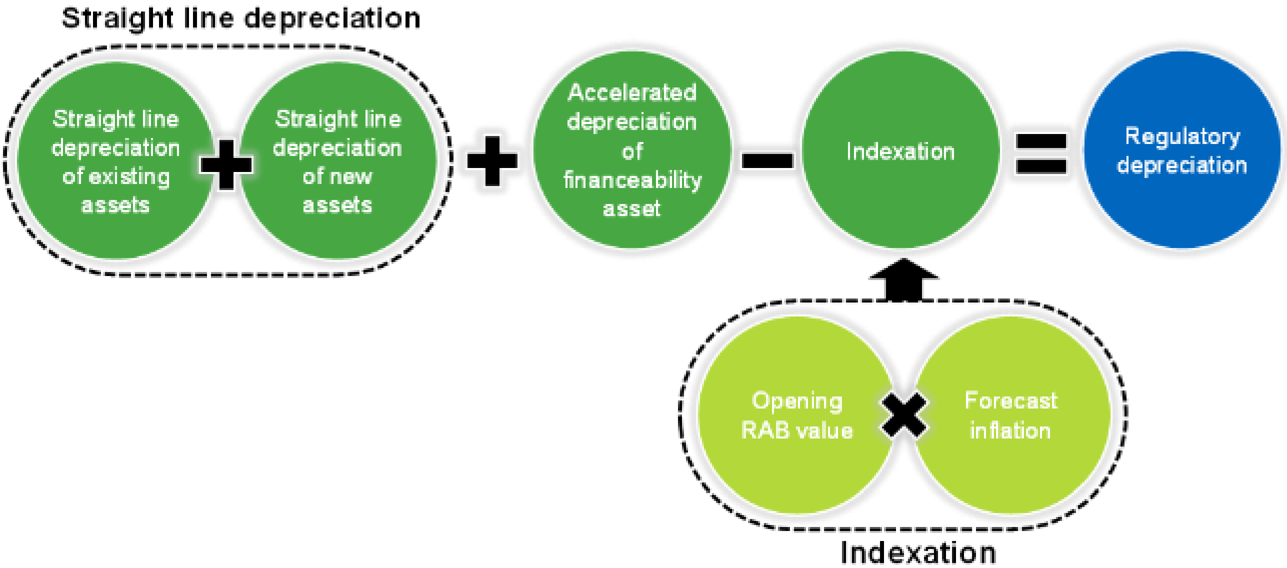
6.4. Depreciation methodology

Depreciation is the mechanism through which we recover our expenditure on our network investments over the economic life of the assets.

We have projected depreciation using the straight-lined depreciation method. Figure 6-2 shows the AER's approach to regulatory depreciation, which is to subtract forecast indexation (which increases the RAB) from straight line depreciation (which reduces the RAB).

[78] AER, Final position paper: Regulatory treatment of inflation, December 2020.

Figure 6-2 How regulatory depreciation is calculated



6.4.1. Straight-line depreciation

We have calculated straight-line depreciation for our existing assets (as at 30 June 2026) and forecast assets for the 2026-31 period within the AER's PTRM using the straight-line depreciation method for asset classes, on an as commissioned basis, with three exceptions.

We have applied an alternative depreciation profile for the two biodiversity offset cost asset classes, using as incurred capex rather than as commissioned capex. This aligns with the AER's position that depreciating biodiversity offset costs on an as-incurred basis better reflects the nature of these costs.[79]

We have also adopted an alternate depreciation profile for the financeability asset class, as discussed in Chapter 6.5.

Table 6-3 sets out our proposed standard asset lives. We propose to use the same asset classes and standard asset lives approved by the AER in its 2023-28 Revenue Determination for all asset classes except biodiversity offsets and equity raising costs. For these costs, we propose to adopt an asset life that reflects the weighted average of standard asset lives of all other assets, in line with the approach taken in HumeLink's Stage 2 Contingent Project Application Determination.

Table 6-3 Proposed asset lives

Asset class	Standard asset lives (years)
Transmission lines	50.0
Substations	40.0
Secondary systems	15.0
Land and easements	N/A
Biodiversity offsets – stewardship sites	45.8

[79] AER, Determination – Transgrid's HumeLink Stage 2 Delivery Contingent Project Application, 2 August 2024, p. ix.

Asset class	Standard asset lives (years)
Biodiversity offsets – direct payments and other costs	45.8
Financeability asset	3.0[80]
Equity raising costs	45.8

6.4.2. Indexation

Indexation for a given year is calculated by multiplying the opening RAB value by forecast inflation. In December 2020, the AER published its approach to estimating expected inflation, which is also reflected in its PTRM. We have applied the AER's approach to estimating expected inflation in this Revenue Proposal. Our forecast inflation is addressed in Chapter 7.7.

6.4.3. Regulatory depreciation

The calculation of the forecast straight-line depreciation, accelerated depreciation, indexation, and regulatory depreciation is presented in Table 6-4.

Table 6-4 Forecast regulatory depreciation ($M, Nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Forecast straight-line depreciation	0.6	4.1	9.1	10.0	10.3	34.1
Accelerated depreciation	3.8	7.8	8.0	4.1	–	23.7
Less forecast indexation	(4.7)	(9.0)	(12.4)	(12.7)	(12.6)	(51.4)
Regulatory depreciation	(0.3)	2.9	4.6	1.5	(2.3)	6.4

6.5. Financeability cashflow adjustment

Financeability refers to the ability of network service providers to efficiently (that is, without unnecessary costs) raise finance to fund their activities in the context of the framework used to determine regulated revenue.[81] Given that transmission is a critical enabler for the transition to net zero, improving the ability of TNSPs to efficiently access finance, where needed, to deliver projects in a timely and efficient way is in the long term interests of consumers. Delayed investment in transmission infrastructure would come at a cost to consumers. With transmission investment occurring in line with the timetable outlined in the ISP and the NSW Network Infrastructure Strategy, cheaper renewable energy sources such as wind and solar can be unlocked for consumers, reducing emissions and wholesale prices. This delivers benefits for consumers both now and into the future.

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

[80] The financeability asset class has a standard asset life of 15 years and a financeability asset life of 3 years.
[81] AEMC, Final rule determination – Accommodating financeability in the regulatory framework, March 2024, p. 38.

financeability issue.[82] In accordance with the EII framework and applicable AER guidance, we have assessed our financeability position and consider that a financeability adjustment is required.

As outlined above, we propose an adjustment to our depreciation schedule to accelerate depreciation of $23.7 million (nominal)[83] to ensure the Project is financeable in each year of the 2026-31 regulatory period.

6.5.1. Financeability test

Clause 6A.6.3A of EII Chapter 6A allows a network operator to include a proposed adjustment to the depreciation schedule to address a financeability issue, where specific conditions are met. This includes that the Project forms part of an actionable ISP project[84] and that a request for the same project has not previously been submitted.[85]

Additionally, to submit a financeability request, EII Chapter 6A also requires that where a concessional finance agreement for the actionable ISP project being assessed or for other actionable ISP projects (other than the project that the financeability request relates to) – that all benefits are being passed through to consumers or where the benefits are not being passed through, the concessional finance agreement specifies how the benefits are to be taken into account by the AER in applying the financeability test.[86]

If these conditions are met, the AER will apply the financeability test outlined in EII Chapter 6A to determine whether or not there is a financeability issue.[87] It will also have regard to its financeability guideline published under the NER[88,89] to ensure consistency in the treatment of financeability between the NER and EII frameworks.[90]

The financeability test requires the TNSP to:

- **Step one:** Calculate a financeability position without the assessed project using the PTRM to determine the MAR using the benchmark gearing ratio (as adjusted for any concessional finance arrangements)
- **Step two:** Calculate a financeability position using the same process above but including the project.

In assessing the financeability position of a network operator, the AER will consider four key metrics as outlined in Figure 6-3 below. To determine the financeability position, the average scores for each metric below are combined to calculate a weighted average quantitative score.

82 EII Regulation, cl. 47D(3), EII Chapter 6A, cl. 6A.6
83 This equates to $22.1 million (real 2025-26).
84 EII Chapter 6A, cl. 6A.6.3A(b)-(h).
85 EII Chapter 6A, cl. 6A.6.3A(d).
86 EII Chapter 6A, cl. 6A.6.3A(e).
87 EII Chapter 6A, cl. 6A.6.3A(i)(1).
88 AER, Financeability guideline, November 2024, p. 3.
89 EII Chapter 6A, cl. 6A.6.3A(
90 AER, Explanatory Statement: Final amendments to Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects, July 2024, p. 9.

Figure 6-3 Key metrics used to assess financeability

FFO interest coverage ratio

Measure of recurring operating earnings compared to the expected interest costs, calculated as the ratio between expected funds from operations (FFO) plus interest expenses, and interest expenses.

Net debt / RAB (gearing)

Level of debt compared to the overall value of the RAB. It will normally reflect the benchmark gearing ration set out in the RORI (currently 60 per cent) but may be adjusted downwards to reflect concessional finance arrangements.

FFO / net debt (FFOND)

Measure of recurring operating earnings compared to the amount of debt held, calculated as expected FFO divided by the debt proportion of the RAB.

RCF / net debt (RCFND)

Measure of the net change in cash and cash equivalents compared to the amount of debt held, calculated as the internal cash flow less expected dividend payments divided by the debt proportion of the RAB.

A financeability issue will exist where the financeability position is either:

- equivalent to or higher than the benchmark credit rating used to estimate the return on debt in the RORI (currently BBB+/Baa1 reflecting a financeability score of 8.5) at step one and deteriorates below this threshold at step two (i.e. financeability score becomes greater than 8.5), or
- lower than the benchmark credit rating at step one and deteriorates further below that position at step two.

If a financeability issue exists, the AER is required to address the issue by applying a depreciation profile that it considers appropriate to provide cashflows to prevent the financeability issue from occurring.[91]

6.5.2. Concessional financing considerations

[redacted]

[91] EII Chapter 6A, cl. 6A.6.3A(m).

[redacted]

6.5.3. Stakeholder feedback

Given this is the first time a financeability request has been made under either the EII framework or the NER framework, early and open engagement with the AER on the proposed approach and the application of the financeability guideline was critical to inform our approach.

Prior to submission, we met regularly with the AER to understand the financeability guideline and how it applies to the Project. We also sought early feedback on our draft financeability modelling. We appreciate the collaborative and positive approach adopted by the AER and consider that it has improved the veracity of our financeability assessment and request. In particular, the AER provided feedback on:

- the underlying base case – including the NER capex program and modelling related to the potential outcomes resulting from capex overspends for Project EnergyConnect
- the limitations surrounding the inclusion of BCSS in any financeability assessment – noting that the EII Chapter 6A only provides for a single test at the time of proposal submission and the current exclusion of BCSS from the Consumer Trustee's Authorisation prevents its inclusion in any financeability test
- the scenarios that might support sensitivity testing of the outcomes – noting that while a single calculation is to be undertaken in performing the financeability test, information arising out of scenario testing would assist in decision making by providing clear markets on what outcomes are more likely than others.

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.

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.

6.5.4. Financeability assessment

We have assessed our ability to submit a financeability request, taking into our individual circumstances and how these correspond with the criteria outlined in EII Chapter 6A and the AER's financeability guideline.

We are eligible to submit a financeability request for the Enabling CWO RNIP (where a financeability issue exists) as this is an actionable ISP project[92] and we have not previously submitted a financeability request for this Project.[93] We also understand that the requirement to only submit a single financeability request for a project (at the time of submitting a Revenue Proposal) limits our ability to include BCSS in the assessment. We confirm that as the current scope of the Consumer Trustee Authorisation does not include BCSS, the costs incurred in acquiring the asset have not been included in our financeability assessment.

Our approach to assessing our financeability position is outlined in Figure 6-5 below. Key assumptions adopted in the base and project scenarios are also summarised in Table 6-7 below.

[92] The CWO REZ project was identified as actionable in the 2020 ISP. The project was listed as an anticipated project in the 2024 ISP.

[93] EII Chapter 6A, cl. 6A.6.3A(b)-(d).

Figure 6-5 Approach to assessing financeability

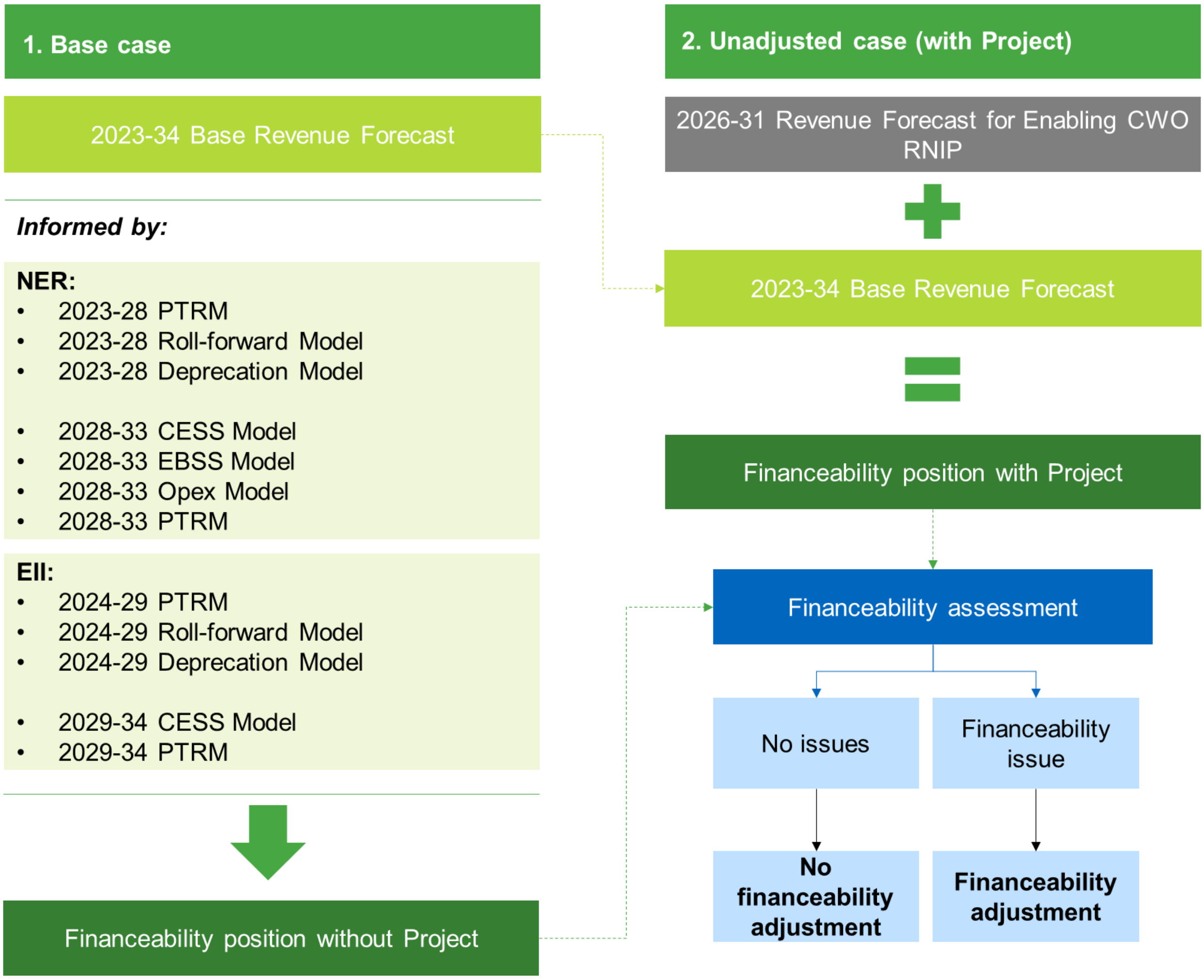


Table 6-7 Key assumptions applied

Base case	Unadjusted case (with Project)
• For Project Energy Connect, all overspends included with the RAB from 2028-29 earn a return on capital and return of capital. • For Project Energy Connect, a CESS penalty equating to 30 per cent of the total overspend (adjusted for financing impacts) applies. • To account for the forecast capital expenditure allowance for the upcoming 2028-33 regulatory period, we have assumed that the three-year average (i.e. 2025-26 to 2027-28) applies across the five year regulatory period (in real 2027-28 dollars). • Actual opex profile for 2023-28 was calculated to ensure no resulting EBSS for the 2028-33 period. Given opex is a pass-through however, any EBSS directly impacts the starting position, for financeability, and hence excluded. • Revenue smoothing for the 2028-33 NER regulatory period applies the 'standard' approach built into the AER's PTRM, removing discretion around how cashflow is smoothed.	• The assumptions applied for the base case apply consistently. • Any costs associated with the future acquisition of BCSS have not been included in the analysis.

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 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.

6.5.5. Financeability request

To address the financeability issue identified, we propose to accelerate depreciation of $23.7 million (nominal) of capital expenditure. This financeability adjustment will prevent the financeability position determined in step one from deteriorating below the financeability threshold.

Figure 6-6 and Figure 6-7 below demonstrate the unadjusted financeability position, and the adjusted financeability position where depreciation is accelerated in the manner specified above.

Figure 6-6 Unadjusted financeability position

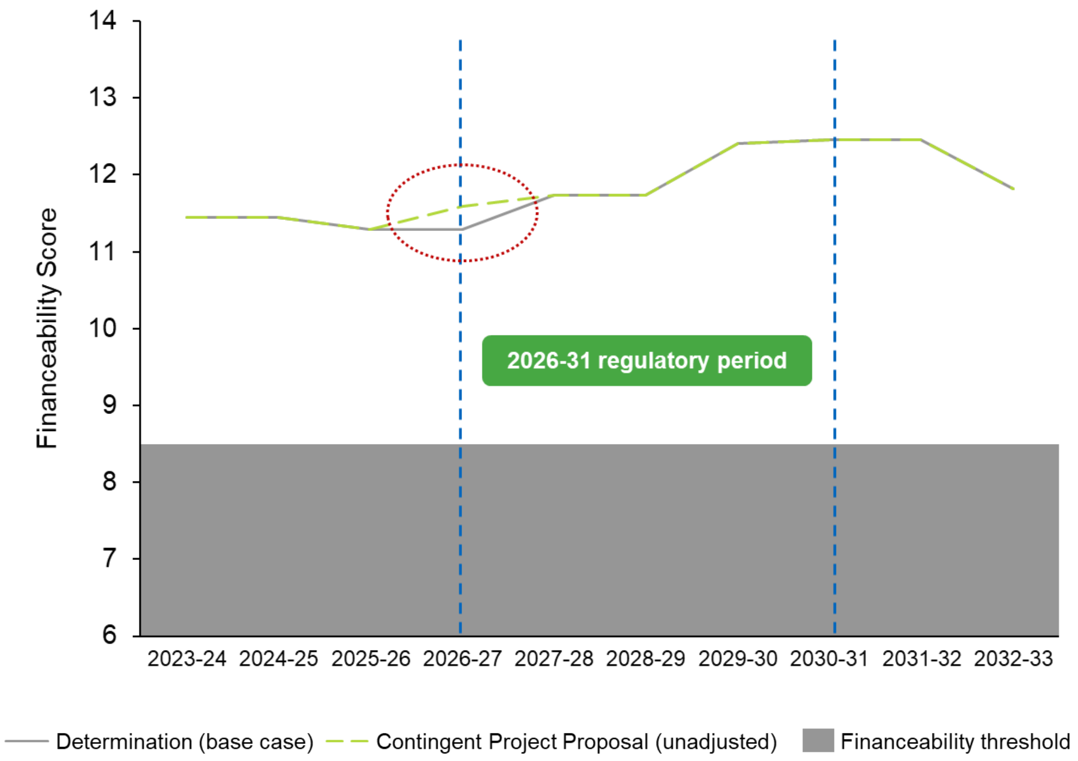
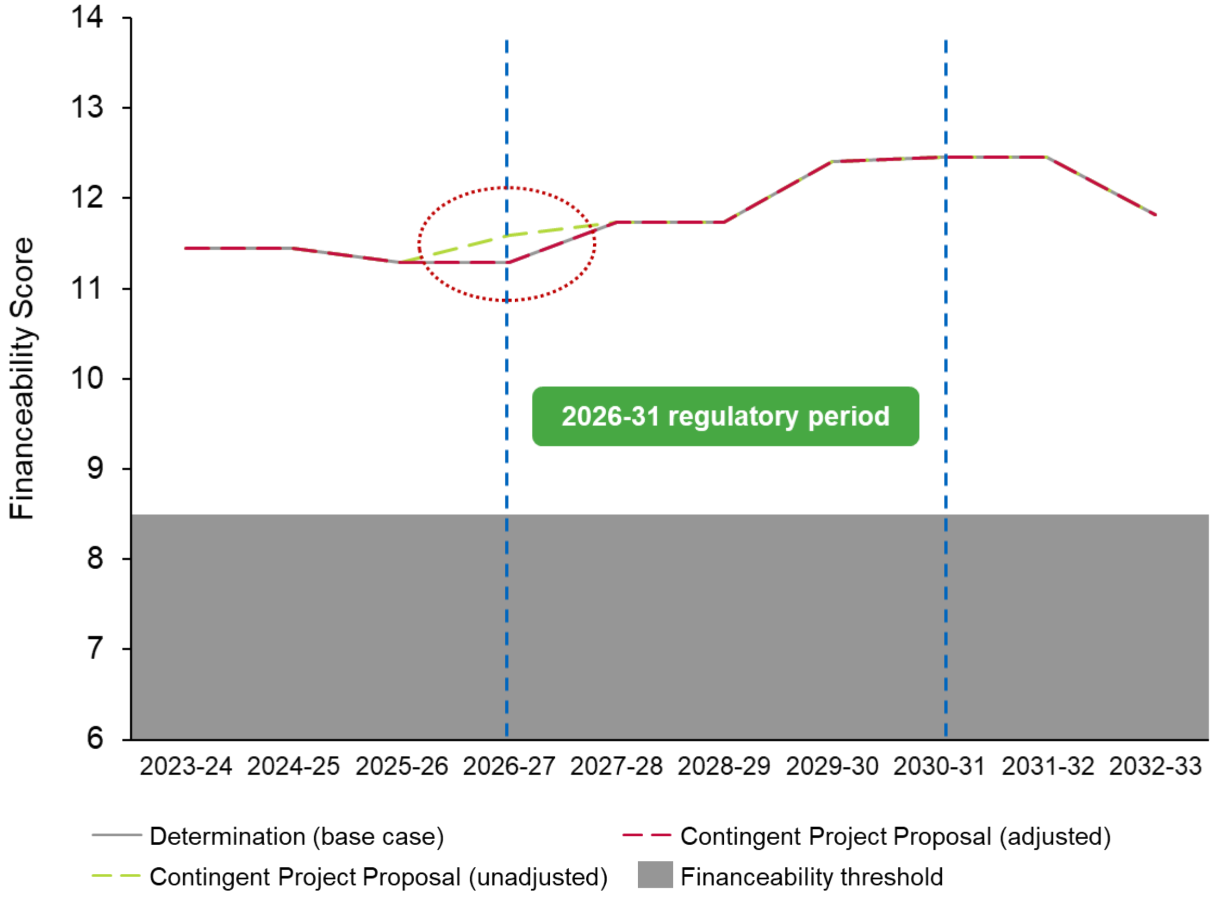


Figure 6-7 Adjusted financeability position



6.5.6. Sensitivities

Under EII Chapter 6A and the financeability guideline, there is no requirement to conduct sensitivities as part of the financeability assessment. Despite this, we appreciate that the adoption of specific assumptions may impact outcomes and as a result, there may be situations where undertaking sensitivity analysis is useful to determine the extent of the financeability issue (and confirm that an issue is likely to exist in future under a range of assumptions).

As mentioned above, engagement with both the AER and TAC highlighted concerns around the assumptions used for the capital overspend for Project EnergyConnect, specifically with determining the appropriate 'base' financeability position (the Base Position). To address these concerns, we have run scenarios which vary the degree of the CESS penalty via the application of a capital expenditure reopener or the draft capital expenditure incentive guidelines, both of which have the ability to reduce CESS on ISP projects.

The scenarios considered assume all overspend for Project EnergyConnect is prudent and efficient and is therefore included in the RAB from 2028-29, earning both a return on capital and return of capital (same as the Base Position).

The scenarios differ from the Base Position by applying different levels of Project EnergyConnect overspend subject to CESS (i.e. 75 per cent down to 0 per cent as can be seen in the table below). The impact of using different percentages of Project EnergyConnect overspend subject to CESS result in a different starting position for the 2028-33 regulatory period compared to the Base Position.

This assessment is important as the CESS penalty directly impacts the forecast regulatory Funds From Operation (FFO) affecting three of the tested Moody's metrics. Specifically, if CESS is lower than under the Base Position (i.e. higher MAR for the regulatory period 2028-2033) than the forecast FFO will be higher than under the Base Position, however it does not mean that the financeability position has improved. It merely resets the starting position from which to assess the impact of a potential financeability outcome when the cashflows for Enabling CWO RNIP are included. This means that the sensitivities below show no trend / linear correlation between a CESS outcome assumption and financeability eligibility for the Enabling CWO RNIP.

Table 6-8 shows the varying levels of CESS exposure and the resulting impact on the Enabling CWO RNIP's financeability assessment.

Table 6-8 Sensitivity analysis to examine the impact of CESS for Project EnergyConnect on financeability

	Base Position	Sensitivity 1	Sensitivity 2	Sensitivity 3	Sensitivity 4
Percentage of overspend subject to CESS	100%	75%	50%	25%	0%
Total Financeability Asset ($M)	21.0	-	17.0	19.0	-
Depreciation year (years)	3	-	8	8	-
Financeability issue year	2026-27	-	2032-33	2031-32	-

This analysis highlights the following:

- Financeability issues are present in three out of the five scenarios tested.
- Transgrid's Base Position is on the edge of two financeability bands leading to a financeability issue when adding the Enabling CWO RNIP.
- With regards to the sensitivities, the following was observed:
  - Sensitivity 1, 75 per cent CESS penalty: Improvement in all base metrics, excluding Net Debt / RAB, where RCF / Net Debt and FFO / Net Debt metrics moving from a lower band to a higher band, at various points in time. When the cashflows from Enabling CWO RNIP were included, this did not offset the increase and hence does not trigger a financeability issue.
  - Sensitivity 2, 50 per cent CESS penalty: Like Sensitivity 1, this caused an improvement in all base metrics, excluding Net Debt / RAB, where each metric increased to a higher band, at various points in time. This improvement in the band however, moved our Base Position from the upper end of one band to the lower end of another such that once the cashflows of the Enabling CWO RNIP were incorporated, it caused a downgrade in the metrics triggering a financeability issue.
  - Sensitivity 3, 25 per cent CESS penalty: Like Sensitivity 2, the same movement was observed however the year in which the financeability issue occurred was different. This difference is a result of the forward looking 3-year average and the point in time movement of the bands.

- Sensitivity 4, no CESS penalty: Like Sensitivity 3, the same movements were observed however, the cashflows for the Enabling CWO RNIP did not cause any deterioration in the financeability position.

Given the above observations, it is important that the financeability issues are addressed. This is because if the financeability issue is not addressed in this determination (due to a view that another outcome is possible), our financeability position may deteriorate and we will not be afforded another avenue to rectify the impact of this individual project on our overall financeability position in future.

In the alternative case, where our financeability position is adjusted, consumers are protected in the event where capital is depreciated and assumptions later change, as the increased cashflow will be factored into the next financeability assessment, reducing the brought-forward depreciation. This is due to the financeability assessment being a whole of business test.

Finally, our assessment does not include the capital expenditure for the BCSS acquisition due to the current scope around the Consumer Trustee's Authorisation. If this capex was included in our assessment, this would further increase the extent of the financeability issue, supporting our financeability assessment.

6.6. Roll forward of the 2026-2031 regulatory period

We propose to use forecast depreciation to roll-forward the RAB to the start of the next regulatory period starting 1 July 2031, consistent with the approach adopted for prescribed transmission services under the NER.

7. Rate of return, inflation and debt and equity raising costs

This Chapter sets out our proposed rate of return, inflation, and debt and equity raising costs for the 2026-31 regulatory period. These values are reflected in the PTRM and rate of return model, included as attachments to this Revenue Proposal.

7.1. Overview

- We estimate a rate of return of **6.78 per cent** for the 2026-2031 regulatory period.
- We estimate forecast inflation of **2.78 per cent**.
- We estimate equity raising costs of **$1.6 million** and debt raising costs of **$0.9 million** over the 2026-2031 regulatory period.

We estimate a rate of return of 6.78 per cent for the 2026-31 regulatory period, using the AER's binding 2022 RORI and recent observable market data. The final rate of return will be calculated using updated market data.

We estimate forecast inflation of 2.78 per cent using the method included in the AER's PTRM. This inflation forecast is used to index the RAB over the 2026-31 regulatory period. The AER will update the inflation forecast in its subsequent decisions to reflect the latest available forecasts published by the Reserve Bank of Australia (RBA).

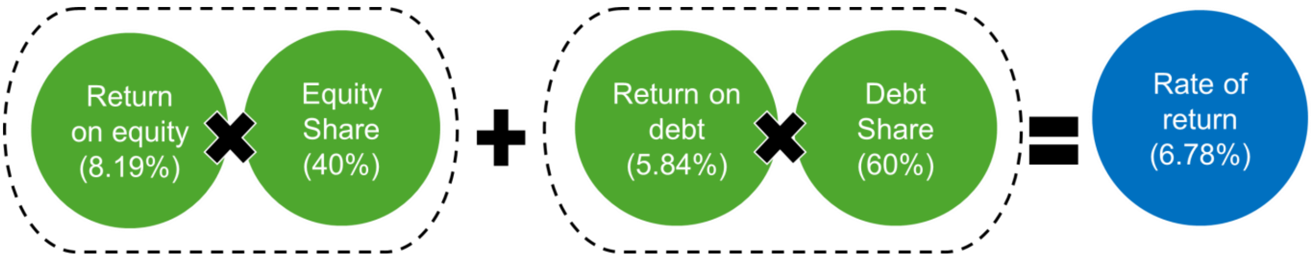
The PTRM also allows for debt and equity raising costs to compensate for efficient capital raising costs. We estimate equity raising costs of $1.6 million and debt raising costs of $0.9 million for the 2026-31 regulatory period.

7.2. Rate of return

The rate of return, otherwise known as the weighted average cost of capital (WACC), represents the average cost of debt and equity an efficient firm would incur to raise funds from a range of investors and capital markets to finance investments in our network. It is the return required by debt and equity investors on invested capital (the RAB) and is compensation for the risks and opportunity costs those investors bear when committing capital to the business.

The rate of return is estimated as a weighted average of the return on equity and the return on debt as shown in Figure 7-1.

Figure 7-1 Our proposed rate of return



We have used placeholder averaging periods to estimate market observable parameters, as follows:

- risk-free rate parameter: 4 to 31 March 2025, and
- prevailing return on debt: 18 to 31 March 2025.

As discussed in Chapter 7.5, the final rate of return (and any annual updates) for the 2026-31 regulatory period will be determined on the basis of the averaging periods agreed with the AER.

Our return on capital allowance is calculated by multiplying the rate of return and the value of our opening RAB in each year of the regulatory period. Forecast return on capital is shown in Table 7-1.

Table 7-1 Forecast return on capital ($M)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Opening RAB (nominal)	167.8	323.1	447.5	455.5	454.1	N/A
Rate of return (%, nominal)	6.78	6.78	6.78	6.78	6.78	N/A
Return on capital (nominal)	11.4	21.9	30.4	30.9	30.8	125.4
Return on capital (real 2025-26)	11.1	20.8	28.0	27.7	26.9	114.3

7.3. Return on equity

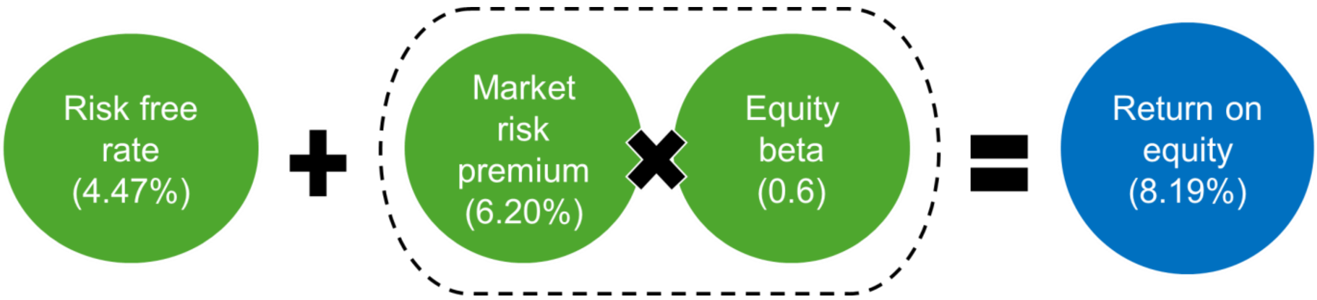
The return on equity is the return required by equity investors to provide equity capital.

We propose a return on equity of 8.19 per cent calculated in accordance with the 2022 RORI. In particular, we have used the Sharpe-Lintner Capital Asset Pricing Model, which, as shown in Figure 7-2, combines a risk-free rate parameter with the product of the market risk premium and equity beta.

We have adopted the value in the 2022 RORI for market risk premium (6.20 per cent) and equity beta (0.6). We have estimated the risk-free rate parameter using yields on Commonwealth Government Securities observed over the 20 trading days from 4 to 31 March 2025 to be 4.47 per cent.

This is a placeholder estimate of the risk-free rate for the purpose of this Revenue Proposal. The AER will calculate our actual risk-free rate using the method outlined in clauses 7 and 8 of the 2022 RORI as well as our nominated averaging period, which is provided as an attachment to this Revenue Proposal.

Figure 7-2 Our proposed rate of equity



7.4. Return on debt

The return on debt is the return required by debt investors for lending funds to invest in new assets and continue financing existing assets.

As required by the 2022 RORI, the return on debt is calculated as a trailing average of past return on debt observations. Given that the 2026-31 period will be the first period for the services provided by the Enabling CWO RNIP, the 2022 RORI requires that we transition over a 10-year period from an on-the-day estimate of the return on debt to a 10-year trailing average, in line with the approach accepted by the AER in the WSB non-contestable Revenue Determination. This means that we will commence the 10-year transition to the full trailing average in 2026-27.

Our estimate of the return on debt for the first year of the 2026-31 period is 5.84 per cent and has been calculated using the methodology outlined in the AER's 2022 RORI. The 2026-27 observation period is a placeholder until actual market data becomes available for the actual averaging period approved by the AER in its final decision for the 2026-31 period.

In line with the 2022 RORI, the 2026-27 observation is to be calculated using corporate bond data published by Bloomberg and Refinitiv (previously Thomson Reuters).

7.5. Averaging periods

As required by the 2022 RORI, we must propose averaging periods that the AER will use to update the market observable parameters used to estimate the return on equity and return on debt. The AER will calculate our actual risk-free rate using the method outlined in the 2022 RORI as well as our nominated averaging periods, provided as an attachment to this Revenue Proposal.

As discussed in Chapter 9.4.2, we propose updating the quarterly payment schedule each year to reflect updates to the return on debt using the approach set out in the 2022 RORI and the averaging periods approved by the AER. This is similar to the process that applies annually to prescribed transmission services.

In the event that the risk-free rate from Transgrid's nominated averaging period is not available at the time of the Revenue Determination, we similarly propose updating the return on equity using the approach set out in the 2022 RORI and the averaging periods approved by the AER.

7.6. Rate of return applied to costs incurred prior to the regulatory period

As discussed in Chapter 6.2.3, we propose including financing costs when capitalising expenditure incurred from 2020-21 to 2025-26 into the opening RAB. Since there was no mechanism to recover this pre-period expenditure before the commencement of the regulatory period, a benchmark efficient business in Transgrid's circumstances would have needed to finance those costs and recover them in future periods. The associated financing costs are prudent, efficient and reasonable and should therefore be recoverable by Transgrid over future regulatory periods.

Therefore, we propose to include a return on capital based on the nominal vanilla WACC for capex incurred from 2021-22 to 2025-26, in line with the WACC adopted in our 2018-23 and 2023-28 Revenue Determinations, adjusted for annual cost of debt updates. This pre-period expenditure, and the return on it, will be capitalised into the opening RAB as at 1 July 2026.

7.7. Forecast inflation

Forecast inflation is used to calculate the depreciation building block and to convert real dollar values to nominal dollar values.

We have calculated forecast inflation based on the AER's December 2020 final decision on the treatment of expected inflation, which is also reflected in the AER's PTRM. This is based on the geometric mean of:

- one years of forecast inflation published by the RBA in its Statement on Monetary Policy, depending on the availability of the RBA's forecasts, and
- four years transitioning to the midpoint of the RBA's inflation target, 2.5 per cent.
- Our forecast inflation is a placeholder value and we expect the AER to update the forecast with the latest information available at the time of its determination (and for actual inflation when annually adjusting revenue).

As shown in Table 7-2, we have forecast inflation of 2.78 per cent per annum by applying this method and using the RBA's February 2025 Statement on Monetary Policy. Our rate of return model and PTRM provided as attachments to this Revenue Proposal set out the detailed calculations of forecast inflation.

Table 7-2 Proposed inflation forecast

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
	RBA forecast	Linear transition to 2.5%				
Inflation forecast (%)	3.20	3.06	2.92	2.78	2.64	2.50
Geometric average (%)	-	2.78	-	-	-	-

7.8. Debt and equity raising costs

Debt and equity raising costs reflect the costs we incur when raising debt and equity capital from external investors and include agency, placement, arrangement, legal, credit rating, and registration fees, and roadshow costs.

We have adopted the AER's preferred approaches and parameters to estimate these costs for a benchmark efficient business (rather than our actual costs), as described in Table 7-3. Our PTRM provided as an attachment to this Revenue Proposal sets out the detailed calculations of our debt and equity raising costs.

Consistent with recent AER decisions, we treat equity raising costs as capex and debt raising costs as opex. Equity raising costs are discussed in our Direct Capex Forecasting Methodology, provided as an attachment to this Revenue Proposal. Similarly, debt raising costs are explained further in our Opex Forecasting Methodology, also provided as an attachment to this Revenue Proposal.

Table 7-3 Debt and equity raising cost estimation approaches and assumptions

Component	Approach and assumptions
Debt raising costs	Debt raising costs are calculated for each year of the 2026-31 period by multiplying the opening RAB value for the year by a unit rate and benchmark leverage ratio. We propose adopting a unit rate of 8.3 basis points per annum as a placeholder, which is the value adopted by the AER in its 2023-28 Determination for our prescribed transmission services.

Component	Approach and assumptions
	We have also adopted the benchmark leverage ratio (i.e. 60 per cent) adopted by the AER in its 2023-28 Revenue Determination for our prescribed transmission services.
Equity raising costs	Equity raising costs are estimated in two steps: • first, the PTRM calculates the share of earnings paid out and then reinvested and uses these values – along with forecast cash flows – to determine how much additional equity is needed to maintain a 60 per cent leverage ratio. • second, the PTRM calculates the costs of the various funding sources, namely retained earnings, reinvested dividends and equity offerings. To apply this method, we propose adopting the parameters that the AER adopted for the 2023-28 Revenue Determination: • imputation payout ratio (or earnings payout ratio) – of 87.87 per cent per dollar of income generated • dividend reinvestment plan take up – of 30 per cent of each dollar paid out as dividends • subsequent equity raising cost – of 3 per cent per dollar of equity raised in a subsequent equity raising, and • dividend reinvestment plan cost – of 1 per cent per dollar of equity reinvested.

Applying these approaches and assumptions gives the debt and equity raising cost forecasts set out in Table 7-4.

Table 7-4 Forecast debt and equity raising costs ($M, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Debt raising costs	0.1	0.2	0.2	0.2	0.2	0.9
Equity raising costs	1.6	-	-	-	-	1.6

8. Estimated cost of corporate income tax

This chapter sets out our forecast tax allowance for the 2026-31 regulatory period and how we have calculated this allowance.

8.1. Overview

Our forecast tax allowance for the 2026-31 regulatory period is **$1.4 million.**

We have calculated our income tax allowance using the AER's revised approach to the treatment of regulatory tax published in 2018 and subsequently reflected in its PTRM. We have used this to develop the PTRM for the Project, which is included as an attachment to this Revenue Proposal.

The approach applies the corporate tax rate of 30.0 per cent less the value of imputation credits (gamma) of 57.0 per cent of forecast tax payable set out in the 2022 RORI.

The approach also:

- recognises immediately expensing capex, and
- applies a diminishing value depreciation method when calculating tax depreciation to most asset classes rather than the straight-line method.

Our forecast tax allowance for the 2026-31 regulatory period is $1.4 million.

8.2. Forecast income tax allowance

This Revenue Proposal includes an allowance for tax costs, consistent with the AER's method for the regulatory treatment of tax and the value of imputation credits (0.57) reflected in the AER's 2022 RORI.

Under clause 6A.6.4 of the EII Chapter 6A, the forecast income tax allowance for a given year is calculated by multiplying estimated taxable income for that year by the expected statutory income tax rate and by 1 less the value of imputation credits. We have applied the statutory income tax rate of 30.0 per cent in the AER's PTRM.

Figure 8-1 shows the calculation of the corporate tax allowance applied. As shown, forecast taxable income is calculated as revenue less taxable expenses. Taxable expenses include the forecast operating costs less forecast tax depreciation less interest costs (based on the cost of debt).

Figure 8-1 How the tax allowance is calculated

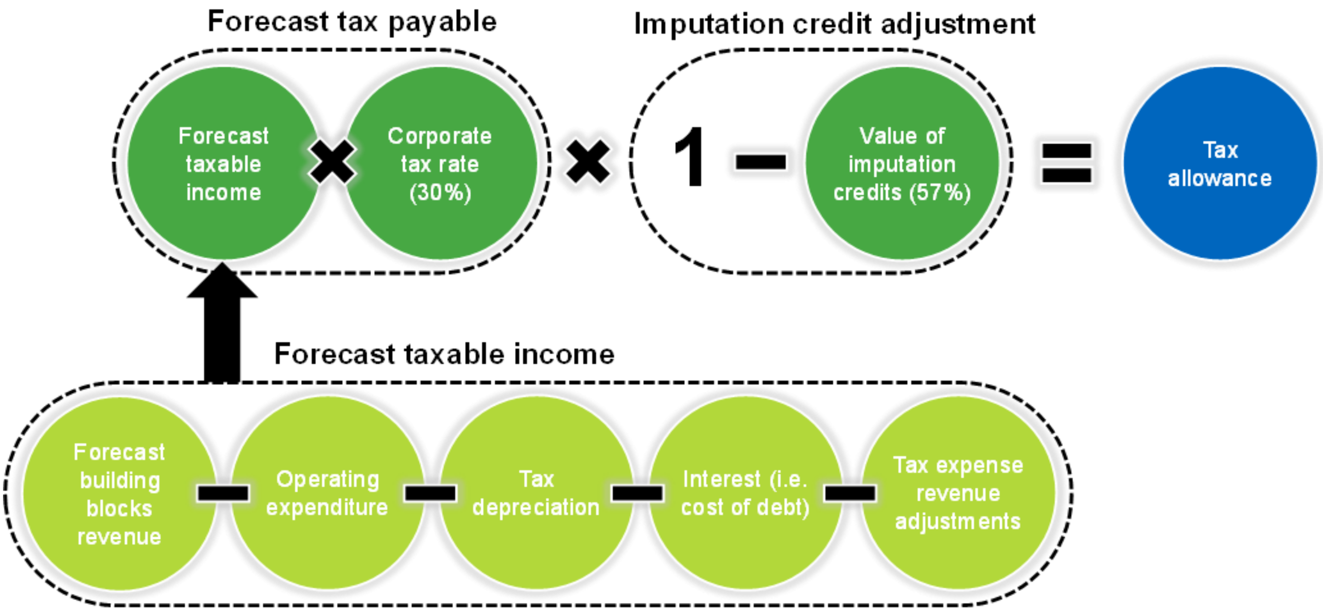


Table 8-1 sets out our forecast tax allowance for the 2026-31 period calculated using the AER's PTRM. Our forecast tax allowance comprises 0.9 per cent of our total building block costs (in real terms).

Table 8-1 Forecast income tax allowance ($M, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Building block revenue	12.2	27.4	40.0	38.2	32.8	150.6
(-) Operating expenditure	(0.7)	(3.3)	(7.5)	(9.2)	(8.0)	(28.8)
(-) Tax depreciation	(1.0)	(8.8)	(16.5)	(16.4)	(15.2)	(57.9)
(-) Interest (i.e. cost of debt)	(5.7)	(10.7)	(14.5)	(14.3)	(13.9)	(59.1)
(-) Tax expense revenue adjustments	-	-	-	-	-	-
Taxable income	4.7	4.6	1.5	(1.7)	(4.2)	4.8
(x) Corporate tax rate (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Tax payable	1.4	1.4	0.5	-	-	3.2
(-) Value of imputation credits (57%)	(0.8)	(0.8)	(0.3)	-	-	(1.8)
Estimated cost of corporate income tax	**0.7**	**0.6**	**0.2**	**-**	**-**	**1.4**

8.3. Forecast tax depreciation

Forecast tax depreciation is an input to calculating forecast taxable income, which is calculated within the PTRM. The regulatory calculation of tax depreciation depends on:

- the value of the regulatory tax asset base (TAB) as at the commencement of the 2026-31 regulatory period (1 July 2026)
- immediately expensed capex, and
- standard and remaining tax lives.

As-commissioned capex is normally depreciated for tax purposes and the assets created by the Project are not expected to be commissioned until well into the 2026-31 regulatory period. However, the biodiversity and financeability asset classes are recognised on an 'as incurred basis'. Noting this, the opening regulatory tax asset base (TAB) is $34.4 million as at 1 July 2026.

Unlike the RAB, the regulatory TAB includes the value of capital contributions (which are expected to be small). These pros attract a tax liability that we will pay, as well as tax expenses that we can claim over the life of the assets.

8.4. Tax asset lives

Table 8-2 sets out the proposed depreciation approach and standard asset lives for each asset class over the 2026-31 regulatory period. The nominated remaining lives of the three 'as incurred' asset classes have been set equal to the standard asset lives shown below.

The depreciation approach and standard asset lives match those adopted by the AER in its 2023-28 revenue determination for Transgrid's prescribed transmission services.

Table 8-2 Proposed depreciation method tax asset lives

Asset class	Depreciation method	Standard tax asset lives (years)
Transmission lines	Diminishing value	50.0
Substations	Diminishing value	40.0
Secondary systems	Diminishing value	15.0
Land and easements	N/A	N/A
Biodiversity offsets – stewardship sites	N/A	N/A
Biodiversity offsets – direct payments and other costs	Diminishing value	50.0
Financeability asset class	Diminishing value	15.0[94]
Equity raising costs	Diminishing value	5.0

[94] As outlined in Chapter 6, the financeability asset life is 3 years however the asset life and standard tax asset life is 15 years.

8.5. TAB roll forward over the 2026-31 period

Table 8-3 shows the forecast regulatory TAB for the 2026-31 period including the impact of immediately expensed capex. Tax depreciation starts in 2026-27. Given the newness of the assets, no disposals are forecast for the 2026-31 regulatory period.

Table 8-3 TAB roll forward over the 2026-31 period ($M, Nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31
Opening TAB	34.4	222.9	412.3	426.7	408.4
Gross capex	189.5	198.6	32.3	-	-
Immediate expensing of capex	-	-	-	-	-
Asset disposals	-	-	-	-	-
Depreciation	(1.0)	(9.3)	(17.9)	(18.3)	(17.4)
Closing TAB	**222.9**	**412.3**	**426.7**	**408.4**	**390.9**

9. Adjustment mechanisms

This chapter sets out the proposed adjustment mechanisms or 'pass through events' that will be used to adjust our revenue and schedule of payments within the 2026-31 regulatory period.

9.1. Overview

Our proposed adjustment mechanisms include:

- six **prescribed** adjustment mechanisms – reflecting the mechanisms intended to be available to all network operators for all non-contestable EII projects under EII Chapter 6A
- four adjustment mechanisms for **costs associated with BCSS** – these adjustments are contemplated in our Project Deed with EnergyCo and are proposed in accordance with clause 21 of the EII Regulation
- four **nominated** adjustment mechanisms – to reflect the pass-through events that were accepted by the AER in our 2023-28 Revenue Determination
- four adjustment mechanisms to reflect our **contractual arrangements with EnergyCo** – this includes adjustments for changes in Infrastructure Planner costs, contractual variations and delay liquidated damages
- three adjustment mechanisms for **routine administrative events** – to ensure inflation, return on debt and return on equity are able to be updated as required
- eight adjustment mechanisms for **other uncontrollable events** – this includes events that are outside of our control and cannot be reasonably mitigated, prevented or insured against.

The EII regulatory framework recognises the difficulty associated with forecasting costs for all foreseen and unforeseen events within the regulatory control period. Specifically, clause 51 of the EII Regulation allows a network operator to propose adjustment mechanisms to the AER to increase or decrease a network operator's revenue, if and when specific defined events occur. This reflects that it is not appropriate to include allowances for these events in base expenditure, due to difficulties in quantifying an accurate revenue allowance.

Reflecting this, EII Chapter 6A prescribes a range of adjustment mechanisms intended to be available to all network operators for all non-contestable projects (prescribed adjustment mechanisms).[95] It also allows network operators to propose other adjustment mechanisms for AER approval ('nominated' adjustment mechanisms), having regard to the nominated pass-through considerations, defined in the NER.[96]

The December 2024 amendments to the EII Regulation[97] also make it clear that a revenue determination can be adjusted for amounts associated with the partial transfer of network infrastructure.[98] This is relevant for the Project in the context of the transfer of BCSS.

[95] EII Chapter 6A, clause 6A.7.3.
[96] EII Chapter 6A, clause 6A.7.3(a1)(5).
[97] Electricity Infrastructure Investment Amendment Regulation (2024) (SI 627), notified 12 December 2024.
[98] EII Regulation, clauses 21 and 54AA.

9.2. Prescribed adjustment mechanisms

Clause 6A.7.3 of EII Chapter 6A prescribes the following cost pass through events:

- regulatory requirements as defined in section 46(3) of the EII Regulation
- a service standard event
- a tax change event
- an insurance event
- an inertia shortfall event
- a fault level shortfall event.

Revenue adjustments for these events are intended to be available for all non-contestable projects.

Clause 46(3) of the EII Regulation specifies that a regulatory requirement means a requirement imposed on the network operator by a relevant law but does not include a requirement to pay a fine, penalty or compensation for a breach of a requirement imposed on the network operator by a relevant law. Relevant laws include:

- the EII Act and EII Regulation
- the National Electricity (NSW) Law or NER
- an Act (or instrument under that Act) that:
  - imposes a tax or levy, or
  - relates to the protection of the environment, or
  - regulates the use of land, or
  - otherwise materially affects the carrying out of the infrastructure project by the network operator.

Other cost pass through events outlined above have the same definition under the EII framework as they do under the NER.[99]

Table 9-1 outlines the prescribed adjustment mechanisms.

Table 9-1 Adjustment mechanisms prescribed in EII Chapter 6A

Adjustment mechanism	Description
Regulatory requirements as defined in section 46(3) of the EII Regulation	An increase or decrease in the revenue Transgrid may recover to accommodate additional prudent, efficient, and reasonable costs Transgrid incurs in complying with a regulatory requirement, as defined in s. 46(3) of the EII Regulation.
Service standard event	An increase or decrease in the revenue Transgrid may recover to accommodate the additional costs Transgrid incurs from a service standard event, as defined in NER Chapter 10, Service Standard Event.
Tax change event	An increase or decrease in the revenue Transgrid may recover to accommodate the additional costs Transgrid incurs from a tax change event, as defined in NER Chapter 10, Tax Change Event.

[99] EII Chapter 6A includes a fault level shortfall event as a pass through event. However, this is now removed from the NER Chapter 6A as a result of the system strength rules, which commence from 1 December 2025. The fault level shortfall event only applies under the NER until 1 December 2025 as a transitional arrangement.

Adjustment mechanism	Description
Insurance event	An increase or decrease in the revenue Transgrid may recover to accommodate the additional costs Transgrid incurs from an insurance event, as defined in NER Chapter 10, Insurance Event.
Inertia shortfall event	An increase or decrease in the revenue Transgrid may recover to accommodate the additional costs Transgrid incurs from an inertia shortfall event, as defined in NER Chapter 10, Inertia Shortfall Event.
Fault level shortfall event	An increase or decrease in the revenue Transgrid may recover to accommodate the additional costs Transgrid incurs from a fault level shortfall event, as defined in NER Chapter 11, Fault Level Shortfall Event.

The process for adjusting revenue as a result of these events is described in Chapter 9.5.

9.3. Adjustment mechanisms associated with BCSS

ACEREZ will develop, construct and pre-commission BCSS as part of the Main CWO RNIP.[100] We have agreed with EnergyCo to purchase BCSS once constructed, undertake final commissioning and operate it as part of the Enabling CWO RNIP. As BCSS is not currently within the scope of our Consumer Trustee Authorisation, costs to purchase, commission and operate it are unable to be included in the base expenditure.

Clause 6(b) of the Consumer Trustee's Authorisation states:

> *If the Network Operator acquires or leases an asset which:*
>
> *(1) comprises part of an authorised REZ network infrastructure project under another instrument under the Act; and*
>
> *(2) connects to or will be used by the Network Operator in connection with the control or operation of the Enabling CWO REZ Network Infrastructure Project,*
>
> *the relevant asset will be deemed to be authorised under this instrument.*

BCSS currently comprises part of ACEREZ's Consumer Trustee Authorisation and is therefore deemed to be authorised by another instrument under the EII Act. It will also connect to and be used in connection with the Enabling CWO RNIP. As such, this transaction will constitute a transfer of REZ network infrastructure project assets under our Consumer Trustee Authorisation.

Pursuant to clause 21 of the EII Regulation, where part of the network infrastructure subject to an authorisation is transferred, the Regulator must, on the approval of the Consumer Trustee, either:

- make a revenue determination in relation to the transferee and the transferred network infrastructure, or
- if satisfied the making of a revenue determination is not required in the circumstances, carry out an adjustment of, or review and remake, another revenue determination that applies to the transferee in accordance with clause 54AA(3).

Clause 54AA(3) of the EII Regulation stipulates that the Regulator can carry out an adjustment of another revenue determination that applies to the transferee if the determination includes a provision for the

[100] AEMO Services, Notice of Authorisation – Main CWO REZ Network Infrastructure Project, 4 June 2024, section 5(a)(1).

adjustment of amounts where network infrastructure is transferred and the Regulator is satisfied that reviewing and remaking the determination is not required in the circumstances.

We consider that the making of a separate revenue determination is not required. BCSS will operate as part of the Enabling CWO RNIP and there will be an existing Revenue Determination for this Project, such that carrying out an adjustment of the determination for the Project to account for the transfer of BCSS is appropriate. To facilitate this, we consider it appropriate to include an adjustment mechanism to provide the AER with a mechanism to reflect the adjustment of amounts as contemplated by clause 54AA(3)(b)(i) of the EII Regulation.

We are also contractually obligated under the Project Deed to include adjustment mechanisms to reflect costs associated with BCSS. The Project Deed specifies we:

- must include an adjustment mechanism to provide for the recovery of the BCSS Purchase Price (without any BCSS Purchase Price adjustment) following the sale and transfer of the BCSS to Transgrid.
- must include an adjustment mechanism to adjust the BCSS Purchase Price amount which is consistent with the mechanism in the BCSS Sale and Purchase Deed.
- may include an adjustment mechanism to cover incremental capital expenditure and incremental operating expenditure for BCSS.

On this basis, we propose four adjustment mechanisms to reflect the costs associated with the transfer, commissioning and ongoing management, operation and maintenance of the relevant network infrastructure, namely:

- where BCSS is acquired (without any adjustment to the purchase price) following the successful transfer under the Sale and Purchase Deed
- where an adjustment to the BCSS purchase price occurs consistent with the mechanism set out under the Sale and Purchase Deed
- where incremental capital expenditure and/or operating expenditure for BCSS is required, as estimated at the time of acquisition
- where annual adjustments to the replacement expenditure and condition based/corrective maintenance components of the capital expenditure and operating expenditure for BCSS are required, due to an inability to accurately forecast these costs at the time of acquisition.

We consider that adjustment mechanisms to reflect the costs incurred in purchasing BCSS (including any purchase price adjustments made) are consistent with clauses 21 and 54AA of the EII Regulation. An adjustment mechanism for the incremental capital and operating expenditure is proposed as a nominated adjustment mechanism under clause 51 of the EII Regulation and clause 6A.6.9 of EII Chapter 6A (as it is not sufficiently related to the transfer of the asset as contemplated under clauses 21 and 54AA, but instead relates to the subsequent commissioning, operating and maintenance required under the Project Deed).

The adjustment mechanism to reflect costs incurred in purchasing BCSS must also allow for any applicable transfer duty payable on the purchase of BCSS to be recovered. Under the *Electricity Supply Act,* certain electricity works are considered to be owned separately from the land in, on or over which they are situated.[101] In these circumstances, transfer duty would apply only to the unimproved value of the land. We are currently confirming the applicability of this for BCSS and may make submissions to the NSW Office of

[101] *Electricity Supply Act 1995* (NSW), s. 51(1); *Duties Act 1997* (NSW), ss. 23, 26.

State Revenue as to the potential application of the relevant legislation. The amount of any adjustment made to capture transfer duty will reflect the actual transfer duty payable, as determined by the Office of State Revenue as well as any legal or administrative costs associated with determining the appropriate duty outcome.

Once we acquire BCSS, the Project Deed requires us to commission the asset before managing, operating and maintaining it on an ongoing basis. We propose non-automatic adjustment mechanisms to reflect the expected costs of purchasing, commissioning, insuring, managing, operating and maintaining BCSS (including a forecast for any capital expenditure or operating expenditure required to manage, operate and maintain BCSS).

However, noting that there is currently uncertainty associated with the forecast capital expenditure and operating expenditure required for BCSS due to the asset being developed, designed and constructed by a third party for which we have limited visibility of until after the transfer of BCSS and then unknown operational experience with the site and equipment design and construction, we consider it appropriate to allow for an annual[102] 'true-up' to adjust the revenue to reflect actual costs incurred for the replacement expenditure and condition based/corrective maintenance components of the capital expenditure and operating expenditure required for BCSS. This ensures that customers pay no more than necessary for these cost components which cannot be forecast with certainty at the time of the non-automatic adjustment mechanism for BCSS incremental capex and opex. This has been reflected in the wording of the proposed mechanism.

Table 9-2 outlines the proposed adjustment mechanisms.

Table 9-2 Adjustment mechanisms relating to transfer of network infrastructure

Adjustment mechanism	Description
Recovery of BCSS Purchase Price	A BCSS Transfer event is triggered where: • the Consumer Trustee approves the transfer pursuant to clause 21 of the EII Regulation and • EnergyCo provides written notice advising the estimated Completion Date of BCSS and requests Transgrid to drawdown funds required to pay the Purchase Price. The adjustment mechanism allows Transgrid to increase (or decrease) its revenue to reflect the costs associated with the transfer of BCSS, comprising: • the original purchase price, [redacted] and any GST payable • any applicable transfer duty payable by Transgrid on the purchase of BCSS, as determined by the NSW Office of State Revenue • legal and administrative costs associated with the transfer, including but not limited to costs associated with determining the appropriate duty outcome.

[102] We have proposed an annual adjustment to reflect relevant costs rather than specifying a trigger event for this adjustment. This aligns with clause 51(2)(a) of the EII Regulation that allows for an adjustment to be carried out at specific times, if necessary.

Adjustment mechanism	Description
BCSS Purchase Price Adjustment	A BCSS Purchase Price Adjustment event is triggered where EnergyCo provides Transgrid with written notice of a purchase price adjustment pursuant to the Sale and Purchase Deed. The adjustment mechanism allows Transgrid to increase (or decrease) its revenue to reflect the costs of any purchase price adjustment (either negative or positive), as specified by EnergyCo in the written notice provided to Transgrid in accordance with the Sale and Purchase Deed.
BCSS incremental capital and operating expenditure	A BCSS Incremental Cost event is triggered where: • EnergyCo provides written notice advising the estimated Completion Date of BCSS; and • the actual or forecast costs of incremental capital and operating expenditure for BCSS are known. The mechanism allows Transgrid to recover the prudent, efficient and reasonable capital and operating costs for BCSS. This includes, but is not limited to: • capital expenditure related to the transfer and commissioning of BCSS • capital and operating expenditure for insuring BCSS (including during the commissioning period) • capital expenditure for replacement and modification • operating expenditure for ongoing management, operating and maintenance costs (including condition based/corrective maintenance) • other incremental capital expenditure and operating expenditure associated with BCSS. For clarity, where a forecast amount is determined and accepted by the AER, the replacement expenditure and condition based/corrective maintenance components will be subsequently updated in the following annual adjustment process to ensure that only actual costs are recovered by Transgrid.
BCSS replacement expenditure and operating expenditure annual true ups	An annual update to revenue for a true up of the actual costs incurred for replacement capital expenditure and condition based/corrective maintenance operating expenditure. Transgrid will submit records of actual audited costs for these categories of costs annually trued up against any forecast expenditure included in the Revenue Determination for these categories.

The process for adjusting revenue as a result of these events is described in Chapter 9.5.

9.4. Other nominated adjustment mechanisms

We adopt prudent risk management procedures to ensure safe, reliable and secure electricity supply. We are compensated for our risk mitigation and prevention activities (including insurance) through our revenue allowance, and the rate of return we earn on our regulated asset base. However, there are other risks that are not compensated by the rate of return and cannot be reasonably mitigated, prevented or effectively insured against.

For this reason, clause 51 of the EII Regulation and clause 6A.6.9 of EII Chapter 6A allow us to propose adjustment mechanisms to recover costs associated with events outside of our control or events that are unable to be efficiently mitigated by us. Clause 51 of the EII Regulation allows for both 'automatic' adjustments and 'non-automatic' adjustments[103]:

- 'Automatic' adjustments would not require the AER to review or remake its revenue determination. The Regulation provides an adjustment for inflation as an example of an automatic adjustment. [104]
- 'Non-automatic' adjustments would require the AER to review or remake its revenue determination. The Regulation provides that this would be required following the occurrence of a significant event.

In considering the appropriateness of certain adjustment mechanisms, the AER will have regard to the nominated pass-through event considerations. The nominated pass-through event considerations are defined in the NER and include:

- whether the event proposed is an event covered by a category of pass through event specified in clause 6A.7.3(a1)(1) to (4) (i.e. the prescribed events outlined in Chapter 9.2 above)
- whether the nature or type of event can be clearly identified at the time the determination is made
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event
- whether the relevant service provider could insure against the event, having regard to:
  - the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms, or
  - whether the event can be self-insured on the basis that:
    - it is possible to calculate the self-insurance premium; and
    - the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services
- any other matter the AER considers relevant and which the AER has notified network service providers is a nominated pass-through event consideration.[105]

Our decision to nominate certain events as adjustment mechanisms has been informed by these considerations. Our nominated adjustment mechanisms fall into four key categories:

- nominated pass-through events accepted in our 2023-28 Revenue Determination
- adjustment mechanisms to reflect contractual obligations
- routine administrative events
- other uncontrollable events

9.4.1. Nominated pass-through events accepted in 2023-28 Revenue Determination

Consistent with the AER's 2023-28 Revenue Determination for our prescribed transmission services and the AER's 2024-2029 Revenue Determination for the non-contestable WSB project, we propose the following nominated pass through events as adjustment mechanisms for the 2026-31 regulatory period:

- insurance coverage event
- insurer's credit risk event
- natural disaster event

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[103] EII Regulation, clause 51(2)(b).
[104] See the note in clause 51 of the EII Regulation where it states that an adjustment may be made for inflation without a review or remake of the revenue determination.
[105] NER, Glossary, definition of 'nominated pass through event considerations'.

- terrorism event.

Table 9-3 outlines the proposed adjustment mechanisms.

Table 9-3 Adjustment mechanisms for previously accepted nominated pass-through events

Adjustment mechanism	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 EII services. For the purpose of this insurance coverage event: • '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. • 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had: - the limit not been exhausted, or - those costs not been unrecoverable due to changed circumstances. A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which Transgrid was regulated. Note: For the avoidance of doubt, in assessing an insurance coverage event through application under clause 6A.7.3(j) of EII Chapter 6A, the AER will have regard to: • the relevant insurance policy or set of insurance policies for the event • the level of insurance that an efficient and prudent Network Operator would obtain, or would have sought to obtain, in respect of the event • any information provided by Transgrid to the AER about Transgrid's actions and processes, and • any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.

<table>
<tr><th>Adjustment mechanism</th><th>Definition</th></tr>
<tr><td>Insurer’s credit risk event</td><td>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:
• 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
• 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:
• 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
• 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.</td></tr>
<tr><td>Natural Disaster Event</td><td>Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2026-31 regulatory control period that changes the costs to Transgrid in providing EII services, provided the cyclone, fire, flood, earthquake or other event was:
• a consequence of an act or omission that was necessary for the Network Operator to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or
• not a consequence of any other act or omission of the Network Operator.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, among other things:
• whether Transgrid has insurance against the event, and
• the level of insurance that an efficient and prudent Network Operator would obtain in respect of the event</td></tr>
<tr><td>Terrorism Event</td><td>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:
• 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 NSW non-contestable services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, among other things:
• whether Transgrid has insurance against the event
• the level of insurance that an efficient and prudent Network Operator would obtain in respect of the event, and
• whether a declaration has been made by a relevant government authority that a terrorism event has occurred.</td></tr>
</table>

The process for adjusting revenue as a result of these events is described in Chapter 9.5.

9.4.2. Adjustment mechanisms to reflect contractual obligations with EnergyCo

The Project Deed contemplates a range of circumstances, when a revenue adjustment is warranted. This includes:

- where the payments required to be made to EnergyCo under the Project Deed (Infrastructure Planner costs) increase or decrease following the initial Revenue Proposal
- [redacted]
- where we propose a variation to the work specified under the Project Deed and this is approved by EnergyCo.

9.4.2.1. Increases or decreases in Infrastructure Planner costs

Clause 46(1)(b)(ii) of the EII Regulation allows us to recover costs for any payments required to be made to EnergyCo under contractual arrangements entered into pursuant to the Consumer Trustee Authorisation. The Project Deed was entered into pursuant to clause 7 of our Consumer Trustee Authorisation and therefore, payments made in accordance with the Project Deed are permitted to be recovered.

The Project Deed requires us to reimburse EnergyCo for a range of costs EnergyCo may incur in respect of the Project (Infrastructure Planner costs), including:

- costs relating to biodiversity offsets (excluding any biodiversity offsets for which we are responsible for obtaining)
- payments made by EnergyCo for early project development activities
- [redacted]
- the costs of variations to be borne by EnergyCo.

Under the Project Deed, EnergyCo must provide us with actual and budgeted Infrastructure Planner costs. We supported EnergyCo in the determination of the amount for inclusion in the Revenue Proposal, noting that at the time of submission, actual and expected reimbursable costs only related to early development activities (the costs for which are driven by the activities we intend to undertake in this period). This amount is included in the proposed base expenditure (refer to Chapter 4.3).

The actual payments to EnergyCo may be higher or lower than this estimated amount. This could be due to a variance between actual costs incurred and the budgeted amount included in the Revenue Proposal (either higher or lower). It could also be due to a cost arising that was not initially foreseen at the time of submission (e.g. a variation). To account for this, the Project Deed requires us to propose an adjustment mechanism to allow for adjustments to the Infrastructure Planner costs.[106] Accordingly, we propose a non-automatic adjustment mechanism to reflect increases or decreases in Infrastructure Planner costs.

As noted above, EnergyCo will fund costs associated with early project development activities undertaken prior to 1 January 2027. An estimate of these costs, based on the expected program of works to be undertaken in this period, is included in the proposed base expenditure. However, it is possible that this expected program of works may be adjusted or delayed, resulting in a lower early project development cost payable to EnergyCo and a need for us to fund certain early development activities in the 2026-31 regulatory period (i.e. post 1 January 2027) ourselves. This would require a recategorisation of the cost (from an Infrastructure Planner cost to a Transgrid-funded cost).

To reflect this, we propose a non-automatic adjustment mechanism to allow for an increase in the approved capital expenditure for the Project to account for the additional activities, at the same time as the relevant decrease in Infrastructure Planner costs due to reduced early project development costs.

Table 9-4 outlines the proposed adjustment mechanisms.

Table 9-4 Adjustment mechanisms related to changes in reimbursable costs payable to EnergyCo

Adjustment mechanism	Description
Increases or decreases in Infrastructure Planner costs	An Infrastructure Planner Cost Change event occurs where EnergyCo gives written notice to Transgrid under the Project Deed, directing a change to the costs payable by Transgrid and/or the dates the reimbursable costs become payable. The mechanism allows Transgrid to increase or decrease the Infrastructure Planner costs approved in its initial Revenue Determination to reflect the amounts advised by EnergyCo in its written notice. This includes adjustments for: [redacted] • costs incurred by EnergyCo relating to a variation (or any costs saved due to implementing the variation) • any other change in Infrastructure Planner costs.
Recategorisation of early project development costs	An Early Project Development Cost Recategorisation event occurs where: • EnergyCo gives written notice to Transgrid directing a change in the amount to be paid by Transgrid relating to early project development activities; and • that change justifies a corresponding adjustment to reflect the recategorisation of Project-related costs. The mechanism allows Transgrid to increase its approved capital expenditure for the Project to account for the prudent and efficient costs to Transgrid of undertaking the development activities that are no longer captured under the scope of EnergyCo's early development activities, at

[106] The Project Deed also specifically requires adjustment mechanisms for [redacted] variation costs. We consider it appropriate to include a single adjustment mechanism for Infrastructure Planner costs (encompassing [redacted] variation costs and the other cost categories outlined above).

Adjustment mechanism	Description
	the same time as decreasing the recoverable Infrastructure Planner costs. (Note: this requires an assessment by the AER for prudency, efficiency and reasonableness of the recategorised costs with reference to the relevant activities to be undertaken).

9.4.2.2. Costs of meeting other contractual obligations

An adjustment to revenue is warranted in circumstances where our costs vary as a result of satisfying our contractual obligations under the Project Deed. This includes:

- [redacted]
- where we propose a variation to the work specified under the Project Deed and this is approved by EnergyCo.

No budgeted costs are included for these events in the initial Revenue Proposal. Instead, it is more appropriate to adjust Transgrid's revenue if and when these events occur.

[redacted]

Under the Project Deed, there is the potential for future variations to be proposed by either EnergyCo or Transgrid. As described above, where EnergyCo proposes the variation, it will bear the associated cost (an Infrastructure Planner cost). We must then seek an adjustment to its revenue and repay any variation costs to EnergyCo.

In cases where we propose the variation and it is accepted by EnergyCo, we must bear the associated costs of carrying out the variation. There may also be instances where a variation results in a cost saving compared to the original scope to be delivered under the Project Deed. As such, we propose a non-automatic adjustment mechanism to allow the AER to adjust the revenue to reflect the prudent and efficient costs associated with a variation (or to reduce revenue by any cost saving brought about by the variation).

Table 9-5 outlines the proposed adjustment mechanisms.

Table 9-5 Adjustment mechanisms related to meeting contractual obligations

Adjustment mechanism	Description
Liquidated damages	A Liquidated Damages event occurs where Transgrid is liable to pay liquidated damages for an upgrade completion stage to EnergyCo under the Project Deed. The mechanism allows Transgrid to decrease its revenue by the amount of any liquidated damages payable by Transgrid under the Project Deed.
Contractual variations	A Variation event occurs where EnergyCo approves a Variation that was proposed by Transgrid and the costs implications of the Variation are known. The mechanism allows Transgrid to increase or decrease its revenue to reflect the prudent, efficient and reasonable costs associated with the negotiation and carrying out of the variation as directed by EnergyCo (including any cost savings that arise as a result of the variation being implemented).

9.4.3. Routine administrative events

Consistent with the AER's 2024-2029 Revenue Determination for the non-contestable WSB project, we propose the following automatic adjustment mechanisms to account for routine administrative events:

- annual updates to revenue for actual inflation
- annual updates to the allowed rate of return to reflect updated return on debt
- an update to the allowed rate of return to reflect updated return on equity.

Table 9-6 outlines the proposed adjustment mechanisms.

Table 9-6 Adjustment mechanisms relating to routine administrative events

Adjustment mechanism	Description
Updates for actual inflation	An annual adjustment to revenue to reflect the actual rate of inflation. Actual inflation is the percentage change in the Australian Bureau of Statistics Consumer Price Index, All Groups, Weighted Average of Eight Capital Cities, from December in year t-1 to December in year t-2.
Updates to return on debt	An annual adjustment to reflect updated return on debt and corresponding applicable rate of return. Updated rate of return is the applicable rate of return calculated for year t, updated for the return on debt and return on equity calculated for year t, in accordance with the applicable rate of return instrument and using the debt averaging period and risk free rate averaging period nominated by Transgrid and accepted by the AER.
Updates to return on equity	An adjustment to the return on equity to true up for the final averaging period for the risk-free rate. In the event the risk-free rate from Transgrid's nominated averaging period is not available at the time of the AER's Revenue Determination, the return on equity is to be updated prior to the first year of the regulatory period. The risk-free rate, and subsequently the return on equity, is to be recalculated using the nominated averaging period as approved in the Revenue Determination.

9.4.4. Other uncontrollable events

We have assessed the key risks for Project, our ability to prevent or mitigate these risks (including through insurance) and the magnitude of the risk if it occurred. We have also considered the potential cost impact to consumers. Where adjustment mechanisms are accepted by the AER, there are no immediate cost impacts to consumers.

We have also engaged extensively with our TAC on this topic and on how we allocate risk. We consider there are number of risks that are most efficiently managed via adjustment mechanisms if and when the event occurs, rather than via an allowance in the AER's Revenue Determination. These relate to:

- contractor force majeure
- unavoidable D&C contract variations
- biodiversity offset cost variances
- planning approval delays
- cancellation of planned outages by AEMO
- latent conditions
- compulsory acquisition easement costs
- legal challenges arising in the compulsory acquisition process.

We consider that these risks justify the inclusion of an adjustment mechanism in the Proposal, on the basis that they are:

- uncontrollable, and cannot be reasonably mitigated or prevented
- cannot be effectively insured against (either via commercial or self insurance)
- are not accounted for in the base expenditure proposed for the Project, the prescribed pass-through events outlined in Chapter 9.2 or the nominated pass-through events proposed in Chapter 9.4.1
- have the potential to have a significant cost impact
- meet the requirements outlined in the nominated pass-through event considerations.

Our TAC provided feedback that any adjustment mechanism should not allow for duplication of costs between the mechanisms and the base expenditure (including other construction costs). We agree with this position and have reflected it in the development of our forecasts and adjustment mechanisms. This is discussed in further detail in the Other Construction Costs Forecasting Methodology.

When forming our position on the application of incentive schemes (such as CESS) and the calculation of our risk allowance, we have assumed that our proposed adjustment mechanisms are accepted. Where the AER adopts an alternate view of appropriate adjustment mechanisms is appropriate, we will need to also reconsider our positions on these aspects of our Revenue Proposal.

9.4.4.1. Contractor force majeure

We are exposed to the risk of costs arising from force majeure events, which disrupt the contractor during construction phase and result in additional construction costs (i.e. these costs would be incurred prior to the Project being built and operational).

It is preferable to address this risk through an adjustment mechanism, rather than seeking an allowance to cover the risk of a Contractor Force Majeure event. This is because the probability of such an event occurring is relatively low and forecasting the cost impact would be extremely difficult. Mitigating via commercial or self insurance is not reasonable or economical.

Noting this, we propose a non-automatic adjustment mechanism to cover any contractor force majeure events that may arise.

9.4.4.2. Unavoidable D&C contract variations

We have entered into a D&C contract with Zinfra, following a competitive procurement process. The cost of the contract is quoted with reference to the preliminary design of the project available at the time of tendering.

The contract allows for variations in the cost of the contract as the design of the project is finalised and final approvals are acquired. This approach means that the final cost of the contract could potentially be lower than pricing each of these variations into a strict fixed-price contract, where the D&C contractor increases the price in response to the additional risk it bears. The presence of these variations means Transgrid (and our customers) are exposed to unavoidable variations in contract prices that may result from:

- Changes **in the final design or construction methodology of the Project**. These costs may arise from changes to the Project scope in the contractor's final detailed design or construction methodology compared to the contractor's assumptions (based on the initial design) in the tender process. The final design and construction methodology will not be known until planning approvals are received, procurement is completed and various contractor assessments are undertaken. In particular, there is currently uncertainty in respect of:
  - final transmission line and secondary panel design due to the need to finalise tower and panel procurement – this is expected to be finalised at the end of 2026.
  - final secondary system design as this must be completed approximately 3 months prior to the commissioning date to ensure all changes caused by other network projects are reflected.
  - final HV / civil design due to the need for the contractor to undertake various assessments (flooding, electromagnetic fields, mine subsidence analysis). To finalise this design, planning approvals are also required (noting that conditions in the EIS may have design implications e.g. tower dulling or other impact mitigation requirements) – this design is expected to be finalised in late 2025.

  Awaiting the outcomes of these processes prior to finalising the D&C contract would result in significant delays. Similarly, seeking to price these costs into the D&C contract prior to the risk being realised would result in a significant price increase.

- **Changes in the price of key project materials** including steel and guy anchors, which result in the contractor incurring higher or lower costs than those reflected in the construction contract. These costs would be incurred prior to the Project being built and operational, and will only be known following finalisation of HV / civil design in late 2025. The cost variation is unavoidable because the contractor is unable to secure a fixed price for materials until this time. This price risk is passed through to us. Requiring the contractor to price this risk into the D&C contract is uneconomical and would result in a significantly higher contract price. Given this, we consider it is more appropriate for this price impact, once known, to be passed through to consumers in a symmetrical manner (i.e. if either higher or lower than the current estimate).
- **Changes in labour rates,** as a result of the expiry and subsequent renewal of the contractor's Enterprise Agreements on 1 July 2027. The contractor has priced its contract for what they consider to be the most likely change in labour rates ([redacted] escalation in labour costs from 2027-28) however the actual rates may be higher or lower than this estimate. For context, this rate change will apply only to contractor works from 1 July 2027 to practical completion (expected to be in February

2029), which equates to approximately [redacted] of the total contract value. During contract negotiation, the contractor indicated that for them to fully take on the risk, it would have significantly increased the fixed-price contract cost. Given this, we consider it is more appropriate for this price impact, once known, to be passed through to consumers in a symmetrical manner (i.e. if either higher or lower than the current estimate).

No purpose is served in exposing us or our customers to the risk of forecasting error involved in us estimating the likely costs associated with these changes. For these reasons, we propose a non-automatic adjustment mechanism for unavoidable D&C contract variations.

However, to ensure customers are not exposed to significant risk and to strengthen our incentive to minimise costs where prudent and efficient to do so, we also propose a cumulative cap of [redacted] (real 2025-26 dollars) for this adjustment mechanism across the regulatory period (similar to the AER's approach for our non-contestable Waratah Super Battery project). This reflects the TAC's feedback that where possible, caps on adjustment mechanisms should be implemented to ensure customers' cost exposure is appropriately limited.

The capped amount has been determined based on analysis of the individual Project risks that may contribute to an unavoidable D&C contract variation and the estimated costs of those risks, depending on the overall magnitude and shape of the distribution for each risk.

9.4.4.3. Variances in biodiversity offset costs

[redacted]

This is currently our best estimate of the likely costs associated with acquitting our biodiversity offsets liability. The timing of the process and a changing regulatory environment means that currently the final cost, and timing of when these costs will fall, is highly uncertain. Relevantly, desktop studies were required to inform our estimate for offset costs associated with line transposition works, as site access is not possible until the second half of 2025. Additionally, our estimate for biodiversity offset costs is contingent on several external factors that could materially affect costs and timing including:

- Our Biodiversity Offset Delivery Cost Estimate informs the estimates for the Mt Piper to Wallerawang portion of the project and depends on utilising offset sites to minimise the costs payable. These sites cannot be confirmed prior to submission of the Revenue Proposal. Facilitation of this (lowest cost) approach to offset delivery is also dependent upon the approval conditions (including whether consent for offsets deferral is provided, discussed further below). We would likely need to incur significant additional costs if required to offset via alternate acquittal pathways.
- Our estimate is currently calculated assuming that consent for deferral of offset liability beyond approval is provided. This is aligned to the circumstances for other recent Transgrid projects and would enable us to secure offsets after construction of the project has begun, providing an opportunity for refinement of impact and offset calculations and identification of cost-effective offset options. Where consent is not provided, offset costs would likely increase.
- Options available for offset acquittal may change, based on the recently introduced *Biodiversity Conservation Amendment (Biodiversity Offset Scheme) Act 2024.* This legislation was introduced in March 2025 and seeks to establish new acquittal options that may potentially apply to the Project.
- There is currently a lack of certainty around the application of a partial vegetation clearing model to the assessment of biodiversity offset costs. Currently, we have assumed a full clearing model applies to the Project on the basis of Departmental advice, however, we are advocating for application of a partial

model, in which case biodiversity offset costs would likely decrease. The quantum of decrease is currently not known.
- Throughout the Project approval process, approvers may require changes to relevant Project features such as vegetation zones, species polygon mapping, species credit determinations and irreversible impact classifications, which impact the relevant offset costs. Any updates to the Threatened Biodiversity Profiles data collection used to inform our estimate of biodiversity offset costs may also influence requirements. Finally, additional credit obligations for indirect or prescribed impacts, such as habitat connectivity, may be imposed by approvers.

Noting these uncertainties, forecasting the likely cost associated with this risk is extremely difficult. While we have sought to proactively engage with relevant authorities including the NSW Department of Planning, Housing and Infrastructure, NSW Department of Climate Change Energy, the Environment and Water and the Australian Department of Climate Change, Energy, the Environment and Water, we are unable to confidently mitigate the risk of forecasting error or insure against the outcome. Delaying the Project until there is more certainty around these costs is also untenable given biodiversity offset costs are unlikely to be known until at least late 2025.

To ensure consumers are not exposed to the forecasting error associated with this cost category, we propose a non-automatic adjustment mechanism to 'true-up' the actual biodiversity offset costs and environment-related operating expenditure, once the outcomes of the above are known. This ensures that consumers pay no more than required for these costs.

Relatedly, we received feedback from some TAC members that it was appropriate to reflect biodiversity offset costs as a pass-through amount.[107]

9.4.4.4. Planning approval delays

The Mount Piper to Wallerawang portion of the Project was declared Critical State Significant Infrastructure (CSSI) in July 2024. All CSSI project applications must be accompanied by an Environmental Impact Statement (EIS).

We submitted a referral for these works under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). Under the EPBC Act, these works are considered a 'controlled action' and require Commonwealth approval. This will be assessed under the bilateral agreement with the New South Wales Government, via our EIS.[108]

We currently expect to exhibit our EIS in September 2025 and subsequently receive a final assessment in mid-2026, which will include Minister's Conditions and requirements for the Project. This assumed timing is based on our recent experience obtaining relevant planning approvals for major projects. This timeline also aligns with the NSW Government Department of Planning, Housing and Infrastructure's guidelines which state that it will seek to make a determination on a State significant infrastructure project within 100 days.[109] Following such a determination, the Australian Government will then require additional time to review the relevant documentation and make its own determination.

[107] Transgrid Advisory Council, meeting minutes, 30 January 2025.
[108] Department of Climate Change, Energy, the Environment and Water, *Mount Piper to Wallerawang Transmission Line Upgrade Project,* EPBC Act Public Portal, Australian Government, https://epbcpublicportal.environment.gov.au/all-referrals/project-referral-summary/project-decision/?id=ed442d7f-753a-ef11-a316-7c1e522b449e.
[109] NSW Department of Planning, Housing and Infrastructure, *Transmission Guidelines,* November 2024, p. 20, https://www.planning.nsw.gov.au/sites/default/files/2024-11/transmission-guideline.pdf.

We note that there is potential for delays in receiving an assessment as other recent projects have been similarly delayed (e.g. Project EnergyConnect, Snowy Hydro 2.0, HumeLink). We have sought to minimise this risk by conducting ongoing consultation with the relevant government departments. [redacted] As the risk is associated with the actions or requirements of a third party that cannot be governed by contractual obligations, this delay risk is outside of our control. Additionally, given it is difficult to forecast the length of such a delay, we would be exposing consumers to forecasting error by including an allowance for this type of risk in our base expenditure. Instead, we consider it more appropriate to pass these costs through, if and when they occur, noting that we are taking steps to minimise this risk where possible. We also received feedback from TAC members that it was generally appropriate to reflect costs caused by third parties and outside of Transgrid control as a pass through amount.[110]

Noting the above, we propose a non-automatic adjustment mechanism to capture prudent, efficient and reasonable costs incurred by us associated with any potential planning approval delays that are outside of our control. We have excluded from the adjustment any costs that we should have reasonably mitigated, to ensure consumers are only incurring residual costs that are entirely outside of our control and have been incurred prudently, efficiently and reasonably.

9.4.4.5. Cancellation of planned outages by AEMO

Due to the brownfield nature of certain aspects of the Project, we will be required to facilitate network outages for the contractor to perform works. AEMO is notified of these planned outages and makes an assessment to determine what network configuration, limitations or other measures are required to maintain power system security.[111] In the seven days prior to the outage, AEMO will reassess based on updated information including weather forecasts or changes in generation patterns. Finally, on the day of the outage, AEMO will check the outage again and provide permission for us to proceed with the outage.

However, there may be instances where AEMO withholds permission (effectively cancelling the planned outage) to ensure the power system maintains secure and reliable, for public safety reasons or to avoid significant disruption to market operation.[112] AEMO notes that the approval status may change at any time, up to and including on the day of the proposed outage.[113]

This means that the outage duration requested for works by the contractor may not be available during the nominated preference period. We have sought to mitigate this risk by developing an outage management plan for the Project and ensuring the contractor is able to re-order works to mitigate the impact of such delays. We also transferred significant risk to the contractor, ensuring that the contractor is only able to make a claim under the contract if an AEMO outage [redacted] Outage cancellations that occur [redacted] Additionally, in order to claim costs, the contractor must be able to demonstrate that, amongst other things, it is ready to utilise the scheduled outage and it has taken all reasonable actions to minimise the associated cost impact. This significant reduces the risk of additional time delays and costs. However, an unmitigable risk remains which is outside of our control. To ensure that consumers are only

110 Transgrid Advisory Council, meeting minutes, 4 March 2025.
111 AEMO, *Network Outages*, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/network-outages.
112 A Direction or Instruction will be issued under clause 4.8.9 of the NER.
113 AEMO, *Network Outages*, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/network-outages.

exposed to the residual risk outside of our control, we have included wording in the proposed adjustment mechanism to limit the adjustment to the prudent, efficient and reasonable costs, excluding those costs that we are able to effectively mitigate, including by reordering works to reduce the impact of any outage cancellation. This approach was recommended by some of our TAC members.[114]

We propose a non-automatic adjustment mechanism where an AEMO-directed or AEMO-instructed cancellation of a planned outage results in cost impacts that we are unable to effectively mitigate. Our TAC supported such an approach, with some members noting that these events were outside of our control and where an AEMO-directed or AEMO-instructed cancellation occurred, there was a consequential benefit being delivered to consumers by ensuring the security and reliability of the network such that the cost was warranted.[115] An adjustment mechanism of this nature would also support increased transparency relating to the costs associated with AEMO's decisions to cancel planned outages, informing future operational decisions.

9.4.4.6. Latent conditions

Project costs may increase as a result of ground and geotechnical conditions being substantially different from expected conditions (this includes such conditions as the presence of asbestos or other contamination that could have not been reasonable foreseen). Contractors are unwilling to take on risks associated with unforeseen latent conditions and as a result, the D&C contractor may be entitled to relief under the contract if and when a latent condition arises. We may also incur additional costs in managing the issue. We have sought to minimise this risk by undertaking site investigation works to inform baseline assumptions for D&C contract. However, it is not possible to understand all latent conditions prior to construction commencement.

We do not consider it appropriate to expose our customers to the risk of forecasting error by including an estimate of these costs in our base expenditure due to the wide variability in potential cost. Instead, we propose a non-automatic adjustment mechanism to recover our prudent and efficient costs, if and when an event of this nature occurs.

9.4.4.7. Compulsory acquisition easement costs

Landholders impacted by the Project will be entitled to compensation under the *Land Acquisition (Just Terms Compensation) Act 1991.* The process of acquisition often takes at least 18 months and involves extensive negotiations between parties to determine the appropriate compensation amounts. Where a negotiated amount cannot be reached between parties, the Valuer General determines the compensation payable to the landholder and the property is compulsorily acquired.

There is the risk that some property may need to be compulsorily acquired for the Project. If this occurs the cost of the acquisition (including disturbance costs) will be determined by the Valuer General. Due to the timeframes of the Project, property acquisition is at various stages of progress. Given this, there is currently significant uncertainty around if compulsory acquisition will be required, and if so, the likely value attributable. Additionally, legal and expert costs are contingent on the number and type of experts engaged by a landholder in any compulsory acquisition process. Rather than including a risk premium in our base expenditure and exposing consumers to the risk of overpricing the relevant cost, we consider it most

[114] Transgrid Advisory Council, meeting minutes, 4 March 2025.
[115] Transgrid Advisory Council, meeting minutes, 4 March 2025.

appropriate to address this uncertainty through the implementation of an adjustment mechanism. This ensures consumers will only pay if and when compulsory acquisition is required.

9.4.4.8. Legal challenges in compulsory acquisition process

Once the Valuer General determines the compensation payable to the landholder in a compulsory acquisition arrangement, the landholder, if unsatisfied with the compensation amount, can lodge an appeal with the Land and Environment Court of NSW. This Court then reviews and makes a determination on the final compensation payable. These court proceedings are often complex and may require engagement of consultants including legal support, qualified valuers, town planners and hydrology experts. The costs involved in such a process can therefore be significant.

To mitigate the likelihood of objections being lodged, all valuations are instructed in accordance with legislative requirements. It is noted that in NSW, acquiring parties generally resolve approximately 90 to 95 per cent of acquisitions through negotiated agreement.[116] Notwithstanding this, we have identified a small number of properties impacted by the Project, where there is a risk of compulsory acquisition due to their extremely complex nature.

The likelihood and cost of these types of legal proceedings is extremely difficult to forecast, noting that this would be informed by the landholders' individual circumstances and the Court's compensation decision and position on an appropriate compensation amount. Most matters could be dealt with through informal, lower-cost mechanisms for dispute resolution such as mediation, conciliation and neutral evaluation. However, in some circumstances, the process may be escalated to a court hearing. We do not consider it appropriate to expose our customers to the risk of forecasting error by including an estimate of these costs in our base expenditure, especially considering the low likelihood of this type of event occurring. Instead, we propose a non-automatic adjustment mechanism to recover our prudent and efficient costs, if and when a legal appeal of this nature occurs.

Table 9-7 outlines the proposed adjustment mechanisms.

Table 9-7 Adjustment mechanisms relating to other events

Adjustment mechanism	Description
Contractor Force Majeure	A Contractor Force Majeure event occurs when the contractor declares a force majeure and the actual or forecast cost implications of that declaration are known. The adjustment mechanism allows Transgrid to recover the prudent, efficient and reasonable additional construction costs incurred by Transgrid during the construction phase as a result of an unforeseen force majeure event impacting the contractor where: • the costs are not covered by an existing insurance policy or adjustment mechanism, • Transgrid has informed EnergyCo of the Force Majeure event consistent with the requirements of the Project Deed, and • the Force Majeure event is declared in accordance with the terms of the construction contract.

[116] Centre for Property Acquisition, Summary of acquisition – financial year 2023-24, NSW Government.

Adjustment mechanism	Description
Unavoidable D&C contract variations	An Unavoidable D&C Contract Variation adjustment mechanism is triggered where: • a change in the final design or construction methodology occurs and the cost implications are known; or • the contract costs are higher or lower than the forecast amount accepted by the AER in relation to this Revenue Proposal as a result of changes in the price of materials or labour rates allowed for under the D&C Contract. Where the mechanism is triggered, Transgrid is required to increase or decrease its allowable revenue to account for the change in prudent, efficient and reasonable design and construction costs associated with these trigger events, up to a maximum cumulative adjustment of [redacted] over the 2026-31 regulatory period.
Biodiversity offset cost variances	The Biodiversity Offset Cost Variance adjustment mechanism is triggered where: • cost implications of the Project's biodiversity offsets are known, and • those costs differ from the amount accepted by the AER in its Revenue Determination. Where the mechanism is triggered, Transgrid is required to increase or decrease its allowable revenue to reflect the prudent, efficient and reasonable costs incurred in disposing of our biodiversity offset liability for the Project.
Planning approval delays	A Planning Approval Delay event occurs where: • the date of receipt of an EIS determination materially impacts Transgrid's delivery schedule; and • the actual or forecast cost implications of the delay are known. The mechanism allows Transgrid to recover prudent, efficient and reasonable costs associated with facilitating the planning approval delays, including any Extension of Time claim under the D&C contract. For clarity, prudent, efficient and reasonable costs do not include costs that Transgrid is able to effectively mitigate.
Cancellation of planned outages by AEMO	An Outage Cancellation event occurs where: • Transgrid had notified AEMO of a planned outage; • AEMO directs or instructs Transgrid to cancel the outage under the NER; and • actual or forecast cost implications associated with the cancelled outage are known. The mechanism allows Transgrid to recover prudent, efficient and reasonable costs associated with the cancellation of the planning outage. For clarity, prudent, efficient and reasonable costs do not include costs that Transgrid is able to effectively mitigate, including by reordering works to mitigate the impacts of any outage cancellation.

Adjustment mechanism	Description
Latent conditions	A Latent Condition event occurs where: • the D&C Contractor notifies Transgrid of a Latent Condition under the D&C Contract, and • submits a claim for extension of time and/or costs associated with carrying out additional work, using additional construction plant or incurring extra costs (including the cost of delay or disruption), complying with requirements of the D&C Contract, and • the actual costs associated with the Latent Condition are known. The mechanism allows Transgrid to recover prudent, efficient and reasonable costs associated with addressing the latent condition, including any additional management costs to resolve any issues.
Compulsory acquisition easement costs	The Compulsory Acquisition adjustment mechanism is triggered where the Valuer General determines an amount for compulsory acquisition easement costs that exceeds the amount included in Transgrid's base expenditure. The mechanism allows Transgrid to recover prudent, efficient and reasonable costs associated with the compulsory acquisition of the necessary easement for the Project, including any legal, administrative or expert costs required to finalise the acquisition.
Legal challenges relating to compulsory acquisition	The Legal Challenges adjustment mechanism is triggered where: • a landholder/s does not accept the compensation offer determined in accordance with the process specified in legislation and lodges an appeal, and • actual or forecast costs associated with the legal proceedings required are known. The mechanism allows Transgrid to recover prudent, efficient and reasonable costs associated with an appeal to the compulsory acquisition process.

9.5. Formulaic description and process for adjusting revenue

Schedule 6A.1 of EII Chapter 6A and section 4.2 of the AER's Information Notice requires us to provide a formulaic description of our proposed adjustment mechanisms, including:

- a description of the components of revenue to be adjusted and the rationale for the adjustment
- the timing of the adjustment for each component or relevant trigger event, and the timing of the application of the revised schedule of payments
- a detailed explanation of the proposed method of indexation, escalation or adjustment, and
- identification of the authoritative source (or sources) of indices or data to be used for any indexation, escalation or adjustment.

A description of the prescribed and proposed adjustment mechanisms, and the rationale for each, is provided in sections 9.2 to 9.4.

The formula below sets out how these adjustment mechanisms should be used to adjust the revenue proposed to be paid to us (and the recalculation of our schedule of payments) within the 2026-31 regulatory period:

$$\sum_{n=1}^{4} NPV(QP_n) = NPV(AR_t\ (Adjusted)) +\ NAA_t + PTC_t$$

Where:

- $NPV(QP_n)$ is the net present value of each quarterly payment in the year t, calculated by applying the *updated rate of return,* expressed as a quarterly-compounding discount rate
- AR_t (Adjusted) is the annual revenue requirement for year t, calculated using the PTRM, adjusted for *actual inflation and updated rate of return*
- NAA_t is the AER's approved non-automatic adjustment amount for year t, which may be a positive or negative, calculated in accordance with the triggers described in sections 9.2 to 9.4, and
- PTC_t is the AER's approved pass through cost for year t, which may be a positive or negative amount, determined in accordance with the pass-through provisions in EII Chapter 6A.

The process for adjusting revenue is outlined in Table 9-8 below. Notably, unlike the NER Chapter 6A which contains an annual price setting process, the EII regulatory framework contains no explicit price control mechanism that can be used to adjust the revenue and incorporate these amounts into updated quarterly payments from the SFV. We have modelled our proposed revenue adjustment process on the NER annual price setting process to ensure consistency. This also mirrors the process accepted by the AER for the WSB project.

Table 9-8 Proposed process to adjust revenue and schedule of payments

Component	Description
Overall	The quarterly payment schedule is updated each year *t* to incorporate the relevant adjustments. The adjustments are incorporated into the EII PTRM, which then outputs the updated quarterly payment schedule. The updated EII PTRM is subject to approval by the AER.
Adjustment of revenue process and timing	The payments are updated for each year using a 3-step process: 1. Transgrid updates the latest version of the EII PTRM to incorporate the adjustments for the forthcoming year and submits this to the AER by 31 March. 2. The AER reviews the updates and advises Transgrid whether it accepts those updates or not by 31 May. If not, the AER provides Transgrid with an amended version of the EII PTRM that it approves. 3. Transgrid provides the updated quarterly payment schedule to the SFV Financial Vehicle by 30 June along with the AER's approval.
Adjustments	The adjustments for year *t* will include: **1. Prescribed pass-through events** in accordance with EII Chapter 6A. 2. **Automatic Adjustments** as defined in Chapter 9.4.2 3. **Non-Automatic Adjustments** as defined in Chapter 9.3 and 9.4.

Component	Description
Model updates	The adjustments are incorporated into the EII PTRM for year *t* as follows: 1. actual inflation for year *t* is entered into the relevant cell at row 60 of the 'Revenue and Payments' sheet. 2. the return on debt for year *t* is entered into the relevant cell at row 496 of the 'PTRM input' sheet 3. any approved Non-Automatic Adjustments are input to the capex, opex, or revenue adjustment sections in the 'PTRM input' sheet as per the AER's approval of those amounts. 4. any approved amounts for prescribed cost pass-through events are input to the capex, opex, or revenue adjustment sections in the 'PTRM input' sheet as per the AER's approval of those amounts. 5. the updated quarterly payment schedule is then available at row 48 of the 'Revenue and payments' sheet.

9.6. Form of control

The EII regulatory framework does not require an explicit form of control to be determined. This is because under this framework, we recover our costs for delivering the Project on the basis that we are paid quarterly payments by the SFV. Given this, there is no need to rebalance revenue across different tariffs or charging parameters.

Transgrid

10. Incentive schemes

This chapter sets out our proposal in relation to the application of incentive schemes to the Project in the 2026-31 regulatory period.

10.1. Overview

For the 2026-31 regulatory period, we propose to:

- apply **a modified CESS** to the Project reflecting 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 (assuming no shift in the timing of capex).
- **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.[117]

Incentive regulation is a key feature of both the NER and the EII regulatory frameworks. The AER's incentive schemes 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.

The AER's non-contestable guideline explains that the AER intends to:[118]

- apply the same expenditure incentive schemes, being the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) that currently apply under the NER
- develop an EII-specific Service Target Performance Incentive Scheme (STPIS), which would apply only from the second regulatory control period. This would not apply to the Enabling CWO RNIP in the 2026-31 regulatory period, and
- not apply either the NER small-scale incentive scheme or the demand management innovation allowance mechanism, consistent with the requirements of clause 47A(5) of the EII Regulation.

We have carefully assessed the Enabling CWO RNIP's characteristics in forming our position on incentive scheme application to the Project. We also consulted with our TAC on this aspect of our Revenue Proposal, to ensure consumer perspectives were considered.

The following sections explain our position on the CESS, EBSS and STPIS.

10.2. CESS

In considering the application of CESS to this Project, we carefully examined the Project's specific factors against the criteria provided in EII Chapter 6A and relevant AER guidance. We consider that the complex

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[117] Clause 6A.7.4(e) of EII Chapter 6A.
[118] AER, Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects guideline, July 2024, p.13.

and specialised nature of this project, when considered alongside the current operating environment and the regulatory framework under which the Project is delivered, necessitates a modified CESS application.

We propose a CESS design that maintains a 30 per cent sharing ratio for capex overspends and underspends within ±10 per cent of the approved allowance. This aligns with the standard, unmodified CESS framework.

For variances that exceed the ±10 per cent threshold, we propose the CESS continues to apply, but with a modified sharing ratio. Specifically, we suggest setting the sharing ratio equal to the average financing cost (for overspends) or benefit (for underspends), assuming no change in the timing of capex.

This approach ensures that we retain a meaningful incentive to pursue efficiencies, even when capex variances exceed the 10 per cent cap. However, it also ensures that the financial impact of extreme overspends remains manageable for the business. This proposed structure is consistent with the approach adopted by the AER for the HumeLink project.

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.

Our CESS position is informed by our proposed capex forecast and in particular, the inclusion of:

- an allowance in our base expenditure for certain project risks that are unable to be effectively mitigated by us (other construction costs),[119] and
- adjustment mechanisms for low probability, high impact events outside of our control that necessitate a 'pass-through' of costs to consumers.[120]

We consider these positions assist in reducing residual risk, such that it is appropriate to only modify CESS in extreme circumstances, where capex overspends or underspends of more than 10 per cent occur.

In the case where our proposed risk allowance or adjustment mechanisms were not substantially accepted, it is likely that our position on CESS would change.

10.2.1. Factors relevant to determining the application of CESS

Clause 6A.6.5A of EII Chapter 6A stipulates that in determining whether and how to apply CESS, the AER should consider, amongst other things:

- the circumstances of the network operator,
- the interaction of the scheme with other incentives that network operators may have in relation to undertaking efficient expenditure, and
- the CESS principles – namely, that a network operator should be rewarded or penalised for improvements or declines in the efficiency of capital expenditure in a commensurate manner.

The AER's non-contestable Guideline notes that the current NER expenditure incentives guideline applies to EII projects.[121] Relevantly, the Capital Expenditure Incentive Guideline states that in determining whether

[119] EII Chapter 6A, clause 6A.5.4(a)(7).
[120] EII Chapter 6A, clause 6A.6.9(a).
[121] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, section 3.3.

to exclude, or vary, the application of CESS to large transmission projects, the AER considers the TNSP's CESS and capital expenditure proposals and in particular:

- the benefits to consumers from the exemption,
- the size of the project,
- the degree of capital expenditure forecasting risk, and
- stakeholder views.[122]

Our consideration of each of these criteria is outlined in Table 10-1 below.

Table 10-1 Factors relevant to determining the application of CESS

Factor	Consideration
Relevant clause 6A.6.5A factors	
The circumstances of the network operator	**Delivery of a complex project in current operating market** As the network operator for the Enabling CWO RNIP, we are required to deliver a complex and unique project under contractually specified timeframes. The Project involves coordinating various parties under multiple interconnected contractual arrangements and under contractually agreed timelines. It requires the delivery and operational interfacing of our network with the ACEREZ-developed network, resulting in increased governance, and coordination and operational requirements for all parties, which has associated commercial complexity. For example, CWO REZ relies on a new contractual framework that links multiple parties. There are six upstream agreements between Transgrid, EnergyCo and ACEREZ and a downstream contract with the D&C contractor. The interdependencies between these agreements create significant risks. Any misalignment in scope, timelines, or technical requirements would likely lead to delays, cost overruns, and associated commercial impacts. The project also involves two distinct delivery streams — Transgrid and ACEREZ — requiring alignment across design, commercial obligations, delivery schedules and complex, high-risk testing activities. During construction, multiple parties operate under defined access, environmental approvals, and pre-commissioning activities. Effective coordination will be challenging to manage overlapping scope and avoid delays. The integration of the REZ, and the resultant variable renewable energy generation, also necessitates careful network planning and increases the complexity of real-time network monitoring and operations. The current operating market is characterised by: • an unprecedented number of infrastructure projects, • an increasingly tight labour market for construction of electricity transmission projects, • global supply chain security and inflationary pressures on construction costs, • social licence issues requiring active consultation and management, and • declining contractor appetite to bear risk due to recent difficulties delivering projects (including Snowy Hydro 2.0, Sydney Lightrail and the M6 Project) and availability of other project opportunities.

[122] AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, p. 7.

Factor	Consideration
	Given these constraints, the risk of unpredictable and uncontrollable events increases, which also increases the likelihood of us overspending compared to our approved revenue. Where an overspend occurred, we would, in ordinary circumstances, be required to fund the gap in financing the investment for the remainder of the regulatory period and would also be potentially penalised under the CESS for any overspends, even when the higher levels of expenditure are efficient. **EII framework** Our circumstances are also heavily influenced by the regulatory framework under which we are delivering the Project. Consideration should be given as to how the EII framework varies from usual NER processes and the appropriateness of applying CESS in this different context. The AER agreed with this position in its recent draft Capital Expenditure Incentive Guideline, noting that given the differences between the NER and the NSW EII Act framework, there may be a need to consider additional factors on a case-by-case basis.[123] Importantly, CESS was designed to apply to incremental capex incurred in delivering a portfolio of projects and programs under the NER framework. However, under the EII framework, each project undergoes a separate revenue determination process and a separate project RAB is established. Unlike the NER framework, which allows expenditure reprioritisation across a portfolio of projects, we lack the flexibility under the EII framework to offset any potential cost increases for the Enabling CWO RNIP against cost reductions for other projects. This significantly increases the potential for overspends, and resultant CESS penalties, for EII projects (as compared to the NER) due to an inability to manage costs across a portfolio.
The interaction of the scheme with other incentives that network operators may have in relation to undertaking efficient operating or capital expenditure	For NER projects, the AER considers that, without a CESS, there is a significant incentive for network service providers to defer expenditure to the end of a regulatory period. This is because forecast capex that is deferred until later in the period will result in a financing benefit for the provider, in the absence of CESS, and effectively incentivises the provider to delay the expenditure.[124] Overall, we consider that the contractual arrangements between Transgrid and EnergyCo appropriately incentivise us to deliver the works within the specified timeframe. Specifically, we are required to achieve practical completion of each separable portion by the dates specified in the Project Deed. Failure to achieve practical completion of each separable portion carries negative commercial impacts including commercial exposure to ACEREZ (for late delivery of engineering and project development deliverables) and the risk of contract termination in the extreme case of late completion of the network augmentation. This means that even in the absence of CESS, we are appropriately motivated to deliver the Project and incur the capex in the years we have indicated in our Proposal.
The CESS principles	CESS is designed to provide a constant incentive to undertake efficient capex. It does so by rewarding network service providers that outperform against their capex allowance and penalising those who spend more than their allowance,

[123] AER, Capital Expenditure Incentive Guideline for Electricity Networks Service Providers – draft guideline for consultation, May 2025, p. 8.
[124] AER, Determination – Transgrid HumeLink Stage 2 Contingent Project, August 2024, p. 53.

Factor	Consideration
	sharing efficiency losses and gains between network service providers and network users. Conceptually, we agree with the CESS principles. However, we consider that rewards and penalties should only apply where there are true efficiency savings or losses. Where overspends or underspends are driven by factors outside of our control, we do not consider it is in the long-term interest of consumers to apply penalties or rewards for differences between actual and forecast expenditure. We consider that capex overspends of over 10 per cent of our capex allowance are unlikely to be heavily driven by inefficiencies. It is more likely that the current operating market and the complexities of the Project may result in events that are outside of our control but have significant cost impacts. In these circumstances, we do not consider that the application of a penalty aligns with the CESS principles that are aimed at sharing efficiency losses.
Guideline considerations	
Benefits to consumers from the exemption	Where a substantial overspend occurred, we would, in ordinary circumstances, be required to fund the gap in financing the investment for the remainder of the regulatory period and would also be penalised under the CESS for any overspends, even when the higher levels of expenditure are efficient. Given the number of projects underway to support the transition, for Transgrid this would lead to generating less (and potentially substantially less) than the benchmark rate of return for equity. Equity needs to accept some risk for project delivery, and a CESS of sorts can therefore be appropriate, however, the regulatory framework provides for a low beta investment outcome and project risk parameters should be established accordingly. Projects such as these are critical to the energy transition and support government commitments to a net-zero future, which will drive down energy prices and ensure consumers continue to receive access to cheaper, more reliable and secure clean electricity. Enabling them to be efficiently funded is also important.
The size of the project	We consider that it is both the size and the complexity of projects that are relevant to the application of CESS. The capex forecast for the Project is $437.9 million This is larger than the historic annual base NER capex for Transgrid prior to the introduction of the larger scale projects such as Project EnergyConnect, HumeLink and VNI West. As described above under ‘The circumstances of the network operator’, the Project is also complex in that it involves coordinating various parties under multiple interconnected contractual arrangements and under agreed delivery timeframes. It also requires interfacing of our network with the ACEREZ-developed network, resulting in increased governance, and coordination and operational requirements for all parties which have associated commercial complexity. The integration of the REZ, and the resultant variable renewable energy generation, also necessitates careful network planning and increases the complexity of real-time network monitoring and operations. These factors each contribute to the relative risk of the Project and the potential investor impact if an overspend exceeding 10 per cent of capex occurred. For these reasons, the modification of CESS as proposed is appropriate.

Factor	Consideration
The degree of capital expenditure forecasting risk	We consider that the complexity and uniqueness of the Project impact the degree of capital expenditure forecasting risk. As outlined above, we are operating in a novel commercial and delivery environment and are subject to an uncertain operating market such that we are exposed to a range of forecasting risks including with respect to the capital expenditure (i.e. labour and non-labour costs) required to manage and deliver the Project and ensure compliance with applicable requirements and standards. We also acknowledge that our CESS position is informed by our proposed capex forecast and in particular, the inclusion of: • an allowance in our base expenditure for certain project risks that are unable to be effectively mitigated by us (other construction costs),[125] and • adjustment mechanisms for low probability, high impact events outside of our control that necessitate a 'pass-through' of costs to consumers.[126] We consider these mechanisms helpful in reducing our risk. We also acknowledge that, as the network operator, we are expected to manage a degree of risk and are compensated for doing so under the RORI. That said, a number of risks that we bear remain uncapped and fall outside the scope of our base expenditure allowance and adjustment mechanisms. For example: • [redacted] [redacted] In addition, where a risk cost allowance has been proposed, it has been derived using a P50 estimate in accordance with standard probabilistic risk estimation techniques. A P50 value reflects the median case of the distribution – meaning there is a 50 per cent chance that actual costs may exceed the allowance. It is important to note that studies of project outcomes that exceed the P50 estimate show clearly that cost increases on projects tend to have significant tail effects: when project costs exceed the original budget, they can do so extremely significantly (in multiples of the original budget) – inevitably reducing investor appetite for further investment. Accordingly, in a worst-case scenario, particularly in the upper tail of the distribution, Transgrid may remain exposed to residual costs, even in instances where contingencies have been applied. Furthermore, in the event of capital overruns, we will be additionally penalised as we will need to fund the overruns primarily with equity. This is also observed for adjustment mechanisms. where typically the capital spend addressed by the adjustment is funded before revenue is recovered in the following year. Both these nuances result in the inability for a network operator such as Transgrid to achieve the benchmark gearing for all funding – being a 60/40 debt to equity ratio. If our proposed risk allowances or adjustment mechanisms are not substantially accepted, contingency has not been allocated to support this, which would mean our risk position would materially increase. In such a scenario, we would reconsider our position on the application of CESS and

[125] EII Chapter 6A, clause 6A.5.4(a)(7).
[126] EII Chapter 6A, clause 6A.6.9(a).

Factor	Consideration
	formally request that the AER not apply CESS to the Project, given the heightened risk exposure.
Stakeholder views	We consulted with our TAC on the application of CESS. Members of the TAC recommended applying an unmodified CESS to the Project.[127] We acknowledge our TAC's position and have carefully considered the application of CESS with this feedback in mind. However, we also consider that ensuring investor confidence is also in the long-term interests of consumers. Our proposed CESS position recognises that in many cases, we are best placed to manage the cost of projects and therefore should face a CESS penalty or reward for those over or underspends that are generated by our efficiency losses or gains, respectively. However, we do not consider that we are best placed to manage extreme events or 'black swan' type events that are likely to lead to overspends above 10 per cent of capex. Moreover, the regulatory framework provides for a low beta investment outcome and project risk parameters should be established accordingly. It is therefore important to modify CESS to prevent any erosion of investor confidence in these circumstances.

10.3. EBSS

We propose to defer the decision on whether EBSS should apply in the 2026-31 regulatory period to the end of the period. This because:

- there is currently no historical revealed opex upon which to base forecasts,
- the one-off and bespoke nature of EII non-contestable projects means we are not able to use suitable benchmarking, and
- the initial regulatory control period will be a design and construction phase meaning opex may not reach a level of recurrency or a steady state.

This proposed approach aligns with the AER's draft position in the *Incentive schemes for non-contestable network projects in NSW* Guidance Note[128] and its final decision on the non-contestable components for the Waratah Super Battery.

[127] TAC, meeting minutes, 30 January 2025.
[128] AER, Incentive schemes for non-contestable network projects for NSW: guidance note draft, August 2023.

10.4. STPIS

The STPIS provides network operators with incentives for maintaining and improving network performance. The STPIS provides an important counterbalance to the EBSS and CESS to ensure that service levels do not reduce as a result of efforts to achieve efficiency gains.

Section 3.3 of the AER's non-contestable guideline explains that the AER will develop an EII-specific STPIS and that this scheme would apply to non-contestable determinations from the second regulatory control period onwards.[129] Therefore, no STPIS will apply to the Enabling CWO RNIP in the 2026-31 period.

We look forward to engaging with the AER as an EII-specific STPIS is developed.

11. Maximum allowed revenue

This chapter sets out our total annual building block revenue requirement (ABBRR) for the 2026-31 regulatory period calculated using a building block approach.

11.1. Overview

Under the EII Chapter 6A, our total ABBRR is calculated in the same way as under the NER Chapter 6A. This involves using a building block approach which estimates our revenue as the sum of the efficient costs to provide our EII services. The building blocks include:

- return on capital – this is discussed in Chapter 7
- regulatory depreciation (or return of capital) – this is discussed in Chapter 6
- operating expenditure – this is discussed in Chapter 5
- revenue adjustments – given it is the first regulatory period for this Project no revenue increments or decrements arising from incentive schemes are relevant
- corporate income tax (net of imputation credits) – this is discussed in Chapter 8.

Table 11-1 summarises the total revenue forecast of $165.1 million (nominal) broken down by building block component. This revenue is calculated within the PTRM, included as an attachment to this Revenue Proposal, as the sum of the building blocks shown in the tables below.

Table 11-1 Maximum allowed revenue over the 2026-31 regulatory period – Summary ($M, nominal and real 2025-26)

Building block	$M, nominal	$M, real 2025-26	Cross reference to other chapters
Return on capital	125.4	114.3	Refer to Chapters 4, 6 and 7
Return of capital	6.4	6.1	Refer to Chapters 4 and 6
Opex[1]	31.9	28.8	Refer to Chapter 5
Revenue adjustments	-	-	N/A

[129] AER, Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects guideline, July 2024, p.14.

Building block	$M, nominal	$M, real 2025-26	Cross reference to other chapters
Corporate income tax	1.5	1.4	Refer to Chapter 8
Maximum allowed revenue	**165.1**	**150.6**	

[1] **Including debt raising costs.**

Table 11-2 shows the year-by-year breakdown of the forecast over the 2026-31 regulatory period in nominal dollars.

Table 11-2 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 adjustments	-	-	-	-	-	-
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**

Table 11-3 shows the year-by-year breakdown of the forecast over the 2026-31 regulatory period in real 2025-26 dollars.

Table 11-3 Maximum allowed revenue over the 2026-31 regulatory period – Detailed breakdown ($M, real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on capital	11.1	20.8	28.0	27.7	26.9	114.3
Return of capital	(0.2)	2.7	4.3	1.3	(2.0)	6.1
Operating expenditure	0.7	3.3	7.5	9.2	8.0	28.8
Revenue adjustments	-	-	-	-	-	-
Corporate income tax	0.6	0.6	0.2	-	-	1.4
Maximum allowed revenue	**12.2**	**27.4**	**40.0**	**38.2**	**32.8**	**150.6**
NPV (as at 30 June 2026)						**132.6**

12. Schedule of payments

This chapter sets out the proposed schedule of quarterly payments that we will be paid over the 2026-31 period by the SFV for carrying out the Project and the methodology by which we have calculated these payments from the total revenue.

12.1. Payment schedule

In accordance with EII Chapter 6A, we have calculated a schedule of quarterly payments that we, as the Network Operator, propose to be paid by the SFV for delivering the Project.

We have calculated these payments based on our forecast MAR for the 2026-31 regulatory period, which is discussed in Chapter 11. We have converted our MAR into a series of quarterly payments within the PTRM, provided as an attachment to this Revenue Proposal, such that the NPV of the payments matches the NPV of MAR.

Table 12-1 shows the forecast quarterly payments for the 2026-31 regulatory period. We propose that these payments are adjusted using the adjustment mechanisms described in Chapter 9.

Table 12-1 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**

13. Other matters

13.1. Confidential information

In accordance with clause 6A.10.1(f)(2) of the EII Chapter 6A and the AER's confidentiality guidelines[130], we have completed a confidentiality template as an attachment to this Revenue Proposal that details the matters for which we are claiming confidentiality.

13.2. Certifications

13.2.1. Certification statement

Schedules 6A.1.1(5) and 6A.1.2(5) of EII Chapter 6A require our directors to certify the key assumptions that underlie our capex and opex forecasts. Our key assumptions for capex are set out in Chapter 4 and for opex, are set out in Chapter 5.

Our certification statement is provided as an attachment to this Revenue Proposal.

13.2.2. Statutory declaration by Chief Executive

The AER's Information Notice requires an officer of Transgrid to make a statutory declaration attesting to the information provided in response to that notice.

In summary, the statutory declaration specifies actual information must be true and accurate and the forecasts and historical estimates are the best forecasts and estimates able to be provided. These standards are intended to deliver the highest quality information to the AER, to ensure it is able to make decisions that are required under the EII Act.

The statutory declaration made by our Chief Executive Officer is provided as an attachment to this Revenue Proposal.

13.3. Compliance checklist

We have completed a compliance checklist, which demonstrates how we have complied with the AER's Regulatory Information Notice. This is provided as an attachment to our Revenue Proposal.

[130] We have used the AER's draft EII Confidentiality Guideline, August 2023. We have also refer to the AER's Better Regulation Confidentiality Guideline, August 2017 (noting the draft status of the EII guideline).