Final decision

Enabling Central-West Orana REZ network infrastructure project (non-contestable)

(1 July 2026 to 30 June 2031)

January 2026

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

AER reference: AER24009373

Amendment record

Version	Date	Pages
1.0	27 January 2026	90

Contents

Note

This is the main document for the final decision on Transgrid's 2026–31 non-contestable revenue determination for the Enabling Central-West Orana Renewable Energy Zone network infrastructure project (CWO Enabling Project). It should be read with all other parts of the final decision.

The final decision includes the following documents:

- **Final decision** (main document)
- Appendix A – Quarterly service payments
- Appendix B – Adjustment mechanisms
- Appendix C – Rate of return averaging periods – Confidential

Overview

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution and transmission systems in all states and territories except Western Australia. We exist to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions.

In 2021 the NSW Government appointed us to be the Economic Regulator of infrastructure projects under the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act). The EII Act enables the NSW Electricity Infrastructure Roadmap (the Roadmap) which sets out a plan for the development of Renewable Energy Zones (REZ) in NSW that will allow multiple renewable generation and storage projects to be grouped into specific locations to achieve several NSW Government policy objectives.

Under the non-contestable framework, a Network Operator (such as Transgrid) is required to submit a proposal to us that determines the amount of revenue it can recover from consumers to carry out a network infrastructure project (such as the CWO Enabling Project). A Network Operator must also periodically apply to us to determine the maximum allowed revenue it can recover from consumers for the continued operation of its projects. We do not decide the size or scale of network infrastructure projects as this responsibility sits with the Consumer Trustee and the Infrastructure Planner.

Our revenue determination involves the assessment and scrutiny of Transgrid's forecast costs to ensure only the prudent, efficient and reasonable costs of delivering the CWO Enabling Project are recovered from NSW consumers. We have assessed Transgrid's proposal in line with the requirements set out in the EII Act, the *Electricity Infrastructure Investment Regulation 2021* (NSW) (EII Regulation) and the process set out in our *Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects* (Non-contestable Guideline).[1]

Our assessment is informed by submissions from the Network Operator as well as from other stakeholders and the AER's Consumer Challenge Panel (CCP35). As outlined in our Better Resets Handbook, we consider that genuine engagement with consumers is likely to result in better quality proposals being submitted to the AER. Proposals that reflect consumer preferences, and meet our expectations, are more likely to be largely or wholly accepted, creating a more effective and efficient regulatory process for all stakeholders.[2]

Our final decision is that Transgrid can recover $128.9 million ($ nominal) for the 2026–31 period. This is $36.2 million (21.9%) less than Transgrid's revenue proposal. This represents what we consider to be the prudent, efficient, and reasonable costs of delivering the CWO Enabling Project. Our determination also includes various incentives for Transgrid to carry out the project efficiently.

---

1 This Guideline was recently updated. See: AER, *Revenue determination guideline for NSW non-contestable projects*, December 2025.

2 AER, *Better Resets Handbook*, July 2024, p. 3.

1 Background

The CWO REZ was declared by the NSW Minister for Energy under section 19(1) of the EII Act in November 2021.[3] It is initially designed to deliver 4.5 gigawatts of network capacity utilising generation from solar, wind and energy storage projects, with capacity to increase to 6 gigawatts by 2038.

The CWO REZ network infrastructure project contains two components:

- the Main CWO REZ network infrastructure project (CWO Main Project) to be carried out by ACEREZ Partnership (ACEREZ).
- the CWO Enabling Project to be carried out by Transgrid.

The CWO Main Project comprises new network infrastructure within the CWO REZ, including the Merotherie and Elong Elong energy hubs, to connect new generation and storage projects to the existing NSW transmission network. We made our contestable revenue determination for the CWO Main Project in December 2024 and remade the determination in June 2025 following financial close for the project being achieved.[4]

The CWO Enabling Project will enable the CWO Main Project to connect to the NSW transmission network. It also comprises upgrades to the existing transmission network to alleviate network constraints so that renewable electricity generated in the CWO REZ can be transported to consumers throughout NSW.

The CWO Enabling Project includes arrangements to acquire the Barigan Creek Switching Station (BCSS) from the CWO Main Project. In October 2025, AusEnergy Services Limited (ASL) approved the transfer of the asset as the authorisation provider under clause 21(2) of the EII Regulation.[5] This transfer would occur after the BCSS is constructed and pre-commissioned by ACEREZ. Transgrid would then purchase the BCSS (at a price of $186.8 million) and then energise and commission the asset.[6]

The revenue proposal does not currently include forecast incremental expenditure related to the BCSS. However, Transgrid has arranged to include these costs (in a future revenue determination) through adjustment mechanisms once the asset is transferred to Transgrid.[7]

1.1 Regulatory framework

As a regulator under the EII Act, one of our functions is to determine the amounts payable for Network Operators to carry out network infrastructure projects as authorised by the

---

3 The declaration was amended in December 2023 (*NSW Government Gazette No 580*) and April 2024 (*NSW Government Gazette No 147*). See: NSW Government, *Gazette No 569*, 5 November 2021.

4 AER, *CWO REZ network project revenue determination*, December 2024; AER, CWO REZ network project - remade revenue determination - summary report, June 2025.

5 ASL, *Central West Orana Renewable Energy Zone - Transfer of Barigan Creek from ACEREZ Partnership to Transgrid*, October 2025.

6 This price may be adjusted through the 'BCSS Purchase Price Adjustment' mechanism; Transgrid, *Central West Orana Enabling Project 2026–31 - Revenue Proposal*, July 2025, p. 8.

7 Further details in Appendix B.

Consumer Trustee or authorised (or directed) by the NSW Energy Minister.[8] There are two ways a Network Operator may be selected to undertake a network infrastructure project:

- Under a contestable process, a Network Operator is selected following a competitive assessment procurement process conducted by the Infrastructure Planner. This process applied to the CWO Main Project.
- Under a non-contestable process, a Network Operator may be selected directly by the Infrastructure Planner.

Under either process, the revenue a Network Operator may collect from undertaking the network infrastructure project is regulated by the AER and specified in a revenue determination.

In May 2024, the Infrastructure Planner, EnergyCo, selected Transgrid as the preferred Network Operator for the CWO Enabling Project because the works were considered not readily separable from the existing network operated by Transgrid.[9] As such, our revenue determination for the CWO Enabling Project is made under the non-contestable process.

We are required to make a revenue determination in accordance with the requirements set out in the EII Act, the EII Regulation and our Non-contestable Guideline. A revenue determination made for a non-contestable process involves an assessment of the Network Operators' forecast costs and revenue to ensure only the prudent, efficient, and reasonable costs of delivering the project are recovered from NSW consumers. Our determination must ensure that the costs for this project do not exceed the maximum amount set by the Consumer Trustee.

In practice this means that, under section 38(6) of the EII Act, we must ensure that the prudent, efficient and reasonable capital costs for development and construction of a REZ network infrastructure project do not exceed the difference between:

- the maximum capital costs amount for the project (which is notified to us by the Consumer Trustee under section 31(1) of the EII Act)[10]
- and the sum of:
  - any amounts paid or payable, under another determination for the project, to a Network Operator for the capital costs of development and construction of the project
  - any amounts that have been paid, or are likely to be paid, out of the electricity infrastructure fund to the Infrastructure Planner for the project.

In addition, in exercising our functions, we are required to take into account the following principles:[11]

- A Network Operator is entitled to:
  - recover the prudent, efficient and reasonable costs incurred for carrying out the infrastructure project.

---

8 EII Act, s. 38(1).

9 EnergyCo, *Central-West Orana Renewable Energy Zone - Rationale and basis for EnergyCo's network recommendations*, May 2024, p. 40.

10 The maximum amount does not apply to the review or remaking of a revenue determination (s.40(3) of the EII Act). Nor does it apply to capital costs determined under the transmission efficiency test when adjusted from time to time. See: EII Act, s. 38(6A)

11 EII Act, s. 37(1); EII Regulation, cl 46(1)(b).

  - recover the prudent, efficient and reasonable costs of complying with a regulatory requirement.
  - recover the payments it is required to make to the Infrastructure Planner under a contractual arrangement, if it was required to enter the contractual arrangement under the relevant authorisation.
  - revenue for the ongoing ownership, control or operation of the infrastructure project that is commensurate to its regulatory and commercial risks.
- Incentives should be given to Network Operators to promote economic efficiency.

Unlike revenue determinations made under the *National Electricity Rules* (NER), we only have 126 business days to make a non-contestable revenue determination under the EII Regulation.[12] During our review process the Network Operator is entitled to be informed of material issues being considered by us.[13]

1.2 Project authorisation and scope

In June 2024, the Consumer Trustee, AEMO Services (now known as AusEnergy Services Limited or ASL), authorised Transgrid to carry out the CWO Enabling Project under previous section 31(1)(b) of the EII Act.[14] Transgrid's revenue proposal must be consistent with the Consumer Trustee's authorisation, and it has little discretion to vary any element.[15]

Clause 5 of the Consumer Trustee's authorisation for the CWO Enabling Project sets out the scope of the infrastructure works to be undertaken.[16] These are set out in Table 1.1 below.

Table 1.1 Scope of works identified in the authorisation for the CWO Enabling Project

Reference	Description of scope of works
Section 5(a)	a new 330 kV single circuit transmission line between Bayswater and Liddell substations
Section 5(b)	a new 330 kV single circuit transmission line between Mt Piper and Wallerawang substations
Section 5(c)	BCSS cut in works involving Lines 5A3 and 5A5 and connection to Wollar substation […] and including remote ends works at Bayswater, Mt Piper and Wollar substations
Section 5(d)	works to the Network Operator's existing 330 kV Line 79 to enable the overcrossing of 500 kV transmission lines to be constructed from BCSS to Merotherie Energy Hub for the CWO REZ

12 EII Regulation, cl. 50(1)(b).

13 This is also a principle we must consider in exercising our functions. See: EII Act, s. 37(1)(d).

14 ASL, *Notice of Authorisation - Enabling CWO REZ Network Infrastructure Project*, June 2024. Consequent on the amendments to the EII Act by the *Energy Legislation Amendment Act 2025*, clause 5 of Schedule 1 of the EII Act provides that the Consumer Trustee is taken to have authorised the project under section 30AA(1)(a) and the authorisation is taken to be an appointment of the Network Operator by the infrastructure planner under section 31A(1).

15 ASL, *Notice of Authorisation - Enabling CWO REZ Network Infrastructure Project*, June 2024.

16 ASL, *Notice of Authorisation - Enabling CWO REZ Network Infrastructure Project*, June 2024.

Section 5(e)	all ancillary plant, equipment or other assets that will be connected to or used by the Network Operator for the purposes of controlling and operating the above network infrastructure
Section 5(f)	any change, modification or addition to the above network infrastructure: 1) required for the Network Operator to comply with its obligations under the National Electricity (NSW) Law or otherwise at law 2) made in accordance with the Project Deed, provided that following the relevant change, modification or addition, the authorised CWO Enabling Project will remain consistent with the description in sections 5(a) to 5(e) of the authorisation

Source: ASL*, Notice of Authorisation – Enabling CWO REZ Network Infrastructure Project*, June 2024.

Transgrid's revenue proposal sets out how its proposed works are consistent with the Consumer Trustee's authorisation.[17] However, the proposal also includes early development costs which we consider fall outside of the authorisation. We discuss this further in section 6.2.1.3.

As explained above, in October 2025, ASL approved the transfer of BCSS from ACEREZ to Transgrid. In addition to the above scope, Transgrid's revenue proposal included arrangements to acquire the BCSS through four adjustment mechanisms.[18]

As required by section 31(1) of the EII Act, ASL, as the Consumer Trustee, also determined a maximum capital amount for the development and construction of the CWO Enabling Project which we have been notified of (section 3.1 discusses our application of the maximum capital amount).

As stated above, Transgrid's revenue proposal contains early development works that we consider to be falling outside the scope of the authorisation. After having removed these costs from the revenue proposal and our final decision, we are satisfied that Transgrid's revenue proposal is consistent with the Consumer Trustee's authorisation.

[17] Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 8. Further details around the proposed costs associated with Transgrid undertaking the above scope of works are set out in section 4 and 5 of the revenue proposal.

[18] Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, pp. 111–114.

2 Revenue determination process

2.1 Revenue proposal

On 31 July 2025, Transgrid submitted a compliant revenue proposal for the CWO Enabling Project with total capital expenditure (capex) of $437.9 million ($2025–26) and proposed total revenue of $165.1 million ($ nominal) over the 2026–31 period.[19] Table 2.1 below summarises the building block revenue in the revenue proposal.

Table 2.1 Transgrid's proposed building block revenue ($ million, nominal) for the CWO Enabling project

Building block	Revenue proposal
Return on capital	125.4
Regulatory depreciation (including proposed accelerated depreciation)	6.4
Operating expenditure	31.9
Revenue adjustments	-
Cost of corporate income tax	1.5
Maximum allowed revenue	**165.1**

Source: AER analysis.

We published Transgrid's revenue proposal on our website on 5 August 2025. Subsequently, we commenced the first round of consultation on the proposal to help us identify the most material and/or contentious issues for the preliminary position paper. Submissions were open for 15 business days and closed on 26 August 2025. We also published these submissions on our website.

2.2 Preliminary position paper

The preliminary position paper is designed to focus on identifying and discussing key issues arising from a Network Operator's revenue proposal. Our 2024 review of the Non-contestable Guideline removed the requirement for us to make a draft decision and for the Network Operator to submit a revised proposal. Instead, we replaced the draft decision with a preliminary position paper that we publish approximately 55 business days after receiving a compliant revenue proposal.

On 20 October 2025, we published a preliminary position paper for the CWO Enabling Project and sought submissions by 17 November 2025.[20] Stakeholders also had the opportunity to ask questions at our public forum on 10 November 2025.

---

19 The quarterly revenue is less than the revenue cap because the quarterly payments bring forward portions of each annual payment which are discounted at the relevant rate of return. See: Transgrid, *M.7 – Central-West Orana Enabling Project 2026–31 – Post Tax Revenue Model (PTRM) (adjusted)*, July 2025.

20 Under our Non-contestable Guideline there is a consultation period of minimum 20 business days on our preliminary position paper. See: AER, *Final guideline – Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, p. 22.

In our preliminary position paper, we focused on financeability, pre-period costs, the capital expenditure sharing scheme (CESS), and adjustment mechanisms.[21] We were likely to not accept Transgrid's proposal on the first three focus issues. For adjustment mechanisms, our position was that we were likely to not accept 4 adjustment mechanisms, while another adjustment mechanism, design and construct contract variations, could be subject to a delayed forecast capex assessment instead of a cap. We were likely to accept the remaining adjustment mechanisms.

On other areas of Transgrid's proposal, we were:

- continuing to assess elements of Transgrid's capex and opex proposal, such as labour and indirect costs, and biodiversity costs.
- likely to find Transgrid's capex proposals for tendered works, other construction costs, and easement acquisitions to be prudent, efficient, and reasonable.
- likely to decide on applying the efficiency benefit sharing scheme (EBSS) at the end of the 2026–31 regulatory period.
- likely to accept Transgrid's approach to calculating total revenue, schedule of payments, closing regulatory asset base, rate of return, regulatory depreciation, and corporate income tax.

2.2.1 Transgrid submission on the preliminary position paper

On 17 November 2025, Transgrid made a submission on our preliminary position paper. Transgrid's submission stated that it accepted our preliminary positions except for:

- Pre-period costs: Transgrid did not agree with our preliminary position to not accept early development costs of $8.2 million ($2025–26). Transgrid's submission reduced the total amount of early development costs by $2 million ($2025–26), representing removal of costs prior to the commencement of the EII Act. Transgrid maintained it is entitled to recover $6.2 million ($2025–26) in pre-period costs as part of its CWO Enabling revenue determination.
- Four adjustment mechanisms; specifically, our preliminary position to not accept adjustment mechanisms for BCSS replacement expenditure and operating expenditure annual true-ups, biodiversity offset costs, compulsory acquisition easement costs and related legal costs. Transgrid also did not agree with our preliminary position to adopt a delayed capex forecast (instead of a cap) for unavoidable design and construct contract variations.

In addition, Transgrid made commitments on stakeholder engagement which we explain further in section 4.1.

2.2.2 AER consultation requirements under the EII Framework

Under the EII Regulation, clauses 49(1) and 49(1A), we are required to consult with the Infrastructure Planner (EnergyCo) and the Consumer Trustee (ASL) before making our revenue determination. We invited submissions from both on our preliminary position paper for the CWO Enabling Project. EnergyCo and ASL had no comments on our paper.

---

21 AER, *Preliminary position paper – Transgrid – Enabling Central-West Orana REZ network infrastructure project 2026–31*, October 2025.

3 Our final decision

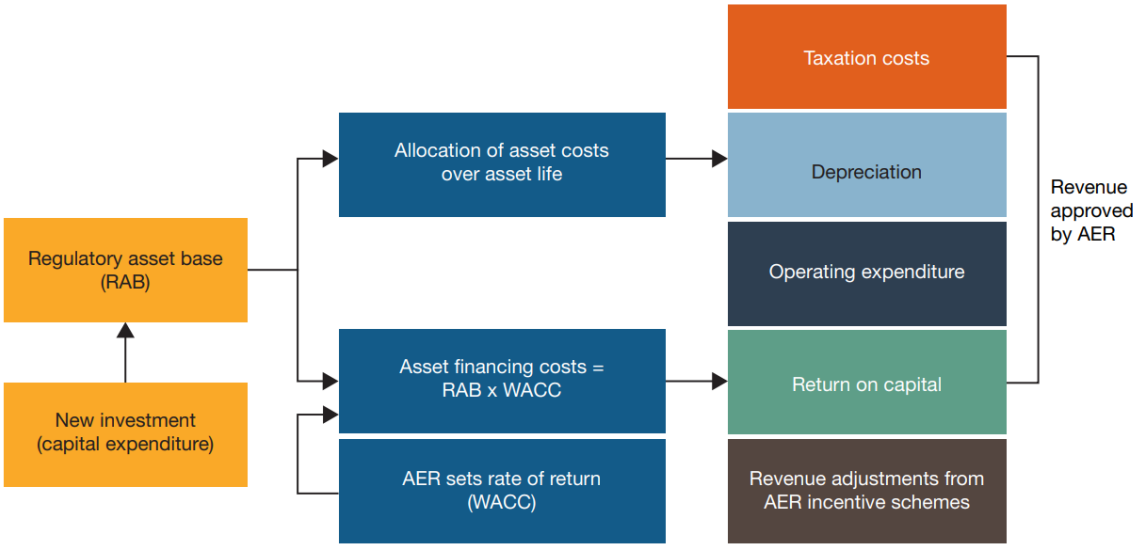
3.1 Key components of our final decision

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for the 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. It delivers benefits to consumers as efficient costs are revealed over time and drives lower cost benchmarks in subsequent regulatory control periods. By only allowing efficient costs in our approved revenues, we ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

Transgrid's proposed revenue reflects its forecast of the efficient cost of providing regulated network services over the 2026–31 period. The revenue proposal, and our assessment of it under the EII Act, are based on a 'building block' approach which looks at five cost components (see Figure 3.1):

1. return on the Regulatory Asset Base (RAB) – or return *on* capital, to compensate investors for the opportunity cost of funds invested in this business.
2. depreciation of the RAB – or return *of* capital, to return the initial investment to investors over time.
3. forecast opex – the operating, maintenance, and other non-capital expenses, incurred in the provision of network services.
4. revenue increments/decrements – usually results from the application of incentive schemes in previous periods, such as the EBSS or the CESS. As this is our first determination for the CWO Enabling Project, there are no revenue increments or decrements.
5. estimated cost of corporate income tax.

Figure 3.1 The building block model to forecast network revenue



In accordance with sections 38(4) and (6) of the EII Act, the amount we have calculated as the prudent, efficient and reasonable capital costs for the development and construction of

the CWO Enabling Project is lower than the confidential maximum amount (maximum capital cost) notified to the AER by the Consumer Trustee.

As flagged in our preliminary position paper, we have undertaken further assessment of Transgrid's remaining non-disclosure claims in the publication of our final decision. Pursuant to clause 53(6) of the EII Regulation, we have decided not to publish some of the information subject to the claims as we are satisfied that it is not appropriate to do so, taking into account the following three factors:

- the public interest
- the extent to which publishing the part of the revenue determination would disclose information that is confidential or commercially sensitive
- the effect of publishing the part of the revenue determination on future competitive assessment processes.

Transgrid has constructively engaged with us on its non-disclosure claims throughout our determination process. This allowed us to minimise the scope of non-disclosure claims, thereby enabling stakeholders to engage effectively with the relevant components of the proposal and our preliminary position.

In future processes, we expect Network Operators to engage with us at an earlier timing and make non-disclosure claims in accordance with the expectations set in our relevant process documents. At present this is the draft Confidentiality Guideline,[22] but we will shortly release more comprehensive guidance on making and assessing non-disclosure claims under the EII Act.

3.2 Key differences between our final decision and Transgrid's proposal

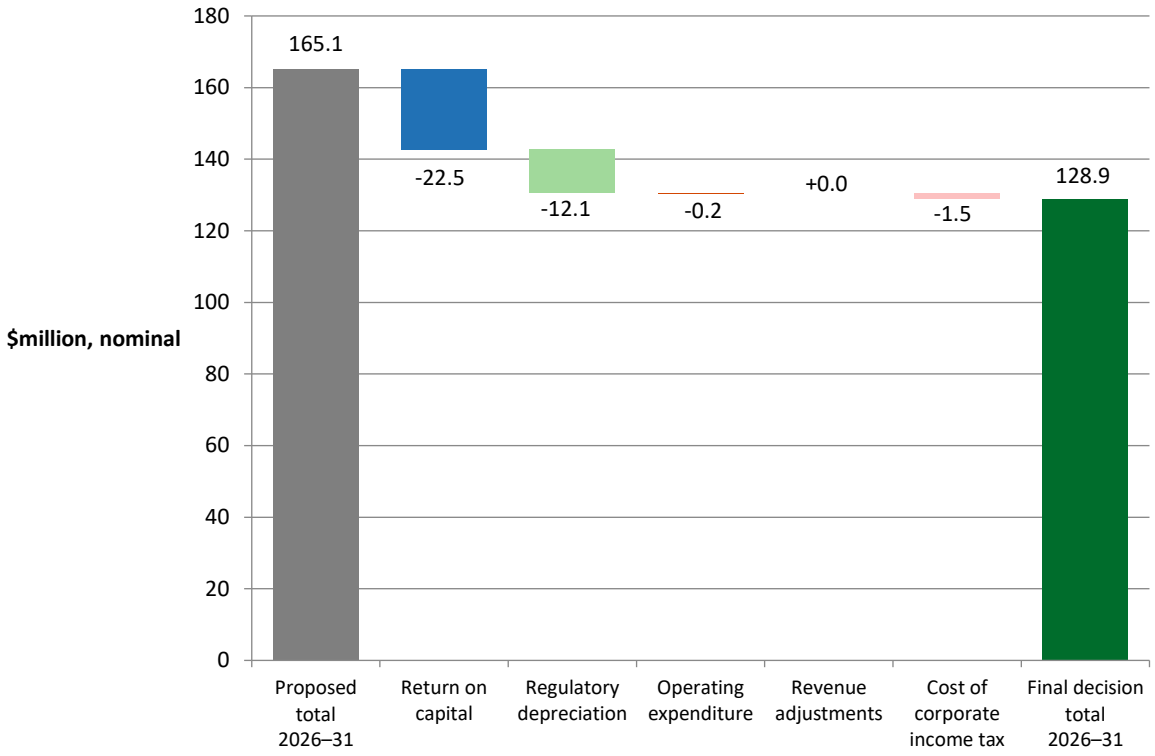
When looking at the 2026–31 period, the key differences between our final decision and Transgrid's proposal for the CWO Enabling project relate to our:

- lower return on capital, driven by a lower forecast rate of return of 6.51% compared to Transgrid's proposed forecast rate of return of 6.78%, a zero opening RAB compared to Transgrid's proposal of $167.8 million ($ nominal) and a lower forecast capex allowance (chapters 6, 7 and 9)
- lower return of capital (depreciation), driven primarily by our final decision to not accept Transgrid's accelerated depreciation for financeability and reducing Transgrid's as commissioned opening RAB to zero (chapters 6 and 8).
- lower capex forecast, due to our final decision reductions to biodiversity offset costs, other construction costs and labour and indirect costs (chapter 9).
- lower estimated cost of corporate income tax, driven primarily by lower taxable revenues (chapter 11).

Figure 3.2 below compares our final decision building blocks with Transgrid's proposal.

22 AER, *Draft – Confidentiality guideline – Electricity Infrastructure Investment Act*, August 2023.

Figure 3.2 Comparison of building blocks between proposal and final decision ($million, nominal)



Source: AER analysis; Transgrid, *Central-West Orana Enabling 2026–31 – PTRM*, July 2025.

4 Stakeholder engagement

It is the responsibility of Network Operators to ensure that consumer views are considered and represented in their revenue proposal. Our role is to consider the consumer engagement process and stakeholder submissions when making our decisions.

Network Operators can demonstrate to us that their proposals are aligned to consumer interests and expectations by conducting comprehensive engagement during pre-lodgement engagement. Often consensus is not possible, in which case the views of the differing groups and how the network sought to make its decision should be reflected in its proposal. We provide guidance on our expectations for consumer engagement in our Non-contestable Guideline and the Better Resets Handbook.[23]

4.1 Transgrid's consumer engagement

Following its authorisation, Transgrid conducted pre-lodgement engagement with its stakeholders through its Transgrid Advisory Council (TAC) from June 2024. The TAC is Transgrid's primary forum for engagement on all regulatory issues under the national framework with TAC members representing consumer advocates, investors and industry participants. Transgrid opted to engage the broader TAC forum on the CWO Enabling revenue proposal as its primary method of consumer engagement.

The TAC met 5 times across 2024–25 with AER staff and CCP35 attending these meetings as observers. CCP35's role was to provide us with feedback on how effective Transgrid's engagement activities were and how its revenue proposal was influenced by its engagement.

We recognise Transgrid's pre-lodgement engagement with stakeholders has improved since the earlier Waratah Super Battery non-contestable project (WSB Project) process in 2023, having taken on the feedback and lessons learnt from that project. For this project, Transgrid conducted 'deep dives' to seek the TAC member's views primarily on risk allocation and adjustment mechanisms, while informing members of other aspects of the proposal.

While improved, Transgrid's engagement fell short of our expectations of pre-lodgement consultation outlined in our Non-contestable Guideline and the Better Resets Handbook.[24] This is evidenced by the submissions we received from CCP35 and members of the TAC which highlighted their narrow scope to influence Transgrid's proposal and limited opportunity to provide feedback on the draft proposal prior to submission to the AER. These submissions together with our observations during TAC meetings informed our preliminary position paper which outlines in greater detail our assessment of the pre-lodgement engagement process.[25]

Our Better Resets Handbook seeks to encourage Network Operators to better engage with their consumers and have consumer preferences drive the development of revenue proposals. It does this by outlining our expectations of how network businesses should engage with their consumers and how that engagement is reflected in their proposals.

---

23 AER, *Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, pp. 17–18.

24 AER, *Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, pp. 17–18; AER, *Better Resets Handbook*, July 2024.

25 AER, *Preliminary position paper – Transgrid – CWO Enabling Project 2026–31*, October 2025.

Network Operators that meet our expectations are more likely to have proposals that are largely or wholly accepted by us.

We recognise that there are constraints to engagement within the framework. This includes the predefined project scope, timeline constraints, and confidentiality restrictions. However, we consider that Network Operators should still strive to meet the expectations of the Better Resets Handbook within the framework. This includes providing greater transparency on predefined elements of the proposal to provide assurance to consumers, and consumers having meaningful opportunities to contribute to elements of the proposal where there is optionality.

Our preliminary position paper provided a list of suggestions for Transgrid to consider in future pre-lodgement engagement for other projects. In response to our preliminary position paper and feedback from TAC members, Transgrid committed to improving its pre-lodgement engagement in line with stakeholder feedback. Transgrid has committed to making improvements aimed at strengthening the transparency, structure and effectiveness of its engagement model, including establishing a specific consumer focussed sub-committee of the TAC and investigating further steps for EII projects.[26]

4.2 Stakeholder submissions

We received four submissions in August 2025 in response to Transgrid's revenue proposal. We addressed these submissions in our preliminary position paper, which was released on 20 October 2025.[27]

On 10 November 2025, we held a public forum about the project after which we received five submissions (including from Transgrid) in response to our preliminary position paper. Table 4.1 below lists the submissions we received on both Transgrid's proposal and our preliminary position paper.

Table 4.1 Submissions on Transgrid's proposal and our preliminary position paper

Submission on Transgrid's proposal[28]	Submission on our preliminary position paper[29]
CCP35	CCP35
Energy Users Association of Australia (EUAA) [a]	EUAA
Louise Benjamin and Gavin Dufty[a]	Louise Benjamin and Gavin Dufty
Save Our Surroundings Riverina	Justice and Equity Centre (JEC)[a]
n/a	Transgrid

a) The EUAA, JEC, Louise Benjamin and Gavin Dufty are all members of Transgrid's TAC.

26 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 2, 13.

27 AER, *Preliminary position paper – Transgrid – CWO Enabling Project 2026–31*, October 2025, pp. 19–21.

28 Stakeholders had 15 business days to provide submissions on the revenue proposal between 5 August 2025 and 26 August 2025.

29 Stakeholders had 20 business days to provide submissions on the preliminary position paper between 20 October 2025 to 17 November 2025.

The non-Transgrid submissions on our preliminary position paper focused on:

- Support for our preliminary positions on the focus issues (outlined in each of the various chapters of this decision) and our recommendations for Transgrid to improve stakeholder engagement in future processes (outlined in the preliminary position paper).
- Limited access to information during pre-lodgement engagement meant that consumers could not meaningfully engage with discussions on various aspects of the proposal. This included Transgrid's CESS and financeability proposals which had the effect of transferring risks to consumers.
- The need for more information on the justification and design of adjustment mechanisms.

The overarching themes from the submissions centred on the allocation of risks between consumers and Transgrid as well as transparency. The submissions explained that during pre-lodgement engagement, consumers could not provide a meaningful and informed position on whether Transgrid was best placed to manage (some or all) risks associated with some adjustment mechanisms because of Transgrid's non-disclosure claims.

We agree with comments made in Louise Benjamin and Gavin Dufty's submission that future proposals should have 'very limited, targeted and justifiable confidentiality claims'.[30] In future processes, we expect Network Operators to carefully consider the extent of their non-disclosure claims. We will also seek to engage on these claims earlier, as we explained in section 3.1.

Where non-disclosure claims are made, Network Operators should provide strong justification, having regard to the matters set out in sub-clause 53(6) of the EII Regulation. Our experience from this project as well as Ausgrid's Hunter-Central Coast REZ network infrastructure project (HCC Project) indicates that Network Operators submitted initial non-disclosure claims that were subsequently withdrawn when asked to provide specific justification.

For example, our preliminary position paper discloses the breakdown of biodiversity offset and easement acquisition costs ($15.0 million and $0.7 million respectively), and the value of the cumulative cap ($25 million) for the 'Unavoidable Design and Construct contract variations' adjustment mechanism. These numbers were not available to stakeholders during earlier consultation stages, even though the adjustment mechanisms associated with these three disclosures ultimately became focus issues in our preliminary position paper.

Our preliminary position was that we were likely to not accept an adjustment mechanism for biodiversity offset costs. In response, the JEC submitted it supported Transgrid's position in TAC meetings but that there was too little information on the degree Transgrid could manage the risk.[31] Meanwhile Louise Benjamin and Gavin Dufty explained that while Transgrid continued to highlight the uncertainty of biodiversity offset costs, it did not justify its

30 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper - 2026-31 Revenue Proposal*, November 2025, p. 4.

31 Justice and Equity Centre, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 4.

$15.0 million estimate.[32] We discuss this issue (as well as stakeholder submissions on the remaining adjustment mechanisms) further in chapter 13 of this final decision.

Open and frank discussions about the costs and nature of risks transferred to consumers requires transparency. Network Operators should be transparent on what risks may occur to the project, and what risk allocations are in scope for discussion. We consider that Network Operators should inform their stakeholders as soon as possible when they decide on risk allocation or transferring risks in their proposal. This gives stakeholders sufficient notice to provide feedback to us when we consult on non-contestable proposals.

Our consideration is informed by CCP35's observations that TAC members only had one two-hour session to learn about (and not provide feedback on) Transgrid's modified CESS and financeability proposals.[33] We discuss our decision on these proposals in chapters 12 and 8 of this decision respectively.

We have considered stakeholder feedback, including from Transgrid, in coming to our final decision and our consideration of specific stakeholder feedback on each individual component of our decision is reflected in the relevant sections of this final decision. We appreciate stakeholder submissions on Transgrid's proposal and our preliminary position paper. The representation of perspectives is critical to supporting our decision making and ensuring a transparent and balanced approach in the non-contestable revenue determination process.

---

32 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 7.

33 CCP35, *Submission - Enabling Central-West Orana RNIP - 2026-31 Revenue Proposal*, August 2025, p. 12.

5 Total revenue and schedule of payments

This section sets out our final decision on the total revenue to be recovered by Transgrid for the CWO Enabling Project over the 2026–31 regulatory control period.

We determine Transgrid's total revenue cap for the period as the sum of its annual building block revenue requirement, using a building block approach.[34] The schedule of payments is derived from the annual building block revenue requirement, on a quarterly basis, in accordance with the EII Regulation and our Non-contestable Guideline.[35] Our final decision determines the total revenue Transgrid is entitled to for the ongoing ownership, control and operation of the CWO Enabling Project, commensurate with the regulatory and commercial risks.[36]

Our assessment approach for total revenue and schedule of payments is detailed in section 2 of our guidance note on AER's EII assessment approach for non-contestable revenue determinations (assessment approach guidance note).[37]

5.1 Transgrid's proposal

Transgrid's proposal included a total revenue of $165.1 million ($ nominal) for the 2026–31 period. Transgrid used the EII post-tax revenue model (PTRM), which is the NER PTRM modified for EII non-contestable determinations, in calculating its total revenue.

Table 5.1 sets out Transgrid's total revenue cap for the CWO Enabling Project as included in its revenue proposal and Table 5.2 sets out its proposed quarterly schedule of payments and the dates on which it is to be paid.

34 EII Chapter 6A, cll.6A.4.2(a)(1) to (2), 6A.14.1(1)(i) to (ii) and 6A.5.4(a).

35 EII Regulation, cll. 52(1) to (2); AER, *Final guideline – Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, p. 19.

36 EII Act, s. 37(1)(c).

37 AER, *Guidance note on AER's EII assessment approach for non-contestable revenue determinations*, September 2025, pp. 3–5.

Table 5.1 Transgrid's proposal – Annual building block revenue requirement and estimated total revenue cap ($ million, 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
Regulatory depreciation[a]	–0.3	2.9	4.6	1.5	–2.3	6.4
Operating expenditure[b]	0.8	3.5	8.2	10.3	9.1	31.9
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	0.6	0.6	0.2	-	-	1.5
Annual building block revenue requirement	**12.5**	**28.9**	**43.4**	**42.7**	**37.6**	**165.1[c]**

Source: Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025.
a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
b) Includes debt raising costs.
c) The estimated total revenue cap is equal to the total annual building block revenue requirement.

Table 5.2 Transgrid's proposal – Schedule of payments ($ nominal)

	Quarter 1 (30 September)	Quarter 2 (31 December)	Quarter 3 (31 March)	Quarter 4 (30 June)	Total
2026–27	2,975,299	3,024,530	3,074,576	3,125,450	**12,199,854**
2027–28	6,888,747	7,002,733	7,118,605	7,236,394	**28,246,479**
2028–29	10,325,134	10,495,980	10,669,653	10,846,200	**42,336,968**
2029–30	10,153,746	10,321,756	10,492,547	10,666,163	**41,634,213**
2030–31	8,956,772	9,104,976	9,255,633	9,408,782	**36,726,163**

Source: Transgrid, *M.6 – Central West Orana Enabling Project 2026–31 – PTRM (adjusted)*, July 2025.

5.2 AER final decision

5.2.1 Total amount and components

We determine a total revenue of $128.9 million ($ nominal) for Transgrid for the 2026–31 period (Table 5.3). This is a decrease of $36.2 million (21.9%) from Transgrid's proposed total revenue of $165.1 million ($ nominal) for this period. This decrease reflects the net impact of our final decision on the various building block costs.

Table 5.3 AER final decision on Transgrid's annual building block revenue requirement and estimated total revenue cap ($ million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Return on capital	-	19.3	27.1	28.2	28.2	102.8
Regulatory depreciation[a]	-	–3.7	–1.0	–0.6	–0.3	–5.6
Operating expenditure[b]	0.8	3.5	8.1	10.2	9.1	31.7
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	-	-	-	-	-	-
Annual building block revenue requirement	**0.8**	**19.1**	**34.3**	**37.8**	**37.0**	**128.9[c]**

Source: AER analysis.
a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
b) Includes debt raising costs.
c) The estimated total revenue cap is equal to the total annual building block revenue requirement.

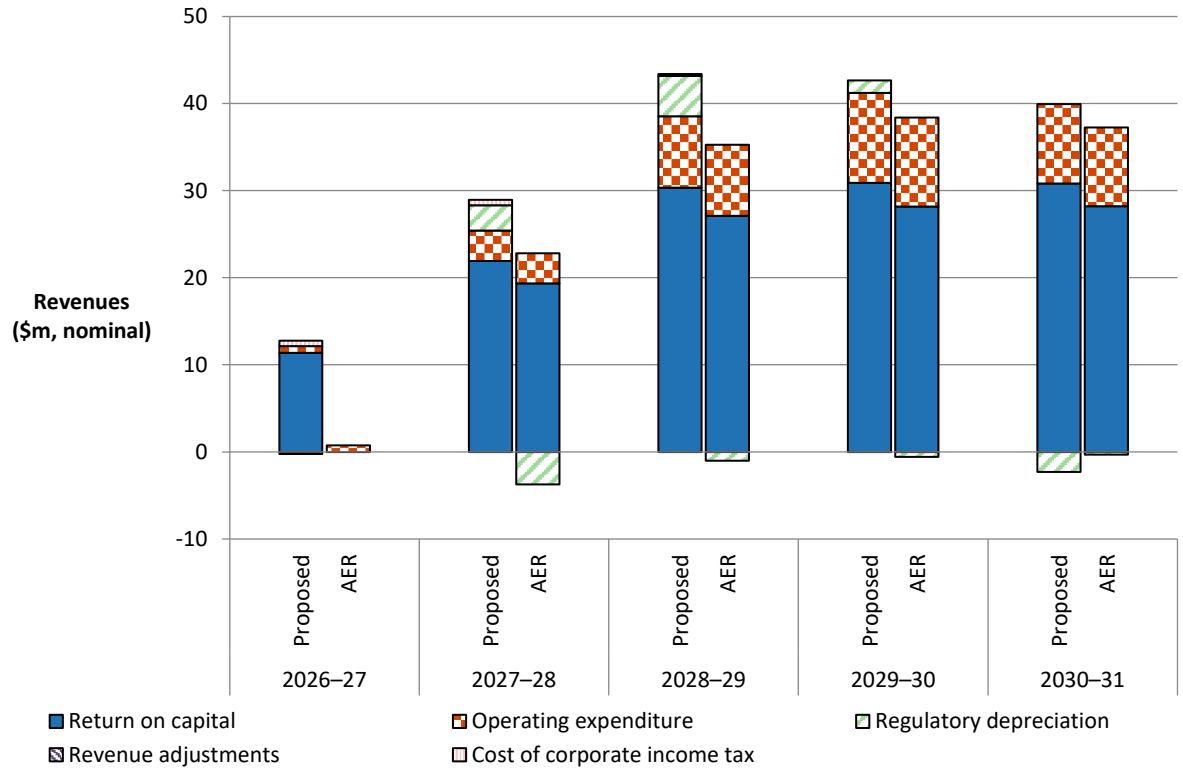
Figure 5.1 compares the building block components from our determination that make up the annual building block revenue requirement with those from Transgrid's proposal.

The changes we made to Transgrid's proposed building blocks include ($ nominal):

- a decrease in return on capital of $22.5 million (18.0%) (chapters 6, 7, 8, and 90)
- a decrease of $12.1 million in regulatory depreciation (chapters 7 and 8)
- a decrease of $0.2 million in operating expenditure (chapters 7 and 10)[38]
- a decrease of $1.5 million to zero in the cost of corporate income tax (chapter 11).

[38] Note that while our final decision is to accept Transgrid's proposed forecast opex, we have updated forecast inflation, which has a minor impact on the opex building block.

Figure 5.1 AER's final decision and Transgrid's proposed annual building block revenue requirement ($ million, nominal)



Source: AER analysis; Transgrid, *M.6 – Central West Orana Enabling Project 2026-31 – PTRM (adjusted)*, July 2025.
Note: There are zero allowances for the cost of corporate income tax and revenue adjustments for the CWO Enabling Project for the 2026–31 period. Opex includes debt raising costs.

The two primary drivers of the overall decrease are the reductions in the return on capital and regulatory depreciation building blocks, reflecting our final decision to approve a zero opening RAB, lower rate of return and lower forecast capex (chapters 6, 7 and 9), and our decision to not accept Transgrid's financeability adjustment for accelerated depreciation (chapter 8). These two building blocks combine for a $34.6 million ($ nominal) reduction of the overall $36.2 million ($ nominal) decrease.[39]

5.2.2 Schedule of payments and payment dates

Our final decision is to determine a quarterly schedule of payments totalling $125.9 million ($ nominal) over the 5 years of the 2026–31 period.[40] This is $35.2 million (21.9%) lower than Transgrid's proposal of $161.1 million. The difference reflects our decision on the various components that make up the annual building block revenue requirement, as discussed in section 5.2.1 above.

---

39 Some components of our final decision, such as removing accelerated depreciation for financeability and reprofiling IPF costs from pre-period to year 1 capex, do not reflect a persistent reduction to Transgrid's revenues. Instead, these two components delay the proposed revenue recovery into later regulatory periods.

40 This is lower than our final decision for the total revenue because the quarterly schedule of payments is progressively recovered by the Network Operator throughout the year, as opposed to the annual building block revenue requirement which is a single annual amount. To ensure equality we determine a quarterly schedule of payments that is equal to revenues in net present value terms.

We accept Transgrid's approach to calculating the schedule of payments. Transgrid has used the EII PTRM to calculate the schedule of payments, consistent with the requirements of the EII Regulation as well as what is set out in our Non-contestable Guideline.[41] We also accept Transgrid's proposed dates on which the quarterly schedule of payments are to be paid, as they align with the payment calculations in the EII PTRM (that is, end of quarter payments).[42]

Table 5.4 sets out our final decision on the schedule of payments and the timing of each quarterly payment for the CWO Enabling Project.

Table 5.4 AER's final decision schedule of payments and timing ($ nominal)

	Quarter 1 (30 September)	Quarter 2 (31 December)	Quarter 3 (31 March)	Quarter 4 (30 June)	Total
2026–27	178,892	181,733	184,620	187,552	**732,797**
2027–28	4,552,205	4,624,504	4,697,951	4,772,565	**18,647,225**
2028–29	8,168,224	8,297,953	8,429,743	8,563,626	**33,459,547**
2029–30	9,022,876	9,166,179	9,311,759	9,459,650	**36,960,464**
2030–31	8,813,359	8,953,334	9,095,533	9,239,990	**36,102,216**

Source: AER analysis.

41 EII Regulation, cl. 52(2).

42 Transgrid, *A.4 – Central West Orana Enabling Project 2026–31 – Regulatory Information Notice Response*, July 2025.

6 Regulatory asset base

The regulatory asset base (RAB) is the value of the assets used by Transgrid to provide regulated network services.[43] Our revenue determination specifies the RAB as at the commencement of the regulatory control period and the appropriate method for the indexation of the RAB.[44] The indexation of the RAB is one of the building blocks that form the annual building block revenue requirement for each year of the 2026–31 period.[45] We set the RAB as the foundation for determining a Network Operator's revenue requirements and use the opening RAB for each regulatory year to determine the return on capital and return of capital (regulatory depreciation) building blocks.[46]

This section presents our final decision on the opening RAB value as at 1 July 2026 for Transgrid and our forecast of its RAB values over the 2026–31 period. It also presents our final decision for establishing the RAB as at the commencement of the 2031–36 period using depreciation that is based on forecast capex.[47]

Our assessment approach for the RAB is detailed in section 3 of our assessment approach guidance note.[48]

6.1 Transgrid's proposal

Transgrid proposed an opening RAB of $167.8 million as at 1 July 2026 ($ nominal). Transgrid is not required to use our roll forward model to determine an opening RAB for this revenue determination as this expenditure occurred prior to the first regulatory control period (2026–31).

Transgrid's proposed opening RAB consists of:

- Infrastructure Planner fees (IPFs) of $152.0 million ($ nominal), adjusted for financing costs of $7.5 million.
- pre-period capex of $8.2 million ($ 2025–26) incurred in 2020–21 and 2021–22, which is prior to the start of the 2026–31 regulatory period.

This totals $167.8 million, which represents Transgrid's proposed opening RAB value as at 1 July 2026 ($ nominal).

Transgrid proposed a forecast closing RAB as at 30 June 2031 of $456.4 million ($ nominal). This value reflects its proposed opening RAB, forecast indexation, forecast net capex, straight-line depreciation and accelerated depreciation over the 2026–31 period. Table 6.1 shows Transgrid's proposed projected RAB over the 2026–31 period.

---

43 EII Chapter 6A, cl. 6A.6.1(a).

44 EII Chapter 6A, cll. 6A.4.2(a)(3A) to (4) and 6A.14.1(5D).

45 EII Chapter 6A, cll. 6A.5.4(a)(1) and (b)(1).

46 EII Chapter 6A, cll. 6A.5.4(a)(2) to (3).

47 EII Chapter 6A cl. S6A.2.2B(a).

48 AER, *Guidance note on AER's EII assessment approach for non-contestable revenue determinations*, September 2025, pp. 6–9.

Table 6.1 Transgrid's proposed RAB for the 2026–31 regulatory control period for the CWO Enabling Project ($million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31
Opening RAB	167.8	323.1	447.5	455.5	454.1
Capital expenditure[a]	155.1	127.3	12.6	-	-
Inflation indexation on opening RAB	4.7	9.0	12.4	12.7	12.6
Less: straight-line depreciation[b]	4.4	11.9	17.1	14.1	10.3
Closing RAB	**323.1**	**447.5**	**455.5**	**454.1**	**456.4**

Source: Transgrid, M.6 – Central West Orana *Enabling Project 2026-31 – PTRM (adjusted)*, July 2025.

a) As incurred, and net of forecast disposals. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling. Includes equity raising costs.

b) Based on as commissioned capex.

Transgrid proposed including pre-period costs of $167.8 million ($ nominal) in the opening RAB for the 2026–31 regulatory period. These relate to IPFs, financing costs and pre-period capex undertaken by Transgrid.

Transgrid proposed to account for $152.0 million ($ nominal) in IPFs as pre-period capex, reflecting EnergyCo's expected costs of funding early development activities to 31 December 2026. The IPFs comprise early works activities undertaken by Transgrid prior to 1 July 2026 in accordance with the Project Development Deed executed in January 2024 and were reimbursed by the Infrastructure Planner (EnergyCo) at the time. Transgrid is contractually required to repay EnergyCo via the IPFs in 2026–2027. Further, Transgrid included financing costs of $7.5 million ($ nominal), which cover the time value of money over the period from when it accrued the pre-period costs to 30 June 2026.

Transgrid also stated that it undertook activities and incurred capex prior to the commencement of the 2026–31 regulatory period (pre-period capex) for $8.2 million ($2025–26). Transgrid indicated these costs related to early development work such as project management, concept design, community and stakeholder engagement and land and environment activities.

6.2 AER final decision

We determine an opening RAB value for Transgrid of $0 million ($ nominal) as at 1 July 2026, a decrease of $167.8 million from the value proposed by Transgrid. We forecast a closing RAB value of $433.7 million ($ nominal) by 30 June 2031. This represents a decrease of $22.6 million (5.0%) compared with Transgrid's proposal. The reasons for our final decision are discussed below.

6.2.1 Opening RAB as at 1 July 2026

We determine an opening RAB value of zero as at 1 July 2026 compared to the $167.8 million from Transgrid's proposal. Our decision to not approve an opening RAB as at 1 July 2026, is based on:

- our decision to remove $152.0 million ($ nominal) in pre-period IPFs and instead allow recovery for this amount in the first regulatory year capex (2026–27) (see section 6.2.1.1)

- our decision to not accept Transgrid's pre-period capex of $8.2 million ($2025–26) (see section 6.2.1.3).

6.2.1.1 Infrastructure Planner costs

In accordance with clause 46(1)(b)(ii) of the EII Regulation, we are required to take into account the principle that Transgrid is entitled to recover payments it is required to pay the Infrastructure Planner (EnergyCo), where the requirement is contained in the contractual arrangements entered under the Consumer Trustee's (ASL) authorisation. To the extent that the IPFs set out in the contractual arrangements conform with clause 46(1)(b)(ii) of the EII Regulation, we are not required to assess the efficiency, prudency and reasonableness of these costs.

Our assessment of Transgrid's proposal and the further supporting information provided by EnergyCo is that Transgrid is required to pay the IPFs to EnergyCo under clause 12.2 and 17.1 of the TNA Project Deed (the Project Deed). The Project Deed is a contractual arrangement that Transgrid is required to enter under clause 7 of the Consumer Trustee's authorisation.[49]

Our final decision is to not accept the approach Transgrid has taken in modelling its IPFs in the EII PTRM, as its revenue proposal seeks an amount that is higher than what it is contractually required to pay EnergyCo. We consider the starting point for modelling IPFs should be ensuring the Network Operator is able to recover the contractual amount that it is required to repay the Infrastructure Planner. This is consistent with our interpretation of clause 46(1)(b)(ii) of the EII Regulation as well as how we have treated IPFs in revenue determinations for other REZ Projects.

We considered IPFs should not be included in pre-period capex but in the year Transgrid is required to contractually make this payment to EnergyCo, which is the first year of the regulatory period (2026–27). Our final decision will ensure Transgrid recovers the full IPF amount of $188.1 million ($2026–27) (which incorporates the $152.0 million proposed by Transgrid in the opening RAB), with no additional compensation for time value of money, in line with the contractual arrangements.

We will exclude these costs from CESS as they are a contractual payment and should not form part of the incentive arrangement (see section 12.2.1).

Although we are not required to assess the efficiency, prudency and reasonableness of IPFs, the following sections are provided to enhance stakeholder transparency over the costs underpinning the IPFs and the governance arrangements in place to ensure prudency, efficiency and reasonableness of costs.

To seek further transparency, on 7 November 2025, we sent a letter to EnergyCo requesting information on the IPFs for the CWO Enabling Project. The information requested included:

- the nature of the underlying contractual costs
- the governance arrangements for the approval and oversight of these costs.

On 25 November 2025, EnergyCo responded to our questions, which included a breakdown of the IPFs as well as details on the governance arrangements for the IPFs.

---

[49] ASL, *Notice of Authorisation – Enabling CWO REZ Network Infrastructure Project*, June 2025.

6.2.1.2 Cost breakdown of Infrastructure Planner Fees

EnergyCo, as the Infrastructure Planner for the project, has a range of obligations it must meet in developing and overseeing the CWO Enabling project. Typically, to meet these obligations, EnergyCo may incur expenses to fund certain pre-development and scoping activities. Similarly, it is expected that the Network Operator may also incur costs prior to the start of the initial regulatory control period, covering project development activities to enable the project to progress according to schedule.

As both categories of expenditure (both EnergyCo and Network Operator costs) occur during a period where the Network Operator does not have any regulated revenues, EnergyCo may fund these costs, on the expectation that the costs would be recovered through payments required to be made to EnergyCo by the Network Operator under a contractual arrangement. These costs are known as IPFs. However, for the CWO Enabling Project, EnergyCo's expenses are recovered through the revenue determination for the CWO Main Project and therefore are not included in this determination. In other words, the IPFs for this project consist solely of Transgrid's Network Operator costs.

Clauses 12.2 and 17.1 of the Project Deed set out the specific provisions and contractual arrangements requiring Transgrid to pay EnergyCo IPFs, totalling up to $188.1 million ($2026–27) to be paid by Transgrid in the first regulatory control period. EnergyCo further provided a breakdown of these estimated IPF costs in Table 6.2. These are estimates only and IPFs will be based on actual costs incurred.

Table 6.2 Infrastructure Planner Fees payable by Transgrid ($ million, 2026–27)

Activities	Cost
Original Project Development Deed amount (excluding Contingency)	33.4
Delivery Partner Early Works Award (including associated Transgrid Internal Labour to oversee Early Works)	10.4
Transgrid Long Lead Equipment (LLE) Procurement	5.2
Line Transposition (1-4) Development Works	17.6
Additional Commercial and Legal Works (compared to PDD assumption of Revenue Determination in February 2025)	5.7
Additional Technical and Delivery Support (compared to PDD assumption of Revenue Determination in February 2025, which was extended to October 2025)	5.2
Extended Project Management Resourcing (compared to PDD assumption of Revenue Determination in February 2025, which was extended to October 2025)	2.6
Development Works for Additional Augmented and Connection Scope (Including for commissioning of BCSS and initial work completed on Line Transpositions 1-4)	0.4
Additional Environment Works (including site investigations, Secretary's Environmental Assessment Requirements (SEARs) studies, surveys, preparation of a Construction Environmental Management Plan (CEMP)).	3.0

Activities	Cost
Extension of Internal Transgrid resources (post previously forecast revenue determination date of October 2025)	12.9
Technical Studies (Voltage Unbalance Study and Non-Credible Contingency Study)	0.7
Biodiversity Offsets	50.7
Delivery Partner Procurement and Mobilisation	9.8
Contingency (Original PDD plus additional early development activities)	30.7
Total	**188.1**

Source: EnergyCo, *Letter to AER regarding TNA Infrastructure Planner Fees*, November 2025.

Governance arrangements for Infrastructure Planner Fees

EnergyCo has established governance arrangements in place for IPFs, including the measures it has put in place to reassure itself of the prudency, efficiency and reasonableness of these costs.

EnergyCo elaborated that IPFs are funded through the Transmission Acceleration Facility (TAF). The TAF is a NSW Government-funded revolving capital facility to fund development activities to accelerate the delivery of critical transmission infrastructure, community and employment benefits and other enabling projects to meet the EII Act and the Roadmap objectives.

The TAF is governed by an independent investment committee, called the TAF Investment Committee. It makes recommendations on TAF funding proposals for decision by the EnergyCo Board and Chief Executive Officer. It has established protocols to ensure accurate monitoring, verification, review and approval of any expenditure associated with the CWO Enabling Project's IPFs. A weekly portfolio meeting, inclusive of the EnergyCo executive team, provides opportunity for project risks and issues to be actioned. Monthly reports are also provided to the EnergyCo Board and TAF Investment Committee on project risks and the status of the Project including spend against the approved TAF funding.

Based on the governance structure and protocols put in place by EnergyCo, we understand that the TAF Investment Committee:

- indicated that it was satisfied that the costs to be incurred for the CWO Enabling Project were reasonable, efficient and necessary for the acceleration of delivered renewable energy in NSW
- endorsed the financing of the forecasted costs for the Project Development Deed phase (from January 2024) and from the execution of the Project Deed (from January 2025) inclusive of Early Development Activities.[50]

[50] The Project Development Deed means the document titled 'Project Development Deed – CWO REZ Project' dated 16 January 2024 entered into between Transgrid and EnergyCo, which was terminated by agreement between the parties when the Project Deed was executed on 31 January 2025. The Project Development Deed required Transgrid to undertake certain development activities to prepare for the CWO Enabling Project.

EnergyCo noted that the TAF funding request proposal included detailed analysis of cost estimates by Transgrid, which was supported by external independent advisors. EnergyCo also received an independent cost estimate which fell within the 10% to 15% range for variances to be expected and considered to be acceptable.

6.2.1.3 Pre-period capex

Our final decision is to not accept Transgrid's proposed $8.2 million ($2025–26) in early development costs, on the basis that Transgrid has not adequately demonstrated that the early development costs relate to the scope of the CWO Enabling Project authorised by the Consumer Trustee.

The early development capex amount contained in Transgrid's proposal of $8.2 million ($2025–26), was later revised down to $6.2 million ($2025–26) in response to our preliminary position paper. This reduction of $2.0 million was due to the removal of costs incurred prior to the enactment of the EII Act on 3 December 2020. The remaining $6.2 million related to costs incurred following the enactment of the EII Act but prior to the authorisation of the CWO Enabling project.

Where Network Operators are required to undertake early development activities prior to a project authorisation, we would typically expect the cost of doing so is compensated by the Infrastructure Planner or other relevant parties via commercial arrangement. Particularly as it is not guaranteed that:

- an authorisation will occur as a result of early development activities, or
- the same entity undertaking early development works will be authorised (or directed) as the Network Operator for the project, and therefore that a subsequent revenue determination will necessarily arise from the early development works.

To the extent a Network Operator incurs early development costs which have not been reimbursed through a commercial arrangement, we would require sufficient evidence that demonstrates these costs are related to the authorised project. The evidence required will vary on a case-by-case basis, however, in general we will examine the following factors (among other considerations):

- the Network Operator demonstrating the activities were required to inform the scoping or development of the project authorisation, with a clear causal link established between the activities undertaken and the information used by relevant parties (e.g. the Infrastructure Planner or Consumer Trustee) in making the authorisation
- confirmation the Network Operator has not recovered the cost through an existing arrangement
- be supported by an acknowledgement by the Infrastructure Planner or authorising party that the cost borne by the Network Operator was required and not reimbursed.

EnergyCo confirmed that Transgrid had been compensated for relevant early development activities through a direct payment at the time of establishing CWO as an EII REZ project.

In response to our preliminary position paper, Transgrid indicated there was a shared understanding between Transgrid and EnergyCo that Transgrid had not been fully reimbursed for all early development activities undertaken to inform the project. We requested documentation referred to in Transgrid's submission supporting this view. However, we consider the documentation provided did not adequately demonstrate a shared

understanding nor meet the expectations set out above. Therefore, our view remains that for the CWO Enabling Project, Transgrid has been unable to adequately demonstrate that the early development costs are expenditures related to the scope of the CWO Enabling Project as authorised by the Consumer Trustee.

The stakeholder submissions supported our preliminary position to exclude early development costs from the opening RAB. Louise Benjamin and Gavin Dufty stated that the evidentiary bar for recovering additional pre-period costs, which weren't approved by EnergyCo, should be high, with other stakeholders such as CCP35, agreeing that these costs be excluded.[51]

As a result, our final decision is to exclude all early development costs ($6.2 million) from the opening RAB on the basis they are not demonstrably related to the project scope and so not reasonable costs for this project.

6.2.2 Forecast closing RAB as at 30 June 2031

We forecast a closing RAB value of $433.7 million ($ nominal) by 30 June 2031 for Transgrid, which represents a decrease of $22.6 million (5.0%) to Transgrid's proposal. The decrease reflects our final decision on the inputs for determining the forecast RAB in the PTRM. Our final decision uses the EII PTRM to forecast the closing RAB at 30 June 2031.

Table 6.3 sets out our final decision on the forecast RAB values for Transgrid over the 2026–31 period.

Table 6.3 AER's final decision on Transgrid's RAB for the 2026–31 regulatory control period ($million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31
Opening RAB	-	297.3	417.0	432.9	433.4
Capital expenditure[a]	297.3	116.0	14.9	-	-
Inflation indexation on opening RAB	-	7.7	10.8	11.3	11.3
Less: straight-line depreciation[b]	-	4.0	9.8	10.7	11.0
Closing RAB	297.3	417.0	432.9	433.4	433.7

Source: AER analysis.
a) As incurred, and net of forecast disposals. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling. Includes equity raising costs.
b) Based on as commissioned capex.

51 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025; CCP35, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025.

7 Rate of return

The return each business is to receive on its RAB, known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.[52]

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and a return on equity to investors.

We also make an estimate of expected inflation over the next 5 years. Alongside our nominal estimate of the rate of return, these determine the effective real return that will be provided to investors over time.

Our assessment approach for the rate of return is detailed in section 4 of our assessment approach guidance note.[53]

7.1 Transgrid's proposal

Transgrid's proposal applied the 2022 Rate of Return Instrument (2022 Instrument).[54] Transgrid proposed the following inputs for the rate of return, expected inflation, and debt and equity raising costs for the 2026–31 period:[55]

- a nominal vanilla weighted average cost of capital (WACC) of 6.78%
- a value of imputation credits (gamma) of 0.57
- an expected inflation rate of 2.78%
- equity raising costs of $1.6 million ($2025–26)
- debt raising costs of 8.3 basis points per annum or $0.9 million ($2025–26).

The nominal vanilla WACC of 6.78% was calculated using market data from placeholder averaging periods. Transgrid has proposed to use its confidentially nominated averaging periods to estimate its final revenue.[56] This included one risk-free rate averaging period (used to calculate the return on equity) and five averaging periods for the return on debt, so that the latter could be updated annually across the 2026–31 period.

7.2 AER final decision

For this final decision, we apply the current 2022 Instrument, consistent with the requirements of the EII Regulation and Transgrid's proposal.[57] The 2022 Instrument specifies how we will estimate:

---

52 EII Chapter 6A, cl. 6A.6.2.

53 AER, *Guidance note on AER's EII assessment approach for non-contestable revenue determinations*, September 2025, pp. 10–12.

54 AER, *Rate of return instrument*, February 2023.

55 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025, pp. 100–104.

56 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal – CONFIDENTIAL*, July 2025, p. 102.

57 AER, *Rate of return instrument*, February 2023; EII Regulation, cl. 47D(4).

- the return on debt
- the return on equity
- the overall rate of return
- the value of imputation credits.

Our final decision estimates an allowed rate of return of 6.51% (nominal vanilla) through the application of the 2022 Instrument to Transgrid's proposal for the 2026–31 period.

We will update the return on debt component of the rate of return each year, in accordance with the 2022 Instrument, to use a 10-year trailing average portfolio return on debt that is rolled forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods. Transgrid will gradually transition the CWO Enabling Project RAB into the trailing average portfolio, as described further below.

As such, our calculated rate of return in Table 7.1 would apply to the first year of the 2026–31 period. A different rate of return may apply for the remaining regulatory years.

Table 7.1 AER's final decision on Transgrid's rate of return for the 2026–31 period

	Transgrid proposal	AER final decision	Allowed return over period
Nominal risk-free rate	4.47%[a]	4.27%[c]	
Market risk premium	6.20%	6.20%	
Equity beta	0.6	0.6	
Return on equity (nominal post-tax)	8.19%[a]	7.99%	Constant (%)
Return on debt (nominal pre-tax)	5.84%[b]	5.52%[c]	Updated annually
Gearing	60%	60%	Constant (%)
Nominal vanilla WACC	6.78%[ab]	6.51%[c]	Updated annually for return on debt
Expected inflation	2.78%	2.60%	Constant (%)

Source: AER analysis; Transgrid, *Central-West Orana Enabling Project 2026–31 – Model 5: Rate of return*, July 2025.
a) Calculated using a placeholder averaging period between 4 March 2025 and 31 March 2025.
b) Calculated using a placeholder averaging period between 18 March 2025 and 31 March 2025.
c) Calculated using different averaging periods to the revenue proposal.

Our final decision is also to:

- accept Transgrid's proposed risk-free rate averaging period and debt averaging periods because they comply with the conditions set out in the 2022 Instrument.[58] We specify these averaging periods in confidential Appendix C.
- apply a value of imputation credits (gamma) of 0.57 as specified in the 2022 Instrument[59]

58 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025, p. 101.

59 AER, *Rate of return Instrument, Explanatory Statement*, February 2023, pp. 240–250.

- accept Transgrid's proposed approach to estimating forecast inflation as it is consistent with our 2020 Inflation Review.[60] However, we have updated the inputs to reflect the latest market data available, resulting in an expected inflation of 2.60%.

7.2.1 True-up for final averaging periods

The 2022 Instrument allows Transgrid to nominate averaging periods for the return on debt and the risk-free rate (used for the return on equity).[61] Transgrid has already nominated these periods, but the time periods available for selection could be before or after this final decision. Therefore, the required market data from Transgrid's nominated averaging periods may not be available in time to include in our final decision.[62] The 2022 Instrument is designed such that even if the latest possible averaging periods are nominated, data relevant to the first year of the regulatory control period can be included in a NER final decision.[63] However, the EII framework has a shorter timeline than a standard NER revenue determination, by about 9 months. This means that our ability to include the relevant market data in an EII final decision depends on the specific dates of the averaging periods nominated by the Network Operator.

To preserve confidentiality over Transgrid's nominated averaging periods, we have included a mechanism in the PTRM to allow us to adjust revenues to true-up for any rate of return not known at the time of the final decision.[64] If this occurs, a placeholder averaging period would be used in our final decision and we would subsequently adjust revenues to 'true-up' and put Transgrid back in the position it would have been in, had the outcomes been known in time for the final decision. This mechanism has been implemented in earlier decisions such as the WSB and HCC Projects.[65] As such, the mechanism being included for the CWO Enabling Project should not be viewed as confirming the averaging periods nominated by Transgrid, but rather ensuring a method is available should it be required. We will continue to incorporate this mechanism in future EII non-contestable processes.

7.2.2 Transition to the trailing average portfolio return on debt

The 2022 Instrument provides for a gradual transition into the 10-year trailing average portfolio return on debt.[66] This transition period commences in the first regulatory year for which the return on debt is calculated using a trailing average for the first time for the relevant regulated service. The transition takes 10 years to complete.

---

60 AER, *Final position – Regulatory treatment of inflation*, December 2020.

61 AER, *2022 Rate of return instrument (version 1.2)*, March 2024, cll. 7–8, 23–24.

62 More specifically, this statement refers to data from the risk-free rate averaging period (which is relevant across the whole 5-year regulatory control period) and the year 1 return on debt averaging period (which is relevant to 2024–25 only). It is always expected that year 2 to year 5 return on debt averaging periods will not be known when the final decision is made.

63 The 2022 Instrument specifies that the risk-free rate averaging period must finish 4 months before the start of the regulatory control period, and the return on debt averaging period must finish 5 months before the start of the relevant regulatory year. See: AER, *Rate of return instrument*, February 2023 (version 1.1 as amended August 2023), cll. 8, 24.

64 See adjustment mechanisms 5 and 7 in Table 13.1 below. We will use a placeholder averaging period as close as practicable to the date of the final decision, noting that some lead time is necessary for data providers to publish the data and for the AER to obtain and process it.

65 AER, *Final decision – Transgrid 2024–29 – Waratah Super Battery Non-contestable*, December 2023, pp. 15–16; AER, *Final decision – Ausgrid 2026–31 – Hunter Central Coast Non-contestable*, December 2025.

66 AER, *2022 Rate of return instrument (version 1.2)*, March 2024, cl. 9.

In the first year, there is only one return on debt estimate, so it is given 100% weight. In each subsequent year, a new estimate is added to the portfolio and given 10% weight, while the weight on the earliest year reduces by 10%. Eventually, after 10 years, a rolling 10-year window is established.

For Transgrid across the 2026–31 period, this means the weights are as follows:

- 2026–27: 100% on 2026–27
- 2027–28: 90% on 2026–27, 10% on 2027–28
- 2028–29: 80% on 2026–27, 10% on 2027–28, 10% on 2028–29
- 2029–30: 70% on 2026–27, 10% on 2027–28, 10% on 2028–29, 10% on 2029–30
- 2030–31: 60% on 2026–27, 10% on 2027–28, 10% on 2028–29, 10% on 2029–30, 10% on 2030–31

This pattern continues until the full 10-year rolling window is established in 2035–36.

7.2.3 Pre-period rate of return

We have not approved any pre-period expenditure in this final decision; therefore, we have not made a decision regarding the pre-period rate of return.

7.2.4 Expected inflation rate

Our estimate of expected inflation included in this final decision is 2.60% (Table 7.2) based on the approach adopted in our final position paper from our 2020 Inflation Review.[67]

Transgrid's proposal adopted our current approach for estimating expected inflation.[68] Our final decision therefore updates the relevant inputs for the latest information available at the time of this final decision.

Table 7.2 AER's final decision on Transgrid's forecast inflation (%)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Expected inflation	2.70	2.65	2.60	2.55	2.50	2.60

Source: AER analysis: RBA, *Statement on Monetary Policy*, August 2025, Table: Output Growth, Unemployment and Inflation Forecasts. See https://www.rba.gov.au/publications/smp/2025/aug/overview.html.

7.2.5 Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 Instrument.[69] This is consistent with the value included in Transgrid's proposal.[70]

67 AER, *Final position – Regulatory treatment of inflation*, December 2020.

68 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025, pp. 102–103.

69 AER, *Rate of return Instrument, Explanatory Statement*, February 2023, pp. 240–250.

70 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025, p. 105.

7.2.6 Capital raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. Our final decision forecasts for debt and equity raising costs are included in the PTRM.

Equity raising costs

Equity raising costs are transaction costs incurred when a service provider raises new equity. We provide an allowance to recover an efficient amount of equity raising costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Equity raising costs are calculated in our PTRM as part of our approved capex for the first year of the period.

Transgrid has forecast $1.6 million ($2025–26) in equity raising costs in the PTRM, using the approach set out in the model. We have updated our estimate for the 2026–31 period based on the benchmark approach using updated inputs. This results in equity raising costs of $3.3 million ($2025–26). This significant increase is a consequence of our decision to reprofile Transgrid's IPF expenditure from the pre-period years, which are excluded by the PTRM in calculating the equity raising capital requirements, into year 1 capex.

Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced, as well as the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. Transgrid has proposed debt raising costs of 8.3 basis points per annum, consistent with our decision for Transgrid's most recent determination under the NER.[71] While our final decision on the CWO Enabling Project has updated the debt raising costs unit rate to 10.2 basis points per annum, there is no consequential change in revenue as we have accepted Transgrid's proposed total opex (section 10) inclusive of its debt raising costs as per its unadjusted PTRM (that is, exclusive of financeability adjustments). Therefore, our final decision includes total debt raising costs of $0.9 million ($2025–26) for the 2026–31 period, consistent with Transgrid's proposal.[72]

---

71 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, May 2025, p. 103.

72 Transgrid's proposal included two separate PTRMs, adjusted and unadjusted, to reflect its proposal to accelerate depreciation for financeability purposes. Accelerating depreciation modifies the forecast RAB profile and consequently affects the calculation of the debt raising cost amounts for each year. As our final decision is not to accept Transgrid's financeability proposal, our final decision's acceptance of Transgrid's proposed opex and debt raising costs similarly is based on the unadjusted PTRM (exclusive of financeability adjustments).

8 Regulatory depreciation

Depreciation is the amount provided so capital investors recover their initial investment over the economic life of the asset (return of capital). In deciding whether to approve the depreciation schedules submitted by Transgrid, we make determinations on:

- The indexation of the RAB and depreciation building blocks for the regulatory control period.[73] The regulatory depreciation amount is then calculated as the net total of the straight-line depreciation less the indexation of the RAB.[74]
- The capability for the Network Operator to efficiently obtain finance to carry out the network infrastructure project, known as financeability.[75] Where our assessment is that there is a financeability issue with a particular REZ project, we will determine the necessary adjustment to the depreciation profile to resolve the financeability issue.[76]

This section sets out our final decision on Transgrid's regulatory depreciation amount, proposed depreciation schedules, asset lives used for calculating the straight-line depreciation and financeability. Our assessment approach for depreciation is detailed in section 5 of our assessment approach guidance note.[77]

8.1 Transgrid's proposal

For the 2026–31 period, Transgrid proposed a total forecast regulatory depreciation amount of $6.4 million ($ nominal). To calculate the depreciation amount, Transgrid proposed to use:[78]

- the straight-line depreciation method employed in our EII PTRM for all standard asset classes
- the same asset classes and standard asset lives for depreciating its forecast capex for the 2026–31 period as those approved in its 2023–28 NER final decision
- a new 'financeability asset class 1' asset class and a corresponding financeability life of 3 years to accelerate the depreciation of $23.7 million of assets related to the 'Secondary system' asset class over the 2026–31 regulatory period to address a perceived financeability issue (discussed further below in section 8.1.1)
- two new asset classes related to biodiversity offsets 'Biodiversity offsets - Stewardship sites' and 'Biodiversity offsets - Direct payments & Other costs' both with a corresponding standard and remaining asset life of 45.8 years calculated as the weighted average of the standard asset lives for all depreciating assets
- the as commissioned method of depreciation for all asset classes other than the three new asset classes for biodiversity offsets and financeability, which have been depreciated on an as incurred basis, reflecting the nature of the costs and implementation of the proposed financeability adjustment respectively

---

73 EII Chapter 6A, cll. 6A.5.4(a)(1) & (3) & 6A.14.1.

74 EII Chapter 6A, cl. S6A.2.4(c).

75 EII Regulation cl. 47D(3); EII Chapter 6A, cl. 6A.6.3(d).

76 EII Chapter 6A, 6A.6.3A(k); EII Chapter 6A, 6A.6.3A(n).

77 AER, *Guidance note on AER's EII assessment approach for non-contestable revenue determinations*, September 2025, pp. 13–18.

78 Transgrid, *M.6 – Central West Orana Enabling Project 2026–31 – PTRM (adjusted)*, July 2025.

- the proposed forecast as commissioned capex for the 2026–31 period
- an expected inflation rate of 2.78% per annum for the 2026–31 period.

Transgrid's proposal included a total capex of $199.8 million ($ nominal, inclusive of WACC escalation) related to IPFs, which are contractual costs Transgrid is required to repay EnergyCo, primarily related to early pre-period works for the CWO Enabling Project. Transgrid has proposed to depreciate these costs in the respective asset classes that the spend related to, rather than as part of a separate 'Infrastructure Planner Fee' asset class.

Table 8.1 sets out Transgrid's proposed annual depreciation amounts for the 2026–31 period inclusive of its proposed financeability adjustment to accelerate depreciation.

Table 8.1 Transgrid's proposed regulatory depreciation for the 2026–31 regulatory control period ($ million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Straight-line depreciation	4.4	11.9	17.1	14.1	10.3	57.8
Less: Inflation indexation on opening RAB	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**

Source: Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025.

8.1.1 Transgrid's financeability proposal

As part of its revenue proposal, Transgrid also submitted a financeability request, in accordance with clause 6A.6.3A of the EII Chapter 6A and our Financeability Guideline.[79] It proposed that the application of the financeability test, as set out in our Financeability Guideline, demonstrates a financeability issue exists for the CWO Enabling Project and therefore proposed to accelerate the depreciation of $23.7 million of assets related to the 'Secondary systems' asset class. Transgrid proposed these assets to depreciate over a period of 3 years, instead of their economic life of 15 years.

The accelerated depreciation results in a $18.6 million ($ nominal) increase in straight-line depreciation over the 2026–31 period, compared to if accelerated depreciation was not applied.[80] This translates to a $17.7 million ($ nominal) increase in revenues.[81] Table 8.2 sets out the initial depreciation schedule prior to applying the financeability adjustment and the net change to the forecast straight-line depreciation schedule as a result of accelerated depreciation.

79 The AER's Financeability Guideline is published under the NER but applies to EII determinations as per our Non-contestable Guideline. See: AER, *Financeability Guideline*, November 2024.

80 The increase in the straight-line depreciation amounts do not align with the total value of the assets shifted for accelerated depreciation because there is a corresponding decrease in the depreciation schedule of the 'Secondary systems' asset class, where the capex amounts were initially being depreciated over a longer life.

81 The difference primarily reflects the offsetting interaction between depreciation and indexation (and by extension the RAB). While accelerated depreciation increases revenues by bringing forward cashflows from future years, it is partially offset by the RAB decreasing at a faster rate, therefore resulting in a lower indexation and return on capital.

Table 8.2 Transgrid's proposed straight-line depreciation pre-financeability adjustment and proposed accelerated depreciation for the 2026–31 regulatory control period

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Straight-line depreciation (pre-financeability adjustment)	0.6	4.3	10.7	11.7	12.0	39.2
Accelerated depreciation for financeability	3.8	7.6	6.4	2.5	–1.7	18.6
Straight-line depreciation (post-financeability adjustment per Transgrid's proposal)	4.4	11.9	17.1	14.1	10.3	57.8

Source: AER analysis; Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025.

In supporting its financeability request, Transgrid also provided:

- a set of confidential documents from the Clean Energy Finance Corporation (CEFC) detailing all relevant concessional financing agreements Transgrid has entered and how this is to be accounted for in its financeability request
- a financeability model demonstrating its financeability position prior to and after accounting for the CWO Enabling Project expenditure[82]
- underlying models and assumptions relied upon by Transgrid in calculating its cashflows on a whole-of-business basis, including relevant sensitivity and scenario analysis.

Transgrid submitted that its modelling demonstrates a financeability issue which requires rectifying in 2026–27, the first year of the regulatory control period. This outcome is based on the following assumptions:

- Financeability modelling undertaken on a whole-of-business basis, inclusive of Transgrid's NER and WSB Project cashflows. In doing so, Transgrid has implemented the full RAB roll forward process set out in our NER RFM and depreciation tracking module and calculated relevant EBSS and CESS impacts.
- Forecast business-as-usual expenditure based on the average of the final 3 years of approved expenditure, after excluding any Integrated System Plan-related capex.
- Forecast rate of return based on the final year of the approved PTRM for the relevant determination.
- The overspend of $1,858.4 million, primarily for Project EnergyConnect, will be fully rolled into the NER RAB, earning a return on and of capital.
- A CESS penalty of 30% (unmodified) will be applied to the full overspend.

82 The template model is published on our website alongside our Financeability Guideline and consolidates the outcomes of any pre- and post-adjustment PTRM to ascertain the appropriate level of accelerated depreciation required (if any), see: Transgrid, *M.8 – Central-West Orana Enabling Project 2026–31 – Financeability Model,* Jul 2025; Transgrid, *M.6 – Central-West Orana Enabling Project 2026–31 – Post Tax Revenue Model (PTRM) (unadjusted),* Jul 2025; Transgrid, *M.7 – Central-West Orana Enabling Project 2026–31 – Post Tax Revenue Model (PTRM) (adjusted)*, Jul 2025.

- Application of the 'default' smoothing approach in the PTRM to Transgrid's NER cashflows, removing discretion around how cashflow can be smoothed and shaped within the regulatory control period.
- Inclusion of all relevant concessional financing amounts provided to Transgrid by the CEFC.

8.2 AER final decision

Our final decision determines a regulatory depreciation amount of –$5.6 million ($nominal) for Transgrid over the 2026–31 period for the CWO Enabling Project. Our final decision represents a reduction of $12.1 million compared to Transgrid's proposed regulatory depreciation amount of $6.4 million.

In calculating the straight-line depreciation amount in our final decision, we:

- accept Transgrid's proposed straight line depreciation method for calculating the regulatory depreciation amount as set out in the EII PTRM, including its proposal to depreciate biodiversity offset-related capex on an 'as incurred' basis, as it is consistent with the provisions in EII Chapter 6A, clause 6A.6.3 and previous determinations for Transgrid under the NER.[83]
- accept Transgrid's proposed asset classes and associated standard asset lives where they are equivalent to the those approved in our most recent NER revenue determination.
- accept Transgrid's proposed new 'Biodiversity offsets – Stewardship sites' and 'Biodiversity offsets – Direct payments & Other costs' asset classes and approach to calculating the standard asset lives. However, we have not made a decision on the remaining asset life for these two new asset classes and have removed it from the PTRM, as we have not accepted Transgrid's pre-period capex (see section 6.2.1 for further discussion).
- accept Transgrid's approach to depreciating IPF costs within the respective asset classes for which the expenditure relates to, as this approach calculates a depreciation schedule that reflects the nature of the assets being depreciated.
- do not accept Transgrid's financeability adjustment to modify the depreciation schedules for financeability by reallocating capex from the 'Secondary systems' asset class to an accelerated depreciation asset class. Our final decision (set out further below in section 8.2.1) is to determine that there is no financeability issue following application of the financeability test and to not modify the depreciation schedules.[84]

Regulatory depreciation is also affected by the indexation of the RAB, which has an offsetting relationship to straight-line depreciation. We have determined a lower RAB indexation compared to the proposal largely due to applying a lower expected inflation rate of 2.60% per annum in this final decision compared to Transgrid's proposal of 2.78% per annum.[85] Due to our final decision's significant reduction in straight-line depreciation as a result of not accepting Transgrid's opening RAB and accelerated depreciation, we have determined a

---

83 EII Regulation, cl. 47D(2); AER, *Determination – Transgrid HumeLink Stage 2 Contingent Project*, August 2024.

84 EII Regulation cl. 47D(3); EII Chapter 6A, cll. 6A.6.3(d), 6A.14.1(5) and (6).

85 Since indexation is deducted from straight-line depreciation, the marginal effect of lower RAB indexation is higher regulatory depreciation.

lower straight-line depreciation amount compared to indexation of the RAB and therefore a negative forecast regulatory depreciation amount for the forecast regulatory control period.

Table 8.3 sets out our final decision on the forecast regulatory depreciation amount for Transgrid's 2026–31 period for the CWO Enabling Project.

Table 8.3 AER's final decision for the 2026–31 regulatory control period ($million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Straight-line depreciation	-	4.0	9.8	10.7	11.0	35.5
Less: Inflation indexation on opening RAB	-	7.7	10.8	11.3	11.3	41.1
Regulatory depreciation	**-**	**–3.7**	**–1.0**	**–0.6**	**–0.3**	**–5.6**

Source: AER analysis.

8.2.1 AER's assessment of financeability

Our final decision is to not make a financeability adjustment for Transgrid's CWO Enabling Project, as our application of the financeability test does not demonstrate that there is a financeability issue. This is consistent with our assessment set out in our preliminary position paper. As a result, we have reversed the changes Transgrid had made in the PTRM to accelerate the depreciation of $23.7 million ($ nominal) from the 'Secondary systems' asset class.

Under clause 47D(3) of the EII Regulation, we must make modifications to any depreciation schedule, if we are satisfied that it is reasonably necessary to ensure:

- the revenue determination is consistent with the principles specified in the EII Act[86]
- the Network Operator is capable of efficiently obtaining finance to carry out the network infrastructure project.[87]

This capability to efficiently obtain finance is what is commonly known as 'financeability'. In practice, a 'financeability issue' arises when the Network Operator has difficulties efficiently raising finance, primarily due to pressures on its credit rating as determined by credit rating agencies such as Moody's.

In our assessment of a financeability request, we are required to apply the financeability test in accordance with the requirements set out in EII Chapter 6A and the Financeability Guideline.[88] Transgrid's financeability request is the first proposal to be submitted to us under our Financeability Guideline, published in November 2024.[89] Our Financeability Guideline sets out further details of the 'financeability test' required to be applied in order to demonstrate a financeability issue. This financeability test measures the 'base case' financeability position of a Network Operator, prior to including any expenditure for which the

86 EII Act, s.3(1)(a) to (c).

87 EII Regulation, s. 47D(3)(b); EII Chapter 6A, cl. 6A.6.3(d).

88 EII Chapter 6A, cl. 6A.6.3A(i).

89 Our Non-contestable Guideline, amended in July 2024, sets out that the Financeability Guideline as published under the NER will also apply to EII non-contestable determinations.

Network Operator is requesting a financeability adjustment for, and post-inclusion.[90] We expect all Network Operators to follow the requirements set out in our Financeability Guideline, to the extent possible, in order for the AER to be able to apply the financeability test to demonstrate whether there is a financeability issue.

In assessing a financeability request, we are also required to have regard to the information set out in the request and any concessional financing the Network Operator may have access to when applying the financeability test.[91] Concessional financing, in the context of NSW Roadmap projects, is typically provided by the CEFC for the purposes of improving the cashflows of a business thereby reducing any financeability issues. This may take the form of favourable financing rates (reducing debt repayments) or hybrid bonds that are treated partially as equity. By lowering the total amount of debt liabilities and reducing the debt RAB portion, a project would become more 'financeable' as key financial metrics that measure a business' ability to obtain efficient financing would be improved.

The financeability test, undertaken through the financeability model published alongside our Financeability Guideline, examines 4 key financial metrics in assessing financeability.[92] A score is assigned to each of the metrics, which measures the financeability position relative to a scale based on Moody's public methodology for assessing the credit rating of regulated electricity networks. We assign scores within a range or band, to reflect that small movements and changes in cashflows year-on-year are unlikely to be a sign of a financeability issue. The weighted average of the 4 scores represent the Network Operator's overall financeability position. A financeability position is first calculated for the 'base case', which is exclusive of any project expenditure for which the Network Operator is proposing a financeability adjustment. A second financeability position is calculated inclusive of the proposed project.

If the financeability position decreases to a lower band from the 'base case', we consider the financeability test demonstrates that a financeability issue exists, necessitating a financeability adjustment.[93] This typically takes the form of modifying the depreciation schedules to bring forward cashflows from future years to earlier years, however, it could also be addressed through other means as set out in our Financeability Guideline.

AER preliminary position

Our preliminary position paper found that a financeability adjustment was not required for the CWO Enabling Project.[94] This was because our assessment indicated, through applying our financeability test, that a financeability issue did not exist. Specifically, if the conditions in Transgrid's concessional financing agreement were adhered to, Transgrid would not appear to experience a degradation in its financeability position from the inclusion of the CWO

---

90 In the context of financeability under the EII Framework, 'base case' refers to the Network Operator's underlying, or starting, position prior to the inclusion of the REZ project expenditure for which a financeability adjustment is being requested. This typically includes its NER determination cashflows and RAB as well as all other determinations made in accordance with the EII Act.

91 EII Chapter 6A, s. 6A.6.3A(i).

92 EII Chapter 6A, s. 6A.6.3A(i) to (l); These are the funds from operation to interest coverage ratio, the net debt to RAB ratio, the funds from operation to net debt ratio and the retained cash flow to net debt ratio.

93 EII Chapter 6A, s. 6A.6.3A(m) to (o).

94 AER, *Preliminary position paper – Enabling CWO REZ network infrastructure project (non-contestable)*, October 2025, pp. 24–26.

Enabling Project capex. This observation held true across several scenarios we tested, by varying the inputs and assumptions underlying Transgrid's revenue proposal.

Our preliminary position's assessment of Transgrid's financeability request involved first determining whether there is a financeability issue, in accordance with the requirements set out in EII Chapter 6A and our Financeability Guideline. This process is referred to as a financeability test, which is undertaken through the financeability model published alongside our Financeability Guideline.

Under clause 6A.6.3A(i) of EII Chapter 6A, in applying the financeability test, we must have regard to the information set out in the financeability request and any concessional financing loan agreements Transgrid has entered into that provide it with favourable financing terms to improve the financeability of these and future projects. As noted above, these typically take the form of favourable financing rates or hybrid bonds that are treated partially as equity, thereby reducing interest (debt) repayments.[95] In relation to a financeability request, a concessional finance agreement must specify how the benefits of any concessional finance are to be taken into account by us in our financeability test and the Network Operator must provide this information to us.[96]

Transgrid's financeability schedule to the concessional financing agreement had set out relevant details as to how we model the concessional financing benefits. Our preliminary position paper found that the CEFC included a requirement to 'do no harm' in the schedule. The relevant clause read as follows:

> **CEFC 'do no harm' requirement**: "Notwithstanding the following sections outlining the way in which the AER will account for the concessional finance provided by the CEFC to TransGrid under the Umbrella Deed (the adjustments), in accordance with this paragraph, when assessing a financeability request the AER will only account for the adjustments when the adjustments reduce the quantum of financeability support the AER would otherwise provide. The adjustments will be considered by the AER in totality i.e. they will either all be wholly accounted for or will all be wholly excluded from the analysis underpinning the AER's financeability support." [97]

Our preliminary position paper interpreted this requirement to mean that concessional financing inputs should only be accounted for in the financeability test if it reduces the financeability adjustment amount (accelerated depreciation or any other form of bringing forward cashflows) to be undertaken by us. Conversely, if the financeability test demonstrates that, absent any concessional financing, there is no (or a less pronounced) financeability issue, we must not include these concessional financing inputs in our financeability modelling. We understand that the CEFC included this requirement to address

---

95 From a regulatory perspective, debt and interest repayments are seen as the key contributor to whether a Network Operator is experiencing financeability issues. This is because the 4 metrics we examine as part of our financeability assessment compare various measures of cashflows against the total debt RAB or interest repayments.

96 EII Chapter 6A, s. 6A.6.3A(e); EII Chapter 6A, s. 6A.6.3A(f)(v).

97 Transgrid, *CEFC - A.25 - Central West Orana Enabling Project 2026–31 - Financeability Schedule*, July 2025.

a rare, but unintended, consequence of concessional financing when assessed in the context of the financeability test as prescribed in EII Chapter 6A.

Generally, concessional financing will, keeping all other factors constant, improve the key financial metrics that we use to measure a business' ability to obtain financing due to the lower debt liabilities. However, as set out above, our financeability test relies on credit bands, or credit notches, to measure a business' financeability position. This allows for some movement within the credit band so that small reductions (or improvements) in these do not change the overall business' financeability position.

In Transgrid's proposed financeability modelling, we discovered that no financeability issue exists when concessional financing inputs are removed. In particular, the key financial metric triggering a financeability issue, the funds from operations to interest coverage (FFO interest coverage) ratio, does not show a material deterioration compared to the 'base case'.

This is because Transgrid's 'base case' FFO interest coverage score sits at the top of the 1.800–2.133 credit band, with significant leeway to shift downwards in response to additional capex (from the CWO Enabling Project) without triggering a financeability issue.[98] However, when concessional financing inputs are included in the base case, Transgrid's financeability position further improves and its score moves to the bottom of the higher credit band of 2.133–2.467.[99] Following this, if the CWO Enabling expenditure is then added to Transgrid's base case, it causes Transgrid's score to fall back to the original 1.800–2.133 credit band. Therefore, a deterioration in Transgrid's credit bands from the CWO Enabling Project expenditure only occurs when concessional financing is added to the Transgrid's base case.

This behaviour appeared to be consistent with the result that the CEFC is seeking to prevent through the 'do no harm' requirement. As such, we considered that Transgrid's financeability request was inconsistent with the requirements of its concessional financing agreement that it entered with the CEFC, and that the financeability test did not demonstrate that there was a financeability issue in the 2026–31 period for the CWO Enabling Project.

Our preliminary position paper also made several observations and set out our concerns with the underlying assumptions and analysis that underpinned Transgrid's financeability proposal. In particular, we highlighted that:

- Transgrid's approach to using a more granular and detailed method to forecasting its 'base case' expenditure introduced additional complexity and made assumptions about future AER decisions that was not explored adequately in its proposal
- an assumption that the entire $1,858.4 million overspend in the base case, with the majority reflecting Project EnergyConnect overspend, would be subject to CESS penalties and therefore cause a reduction in Transgrid's cashflows of $657 million ($2027–28). This assumption was not adequately explained and lacked supporting information on why this assumption was taken to be the main scenario rather than exploring other sharing ratios. We found that the proposal did not engage with, nor explore the implications of, the recent Australian Energy Market Commission (AEMC)

98 A higher score indicates a better financeability rating.

99 Transgrid's concessional financing inputs are applied to its 'base case' financeability position. There are no benefits relevant to the CWO Enabling Project expenditure.

rule change and the provisions set out in our (at the time) draft Capital Expenditure Incentive Guideline.[100]

- to the extent that a significant driver of any perceived financeability issues was derived from the underlying 'base case' modelling, Transgrid's financeability proposal lacked consideration for revenue smoothing as an approach to reprofiling of revenues to address cashflow concerns
- Transgrid's proposal did not address the concerns of stakeholders and consumer representatives that were raised during the pre-engagement on the CWO Enabling Project.

Stakeholder submissions and AER final decision

Transgrid's submission to our preliminary position paper accepted our assessment that there was no financeability issue associated with the CWO Enabling Project and did not pursue a financeability adjustment. Furthermore, stakeholder submissions also agreed with our assessment. For example, Louise Benjamin and Gavin Dufty submitted that Transgrid's financeability proposal was 'inappropriate.'[101] Our preliminary position was also supported by CCP35 and the JEC.[102]

However, Transgrid noted that its financeability proposal stemmed from an alternative interpretation of the CEFC's 'do no harm' requirement and was seeking clarification on the CEFC's intent for this requirement to inform its future financeability proposals.

This requirement is important to our final decision on financeability and that any lack of clarity may negatively impact the effectiveness of Transgrid's future engagement with ourselves and other stakeholders on other financeability proposals. We have therefore separately reached out to the CEFC in order to confirm that our understanding of the concessional financing requirements is reasonable and consistent with the CEFC's intentions. Specifically, in its response to us seeking confirmation of our interpretation of the 'do no harm' requirement the CEFC stated:

> *CEFC notes in particular AER's interpretation of the 'do no harm' requirement documented under the Umbrella Deed between CEFC and Transgrid, and the application of this requirement in assessing Transgrid's financeability request for the CWO Enabling Project. CEFC considers AER's interpretation and application (as set out under Position Paper section 4.1.2) to be consistent with its understanding of the content and intent of the 'do no harm' requirement and has no further comments to raise in this regard.*

Having established that our preliminary position paper's interpretation of the CEFC 'do no harm' requirement is consistent with the intent, we confirm our final decision is to not apply a financeability adjustment, as we consider that the financeability test does not demonstrate that there is a financeability issue with the CWO Enabling Project. We have reviewed the

---

100 AEMC, *Managing ISP project uncertainty through targeted ex post reviews*, August 2024; AER, *Capital Expenditure Incentive Guidelines Review 2025 – Explanatory Statement for Draft Guidelines,* May 2025, pp. 26–27.

101 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025.

102 CCP35, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025; Justice and Equity Centre, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025.

non-disclosure claims on the material submitted to us by Transgrid in relation to its financeability proposal, including relevant schedules and contractual agreements with the CEFC. Our final decision is not to publish this information as we are satisfied it is not appropriate, taking into account the 3 factors in clause 53(6) of the EII Regulation, including that:

- There is limited public benefit from disclosure of the minutiae and operation of the CEFC's concessional financing agreement and how the concessional financing is to be structured.
- There is a significant risk of commercial harm to Transgrid and CEFC if the information was disclosed as they pertain to sensitive negotiations over commercial financing.
- There are significant negative impacts on future processes from any disclosure as it would undermine the CEFC's position and ability to negotiate appropriate financing arrangements for other projects.

We consider that, in this case, the potential for commercial harm and negative impact on future competitive processes outweighs the limited public benefit that would arise from disclosure of further contractual details. As such, we have limited our disclosure to the 'do no harm' requirement, consistent with our preliminary position paper.

Our final decision PTRM therefore removes the 'Financeability asset class 1' asset class and ensures the capex subject to accelerated depreciation in Transgrid's proposal is reallocated back into the 'Secondary systems' asset class to depreciate over the standard asset life of 15 years.

8.2.2 Standard and remaining asset lives

Transgrid proposed the same asset classes and standard asset lives as those we approved in our 2023–28 NER final decision for Transgrid.[103] We accept the proposed asset classes and asset lives as they are identical to those determined for Transgrid under the NER, which we have assessed to be reflective of the economic life of the assets.[104] Therefore, we consider Transgrid's proposed asset lives and depreciation schedule results in a profile that reflects the nature of the asset over the economic life of the asset. The proposed standard asset lives are also broadly comparable with those approved by us for other network service providers under the NER.

We also accept Transgrid's proposed approach to calculating the standard lives for the two new biodiversity offsets-related asset classes, 'Biodiversity offsets – Stewardship sites' and 'Biodiversity offsets – Direct payments & Other costs' to be reasonable.

We have approved similar asset classes under the NER for Transgrid as part of its contingent projects for Humelink stage 2 and VNI West stage 1.[105] In both decisions, we accepted Transgrid's approach to equate the standard asset lives for biodiversity offsets with the weighted average of the standard asset lives for all depreciating assets associated with the project. This is because we considered costs associated with biodiversity offsets are inextricably linked to the project life, as the biodiversity credits are used to offset the project's

---

103 AER, *Transgrid 2023–28 – Final Decision – Overview*, April 2023.

104 EII Chapter 6A, cl. 6A.6.3(b)(1).

105 AER, *Determination – Transgrid VNI West Stage 1 Early Works Contingent Project*, May 2024, pp. 42–43; AER, *Determination – Transgrid HumeLink Stage 2 Contingent Project*, August 2024, pp. 60–61.

biodiversity obligations. Transgrid has continued with this approach in calculating the biodiversity offsets for the CWO Enabling Project.

However, we have not made a decision on Transgrid's proposed remaining lives for the biodiversity offset asset classes. This is because our final decision is to approve a zero opening RAB for the CWO Enabling Project in our PTRM. As set out in section 6.2.1 above, we have not accepted Transgrid's pre-period expenditure for the CWO Enabling Project, thereby reducing Transgrid's opening RAB to zero.

Per our decision to not accept Transgrid's financeability adjustment (detailed in section 8.2.1 above), we have removed Transgrid's proposed 'Financeability asset class 1' asset class and associated remaining and standard lives. Similarly, we have also removed several asset classes that do not have any forecast capex allocated to them.[106] Transgrid has not raised any concerns with the removal of these unused asset classes.[107]

Table 8.4 sets out our final decision on the standard asset lives for the 2026–31 period for Transgrid's CWO Enabling Project.

Table 8.4 AER's final decision on Transgrid's standard asset lives for the 2026–31 period (years)

Asset class	Standard asset life
Transmission Lines	50.0
Substations	40.0
Secondary System	15.0
Land & Easements[a]	n/a
Biodiversity offsets – Stewardship sites	45.3
Biodiversity offsets – Direct payments & Other costs	45.3
Equity raising costs	45.3

Source: AER analysis.
a) Not applicable. We have not assigned a standard or remaining life to the Land & easements asset class because the assets are not subject to depreciation.

106 The unused asset classes we have removed are: underground cables, communications (short life), SIPS control, business IT, minor plant, motor vehicles and mobile plant, transmission line life extension, synchronous condensers, leasehold land and property, buildings – capital works, and in-house software.

107 Transgrid, *Response to AER information request #03*, August 2025.

9 Capital expenditure

Capital expenditure (capex) refers to investment made for the development and construction of network infrastructure. This investment mostly relates to assets with long asset lives (30–50 years), the costs of which are recovered over several regulatory control periods.

Under the regulatory framework, Transgrid's revenue proposal must include the total forecast capex it considers is required to comply with all regulatory requirements in providing regulated network services and maintaining the safety of the network infrastructure project through the supply of regulated network services (the capex objectives).[108] We must determine whether we are satisfied Transgrid's forecast capex (including pre-period capex) reasonably reflects the capex criteria with regard to the capex factors specified in EII Chapter 6A.[109] If we are not satisfied, we must set out the reasons for this decision and an estimate of the total capex we are satisfied reasonably reflects the capex criteria, taking into account the capex factors.[110]

Our assessment approach for capex is detailed in section 6 of our assessment approach guidance note.[111]

9.1 Transgrid's proposal

Transgrid proposed $436.4 million ($2025–26) in forecast capex for the CWO Enabling Project.[112] This comprises:

- $193.5 million for IPFs payable to EnergyCo incurred in accordance with clause 46(1)(b)(ii) of the EII Regulation. Transgrid proposed $152.0 million for pre-period IPFs and $41.5 million for IPFs in the first year (2026–27) of the regulatory control period.
- $8.2 million in pre-period costs for early development activities prior to the commencement of the Project Development Deed with EnergyCo.
- $234.6 million of forecast period capex. This forecast comprises direct costs for tendered works, easement acquisition, biodiversity offsets and other construction costs, as well as labour and indirect costs.

Table 9.1 outlines Transgrid's total forecast capex by category and year.

108 EII Chapter 6A, cl. 6A.6.7(a).

109 The capex criteria include (1) the efficient costs of achieving the capex objectives; (2) the costs a prudent operator would require to achieve the capex objectives; and (3) a realistic expectation of the cost inputs required to achieve the capex objectives, see: EII Chapter 6A, cl. 6A.6.7(c); EII Chapter 6A, cl. 6A.6.7(e).

110 EII Chapter 6A, cl. 6A.14.1(2).

111 AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations,* September 2025.

112 Excludes forecast equity raising costs of $1.6 million.

Table 9.1 Transgrid's total capex forecast ($ million, 2025–26)

Category of capex	Pre-period	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Early development activities	8.2	-	-	-	-	-	8.2
IPFs	152.0	41.5	-	-	-	-	193.5
Tendered works	-	74.2	65.9	4.9	-	-	145.0
Easement acquisition	-	0.7	-	-	-	-	0.7
Biodiversity offset costs	-	5.4	9.6	-	-	-	15.0
Other construction costs	-	4.8	5.0	1.9	-	-	11.7
Labour and indirect costs (including labour escalation)	-	18.5	36.7	7.0	-	-	62.2
Total capex (excluding equity raising costs)	**160.2**	**145.2**	**117.2**	**13.8**	**-**	**-**	**436.4**
Equity raising costs	-	1.6	-	-	-	-	1.6
Total capex	**160.2**	**146.8**	**117.2**	**13.8**	**-**	**-**	**437.9**

Source: Transgrid, *M.1 Enabling CWO RNIP - Capex Forecast Model* (Confidential), November 2025.

Note: Totals may not sum due to rounding. Transgrid submitted a new Capex Model in response to information request #7. This changed the profile of labour and indirect costs from its original proposal, but not the total capex forecast.

Transgrid submitted that its 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.[113]

Transgrid's capex forecasting approach was informed by lessons learnt from previous projects and based on a combination of competitively sourced and market tested costs that were validated using internal benchmarking and independent verification.[114] Independent assurance was provided by Transgrid's external advisor, GHD, to validate the scope of works and associated cost estimates. It concluded Transgrid's forecast capex to be prudent, efficient and reasonable, and appropriate to meet the requirements set out in the Project Deed with EnergyCo and Consumer Trustee Authorisation.[115] Additionally, E3 Advisory was engaged to verify and assess Transgrid's biodiversity offset cost forecast, which was partly prepared by GHD.

Our preliminary position paper explained that our assessment of forecast capex was ongoing and that we were assessing additional information provided by Transgrid.[116]

---

113 Transgrid, *A.8 – Direct Capex Forecasting Methodology*, July 2025, p. 9.

114 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 56.

115 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 74.

116 AER, *Preliminary position paper – Transgrid – CWO Enabling Project 2026–31*, October 2025, p. 12.

9.2 AER final decision

Our final decision is to provide an alternative capex estimate of $402.8 million ($2025–26).[117] We consider this forecast to reflect prudent, efficient and reasonable costs to meet the capex objectives. Our alternative estimate reflects the following decisions:

- including Transgrid's forecast of IPFs in our alternative capex estimate but re-profiling these costs to 2026–27 to reflect the timing that Transgrid is contractually required to make this payment to EnergyCo. This re-profiling reduces the IPF forecast in real $2025–26 from $193.5 million to $182.3 million. We discuss IPFs further in sections 6.2.1.1 and 6.2.1.2.
- excluding $8.2 million of pre-period costs for early development activities incurred prior to the authorisation of the project and the establishment of the EII Act. We discuss these costs further in section 6.2.1.3.
- substituting Transgrid's forecast period capex of $234.6 million with an alternative estimate of $220.5 million, based on our updates to biodiversity offset costs, other construction costs, and labour and indirect costs. Our assessment of forecast capex for each category is provided in this section.

Table 9.2 sets out our final decision on Transgrid's forecast capex by year and category.

Table 9.2 AER's final decision total capex forecast ($ million, 2025–26)

Category of capex	Pre-period	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Early development activities	-	-	-	-	-	-	-
IPFs	-	182.3	-	-	-	-	182.3
Tendered works	-	74.3	66.1	4.9	-	-	145.3
Easement acquisition	-	0.7	-	-	-	-	0.7
Biodiversity offset costs	-	3.5	6.3	-	-	-	9.8
Other construction costs	-	4.1	4.4	1.7	-	-	10.2
Labour and indirect costs (including labour escalation)	-	16.1	31.4	7.0	-	-	54.5
Total capex (excluding equity raising costs)	**-**	**281.1**	**108.1**	**13.5**	**-**	**-**	**402.8**
Equity raising costs	-	3.3	-	-	-	-	3.3
Total capex	**-**	**284.4**	**108.1**	**13.5**	**-**	**-**	**406.0**

Source: AER analysis.

Note: Values also reflect our decision to update the nominal vanilla WACC and expected inflation (see section 7.2). Totals may not sum due to rounding.

[117] Excludes our updated forecast of equity raising costs of $3.3 million.

9.2.1 Tendered works

Transgrid proposed $145 million for tendered works, which are also referred to as design and construct (D&C) contractor costs in Transgrid's proposal.[118] These works include new transmission lines, substations, secondary systems and transpositions, across 7 separable portions.

Transgrid appointed Zinfra to undertake these works under a fixed-price lump sum contract, with limited adjustment items.[119] The proposed costs are the outcome of a competitive tender process and Transgrid provided its tender evaluation documentation outlining the tender and assessment process it followed to select its preferred bidder. Transgrid's assessment was also verified by an independent value-for-money assessment.

We requested further information from Transgrid to better understand the relationship between the proposed tendered works costs and 'other construction costs', which are quantified risk costs (which we discuss in section 9.2.4). In response, Transgrid provided Zinfra's pricing schedule and demonstrated there is no duplication in risk costs across the proposed tendered works costs and other construction costs.

Based on Transgrid's competitive tender process and its response to our further questions, we are satisfied the proposed tendered works costs are prudent, efficient and reasonable. These costs are also subject to revenue adjustment mechanisms, which we discuss in chapter 13.[120]

9.2.2 Easement acquisition costs

Transgrid proposed $0.7 million in easement acquisition costs in the forecast period, for easement acquisitions relating to line transpositions. The majority (over 90%) of Transgrid's forecast easement acquisition costs are included in IPFs, as they are expected to be incurred prior to January 2027. These costs include landholder compensation, option and legal fees, landholder disturbance costs, compulsory acquisition costs and transfer duty and survey fees.

Transgrid noted that line transposition works are at an early stage of development and greater certainty of costs will be known closer to possession of site, which is expected to occur in early 2027. Transgrid considered NSW property acquisition data to inform its estimate of property acquisitions likely to be settled by agreement. This data also informed its estimate of costs to be realised prior to 31 December 2026 (and included in IPFs), and remaining costs from January 2027 onwards (the $0.7 million forecast).

We are satisfied that these costs are necessary for the project to proceed, based on the number of impacted landholders and likely levels of compensation. We are also satisfied with Transgrid's approach to distinguish IPFs from its forecast costs. On this basis, we are satisfied the proposed easement acquisition costs are prudent, efficient and reasonable. However, as discussed in section 9.2.4, we have excluded the related risk cost for property

---

118 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 57.

119 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 59.

120 See 'Contractor Force Majeure' and 'Unavoidable D&C Contract Variation' events.

valuation uncertainty from our alternative capex estimate. These costs are also subject to revenue adjustment mechanisms, which we discuss in section 13.[121]

9.2.3 Biodiversity offset costs

Transgrid proposed $15 million for biodiversity offset costs in the forecast period. A further $12.4 million is included in IPFs as they are expected to be incurred prior to January 2027. Of the proposed forecast period costs:

- $13.8 million relates to augmentation works from Bayswater to Lidell and Mount Piper to Wallerawang
- $1.3 million relates to transmission tower line transpositions for two circuits from Bayswater to Barigan Creek and Barigan Creek to Mount Piper.

Transgrid engaged GHD to provide biodiversity services for the project, including deriving a cost estimate for Transgrid's revenue proposal and developing the Biodiversity Assessment Report (BDAR), which forecasts the number of biodiversity credits required to offset the project's impacts and their associated costs, and forms part of the Environmental Impact Statement (EIS) for the project. GHD's advice is the basis for the $13.8 million forecast for augmentation works. This forecast assumes that Transgrid will generate most of its offset credits via Biodiversity Stewardship Agreements (BSAs), with the remaining to be secured via Biodiversity Conservation Fund (BCF) payments.

The transposition works do not require an EIS and Transgrid noted that offsets will only be required where biodiversity values are significantly affected. For its capex forecast, Transgrid undertook conservative rapid desktop assessments to estimate offset liabilities and potential costs.

Noting the uncertainty associated with biodiversity offset costs, Transgrid also proposed an adjustment mechanism for variances in forecast and actual biodiversity offset costs.

GHD's report to Transgrid (including its cost estimate for the project) was provided in December 2024.[122] Transgrid submitted the BDAR for the Mount Piper to Wallerawang Transmission Line Upgrade augmentation works in August 2025 as part of its EIS for the project.[123] We found that the credit requirements outlined in the BDAR indicate that fewer credits will now be required for the project, relative to GHD's initial forecast. Therefore, Transgrid will incur less capex as it has the potential to generate all its offset credits via BSAs and avoid making BCF payments.

Also, GHD's cost estimate includes costs for 'impact contingency', 'assessment contingency' and 'credit price escalation contingency'. We consider that these are no longer necessary as credit numbers are now confirmed and BCF payments can be avoided due to the now lower credit requirements.

Finally, we consider that, while still uncertain, it is most likely that Transgrid will not require biodiversity offset credits for the transposition works.

---

121 See 'Compulsory Acquisition' and 'Legal Challenges' events.

122 Transgrid, GHD - *A.23 – Central West Orana Enabling Project 2026-31 – Biodiversity Cost Estimate Report*, December 2024.

123 NSW Department of Planning, Housing and Infrastructure, *Mount Piper to Wallerawang Transmission*, accessed 7 January 2026.

Accounting for the above adjustments, our alternative estimate of biodiversity offset costs in the forecast period is $9.8 million. However, we recognise that although credit numbers are confirmed, some uncertainty remains regarding potential offset acquittal methods that will be available to Transgrid as well as the offset requirements for the transposition works. Therefore, these costs will be subject to a revenue adjustment mechanism, which we discuss in section 13.[124]

9.2.4 Other construction costs

Transgrid proposed $11.7 million for other construction costs to cover residual risks expected to affect the cost of the project and not adequately compensated for in its return on capital or able to be transferred, avoided or mitigated (or included as adjustment mechanisms).[125] Transgrid proposed this allowance in its base expenditure to adequately address these risks, as provided for under clause 6A.5.4(a)(7) of EII Chapter 6A.

The residual risks include:

- inherent uncertainty (i.e. inherent quantity and productivity risks) with time or cost impacts – these risks are associated with the uncertainty of the cost item estimated or the duration of an activity in the schedule, i.e. the risk does not arise due to a specific 'event'
- inclement weather impacts, including from rain, heat, fire and wind delays – informed by the use of an inclement weather analysis tool
- contingent risk events (i.e. discrete risks) with time or cost impacts – relating to specific events that may or may not occur
- prolongation – related to the indirect costs incurred if the project extends beyond the budgeted timeframe.

To inform our review we requested that Transgrid provide its risk register, which details individual risks and associated forecast cost impacts. Transgrid's response demonstrated that forecast costs represent P50 estimate, where there is an equal probability that costs will be greater or less than the estimate.

In our alternative estimate we have excluded forecast costs associated with the following risks:

- Property valuation uncertainty – where property costs do not come in at budget due to landholder challenges and increased legal costs associated with the number of minor interests. We found that Transgrid already applied a conservative premium in its forecast of landholder compensation, based on its experience on the HumeLink project. Therefore, we do not consider an additional risk cost is necessary. In addition, potential compulsory acquisition costs (and associated legal costs) are the subject of an adjustment mechanism (see chapter 13).
- BSA price uncertainty – for potential increased complexity in labour effort to deliver the proposed BSAs (e.g. legal costs) and increased prices of offsets affecting the proposed cost of delivering BSAs. As noted in section 9.2.3, we now consider that biodiversity

124 See 'Biodiversity Offset Cost Variance' event.

125 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 50.

offset costs are more certain, and any changes in costs relative to our forecast will be the subject of an adjustment mechanism (see chapter 13).

Based on these adjustments, our alternative estimate of other construction costs in the forecast period is $10.2 million.

9.2.5 Labour and indirect costs

Transgrid proposed $61.9 million for labour and indirect costs.[126] This total includes $41 million for direct labour and labour related costs and $20.8 million for indirect costs, which are calculated based on Transgrid's approved cost allocation method (CAM).[127] Transgrid submitted that this forecast reflects the project's unique delivery environment, which presents a range of technical, commercial and delivery challenges.[128]

Within labour and labour-related costs, Project Delivery Management comprises most of the forecast capex ($31.2 million), and includes the project management, construction management, commercial management and project controls functions.[129] Other categories include Other support and corporate roles ($5.8 million), Land and environment ($2.8 million), Project Development ($1.0 million) and Community and stakeholder engagement ($0.2 million).

GHD assessed Transgrid's labour and indirect cost forecasts and concluded that the costs were efficient and necessary to deliver the project or reduce project risk. GHD reviewed elements of the proposed Project Delivery Management capex, and noted that:

- project management costs for the project are in line with expectations, based on a comparison with Transgrid's EnergyConnect and HumeLink projects
- few benchmarks exist for commercial management costs. These costs make up a larger portion of total capex when compared with Transgrid's HumeLink project. However, HumeLink is less complex than the CWO Enabling Project.

We consider GHD's benchmarking did not meaningfully support Transgrid's proposed level of labour and indirect costs, as it only compared these costs against costs for other Transgrid projects, which were not comparable in size or complexity. We undertook our own analysis of these costs but our ability to benchmark these costs was also somewhat limited due to differences in projects. Our analysis found that Transgrid's forecast of labour and indirect costs (and particularly Project Delivery Management capex) appears materially higher than for comparable projects. We consider that:

- as a high-level comparison, Transgrid's proposed labour and indirect costs represent 26% of total forecast capex for the project. In our 2023–28 revenue determination for Transgrid, forecast capitalised overheads represented 12% of total forecast capex.

---

126 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, pp. 66–68.

127 Under which 30% of forecast costs are allocated to indirect costs.

128 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 66.

129 Transgrid, *A.9 - Central West Orana Enabling Project 2026-31 - Labour and Indirect Capex Forecasting Methodology*, July 2025, p. 14.

- in our revenue determinations for ElectraNet's contingent projects, forecast capitalised overheads represented 7% of total capex (Project EnergyConnect and System Strength) and 9% (Eyre Peninsula Reinforcement)[130]
- Transgrid's proposed Project Delivery Management capex represents 17% of total forecast capex for the project. This compares against 11% for Ausgrid's HCC Project (AER final decision) for similar activities (including owner's costs and CAM allocated indirect costs) and TasNetworks' North West Transmission Developments Stage 1 Project (proposal) for the same type of activities (Project Management, Commercial Management and Project Execution).[131]

We requested further information from Transgrid to support the proposed number of full-time equivalents (FTEs) related to Project Delivery Management, including the duties and responsibilities to be provided by each new role.

In response, Transgrid provided a detailed breakdown of FTE numbers, roles and responsibilities for each sub-category of Project Delivery Management capex. Transgrid noted that it developed the labour and indirect cost forecast using a 'bottom-up build' approach, which accounts for the project's complex and unique delivery environment. It reiterated the need for holistic oversight and coordination to guide the project from early development to commissioning to assure the safety and quality of construction, despite the construction work being carried out under a D&C contract.

Transgrid explained that forecast FTE positions are particularly high in peak construction periods due to the need to match Zinfra's schedule (which includes the need for Transgrid staff to work overtime and weekends). Transgrid stated that using existing staff on overtime is more cost-effective than onboarding additional personnel, especially for remote site coverage and transmission line activities linked to outage windows.

Transgrid also notified us that its forecast commercial management activities were incorrectly distributed between January 2027 and April 2028, and should instead be distributed between January 2027 and June 2029, to manage close-out requirements, defects, final variations and release of securities. It accordingly submitted an updated version of its Capex Model.

Transgrid's bottom-up build for these costs was not subjected to a top-down challenge, aside from GHD's benchmarking. For example, Transgrid did not identify synergies between aspects of its proposed capex or demonstrate that any subjectivity in the bottom-up forecasts had been addressed. We recognise that the project's contractual arrangements are complex in nature, and therefore, relative to other projects, a higher level of costs related to Project Delivery Management is to be expected. However, we are not satisfied that the level proposed by Transgrid reflects prudent, efficient and reasonable costs. We derived our own alternative estimate for these costs by making the following adjustments to the proposed FTE numbers:

- Project management – reduced from 9.9 to 7.5 average FTEs by removing duplicated project managers and engineers attributed to substations and transmission lines.

---

130 AER, *Final Decision – ElectraNet – Project EnergyConnect Contingent Project*, May 2021; AER, *Final Decision – ElectraNet – Eyre Peninsula Reinforcement contingent project*, September 2020.

131 AER, *Final decision – Ausgrid – Hunter-Central Coast REZ non-contestable project 2026–31*, December 2025; TasNetworks, *NWTD Stage 1 Contingent Project Application – Construction – A.1 Principal Application*, October 2025.

- Commercial management – reduced from 10.0 to 5.5 average FTEs by removing roles attributed to 'emerging projects', as we do not consider these are explicitly for the purpose of this project.
- Construction management – reduced from 17.3 to 16.5 average FTEs to reflect roles miscategorised which are already allocated under Project management.

Using Transgrid's Labour and Overhead Costs Model, our updates to FTE numbers results in an alternative estimate for labour and indirect costs of $54.2 million, which is $7.6 million less than Transgrid's proposal. With this amount, we consider Transgrid will have sufficient resources to effectively oversee and manage its contract partner to ensure the successful delivery of the project. These costs will also be subject to revenue adjustment mechanisms, which we discuss in chapter 13.[132]

9.2.6 Labour escalation

Transgrid proposed $0.3 million for labour escalation costs over the duration of the regulatory period.[133] The labour escalators for 2026–27 and 2027–28 align with those in its 2023–28 Revenue Determination made under the NER.[134] For 2028–29 to 2030–31 the labour escalator is assumed to be equivalent to the average applied in 2026–27 and 2027–28 of the NER determination.

We are satisfied with Transgrid's approach to estimating labour escalation costs. However, based on our assessment of labour costs, labour escalation will apply to a lower level of capex, which results in a small decrease (approximately $0.03 million) in forecast labour escalation costs in our alternative capex estimate.

132 See 'Planning Approval Delay event', 'Outage Cancellation event' and 'Latent Condition event'.

133 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, pp. 71–72.

134 AER, *Transgrid 2023–28 – Final Decision – Overview*, April 2023.

10 Operating expenditure

Operating expenditure (opex) refers to operating, maintenance and other non-capital expenses associated with the project. Forecast opex for regulated network services is one of the building blocks we use to determine a Network Operator's total revenue cap.[135]

Under the regulatory framework, Transgrid's revenue proposal must include the total forecast opex it considers is required to meet or manage the expected demand for regulated network services, comply with all applicable regulatory requirements and maintain the safety of the network infrastructure project through the supply of regulated network services (the opex objectives).[136] We must determine whether or not we are satisfied Transgrid's forecast opex (including pre-period opex) reasonably reflects the opex criteria.[137] In doing so, we must have regard to the opex factors specified in EII Chapter 6A.[138] If we are not satisfied, we must explain this decision and provide an estimate of the total opex we are satisfied reasonably reflects the opex criteria, taking into account the opex factors.[139]

Our assessment approach for opex is detailed in section 8 of our assessment approach guidance note.[140]

10.1 Transgrid's proposal

Transgrid proposed $27.9 million ($2025–26) in forecast opex (excluding debt raising costs) over the 2026–31 period.[141] Transgrid has not sought to recover any pre-period opex in its revenue proposal.

Table 10.1 sets out the total forecast opex by category and year.

135 EII Chapter 6A, cl. 6A.5.4(a)(6).

136 EII Chapter 6A, cl. 6A.6.6(a).

137 EII Chapter 6A, cl. 6A.6.6(c). The opex criteria include (1) the efficient costs of achieving the opex objectives; (2) the costs a prudent operator would require to achieve the opex objectives; and (3) a realistic expectation of the cost inputs required to achieve the opex objectives.

138 EII Chapter 6A, cl. 6A.6.6(e).

139 EII Chapter 6A, cl. 6A.14.1(3).

140 AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations,* September 2025.

141 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal*, July 2025, p. 13.

Table 10.1 Transgrid's proposed opex by category ($ million, 2025–26)

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**

Note: Numbers may not sum due to rounding.

Source: Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025.

10.2 AER final decision

Our final decision is to accept Transgrid's forecast opex of $27.9 million ($2025–26, excluding debt raising costs) as we consider this forecast reasonably reflects prudent, efficient, and reasonable costs to meet the opex objectives.[142]

As this is Transgrid's initial revenue determination for the CWO Enabling Project we do not have a base year from a preceding regulatory period on which to assess its proposed opex. As such, we did not rely on our usual base-step-trend forecasting approach to develop an alternative estimate for opex. Instead, we relied on a bottom-up cost assessment approach to evaluate whether each of the forecast opex cost categories are prudent, efficient and reasonable.

10.2.1 Maintenance costs

Transgrid proposed $1.6 million for maintenance activities relating to the newly built transmission lines and modifications to existing substations. Transgrid also proposed maintenance costs related to interface equipment, which will be installed at the BCSS to enable integration of the REZ into Transgrid's network.

Having reviewed the information and assumptions provided by Transgrid, we consider that these costs have been reasonably estimated, and that this type of expenditure forms part of base operating expenditure for all EII projects. On this basis, we are satisfied its proposed maintenance costs are prudent, efficient and reasonable.

142 As noted in section 7.2.6, we have accepted Transgrid's forecast of debt raising costs based on its unadjusted PTRM.

10.2.2 Operating costs

Transgrid proposed $22.8 million for operating costs, which represent the majority of its total opex forecast. It submitted that these costs reflect the additional labour and operational activities necessary to:

- manage the expanded assets and the newly created interface with EnergyCo and ACEREZ
- adapt operations to support the material increase in renewable energy generation
- comply with contractual and regulatory obligations across asset management, network planning, network operations, commercial contract management and preparation of regulatory submissions.

Transgrid also proposed an adjustment mechanism for an annual true-up of operating costs related to the BCSS. This is discussed in chapter 13.

We sought further information about Transgrid's bottom-up forecast of commercial contract management costs ($7.0 million), including duties and costs relating to the various contracts. In response, Transgrid provided a detailed forecast of specific activities, including an estimate of FTE hours and the frequency of each activity related to:

- Transgrid Non-Contestable Augmentation Project Deed (between Transgrid and EnergyCo)
- REZ Network Connection Agreement (between Transgrid and ACEREZ)
- TNA Interface Deed (between Transgrid, EnergyCo and ACEREZ)
- Line Crossing Deed (between Transgrid and ACEREZ)
- Coordination Deed (between Transgrid and EnergyCo).

For obligations contingent on specific events, Transgrid applied a probability weighting to estimate the expected frequency. Transgrid also noted that, without sufficient resourcing, it would be exposed to disputes, compliance breaches or potential under-recovery.

We consider this type of opex could instead be forecast through incremental analysis rather than the bottom-up approach adopted by Transgrid. This is because commercial contract management activities are relatively common for Transgrid and there may be opportunities for it to utilise existing staff for this project. However, in this instance, we are satisfied that Transgrid's bottom-up forecast provides a reasonable estimate of FTE hours and the frequency of commercial contract management activities.

For other operating costs, such as asset management, network planning and operations, Transgrid's bottom-up approach provides a reasonable estimate of the required activities and costs for each activity.

Additionally, we consider this type of expenditure forms part of base operating expenditure for all EII projects where the Network Operator is required to operate and maintain a regulated network.

Therefore, we are satisfied that Transgrid's proposed operating costs are prudent, efficient and reasonable.

10.2.3 Insurance costs

Transgrid proposed $1.3 million for insurance costs to cover the estimated premiums based on independent report prepared by Lockton Australia. These costs represent a step-change

and account for the estimated premiums for industrial special risks and operational third-party insurance covering the project's assets once commissioned.

Having reviewed the information and assumptions provided by Transgrid, we consider that these costs have been reasonably estimated, and that this type of expenditure forms part of operating expenditure for all EII projects. We are therefore satisfied its proposed insurance costs are prudent, efficient and reasonable.

10.2.4 Vegetation integrity rehabilitation

Transgrid proposed $0.7 million for vegetation integrity rehabilitation costs to fulfill its legislative obligations to restore and maintain native vegetation to its target condition within the easement clearance zone for the project. This cost estimate was informed by revealed costs for similar projects.

We accept these works are necessary, and based on the information provided by Transgrid, we are satisfied its proposed vegetation integrity rehabilitation costs are prudent, efficient and reasonable.

10.2.5 Strategic Benefit payments

Transgrid proposed $0.7 million in strategic benefit payments to cover the expected compensation amounts payable to landowners impacted by the project under the NSW Strategic Benefit Payments Scheme.[143]

We consider this forecast is appropriate given the number of impacted landowners and cost payable to these landowners under the scheme. Consequently, we are satisfied Transgrid's proposed costs for strategic benefit payments are prudent, efficient and reasonable.

10.2.6 Cost escalation

Transgrid proposed $0.9 million for labour escalation costs over the regulatory period. The labour escalators for 2026–27 and 2027–28 align with those in its 2023–28 Revenue Determination made under the NER.[144] For 2028–29 to 2030–31 of the CWO Enabling Project, the labour escalator is assumed to be equivalent to the average applied in 2026–27 and 2027–28 of the Revenue Determination.

Based on the information provided by Transgrid, we are satisfied its proposed cost escalation costs are prudent, efficient and reasonable.

143 EnergyCo, *NSW Strategic Benefit Payments Scheme explained,* accessed 2 January 2026.

144 AER, *Transgrid 2023–28 - Final Decision – Overview*, April 2023.

11 Corporate income tax

Our revenue determination includes the estimated cost of corporate income tax for Transgrid's 2026–31 period.[145] Under the post-tax framework, the cost of corporate income tax is calculated as part of the building block assessment using our EII PTRM. This amount allows Transgrid to recover the costs associated with the estimated corporate income tax payable during the 2026–31 period. Our assessment approach for corporate income tax is detailed in section 9 of our assessment approach guidance note.[146]

11.1 Transgrid's proposal

Transgrid proposed an estimated cost of corporate income tax of $1.5 million ($ nominal) for the 2026–31 period using the EII PTRM, and with the following inputs:[147]

- an opening tax asset base (TAB) value as at 1 July 2026 of $34.4 million ($ nominal), consisting of pre-period capex (early development works and IPF costs) for biodiversity offsets and financeability which were proposed to be depreciated on an as incurred basis
- an expected statutory income tax rate of 30% per year
- a value of imputation credits (gamma) of 0.57
- asset classes and standard tax asset lives for depreciating its forecast capex for the 2026–31 period consistent with those approved by the AER for the 2023–28 Transgrid determination under the NER[148]
- three new asset class for 'Biodiversity offsets – Stewardship sites', 'Biodiversity – Direct payments & Other costs' and 'Financeability asset class 1' and associated tax standard and remaining asset lives for the 2026–31 period.[149]

Table 11.1 sets out Transgrid's proposed cost of corporate income tax for the 2026–31 period.

Table 11.1 Transgrid's proposed cost of corporate income tax for the 2026–31 regulatory control period ($ million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Tax payable	1.5	1.4	0.5	-	-	3.4
Less: value of imputation credits	0.8	0.8	0.3	-	-	1.9
Net cost of corporate income tax	**0.6**	**0.6**	**0.2**	**-**	**-**	**1.5**

Source: Transgrid, *M.6 – Central West Orana Enabling Project 2026-31 – PTRM (adjusted)*, July 2025.

145 EII Regulation, cl. 50A(b), EII Chapter 6A, cl. 6A.5.4(a)(4).

146 AER, *Guidance note on AER's EII assessment approach for non-contestable revenue determinations*, September 2025, pp. 33–37.

147 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal*, July 2025; Transgrid, *Central-West Orana Enabling 2026–31 – PTRM*, July 2025.

148 AER, *Transgrid 2023–28 – Final Decision – PTRM*, April 2023.

149 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue proposal,* July 2025, p. 107.

11.2 AER final decision

Our final decision on the estimated cost of corporate income tax is zero over the 2026–31 period, compared to Transgrid's proposal of $1.5 million ($ nominal). Our final decision also forecasts a tax loss of $15.9 million ($ nominal) in the final year of the 2026–31 period. This is because the CWO Enabling project is a new standalone project under the EII Act, and therefore total tax expenses outweigh taxable revenues. The key components of our tax treatment are discussed in the following sections.

11.2.1 Opening TAB as at 1 July 2026 and remaining tax asset lives

Our final decision does not include an opening TAB value or remaining tax lives for Transgrid as at 1 July 2026. Transgrid proposed an opening TAB of $34.4 million, reflecting its approach to depreciate pre-period capex associated with biodiversity offsets and financeability on an as incurred basis.

The PTRM calculates tax depreciation on as commissioned capex. As discussed in section 6.2.1 above, we have determined a zero opening as commissioned RAB compared to Transgrid's proposal, reflecting our final decision to not include early development costs and reallocate all pre-period IPFs into year 1 capex. Consequently, our final decision is to not approve an opening TAB as there is no as commissioned capex prior to 1 July 2026. Given that there is no opening value for the TAB, there is no need to nominate remaining tax lives.

11.2.2 Standard tax asset lives

We accept Transgrid's proposed standard tax asset lives for Transmission lines, Substations, Secondary systems, Land and easements and Equity raising costs, because they are:

- consistent with the values prescribed by the Deputy Commissioner of Taxation in ATO Taxation Ruling 2025/20[150]
- the same as the approved standard tax asset lives in our 2023–28 determination for Transgrid under the NER.[151]

In addition to these asset classes which align with Transgrid's 2023–28 determination under the NER, Transgrid also proposed two new asset classes of Biodiversity offsets – stewardship and Biodiversity offsets – direct payments with corresponding tax lives of 'not applicable' and 50 years respectively.

As discussed in section 8.2, we have accepted the two new Biodiversity offsets asset classes. Our final decision is also to accept the proposed standard tax asset lives for these two asset classes as they are consistent with standard tax application as well as previous AER determinations under the NER.[152]

- We consider costs associated with land purchases for establishing the biodiversity stewardship sites are not subject to tax depreciation, per the Income Tax Assessment Act 1997 and therefore, no standard tax asset life is applicable for these costs.
- We understand that the Biodiversity offsets – direct payments asset class represent a capital cost to be incurred in developing the transmission network. As a result, these

150 ATO, *Taxation Ruling LI 2025/20 – Income tax: effective life of depreciating assets* (applicable from 15 September 2025).

151 AER, *Final Decision – Overview – Transgrid – 2023–28 Transmission revenue proposal*, April 2023.

152 AER, *Determination – Transgrid HumeLink Stage 2 Contingent Project*, August 2024, p. 61.

costs should be included in the cost base of the relevant capital asset asset—that is, the transmission line which gave rise to the biodiversity offset obligation. Therefore, it is appropriate to assign the same tax asset life of 50 years for the 'Transmission line' and 'Biodiversity offsets – direct payments' asset classes.

However, we have not made a decision on Transgrid's proposed standard tax asset life for the 'Financeability asset class 1' asset class. This is because our final decision is to not accept Transgrid's proposed financeability adjustment (see section 8.2.1 for further information) and as such, we are not required to assess the corresponding tax life for this asset class.

Finally, section 8.2.2 sets out our decision to remove a number of asset classes that are not used for the CWO Enabling Project as these asset classes do not have any forecast capex allocated to them.[153] Consistent with the approach set out above, we have similarly not made a decision on the standard tax asset lives for these removed asset classes.

Table 11.2 sets out our final decision on the standard tax asset lives for Transgrid. We are satisfied that the standard tax asset lives are appropriate for application over the 2026–31 period. We are also satisfied that the standard tax asset lives provide an estimate of the tax depreciation amount that would be consistent with the tax expenses used to estimate the annual taxable income for a benchmark Network Operator delivering an efficient service.[154]

Table 11.2 AER's final decision on Transgrid's standard tax asset lives for the 2026–31 regulatory control period (years)

Asset class	Standard tax asset life
Transmission lines	50.0
Substations	40.0
Secondary systems	15.0
Land and easements[a]	n/a
Biodiversity offsets – stewardship[a]	n/a
Biodiversity offsets – direct payments	50.0
Equity raising costs[b]	5.0[c]

Source: AER analysis.
a) Not applicable. We have not assigned a standard tax asset life to the Land and easements and Biodiversity offsets – stewardship asset classes because these assets are not subject to tax depreciation.
b) The Equity raising costs asset class use the straight-line method for tax depreciation. All other asset classes use the diminishing value method of tax depreciation.
c) Under section 40-880 of the ITTA 1997, certain business capital expenditures, such as equity raising costs in this instance, are deductible on a straight-line basis over five years.

153 The unused asset classes we have removed are: underground cables, communications (short life), SIPS control, business IT, minor plant, motor vehicles and mobile plant, transmission line life extension, synchronous condensers, leasehold land and property, buildings – capital works, and in-house software.

154 EII Chapter 6A, cl. 6A.6.4.

12 Incentive schemes

When making a revenue determination, we are required to take into account the principle that incentives should be given to Network Operators to promote economic efficiency, and to pass such efficiencies on to consumers.[155]

Under the NER framework, we have developed the Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS) to provide financial incentives to Network Service Providers to identify and include efficiencies in the construction, and ongoing operation, of projects. In accordance with our Non-contestable Guideline, we will apply these incentive schemes when making a non-contestable revenue determination, noting there are several matters our Non-contestable Guideline must not deal with including small-scale incentive schemes, the demand management innovation allowance mechanism, and removal of assets from the RAB.[156] Our current CESS is set out in version 4 of the Capital Expenditure Incentive Guideline.[157] Our current EBSS and assessment approach (for both the CESS and the EBSS) is detailed in chapter 11 of our assessment approach guidance note.[158]

We must decide how any CESS is to apply to the Network Operator.[159] EII Chapter 6A sets out the factors we must take into account when deciding whether to apply a CESS, including the capital expenditure sharing scheme principles.[160] We have the discretion to decide whether to apply the EBSS to the Network Operator.[161]

12.1 Transgrid's proposal

12.1.1 Transgrid's proposed CESS

Transgrid proposed a modified CESS for the CWO Enabling Project, where if actual capex exceeds ±10% of our approved capex forecast, the sharing ratio would be equal to the average financing costs (for overspends) or financing benefit (for underspends), assuming no shift in the timing of capex.[162] The standard 30% sharing ratio would apply to overspends and underspends within ±10% of our approved allowance. Transgrid submitted that this approach would provide a meaningful incentive to pursue efficiencies, even when capex variances exceed the 10% cap while ensuring any financial impact of extreme overspends remains manageable for the business. This modified CESS would be consistent with our decision on Transgrid's HumeLink project.[163]

Transgrid submitted the complex and unique nature of this project, when considered alongside the current operating environment and the regulatory framework under which the

---

155 EII Act, s. 37(1)(b).

156 AER, *Guideline: Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, p. 6; EII Regulation, cll. 47A(5)(f) to (g), (j).

157 AER, *Capital Expenditure Incentive Guidelines for Electricity Network Service Providers (Version 4)*, August 2025.

158 AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations*, September 2025, pp. 46–52.

159 EII Chapter 6A, cll. 6A.4.2(a)(6A), 6A.14.1(5A).

160 EII Chapter 6A, cl. 6A.6.5A.

161 EII Chapter 6A, cl. 6A.6.5(a).

162 Transgrid, *Central West Orana Enabling Project 2026-31 – Revenue Proposal*, July 2025, pp. 133–134.

163 AER, *Transgrid 2023–28 - Final Decision – Overview*, April 2023.

project is delivered, necessitated a modified CESS application. Specifically, it highlighted the need to co-ordinate various parties under multiple interconnected contractual arrangements and under contractually agreed timelines, including the delivery and operational interfacing with other pre-existing networks, which results in increased governance, coordination and operational requirements, and a level of commercial complexity. Transgrid considered a modified CESS balances the need to appropriately incentivise it to reduce the cost of the project for consumers while ensuring that investor confidence is not eroded, resulting in a reasonable sharing of the benefits and risks between Transgrid and consumers.

In responding to our preliminary position paper, Transgrid acknowledged our preliminary position to apply the standard CESS and did not intend to re-propose a modified CESS for this project. However, Transgrid suggested some capex categories should be excluded from the CESS if we did not accept all its proposed adjustment mechanisms for other uncontrollable events.

12.1.2 Transgrid's proposed EBSS

Transgrid proposed that we defer a decision on whether to apply the EBSS to the end of the 2026–31 period based on:[164]

- there being no historical revealed opex on which to base forecasts
- the one-off and bespoke nature of EII non-contestable projects does not enable the use of suitable benchmarking
- 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.

Transgrid indicated its proposed approach aligned with our draft Incentive schemes for non-contestable network projects in NSW Guidance Note and our final decision on the non-contestable components for the Waratah Super Battery.[165]

12.2 AER final decision

12.2.1 Application of the CESS over 2026–31 period

Our final decision is to apply the standard CESS as set out in version 4 of the Capital Expenditure Incentive Guideline, but to exclude capex related to IPFs.[166] We do not consider Transgrid has adequately justified its proposal to modify the CESS sharing ratios for the project.

In considering whether to apply a modified CESS, our default position is to apply the standard CESS, set out in the Capital Expenditure Incentive Guideline, and we will make exclusions or modifications in only limited circumstances where there is a strong case to do so.[167]

---

164 Transgrid, *Central West Orana Enabling Project 2026-31 – Revenue Proposal*, July 2025, p. 139.

165 AER, *Draft Guidance note – Incentive schemes for non-contestable projects in NSW*, August 2023; AER, *Final decision – Transgrid 2024–29 – WSB non-contestable*, December 2023.

166 AER, *Capital Expenditure Incentive Guideline*, August 2025.

167 AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations*, September 2025, p. 49.

In determining whether to vary the application of the CESS for the CWO Enabling Project, we have considered:[168]

- benefits to consumers. Transgrid did not submit specific information or analysis to demonstrate that modified CESS sharing ratios would provide benefits to consumers. It argued the risk of unpredictable and uncontrollable events arising from the current operating market increases the likelihood of it overspending compared to our approved revenue. This is due to factors such as the unprecedented number of projects, a tight labour market, global supply chain issues and inflationary pressures, active consultation requirements to achieve social licence and declining contractor-owned risk. While these factors could impact the project, we consider they are adequately addressed by the capex forecast and revenue adjustment mechanisms.
- the size of the project. The CWO Enabling Project is much smaller than Transgrid's HumeLink project and its 2023–28 revenue determination (where we have applied a capex allowance that is subject to the CESS). In this case, the potential for material CESS penalties due to a capex overspend is far smaller.
- the degree of capex forecasting risk. Capex forecasting risk is mitigated by the inclusion of risk costs (other construction costs) in our capex allowance as well as revenue adjustment mechanisms. Our final decision accepts Transgrid's proposed adjustment mechanisms related to 'other uncontrollable events', which could otherwise lead to higher than expected capex. Therefore, we do not consider that in this instance capex forecasting risk is a relevant factor that would prompt us to modify the existing sharing ratios under the CESS.
- stakeholder views. Our preliminary position not to apply a modified CESS was supported in all submissions received from stakeholders.[169] Some members of the TAC submitted that they had minimal direct engagement with Transgrid and stated that they had not received adequate reasoning for its departure from an unmodified CESS or a consumer focussed position.[170]

As noted in section 6.2.1.1, our decision is to shift pre-period IPFs to 2026–27 (the first year of the regulatory control period). We consider that these costs should be excluded from the CESS as they reflect contractual amounts payable to EnergyCo. Aside from this adjustment, our alternative capex estimate (excluding equity raising costs) will be subject to the CESS.

We are satisfied that our application of the CESS will provide Transgrid with an appropriate incentive to undertake efficient capex for the CWO Enabling Project, and the approved adjustment mechanisms (discussed in chapter 13) will allow Transgrid to manage any remaining uncertainty associated with the project.

Table 12.1 shows the capex values that will be subject to the CESS under our decision.

---

168 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers (Version 4)*, August 2025, p. 9.

169 CCP35, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025, p. 12; EUAA, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025, p. 2; JEC, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025, p. 3.

170 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025, p. 5

Table 12.1 AER's final decision on capex subject to CESS ($ million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Capex subject to CESS	98.8	108.1	13.5	0.0	0.0	220.5

Source: AER analysis.

12.2.2 Application of the EBSS over 2026–31 period

Our decision on whether to apply the EBSS will be made at the end of the 2026–31 period as there is currently no historical opex upon which to base forecasts. At that time, we will consider whether Transgrid has revealed opex that is efficient and whether the base level of opex is at a steady state such that it could be used to forecast opex for the following regulatory period. This is consistent with our assessment approach guidance note and final decisions on non-contestable components for both the Waratah Super Battery and Ausgrid's HCC Project.[171]

[171] AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations*, September 2025, pp. 50–52; AER, *Final Decision – Transgrid 2024–29 - WSB non-contestable*, June 2024 (remade); AER, *Final decision – Ausgrid – Hunter-Central Coast REZ non-contestable project 2026–31*, December 2025.

13 Adjustment mechanisms

Adjustment mechanisms are pre-defined circumstances that allow a Network Operator to request the adjustment of any amount set out in a revenue determination.[172] These mechanisms are intended to account for risks that are outside a Network Operator's control, and cannot be efficiently mitigated through other means.

Our approach to considering revenue adjustment mechanisms is described in our revenue determination Guideline for non-contestable projects and our assessment approach guidance note.[173]

Our role as the Regulator in a non-contestable EII process is to determine the amount payable to the Network Operator for carrying out the network infrastructure project based on an assessment of its revenue proposal and supporting information.[174] A Network Operator may include in its revenue proposal mechanisms to adjust any amount provided for in our revenue determination. The EII Regulation provides the AER with discretion as to whether to include an adjustment mechanism in its determination or potentially include it in an amended form.

As a general principle, negotiations between a Network Operator (in this case, Transgrid) and the Infrastructure Planner (EnergyCo) do not constrain the AER when making its determination under a non-contestable framework. We act as an independent assessor[175] of whether the proposed adjustment mechanisms will contribute to the recovery of prudent, efficient and reasonable costs.[176]

We acknowledge that where a competitive assessment process has been found by the AER to be genuine and appropriate and has produced contractual outcomes (including mechanisms for adjustment of revenues) these are to be considered prudent, efficient and reasonable and we must incorporate them in our determination.[177] However, this is not the case for non-contestable projects.

13.1 Transgrid's proposal

Transgrid proposed 29 adjustment mechanisms in its revenue proposal. These were:[178]

- 6 prescribed adjustment mechanisms, for events prescribed in EII Chapter 6A of the revenue determination Guideline for non-contestable projects.
- 3 adjustment mechanisms for routine administrative events, to ensure inflation, return on debt and return on equity are able to be updated as required.

---

172 EII Act, s. 38(3), EII Regulation, cl. 51.

173 AER, *Final guideline – Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects*, December 2025, p. 29; AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations*, September 2025, pp. 38–45.

174 EII Act, s. 38(1).

175 EII Act, s. 64(5); the Consumer Trustee also acts independently (EII Act, s. 60(5)) but not the Infrastructure Planner Act, (EII Act, s. 63(8)).

176 EII Act, s. 37(1)(a).

177 EII Regulation, 51(3)(b).

178 Transgrid, *Central West Orana Enabling Project 2026–31 – Revenue Proposal, July 2025*, pp. 106–132.

- 4 nominated adjustment mechanisms, to reflect the pass-through events that were accepted by the AER in Transgrid's 2023–28 Revenue Determination.
- 4 adjustment mechanisms to reflect Transgrid's contractual arrangements with EnergyCo, this includes adjustments for changes in Infrastructure Planner costs, contractual variations and delay liquidated damages.
- 4 costs associated with the BCSS, these adjustments are contemplated in Transgrid's Project Deed with EnergyCo and are proposed in accordance with clause 21 of the EII Regulation.
- 8 adjustment mechanisms for other uncontrollable events, that are outside of Transgrid's control and cannot be reasonably mitigated, prevented or insured against.

13.2 AER final decision

Our final decision is to accept 26 of the 29 adjustment mechanisms as proposed by Transgrid (some with minor changes for clarity or consistency with our final decisions for the WSB Project and the HCC Project). We have not accepted:

- 2 of the proposed prescribed adjustment mechanisms for events prescribed in EII Chapter 6A of the Non-contestable Guideline (the inertia shortfall and fault level shortfall events). This is because these two events were removed as prescribed events in clause 6A.7.3(a1) of EII Chapter 6A, which aligns with the removal of the events as prescribed pass through events from clause 6A.7.3(a1) of the NER following AEMC rule changes.[179]
- The BCSS replacement expenditure and operating expenditure annual true-ups event. Our reasoning for this decision is explained in section 13.2.1.

A summary of the adjustment mechanisms accepted in our final decision is set out in Table 13.1 below, accompanied by a brief operational description of each adjustment event. The precise wording of each adjustment mechanism is contained in Appendix B of this final decision, alongside our reasons for the inclusion of each adjustment mechanism.

Where there was an adjustment event or a category of events referred to by multiple names in Transgrid's proposal we have standardised the name of the adjustment event. We have included the other name(s) of these adjustment events in our footnotes where we consider the names are materially different from Transgrid's proposal. Where possible we have tried to align these names with the names used in our final decision for the HCC Project.

Table 13.1 Adjustment mechanisms accepted in our final decision

#	Accepted mechanism	Brief description of the adjustment event
Adjustment mechanisms for events prescribed in EII Chapter 6A		
1.	Regulatory Requirements as defined in cl.46(3) of the EII Regulation	A change in costs arising from complying with regulatory requirements.
2.	A service standard event	A change in costs arising from accommodating a service standard event.

[179] The inertia shortfall event was removed from clause 6A.7.3(a1) of the NER in December 2024 by the AEMC's *Improving security frameworks for energy transition* rule change, and the fault level shortfall event was removed from clause 6A.7.3(a1) of the NER in 2022 by the AEMC's *Efficient management of system strength on the power system* rule change.

#	Accepted mechanism	Brief description of the adjustment event
3.	A tax change event	A change in costs arising from accommodating a tax change event.
4.	An insurance event	A change in costs arising from an insurance event.
Adjustment mechanisms for routine adjustment events		
5.	Risk-free rate update[180]	Update to the return on equity to true-up the final averaging period for the risk-free rate.
6.	Annual update for actual inflation	Annual updates to revenue to account for actual (as opposed to forecast) inflation.
7.	Return on debt update	Update to the allowed rate of return, using more recent averaging periods.
Adjustment mechanisms for standard events[181]		
8.	Insurance coverage event	A change in costs arising from a change in insurance coverage due to changes in the insurance market.
9.	Insurer's credit risk event	A change in costs due to an insurer of this project becoming insolvent.
10.	Natural disaster event	A change in costs due to a natural disaster.
11.	Terrorism event	A change in costs due to a terrorism event.
Adjustment mechanisms for EnergyCo contractual events[182]		
12.	Infrastructure Planner Cost Change event	A change in Infrastructure Planner costs to reflect the amount advised by the Infrastructure Planner in its written notice.
13.	Early Project Development Cost Recategorisation event	A change in costs arising from a written notice from the Infrastructure Planner directing the recategorisation of early project development activities to project-related costs.
14.	Liquidated Damages event	A reduction in revenue in the event Transgrid is required to pay liquidated damages to the Infrastructure Planner.
15.	Contractual Variations event	A change in costs due to Transgrid having to comply with a contractual variation as directed by the Infrastructure Planner.
Adjustment mechanisms for BCSS-related events[183]		
16.	BCSS Transfer event[184]	A change in costs to reflect the costs associated with the purchase and transfer of the BCSS to Transgrid.
17.	BCSS Purchase Price Adjustment event	A change in revenue Transgrid can recover to reflect the costs of an adjustment of the purchase price for the BCSS.

180 Transgrid referred to this event as the 'Updates to return on equity' event.

181 Transgrid referred to these events as 'Nominated pass-through events accepted in 2023–28 Revenue Determination' and 'Adjustment mechanisms for previously accepted nominated pass-through events' in its proposal.

182 Transgrid referred to these events as 'Adjustment mechanisms related to changes in reimbursable costs payable to EnergyCo' and 'Adjustment mechanisms related to meeting contractual obligations' in its proposal.

183 Transgrid also referred to these events as 'Adjustment mechanisms relating to transfer of network infrastructure' events and 'Adjustment mechanisms for costs associated with BCSS' events in its proposal.

184 Transgrid also referred this event as the 'Recovery of BCSS Purchase Price' event.

#	Accepted mechanism	Brief description of the adjustment event
18.	BCSS Incremental Cost event	A change in incremental capital and/or operating costs incurred by Transgrid related to the operation of the BCSS.
Adjustment mechanisms for other adjustment events[185]		
19.	Contractor Force Majeure event	A change in construction costs incurred due to a force majeure event impacting the construction contractor.
20.	Unavoidable Design and Construct (D&C) Contract Variation event	A change in D&C costs due to changes in the final design or construction methodology, and/or certain contractual component prices, specified in the contractual arrangements.
21.	Biodiversity Offset Cost Variance event	A change in revenue Transgrid can recover to reflect costs it incurred in disposing of biodiversity offset liability for the Project.
22.	Planning Approval Delay event	A change in costs incurred by Transgrid due to planning approval delays.
23.	Outage Cancellation event[186]	A change in costs incurred by Transgrid due to the cancellation of a planned outage by AEMO.
24.	Latent Condition event	A change in costs incurred by Transgrid due to addressing a latent condition specified in the D&C contract.
25.	Compulsory Acquisition event	A change in costs incurred by Transgrid due to the compulsory acquisition of a necessary easement for the project.
26.	Legal Challenges event[187]	A change in costs incurred by Transgrid due to an appeal to the compulsory acquisition process.

Source: Transgrid, *Central West Orana Enabling Project 2026-31 - Revenue Proposal*, July 2025, pp. 106-132.; AER analysis.

13.2.1 Adjustment mechanisms for BCSS-related events

Our final decision is to accept 3 of the 4 BCSS-related events proposed by Transgrid, subject to some minor wording amendments, and to not accept the final adjustment event for truing up actual expenditure. The precise wording for the adjustment events we have accepted in this final decision are set out in Appendix B.

Specifically, our final decision includes adjustment mechanisms for the following 3 BCSS-related events:

- BCSS Transfer event
- BCSS Purchase Price Adjustment event
- BCSS Incremental Cost event.

The BCSS asset is currently not included in the Consumer Trustee authorised scope for Transgrid's CWO Enabling Project and as such, it is unable to be included in any relevant expenditure in its forecast capex and opex for the 2026–31 period. We therefore consider Transgrid's proposed justification for the need for these adjustment events to be reasonable,

185 Transgrid also referred to these events as 'Other uncontrollable events' in its proposal.

186 Transgrid also referred this event as the 'Cancellation of planned outages by AEMO' event.

187 Transgrid also referred this event as the 'Legal challenges relating to compulsory acquisition' event.

consistent with the position presented in our preliminary position paper, as they relate to costs it would be required to incur if the BCSS asset was a part of its authorisation.[188]

In particular, we agree with Transgrid's characterisation of the BCSS transfer as a transfer of network infrastructure contemplated under clause 21(1)(c)(ii) of the EII Regulation. We also consider that some components of the 'BCSS Transfer' event and 'BCSS Purchase Price Adjustment' event relate to payments that Transgrid must make to EnergyCo under a contractual arrangement it was required to enter into under the authorisation, consistent with clause 46(1)(b)(ii) of the EII Regulation. We therefore will not assess the prudency, efficiency and reasonableness of the expenditure proposed under these 2 adjustment events.

We consider Transgrid's proposed 'BCSS Incremental Cost' event is reasonable. We would expect Transgrid to incur incremental expenditure related to taking over operational control of the BCSS asset at the time of transfer. Our final decision on capex and opex (sections 9.2 and 10.2) does not include any forecast expenditure related to this asset, consistent with Transgrid's proposal. We will determine the capex and opex amounts to be included in Transgrid's determination as part of an application for this adjustment event, subject to our standard assessment for prudency, efficiency and reasonableness.

However, we consider that the final adjustment mechanism, 'BCSS Replacement Expenditure and Operating Expenditure Annual True Ups' event (annual true-up adjustment) is not appropriate, given the circumstances of the CWO Enabling Project. Transgrid's key concern was that, as part of the 'BCSS Incremental Cost' event, it would be unable to include an efficient expenditure forecast due to the limited visibility of the design and construction of BCSS, leading to increased risk to Transgrid.

Our preliminary position paper set out our assessment of Transgrid's justification for the annual true-up adjustment, where we were not convinced that it had adequately justified shifting the costs of managing forecasting risk onto consumers. Our reasoning was that:

- Transgrid had been consulted on various aspects of the BCSS asset, particularly in relation to the interface component of the asset. This included opportunities to review and comment on the interface design and participation in a safety workshop.
- It was not clear how the lack of knowledge on other design specifications unrelated to the interface component materially affected Transgrid's ability to forecast related maintenance and operational expenditure for the BCSS transfer. In particular, the BCSS would be a new asset at the point of transfer midway through the 2026–31 period and Transgrid would have the opportunity to provide a new expenditure forecast shortly afterwards at the next regulatory control period.
- EnergyCo has put in place several measures in the TNA Interface Deed to ensure the BCSS asset is free from major defects which preclude the commissioning and energisation of BCSS, such as the requirement for the design and construction of BCSS (by ACEREZ as the Network Operator for the CWO Main Project) to be signed off by an Independent Certifier. The TNA Interface Deed also includes defects provisions which have been negotiated and agreed by ACEREZ and Transgrid, which includes a defect

[188] AER, *Preliminary position paper – Enabling CWO REZ network infrastructure project (non-contestable)*, October 2025, pp. 36–37.

liability period for ACEREZ to rectify minor and/or major defects. These appear to be risk-mitigation strategies designed to address Transgrid's concerns.

- We considered that Transgrid's experience with commissioning other switching stations to be sufficient in allowing it to provide a forecast of the necessary capex and opex required to operate BCSS. In light of the material provided to us by Transgrid at the time of our preliminary position paper, its concerns around the novelty of the technology used and lack of familiarity with the subcontractors engaged by ACEREZ in the construction of BCSS did not appear to be material enough that it would warrant shifting this risk to consumers.

In response to our preliminary position paper, Transgrid maintained its position that the annual true-up adjustment was required. It provided further reasoning justifying this position, primarily that:[189]

- The majority of Transgrid's interactions and consultation with EnergyCo on BCSS is in relation to the interface component and cut-in works, rather than the switching station itself. As a result, the early engagement does not mitigate the forecasting risk associated with the unknown design specifications of BCSS.
- Transgrid's concern regarding forecasting risk arises from uncertainty around the asset management approach ACEREZ has adopted in the construction of BCSS. It claims that while defect remediation provisions ensure that BCSS is safe for operation, it does not require adherence to a particular asset management strategy. This lack of clarity on whether the design specifications places greater weight on replacement capital expenditure (repex) or opex inhibits Transgrid from being able to include an expenditure forecast consistent with the requirements of the asset.
- The new technology and unfamiliar contractors being employed by ACEREZ in designing and constructing BCSS means that its experience with commissioning other similar switching stations is irrelevant to reducing the uncertainty risk in forecasting BCSS-related capex and opex.

Transgrid's submission, however, suggested amending this adjustment event from an annual true-up to be a one-off true-up to manage the concerns we raised in the preliminary position paper around the forecasting risk allocation.

In reviewing the additional material and explanation provided by Transgrid, we acknowledge that Transgrid's lack of visibility and familiarity with the design specifications of BCSS has a material impact on its ability to accurately provide a forecast of the necessary repex and opex associated with this asset. While the Independent Certifier and warranty agreement for minor defects will address potential construction or early operational issues at the point of the BCSS transfer, it does not directly mitigate against forecasting risk, particularly when Transgrid is not privy to details around how the asset was designed.

However, we are not convinced that this concern adequately justifies Transgrid's proposed inclusion of an adjustment mechanism to true-up for actual expenditure. Our regulatory framework is built on encouraging Network Operators to become more efficient through incentive-based regulation, which is inconsistent with Transgrid's proposal to recover actual costs with no consideration for an ex-post assessment of prudency, efficiency or reasonableness. Our view, which is shared by the AEMC, is that for appropriate incentives to

---

189 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal,* November 2025, pp. 5–7.

be maintained, any adjustment mechanism should only be accepted when it is the least inefficient option and when event avoidance, mitigation, commercial insurance and self-insurance are unavailable or found to be inappropriate.[190]

Further, passing through actual costs would shift the entire forecasting risk onto consumers, who are least equipped to manage this risk. We consider any deviation from our standard approach to incentive regulation requires a high bar for change regardless of whether the true-up event is a one-off or annual mechanism, which Transgrid's submission does not appear to address.

In assessing how best to manage the BCSS forecasting risk, we explored the option of replacing the proposed annual true-up adjustment with a delayed capex forecast adjustment, similar to that which we have approved for Ausgrid's HCC Project.[191] When applied, the adjustment could allow Transgrid a one-off opportunity to revise its forecast capex and opex, which would have been initially approved through the 'BCSS Incremental Cost' event at the time of the BCSS transfer to Transgrid. Under such an approach:

- Transgrid's concerns around forecasting risk would be managed and minimised to a significant extent through allowing Transgrid an opportunity to develop experience and familiarity with the BCSS asset (including building expertise in any new technology employed in the construction of the switching station), before requiring Transgrid re-propose a forecast expenditure profile.
- A delayed capex forecast adjustment would allay our key concern with maintaining the incentive framework for Transgrid, as the delayed capex forecast adjustment only revises future expenditure, rather than truing-up for actual costs.

However, a key consideration to applying the delayed capex forecast adjustment is determining a clear timing for the trigger event. Unlike our HCC decision, the BCSS capex subject to a delayed adjustment will only be included in Transgrid's determination midway through its regulatory control period as part of a separate adjustment mechanism. As such, a delayed capex adjustment is to only apply a certain time after these costs have been proposed and approved. Transgrid's submission suggested a timing at the end of the warranty period for minor defects, two years after the operation of BCSS, as an appropriate timing for its one-off true-up mechanism. We would likely consider a similar timing when applying a delayed capex forecast adjustment, which would result in a potential adjustment mechanism towards the end of the 2026–31 period for the CWO Enabling Project. At that point in time, we would expect Transgrid to be preparing another expenditure forecast for its revenue proposal for the subsequent revenue determination (2031–36 regulatory period).

A delayed capex forecast adjustment may only be applicable to a short period of time before being replaced by a new determination. Therefore, we consider there is minimal risk to Transgrid if it were to only revise its forecast expenditure in its revenue proposal for the subsequent revenue determination, rather than during the 2026–31 period. This is

---

190 AER, *Guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations*, September 2025, p. 40; AEMC, *Rule Determination – Cost pass through arrangements for Network Service Providers*, 2 August 2012, pp. 19–20.

191 AER, *Final decision – Ausgrid – Hunter-Central Coast REZ non-contestable project 2026–31*, December 2025, pp. 67–69.

particularly the case with a completely new asset such as BCSS, where we would expect there to be minimal repex requirements in the initial years.

13.2.2 Other adjustment events – changes from our preliminary position

In our preliminary position paper, we said that we were likely to accept 2 of Transgrid's proposed adjustment mechanisms for 'Other adjustment events', but with potential modifications. These were:

- 'Unavoidable D&C contract variations' event. We considered applying a delayed capex forecast instead of a cumulative cap as proposed by Transgrid.
- 'Planning Approval Delay' event. We suggested that the adjustment mechanism trigger requires refinement.

Our preliminary position was that we were likely to not accept 3 of Transgrid's proposed adjustment mechanisms in the 'Other adjustment events' category. These were the:

- 'Biodiversity Offset Cost Variance' event
- 'Compulsory Acquisition' event
- 'Legal Challenges' event.

Since our preliminary position paper, Transgrid has provided us with additional information which prompted us to change or adjust our positions on these adjustment mechanisms. Our final decision is to accept all of Transgrid's proposed 'Other adjustment events' and our reasoning is discussed in more detail below.

Unavoidable D&C Contract Variations event

Our preliminary position was to accept this adjustment mechanism. However, we were considering whether a delayed capex forecast or the maximum expenditure cap of $25 million proposed by Transgrid represented the best option to constrain risk for consumers.

In response to our preliminary position paper, particularly our proposal to apply a delayed capex forecast, Transgrid submitted that:[192]

- Due to the project timeline and its risk profile (which include a variety of risks), it would be difficult to identify a single trigger which would substantially reduce the uncertainty in the forecast.
- As some key risks will occur late in the construction period, milestones earlier in the regulatory period will still carry significant uncertainty.
- Conversely, if the trigger occurs late in the period, the activities would be almost entirely de-risked, so forecasting would not adequately incentivise it to mitigate risk and seek efficiencies in these activities.
- Its maximum expenditure cap would be applied at the beginning of the period and capture all the risks immediately, allowing for stronger incentives for it to minimise costs without completely de-risking the activities.

---

192 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 7–9.

We consider that a single trigger milestone where uncertainty is substantially reduced could be identified. This milestone would be when Transgrid issues the final designs to its contractors. However, this milestone would likely occur in the last year of the regulatory period (2030–31), so a delayed capex forecast would not provide incentives for Transgrid to efficiently constrain its capex until the last regulatory year. At this point, most of the risk would be resolved and the forecast capex would carry almost no risk.

We also consider that the uncertainty associated with this adjustment mechanism is significantly lower than the uncertainty faced by Ausgrid on similar adjustments it proposed in its HCC Project, where we applied a delayed capex forecast. This is due to Transgrid having had more time to investigate potential risks prior to submitting its CWO Enabling revenue proposal. As such, Transgrid were better able to estimate the appropriate amount for a maximum expenditure cap.

Transgrid has proposed the application of an expenditure cap to these costs, which would provide it with some incentive to spend efficiently. We consider that the proposed $25 million cap, which is a proxy for the estimated magnitude of the proposed adjustment, is not large relative to the size of the project capex (approximately 6% of total capex, excluding BCSS). As such, the weaker incentives provided by the maximum expenditure cap as opposed to the CESS, would not significantly weaken the total incentive for Transgrid to efficiently constrain its capex.

In their submission to our preliminary position paper, Louise Benjamin and Gavin Dufty commended us for looking to apply the delayed capex forecast adjustment to the Unavoidable D&C Contract Variations event.[193] However, their submission also considered that the delayed capex forecast adjustment should only be applied where appropriate, and that the timing of the trigger is very important.

On balance, we consider that the Unavoidable D&C Contract Variations event is better suited to an expenditure cap than a delayed capex forecast adjustment. This is due to the level of uncertainty, timing and magnitude of the risk costs involved. Additionally, Transgrid's proposed cap of $25 million appears reasonable, and we consider it will provide adequate incentive for Transgrid to spend its related capex efficiently. Our final decision is to accept this adjustment event with a maximum expenditure cap (cumulative adjustment) of $25 million over the 2026–31 regulatory period.

Planning Approval Delay event

Our preliminary position was to accept this adjustment event. However, we considered the adjustment mechanism trigger should be refined to specify:

- the definition of a 'material impact' on Transgrid's delivery schedule with reference to a date relative to the expected EIS approval in mid-2026
- the nature of costs that could potentially increase in the event of planning approval delays.

In its submission to our preliminary position paper, Transgrid suggested an updated definition. This specified the timing window (5 business days delay) in relation to the expected EIS determination (8 June 2026) and subsequent Construction Environmental Management Plan approvals within 91 days of EIS approval. It stated that any delays beyond 5 days resulted in

---

193 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper - 2026-31 Revenue Proposal*, November 2025, p. 6.

its contractor missing an outage window, which would have a significant time and cost impact for the project (potentially a 4-month delay depending on outage schedules).

Transgrid's updated definition also included further detail on the types of costs likely to be incurred but submitted that it is not appropriate to limit the applicable cost categories upfront to exclude any specific cost category. Transgrid considers it more appropriate that an assessment of the prudency and efficiency of incurring these costs is undertaken at the time of application, rather than restricting the adjustment mechanism to a specific type of cost.

Our final decision is to accept the updated definition of Transgrid's proposed 'Planning Approval Delay' event. We consider that the addition of the 5 business day timing window sufficiently quantifies material impacts and adequately reflects the risks Transgrid is addressing with this adjustment.

We agree with Transgrid's argument that due to the uncertainty of the length of the delay, the types of delay costs it may incur could be difficult to fully specify in advance. We agree that the appropriate costs are best determined at the time of Transgrid's application for this adjustment event, where they will be subject to our assessment of prudency, efficiency and reasonableness. However, in our final decision, we consider it appropriate to include a reference to the types of costs that might be considered under this adjustment event. While this list of costs is not exhaustive, we consider that noting the types of cost provides greater clarity for stakeholders over the potential costs without excluding Transgrid from recovering other costs we deem prudent, efficient and reasonable.

Transgrid submitted that prudent, efficient and reasonable costs associated with facilitating the planning approval delays, including any Extension of Time claim under the D&C contract could include:[194]

- prolongation costs for the D&C contractor's work
- prolongation costs for Transgrid's project management and environmental management resources, including any additional contractor or consultant support required during the EIS delay period.

For clarity, prudent, efficient and reasonable costs do not include costs that Transgrid is able to effectively mitigate.

Biodiversity Offset Cost Variance event

Our preliminary position was to not accept this adjustment mechanism. Our concern was that, if accepted, Transgrid will not be incentivised to acquit its offset liabilities efficiently. It would also be very difficult for us to determine ex-post whether Transgrid could have acquitted its offset liabilities more efficiently. We were considering two approaches to biodiversity offset costs and the related adjustment mechanism for the project:

- Not accept the proposed adjustment mechanism but accept the proposed capex for biodiversity offset costs.

194 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 9.

- Apply a delayed capex forecast mechanism, noting that a delayed (and more accurate) capex forecast could be provided after the EIS is approved (which is expected to be in mid-2026).

In response to our preliminary position paper, Transgrid maintained that this adjustment mechanism remains appropriate as these costs are influenced by various factors outside its control. It submitted that applying a delayed capex forecast is largely redundant, as it cannot mitigate, or otherwise reduce, the biodiversity offset costs in any meaningful way. Transgrid also suggested that if this adjustment mechanism was not accepted, these costs should be excluded from the CESS.

The JEC indicated support for Transgrid's proposed adjustment mechanism, noting biodiversity offsets should be treated as a pass-through cost given its limited control over them.[195] Louise Benjamin and Gavin Dufty's submission asked if the costs associated with this event could be divided into separate adjustment events and then treated differently according to their level of uncertainty.[196] They suggested the more certain biodiversity offset costs be included in the forecast expenditure or under a delayed forecast mechanism and so subject to CESS earlier in the regulatory period. The more uncertain biodiversity costs could then be treated either as an adjustment event or under a delayed forecast mechanism with a different, later trigger.

We consider that it may have been possible to distinguish elements of this cost category based on their level of certainty and that a delayed capex forecast mechanism may have been a credible option for at least some of the more certain biodiversity offset costs. For example, the augmentation works are subject to an EIS, whereas the transposition works are not. We met with Transgrid, and it confirmed since it has completed its BDAR and submitted its EIS, the number of biodiversity offset credits required for the project is effectively certain (for augmentation works), and so uncontrollable cost variations are now limited to changes in prices, which vary according to offset acquittal method. However, Transgrid did not identify and separate these costs from the other biodiversity offset costs or provide a forecast of these costs which we could include in our capex forecast. We consider that in the future Transgrid, and other Network Operators should seek to identify and separate out costs which will be certain enough to reasonably forecast prior to or early in the regulatory period. We consider that in most cases these costs should then be proposed as part of the risk costs in the capex forecast or as a delayed capex forecast adjustment.

We recognise that cost variations for the non-controllable elements of this adjustment are more likely to be due to factors outside Transgrid's control, even if a delayed capex forecast is applied. Transgrid noted that its acquittal pathway remains uncertain. If it can apply a Strategic Offset Delivery Agreement, the final offset costs will be determined by NSW Department of Climate Change, Energy, the Environment and Water (NSW DCCEEW). If not, then it is expected that Transgrid will follow through with the acquittal methods included in its revenue proposal.

For Ausgrid's HCC Project, a delayed capex forecast adjustment mechanism was our preferred approach because it was applicable to tendered works costs, which represented

---

195 Justice and Equity Centre, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 3.

196 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 7.

the majority of Ausgrid's forecast capex. For this project, biodiversity offset costs only represent around 5% of Transgrid's forecast capex.

For these reasons, we have accepted the adjustment mechanism as proposed by Transgrid in our final decision. However, we encourage Transgrid and other Network Operators to distinguish between risks that are even partially within their ability to influence and able to be reasonably estimated, and those which are not. Network Operators should carefully consider the appropriate approach to efficiently manage risks in each of these categories.

Our preliminary position to not accept this adjustment mechanism was based on an assumption that the forecast capex for biodiversity offsets ($15 million) would be accepted in our decision. However, as noted in section 9.2.3, Transgrid's forecast contained numerous contingencies and cost certainty has improved since its EIS submission (for the augmentation works component). We are now satisfied that our alternative estimate of biodiversity offset costs represents the most prudent, efficient and reasonable estimate, based on the latest available information.

Our decision will benefit consumers because our alternative capex estimate will lead to lower costs to consumers. Although changes in biodiversity offset costs (relative to our decision) can be proposed under this adjustment mechanism (and will not be subject to the CESS), we consider our analysis for this decision has refined Transgrid's initial cost estimate such that any future cost variations are likely to be minimal and (for the augmentation works component) limited to the available acquittal methods. In assessing future revenue adjustments for biodiversity offset costs, we will consider information included in Transgrid's revenue proposal, including GHD's report, as well as new information such as the BDAR included in the EIS. We may also liaise with NSW DCCEEW to understand the acquittal methods that were available to Transgrid over time.

Compulsory Acquisition event

Our preliminary position was to not accept this adjustment mechanism. We considered that Transgrid has some ability to control and forecast these costs because a relatively small number of landholders are impacted by the project, and most acquisition costs will be incurred in the near-term (by the end of 2026). Also, Transgrid's capex forecast applied a premium to Transgrid's initial valuation for landholder compensation, which was based on the actual compensation paid for property for the HumeLink project. Its forecast also included risk costs for 'Property valuation uncertainty'.

In response to our preliminary position paper, Transgrid submitted that:

- Its base expenditure estimate assumes all easements will be secured through negotiated agreements with landholders.
- The proposed risk cost allowance has been included to account for potential complex property issues that may lead to higher-than-expected negotiated compensation outcomes. For example, Transgrid is currently experiencing a protracted negotiation with a landholder, where the landholder's counter-estimate was more than 17 times the amount included in Transgrid's expenditure proposal. Transgrid noted that given the significant discrepancy, compulsory acquisition is now likely to occur.
- If we did not accept this adjustment mechanism, it would need to revise its forecast expenditure to include a $5.65 million allowance to partially account for bearing this risk and exclude these costs from the CESS.

Our final decision is to accept this adjustment mechanism. Based on Transgrid's updated information, we consider that there is a greater likelihood that Transgrid may have to compulsorily acquire property. However, the costs are still highly uncertain, and we consider that approving the proposed adjustment mechanism is likely more beneficial for consumers than adding in additional risk cost to Transgrid's capex forecast. By accepting this adjustment mechanism, we ensure that consumers will only pay if, and when, compulsory acquisition occurs and only the amount required.

Legal Challenges event

Our preliminary position was to not accept this adjustment mechanism. This was largely for the reasons outlined above (in the 'Compulsory Acquisition' event section), and because any costs would likely be immaterial and not have a significant cost impact.

In response to our preliminary position paper, Transgrid submitted that:

- The likelihood and cost of these types of legal proceedings is extremely difficult to forecast, and differences in forecast and actual legal costs could be material and have a significant cost impact.
- If we did not accept this adjustment mechanism, it would need to revise its forecast of other construction costs (risk costs) to include an (unspecified) allowance to partially account for it bearing this risk and exclude them from the CESS.

Consistent with the 'Compulsory Acquisition' event, we have accepted this adjustment mechanism in our final decision. We no longer consider that the costs would likely be immaterial. Additionally, we consider that these costs are not reasonably forecastable, given the uncertainty surrounding the likelihood and magnitude of the costs Transgrid may incur.

13.2.3 Stakeholder submissions on adjustment mechanisms

We received 5 submissions to our preliminary position paper on adjustment mechanisms. Table 13.2 shows a summary of the stakeholder feedback we received on adjustment mechanisms and our response.

Table 13.2 Summary of stakeholder submissions on adjustment mechanisms

Adjustment mechanism aspect	Stakeholder submissions	Our response
'BCSS Replacement Expenditure and Operating Expenditure Annual True Ups event (annual true-ups adjustment)	Transgrid's submission maintained its position that the proposed annual true-ups adjustment remains appropriate.[197] Lousie Benjamin and Gavin Dufty's submission supported our preliminary position on the treatment of the annual true-ups adjustment.[198]	We address these submissions in section 13.2.1.

197 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 5–7.

198 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 6.

Adjustment mechanism aspect	Stakeholder submissions	Our response
'Unavoidable D&C Contract Variations' event	Transgrid's submission supported our likely acceptance of this adjustment event and maintained the application of a cumulative cap of $25 million.[199] The EUAA submission supported our preliminary position on the application of a deferred capex forecast to the Unavoidable D&C adjustment mechanisms across the HCC and CWO Enabling Projects. It considered the application of the deferred capex approach constructively supported that application of an unmodified CESS.[200] Lousie Benjamin and Gavin Dufty's submission also supported our preliminary position on the application of a deferred capex forecast to the Unavoidable D&C Contract Variations event. This submission also asked the AER to reject adjustment events if they were already covered by forecast capex or risk costs; could be negotiated as part of commercial discussions with EnergyCo; or efficiently mitigated by Transgrid.[201]	We consider that the deferred capex approach can appropriately incentivise Network Operators to spend efficiently and therefore support the operation of the CESS. However, it is not the best option to achieve this outcome in every situation. Where the delayed capex forecast is only possible towards the end of the regulatory period, the incentives created by a forecast of these costs are limited. Additionally, other approaches such as a maximum expenditure cap, may provide similar or greater incentives for the Network Operator to spend its capex efficiently. This is often the case where the uncertainty around the costs is not relatively high compared to usual forecasting uncertainty, or the magnitude of the costs is relatively small compared to the total capex expenditure. Given the level of uncertainty in this case, we consider that an adjustment mechanism is preferable to adding a risk cost. Particularly because if we did add a risk cost and the event does not occur, Transgrid would receive a CESS reward simply because the event didn't occur. Our response to Transgrid's submission along with our reasoning for not applying the delayed capex forecast approach to specific adjustment events is explained further in section 13.2.2.
'Planning Approval Delay' event	Transgrid's submission supported our likely acceptance of the Planning Approval Delay event. Transgrid also refined the definition of a 'material impact' and specified the costs that the Planning Approval Delay event should relate to in its submission.[202]	We address Transgrid's submission in section 13.2.2.

199 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 7–8.

200 EUAA, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 1–2.

201 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 6–7.

202 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 9–10.

Adjustment mechanism aspect	Stakeholder submissions	Our response
'Biodiversity Offset Cost Variance' event	Transgrid's submission maintained the proposed 'Biodiversity Offset Cost Variance' event remains appropriate.[203] Louise Benjamin and Gavin Dufty's submission questioned what the advantage is for consumers if the costs are included in the forecast and then excluded from the operation of CESS.[204] They were concerned that Transgrid included $15m in their Revenue Proposal despite the uncertainty around biodiversity offset costs and the risks for consumers of Transgrid obtaining a CESS reward. They asked us to elaborate on our concerns about these costs in the final determination over and above the detail in pages 40-41 of the Preliminary Position Paper. Specifically, the uncertainty surrounding these costs and any suggestions we have for networks to narrow the uncertainty, as this would be useful for future projects. They also questioned the possibility of dividing this cost category further and treating costs differently based on the timeline and level of uncertainty associated with the costs. The JEC noted it could not offer much perspective on this mechanism as there is too little information regarding the basis of the $15 million estimate.[205] However, it noted that the cost estimate was for biodiversity offsets in a project that seem to fall entirely on brownfield sites.	We address these submissions in section 13.2.2 and discuss Transgrid's forecast of biodiversity offset costs in section 9.2.3.
'Compulsory Acquisition' and 'Legal Challenges' events	Transgrid's submission maintained that the proposed adjustment mechanisms for compulsory acquisition easement costs and legal challenges associated with the compulsory acquisition process remain appropriate.[206]	Our response to Transgrid's submission along with our reasoning for applying a different approach to these adjustment mechanisms our final decision is detailed in section 13.2.2.

203 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 8–9.

204 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 6–7.

205 Justice and Equity Centre, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 3–4.

206 Transgrid, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 10–12.

Adjustment mechanism aspect	Stakeholder submissions	Our response
	Lousie Benjamin and Gavin Dufty's submission supported our preliminary position on the treatment of the 'Compulsory Acquisition and Legal Challenges' events.[207]	
Application of a materiality threshold	Louise Benjamin and Gavin Dufty's submission urged us to clearly indicate in our final determination that we intend to apply a high level of scrutiny to future claims by Transgrid under all the non-automatic Adjustment Events. It noted that under NER cost pass through processes these similar unavoidable events are subject to a 1% Maximum Allowed Revenue (MAR) threshold for cost pass through claims.	We considered the application of materiality thresholds as a way of incentivising the Network Operator to incur only efficient costs. We consider the EII Regulation allows us to specify that a particular adjustment includes a materiality threshold, or a maximum cost recovery cap. In most nominated pass throughs events under the NER, a materiality threshold is applicable. This is due to the Network Operator's ability to reprioritise or substitute its projects, to avoid seeking cost recovery through the pass through mechanism. In general, a Network Operator does not have this same ability to reprioritise or substitute projects under the EII framework. For this reason, we have not applied a materiality threshold to any adjustment mechanisms in our final decision. However, we will intend to apply a high level of scrutiny to future claims by Network Operators under all adjustment events.
Consumer engagement in the adjustment event application process	CCP35's submission commended the AER for explaining how it assessed Transgrid's proposed adjustment events and in particular its consideration as to who is best placed to manage certain risks, such that the burden is not shifted onto consumers without sufficient evidence or reasoning.[208] It also encouraged the AER to establish a process (such as a customer panel and a CCP) to ensure consumer views are considered should Transgrid seek any adjustments to its proposal in the future.	Stakeholders play a vital role in shaping our revenue determinations. We consider that stakeholder engagement in terms of adjustment mechanisms is most valuable during our revenue determination process. This is because they are able to influence the scope and operation of the adjustment mechanism. In our assessment of an application for a revenue adjustment, including a delayed capex forecast adjustment, we are primarily focused on considering the prudency, efficiency and reasonableness of the costs we have already determined to be within the scope of the mechanism. While we acknowledge stakeholder submissions indicating an interest in being consulted on adjustment decisions, we have very limited time in which to complete our assessment

207 Louise Benjamin and Gavin Dufty, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, p. 6.

208 CCP35, *Submission on the Enabling Central-West Orana RNIP preliminary position paper – 2026–31 Revenue Proposal*, November 2025, pp. 12–13.

Adjustment mechanism aspect	Stakeholder submissions	Our response
		and allowing time for additional stakeholder consultation would further restrict the assessment time available to us. Given the limited time, the fixed scope of the mechanism, and the technical nature of the costs involved, we consider that effective stakeholder consultation during the application assessment process is generally not feasible. However, we reserve the right to conduct targeted consultation in assessing an adjustment proposal if we consider it necessary.

14 Components of our final decision

Our final decision on Transgrid's Enabling Central-West Orana REZ network infrastructure project for the 2026–31 regulatory control period comprises the components set out in Table 14.1 below.

Table 14.1 Components of our final decision under the EII Act, the EII Regulation, and the EII Chapter 6A

Provision reference	AER final decision
EII Act, s.38(1)	The AER's final decision is to determine a total revenue of $128.9 million ($ nominal) for the 2026–31 period.
EII Act, s.38(2)(a)	The AER's final decision is to approve $27.6 million ($2025–26) in repayment of capital costs as determined under the transmission efficiency test.
EII Act, s.38(2)(b)	The AER's final decision is to approve a return on capital costs amount of $102.8 million ($ nominal) for capital costs that have not been repaid.
EII Act, s.38(2)(c)	The AER's final decision is to approve a revenue allowance of $31.7 million ($ nominal) for operating costs.
EII Regulation, cl.50A(a)	The AER's final decision is to approve an allowance of $41.1 million ($ nominal) for the indexation of the regulatory asset base.
EII Regulation, cl.50A(b)	The AER's final decision is to approve an allowance for the estimated corporate income tax of zero.
EII Regulation, cl.50A(c)	The AER's final decision does not include an allowance for any revenue increments or decrements resulting from the operation of incentive schemes as there are no incentive schemes in operation at the time of this final decision.
EII Regulation, cl.50A(d)	The AER's final decision is to approve an allowance of $4.5 million ($2025–26) for the repayment of prudent, efficient and reasonable capital costs not included in the component specified in section 38(2)(a) of the EII Act.
EII Regulation, cl.50A(e)	The AER's final decision does not include any allowances for other risks not already compensated under section 38(2)(b) of the EII Act.
EII Regulation, cl. 52(1) and cl. 52(2)(a)&(c)	Our final decision includes a schedule of the amounts to be paid to the Network Operator and the date on which each amount is to be paid for the 5 years of the 2026–31 regulatory control period, as set out in section 5.2.2 and Appendix A to this final decision.
EII Chapter 6A, cl.6A.14.1(1)(i)	The AER's final decision is not to approve the total revenue cap set out in Transgrid's building block proposal. Our final decision on Transgrid's total revenue cap is $128.9 million ($ nominal) for the 2026–31 regulatory control period. This decision is discussed in section 5.2 of this final decision.

Provision reference	AER final decision
EII Chapter 6A, cl.6A.14.1(1)(ii)	The AER's final decision is not to approve the maximum allowed revenue (MAR) for each regulatory year of the regulatory control period set out in Transgrid's building block proposal. Our final decision on Transgrid's MAR for each year of the 2026–31 regulatory control period is set out in section 5.2.1 of this final decision.
EII Chapter 6A, cl.6A.14.1(1)(iii)	The AER has not made a decision on the values that are to be attributed to the performance incentive scheme parameters for any service target performance incentive scheme, as this scheme is not applicable for the 2026–31 regulatory control period.
EII Chapter 6A, cl.6A.14.1(1)(iv)	The AER has not made a decision on the values that are to be attributed to the efficiency sharing benefit scheme parameters for any efficiency benefit sharing scheme (EBSS), as the AER's final decision does not include application of the EBSS for the 2026–31 regulatory control period. The decision on whether to apply the EBSS will be delayed until the end of the 2026–31 regulatory control period as set out in section 12.2.2 of this final decision.
EII Chapter 6A, cl.6A.14.1(1)(v)	The AER's final decision is to approve the commencement and length of the regulatory control period as Transgrid proposed in its revenue proposal. The regulatory control period will commence on 1 July 2026 and the length of this period is five years, expiring on 30 June 2031.
EII Chapter 6A, cl.6A.14.1(2)(ii)	Acting in accordance with clause 6A.6.7(d) of EII Chapter 6A, the AER's final decision is to not accept the total forecast capital expenditure of $437.9 million ($2025–26, inclusive of equity raising costs) set out in Transgrid's proposal. Our final decision, therefore, includes a substitute estimate of Transgrid's total forecast capital expenditure for the 2026–31 regulatory control period of $406.0 million ($2025–26, inclusive of equity raising costs). The reasons for our decision are set out in section 9.2 of this final decision.
EII Chapter 6A, cl.6A.14.1(3)(i)	The AER's final decision is to accept Transgrid's proposed total forecast operating expenditure inclusive of debt raising costs of $28.8 million ($2025–26) for the 2026–31 regulatory control period. The reasons for our decision are set out in section 10.2 of this final decision.
EII Chapter 6A, cl.6A.14.1(5)	In accordance with 6A.6.3A of EII Chapter 6A, the AER's final decision is to determine that there is no financeability issue for the CWO Enabling Project following the application of the financeability test.
EII Chapter 6A, cl.6A.14.1(5A)	The AER's final decision is that the capital expenditure sharing scheme (CESS) as set out in the version 4 of the Capital Expenditure Incentive Guidelines, will apply to Transgrid in the 2026–31 regulatory control period. This is set out in section 12.2.1 of this final decision.
EII Chapter 6A, cl.6A.14.1(5B)	Acting in accordance with clause 6A.6.2 of EII Chapter 6A, the AER's final decision is that the allowed rate of return for the 2026–31 regulatory year is 6.51% (nominal vanilla), as set out in section 7.2 of this final decision. The rate of return for the remaining regulatory years may be updated in accordance with the approved adjustment mechanisms for the actual risk-free rate and annual return on debt.

Provision reference	AER final decision
EII Chapter 6A, cl.6A.14.1(5C)	The AER's final decision is that the allowed imputation credits for each regulatory year of the 2026–31 regulatory control period, as also referred to in clause 6A.6.4, is 0.57. This is set out in section 7.2.5 of this final decision.
EII Chapter 6A, cl.6A.14.1(5D)	Acting in accordance with clause 6A.6.1 and schedule 6A.2 of EII Chapter 6A, the AER's final decision is that the opening regulatory asset base as at the commencement of Transgrid's 2026–31 regulatory control period, being 1 July 2026, is zero. This is set out in section 6.2.1 of this final decision.
EII Chapter 6A, cl.6A.14.1(5E)	The AER's final decision is that the depreciation approach used to establish the regulatory asset base at the commencement of Transgrid's 2031–36 regulatory control period as at 1 July 2031 is based on forecast capital expenditure (forecast depreciation). This is set out in section 6.2 of this final decision. For completeness, the regulatory depreciation amount that is approved in this final decision is –$5.6 million ($ nominal) for the 2026–31 regulatory control period.
EII Chapter 6A, cl.6A.14.1(6)	The AER's final decision is to not modify the depreciation schedules under clause 6A.6.3(d) and EII Regulation, clause 47D(3). For completeness, the AER's final decision has determined the depreciation schedules in accordance with 6A.6.3(b) of EII Chapter 6A, as set out in section 8.2 of this final decision.
EII Chapter 6A, cl.6A.14.1(9)	Acting in accordance with clause 6A.6.9 of EII Chapter 6A, the AER's final decision does not determine additional pass-through events that are to apply for the regulatory control period other than those set out in adjustment mechanisms section of this final decision. Our final decision on adjustment mechanisms is set out in section 13.2 and Appendix B of this final decision.

Glossary

Term	Definition
2022 Instrument	Rate of Return Instrument (2022)
ACEREZ	ACEREZ Partnership
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASL	AusEnergy Services Limited (previously AEMO Services Limited)
assessment approach guidance note	guidance note on the AER's EII Assessment Approach for Non-contestable revenue determinations (September 2025)
BCSS	Barigan Creek Switching Station
BDAR	Biodiversity Assessment Report
BCF	Biodiversity Conservation Fund
BSA	Biodiversity Stewardship Agreement
CAM	Cost allocation methodology
capex	capital expenditure
Capital Expenditure Incentive Guideline	Capital Expenditure Incentive Guideline (August 2025)
CCP35	consumer challenge panel, sub-panel 35
CEFC	Clean Energy Finance Corporation
Confidentiality Guideline	Draft confidentiality guideline - Electricity Infrastructure Investment Act (August 2023)
Consumer Trustee	A person or body authorised under section 60 of the EII Act to exercise the functions of the Consumer Trustee. The Consumer Trustee is required to act independently and in the long-term financial interests of NSW electricity consumers. ASL has been appointed to undertake this role.
contractual arrangement	Contracts that the Network Operator enters into as required under the Consumer Trustee's authorisation or Minister's authorisation or direction. This includes contracts made between the Infrastructure Planner and the Network Operator for carrying out a network infrastructure project under section 63(4)(a) of the EII Act.
CWO Enabling Project	Main CWO REZ network infrastructure project carried out by ACEREZ
CWO Main Project	Enabling CWO REZ network infrastructure project carried out by Transgrid
CWO REZ	Central-West Orana Renewable Energy Zone
D&C	Design and construction

Term	Definition
EII Act	Electricity Infrastructure Investment Act 2020 (NSW)
EII Chapter 6A	Appendix A of the Non-contestable Guideline, a modified version of Chapter 6A of the NER that applies to EII projects
EII framework	The EII Act and any regulations made under it.
EII PTRM	refers to a NER PTRM that is modified for the purposes of making non-contestable revenue determinations under the EII framework (EII Act and EII Regulation)
EII Regulation	Electricity Infrastructure Investment Regulation 2021 (NSW)
EnergyCo	Energy Corporation of NSW
EIS	environmental impact statement
EUAA	Energy Users Association of Australia
FFO interest coverage ratio	Funds from operations to interest coverage ratio
Financeability Guideline	Financeability Guideline (November 2024)
FTE	full-time equivalent
gamma	value of imputation credits
HCC Project	Hunter-Central Coast REZ network infrastructure project carried out by Ausgrid
Infrastructure Planner	A person authorised to exercise the functions of an infrastructure planner under section 63 of the EII Act. The Infrastructure Planner performs a range of planning and contracting functions. The Energy Corporation of NSW (EnergyCo) has been appointed to undertake this role for the five REZs specified in the EII Act.
IPFs	Infrastructure Planner Fees
JEC	Justice and Equity Centre
MAR	maximum allowed revenue
maximum capital cost	an amount notified to the regulator representing the maximum amount for the prudent, efficient and reasonable capital costs for development and construction of the REZ network infrastructure project that may be determined by the regulator under section 38(4) of the EII Act.
NER	National Electricity Rules
Network Operator	As defined in the EII Act, means a person who owns, controls, or operates, or proposes to own, control or operate, network infrastructure. In respect of the CWO Enabling Project the network operator is Transgrid.
Non-contestable Guideline	Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects (December 2025)

Term	Definition
opex	operating expenditure
Project Deed	TNA Project Deed entered between EnergyCo and Transgrid
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement capital expenditure
REZ	Renewable Energy Zone
TAB	tax asset base
TAC	Transgrid Advisory Council
TAF	Transmission Acceleration Facility
the Roadmap	NSW Electricity Infrastructure Roadmap
Transgrid	The Network Operator for the CWO Enabling Project
WACC	weighted average cost of capital
WSB Project	Waratah Super Battery non-contestable project carried out by Transgrid