Ausgrid

Hunter-Central Coast Renewable Energy Zone Network Infrastructure Project

HCC REZ Reg Panel Report to the AER

A customer's perspective in the development of Ausgrid's HCC REZ regulatory proposal

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Key Messages

Ausgrid established the Hunter Central Coast (HCC) REZ Regulatory Panel (Panel) to obtain a customer's perspective in the development of Ausgrid's HCC REZ regulatory proposal. They were under no obligation to appoint the Panel but the fact that they did illustrates the core focus Ausgrid has on ensuring consumers' interest are represented as much as possible in its development of the HCC REZ network infrastructure (HCC RNI) Project. Ausgrid was clear that the scope of the Panel's work would be constrained by the HCC REZ proposal process under the NSW Electricity Infrastructure Investment Act 2020 (EII Act) and related legislation.

Our initial focus was to understand those constraints with a particular focus on the level of risk consumers bore and how this might be limited given current experience of major energy project cost and schedule blowouts. We soon learned that our ability to do that was very constrained. The NSW Roadmap framework is very prescriptive. It prioritises the speed of delivery over comprehensive analysis, confidential agreements over allowing direct consumer engagement.

This is driven by a desire to meet 2030 targets and that the faster a network project is approved, the faster it is built, the faster renewable generation is connected and the faster lower prices will come. This is why 'reasonable' was added to the NER definition of the AER's role to assess 'prudency and efficiency'. The NSW Roadmap was designed to be faster than the NER RIT-T process where the AER only assesses expenditure on the basis of 'prudency and efficiency'. 'Reasonable' allows the AER to approve revenue proposals that have less detail and less certainty. For network developers to commit to faster construction requires more risk to be taken by consumers or the Government and the Government has decided that it will be consumers. Consumers have had no voice in this decision and are expected to accept it because they are told it will deliver lower power prices sooner.

1. *The lack of transparency in the planning process implies a high degree of trust is required from consumers on whether the projects are meeting the EII Act's objective of the long term financial interests of NSW consumers*

- The EII framework sees confidentiality as critical to the commercial operation of the planning and tendering process. Whilst we appreciate the need for such an approach at times, it severely compromises the ability for consumers, who, after all, are being asked to pay for this investment, to have confidence that the investment meets the Act's objective of 'the long-term financial interests of NSW electricity customers' (LTFIC)
- Many documents that are relevant to assessing whether consumers' interests have been protected are not available for review or the versions available for review contain little detail other than conclusions; consumers have to take the decisions of EnergyCo and the Consumer Trustee on trust
- There is no provision in the EII Act for any formal consumer engagement. Yet the fast approvals process has resulted in considerable risk being assigned to consumers when consumers were never in the room to have their input into those decisions.

We support the options presented in the recent NSW Transmission Planning System Review Options Paper to improve consumer engagement.

2. *Ausgrid's engagement has been excellent given the limited time available under their contract with EnergyCo*

We commend Ausgrid for their openness with the Panel and the constructive way in which they have responded to all our questions and concerns. Ausgrid's approach is industry leading, and we hope it sets a precedent for future Roadmap projects. We believe that EnergyCo and AEMO Services can learn from Ausgrid's approach.

Following our Terms of Reference we make the following comments:

- the pre-lodgement engagement complied as best it could with the Better Resets Handbook given the short time period available; more information could have been provided in Section 3.4 of the Revenue Proposal on how Ausgrid's social licence related engagement shaped their proposal
- Consumers are taking considerable risks in the project through the Adjustment Events; given these were agreed between Ausgrid and EnergyCo in their negotiations on the Commitment Deed, the Panel had no ability to change that risk allocation
- Ausgrid has certainly considered consumer perspectives as much as it could, given the very prescribed Roadmap process that gives them little time for engagement and very little flexibility to consider consumer views
- The AER's role is closely prescribed and so the Panel has little scope to recommend what the AER can consider. The areas we recommend for closer AER scrutiny are:
    - Clearer definition of 'reasonable' and how it has influenced its decision including how different would it have been if it was assessing the Revenue Proposal on the basis of the NER's 'prudent and efficient'?
    - Seek more information from EnergyCo on the Infrastructure Planner Fee, even though it is outside the AER's capex assessment
    - Highlight the legislative changes to the Maximum Capital Cost as it is no longer a cost cap for consumers
    - Closely examine the proposed ongoing engagement costs including the Social Licence Plan, Local Engagement Committee and community engagement expenditure
    - Carefully review the Adjustment Events to ensure that consumers are bearing an appropriate level of risk for the Project and review the increase in the number and scope of Adjustment events included in the Commitment Deed since the AER's Waratah Super Battery decision
- Our observations of the land owner and community engagement suggest it is best practice within the time constraints Ausgrid faces
- Given the time constraints to properly execute design details and community consultation, Ausgrid is proposing a technically competent engineering solution consistent with good practice
- The capex accuracy is lower than the Panel considers is appropriate for project approval and lower than the AER is currently requiring for Project Marinus but agree with Ausgrid that it is the most accurate estimate possible given the time constraint.

Structure of this Report

This Report is structured as follows:

1. Introduction

1.1. The HCC REZ Network Infrastructure Project

The HCC RNI Project involves developing two high-capacity 132kV connection nodes for yet-to-be developed renewable energy generators and storage in the Upper Hunter region, and an additional 1 GW of power transfer capacity into the NSW transmission system across both the Upper and Lower Hunter regions. There are two parts:

- the establishment of two 132kV switching stations / generator connection points at new switching stations at Sandy Creek (Muswellbrook) and Antine (Lake Liddell); and
- Construction of new 132kV network double circuit power line between the Upper and Lower Hunter region.

The solution will deliver 400 MW of firm (N-1) generation transfer capacity into the Upper Hunter transmission node at Muswellbrook and 600 MW of transfer capacity to the Southern Hunter region through Kurri Kurri and further to the major load centre of Newcastle. Ausgrid is contractually obliged to deliver 350 MW of transmission capacity by 2026 with full capability by 2028, an aggressive timeframe for such a project.

The project was the result of Roadmap modelling by EnergyCo that concluded it was part of the optimal project mix to meet the EII Act's[1] 2030 renewable energy target. It was developed as a 'non-contestable' project i.e. two bidders (Ausgrid and Transgrid) were invited to put proposals to construct the project. This was in contrast to the fully competitive process used to select ACEREZ for the Central-West Orana (CWO) REZ.

Ausgrid has been selected to be the developer and it entered into a Commitment Deed with EnergyCo setting out the contractual arrangements. This included Ausgrid submitting a revenue proposal for 2026-31 to the AER which would then assess whether the proposed costs were 'prudent, efficient and reasonable'. In parallel with Ausgrid developing its revenue proposal:

- EnergyCo as the infrastructure planner for network infrastructure projects in REZs (RNIPs) recommended to AEMO Services that it should authorise Ausgrid to carry out the HCC RNI Project because it was in the long-term financial interests of NSW electricity consumers, and
- AEMO Services made that recommendation.

Ausgrid has now submitted its HCC RNI Project 2026-31 Revenue Proposal to the AER to assess whether the proposed costs are 'prudent, efficient and reasonable'. The HCC RNI Project is the first revenue proposal to be considered by the AER under its revised Guideline for non-contestable projects[2].

This EII process is quite different from that under the National Electricity Rules (NER):

- The objective is the 'long term financial interests of NSW electricity consumers' (LTFIC).

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[1] Electricity Infrastructure Investment Act 2020

[2] https://www.aer.gov.au/system/files/2024-07/AER%20-%20TET%20%26%20revenue%20determination%20guideline%20for%20non-contestable%20network%20infrastructure%20projects%20%20-%20July%202024.pdf

- It is driven by a desire to build network infrastructure at a faster pace than the NER allows to meet the EII's 2030 renewable energy targets.

Apart from strict confidentiality that severely limits publicly available information, the EII Act, unlike the NER, has no requirement for consumer engagement in the project development process. There was no obligation on Ausgrid to set up the Panel, let alone to undertake the extensive engagement they have with us.

1.2. Assessment Approach

The Panel was established in mid-December 2024. Members were selected following an EOI process conducted with current and former members of Ausgrid's Customer Consultative Committee (CCC) and Reset Customer Panel (RCP) from the 2024-29 regulatory reset. Our Terms of Reference (ToR) are set out in section 4.5 of Ausgrid's Customer Consultative and Specialist Committees ToR November 2024[3]. Recognising the Panel's work would be constrained by the HCC REZ proposal process under the Electricity Infrastructure Investment Act (EII Act) and related legislation, our role was to:

- provide a customer's perspective in the development of Ausgrid's HCC RNI Project Revenue Proposal;
- advise on the extent to which the Panel believes Ausgrid's pre-lodgement engagement complied with the AER's Better Resets Handbook (BRH), given the time constraints under the EII framework;
- consider the allocation of risk between Ausgrid and customers, including contingency and post determination adjustment events (Adjustment Events);
- demonstrate that the perspectives of consumers have been considered in Ausgrid's approach to the HCC RNI Project; and
- prepare an independent report to the AER identifying key issues that the AER should consider when reviewing the Revenue Proposal.

In addition to these Panel roles, through the course of our review Ausgrid sought Panel feedback on 'social licencing'[4], the technical solution, capex forecast accuracy and other revenue components including incentive schemes, depreciation and opex. While not expressly within the scope of the ToR, these issues are closely related to the requirement that the Panel provide a customer's perspective in the development of Ausgrid's HCC RNI Project Revenue Proposal. Throughout this Report we include reference to other Roadmap and AER decisions that, while not specifically within our ToR, have informed our approach.

In the course of our review we have had extensive engagement with Ausgrid, the AER, EnergyCo and AEMO Services including:

- observing landowner and community engagement at Branxton and Singleton
- touring the route
- six formal meetings with Ausgrid to discuss a range of issues[5]
- receiving early drafts of various part of Ausgrid's draft Revenue Proposal
- meetings with AER, AEMO Services and EnergyCo.

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[3] https://www.ausgrid.com.au/-/media/Documents/Customer-engagement/CCC/Customer-Consultative-and-Specialist-Committees--Terms-of-Reference.pdf?rev=b18a92c5d34d44588a24dd58aecaa55b

[4] Section 2.1 in Attachment 3.1

[5] These are detailed in Section 3.1 and Att. 3.1

The AER observed all of the formal meetings we had with Ausgrid, EnergyCo and AEMO Services.

The Panel's substantive correspondence with the AER, EnergyCo, AEMO Services and Ausgrid is reproduced in appendices to this Report.

It soon became apparent that the scope of our engagement and our ability to influence the outcome was very constrained by the prescribed processes in the EII Act that limit transparency and consumer engagement. Given this context we concluded that the Panel's focus, through deep engagement with Ausgrid and other stakeholders, would be on three areas:

- bring as much transparency as possible to the overall process so that consumers know what they are being asked to pay and why
- see what measures we can influence Ausgrid to make within the constraints of its Commitment and Project Deeds with EnergyCo to ensure risk assigned to the party best able to manage it – whether it be Ausgrid, its suppliers and contractors or NSW electricity consumers, and
- investigate whether the $46.9M contingency allowance (included in the $590.8m capex) and Adjustment Events (events where Ausgrid can apply to the AER for a pass though of higher costs) are reasonably allocated and are not duplicative of 'base' capex before contingency.

We commend Ausgrid for their openness with the Panel and the constructive way in which they have responded to our concerns. Ausgrid's approach is industry leading, and we hope it sets a precedent for future Roadmap projects. We look forward to further engagement with Ausgrid and the AER post lodgement of the Revenue Proposal particularly around:

1. Ausgrid's community engagement to date
2. the $24.1m community engagement and social licence capex
3. the seven procurement-induced cost uncertainty events set out in Section 8.5 of the Revenue Proposal discussed in Section 5.2.2 below, and
4. making a submission on the AER's preliminary position paper.

2. How the regulatory framework under the EII Act limits transparency for consumers

2.1. Introduction

This section begins by examining the roles of the major players under the EII Act based on meetings we had with the AER, EnergyCo and AEMO Services. The Panel prepared questions in advance of those meetings which are included in Appendices A, B and C. The meetings with EnergyCo and AEMO Services were attended by Ausgrid (as observers), AER staff and the CCP.

We then discuss some key topics supporting our views on the lack of transparency – no formal requirement for consumer engagement, the AER's role in assessing the 'prudency, efficiency and reasonableness' of Ausgrid revenue proposal, the role of cost benefit analysis in supporting the EII objective of the LTFIC, the EII Act MCC definition, EnergyCo' s IP Fee, and the accuracy of the capital cost estimate.

2.2. The roles under the EII Act

Actionable projects under the ISP are planned by AEMO and then come under the detailed assessment and review of the AER under the RIT-T process[6]. Under the EII Act, EnergyCo and AEMO Services have major roles with the AER having a much lesser and very constrained role set out in the AER's March 2021 Guidance Note Regulation of actionable ISP Projects[7].

2.2.1. EnergyCo

In our meeting with EnergyCo they stressed their role as ensuring accelerated delivery of Roadmap projects with AEMO Services, as the Consumer Trustee, playing a role as a strong check on EnergyCo' s quick delivery mandate. EnergyCo is keen to evolve their role as they progress through Roadmap projects – HCC REZ is now the third following Waratah Super Battery and the CWO REZ. An example was their decision to have the draft Project Deed in place for the HCC RNI Project by the end of 2025 when the risk of completion cost and timing goes to Ausgrid. This involved negotiating all aspects of the draft Project Deed, including liquidated damages (LDs), agreed in the course of negotiating the Commitment Deed. EnergyCo advised that this had the benefit of clarifying the project risks.

Each Roadmap project is charged an IP Fee to recover EnergyCo' s administrative costs and to reimburse the developer for predetermination expenditure.

2.2.2. AEMO Services in its role as Consumer Trustee

AEMO Services has three key functions:

- Preparation of the Infrastructure Investment Opportunities (IIO) report published every two years setting out a 20-year Development Pathway for electricity infrastructure investment and a rolling, decade-long schedule for tenders which will identify where, when, and at what cost new energy generation, storage and firming infrastructure is needed; the last one was published in December 2023[8]
- preparation of the authorisation for the HCC RNI Project, based on cost benefit modelling[9] to determine what is in the LTFIC, and
- to calculate the MCC for each project.

We had a very constructive meeting with AEMO Services to help us understand the purpose and limits of the Consumer Trustee's role under the EII framework. We discussed the Panel's questions set out in Appendix C, which focussed on:

- the cost benefit modelling to support its authorisation decision, and
- why the MCC was changed in 2024 to no longer operate as a cap and the risks to customers from that policy change.

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[6] https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf
[7] https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf
[8] https://aemoservices.com.au/-/media/services/files/publications/iio-report/2023/2023-iio-report-december_final.pdf?la=en
[9] https://aemoservices.com.au/-/media/services/files/publications/authorisation-function/241203-december-network-authorisation-process-and-approach-paper.pdf?la=en

We acknowledge that AEMO Services is seeking to balance the need for confidence to protect the integrity of bidding processes and transparency so that customers can be confident that the HCC RNI Project will be in the LTFI of NSW electricity consumers. During the meeting the AEMO Services representatives invited the Panel's feedback on the CWO REZ Statement of Reasons[10] published by AEMO Services in June 2024. We were specifically asked by AEMO Services to provide feedback on whether we believed AEMO Services had achieved the right balance between transparency and commercial in confidence issues in the CWO REZ Statement of Reasons. Our aim in providing the feedback was to influence AEMO Services to give greater transparency in the future HCC RNI Project Statement of Reasons.

Our feedback to AEMO Services is included in Appendix D.

2.2.3. AER

The AER's role in a non-contestable project like the HCC RNI Project is significantly reduced from its oversight and approval role for projects under the NER. Its EII role is twofold:

- to review the Revenue Proposal for 2026-31 and determine whether the capex and opex being sought by Ausgrid is 'prudent, efficient and reasonable', in a much more condensed timeframe than it has to assess 'prudency and efficiency' under the NER. Consideration of EnergyCo' s IP Fee is outside of the scope of the AER's review, and
- assess applications by Ausgrid for additional costs under the Adjustment Events in the Commitment Deed.

The AER has the ability to review and adjust the Adjustment Events[11].

We are grateful that the AER staff participated in all of our meetings with Ausgrid, as well as responding to our queries in between. The AER also facilitated our meeting between AEMO Services and the Panel as well as attending that meeting and our meeting with EnergyCo. We are grateful to the AER staff for the time that they gave the Panel as we developed our understanding of the EII framework. We have also valued the constructive participation of the AER's independent CCP representative in observing the Panel's work.

2.3. Key issues that arise from the EII framework

2.3.1. There is no formal requirement for consumer engagement

Farrier Swier is currently undertaking a review of the NSW transmission planning system for the NSW Government. Its recently published Options Paper[12] comments on consumer engagement under the EII Act (p.66):

> *"The current regulatory obligations and practices under the EII Act lack sufficient transparency and engagement obligations and processes to enable consumers, local communities and other affected stakeholders to understand and engage in decisions that affect them*

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[10] https://aemoservices.com.au/-/media/services/files/publications/authorisation-function/statement-of-reasons-cwo-main.pdf?la=en

[11] See Section 5.5 in the AER Non-contestable Guideline

[12] https://www.energy.nsw.gov.au/sites/default/files/2025-04/NSW-transmission-planning-review-Options-Paper-v2.pdf

there are no obligations on EnergyCo or AEMO Services to engage with consumers when making transmission planning and approval decisions under the EII Act and none of the engagement requirements under the NER apply to EII Act decisions."

And further at p.38:

"The EII Act does not refer to consumer engagement and there are no obligations on bodies such as EnergyCo or AEMO Services to consult with electricity customers or their representatives. There is a Roadmap Consumer Reference Group that can be used by Roadmap bodies, but it appears to be used in a limited and ad hoc way."

The Options Paper proffers a range of possible options for increased consumer engagement by EnergyCo and AEMO Services including:

- amending the EII Act to require EnergyCo and AEMO Services to undertake consumer engagement through the establishment of a Consumer and Community Panel
- requiring consultation prior to making key decisions including authorisation of a RNI Project
- requirement to publish and publicly consult on draft of key decisions and explain how they have reflected feedback in their final decisions and
- requiring EnergyCo to consult, develop and publish a stakeholder engagement plan and a specific one for each REZ, similar to the plan AEMO develops with the ISP Consumer Panel for each ISP.

We support these options.

2.3.2. Assessing 'prudent, efficient and reasonable' project costs

Panel members' extensive experience working with the AER on network resets means we are familiar with, and highly supportive of, the AER's approach to assessing the prudency and efficiency of networks capital expenditure. This NER process provides information that supports both the economic analysis and the explanation of technical trade-offs that have been considered[13].

By contrast, the EII framework adds the word 'reasonable' to 'prudent and efficient' in the AER's test for network costs and requires the AER to make its determinations in a shorter timeframe.

It is difficult to see how the AER can fully assess prudency, which has traditionally been interpreted as 'expenditure at the right time' or efficiency, which has been interpreted as 'the right amount of expenditure'. Roadmap projects and their timing are authorised by EnergyCo and the Consumer Trustee, not the AER. Further the AER has no authority to review the Infrastructure Planner Fee (IP Fee) component of capex, which is $162.7m or 28% of the HCC RNI Project capex. We discuss this further below in Section 2.3.5.

In the case of 'reasonable' the EII Act says (emphasis added):

Sec 31.2 EII Act

*"If the consumer trustee authorises a network operator under subsection (1)(b), the consumer trustee must, by written notice to the regulator, set a **maximum amount for***

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[13] AER, Better regulation: Expenditure forecast assessment guideline for electricity distribution, November 2013, pp 8–9

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)."*

Sec 37(1)(a) EII Act

"A network operator is entitled to recover ***the prudent, efficient and reasonable costs*** *incurred by the network operator for carrying out the infrastructure project."*

Sec 38(4) EII Act

"Before making a determination, the regulator is to calculate the prudent, efficient and reasonable capital costs for development and construction of the network infrastructure project, which is referred to as the ***transmission efficiency test."***

AER non-contestable guidelines Section 1.3 (p.5)

Without providing a definition of 'reasonable'. The AER Guideline says that the AER applies:

"…the Transmission Efficiency Test to calculate the ***prudent, efficient and reasonable capital costs*** *for development and construction of a network infrastructure project"*

defining 'reasonable' as (p.25):

"In assessing whether the capital costs are reasonable, we will assess whether the costs, and the calculation of those costs, are based on reason or reasonably open based on the facts before us."

A dictionary definition of 'reasonable' is 'based on or using good judgement, being fair, practical and sensible' or 'as much as is appropriate'[14].

During our meeting with the AER we sought to better understand their approach to 'reasonable'. Appendix A sets out our note to the AER prior to that meeting. The AER confirmed that reasonable would depend on the context of the project including the scale, scope and timeframe.

Our discussions with EnergyCo and AEMO Services led to us concluding that 'reasonable' was a proxy for 'how can we speed up the project development timeline by not spending too much time on getting a 'prudent and efficient' cost estimate'. More accurate cost estimates e.g. AACE Class 1 or 2 estimates take longer, and it was in the LTFIC to approve construction of Roadmap projects on the basis of less accurate cost estimates. This lack of accuracy for the network developer seems to be compensated for by shifting cost risk to consumers.

Ausgrid's view on the definition of 'reasonable' is:[15]

"Our view is that 'reasonable' requires a tailored assessment of whether good industry practice has been employed in the circumstances under which a cost estimate has been developed. In the case of the HCC RNI Project, this requires a holistic assessment of the following considerations:

[14] The Cambridge Dictionary https://dictionary.cambridge.org/

[15] Revenue proposal Section 5.2.3 p.40

- *NSW Government policy requiring HCC RNI to provide 1 GW of transfer capacity within a highly constrained timeframe*
- *limits on the amount of funding available for project development activity. The activities that were limited to available funding included detailed design development, detailed site investigations and sampling, environmental assessment and reports, and developing detailed project staging plans*
- *restrictions on joint planning with Transgrid and on engaging with a wide range of relevant stakeholders, including directly impacted landholders, broader community, Transport for NSW, councils, MPs, and other government agencies before January 2025*
- *the timing of Ausgrid's formal engagement as the HCC REZ Network Operator, which did not occur until mid-December 2024."*

We look forward to the AER providing additional clarity on how it interprets 'reasonable' in its decision on the Ausgrid Revenue Proposal and how that interpretation has influenced its decision.

2.3.3. The role of Cost Benefit Analysis

CBA has been used extensively in the assessment process for the HCC REZ:

- AEMO Services modelling in the 2023 IIO Report[16]
- EnergyCo, in its role as the Infrastructure Planner, in preparing its Infrastructure Planner Recommendation Report (IPRR) recommending to the Consumer Trustee that it authorise Ausgrid to carry out the HCC RNI Project[17] and
- AEMO Services Consumer Trustee's statement of reasons for authorising the HCC REZ RNIP for Ausgrid[18].

However, the level of transparency around these various reports is quite limited and the organisations expect consumers to take the conclusions on trust. Our focus here is on the latter two reports.

The Panel was keen to access the full IPRR for the HCC RNI Project to understand the cost benefit modelling supporting the decision to recommend the project. Unfortunately, that was not possible. On 7 March EnergyCo advised us:

> *"The HCC REZ Infrastructure Planner Recommendation Report (IPRR) was submitted by EnergyCo (the IP) to AEMO Services (the CT) on 20 December 2024. This is a confidential recommendation, to allow the Consumer Trustee to undertake its network authorisation assessment process. Unfortunately, this IPRR is not shareable at this time."*

EnergyCo noted that publication of an IPRR is not a mandatory requirement under the EII regulatory framework but acknowledged that it is an important step to provide further

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[16] https://aemoservices.com.au/-/media/services/files/publications/iio-report/2023/2023-iio-report-december_final.pdf
[17] https://www.energyco.nsw.gov.au/sites/default/files/2025-04/HCC%20REZ%20IPRR%20-%20Public%20Report_0.pdf
[18] https://aemoservices.com.au/-/media/services/files/products/rez/hcc/250508-approved-hcc-rnip-statement-of-reasons.pdf?la=en

transparency. The public version of the HCC REZ IPRR was subsequently published on 16 April [19]. EnergyCo' s description is (p.8):

> *"This document has been prepared to provide a summary of EnergyCo' s recommendation to the Consumer Trustee and the basis for these recommendations"*

The EnergyCo report concludes (p.18) that the HCC RNI Project:

> *"…is expected to result in a net benefit for NSW electricity consumers of $270.5m (real $2024) to 2079 relative to a scenario in which the RNIP is not built but the Roadmap target of 12GW by 2030 is still met. This scenario likely provides a lower estimate of the benefits …as it relies on low likelihood assumptions that if the RNIP does not proceed, other REZs can vary in both timing and size to be developed just in time to minimise prices for NSW consumers"*

The 'summary' has a qualitative description of cost and benefit categories. EnergyCo has acknowledged the important point that[20]:

> *"As with all modelling, actual benefits may differ from expected."*

However, it does not also state that while benefits are uncertain, costs are certain once they are spent.

AEMO Services published its HCC RNI Project Statement of Reasons to authorise the project on 8th April. It describes its report as a 'public summary' that is (p.2):

> *"… for information purposes only. It is published to outline the approach taken by the Consumer Trustee in reaching its decision, is a summary of that decision and is not intended to be comprehensive."*

The Consumer Trustee's authorisation is based on it independently satisfying itself that the recommended project is in the LTFIC including that the capital costs does not exceed the Maximum Capital Cost (MCC). In doing this the Consumer Trustee considers the EnergyCo recommendation and decides whether to undertake its own CBA. In this case it decided to do just that. The December 2023 IIO report was now out of date and the next edition is not due for publication until later this year. Given this the Consumer Trustee (p.16):

> *"…decided that it is in the LTFI of NSW electricity customers to use an updated development pathway for assessing whether to authorise the HCC RNIP. Accordingly, the CBA uses a development pathway updated from the 2023 IIO Report development pathway to utilise updated assumptions and the 2024 ISP modelling."*

However, there is a fundamental problem in taking that approach highlighted by the current Farrier Swier review of NSW transmission planning. The Review's recently published Options Paper noted[21]:

> *"The ISP and IIO Report are prepared by related parties (AEMO and AEMO Services) and the IIO Report currently places significant reliance on inputs, assumptions and modelling from the ISP.*

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[19] https://www.energyco.nsw.gov.au/sites/default/files/2025-04/HCC%20REZ%20IPRR%20-%20Public%20Report_0.pdf
[20] Footnote 16 p.18 https://www.energyco.nsw.gov.au/sites/default/files/2025-04/HCC%20REZ%20IPRR%20-%20Public%20Report_0.pdf
[21] See p. 26 https://www.energy.nsw.gov.au/sites/default/files/2025-04/NSW-transmission-planning-review-Options-Paper-v2.pdf

However, the two reports have different scopes and objectives. The ISP's primary purpose is to assess major transmission projects, while the IIO Report also has important objectives of assessing and recommending development pathways and tender plans for generation, storage and firming projects.

The two reports also optimise for different objectives. The ISP's objective under the NER is to minimise total system costs across the NEM (e.g. capital expenditure, fuel costs, other operating costs and the value of emissions) while meeting power system needs. The IIO Report's objective under the EII Act is to minimise consumer costs in NSW, i.e. electricity prices for NSW electricity customers. These differences mean that it is difficult for the IIO Report to use the ISP's modelling, scenarios, inputs and assumptions without modifications."

AEMO Services say (p.4):

"A detailed explanation of the analysis of the Consumer Trustee's CBA is set out in Section 4.1.2.2."

This was provided as a four-page qualitative summary arguing that the CBA analysis:

- was consistent with the NSW Government Guide to Cost-Benefit Analysis and 'other requirements of the EII Regulation' without setting out what they were
- estimates the project benefits assessed against a counterfactual that is only briefly described
- the costs and benefits under the three scenarios (similar to those in the 2024 ISP) were sensitivity tested against eight variables including increases in the cost of the project; changes in weather and outage patterns; different emissions values and discount rates; different approaches to benefits continuation, and different benefit start years without any details on the actual sensitivity methodology or values
- included a risk analysis that was informed by EnergyCo risk analysis and the 'Consumer Trustee's own quantitative and qualitative analysis' with no details on the quantitative analysis and
- examined the risks to the net benefits to customers providing a qualitative analysis of why the "credible upside risks of authorising the HCC RNI Project substantially outweigh any credible downside risks" with the project having a significant net benefit under the adjusted Step Change scenario that the Consumer Trustee has primarily relied on.

This analysis led to the conclusion (p.20):

"Based on this analysis, the Consumer Trustee considers that authorising the HCC RNIP is likely to be in the LTFI of NSW electricity customers."

Unlike the process AEMO uses to develop the ISP, there has been no transparency from EnergyCo or the Consumer Trustee on the modelling methodology, scenarios, assumptions or sensitivity testing let alone an opportunity to make submissions on these matters. All consumers see is a 'summary' document that is heavily qualified showing the results from what can only be described as a 'black box'.

If the HCC RNI Project is a great project, then we cannot understand the reluctance to transparently demonstrate that to NSW electricity consumers. The answer we have been given by both EnergyCo and the Consumer Trustee is 'confidentiality'. It seems that the requirement under the legislation to only provide the MCC to the AER and the Minister is driving the lack of transparency in EnergyCo and Consumer Trustee reports.

2.3.4. Maximum Capital Cost

A key part of the original Roadmap legislation to achieve its goal of being in the LTFIC was the concept of the MCC. Section 38(6) of the original EII Act states:

> *"The amount determined by the regulator under subsection (4) for a network operator authorised by the consumer trustee to carry out a REZ network infrastructure project must not exceed the maximum amount, if any, notified to the regulator by the consumer trustee under section 31(2) for the network operator."*

The MCC is set by the Consumer Trustee[22]:

> *"… by reference to the net benefit to customers from its CBA. It is important to note that this CBA is conducted across a range of conservative and optimistic scenarios, which results in a range of net benefit outcomes considered by AEMO Services in setting the maximum amount."*

The Consumer Trustee provides that MCC only to the AER and the Minister and no other person[23].

Section 38(6) was interpreted as meaning that the MCC applied for the life of the asset ie not only to the initial determination by the AER which is what Ausgrid is now going through, but also to each subsequent 5-year determination. The revenues over the life of the project could never exceed the MCC so the MCC was a genuine cap on the amount that could be recovered from NSW consumers. Any additional costs above the MCC would have to be funded either by the Government or the network owners.

In October 2024, sec. 38 was amended to add new subsections (3A), (3B) and (6A)[24]. These provisions have the effect that the MCC does not apply to any adjustments to the allowed revenue. So if costs increase over time due to one or more Adjustment Events, the allowed revenue in a future AER determination can exceed the MCC which was originally set by the level of benefits in the EnergyCo CBA. These provisions will apply to all future AER regular five year determinations for all Roadmap projects.

These changes seem to have been initiated to cover the Government for the risk that costs increase above the MCC, a project developer decides to abandon a project prior to completion and the Government has to complete the project. At the time of the amendments Engineering, Procurement and Construction (EPC) contractors were leaving or threatening to leave Snowy 2.0 and Project Energy Connect because of a substantial increase in their costs above their bid price.

The second reading speech on 15 November 2024 for the *Energy Amendment (Long Duration Storage and Investment) Bill 2024*[25] that introduced these changes makes it clear that that the change to the MCC was for the benefit of networks and to protect the Government from having to step into an incomplete project (emphasis added):

> *"The purpose of the maximum amount is to act as a consumer protection against significant capital cost increases between the authorisation and the initial revenue*

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[22] P.24 https://aemoservices.com.au/-/media/services/files/publications/authorisation-function/statement-of-reasons-cwo-main.pdf?la=en

[23] P.25 https://aemoservices.com.au/-/media/services/files/products/rez/hcc/250508-approved-hcc-rnip-statement-of-reasons.pdf?la=en; amendments in late 2024 allow the Minister to tell others

[24] Energy Amendment (Long Duration Storage and Investment) Act 2024 https://www.parliament.nsw.gov.au/bills/Pages/bill-details.aspx?pk=18673

[25] https://www.parliament.nsw.gov.au/Hansard/Pages/HansardResult.aspx#/docid/'HANSARD-1323879322-148074'

> *determination. The EII Act can currently be interpreted as requiring the regulator to apply that maximum capital cost amount to the initial revenue determination as well as all future revenue determinations and remakes of revenue determinations. That is problematic because of the way the maximum capital cost is calculated and because it could, even where cost changes are justified and prudent, leave a project that is partially or completely constructed with no revenue to recover capital or operating costs. That could also expose the Government to financial costs.*
>
> *The proposed amendments reduce these risks and provide legislative certainty to network operators, while retaining consumer protections by maintaining the maximum amount's application to the first revenue determination."*

It appears that the developer of the CWO REZ has already made an application to vary the AER's revenue determination made in December 2024 and published in April 2025[26]. No details are provided other than the proposed adjustments[27]:

> *"…reflect the final Project Deed agreed at Contract Close, and the project revenue and costs as updated through the Financial Close process that was completed on 4 April 2025."*

The consequence of this change to the MCC is that the NSW Government has put these risks onto consumers to ensure project completion and ongoing operation. This is inconsistent with the principle that these project delivery risks should be borne by the party best able to manage those risks. Clearly consumers are powerless to manage these risks and if networks claim they are unable to manage the risks, then this should fall to Government to manage as part of taking on the infrastructure planning function for Roadmap projects. After all it was the Government's desire to speed up projects that is the core of the EII Act.

We do not believe this change in the MCC has been made explicit either by EnergyCo in its IPRR nor by AEMO Services in its Statement of Reasons. For example, the HCC RNI Project IPRR refers to the MCC on p.15 (emphasis added):

> "*The Consumer Trustee authorises the HCC RNI Project and sets a confidential MCC. The MCC sets "a 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 AER."*

EnergyCo notes (p.16) that the revenue for the HCC RNI Project can 'be varied by the AER under strict provisions in the EII Act'. We believe that a reasonable consumer reading these pages would conclude that the MCC is a cap on all AER decisions relating to the HCC RNI Project rather than a cap on the AER's initial determination. There is no mention of the approved capex being able to exceed the MCC.

At p.18 of the HCC RNI Project Statement of Reasons, AEMO Services states:

> *"The Infrastructure Planner's recommendations set out the steps that the Infrastructure Planner and network operator will take to mitigate the risks of cost increases.*
>
> *The Consumer Trustee also notes that the costs that can be recovered by the network operator from electricity customers will be determined by the AER under the EII Act,*

---

[26] https://www.aer.gov.au/industry/registers/determinations/main-central-west-orana-renewable-energy-zone-network-project-contestable/update

[27] https://www.aer.gov.au/industry/registers/determinations/main-central-west-orana-renewable-energy-zone-network-project-contestable/update

EII Regulation and the AER's revenue determination guideline for NSW non-contestable projects.

Under this process, the AER will assess whether the network operator's proposed costs are prudent, efficient and reasonable. The Infrastructure Planner's recommendations set out a series of proposed variation events that could result in an increase in costs. However, the Consumer Trustee notes that the AER will determine which of these proposed variation events are permitted under the network operator's revenue determination and whether any increases in costs are prudent, efficient and reasonable."

Despite AEMO Services noting that the Commitment Deed sets out a series of proposed variation events that could result in an increase in costs, AEMO Services relies on steps agreed between EnergyCo and Ausgrid to mitigate these risks. However, none of these events or mitigants are referred to in the public HCC RNI Project IPRR. The Panel believes that these cost increase events and any agreed mitigants should be made public, particularly as they formed a key part of the Consumer Trustee's decision to authorise the HCC RNI Project. We note that AEMO Services also relies on the AER's review role in relation to costs for variation events.

We recommend that the AER highlight the legislative change to the MCC and the increased risk to consumers from this change in its determination on the HCC RNI Project. We also encourage AEMO Services and EnergyCo to make this policy change clearer in their documents to increase the transparency of the risks and costs that customers are being asked to assume as a result of the legislative change.

The potential for the actual cost to exceed the MCC is also not made clear in Ausgrid's Revenue Proposal. This is why our engagement with Ausgrid has had particular focus on the contingency and wide scope of Adjustment Events. We discuss this further below in Section 5.2.

2.3.5. Infrastructure Planner Fee

In order to recover EnergyCo' s administrative costs and to reimburse the network developer for predetermination expenditure, each EII Project bears an IP Fee. The IP Fee is set by EnergyCo and the network developer is required to pay the IP Fee as part of 'pre- period expenditure'. The Panel was very surprised when we learnt that the prudency, efficiency and reasonableness of the IP Fee is not reviewable by the AER. The total value of the IP Fee for the HCC REZ is $162.7m or 28% of total capex[28]:

EnergyCo – project development costs including [redacted] paid to Ausgrid for early works[29]	$81.7m (14% of total capex)
EnergyCo – operations costs	$11.2m (2% of total capex)
Ausgrid costs for project development, planning and early works prior to financial close (this capex is	$69.8m (12%)

[28] Revenue Proposal p.62

[29] The Panel invited Ausgrid to disclose in its revenue Proposal that it would be repaid the [redacted] for early works as part of the IP Fee, however Ausgrid has chosen not to do this. See the Panel feedback on the draft Revenue Proposal in Appendix D

incorporated in the relevant capex categories in the Revenue Proposal)	
Total	$162.7m (28%)

The Panel was unsuccessful in its efforts to get more transparency from EnergyCo about the IP Fee. We appreciate Ausgrid providing some additional detail in the Revenue Proposal that it covers[30]:

- investigate, plan, coordinate and carry out planning, design, construction and operation of storage and network infrastructure
- assess and make recommendations to the Consumer Trustee about the REZ network infrastructure projects required for the REZ
- assess and make recommendations about contractual arrangements that a Network Operator may be required to enter into to carry out a REZ project under an authorisation.

In the recent AER review of the 'prudent, efficient and reasonable' costs for the CWO REZ, the IP Fee was $2.767b. We do not know what percentage this was of the total capital costs because that was redacted in the AER decision. While out of scope, the AER sought further understanding of these costs and found they cover[31]:

- Construction Fees – paid to EnergyCo during the delivery phase of the project for development and delivery activities undertaken or planned to be undertaken by EnergyCo prior to Financial Close or during the delivery phase ($747m)
- Operating and Maintenance (O&M) Fees – paid to EnergyCo for functions to be performed by EnergyCo during the operations phase of the project ($1,293m)
- Recovered fees – payments for agreed early works activities by ACEREZ ($726.5m)

All the AER could establish was that the costs were approved through EnergyCo' s internal governance process. There was no customer engagement on these costs. The Panel cannot understand why details of these costs are redacted for all Roadmap projects given:

- ACEREZ and Ausgrid have both won the right to develop their respective REZs
- the materiality of the fee
- the inclusion of two contractual compliance nominated Adjustment Events in the Commitment Deed (the Infrastructure Planner Fee event and A change in expenditure timing offset event) which enable EnergyCo to vary the IP Fee over time.

We recommend the AER continue to press EnergyCo for greater information about the prudency and transparency of these significant costs.

2.3.6. Accuracy of cost estimates

Given the focus under the EII Act to speed-up the timetable to construct REZs, we discuss two related issues:

- what is the level of accuracy available to the AER in its assessment? and

[30] Section 6.1.1
[31] See pp 26-7 https://www.aer.gov.au/system/files/2025-04/CWO%20REZ%20network%20project%20revenue%20determination.pdf

- is that level of accuracy an appropriate basis for the AER to assess whether the capex of $497.9m ($590.8m total capex less the EnergyCo component of the IP Fee of $92.9m) is 'prudent, efficient and reasonable'?

The AER RIT-T Guideline does not require a proponent to use the AACE framework, but its use is spreading. If a network does decide to use the AACE framework there is no requirement to apply a specific classification level within the AACE cost estimate classification system[32]. However, the network must set out what level of accuracy they have assumed and why the cost estimate falls within the specified class[33].

Consumer advocates have pushed hard for such a requirement[34] but that was rejected by the AEMC. Consumer concerns that led to that rule change request have only been amplified by recent events with ISP projects experiencing large, unexpected cost increases and schedule overruns. For example, the AER's approval for Project Energy Connect in early 2020 was based on a capex of $1.53b just for the NSW part and completion by 2022-24[35]. The latest estimated cost is $3.6b and completion by 2026[36].

AEMO has recognised the significant increase in ISP project costs with its just published 2025 Electricity Network Options Report[37]. It has real cost increases (ie after inflation) over the numbers used in the 2024 ISP of 25-55% for overhead transmission line projects and 10-35% for transmission substation projects. Key cost drivers are sustained supply chain pressures on materials, equipment and workforce, and market competition driven by a high number of concurrent projects under development, as well as project complexity, social licence and additional contracting costs.

We welcome the AER's recent move towards increasing the focus on capex accuracy in its consideration of network capex proposals under the NER. In November 2024 the AER decided that it required 'market tested' Class 2 (-15% to +20%) costs before it could consider approving the 'prudent and efficient' costs for Marinus Stage 1 Part B construction costs[38]. It would not consider Class 3 or 'untendered' costs. This has led to a two-step process – in step 1, the Class 2 costs for undersea cable and installation and converter station equipment submitted in November 2024. Step 1 expenditure was approved in a Draft Decision released on 16th May 2025[39] with the AER saying that[40]:

> *"Our role is to assess the efficiency and prudency of the forecast construction costs to ensure consumers pay no more than necessary."*

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[32] https://www.pathlms.com/aace/courses/2928/documents/12530
[33] See pp 28-9 https://www.aer.gov.au/system/files/2024-11/AER%20-%20RIT-T%20application%20guideline%20%28clean%29%20-%2021%20November%202024.pdf
[34] https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs
[35] https://www.aer.gov.au/industry/networks/contingent-projects/electranet-sa-energy-transformation-regulatory-investment-test-transmission-rit-t
[36] https://www.transgrid.com.au/media-publications/news-articles/energyconnect-update/
[37] https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report-consultation
[38] https://www.aer.gov.au/system/files/2024-12/Marinus%20Link%20-%20Revised%20Commencement%20and%20Process%20Paper%20-%20December%202024.pdf
[39] https://www.aer.gov.au/system/files/2025-05/AER%20Initial%20Draft%20Decision%20-%20Marinus%20Link%20Stage%201%2C%20Part%20B%20%28Construction%20costs%29%20Transmission%20Determination%202025-30.pdf
[40] https://www.aer.gov.au/news/articles/communications/consultation-opens-our-initial-draft-decision-marinus-link-transmission-determination

Step 2 would require a revised proposal in July 2025 with all Step 1 and Step 2 costs at 'market tested' Class 2 accuracy. The AER commented that:

> *"We consider that the additional (supplementary draft decision) step is required to provide stakeholders with an opportunity to comment on the full scope of works and the more accurate costings to be provided in July 2025. To move directly from a revised proposal to a final decision, as proposed by Marinus Link, limits the capacity for consumers and other stakeholders to inform our final decision." (p.5)*

The AER's timetable for its final decision depends on when they receive the revised proposal and whether costs have further increased from the estimate provide in November 2024.

The capex in the Ausgrid proposal is between a Class 3 and Class 2 AACE estimate. We discuss this further in Section 5 below.

3. Observations on the HCC RNI Project technical solution

3.1. Project Parameters

3.1.1. Introduction

In this section of our Report, the Panel has considered several aspects of the actual construction project itself:

a) the nature of the technical solution, considering its suitability and practicality in meeting the required project scope and timing;

b) the risks to the on-time, on-budget, to-scope delivery of the project;

c) community and landholder engagement related to the social licence to proceed with the project as planned, identifying Ausgrid's consideration of design changes to meet community needs, investment in local support services and landholder needs to support the amenity of the project, and exploring access requirements to existing easements; and

d) engagement to identify potential risks to the project, including community concerns that are both the project itself and the more unrelated works such as the Hunter Transmission Project or the development of the renewable generation projects themselves.

3.1.2. Access to information

Ausgrid has been excellent in its provision of technical information regarding the project to the Panel. Within the constraints of commercial-in-confidence requirements, Ausgrid has made available design information, project planning Gantt charts, detailed risk analysis and a full-day field visit to site to give the Panel a detailed insight into the HCC RNI Project itself.

Throughout the study period, Ausgrid has been responsive and respectful to the Panel's many requests for more detailed technical information, including design considerations, planned mitigation actions related to the risk assessment, procurement plans and early insight into the needs of the construction and support contracts.

In particular, Ausgrid has provided detailed information regarding:

a) the proposed technical solution, including design criteria and route plans;

b) detailed Gantt charts showing project staging, planning, work scheduling and critical path issues;

c) project risk analyses, with detailed spreadsheets considering project risks, likely occurrents and impact, and mitigation factors;
d) a site visit to examine first-hand the project plan and understand the risk elements; and
e) ad-hoc discussions and responses to information requests on particular technical details of the project.

Over the assessment period, Ausgrid held a number of workshops with the Panel and the Ausgrid technical and project team. These included:

a) a detailed analysis of the contractual risks and mitigation options (February 2025);
b) the capital investment summary for the line and substation development (March 2025); and
c) the risk workshop devoted to project contingency methodology and outcomes (March 2025).

3.1.3. A note on the public's perception of the proposed solution

Whilst visiting the region and the site of the proposed 132kV switching station at Antine (Lake Liddell), it was hard not to observe the landscape crisscrossed with 132kV, 330kV and 500kV lines in the Upper Hunter Region. In addition, the recently decommissioned 2000MW Liddell power station looms large over the site of the proposed Antine switching station.

The Panel acknowledges that historically, the transmission lines between Liddell and Newcastle have been some of the most constrained in the state, and that the proposed Ausgrid solution makes much better use of a currently underutilised power line corridor between the Upper Hunter and Newcastle.

However, from the perspective of an informed observer, it seems curious that the significant existing power transmission infrastructure - now relieved of the duty to transport 2000 megawatts of power from Liddell Power Station and soon to be enhanced with a new 500kV transmission circuit between Bayswater and Olney - could not be repurposed at least in the short to medium term to meet the requirements of the renewable energy zone; especially in the context of a desire to improve the utilisation of existing assets before constructing new assets.

We do not intend to question or contradict the planning and tendering processes that led to this decision; and we recognise that the cost of establishing a new 132 / 330kV connection point in the area is not insignificant. Instead, our issue is about transparency of planning and the clearly communicating the need for the investment. We wish to highlight a question that must exist in any local energy consumer's mind when looking at the site: '"*Why build more lines, when you have all that infrastructure only five kilometres away*?"

Below is an aerial view showing the proximity of the proposed Antine switching station and the decommissioned Liddell Power Station. Solely for perspective, the orange line in the figure is approximately five kilometers long.

Figure 1 Aerial view of the vicinity of the proposed Antine Switching Station (source: Google Earth)

We suggest that in making the final decision, a public position explaining why the existing infrastructure is insufficient to meet the HCC REZ's immediate requirements would be very useful and would aid the community's understanding and acceptance of the cost and impact of the new HCC RNI Project.

3.2. System Requirement

Ausgrid notes 3 distinct components of the HCC RNI Project, with each delivering a component of the required new network capacity:

a) **Portion 1:** By January 2026, upgrade of secondary (protection and communication) systems to permit an additional 350 MW of transfer capacity through the existing network. This work is dictated by power system security obligations under section 5.1 of the NER.

b) **Portion 2:** By July 2028, increase the power transfer capacity to 630MW, through the following:

    I. construct a new 132kV switching station at Sandy Creek, adjacent to the existing Muswellbrook 132/33kV station, and rearrangement of the existing 132kV network including the retirement of the aged 132kV busbar at the existing substation.

    II. Establish an optical fibre ground wire (OPGW) communications circuit south to Berowra, including a crossing of the Hawkesbury River.

    III. Construct a high-capacity double-circuit 132kV single tower overhead line from Singleton to Kurri.

c) **Portion 3:** By August 2028, construct a new 132kV switching station at Antine (Lake Liddell) and a new high-capacity double-circuit 132kV single tower overhead line from Antine to Singleton.

The geographic area of the HCC REZ is set out in the following diagram from the EnergyCo (Infrastructure Planner) report of 30 April:

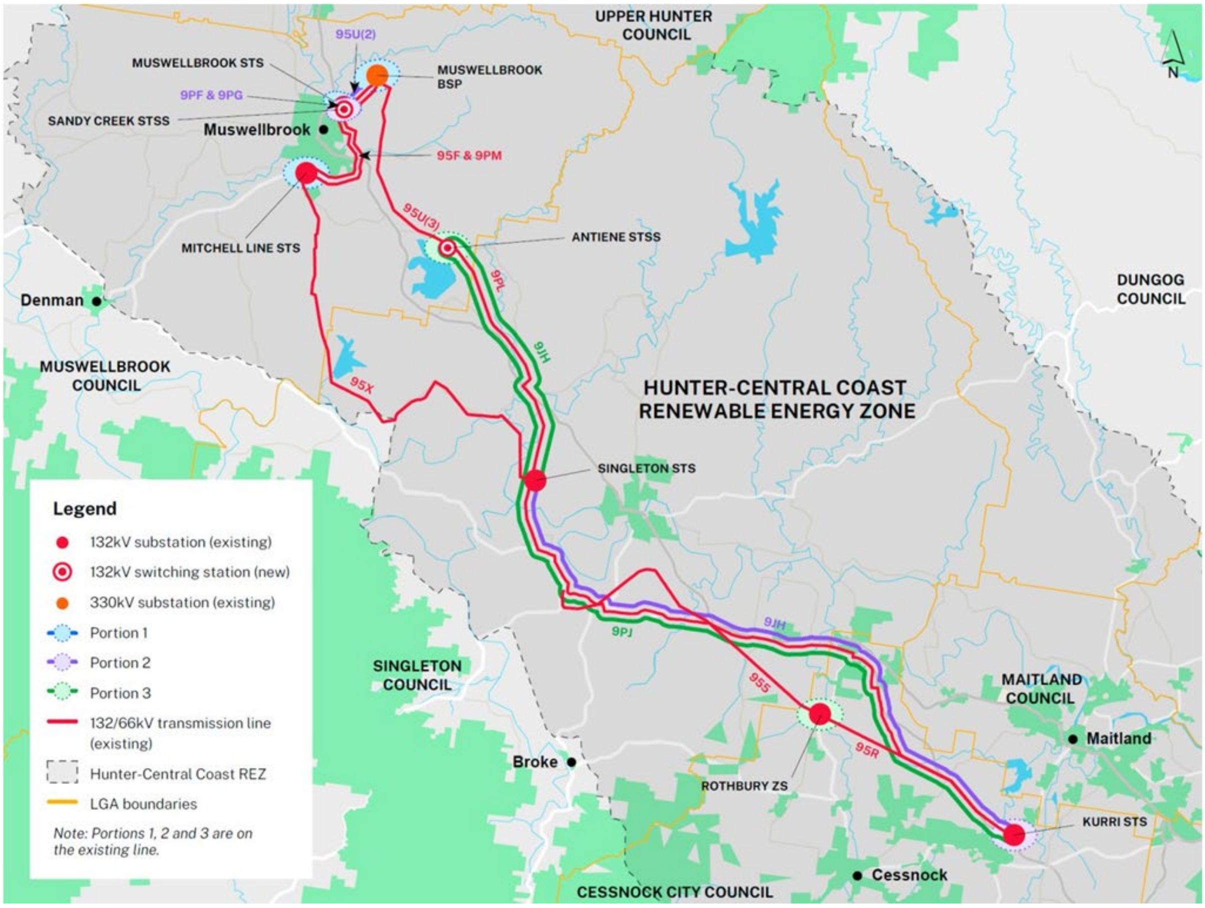


Figure 2: Geographic area of the Hunter-Central Coast REZ

Completion of portion 3, which is planned to proceed in parallel with portions 1 and 2, will deliver the final required transfer capacity of 1 GW.

Ausgrid notes in its Revenue Proposal (p.37) that the technical solution has met the approval of the Consumer Trustee.

The HCC RNI Project includes the construction of new 132kV feeder bays at Kurri Kurri and minor protection work at Transgrid connection points.

The primary works include:

- the Sandy Creek (Muswellbrook) 132kV Switching Station / connection point,
- the Antine (Eastern Hub) 132kV Switching Station / connection point, and
- the new double circuit 132kV transmission line from Antine / Singleton / Kurri Kurri.

The project includes a number of other segments, including protection upgrades, reconstruction of some existing 66kV lines, a series reactor, substation busbar extensions and the installation of new fibre-optic commmunication.

Technical assessment of the proposed works

3.2.1. Design

From the detailed information provided by Ausgrid, the majority of the functional design was complete, with some detail for the line route still under consideration.

A contemporary, yet largely traditional system design is being considered. The connection point and transmission capability is largely N-1, assumed to be meeting an EnergyCo requirement. Transmission circuits are high capacity, multiple conductor-per-phase design.

Ausgrid has not indicated the use of any experimental or breakthrough design criteria for the switching stations, protection and control or lines. Work is designed to be performed by design and construct contractors familiar with this type of work.

Switching stations

Switching station design is for outdoor HV equipment using modern communication and control techniques on greenfield sites, with an open bus design and integrated protection and control systems. The sites chosen for the two stations are on open, flat ground some distance from sensitive developments such as residential subdivisions or areas of possible inundation.

Vegetation clearing at the Sandy Creek site is moderate, and the Antine site is clear save for some trees along the boundary that will need to be cleared for line entry and site works. Our site visit did not indicate any obvious risks to construction access, line routes or environmental or topological concerns.

Both proposed switching station sites are well away from houses and development but may be visible from some distance. There is a housing development growing on the township side (SW) of the proposed switching station site at Sandy Creek that could present a visual amenity risk, but as Ausgrid already owns the site, planning approval concerns are unlikely.

There is a recreational area and caravan park on the banks of Lake Liddell adjacent to the Antine site, however Ausgrid has focussed a significant amount of effort in working with the operator of the site and do not anticipate the works to be challenged. The site is under government control. There may be further work to be undertaken regarding cultural heritage, however Ausgrid has also devoted significant effort to that aspect of the project and express no major concerns.

Of interest is the connection capacity at each of the newly constructed switching stations. The Panel's work did not include consideration of the capital contribution regime that would apply for proponents of renewable generators requiring connection at the new sites.

We understand that the cost of a connection bay is of the order of $700,000 and recognise that it is a balancing act as to how many to build – being a bit cheaper to build them at the initial construction phase, but risky in tying up assets and capital on something that may not get used for some time.

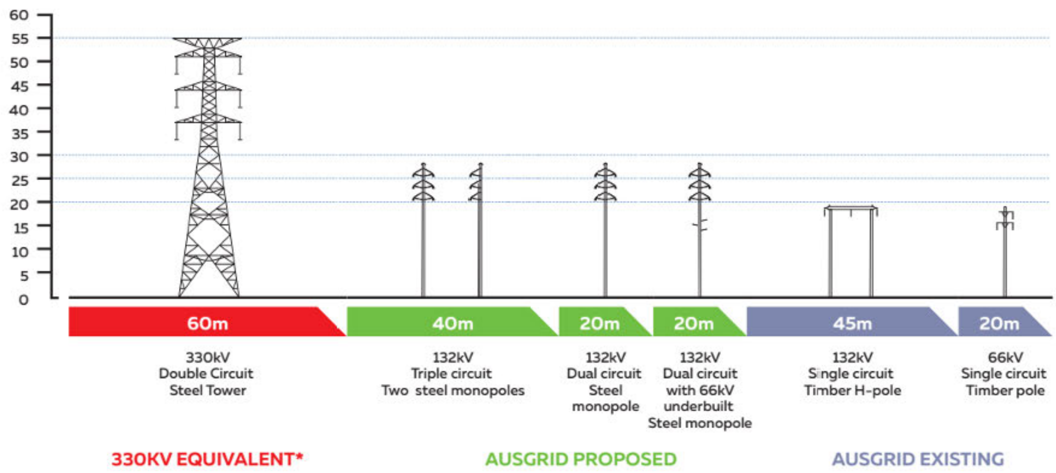
The cost structure (i.e. will customers pay?) for the provision of the connection assets, such as the feeder bays, to the generation assets will be an important issue for future consideration.

Lines and structures

As noted in the Revenue Proposal, Ausgrid intend construction of a new double-circuit monopole design, high-capacity steel-tower line, mostly in place of an existing 'H-frame' line on Ausgrid easement. The line has a design capacity of two 600 MVA circuits. The new structures represent a functional and efficient design for such a high-capacity double circuit line.

Ausgrid made some mileage of the fact that the new line was more or less a ‘replacement’ of an existing line mostly on current easement, but it is clear that the new line will be significantly taller than the existing one, with steel that will be quite shiny for some years, and lots of conductors on the structure itself.

In the earlier stages of engagement, Ausgrid used diagrams from Transgrid to represent the likely visual impact of the new lines. This diagram still forms part of the Revenue Proposal at p.2:



*Source: Transgrid (6 December 2021) *Environmental Impact Statement - Energy Connect (NSW - Eastern Section) - Technical paper 13 - Electric and magnetic field study*. Available at: https://www.transgrid.com.au/media/0yijlr0d/technical-paper-13-electric-and-magnetic-field.pdf

Figure 3: Comparing the HCC RNI’s 132 kV solution to other structures

In our meeting with Ausgrid on 14 April we stressed with Ausgrid that this information may have been misleading, or at least not clearly indicative of the visual impact of the proposed development when compared to existing electricity infrastructure. (see Appendix E). Whilst we acknowledge Ausgrid’s advice that the diagram’s purpose is to compare the proposal with other possible solutions, this was not made clear. The issue will be that all the other towers are dull steel, flatter construction, and many are the ECNSW construction standard of single circuit on a dull, green-painted concrete pole. The new line will be very different in the number of wires that it carries, its height, and the shiny steel construction.

The Panel sent Ausgrid our feedback on this issue (see Appendix F) and in the meeting on 14 April we suggested better use of photomontages that give the community a better impression of what is proposed. We were concerned that the information provided as part of the consultation underplayed the significant change in the line landscape and could risk intervention by landholders soon after construction commenced, leading to a heightened risk of redesign and delay.

Ausgrid later confirmed that they used photomontages of the proposed line and switching stations to assist in consultation sessions with landowners in late January and early February, and in the Revenue Proposal by including Figure 5-3 below (p.45):

Figure 5-3: Photomontage of existing and proposed transmission lines

Should visual amenity become an issue, Ausgrid have advised us that there remains the option of painting some of the poles / towers green, consistent with the application for many concrete-pole line structure in the area. We were advised that the cost to paint a pole would be around $4000.

The line routes include segments that are on lower ground, off the road. Construction access will be very dependent on ground conditions and weather.

Line routes and easements

A major feature of the HCC RNI Project is that the bulk of the line construction will be on existing easements, where an older single-circuit line will be replaced with higher voltage, higher capacity lines. By using existing easements, the traditional need for the negotiation and establishment of line easements on a greenfield route is significantly reduced.

The Antine (Lake Liddell) site is the northern end of new line. It will run southward across undulating lightly treed grazing and reclaimed coal mine land. The region has dozens of powerlines and many areas of major infrastructure construction. The southern half of the new line will run along the motorway south towards Kurri Kurri in close proximity to other large overhead power lines.

3.2.2. Geotechnical studies

A major line of enquiry by the Panel was the extent to which Ausgrid had carried out geotechnical surveys in order to have higher confidence regarding individual pole footing design. Our concerns arose mainly from the nature of the land across which the new lines were to be built, given the high incidence of mining activities in the area.

Ausgrid advised that some geotechnical studies of high-risk sites had been undertaken as part of their early works, but otherwise the risk of redesign lay in the contingency allowance. The Panel was not entirely satisfied by this reply, but we recognise that Ausgrid has significant experience of line works in the area, and that the compressed timeframe under the EII framework for the delivery of the project suggested that this was a compromise that represented acceptable risk.

3.2.3. Other works

Transgrid

The Panel raised the issue of coordination with Transgrid regarding protection upgrades at the transmission connection points. This work is predominantly in Portion 1, allowing an initial transfer capacity. Ausgrid noted that coordination with Transgrid, including information on the cost and resource availability to do the work was limited, if not non-existent, due to the need for commercial confidentiality due to Transgrid being an alternative tenderer. The competitive nature of the procurement process limited Ausgrid's ability to consult on this scope without revealing key elements of their proposed solution.

We highlighted the need for coordination and resolution of the issues at the boundary. Ausgrid have advised that a staff member specifically allocated to the coordination with Transgrid has been assigned.

Sandy Creek / Muswellbrook STS

The works to establish the Sandy Creek (Muswellbrook) new connection point includes a change to the 132kV feeder arrangement at the ageing Muswellbrook sub transmission station. Ausgrid advised of long-standing plans for the demolition and reconstruction of the old (50+ years) 132kV bus at the current 132/33kV sub site. However, with this proposal, the connection will include reconfiguration to transformer-ended feeders, obviating the need to rebuild the 132kV bus at Muswellbrook at an estimated cost of around $5M.

This is a useful initiative in removing some capital and operating (maintenance) costs from existing assets.

3.3. Construction planning

3.3.1. System requirement and project timing

Ausgrid anticipates the ability to connect generators as early as January 2026, with 1 gigawatt of transfer capacity available by July 2028.

Ausgrid provided the Panel with a detailed project plan, including an assessment of the works on the critical path. Our assessment is that Ausgrid's approach to the project is robust, with significant resources allocated to the tasks. We note that the major task of Contractor Mobilisation is due to commence in February 2026.

3.3.2. Procurement

The majority of primary plant and equipment will be supplied by Ausgrid through their existing supply arrangements. Contracts to supply major plant and equipment, such as the steel poles, are in place with local and overseas suppliers, including China. Ausgrid advised that firm processes were not yet available. The Panel expressed interest in what guidance Ausgrid applied to the procurement of plant at a time when there is pressure for the supply of line and substation materials for many projects in Australia and overseas. We were advised that there has been no indication of likely shortages, delays or major cost increases. However, we made a strong point to Ausgrid to be particularly wary of delays in equipment delivery and increases in cost. Ausgrid noted that the impacts will be on both the substation construction contractor and the teams working on the line construction, and the contingency cost allowance will be able to address the costs of any change.

The Panel discussed the ability to move components of the work programme around to cater for any delays, which was agreed to be possible, but becoming more limited as the project progressed.

3.3.3. Outstanding planning matters

Our assessment is that, whilst aggressive, the project involves a feasible timetable so long as delay risk can be reasonably mitigated. In April 2025, we understood that a number of significant 'loose ends' in line design and finalisation of the route remained, including:

a) confirming that the to-be-replaced existing 132kV line can be released from service as expected, including arrangements with the local mine that is fed as a radial from that line. (Ausgrid has recently confirmed that the line can be released from service as required);

b) access to railway easements and rail crossings are arranged and access granted as scheduled and required. To miss these approved times could significantly impact the work programme; and

c) outstanding design details, [redacted], can be agreed and finalised.

Ausgrid advise that materials and specialist labour remain available as anticipated.

Local contractors

An important factor in the EnergyCo objectives is to encourage the use of local labour and contractors. Ausgrid advised the Panel that they have already approached local service providers, and see no issues in the use of experienced contractors and local resources

3.4. Summary of the Panel's technical assessment

Overall, we see the solution as proposed by Ausgrid as technically competent, using contemporary design principles and materials. The line being mainly on existing easement is a significant efficiency, as is the establishment of the two new connection stations as greenfield sites, well away from residential and other sensitive areas.

We have expressed our concern regarding the design of the overhead line in the context of existing powerlines, however given the amount of infrastructure in the area we see the risk any community concerns leading to project delays, significant additional costs or the need for redesign as low.

The Panel notes the cost assessments by GHD and others (which we discuss in Section 5 below), as well as the cost principles being applied. The use of competitive tender for major parts of the work is seen as a reasonable reflection of market going rates.

We recognise that many parameters that would normally be considered for such an investment, such as timing to reflect the certainty and quantum of the required connections, project staging and assessment of forecasting inputs is restricted due to confidentiality requirements.

A number of uncertainties remain in the project delivery phase; however we believe that Ausgrid has done the best they can, given the truncated timeframe for delivery. The detail of project scheduling and risk analysis, along with the desire to undertake a higher level of early works, is useful in this context. It is also clear that loose ends will be as a matter of priority addressed over time.

We do recommend that Ausgrid maintain a robust project progress reporting system to ensure timely and effective identification of project delays and opportunities for programme flexibility.

4. Panel's engagement with Ausgrid on social licence issues

4.1. Introduction and summary

We have found working with Ausgrid on the technical, regulatory and engagement pieces of the HCC RNI Project continued the highest levels of transparency, co-operation and commitment to engagement that we saw as members of the RCP during the recent Ausgrid 2024-29 Regulatory Reset. At no time through our entire work do we feel that Ausgrid has constrained our scope of investigation and challenge or has not been thorough and responsive to our requests for information. At all times Ausgrid have met our information requests in a timely and complete manner, and the appropriate technical or regulatory staff have always been accessible throughout the process.

Our engagement with Ausgrid began with the Panel seeking a fuller understanding of what we might be able to influence. As the commentary in the previous section indicates, there are major areas where the EII Framework prescribes key parts of the project development process:

- That the HCC RNI Project should proceed
- No influence over the deliverability risks imposed by EnergyCo's timeline
- Confidentiality of much of the project review reports such as the CBAs supporting the overall net benefits of the HCC RNI Project
- No influence over the accuracy of Ausgrid's capex forecast
- No ability to observe EnergyCo' s engagement with the community
- No ability to influence the risk allocation between Ausgrid, its contractors and consumers.

We believe that Section 3.4 of Ausgrid's Revenue Proposal, presenting a high-level view of how engagement influenced the proposal, is generally accurate except that it excludes reference to how the Revenue Proposal has been shaped by its landowner and community engagement (as opposed to its engagement with the Panel), which is a key requirement under the BRH.

This section covers social licence related issues – landowners and local communities.

4.2 Engagement with landowners and local communities

4.2.1 Ausgrid's approach

In developing its Community and Stakeholder Engagement Plan (CSEP), Ausgrid drew directly on the Australian Energy Infrastructure Commissioner's recommendations for community engagement in renewable energy infrastructure projects. This includes alignment with the IAP2 framework and adherence to principles of transparency, accessibility, and responsiveness. It also meets the expectations set out in Section 3.2 of the AER Social Licence Guidelines[41].

Ausgrid has undertaken comprehensive stakeholder consultation through numerous engagement and communication activities guided by the principles outlined in Ausgrid's Community Engagement handbook. This approach has increased awareness of the HCC RNI Project, allowing stakeholders and the community to share their input and feedback on key areas of interest. The project-specific engagement approach has the aims of building

[41] https://www.aer.gov.au/industry/registers/resources/reviews/social-licence-electricity-transmission-projects

trust and confidence, reaching diverse audiences and understanding local aspirations and preferences.

The Review of Environmental Factors (REF) is currently on exhibition until June 2025. The REF provides a comprehensive analysis of all potential environmental impacts and risks associated with the HCC RNI Project. The formal exhibition period gives stakeholders an opportunity to understand and provide feedback on the REF, encouraging sustainable and environmentally responsible project outcomes.

As we noted above, Ausgrid was prevented from engaging with landowners until after the Commitment Deed was signed in December 2024. Landholders, as directly affected stakeholders, have been a key priority for engagement, receiving detailed project information primarily through face-to-face interactions. Impacted landowners and businesses were identified as having a 'high' level of interest and a 'low' level of influence. The public participation goal under the IAP2 spectrum was 'inform and consult'[42].

A dedicated engagement team lead a number of engagement activities including face to face community forums that provided for one-on-one meetings with individual landowners, online community forums, presentations to business organisations and community updates/ newsletters. Maps were developed to help landholders identify opportunities and constraints specific to their properties. Their feedback led to refining the alignment, both at the individual property level and across the broader corridor.

4.2.2 Panel comments

Ausgrid was subject to tight confidentiality restrictions imposed on it by EnergyCo, which prevented it from conducting the usual community engagement and due diligence activities that it would follow in a NER project[43]. Ausgrid was allowed to commence engagement with landowners only after it was announced as preferred Network Operator for the delivery of the HCC RNI Project on 17 December 2024[44].

In the HCC RNI Project Statement of Reasons at p.8 AEMO Services refers to EnergyCo's obligations to consult with relevant stakeholders (as opposed to consumers) when developing its recommendations:

> *"The Infrastructure Planner is required to consult with relevant stakeholders when developing its recommendations. The Infrastructure Planner's recommendations to the Consumer Trustee set out the consultation that it undertook with AEMO, network operators, local councils, local communities, First Nations communities, customers and government, and how it took their feedback into account in developing its recommendations."*

We understand that EnergyCo conducted community engagement about the HCC RNI Project before this time during the RFT however the results of this community engagement have not been made public in the IPRR[45]. The IPRR lists benefits for the local community at

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[42] See p.5 Attachment 3.1 Regulatory stakeholder engagement approach
[43] See for example p.87 of the Revenue Proposal and the rationale in Table 2 of Att. 8.1
[44] See Attachment 3.1
[45] In the foreword to the IPRR EnergyCo's CEO lists the stakeholders consulted but does not discuss the issues raised during that engagement: '*I'd like to thank the many groups and partners we worked with to develop this recommendation. They include: the local councils in the HCC region; the HCC First Nations Working Group, DCCCEEW, AEMO Services, the Scheme Financial Vehicle; AEMO, the AER, Transgrid and renewable and storage developers with projects planned for the HCC REZ.*'

pp 20-21, however it is unclear to what extent these issues were raised during community engagement or were pre-determined outcomes required by EnergyCo. As far as we know Ausgrid also has no visibility of the results of EnergyCo's early engagement.

The constraints on Ausgrid's ability to engage with landowners and the community prior to submitting a binding bid has resulted in incomplete project design and cost estimation processes which Ausgrid claims support many of the risks covered by the risk costs and the Adjustment Events discussed in section 6.2 below. The Panel is very concerned about the clear risks to consumers from the acceleration of projects under the EII Framework without adequate prior community engagement, incomplete project route selection and designs based on less accurate cost forecasts.

The Panel had the opportunity to observe landholder engagement in Branxton and Singleton in January 2025. Our observations:

- Great mix of Ausgrid/project people (engagement, regional, property and engineering) available to discuss any issues raised.
- Local landowners keen to understand as much as possible about the HCC RNI Project's impact on them during construction and operation. Ausgrid had all the information required to have detailed discussions on the proposed route with lots of discussion around impacts on particular landowners. Ausgrid was asking were there any particular issues on the land that Ausgrid should be aware of? Should that lead to a change in route and if so what change?
- There was much discussion on the impact construction activities would have on their land and Ausgrid discussed its 'restore to original' commitment. Ausgrid described how they would develop a construction management plan for each property the line traverses eg specific characteristics of where dwellings are located, gate protocols etc.
- Landowners very much appreciated the open discussion - there was no time pressure with some staying over an hour with deep discussions.
- There were other community engagement activities for other projects some attendees had been involved in:
- Some landowners were expressing strong reservations about a proposed solar farm north of Singleton they did not support (it was using prime agricultural land) and where they considered community engagement was poor; they wanted to know if the farm would connect to the Hunter REZ (no) because this may provide an avenue to oppose the farm;
    - Other landowners wanted to understand how the Transgrid Hunter Transmission Project (HTP) was fitting in with Hunter REZ (one landowner was likely to have Hunter REZ and HTP on their property); and
    - Others commented on the poor engagement undertaken by the developers of the Hunter Gas Project.
- Apart from the risk of 'engagement fatigue' (identified in the CSEP) there was the risk of 'collateral damage' from poor quality engagement by other organisations – the importance of Ausgrid being able to differentiate itself, which our observations indicated they seem to successfully do.
- Overall, it was quality engagement – knowledgeable Ausgrid staff, great resource materials; the number of staff meant that there was no time pressure on individual

discussions; attendees could raise any issue they wanted and were happy with the hearing they received, and the information supplied.

- Attendees tended to be supportive of Ausgrid's plans and we did not see any red flags on Ausgrid obtaining landowner approvals.

Panel members also observed 2 webinars where information was provided. In one of those webinars several questions were raised, and we asked Ausgrid to advise the Panel on how it intended to close the loop and provide those residents with answers.

Following our site visit in March, the Panel also engaged with Ausgrid on the visual impact of the new poles and their potential for community pushback leading to project delay and higher costs. The impact comes from the poles being taller than the ones they are replacing, with more conductors and reflective brightness of the new circuits. This could be particularly problematic at Lake Liddell (where the poles run southward across undulating lightly treed grazing and reclaimed coal mine land and are likely to be very visible from some distance for some years until the shine wears off) and the route beside and parallel to the freeway south towards Kurri Kurri.

Ausgrid responded to the Panel that visual impact has been a key focus of engagement from the outset. The visual representations of the proposed steel structures were presented at all community engagement activities, including one-on-one landholder meetings and community information sessions. These visuals are also a key component of the REF exhibition which includes site-specific imagery and impact assessments.

Ausgrid are also actively addressing concerns regarding the brightness and reflectivity of the steel poles with the initial 'shine' fading over time. This finish is comparable to other infrastructure already present in the region, including telecommunications poles. Where negotiations with landholders warrant it, Ausgrid will paint the new poles the required colouring. Ausgrid has made a small allowance for painting some poles. This funding is separate from the $5m social licence fund. The Panel's correspondence with Ausgrid is in Appendix F.

Based on their engagement Ausgrid do not believe that visual amenity presents a significant risk to project timing or delivery.

4.3 Social licence and community engagement capex

Ausgrid is proposing $24.1m capex for community and social licence activities. The breakdown of this capex is set out in table 5-16 in Section 5.4.7 of the Revenue Proposal:

Table 5-16: Proposed community and social licence capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Labour (internal)	17.7	74%	Internal	• Labour rates based on internal sources • Efficiency benchmarked against ANS labour rates
Contracted services	1.1	4%	External	• Market tested prices
Social Licence Plan	5.3	22%	Internal	• Industry benchmarking performed by cost consultant
Total	**24.1**	**100%**		

This expenditure has been the focus of detailed engagement between the Panel and Ausgrid since January.

4.3.1 Social licence activities expenditure

Ausgrid has used different terms in its Revenue Proposal and Att. 5.7 to describe its investment in building social licence[46]. In Att. 5.7 Ausgrid refers to its Social Licence 'Plan' when Att. 5.7 and the Revenue Proposal also refer to the Social Licence 'proposal'. Section 5.4.7 combines expenditure on community and social licence and refers to a social licence 'strategy'.

In response to Panel questions Ausgrid informed us on 7 February that EnergyCo' s RFT required Ausgrid to include a 'social licence plan' as part of its tender. Ausgrid also advised us that EnergyCo did not specify the approach adopted by Ausgrid in Att. 5.7 nor the size of any social licence investment. Due to confidentiality constraints imposed by EnergyCo we have not seen the RFT. We recommend the AER review the RFT to determine what EnergyCo actually required for community engagement and/or for social licence activities[47].

Our understanding of Ausgrid's proposed capex of up to $5.3m (real FY26) to implement its Social Licence Plan is:

- $5m will be allocated to set up and run a local supervisory committee with the balance of the $5m to be allocated by that committee for social licence activities
- $0.3m will be allocated for Ausgrid's internal costs to administer the Social Licence Plan.

We understand that the $5m is for the social licence activities, as opposed to the community engagement to identify the need for specific social licence activities. The details of the governance surrounding the expenditure of the $5m are set out in Att. 5.7.

The Panel supports the need for justified investment in social licence activities for major transmission projects, following community issues and concerns identified from prior community engagement. The AER also recognises the benefits for projects of transmission networks building social licence in the AER Social Licence Guidelines. In February Ausgrid confirmed with the Panel that its proposed Social Licence Plan would comply with the AER Social Licence Guidelines. However, Att. 5.7 does not reference the AER Social Licence Guidelines instead it refers to the RIT Guidelines and the CBA Guidelines, which Ausgrid acknowledges do not specifically apply to the HCC RNI Project. We recommend that the AER invite Ausgrid to provide more detail on how its approach meets the AER Social Licence Guidelines and in particular the important distinction that the AER draws between effective community engagement to identify risks to building social licence and social licence activities in response to engagement feedback to build and maintain social licence[48].

In February Ausgrid advised us that it has not yet commenced engagement with the community about the need for this $5m Social Licence Plan nor what it should be spent on. Ausgrid also confirmed it expected to commence engagement on this topic in the second half of this year.

The proposed governance for Ausgrid's Social Licence Plan involves the establishment of the Local Engagement Committee (HCC LEC) which will decide on the priorities for the $5m. The Panel was keen to review the minutes and operation of the HCC LEC.

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[46] We raised our concern about this issue with Ausgrid in our meeting on 14 April
[47] EnergyCo makes no reference to social licence in the public IPRR. It does highlight an Aboriginal participation plan and regional employment and business opportunities but these are separate programs from the Social Licence Plan
[48] This distinction was critical to the AER's decisions to approve social licence funding for ISP CPAs in Humelink Stage 2 (August 2024) and VNI-West Stage 1 (May 2024)

However, in February Ausgrid advised us that the HCC LEC has yet to be established. This means the Panel has been unable to review the composition of this committee nor review any governance arrangements other than what is set out in Att. 5.7. Ausgrid also advised the Panel that it is still in discussions with EnergyCo about its views on whether an existing Hunter reference panel could be expanded or whether Ausgrid should start its own panel. We are not familiar with the existing Hunter reference panel nor its governance.

By contrast, each of the Panel members were foundation customer members of NIAC and two of us remain members of NIAC. NIAC's governance results in the allocation of the envelope of innovation expenditure to programs that have the support of customers. The NIAC governance also includes accountability from Ausgrid for the implementation of that expenditure. The Panel recommends that the AER review the proposed governance of the HCC LEC. We are also concerned that the AER does not appear to have required Transgrid in the Humelink and VNI West decisions to report to the AER about the delivered outcomes and community benefits of its social licence activity expenditure. The Panel believes this could be included as an annual obligation on Ausgrid in the AER's HCC RNI Project determination as well as on all TNSPs in the revision of the AER Social Licence Guidelines seeing this is an evolving category of expenditure.

In Section 2.2 of Att. 5.7 Ausgrid provides 2 reasons to support the prudency, efficiency and reasonableness of the $5.3m expenditure for its Social Licence Plan.

The first reason is a benchmarking exercise Ausgrid says it has undertaken. We asked Ausgrid for a copy of its benchmarking exercise and they referred us to the Transgrid document, Community Investment and Benefits Strategy, December 2023[49], referenced in footnote 4 at p.8 of Att. 5.7.

The Panel reviewed the Transgrid document entitled Transgrid Social Licence Framework referenced in footnote 4 and we are concerned that Ausgrid has not accurately set out what Transgrid said. In Att. 5.7 Ausgrid states:

> *"Although benchmarking data is limited, studies suggest that major infrastructure projects should allocate between 1.0-1.3% of their total budget to social licence activities."*

The Ausgrid statement suggests that just social licence activities might amount to 1% or 1.3% of total project costs.

The full extract from the Transgrid Framework (p.8) is this statement (emphasis added):

> *"Current limited benchmarking data, suggests that proponents of major infrastructure projects worth $2 billion or more should aim for between 1.0-1.3% of the total project budget<u>, inclusive of community and stakeholders' engagement and community investment programs</u>, as identified in prominent research by the Australian National University's Institute for Infrastructure in Society (I2S)."*

The Panel was unable to find the relevant I2S study and on 30 April we asked Ausgrid to send us a link to the relevant study that Ausgrid and Transgrid have referred to. We did not receive that study prior to finalising this report. The Panel doubts that the benchmarking study is relevant to the HCC RNI Project. We note that Transgrid states that I2S looked at several projects worth $2b or more and the HCC RNI Project is considerably less at $590.8m. The Panel recommends that the AER reviews this I2S study to see what types of

49 https://www.aer.gov.au/system/files/2024-02/Transgrid%20-%20HumeLink%20CPA%20stage%202%20-%20Social%20Licence%20Framework%20-%2006%20December%202023%20-%20Public.pdf

projects I2S used in its study - greenfield or brownfields and to determine its relevance to the benchmarking claim.

Table 5-16 makes it clear that the $24.1m proposed by Ausgrid is significantly more than 1% of the HCC RNI Project capex. The Panel does not express a view on whether 1%-1.3% for the community engagement and Social Licence Plan for the HCC RNI Project is prudent but even if it was that would be a total investment between $5.908m and $7.68m and not $24.1m.

The second reason given by Ausgrid to support the prudence, efficiency and reasonableness of the $5.3m capex allowance is that the NSW Government's Strategic Benefit Payments scheme (SBP Scheme) does not apply to the HCC RNI Project and Ausgrid has not increased the expenditure in its Social Licence Plan to compensate for this. The SBP Scheme involves additional payments to landowners over and above compensation for compulsorily acquired land. The SBP scheme policy document[50] does not refer to the objective of building social licence, rather at p.8 it describes payments under the SBP Scheme as benefit sharing:

> *"….private landowners who host this infrastructure should receive a greater share of the benefits of building and operating new transmission lines."*

We note that in the Humelink stage 2 decision the AER assessed strategic benefit opex payments separately from social licence payments and noted that the key driver of the proposed strategic payments was not to achieve social licence[51]. The Panel does not believe that the absence of SBP Scheme strategic payments can be relied on to justify the prudency, efficiency and reasonableness of the $5.3m Social Licence Plan. By contrast the AER defines social licence much more broadly than the immediately impacted landowners hosting the infrastructure to focus on the community as a whole:

> *"Social licence is linked to general awareness and acceptance of a project within a community and is directly linked to a project's credibility. Successful project proponents have clear strategies and programs to form good relationships and acknowledge these are built over time[52]."*

The social value priority areas (activities) which Ausgrid claims have been identified to date from Ausgrid's community engagement are listed in Section 3.2.1 of Att. 5.7:

- *"to create employment, including employment for First Nations people, women, and other under-represented demographics*
- *to invest in education and training*
- *to promote local industry, manufacturing and jobs*
- *making electricity accessible for all, and*
- *introduce/develop legacy Ausgrid social value initiatives."*

The Panel acknowledges that these priorities appear consistent with the activities contemplated by other social licence programs. However the Panel is unable to confirm from direct observation that these activities aimed at these issues have been raised during community engagement. In Section 4.2 above we summarise what we saw during the limited

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50 https://www.energyco.nsw.gov.au/sites/default/files/2022-10/policy-paper-strategic-benefit-payments-scheme.pdf
51 AER determination Transgrid's Humelink Stage 2Delivery CPA 2 August 2024 at p.46
52 https://www.aer.gov.au/system/files/2024-09/AER%20-%20slides%20for%20social%20licence%20%28broader%20stakeholders%29%20-%2029%20August%202024.pdf

community engagement that we observed. During the final meeting with the Panel on April 14 before lodgement of the Revenue Proposal we advised Ausgrid that we were concerned that they had not adequately provided a summary or independent reporting of its community engagement and any issues raised. We have reviewed Att. 3.1 and we still believe that Ausgrid has not provided sufficient detail of the issues raised by the community during community engagement that would support expenditure on social licence activities.

We recommend that the AER ask Ausgrid to provide greater detail of the community engagement to date and provide evidence of the areas identified during that engagement that will be targeted by the Social Licence Plan.

4.3.2 Community engagement expenditure

In April we also sought information from Ausgrid about the additional $17.7m internal labour and $1.1m contracted labour for community engagement activities. Ausgrid advised us that this expenditure includes time for up to 12 Ausgrid FTE for 3.5 years who would perform various activities discussed in Att. 5.6. We note that 5 of the 12 FTEs would be working on land and property activities. The Panel is concerned that there is insufficient detail about the need for these staff for community engagement (in addition to the $5.3m Social Licence Plan) for a largely brownfields project. Ausgrid has repeatedly advised us that no significant issues have arisen in community engagement to date. Certainly we did not observe major community issues during the engagement discussed in Section 3.2 above.

The Revenue Proposal acknowledges at p.7 that by almost entirely repurposing existing Ausgrid corridors with higher capacity lines that its proposed development for the HCC RNI Project will be less disruptive and will minimise community impacts compared to other greenfield options. The IPRR (at p.22) also reinforces that Ausgrid's proposal will minimise community and environmental impacts.

On 2 May Ausgrid provided additional information to the Panel to support $6.9m of the $17.7m. We have included Ausgrid's response in Appendix G. We are aware that in Section 4.2.3 of its recent Statement of reasons AEMO Services has referred to Ausgrid's CSEP as one of the reasons why it concluded that the HCC RNI Project is consistent with the objects of the EII Act. Nevertheless we recommend that the AER review the CSEP and the $17.7m and $1.1m contracted community engagement costs and invite Ausgrid to provide greater clarity to support the need for this level of expenditure for the HCC RNI Project. The Panel looks forward to further engagement on this issue with Ausgrid and the AER.

5. Panel's engagement with Ausgrid on building block issues

5.1. Capex cost accuracy

5.1.1. Ausgrid's approach

Ausgrid is proposing total capex of $(25/6)590.8m (p.4):

Base capex (including Ausgrid portion of the IP Fee)	$451.1m
EnergyCo portion of the Infrastructure Planner Fee	$92.9m
Risk costs (contingency)	$46.9m
	$590.8m

which includes $283m in expenditure incurred before 1st July 2026 and $307.9m forecast capex for the 2026-31 Regulatory Period. The cost estimate is based on considerable scope definition and a detailed risk assessment. The AER Guideline[53] does not require any specific AACE cost accuracy class and Ausgrid makes no claim itself on the level of accuracy. In March, Ausgrid provided a Turner and Townsend report to the Panel that concludes that the current estimate is an AACE Class 3 estimate (p.4):

> *"Ausgrid's HCC REZ cost estimate falls within the mid stages of project definition for Class 3 and Class 2 estimate"[54].*

Class 3 has an accuracy range of -20% to +30%. Based on Turner and Townsend advice, Ausgrid expects to move to a Class 2 (accuracy range of -15% to +20%) by Q2, 2026.

Ausgrid argues that its estimate is 'prudent, efficient and reasonable' under the EII Act, noting the differences with the NER with the scope of the assessment under the former being 'narrower'. Ausgrid has developed a capex proposal that it argues is prudent because it (pp 36-37):

- aligns with the investment needed to deliver the technical specifications set by the Infrastructure Planner
- is supported by the competitive tension that applied in the selection of Ausgrid as the Network Operator of the Project, and
- the additional oversight under the EII framework…

It is efficient because of the way the capex estimate was developed through a combination of market prices from competitive procurement processes and 'established method' adopting costings from the 2024-29 reset or established AER practice (p.38).

It is reasonable because (p.39):

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[53] https://www.aer.gov.au/system/files/2024-07/AER%20-%20TET%20%26%20revenue%20determination%20guideline%20for%20non-contestable%20network%20infrastructure%20projects%20%20-%20July%202024.pdf

[54] The Panel does not know why the Turner and Townsend report was not included as an Attachment to Ausgrid's Revenue Proposal, although it is referenced at p.40 and the GHD refers to Turner and Townsend developing forecast labour costs using first principles

"…it is based on good industry practice within the accelerated timeframes that apply under the EII Act"

Ausgrid provide two reports to support its position. A report by GHD[55] that concludes that the base estimate of $451.1m (total costs excluding contingency and the IP fee) (p.i):

"…are supported by tender outcomes or reasonable estimates that draw upon the scope definition and supported by price estimates. The estimate reflects the scope at its current level of definition and are required to deliver the project scope or to reduce risk.

…the capital forecast represents a blend of Class 2/3 estimates representing the best available estimate at this stage of the project's development. The forecast is considered prudent, efficient and reasonable for carrying out the HCC RNIP".

This is based on a combination of factors – competitive tendering for transmission lines and substation packages; cost of free issue equipment based on existing or refreshed panel agreements; compensation and land acquisition based on an independent expert estimate, and owner costs using internally known rates. GHD did a bottom up assessment of the Ausgrid costs and then a limited top down benchmark of the substations and underground power cables component ($102.5m) against the AEMO ISP Transmission Cost Database Class 5b and 5a estimates that are respectively ± 50% and ± 30% (ie not directly corresponding with the AACE Class 5 accuracy levels).

Turner and Townsend were engaged to develop the cost model and advise on best practice procurement processes. They concluded that the current estimate is an AACE Class 3 estimate which (p.4):

"*Ausgrid's HCC REZ cost estimate falls within the mid stages of project definition for Class 3 and Class 2 estimate".*

Class 3 has an accuracy range of -20% to +30%. Based on Turner and Townsend advice, Ausgrid expects to move to a Class 2 (accuracy range of -15% to +20%) by Q2, 2026. Ausgrid has advised that while they lodged their Revenue Proposal and supporting modelling in May, they will be able to provide project updates to the AER until September.

This section focusses on the base cost estimate of $450m. The next section focusses on contingency.

5.1.2. Panel comments

At the outset we wish to again acknowledge the excellent engagement we have had with Ausgrid as we have reviewed the capital costs. We also acknowledge that there are a number of factors that serve to limit Ausgrid's (and consumers') upside risk on both increased cost and extended schedule (which has a cost impact) e.g. being substantially constructed on existing rights of way in Ausgrid's existing network footprint; competitive tendering for delivery packages on transmission lines and substations with detailed scope definition; using many existing Ausgrid contractors for major parts of the works, and Ausgrid having the EPC Management role itself.

The Turner and Townsend report is quite short and high level with little detail to support their conclusions. The report states:

"The project does not have all construction drawings ready, but early tender estimates are available. This suggests that the maturity level of project definition deliverables is

[55] Attachment 5.2 Independent Verification and Assessment 16 April 2025

between 10% and 40%, aligning with Class 3 estimates with some characteristics of a class 2 estimate."

They provide no commentary on whether this cost Class provides a firm basis for the AER's assessment.

The GHD report is a much more substantial report that systematically reviews all aspects of direct and indirect costs. On contingency it simply adopts the results from the Ausgrid Risk and Contingency report prepared with IAG. While this report is welcome and sets a new standard for cost transparency, we recommend that the AER review it closely.

We make the following comments on the capex forecast in the Revenue Proposal:

- In Section 4.3 above the Panel concluded that Ausgrid had not sufficiently justified the $24.1m for community engagement and social licence capex.
- A major reason for underestimating capex in other projects has been actual capex and labour escalation has been much greater than assumptions made at the time of the investment decision. GHD accept the Turner and Townsand forecast general escalation index which is applied to labour and materials cost categories. The general escalation index outlined in the table below includes CPI.

[redacted]

[redacted] Other contracts have escalation handled by Adjustment Events. All this means that there is relatively small amount of total capex excluding the IP Fee (where there is no escalation) that the escalation factors apply to.

These contract costs can then have a contingency component and may be subject to further escalation from Adjustment Events which we discuss further below.

GHD acknowledges the limitations of benchmarking Ausgrid AACE Class 3 estimates against AEMO TCD non-AACE Class 5a and 5b estimates. We do not think that any firm conclusions can be drawn from this benchmarking.

Ausgrid argue that the risk of changes in their capex estimate are symmetrical which they define as 'could be higher or lower'. Our view of symmetrical is an equal probability of being higher or lower. Ausgrid should explain their approach in more detail.

In summary, we believe the cost estimate that Ausgrid will provide to the AER is the most accurate possible in the timetable they have to achieve i.e. it is 'reasonable' on Ausgrid's definition. But that is not the same as saying the Panel believes the cost estimate is accurate enough to enable the AER to make its 'prudent, efficient and reasonable' judgement.

As we discussed in Section 2 above, this is driven by the EII framework which gives the AER a very specific role in a constrained timetable. Where the AER sets the information and timetable requirements for NER projects it requires considerably more information and time to evaluate.

5.2. Ausgrid's approach to risk, contingency and Adjustment Events

5.2.1 Ausgrid's approach

5.2.1.1 General approach to risk assessment

Section 5.3 of the Revenue Proposal (pp 40-5) sets out Ausgrid's approach to the allocation of project risks and why it believes it results in efficient outcomes for consumers. It does this by (p.40):

> *"… allocating risks to the party that is best placed to bear and/or manage that risk"*.

Ausgrid first assess the risk characteristics and then allocates them to one of three groups:

- Group A – capex costs with a high degree of forecast certainty;
- Group B – capex costs that are uncertain, but the event risk and/or consequences are somewhat under the control of Ausgrid or our contractors and can be reasonably estimated, and so the risk is best borne by Ausgrid or our contractors; or
- Group C – capex costs that are uncertain and beyond the control of Ausgrid or its contractors, and where the event risk and/or consequences of the event cannot be reasonably estimated by Ausgrid, so the risk is best borne by consumers.

Ausgrid believes that this grouping ensures Ausgrid:

- appropriately allocates the risk to the party that is best placed to bear and/or manage that risk;
- avoids double counting of any risk, by ensuring that risk events cannot be included as both a contingent cost allowance and as an adjustment event; and
- allows Ausgrid to set a contingent cost allowance which is reasonable and proportionate for the HCC RNI Project.

So capex is divided into three groups:

- Base capex - high degree of certainty that it will be incurred by Ausgrid; or
- Contingency - expected risks are reasonably foreseeable where Ausgrid or its contractors are best placed to manage the risks; or
- Revenue adjustment events - which are less foreseeable, uncertain risks that are not under the control of Ausgrid or its contractors, or cannot be reasonably estimated, so the positive and negative impacts of these events are best borne by consumers.

5.2.1.2 Contingency

Ausgrid defines Risk (contingency) costs in its Revenue Proposal (p.41) as:

> *"… the expected cost of risks that are reasonably foreseeable to be encountered and where Ausgrid, or its contractors, are best placed to manage these risks".*

The AER's RIT-T Guideline says that if contingency is included then the proponent must explain[56]:

- the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to
- how the level or quantum of the contingency allowance was determined.

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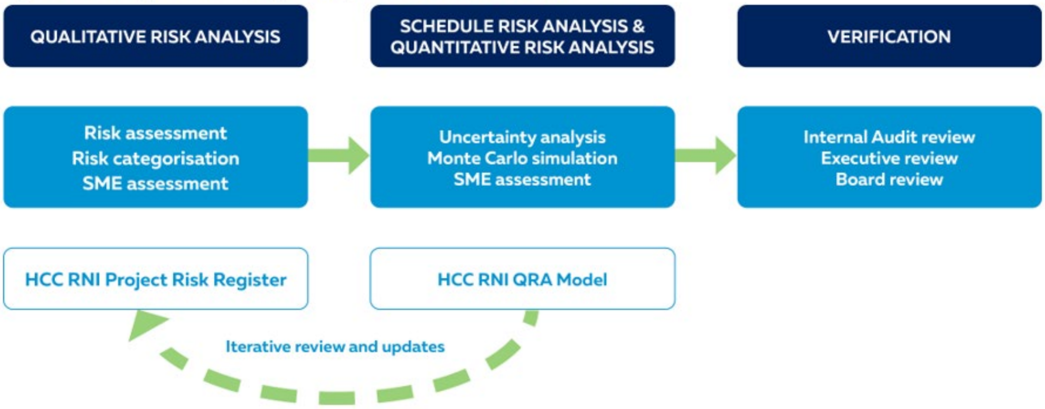
[56] Ibid p.57

Ausgrid's process, following ISO31000:2018 Risk Management-Guidelines, had three steps[57]:

- qualitative process to identify and assess all project risks;
- qualitative review of the residual project risks which have a financial impact as their primary consequence category; and
- monte carlo analysis to model a probabilistic contingency value for these residual risks where it is not efficient to fully mitigate, avoid or transfer the risk to another party or the cost of mitigation exceeds the expected cost impact should the risk eventuate.

Ausgrid's approach is summarised in Figure 5-2 (p.43):

Figure 5-2: Ausgrid risk management process for the HCC RNI



While Ausgrid was able to evaluate many risks in the course of putting its bid together, it was unable to liaise with landowners, key stakeholders and local communities until after the Commitment Deed was signed in December 2024. These risks are less developed.

The qualitative risk analysis identified 85 risks. The quantitative analysis developed the contingency amount for each based on probability of occurrence multiplied by costs. Costs were assessed at P10 (optimistic), P50 (likely) and P90 (pessimistic) based on Ausgrid SME judgement. The P50 value i.e. 50% chance that the HCC RNI Project can be delivered to the amount or less, was chosen. It is not an AER direction, but the AER rejected Transgrid's proposed P70 for the calculation of risk costs in HumeLink Stage 2 preferring instead a P50 level[58]. The risk register was run through @Risk software that used a Monte Carlo analysis to select the HCC RNI Project cost contingency allowance.

The major risks were delays e.g. greenfield switching station subcontractor scope, Ausgrid delay and Kurri Kurri STSS subcontractor scope. The cost of a delay varies over the course of the construction schedule – lower at the start, higher at the peak of the schedule. Contingency is required at even the most optimistic of scenarios e.g. the P50 contingency was \$32.7m. The 99% contingency was \$135.9m. It is a 'live' risk register. Risks have dropped out or changed level of contingency as they have been better understood and mitigation measures developed. The P50 in April was \$53m. The capex estimate in this Revenue Proposal has a contingency of \$46.9m, the same amount Ausgrid used in its final bid to EnergyCo i.e. less than the current P50 estimate.

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[57] Attachment 5.9 Risk & Contingency Report at p.1
[58] https://www.aer.gov.au/system/files/2024-08/AER%20-%20Determination%20-%20Transgrid%20HumeLink%20Stage%202%20Contingent%20Project%20-%20August%202024.pdf at p.28

5.2.1.3 Adjustment events

There are 23 DSP Adjustment Events in the Commitment Deed where risks can be passed to consumers subject to AER approval. These Adjustment Events resulted from negotiations between Ausgrid and EnergyCo through the bidding process. A key assumption in Ausgrid's Proposal is that the proposed Adjustment Events are approved by the AER. These events are in three categories:

- predetermined events eg change in taxes
- automatic adjustment mechanisms and standard pass-through events in the NER eg changes to the allowed WACC or changes in insurance costs
- Nominated cost adjustment events:
    - EnergyCo contractual compliance eg change in NSW law or the Infrastructure Planner fee
    - Procurement induced cost uncertainty events.

5.2.2 Panel comments

5.2.2.1 General approach to risk assessment

At a general level we find it difficult to reconcile two Ausgrid statements:

- allocating risks to the party that is best placed to bear and/or manage that risk, and
- any risk that cannot be reasonably measured by Ausgrid should be borne by consumers

Consumers have no way of managing these risks and Ausgrid provides no justification that consumers are 'best placed' to manage that risk. And here consumers have had no say in what is included as an Adjustment Event, as they were not in the negotiation on the Commitment Deed.

We describe Ausgrid's risk allocation as 'consumers bear the risks that Ausgrid or its contractors are not willing to'. Ausgrid's argument supporting these adjustment events (p.80) is similar. If they were not approved then contingency would increase significantly above $46.9m for those they could measure – which is why they are Adjustment Events, not contingency. That would mean a much higher guaranteed cost to consumers. There are also some they could not measure and this may mean potential proponents are less likely to bid to build the REZs because of the risk they would be required to bear.

Even if Ausgrid were to agree with our interpretation we expect their response to be the consumers' exposure is limited by AER oversight. The AER has to determine the 'prudent, efficient and reasonable' cost of any Adjustment Event application.

But our concern is with the breadth and definition of the Adjustment Events as they cover events that we consider that Ausgrid or its contractors are far better placed to manage i.e. they should be in base capex (as part of the risk allocation in procurement contracts) or as contingency where the selection of the P50 cost means Ausgrid shares a risk that it has at least some ability to mitigate when consumers have none.

In our discussions Ausgrid sought to argue that these risks are symmetrical which they defined as 'they can go up and down' so consumers can benefit from this being an Adjustment Event with no explanation on probability and size of rise or fall. Our definition of symmetrical is that there is an equal chance of them going up or down. Given that definition, the risks are far from symmetrical.

5.2.2.2 Project delivery – cost and timing risks and contingency

Panel comments on the risk register

The approach to reviewing the risk register and estimating contingency has been a major focus of the Panel. Ausgrid provided the Panel with a comprehensive contingent risk register as pre-reading to a lengthy risk workshop with Ausgrid and their consultants, IAG, in March. The purpose was to gain an understanding of the risk analysis and contingency modelling and test the methodology and conclusions. Appendix H includes the questions that we sent to Ausgrid in advance of the risk workshop and demonstrates the extent of the information that we sought and that Ausgrid provided to the Panel

It is useful to examine the highest risks by stage of the project.

[redacted]

Most, if not all, of these risks, are a consequence of the need to build the project quickly with reduced time in the design and contractual phase to mitigate risk. The condensed timetable requires Ausgrid to be flexible to redesign, redeploy or reschedule parts of the work to minimise the risk of significant delays. [redacted]

The top-level risk mitigations looked for include:

- Flexibility in being able to reschedule and relocate work. This will require a high level of materials availability and contractual flexibility
- Materials for the various stages of the work being available well before they are required, without incurring too many warehousing costs
- The design and engagement teams remain available well into the construction phase, able to adjust the programme, update or revise any designs or continue with complex and detailed landholder and government negotiations
- The impact of these high-level risks includes both timing (risk of delays, stand-down / stand-up costs) and commercial (redesign, reordering materials, contract variations).

Comments on particular risks:

[redacted]

[redacted]

Ausgrid notes three risks that have a high likelihood of occurring. These are reasonable and, [redacted], are not outside common practice.

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

While the risk register and mitigation considerations are comprehensive there is continuing concern on costs and schedule material cost escalations, labour cost escalations (including contract labour demand), key material procurement delays and skilled labour availability shortages. Ausgrid continues detailed design work to further mitigate risk. Most major plant is more or less off the shelf and about half are overseas manufacture. Early materials procurement would be useful due to the short delivery timeline, but all will need to fit into the EnergyCo planning and funding process.

5.2.2.3 The calculation of the contingency allowance

We spent some time examining how the risk register was used to determine contingency. Our main conclusion was that while contingency calculation was sophisticated and best practice in its modelling methodology, it is still a deterministic ‘black box’ that relies on individual judgement by SMEs to set the $ consequence values for the Monte Carlo modelling. We expect that other major network projects have undertaken similar type analyses and still grossly underestimated the required contingency. We focussed on particular risks:

- [redacted]
  - [redacted]
  - [redacted]
- [redacted]

[redacted]

- [redacted]

This led to a wider discussion on the potential overlap between contingency and Adjustment Events, particularly where contingency events could be classified as an '[redacted]' Adjustment Event. Ausgrid said that there is no overlap and the Adjustment Events were negotiated to be separate from the events included in Ausgrid risk costs. Ausgrid reassured the Panel they have no intention of 'double counting'.

The Panel asked Ausgrid to provide a summary table showing where risk is accounted for in three cost categories – base price, contingency and Adjustment Events. [redacted]

- [redacted]
- [redacted]

In the end we concluded that the contingency allowance seems reasonable given the items it was meant to cover and the scope of the Adjustment Events given the pressure to build quickly. Our concern was that scope which included matters that should be risks borne by Ausgrid or its contractors, not consumers who have no way of mitigation. We note that Ausgrid included specific information in Table 2 of Att. 8.1 in response to our concern about potential overlap between risks covered by the risk cost allowance the Adjustment Events.

We look forward to the AER review to ensure there is no double counting.

5.2.2.4 <u>Adjustment Events</u>

As we noted above, the change in the legislation now allows project developers to obtain approval for additional costs from the AER using Adjustment Events in the Commitment Deed which can allow the final costs to exceed the MCC. Discussions with customer advocates indicates that this is not well understood. Our focus is on the nominated cost adjustment events where the Panel may have an influence.

Section 8.4 of the Revenue Proposal sets seven EnergyCo contractual compliance nominated adjustment events. Due to confidentiality constraints imposed by EnergyCo we have not seen neither the Commitment Deed nor the Draft Project Deed. We note that in the Waratah Super Battery determination the AER approved only one adjustment event in this category for additional contractual payments to EnergyCo. We are very concerned about the increase to seven events in the HCC RNI Commitment Deed.

Were the AER to approve any of the Adjustment Events in the Commitment Deed, we recommend that the AER consider setting a cap. In particular two of the seven events - DSP IP Fee Adjustment and Reduction in IP Fee due to reduced Technical Services Payments - can result in increases and decreases to the IP Fee. Only the second of these events aims to be revenue neutral over regulatory periods.

As part of its review of the Commitment Deed and draft Project Deed we would also welcome the AER providing commentary in its decision on the increase in these contractual pass-through events and considering if there are other ways in future EII projects that these risks could be managed by EnergyCo, other than passing through these costs to consumers after the event.

Table 8-5 sets out seven procurement induced cost uncertainty nominated adjustment events. The clear risk to consumers is the increased costs that flow from the AER allowing 'reasonable' increased costs to meet a tight completion timetable Ausgrid has under the Project Deed. In our discussion of these events Ausgrid argued that several of these events are symmetrical – they can go up and down. As we noted above, our views of symmetrical is that there is an equal probability of the costs going up and down. Ausgrid provided no evidence to support that view of symmetrical.

Take the case of '[redacted]'. [redacted]

[redacted]

[redacted]

We have suggested to Ausgrid that they commit to trigger events (e.g. cost increase application has to be a minimum amount) and a cap on some Adjustment Events like this one. No commitment has been offered.

Then what about the example where costs have fallen? We look forward to Ausgrid transparently applying for Adjustment Events that result in a lowering of costs.

We are pleased that Ausgrid has agreed to continue engaging with the Panel and the AER on these seven Adjustment Events following the lodgement of the Revenue Proposal. This discussion will include:

- [redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]

The AER's final decision for the Waratah Super Battery on 15 December 2023[59], predated the change to the MCC in November 2024. We note that in the Waratah Super Battery decision the AER rejected some adjustment events requested by Transgrid and imposed a maximum cap on another and changed wording to strengthen the AER's ability to review the efficiency of the claimed spend[60].

Given the change to the role of the MCC to benefit networks and to transfer greater project delivery risks to consumers, we believe that it is even more important for the AER to review these Adjustment Events and impose limits on the future revenue that can be claimed.

5.3 Incentive schemes

Ausgrid proposes to exclude the $5.3m Social Licence Plan from the Capital Expenditure Sharing Scheme (CESS). The Panel understands the rationale for this exclusion is to ensure that the full benefit of the $5m fund is delivered to the community. There is quite a bit of history between the Panel, Ausgrid and the AER on whether individual capex programs, such as Ausgrid's innovation program, should be excluded from the CESS. The Panel acknowledges the similarity between the Social Licence Plan with oversight by the HCC LEC and the network innovation program with oversight by NIAC. In both cases consumers would expect Ausgrid to spend the full amount of these programs for the benefit of Ausgrid (and NSW distribution connected) customers rather than treating underspends as an efficiency. The Panel notes that the purpose of social licence expenditure is to help build community acceptance of projects by using clear strategies and programs to form good relationships, acknowledging these are built over time.

The Panel believes that the community (and likely EnergyCo) would have a reasonable expectation that:

- all the approved revenue would be invested for the benefit of the local community
- were efficiencies found by Ausgrid in delivering the identified priorities then those savings would be reinvested in additional social value activities in the community.

We note that the AER did not exclude Transgrid's social licence expenditure from CESS in the Humelink stage 2 decision. The Panel makes no further comment on whether the AER should exclude any approved expenditure for social licence activities from the application of the CESS and leaves this to the AER.

5.4 Depreciation

Ausgrid's proposal for as commissioned depreciation involves a 3 staged approach based on the timing of the capacity being made available. In discussions with Ausgrid in early March we received assurances from Ausgrid that 'being made available' meant the percentage of MW generation able to connect at each milestone event. The following slide was presented by Ausgrid to the Panel on 6 March:

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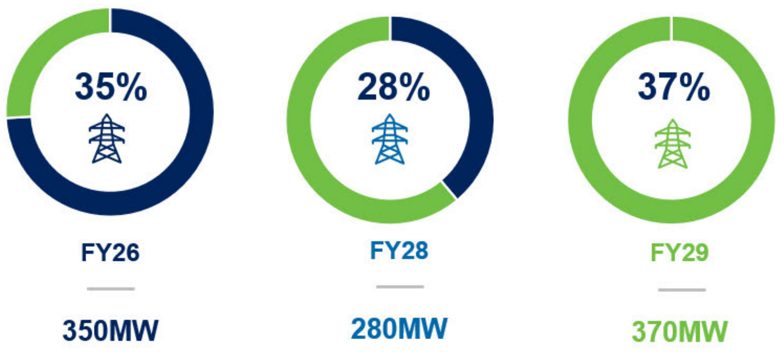
[59] https://www.aer.gov.au/industry/registers/determinations/waratah-super-battery-network-augmentation-and-sips-control-system/final-decision

[60] Ibid at Section 13 pp 33-34 and the AER's September 2023 Draft Decision

‘As commissioned’ expenditure



The Panel believes Ausgrid’s staged approach to depreciation appears to be reasonable for the HCC RNI Project as it reflects the staged nature of this Project.

5.5 Treatment of decommissioned assets

Following the Panel’s site visit in early March it became apparent that the HCC RNI Project involves the early replacement of functioning assets that had not yet been fully depreciated. Of particular focus to the Panel were the many green concrete poles and in particular the relatively new line close to Newcastle. We understand that some of these assets were gifted to Ausgrid. In March the Panel raised the following questions with Ausgrid about the impact of scrapping the existing line on the RAB. Ausgrid’s responses were provided in the risk workshop on 27 March:

1. Will the existing line assets be fully depreciated and out of the RAB by the time of commissioning HCC REZ?

   <u>Ausgrid response</u>: No. The RAB value of the assets being decommissioned is approximately $11m. We estimate that the existing assets will have a weighted average RAB remaining life of 34 years by the time of commissioning of HCC REZ.

2. If not, will there be accelerated depreciation of the existing line assets in 2024-29 to ensure it does have zero RAB value when the HCC REZ is commissioned?

   <u>Ausgrid Response</u>: We do not propose to accelerate the depreciation of the existing assets to a zero RAB value by the time of commissioning HCC REZ. Ausgrid proposes that the value of the assets remains on its NER RAB and continues to be depreciated over their remaining life.

3. If yes, then how much is this and why should Ausgrid consumers pay for this when the benefit of dismantling the existing line is for the Roadmap and hence all NSW customers should pay the accelerated depreciation?

   <u>Ausgrid Response</u>: The potential bill impact of the decommissioned assets remaining on the NER RAB is negligible:

   - *around 16c/year per residential customer (out of an annual bill of around $789 for a typical residential customer on a flat tariff)*

- *around 30c/year for a small business customer (out of an annual bill of around $1,560 for a typical small business customer on a flat tariff)*
- *These amounts will diminish over time.*

In Section 6.7 of the Revenue Proposal Ausgrid states that it intends to leave the $6.9m (nominal) for decommissioned assets with a weighted average RAB remaining life of 34 years in the NER RAB and will continue depreciating this over the remaining life of those assets. Ausgrid advise that the impact is negligible - ~$0.20/yr for a residential customer and $0.50/yr for a small business customer. We understand that given the Commitment Deed and the draft Project Deed have been fully negotiated by Ausgrid and EnergyCo there is no easy mechanism to vary this by adding the $6.9m to the negotiated $590.8m HCC RNI Project cost.

Our view is that as a matter of principle that these remaining costs should be recovered from all NSW electricity consumers under the Roadmap costs. As part of negotiations for all future brownfields projects, the Panel recommends that network(s) and EnergyCo agree that the remaining value of any decommissioned assets in the NER RAB are transferred to the Roadmap project and recovered via Roadmap charges. We encourage the AER to provide its views on this as part of its determination. The Panel believes it is important for NSW customers to have transparency of the full costs of Roadmap projects. We strongly support the extension of Roadmap costs to transmission connected customers and we look forward to the NSW Government adopting recommendation 15 of the O'Reilly review.

5.6 Opex

Ausgrid's approach

Opex forecasts apply Ausgrid's approved cost allocation model to allocate costs between 'EII Act services and 'other services' subject to regulation under the NER. A bottom up approach has been used to determine opex components – vegetation management, maintenance, operations, regulatory costs and overheads. It totals $($25-6)15.6m over the 5 years.

Panel comments

Ausgrid had to do a bottom up build because there is no base year costs to build on. We leave the AER to assess prudency, efficiency and reasonableness.

Appendix A

Notes for discussion with AER and Ausgrid – 11th February 2025 Interpreting 'prudent, efficient and reasonable' costs for EII projects

Introduction and focussing question

The question we have as the Hunter CC REZ Regulatory Panel is:

> *How will NSW consumers get confidence the final capital cost and allocation of risk of Hunter CC REZ between Ausgrid and NSW electricity consumers will be 'prudent, efficient and reasonable' as required by the EII Act?*

We are familiar with 'prudent' and 'efficient' but not 'reasonable'. We have been unable to find any Government explanation for including 'reasonable' in the Electricity Infrastructure Investment Act's 2020 (EII Act) Transmission Efficiency Test (TET). We assume it was included because it was meant to have impact in addition to 'prudent and efficient.

One explanation could be that its inclusion was to give EnergyCo, the Consumer Trustee, networks and the AER some flexibility to enable projects to be developed quickly to meet the EII Act's renewable energy and emission targets. Certainly the need to build generation as fast as possible to replace aging coal plant was a key driver of the legislation Our impression is that the inclusion of 'reasonable' may soften the prudent and efficient requirements. There is a perception that the more accurate the capex cost estimate the longer planning takes and this will delay consumers getting the Roadmap benefits. This 'fast build' objective is seen in the fast-track timetable the AER has to evaluate HCC REZ compared with Ausgrid's 2024-29 regulatory proposal.

However, this argument about cost accuracy and project timetable was rolled out for Project Energy Connect (PEC) and it has not served consumers well. PEC's initial cost was estimated at $1.53b ($2020) with completion by 2022-24. An attempt by consumer advocates to ensure the AER required a more accurate cost estimate of ISP projects was rejected by the AEMC. Project delay was given as a major reason for the rejection. Yet in the absence of this greater accuracy, the PEC cost is now estimated at $4.1b ($2023) with completion by September 2026.

Given this experience we believe that, irrespective of the reason for inclusion of 'reasonable' in the legislation, NSW consumers need a clear understanding of how the application of 'reasonable' will impact on the accuracy of the capex estimate and the associated risk allocation between network and consumers that Ausgrid will submit in May. We think consumers want confidence that Ausgrid's principle of 'risk should be allocated to the party best able to control it' is followed.

This is even more important given the 'fast track' AER approvals process and the opportunity for Ausgrid to include revenue adjustment mechanisms in its proposal. This transparency around capex accuracy and risk allocation will give NSW consumers proper protection against network cost and timetable overruns that should be best borne by the network.

What do the EII Act, AER Guidelines and previous AER and AEMO decisions say about 'reasonable'?

The term 'reasonable' capital costs was introduced by the EII Act in 2020. The EII Act sets out the TET referring to 'prudent, efficient and reasonable capital costs' but does not define 'reasonable' nor does the EII Regulation, explanatory memorandum nor the second reading speeches.

Attachment 1 has extracts from the EII Act and Regulations that refer to reasonable capital costs. We are concerned that the principles that the AER must consider when calculating the prudent, efficient and reasonable costs focus on cost recovery by the network and revenue commensurate with the regulatory and commercial risks but has no mention of consumer impact. Whilst there is a principle that refers to the role of incentives in promoting efficiency there is little to reassure consumers that risk allocation of the regulatory and commercial risks in a quick build project will be allocated to the party best able to manage that risk as a guiding principle.

In the AER Roadmap Guideline, the AER's role is described as:

> *"We apply the Transmission Efficiency Test to calculate the prudent, efficient and reasonable capital costs for development and construction of a network infrastructure project (Transmission Efficiency Test guideline)" (p.5)*

and

> *"We do this by assessing the prudency, efficiency and reasonableness of the Network Operator's proposed costs in relation to authorized or directed network infrastructure project" (p.8).*

In Section 5.2.3 the AER discusses how it will apply the TET. It provides the definitions of prudent (reflects the best course of action, considering available alternatives) and efficient (results in the lowest cost to consumers over the long term) in the Expenditure Assessment Guideline. In assessing whether the costs are reasonable (p.25) the AER states:

- "In assessing whether the capital costs are reasonable, we will assess whether the costs, and the calculation of those costs, are based on reason or reasonably open based on the facts before us.
- "Accordingly, in calculating prudent, efficient and reasonable capital costs, we will calculate costs that are prudent and efficient as per our current Expenditure Assessment Guideline, whilst ensuring that the calculations are reasonably open based on the facts before us."

To help us understand how the AER's approach to 'reasonable' might be applied in the Hunter CC REZ case, we also looked at the growing use of 'reasonable' by the AER and AEMO in their work on capex cost estimation. This is discussed in Attachment 2. As a result of this review in Attachments 1 and 2 we propose the following issues for discussion.

Proposed issues for discussion

As a start, we would find it very helpful if the AER were to provide examples of:

- what you think is 'reasonable' capital cost accuracy and risk allocation
- what you think is 'unreasonable' capital cost accuracy and risk allocation.

For example, when the Guideline quoted above says:

> *"In assessing whether the capital costs are reasonable, we will assess whether the costs, and the calculation of those costs, are based on reason or reasonably open based on the facts before us."*

How will the 'facts' of the massive increase in major project capex and risk borne by consumers with Project Energy Connect (PEC) compared with what the AER has previously approved as 'prudent and efficient' influence your approach to Ausgrid's the Hunter REZ capex estimate? We think the PEC experience, which is also being seen in many other large network projects eg HumeLink, Copperstring and VNI West, should have a significant influence on the accuracy of the capex estimate that Ausgrid submits and the risk allocation associated with that capex estimate.

With this in mind, we would propose the following for discussion:

- In its May 2025 submission to the AER that Ausgrid provides a capex estimate in a specific AACE cost class (no less than Class 2 which is a range of - 15% to + 20%); we do not think this is an onerous obligation on Ausgrid given the work they have done so far with up to 70% of forecast costs to be externally delivered with costings based on a competitive tender process
- What costs this is meant to include eg contingency?
- A process for the AER to assess the accuracy of Ausgrid's claim to have submitted a particular AACE Class estimate
- Clear allocation of cost overrun risk between consumers and Ausgrid
- Clear guidance on how the AER will assess subsequent Determined Service Payments adjustment events

With the aim of providing NSW consumers with a very clear understanding of what risks they are taking and what risks Ausgrid shareholders are taking. We look forward to discussing these matters with the AER and Ausgrid.

Attachment 1 - EII Act and Regulation

‘Reasonable (capital) costs’ is referred to in sections 31, 37 and 38 of the EII Act (emphasis added).

“Section 31 Consideration of recommendations by infrastructure planner

> *…*
>
> *Section 31(2) If the consumer trustee authorises a network operator under subsection (1)(b), the consumer trustee must, by written notice to the regulator, set a 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).”*

“Section 37 Regulator to take into account principles

> *Section 37 (1) In exercising functions under this Division, the regulator is to take into account the following principles—*
>
> *(a) a network operator is entitled to recover the prudent, efficient and reasonable costs incurred by the network operator for carrying out the infrastructure project,*
>
> *(b) incentives should be given to network operators to promote economic efficiency,*
>
> *(c) a network operator is entitled to revenue for the ongoing ownership, control and operation of an infrastructure project that is commensurate with the regulatory and commercial risks to the network operator,*
>
> *(d) a network operator is entitled to be informed of material issues being considered by the regulator under this Division,*
>
> *(e) other principles prescribed by the regulations.”**

“Section 38 Regulator to determine amount payable to or by network operators for network infrastructure

projects

> *…*
>
> *“Section 38(4) Before making a determination, the regulator is to calculate the prudent, efficient and* ***reasonable capital costs*** *for development and construction of the network infrastructure project, which is referred to as the transmission efficiency test.*
>
> *(5) The regulator is to publish guidelines on its website about the transmission efficiency test.*
>
> *(6) The amount determined by the regulator under subsection (4) for a network operator authorised by the consumer trustee to carry out a REZ network infrastructure project must not exceed the maximum amount, if any, notified to the regulator by the consumer trustee under section 31(2) for*
>
> *the network operator.”*

*Regulation 46 of the EII Regulation 2021 prescribes the following additional principles for the AER for the purposes of section 37(1)(e) of the EII Act:

*“**46 Principles for regulator—the Act, s 37(1)(e)***

(1) The following principles are prescribed—

(a) a genuine and appropriate competitive assessment process—

(i) results in the costs of carrying out an infrastructure project being prudent, efficient and reasonable, and

(ii) provides incentives to promote economic efficiency, and

(iii) results in revenue for the ongoing ownership, control and operation of the infrastructure project being commensurate with the regulatory and commercial risks,

(b) a network operator is entitled to recover the following—

(i) prudent, efficient and reasonable costs incurred by the network operator in complying with a regulatory requirement,

(ii) payments required to be made by the network operator to the infrastructure planner under a contractual arrangement, if the network operator was required to enter the contractual arrangement under the relevant authorisation,

(iii) reasonable costs incurred by the network operator, as assessed by the regulator, if the regulator fails to make a revenue determination within the time period specified in clause 50,

(c) an appropriate referenced costs process—

(i) results in the costs of carrying out an infrastructure project being prudent, efficient and reasonable, and

(ii) provides incentives to promote economic efficiency, and

(iii) results in revenue for the ongoing ownership, control and operation of the infrastructure project being commensurate with the regulatory and commercial risks.

(2) The regulator must, when assessing reasonable costs for the purposes of subclause (1)(b)(iii), take into account whether the network operator contributed to the delay.”

Attachment 2 – How the AER has considered 'reasonable' in other Guidelines

Expenditure Assessment Guideline

The latest version published in October 2024 has a few references to 'reasonable' relating to data sources, assumptions and methodologies, but none specifically relating to capex estimation.

The AER CBA Guideline

The latest version published in November 2024, has 'reasonable' 32 times. Some examples:

- The CBA guidelines set out requirements, considerations and discretionary elements for developing economically reasonable inputs and assumptions (section 3.2.1), and scenarios (section 3.2.2) (p.10)
- Using professional judgement… to select an optimal development path that has a positive net economic benefit in the most likely scenario—and explaining:
    - Why the level of risk neutrality or risk aversion chosen is a reasonable reflection of consumers' level of risk neutrality or risk aversion (p.32)
- There may be material uncertainty regarding the costs of a credible option when the RIT-T proponent undertakes the RIT-T assessment. If there is a material degree of uncertainty in the costs of a credible option, the RIT-T instrument states that the RIT-T proponent must calculate the expected cost of the option under a range of different reasonable cost assumptions (p.68)

How the AER has approached capex approvals and risk allocation for major network projects in recent years

Here we discuss the AER's developing approach to what costs it includes in capex approvals and how it has expanded its use of 'reasonable' to describe a capex estimate, even though 'reasonable' is not in the rules covering ISP projects. We cover two categories of projects:

- those assessed under the national rules – PEC and HumeLink and the AER CBA Guideline; and
- the Waratah Super Battery (WSB) , the first and only project assessed under the EII Act and AER Roadmap Guidelines.

Project Energy Connect (PEC)

In its initial assessment published in January 2020 that reviewed the project under the now deleted Rule 5.16.6, there are many references to the 'reasonableness of inputs and assumptions' but Appendix A6 made no mention of 'reasonable' in the capex estimate, which was $1.53b ($2020) ($1.1b in NSW and $0.38b in SA).

In its next assessment for the contingent project application the AER press release (31st May 2021) said:

> "We have undertaken a thorough assessment of the proposed costs, including input from technical experts and public consultation, and our decision is that the total cost for Project EnergyConnect is $2.28 billion, a 4 per cent reduction from the $2.36 billion initially proposed by TransGrid and ElectraNet."

The AER's decision on the Transgrid part of PEC – their application proposed $1.866m and the AER approved $1.818m:

> "which was informed by latest available information on likely costs".

The AER go on to say:

> "However, we have not included additional allowances for project risk costs as proposed by TransGrid, as we consider that our forecast of capex provides for TransGrid's prudent and efficient project costs and TransGrid is best placed to mitigate the likelihood of additional costs being incurred in the delivery of the project. We also recognise that TransGrid proposes to enter into fixed price contracts to deliver the majority of the works required for the project. This approach in large part protects both TransGrid and consumers from the risk of project cost overruns."

This is very similar to what Ausgrid are now saying about the HunterCC contractual arrangements.

However, the PEC fixed price contracts did not provide any protection for consumers. Elecnor gave Transgrid a choice – negotiate a new contract or we walk away. Transgrid decided to sign a new fixed price contract with the result that the price for PEC is now $4.1b. Transgrid decided not to pursue its contractual rights in the Spanish Courts because that would delay the project i.e. Transgrid's shareholders were not willing to fund the project themselves. Transgrid are now expected to make another application to the AER for a revised approved capex and we await the AER's decision on how much of Transgrid's failed contract management is going to be borne by consumers.

Humelink

In August 2022, the AER approved Transgrid's CPA 1 part 1 application for $322m ($17-18). We make two points here:

(i) The use of 'reasonable' as an additional descriptor of 'prudent and efficient' (p.vi):

On our brief search this is the first time we could find the AER using 'reasonable' explicitly in reference to capex costs. There is no explanation of what 'reasonable' means.

> "We have examined Transgrid's proposed capex forecast and our view is that the amount proposed is **reasonable**, prudent and efficient to deliver early works for HumeLink, in the context of the benefits to consumers as outlined above. In particular, we consider that:
>
> - Transgrid's proposed scope of works are **reasonable** as a whole and adopt a prudent approach to meeting the objectives of early works for HumeLink. Importantly, this accounts for the objective to deliver the project to the target project delivery date of 2026-27 as set out in AEMO's 2022 ISP."

Perhaps it was simply the AER reflecting the conclusion of its consultant when it says (p.12):

- … EMCa found that Transgrid's cost methodology is reasonable and likely to result in a reasonable estimate for forecast capex."

Then at p.13:

> "Overall, we consider Transgrid's proposed approach is reasonable to reduce cost uncertainty and project risks, while ensuring it meets its objective of deliverability by 2026."

When we go to EMCa's report we find the word 'reasonable' is used 49 times. It seems to be applied to two project stages:

1. The cost estimate at the time of the CPA was an AACE Class 4 estimate and that is a 'reasonable' level of accuracy at that stage of the project development process (p.20):

Transgrid's current total HumeLink project cost estimate is of a preliminary nature

126. Transgrid describes its cost estimate accuracy for HumeLink as Class 4, in accordance with the AACE International Recommended Practice and Estimate Classification, being that it is preliminary in nature for the purpose of a study or feasibility. This means that the project scope definition (or maturity) is low, being 1% to 15% of full project definition. The cost estimation accuracy for a Class 4 estimate can vary within a wide range, typically in the order of +/-30% (and up to +50%).

127. Transgrid states that its assessment of the risks in the Stage 1 CPA '*[have] been considered for each activity and associated cost using a qualitative approach to determining the mid-point (i.e. P50) estimate of the forecast costs.*'[25]

128. Based on our understanding of the available information, and prior to engagement with the market for the largest component of the forecast capex, the cost estimate remains preliminary and we consider that Transgrid's characterisation of the current cost estimate range as 'Class 4' is reasonable.

2. What level of cost accuracy should be achieved at the end of Stage 2 after Transgrid have spent the $$ they have applied for in this Stage 1 CPA? (p.21):

Transgrid's targeted accuracy range for the total project cost estimate at the conclusion of Stage 1 appears reasonable

135. Cost estimation accuracy improves as the level of the project definition is increased. There is a trade-off between the requirement to invest in time and resources up front (and associated level of commitment to the market) and the expectation of a reduction to the expected range of outcomes and an associated improvement in cost estimation accuracy.

136. We expect that for an infrastructure project of this scale, a cost estimate approaching Class 2 following early works (and therefore at FID) would be a reasonable expectation for consumers. In some areas, such as for final compensation for land or environmental offset costs, there may be aspects of the cost that cannot be accurately determined until closer to the time. In broad terms, this means that at FID, the cost estimate should improve to a range approximating +/- 10%.

137. Given the current wide cost range, and significant negative impact that a cost towards the upper end of the current range would have to the net benefit of the project, we were surprised to find only limited recognition of this range in Transgrid's CPA and no explicit targets for improvement to the cost estimate range as outcomes from Stage 1.

EMCa then go on to note that questions from the EUAA (you can read more in the EUAA's submission on the CPA application) led Transgrid to provide a detailed breakdown of the level of cost accuracy in each major cost class which EMCa provides on pp 21-22. EMCa go on to say (p.22):

> 139. In response to questions from the EUAA, Transgrid advised that it is seeking to achieve Class 2 in most cases, particularly for those capex components that are subject to a market-tested procurement process. We consider that this is reasonable.
>
> 140. We consider that the Stage 1 (Early Works) activities that Transgrid has planned should facilitate identification and management of cost and delivery risks.

While this says what Transgrid 'is intending to achieve' rather than 'committing to provide', EMCa concluded that it was a sufficient basis for them to say the Transgrid proposal was '**reasonable**'.

A clarification note here: According to the AACE cost classification, the expected accuracy range is -15% to

(ii) The AER did not require Transgrid to use the early works funding to produce a specific Class cost estimate

While the AER was able to draw on the EMCa report to conclude (p.13):

> *"Overall, we consider Transgrid's proposed approach is reasonable to reduce cost uncertainty and project risks, while ensuring it meets its objective of deliverability by 2026."*

they did not place any requirement on Transgrid to use the approved early works funding to produce a cost estimate in accordance with their promises of 'Class 2 in most cases'.

So we are left with a lot of uncertainty about how the AER defines 'reasonable'.

The AER used 'reasonable' in a similar way in its decision on Early Works Stage 1 part 2 eg see pp. vi and 8.

Waratah Super Battery

Given this decision was applying the EII Act, we thought it might have more information on the AER's definition of reasonable. However, it seems that the AER has simply accepted Transgrid's definition.

Transgrid's definition of 'reasonable' in its submission to the AER was a ± 20% cost estimate because that is what it asked GHD to opine on (p.65):

5.12. Independent external validation

We engaged GHD to undertake an independent engineering verification and assessment of our capex forecast. GHD's assessment:

- verified that the scope of the Project is appropriate to meet the requirements in the Ministerial Order
- considered the reasonableness of the Basis of Preparation (BOP) detailed in the capital forecasting methodology
- assessed the accuracy and supportability of the resulting capital forecast using a range of assurance techniques. These included validation against tender results, benchmarking against comparative projects, selection testing recalculation and alignment with industry practice
- considers our capex forecast is reasonable if it is within ± 20 per cent the level of accuracy expected at this project stage taking into account the BOP and considering level of support held / developed for each capital forecast component.

GHD describes its scope as (p.1):

> "Under the TET the AER will consider all information and matters set out in EII Chapter 6A, Schedule 6A.1. GHD's scope of works is limited to independent verification and assessment of whether the:
>
> - Scope of the project is appropriate to meet the requirements in the Ministerial Order
> - BOP detailed in the capital forecasting methodology is reasonable
> - Capital forecast is within ± 20 per cent the level of accuracy expected at this project stage considering the BOP and the level of support held / developed for each capital forecast component. With the accuracy and supportability of the resulting capital forecast assessed using a range of assurance techniques. These included validation against tender results, benchmarking against comparative projects, selection testing, recalculation and alignment with industry practice
> - Capital costs for development and construction for the network infrastructure project are prudent, efficient and reasonable
> - Proposed staging of development and construction capex complies with the terms of the Consumer Trustee's or Minister's authorisation or direction"

Transgrid provides no justification for how it selected ± 20% apart from its statement that this level of accuracy is the level 'expected at this project stage". Transgrid makes no reference to its 'intention to provide' a Class 2 expressed to the EUAA and the EMCa for HumeLink as being appropriate at HumeLink's 'project stage' which seems to be very similar to the WSB submission to the AER.

Transgrid uses circular logic to justify its submission (p.66):

> "Overall, GHD concluded that our forecast capex for the Project is likely to sit within ± 20 per cent which is considered to be reasonable at this stage of the project development and that our development and construction capex is prudent, efficient and reasonable. GHD's independent review therefore supports the consistency of our forecast capex with that which would be incurred by a prudent, efficient and reasonable business."

Transgrid sets the standard that GHD has to use. We do not see this as an 'independent' report as represented by Transgrid.

Unlike what happened with the Humelink early works proposal, the AER did not commission an independent report on the proposed capex either at the Draft or Final Decision stage, perhaps because of the short timetable under the EII Act. The AER approved the Transgrid proposal in full, concluding (p.2):

> "This represents what we consider to be the prudent, efficient, and reasonable costs of delivering the WSB project, ensuring consumers pay no more than necessary for safe and reliable electricity."

The AER's final decision made no reference to the GHD report.

AEMO ISP uses 'reasonable' when referring to project capex and provides data to support its interpretation

AEMO refers to 'reasonable' in its Transmission Cost Database developed to estimate network costs and published as part of it Transmission Expansion Options Report. Section 2.3 (pp. 28- 30):

> *"…AEMO's approach to reviewing cost estimates provided by TNSPs such that they are complete and consistent, and to validate that AEMO's transmission cost estimation process is reasonable."*

AEMO concluded that AACE Class 5 estimates (it used two categories) were 'reasonable'.

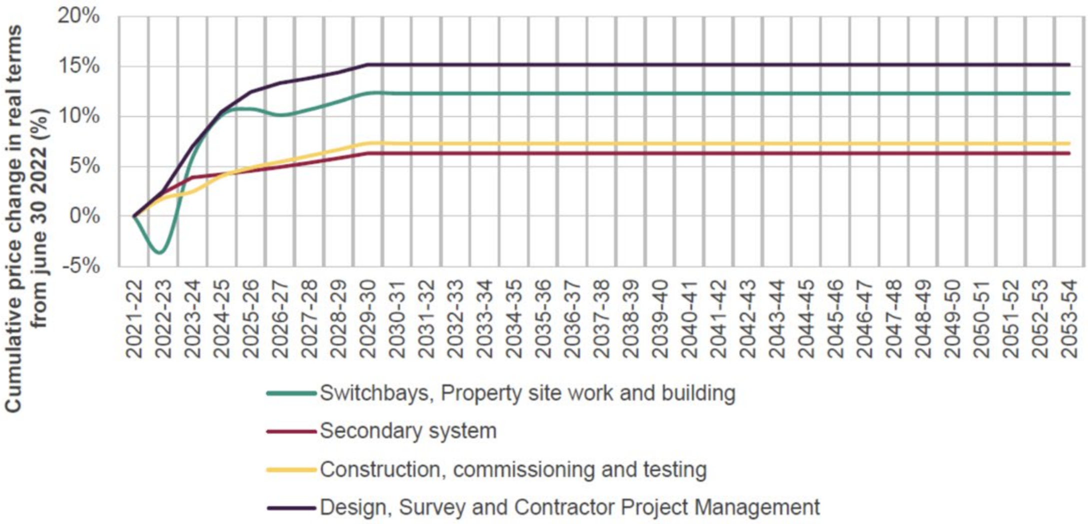
Table 7 Class 5 estimate sub-categories

Class	Definition	Unknown risk allowance[A]	Accuracy[B]
Class 5b	Concept level scoping with no site-specific review or TNSP input	Up to 30%	±50%
Class 5a	Screening level scoping including high level site-specific review and TNSP input	Up to 15%	±30%

A. Unknown risk allowance defined as a percentage of the total network element cost (which does not include indirect costs).
B. Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

The following Figure (p.38) is an example of AEMO's interpretation of 'reasonable' for various network cost categories:

Figure 12 Forecast cumulative cost changes for transmission project cost components: construction, services and secondary (electrical) systems, in real terms



This shows that AEMO consider a cumulative real price change from 2021-11 to 2029-30 of:

- ~6-7% for 'construction, commissioning and testing' and 'secondary system', and
- ~12-15% for 'switchbays, property site work and building' and 'design, survey and contractor project management'

were 'reasonable'. AEMO concludes that (p.37):

> *"AEMO considers that this forecasting approach reflects reasonable consideration of a heightened level of demand for transmission project resources, noting that costs have already been elevated substantially by recent global price shocks and that these impacts are reflected in the updated Transmission Cost Database. AEMO acknowledges that the ultimate 'new normal' for transmission infrastructure is not yet known and will be highly dependent on international global headwinds, local and international policy, and market changes."*

At first glance that seems well below the PEC contracting experience. Perhaps a source of the difference is that AEMO is referring to Class 5 estimates while the latest Transgrid PEC estimate of $4.1b ($3.6b is Transgrid's portion of PEC) is likely to be a Class 2.

Appendix B

Questions from the Ausgrid HCC REZ Reg Panel (the Panel) to EnergyCo for discussion on Thursday 6 March 2025

Background

Ausgrid established the Panel in December 2024. Our remit is to provide customer views about the allocation of risk between Ausgrid and customers in the context of the HCC REZ (the Project) and to provide written reports to the AER as part of its revenue approval process.

We look forward to meeting with representatives of EnergyCo on 6 March 2025. The purpose of this note is to set out some of the issues we are keen to discuss with EnergyCo.

Project costs, benefits and development timetable

(i) Project costs and development timetable

We were unable to attend the 2025 IIO report briefing last week and have not been able to locate the 2025 report on the AEMO Services IIO website

1. The 2023 IIO Report (Table 4, p.46) says the optimal timing for the Project under the development pathway is 2026-27; is this still the case in the 2025 report and if not, what is the reason for the change?
2. Is the Project on track to meet the 2025 IIO timetable?
3. Could you please explain how network costs are estimated in the IIO modelling (2023 IIO Report p.51):

Scheme (Transmission) costs	**EII Act network infrastructure** – The annualised capital costs (reported for 20 years only) of new 'REZ network infrastructure projects' or 'priority transmission infrastructure projects' (as defined under the EII Act) that are funded by the Scheme Financial Vehicle. The capital costs are annualised over their economic lifetime[73] using a 3.04%[74] rate of return, noting that the Development Pathway only reports on a 20-year period. This simplified approach utilises class 5b estimates on capital costs of transmission projects provided by EnergyCo, and makes theoretical simplified assumptions on how these are recovered by customers over time. It excludes construction finance and considerations of depreciation.	Via distribution network service providers under the EII Act contribution determination process[75]

(ii) Project benefits

The 2023 IIO report said (p.53) said:

> *"The NSW Government is undertaking modelling to provide an update on customer benefits of the infrastructure that is planned to be enabled by the Roadmap. This modelling is undertaken as a separate exercise to the modelling for this report but uses a comparable set of input assumptions.*

1. Where have the results of this modelling been published?
2. How have the benefits for HCC REZ been separated out from the overall Roadmap benefits?

Maximum Capital Cost (MCC)

1. How does AEMO Services calculate the MCC for the HCC REZ?
2. Does the MCC calculation include consideration of costs as well as benefits from the Project?
3. What level of accuracy does AEMO Services aim for in any costs build up? Is it the same Class 5b in the IIO report and how do you define Class 5b – the same as AEMO in the ISP Transmission Cost Database ie ±50%?
4. Is there any level of costs at which EnergyCo has concluded that the Project should not proceed?
5. How are the Project benefits calculated for the MCC?
   - What are your key assumptions that influence benefit measurement (e.g. closure of Eraring; delay in delivery of the Project; delay in generation connection)
   - What sensitivity testing have you done on those key assumptions?
   - Can you provide us with a profile over time of the expected benefits and the basis of that profile?
6. What level of confidence can consumers give to AEMO Services/EnergyCo's estimate of benefits forecast?
7. The AER has confirmed that the:
   - MCC applies only to the AER's initial revenue determination but does not apply to subsequent revenue determinations or to revenue adjustments; and
   - EII Act sections 38(6A) and 40(3) were introduced by NSW specifically to ensure it operated this way.

Does EnergyCo believe that if the final AER approved cost plus adjustment events exceeds the MCC that this is in long-term financial interests of NSW electricity consumers? If yes, why?

Infrastructure Planner Fee (IP Fee)

1. How does EnergyCo calculate the IP Fee?

2. What costs does the IP Fee cover?

3. How do customers benefit from the IP Fee?

Implications for Roadmap Costs

1. What is the timetable for all HCC REZ costs being included in the AER annual determination of Roadmap charges to be recovered from distribution customers?
2. Are there any costs associated with HCC REZ that are being paid for by consumers in 2024-25? In 2025-26?
3. What is the forecast category and profile of HCC REZ costs to be paid for under Roadmap charges from 2025-26? eg if the capex is say [redacted], how will return of capital (depreciation) be recovered under the roadmap – straight line over x years?

3 March 2025

Appendix C

Questions from the Ausgrid HCC REZ Reg Panel (the Panel) to AEMO Services Limited (AEMO Services) for discussion on Tuesday 18 March 2025

Background

Ausgrid established the Panel in December 2024. Our remit is to provide customer views about the allocation of risk between Ausgrid and NSW electricity customers in the context of the HCC REZ (the Project) and to provide written reports to the AER as part of its revenue approval process.

We look forward to meeting with representatives of AEMO Services on 18 March 2025. The purpose of this note is to set out some of the issues we are keen to discuss with AEMO Services. The Panel has found the EII arrangements complex and whilst some of our questions may appear repetitious, it stems from our desire to gain as much clarity as possible on the whole process. The Panel previously met with representatives of EnergyCo on 6 March 2025 to discuss the Infrastructure Planner Fee and Roadmap costs more generally.

IIO Report - Project costs, benefits and development timetable

(i) IIO Report and development timetable

We understand that AEMO Services is currently preparing the 2025 IIO Report, which is due to be published in the 3rd qtr. 2025.

1. Is that publication date correct?
2. Will the AEMO Services authorisation process for HCC REZ be based on the 2025 IIO Report?
3. The 2023 IIO Report (Table 4, p.46) says the optimal timing for the Project under the development pathway is 2026-27. EnergyCo confirmed that this date has been revised in the Project's Commitment Deed to 2028. Can you confirm whether the 2025 IIO Report will include 2028 as the optimal timing for the Project?

(ii) Project costs

1. Could you please explain how network costs are estimated in the IIO modelling (2023 IIO Report p.51):

Scheme (Transmission) costs	**EII Act network infrastructure** – The annualised capital costs (reported for 20 years only) of new 'REZ network infrastructure projects' or 'priority transmission infrastructure projects' (as defined under the EII Act) that are funded by the Scheme Financial Vehicle. The capital costs are annualised over their economic lifetime[73] using a 3.04%[74] rate of return, noting that the Development Pathway only reports on a 20-year period. This simplified approach utilises class 5b estimates on capital costs of transmission projects provided by EnergyCo, and makes theoretical simplified assumptions on how these are recovered by customers over time. It excludes construction finance and considerations of depreciation.	Via distribution network service providers under the EII Act contribution determination process[75]

2. Will it be any different in the 2025 IIO Report? eg Class 5b estimates have an estimate that could increase by 50% (2024 ISP Appendix 6 p.113):

Table 73 Cost increases applied to relevant transmission augmentation in *Constrained Supply Chains* sensitivity

Class	Cost increase	Transmission projects
Class 3	12%	HumeLink
Class 4	30%	VNI West, Project Marinus Stage 1, Project Marinus Stage 2
Class 5	50%	QNI Connect Option 2
Class 5a	30%	Waddamana to Palmerston transfer capability upgrade
Class 5b	50%	Queensland SuperGrid North Option 1, Gladstone Grid Reinforcement, Queensland SuperGrid South Option 1, Queensland SuperGrid South Option 5, New England REZ Transmission Link 1, New England REZ Transmission Link 2, New England REZ Extension, Hunter-Central Coast REZ Network Infrastructure Project, Hunter Transmission Project, Sydney Ring South Option 2d, Mid North South Australia REZ Expansion

3. What capex will be included for HCC REZ in the 2025 IIO Report?

(iii) Project benefits

The 2023 IIO report said (p.53):

> "The NSW Government is undertaking modelling to provide an update on customer benefits of the infrastructure that is planned to be enabled by the Roadmap. This modelling is undertaken as a separate exercise to the modelling for this report but uses a comparable set of input assumptions."

1. Where have the results of this modelling been published?
2. How have the benefits for HCC REZ been separated out from the overall Roadmap benefits?

Network Authorisation Process

We have reviewed the most recent AEMO Services' Network Authorisation Process (AEMO Process) published in 2024.

(i) Infrastructure Planner Recommendation Report (IPRR)

EnergyCo informed us that they submitted the HCC REZ IPRR to AEMO Services in

December 2024. We are aware that this is a confidential recommendation to allow AEMO Services as the Consumer Trustee to undertake its network authorisation process.

1. Can you advise when the public version of the formal IPRR will be published? We

understand the public version of the CWO IPRR report was published some time

after the CWO was authorised.

(ii) Cost benefit analysis

1. How does AEMO Services interpret its obligation to be satisfied that the Project is in the long-term financial interests of NSW electricity consumers (LTFIC)?
2. For this Project will AEMO Services be giving primary consideration to CBA or the modelling in the IIO Report?

3. What level of cost accuracy does AEMO Services aim for in its costs modelling? Is it the same as in the IIO Report? What class cost accuracy does AEMO Services regard the $[redacted] HCC REZ nominal dollars?
4. We note that under Sec 19B(4) of the Electricity Infrastructure Investment regulation (2021) (EII Reg) that AEMO Services can still be satisfied that a project is in the LTFIC even where the quantitative measurements of the CBA are negative by having regard to both the 'quantitative' and 'qualitative' elements of the CBA.
5. What are examples of 'qualitative'' elements?
6. Has AEMO Services authorised Roadmap projects in the past relying on sec 19B(4)?
7. Are there any circumstances under which AEMO Services would not issue a network authorisation? If yes, what are they?
8. What level of transparency will AEMO Services give NSW customers about the CBA of the Project eg whether the project has negative benefits based on 'quantitative' elements and the authorisation requires consideration of 'qualitative' elements'
9. Is the ultimate level of actual capex on project completion irrelevant once the authorisation has been issued?
10. Does EnergyCo modelling for the HCC REZ IPRR have any relevance to AEMO
11. Services CBA?

Maximum Capital Cost (MCC)

1. How does AEMO Services interpret "reasonable" capital costs under section 31(2) of the EII Act when it sets the MCC for the HCC REZ?
2. How does AEMO Services calculate the level of development and construction costs for the MCC?
3. What level of accuracy does AEMO Services aim for in any costs build up? Is it the same Class 5b in the IIO report and the ISP ie ±50%?
4. Is there any level of costs at which AEMO Services will conclude that the Project
5. should not proceed?
6. Is there any limit on what the ultimate capex costs borne by NSW consumers under Roadmap costs could be under adjustment events approved by the AER?
7. How are the Project benefits calculated for the MCC?
8. What are your key assumptions that influence benefit measurement (e.g. closure of Eraring; delay in delivery of the Project; delay in generation connection)
9. What sensitivity testing have you done on those key assumptions?
10. Can you provide us with a profile over time of the expected benefits and the basis of that profile?
11. What level of confidence can consumers give to AEMO Services estimate of benefits forecast? Is it simply a 'point in time' estimate that will change over time? What sensitivity does AEMO Services undertake on benefits?
12. Is AEMO Services measure of the benefits any different from the measure of benefits referred to above in the 2023 IIO Report as being undertaken by the NSW Government?
13. It appears that the CBA is assessed over a 20-year time period (Is this correct?) with the use of terminal values for additional benefits beyond year 20. How are these terminal values calculated?
14. Does the notice of the MCC given to the AER under sec 31(2) of the EII include the detailed modelling and calculations referred to in section 3.4.2 of the AEMO
15. Process?
16. Do you expect the MCC to change if applying the 2025 IIO Report vs 2023 IIO
17. Report? If so, why? If not, then why not?
18. The AER has confirmed that the:

a. MCC applies only to the AER's initial revenue determination but does not apply to subsequent revenue determinations or to revenue adjustments; and
b. EII Act sections 38(6A) and 40(3) were introduced by NSW specifically to ensure it operated this way.

Does AEMO Services believe that if the final AER approved cost plus adjustment events exceeds the MCC for the Project that this is in the LTFIC? If yes, why?

13 March 2025

Appendix D

HCC REZ Reg Panel feedback to AEMO Services on the CWO REZ statement of reasons

Dear Melanie and Dominic

Thank you for meeting with us on 18 March. We found the discussion very helpful to understand the purpose and limits of the Consumer Trustee's role under the EII Framework.

Thank you also for inviting our feedback on the Central-West Orana (CWO) REZ statement of reasons published by AEMO Services (the Consumer Trustee) in June 2024.

We found the description of the roles of EnergyCo, the Consumer Trustee and their relationship (pp7-8) very helpful on determining what comments we could provide:

> *"When deciding whether or not to authorise, the Consumer Trustee is required to consider the Infrastructure Planner's recommendations and decide whether the recommended project should be authorised. In doing so, its approach is to undertake a CBA to determine if the project is in the long-term financial interests of customers against a counterfactual where the recommended project does not proceed and to determine whether a decision to authorise is consistent with the objects of the EII Act."*
>
> *Importantly, the Consumer Trustee's authorisation process and subsequent decision does not consider whether or not there may be an alternative option for the recommended RNIP that better delivers in the long-term financial interests of NSW electricity customers. It is the responsibility of EnergyCo, in exercising its statutory function as the Infrastructure Planner, to assess and make recommendations to the Consumer Trustee about REZ network infrastructure projects under section 30 of the EII Act and regulations made under the EII Act."*
>
> *…*
>
> *As explained in the NAPAP, the Consumer Trustee does not undertake its own stakeholder consultation when making an authorisation decision and relies on the consultation undertaken by the Infrastructure Planner. Further, the Consumer Trustee does not assess the fitness of the network operator to carry out the project. EnergyCo undertakes assessment of the network operator through its competitive tender processes and when recommending a network operator through a non-contestable process. The network operator's role and performance will be governed by contractual arrangements between EnergyCo and the network operator, and relevant regulatory requirements including National Electricity Rules registration requirements and the NSW transmission licencing regime."*
>
> *…*
>
> *Further, the Consumer Trustee's authorisation decision does not consider whether the capital costs of the recommended RNIPs are prudent, reasonable or efficient. Determining the prudent, reasonable and efficient costs that can be recovered by the network operator is the responsibility of the Regulator under section 38 of the EII Act. The AER has been appointed by the Minister as the Regulator for this purpose."*

Our overall conclusion from reading the statement of reasons is that given the requirements under the EII legislation, the Consumer Trustee's role is very constrained in both its scope and ability to provide details of its work. These constraints also apply to EnergyCo and the

AER. Consumers are required to trust that all entities having a role in Roadmap investments will implement the Parliament's intentions around the 'long term financial interests of NSW consumers'. Consumers might prefer a lot more transparency around how this objective is being interpreted by the Consumer Trustee (and EnergyCo) but confidentiality requirements prevent more detail being provided.

You simply do a CBA on the 'with' and 'without' options for the project proposed by EnergyCo and the Consumer Trustee accepts the EnergyCo capex estimate.

We are aware from our work on Ausgrid's customer committee that the NSW DNSPs are preparing a 'NSW Distribution ISP' to be released later this year. This will focus on the ability to use spare capacity in the distribution system to connect renewables quicker and cheaper than through the ISP or Roadmap. We are also aware of Ausgrid's claim that the size of the HCC REZ can be considerably expanded at relatively low cost.

It is unclear how NSW consumers will get confidence that the NE and SW REZs are better projects than utilising existing spare capacity in the NSW distribution network. From what we have read of the existing roles our initial view is that it would be up to EnergyCo as the Infrastructure Planner to determine this, but we are unclear about how it might also be accounted for in the Consumer Trustee's analysis of the 'counterfactual'.

We have two specific comments for the Consumer Trustee to consider as you approach an authorisation decision for HCC REZ which are also relevant for the corresponding reports on the NE and SW REZs.

1. Provide more detail on the counterfactual case

This report seeks to explain the base case but even that explanation is confusing. On p.15 it says the document includes the two recommended CWO REZ network Infrastructure projects, whereas on p.4 the statement expressly states that it is confined to the main project only. We don't know what projects are in the counterfactual apart from it not involving construction of the base case project. What is included in the counterfactual and how does the Consumer Trustee get the necessary detail on costs and benefits to do the comparison with the base case?

There is some oblique information on the counterfactual on p.16:

> *"The CBA results demonstrate that NSW electricity customers are likely to be worse off if the Main CWO REZ Network Infrastructure Project does not proceed. This is particularly the case if the future follows an accelerated change trajectory (consistent with the Powering Australia scenario) or the other network projects that the counterfactual relies on are delayed (consistent with the Delayed Transmission scenario)."*

We suggest that the Consumer Trustee provides greater information about the counterfactual. It is also unclear to us what the 'accelerated change trajectory' is. We recommend that the Consumer Trustee explain this and the assumptions underpinning this scenario is more detail. We do not think that the following explanation on p 16 is sufficiently clear:

> *"Assumptions more in line with the 2024 ISP, with higher demand values compared to the 2022 ISP and a national target for 82% renewable electricity by 2030."*

For example, given the NSW DNSPs 'NSW ISP' is expected to show the large spare capacity that is available in the existing grid, how do consumers get confidence in future decisions on the NE and SW REZs that they are indeed the best projects in the long-term financial interests of NSW customers compared with utilising existing DNSP capacity? Hopefully future 'counterfactuals' will include greater utilisation of this spare capacity.

2. Explain how the change in the legislation last year around MCC impacts on Consumer Trustee modelling

The statement of reasons says (p.14):

> "*The maximum capital cost is an important protection for customers against the risk that the construction and development capital costs of the project increase compared with the costs set out in the Infrastructure Planner's recommendations and result in the RNIP no longer having a net financial benefit to NSW electricity customers. The requirement for the maximum capital cost to remain confidential to the Consumer Trustee and the Regulator supports the effectiveness of this protection*."

The summary (p.5) pointed to three risks – increased costs passed through to consumers, access fees recovered from generators do not cover the full costs of 'hub to project' assets or system strength assets and delayed benefits to consumers from project delays. The Consumer Trustee concluded that (p.5):

> *"… in the view of the Consumer Trustee, the mitigants identified by the Infrastructure Planner are sufficient so that these risks are not material enough to undermine the overall net benefit of the project or justify a decision to not authorise."*

As we discussed in our meeting, the EII legislation has now been amended to allow the total capex (after post determination revenue adjustments approved by the AER) to exceed the MCC. The Consumer Trustee should explain how that risk is going to be incorporated into future modelling.

The discussion on pp 16-17 is relevant here. It discusses the 'qualitative risk assessment' and refers to an increase in costs to customers above the costs used in the CBA modelling. And then concludes that the Consumer Trustee's risk assessment rated these risks (not just the cost ones but also benefits and timing) as low or medium because:

- the inclusion of a contingency for expected cost increases in the CBA;
- the relatively large net benefits identified in the CBA, which means that even a reasonably large increase in the project's costs is not expected to have a material impact on whether the project will deliver net benefits for customers;
- the applicable mitigation measures, which are discussed below; and
- many of the identified risks would also apply in the counterfactual so do not materially affect the net benefits of the project."

Now that the MCC is no longer the maximum cost, how will the Consumer Trustee give consumers confidence that a project, where the costs may exceed the MCC over the life of the project, is still a net benefit project?

Kind regards

Mark Grenning, Louise Benjamin and Mike Swanston

31 March 2025

Appendix E

HCC REZ REG Panel feedback topics for discussion on 14 April on Ausgrid's draft revenue proposal for the delivery of the Hunter-Central Coast Renewable Energy Zone Network Infrastructure Project (HCC RNI Project)

Areas for greater transparency

- P.8 - Depiction of 330kV double circuit structures
- P.13 - the description of the MCC in the AER part of Table 1-1 is misleading; AER decisions on adjustment events can result in the actual cost exceeding the MCC
- P.9 and p.35 - Ausgrid's portion of the Infrastructure Planner Fee
- P.17 – reference to EnergyCo' s Public IPRR – when will that be available? Prior to the AER's decision on this proposal?
- P.24 – when does Ausgrid think it will get EnergyCo' s feedback on the revenue proposal? Will that feedback be available to the Panel?
- P.33 – how is the $77m early works funding spread across the cost lines in Table 5-1?
- P.58 – how was the 25-year standard life for the Infrastructure Planner Fee selected?
- Capex in base allowance for painting of select poles to mitigate visual impact concerns as needed
- Pp 36-8 – why is there no discussion of the AACE Class 3/class 2 accuracy of capex forecast?
- Pp 37-8 - Meaning of 'market price' heading in Table 5.3 – suggests it might be fixed when it is not?
- P.47 – [redacted] – correct?; [redacted] ? confirming what we think we heard from Ausgrid – [redacted] (p.76)? Is there a worst-case scenario? (this may be covered in Attachment 13)
- P.58 – how was the 25-year asset life for the Infrastructure Planner Fee determined?

Meaning of 'reasonable'

P.38 - this issue needs elaboration to set out the discussions with the Panel on this topic. The summary here does not reflect the Panel's views

1. Panel's influence

- Pp 22-4 Table 3-2 - Include reference to the meeting with AEMO Services Ltd
- Engagement with the Panel on our potential concerns around the visual impact of the new poles and Ausgrid's plans to paint select poles as needed to meet community expectations
- Pp 25-26 Table 3-3 – more detail on our role in influencing the drafting of the Revenue Proposal in all the topics listed ie separate from the influence of discussions with AER and EnergyCo; for more on adjustment mechanisms (see dot point 6 below)

2. <u>Summary of engagement with landowners and communities and how Ausgrid has responded</u>

- The Panel would like to see more evidence that Ausgrid has followed section 3.5.1 of the AER non contestable guideline
- What were findings of EnergyCo engagement undertaken before Ausgrid could start? What has Ausgrid done to address any issues that arose in EnergyCo's engagement?
- What have you heard since you started engagement? Pp.25-26 does not set out a summary of the engagement nor what Ausgrid heard and there does not appear to be an attachment setting this out in the document list
- What does this sentence on p.25 mean? "*Most stakeholders have expressed a willingness to collaborate with Ausgrid, demonstrated interest in identifying a preferred route, and emphasised their desire to remain informed and engaged as the HCC RNI Project progresses*."
- At this stage the Panel does not see evidence of a clear link between landowner and community engagement and the Revenue Proposal

3. <u>Approach to contingency</u>

- Pp 38-9 - why is the term 'allocating the risks to the party best placed to manage that risk' used to justify the allocation of Group C capex cost risks to consumers? what mechanisms does Ausgrid think consumers have to mitigate these risks?
- Given the extent of engagement with the Panel to ensure that the risk costs do not duplicate base allowance or adjustment mechanisms, the Panel suggests Section 5.4.9 (p.56) needs greater explanation. At the moment it merely points the reader to Attachment 2
- P.48 – what are the costs of Transgrid 'enabling activities' - there is mention in the secondary systems section; [redacted]

4. <u>Adjustment events and mechanisms</u>

- The Panel has some initial comments on Chapter 8 but more comprehensive comments await a review of Attachment 13 with our focus on the additional adjustment events allowed under EII Chapter 6
- P.41 and p.70 how does Ausgrid define 'symmetrical' and 'unavoidable'? How can consumers have confidence that Ausgrid will be applying for lower revenue under these 'symmetrical' adjustment events
- P.35 and p.70 The key assumption in the proposal is that the proposed adjustment events will be approved by the AER – it would be good to have a comparison between what Ausgrid is proposing in Table 8.2 on pp 75-77 and the three AER approved non automatic adjustment events for Transgrid in the Waratah Super Battery (WSB) determination
- Following a review of Attachment 13 and the information in the previous dot point, the Panel believes the next step on adjustment events and mechanisms is a discussion between Ausgrid, the AER and the Panel on each of the 7 Procurement induced cost uncertainty nominated pass through events in Table 8-2 to explore need, drafting of trigger events and possible caps

[redacted]

- P.26 and p.70 The Panel notes Ausgrid's assurance of no double counting but the Panel has not been able to verify this

5. <u>Capex</u>

- Is there any double counting in the various internal labour costs in chapter 5 between this revenue proposal and the 2024-29 revenue proposal. For example:
    - p.50 $48.9m owners' costs
    - p.53 $17.7m community and social licence
    - p.54 $5.6m design works
    - p.55 $0.8m regulatory costs

- Wouldn't those overhead costs have already been included in the 'normal' 2024-29 revenue decision? We understand 'contracted services' are 'new/additional' costs but did Ausgrid have to specially employ additional internal labour to do these tasks eg did the reg team need to expand to cover HCC REZ?

Appendix F

Correspondence between the Panel on Ausgrid concerning the visual amenity of the proposed steel poles

<u>Email from the Panel to Ausgrid on 21 March 2025</u>

Dear [redacted]

Recently the Panel has been discussing an issue that arose initially following the landowner/community engagement that we observed. Following our site visit list week the Panel wishes to raise a concern with Ausgrid on a no surprises basis.

Quality of engagement

We acknowledge that Ausgrid has undertaken some very useful and quality engagement on the project to date; and note the feedback that many of the contacts through that engagement are understandably blurring the requirements of this project with others in the region. This includes transmission system work and the actual development of the renewable generators themselves.

Our conservative approach to environmental risks, in particular visual amenity, comes in part from the recent reports from the Australian Energy Infrastructure Commissioner that outlines cases relating to community engagement, safety, natural environment, and amenity. The Commissioner has also referred to several publications that outline the expectations of engagement for major infrastructure development.

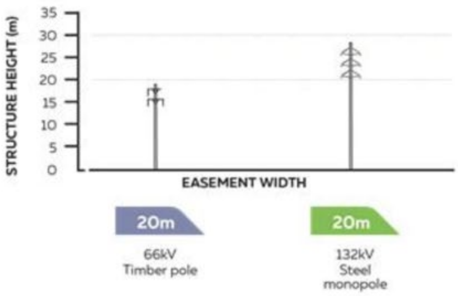
The significant amount of existing and under-construction infrastructure in the area suggests that many landholders are likely to be somewhat desensitised to further power line development. Despite this, we are seeking confidence that Ausgrid has followed good industry practice in the engagement and has adequate risk management plans in place to address landholder and community complaints should they arise after construction commences. In particular, we view these complaints as introducing the risk of construction delays and/or increases in cost through the need for redesign or a change of materials.

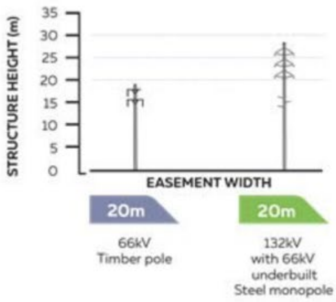
The new pole line is the predominant concern.

Ausgrid has made clear in its engagement with the community and with the Panel that the existing poles and conductor will be replaced with taller steel structures, many of which will carry considerably more conductor. To date we have observed Ausgrid sharing mock up diagrams to highlight the differences between the visual impact of the current poles and the proposed poles. See for example the diagram shared with the Panel and with the community on the webinars we observed in February.

What will the new infrastructure look like?

Ausgrid would replace approximately 85km of existing transmission lines between Kurri Kurri and Muswellbrook. Below are diagrams showing indicative pole structures.





66kV single pole structures, which reside in a typical 20m wide corridor, would be replaced by one new steel monopole one of two arrangements, either: 132kV steel monopole (left); or 132kV with 66kV underbuilt steel monopole (right).

132kV two pole structure (H-pole), which reside in a typical 45m wide corridor, would be replaced by two 132kV steel monopoles (as above).

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Our concern is that the constructions are significantly taller and more prominent than not only the timber ‘H frame’ constructions that they are replacing, but also quite different to the single circuit green concrete poles already widely used for sub-transmission in the area.

We have not seen engagement to date with physical models or examples of the ‘shiny' steel to be used compared to the existing green poles.

Following the site visit last week we believe that there is a potential risk for pushback from the community during or following construction about the height, number of conductors and the reflective brightness the new circuits. Our concerns are based on a few factors:

1. From the Lake Liddell site at the northern end of the new line, the poles will run southward across undulating lightly treed grazing and reclaimed coal mine land. It is likely that they will be very visible from some distance for some years until the shine wears off.
2. Many towers already in the area are constructed of dull steel, horizontal construction. The existing sub-transmission is of an older construction, mostly of single circuit (4 wires) vertical on dull, green-painted concrete poles. The new line will be very different in the number of wires that it carries, its height, and the brightness of the steel construction (initially, at least).

We also note that the southern half of the line and its shiny towers will run immediately beside and parallel to the motorway south towards Kurri Kurri.

As stated earlier, community or statutory body concern could amount to nothing; and this is probably the most likely outcome. However, once construction starts there is a risk of community (or TMR) concern and negative media that could lead to additional costs as a result of project delays or the need to redesign some structures.

We are keen to discuss with you and Ausgrid's engagement leads for the Project whether:

1. Ausgrid believes that visual amenity presents a risk to project timing or could introduce a need for redesign.
2. Ausgrid believes that its engagement on this issue to date meets the AER's expectations for best practice engagement as discussed in section 3.2 of the AER's Social Licence guidelines for electricity transmission projects;
3. Future engagement on this issue could be enhanced; and
4. Ausgrid plans to use any of the $5m social licence fund as a contingency to paint some of the more visible towers post construction if needed and if so, whether this is an efficient approach.

Best wishes

Mike, Mark and Louise

Response from Ausgrid to the Panel on 25 March 2025

Dear Mike, Mark and Louise,

Thank you for your considered feedback following the recent site visit and community engagement observations. We appreciate the opportunity to respond on a no surprises basis and welcome the Panel's constructive input.

Quality of engagement

We acknowledge and understand the Panel's concerns regarding the quality of engagement, particularly with respect to the visual impact of the new pole infrastructure. Ausgrid is committed to delivering best-practice engagement in line with industry guidance and community expectations.

In developing our Community and Stakeholder Engagement Plan (CSEP), we drew directly on the Australian Energy Infrastructure Commissioner's (AEIC) recommendations for community engagement in renewable energy infrastructure projects. This includes alignment with the IAP2 framework and adherence to principles of transparency, accessibility, and responsiveness.

We also acknowledge the complexity in distinguishing Ausgrid's project from other regional infrastructure developments. This has been a consistent challenge and one we are actively addressing through tailored, project-specific messaging, visual materials, and dedicated community engagement resources.

Visual amenity – current and future engagement

The new pole line has been a key focus of our engagement from the outset. Ausgrid has presented visual representations of the proposed steel structures at all community engagement activities, including one-on-one landholder meetings and community information sessions. These visuals are also a key component of the Review of Environmental Factors (REF) exhibition which will include site-specific imagery and impact assessments.

During the upcoming REF exhibition, we will further enhance visibility of these visual representations, including publication in the April newsletter and additional materials made available online and at community sessions. This will ensure the community has a clear understanding of the proposed changes and associated visual impacts.

We are also actively addressing concerns regarding the brightness and reflectivity of the steel poles. As noted, the initial 'shine' does tend to fade over time. This finish is comparable to other infrastructure already present in the region, including telecommunications poles. Where negotiations with landholders warrant it, Ausgrid will paint the new poles the required colouring. Ausgrid has made a small allowance for painting some poles.

Response to panel questions

1. **Visual amenity risk to project delivery**
   Based on the breadth and depth of our engagement to date, we do not believe visual amenity presents a significant risk to project timing or delivery. Visual representations have been made available to landholders and will be a key topic during the REF exhibition (see attached). Nevertheless, we have set aside funding to allow for painting of select poles, should community feedback during construction warrant it. It is worth noting that, depending on landscape context (particularly against the blue skyline), green poles can at times be more visually prominent.
2. **Alignment with AER Social Licence Guidelines**
   Yes, Ausgrid believes our engagement meets the expectations set out in Section 3.2 of the AER's Social Licence Guidelines. Our CSEP includes references to the guidelines and incorporates best practice community engagement approaches, including early involvement, transparency, and the creation of feedback loops.
3. **Opportunities to enhance future engagement**
   The REF exhibition period will be the most comprehensive engagement phase, and we are using this opportunity to enhance communication on visual impacts. Our approach includes clearer visual tools of the pole structures.
4. **Use of the $5 Million Social Licence Fund**
   We do not intend to use the $5 million Social Licence fund to address visual amenity concerns. However, separate funding has been allocated specifically for pole painting where warranted, and this is already embedded in our current planning. We will continue to monitor and assess community feedback to determine the most appropriate response in each location.

Once again, thank you for your engagement and ongoing support. We look forward to continuing our dialogue throughout the REF exhibition period and welcome any further feedback or discussion from the Panel.

Thanks, [redacted]

Appendix G

Ausgrid response to the Panel on 2 May in relation to the Community and social licence costs

"Of the $17.7 million allocated to this category, $6.9 million relates specifically to 'land and property' activities. These activities will be carried out by 5 of the 12 FTEs included in the 'community and social' cost category. This breakdown is shown in the first table below, sourced from Attachment 5.6 – Labour Model (see the 'internal labour' tab).

The second table below outlines the specific activities these 5 FTEs will undertake. Their involvement is necessary due to the extensive geographic footprint of the project, which spans nearly 125 km from Newcastle to Kurri Kurri – underscoring the scale and the breadth of property related issues that are likely to pop up across varied communities and landscapes. We also estimate that we'll need to deal with approximately 120 landholders.

The second table below sets out a high-level summary of the land and property team's work. It includes land access, property transactions, and negotiations with landowners. On reflection, these types of activities are perhaps not typically associated with 'community and social' expenditure which prompted us to get this clarification to you before the panel finalises their report."

Role	Activities	FTEs
Land & Property Access Manager (LPAM)	• Direct point of contact for Landowners • Undertake ongoing land access engagement with Landowners • Develop the Property and Landowner Management Plans consistent with industry best practice • Lead management of land and property access for Community and Stakeholder Engagement, First Nations and Environment teams	1 FTE
Property Transaction Manager (PTM)	• Ensure the land and property acquisitions for the Project are undertaken in accordance with the appropriate legislation and policies • Facilitate the development of the appropriate legal documentation • Obtain appropriate internal approvals to facilitate access arrangements and acquisitions	2 FTEs
Land and Property Coordinators (LPC)	• Additional point of contact for Landowners • Develop, enhance and maintain relationships with Landowners, residents and neighbours • Manage Landowner/resident negotiations	2 FTEs

Role	Activities	FTEs
	• Co-develop property-specific PMPs with Landowners, residents and neighbours	
Total		5 FTEs

Appendix H

Questions for discussion with Ausgrid in the Risk meeting on 27th March 2025

Introduction

Our conclusion from a review of various EnergyCo and AEMO Services documents and the discussion with EnergyCo last week is that HCC REZ is going to proceed. EnergyCo and AEMO Services have been tasked to implement Government policy with the aim of achieve renewable energy targets by 2030 to protect NSW consumers from the risk of coal plant closure. So it is not a matter of 'if', so

much as 'when' – and how to balance costs and benefits in the context of the project schedule to meet the targets.

This means our focus is on the risks to consumers on what HCC REZ capex they will pay through Roadmap charges. Our role is to minimise the costs above the [redacted] bid price while still allowing Ausgrid to meet the timetable it will have under the Project Deed. Three important and related ways of doing this are:

- Bring as much transparency as possible to the overall process so that consumers know what they are being asked to pay and why
- Seek to have risk assigned to the party best able to manage it – whether it be Ausgrid, its suppliers and contractors or NSW electricity consumers and
- Investigate whether the $48m contingency allowance (included in the $611m) and adjustments events are reasonably allocated and are not duplicative of 'base' capex before contingency

As we have peeled away the layers of the onion for HCC REZ we have found:

- The bid price of [redacted] is far from being a cap given the range of DSP Adjustment Events where Ausgrid can make application to the AER for the pass through of increased costs associated with different 'events'
- What we see so far is a raft of circumstances, some within and some outside of Ausgrid's control that will contribute to a higher that [redacted] cost.

Our focus in the risk workshop is to understand how capex risk can be efficiently allocated so that NSW consumers pay no more than is necessary to build the HCC REZ in the Commitment Deed/Project Deed timetable.

Explanation of the columns in the table

- In our meeting on 6th March we expressed our confusion at what the columns 'Total (Real)', 'Escalation' and 'Total (Real)' meant; Ausgrid undertook to provide an explanation

Greater clarity on the accuracy level of the capex costs

- This refers to the costs in Slide 10 (excel spreadsheet 'Capex summary') for our Panel meeting on 6th March
- During the meeting [redacted] and [redacted] mentioned that the line items were either 'Class 2' and 'Class 3' – what does Ausgrid mean by those terms - the same as the AACE Guideline and, if so, what is the explicit estimate range (the AACE Guideline gives a range of '+' and '-' accuracies for each cost class)

- Could you put in an additional column and allocate a cost class to each line in the spreadsheet (including a weighted average in the total capex line) and explain why they are either class 3 or 2? Understand the IP Fee is fixed and will not vary
- For those currently classified as Class 3, what is currently preventing you from providing a Class 2; ditto for those currently classified Class 2, what is preventing you from providing a Class 1?
- Are the current cost classes for each line item what you will be going with in your May submission to the AER or will they be further refined to a more accurate cost class?
- What increased level of cost accuracy do you think is possible in each line prior to the AER making its final determination?
- As requested on 6th March can you provide a breakdown of the [redacted] owners' costs by category and timeline of expenditure?

Understanding the level of contingency in the existing cost numbers

- Is there any contingency in the existing 'Total (Nominal)' cost numbers eg is there any contingency in the transmission lines cost of [redacted]?

Understanding the contingency allowance

- This has been described to us as a P50 estimate ie 50% chance of being above or below the [redacted]; what cost accuracy class does P50 align with?
- Could you put in an additional column for each cost line showing how much of the contingency $ are allocated to each line and the contingency allocation $ as a % of the 'Total (Nominal)' capex column
- What are the specific risks this contingency $ amount is covering in each line? How have those risks been addressed in the existing contractual arrangements eg how is the level of contingency in the transmission costs line reflective of the risk allocation agreed in the contract with Genus or the contracts Ausgrid has with various suppliers for equipment that is 'free issued' to Genus?
- How would this contingency $ fall as line items increase their Class cost accuracy eg as a line item goes from Class 3 to Class 2, what does that do to the contingency?

Early works funding

- We would like clarity on the approved early works funding of ~$70m e.g. which line(s) does it appear in in Slide 10? How is Ausgrid proposing to use these funds to reduce consumer risk?

Project delay risk

- Given Ausgrid incurs LDs under the Project Deed if full 1GW of capacity is not commissioned by [redacted]), what mitigation (contingency?) has Ausgrid included across its third-party contracts and internal supply chains to mitigate this risk?

Risk register

- It would be great if we could receive the risk register at least one week before our meeting – that may well answer some of our questions above as well as raise a lot more specific and more detailed questions that we can send before the 27th March.

Impact of scrapping the existing line on the RAB

- Will the existing line assets be fully depreciated and out of the RAB by the time of commissioning HCC REZ?
- If not, will there be accelerated depreciation of the existing line assets in 2024-29 to ensure it does have zero RAB value when the HCC REZ is commissioned?
- If yes, then how much is this and why should Ausgrid consumers pay for this when the benefit of dismantling the existing line is for the Roadmap and hence all NSW customers should pay the accelerated depreciation?

For Ausgrid to consider

We want to test Ausgrid's willingness to put a cap on contingency – either the total amount or individual components. The most obvious example would be owners' costs - [redacted].

14 March 2025