AEMC

REVIEW

Australian Energy Market Commission

DRAFT REPORT

TRANSMISSION PLANNING AND INVESTMENT - STAGE 2

02 JUNE 2022

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: EPR0087

CITATION

AEMC, Transmission planning and investment - Stage 2, Draft report, 02 June 2022

ABOUT THE AEMC

The AEMC reports to the Energy Ministers' Meeting (formerly the Council of Australian Governments Energy Council). We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the Energy Ministers' Meeting.

SUMMARY

1 Australia is undergoing a transformational shift to net zero. A grid that is underpinned by centralised thermal generation is moving to one that is dominated by decentralised renewable generation. There is broad consensus that transmission is a critical enabler for the transition of both the NEM and the broader economy to net zero. An unprecedented level of investment is required. It is vital that we get the right balance between timeliness to meet the needs of the transition and rigour to ensure customers are not paying for more than they should. The speed and scale of decarbonisation of the NEM require substantial investment in and build of transmission infrastructure to bring power from renewable generation and storage to consumers.

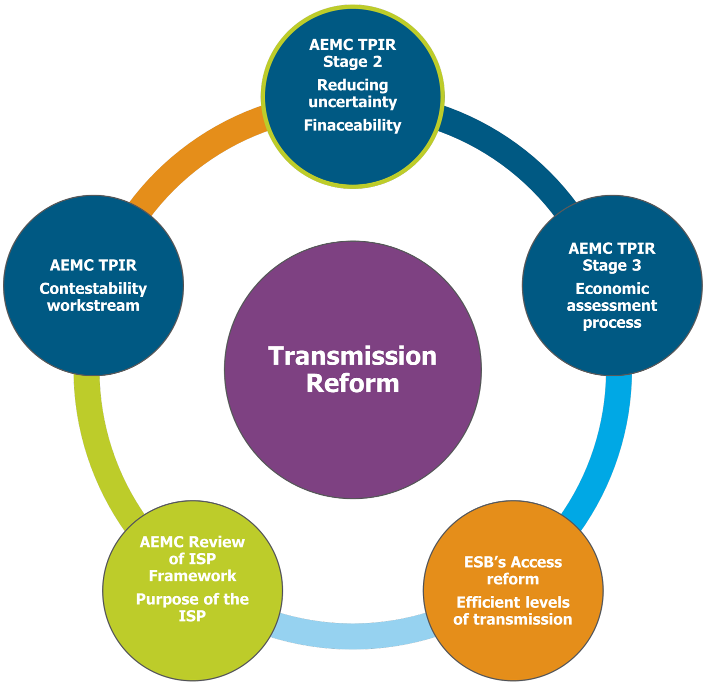
2 The combination of the scale of transmission investment required coupled with the speed of the energy transition, presents unique opportunities and challenges as to whether the existing regulatory framework is fit for purpose to support the scale of investment required for major transmission projects. The current regulatory framework was developed to support incremental growth, not the current level of step-change growth set out in the Integrated System Plan (ISP). It is therefore essential the regulatory framework is sufficiently flexible to support the timely and efficient delivery of transmission projects, while ensuring these investments are in the long-term interests of consumers.

The Stage 2 draft report is part of a larger body of work to support the efficient use of transmission infrastructure and the timely and efficient delivery of major transmission projects

3 The Review is part of a larger program of work to make sure the national regulatory framework is flexible enough to support the transformational shift in the energy market. The program of work seeks to create a national regulatory framework for transmission that is fit-for-purpose and ensures major projects in the medium-to long-term are delivered in the most timely possible way with robust consumer protections in place.

4 The upcoming Review of the ISP is also focused on these issues, while the Energy Security Board's (ESB) access reform workstream seeks to address increasing congestion in the grid by looking at the most efficient use of transmission, generation and storage assets so consumers are not paying more than they need to.

Figure 1: Stage 2 of the Transmission review is part of a larger body of work on transmission reform



Source: AEMC

5 The Commission's Review looks at multiple issues relating to the planning and delivery of transmission infrastructure. Many of these issues are complex and interlinked, but all go to the overarching objective of obtaining the right balance between time and efficiency to support the transition to net zero. Our goal is to recommend reform to improve investor and consumer confidence.

6 A different approach has been taken to this Review with work being delivered in stages. This recognises that some issues can be addressed more quickly, while others will require significant work due to their inherent complexity. These stages are:

- Stage 2 – near-term reforms: This stage focuses on both reducing uncertainty and near-term solutions, including recommendations to address any foreseeable financeability issues which may arise.
- Stage 3 – longer-term reforms: This stage focuses on issues that are of considerable complexity and are longer-term reforms. The key area of focus for Stage 3 is whether there are potential opportunities to improve the balance of timeliness and rigour in the economic assessment process.
- Contestability workstream: This workstream focuses on examining whether contestability in the provision of transmission services could be a proportionate alternative approach to the existing regulation of transmission projects. This will involve examining various potential models of contestability to assess their relative costs and benefits through a

high-level analysis and comparison to determine if contestability should be explored in more detail.

7 As well as the complementary work in access reform and the upcoming ISP review, the *Material change in network infrastructure costs rule change* is also being progressed. Issues relating to the economic assessment process, cost estimate accuracy and transparency will be explored under the rule change.

Stage 2 draft recommendations are designed to help manage uncertainty in the near-term

8 The draft recommendations in Stage 2 are designed to help manage uncertainty in the near-term to support the timely and efficient delivery of major transmission projects. The Commission has drawn on stakeholder feedback to prioritise 4 key issues we consider can be addressed in the near-term. These 4 issues are the focus of Stage 2 and this Draft report, with the Commission's recommendations on each issue detailed below. Two issues have been moved to the Stage 3 report. This allows these issues to be considered in the broader context of matters to be examined in Stage 3.

Introducing greater flexibility to mitigate the foreseeable risk that financeability concerns may arise in the future

9 The Commission has considered whether the revenue framework appropriately supports the financing of major transmission investment programs, with a long-term focus. The Commission's draft position is that the revenue setting framework would benefit from more flexibility to address the risk of financeability challenges that may arise in the future. This flexibility should provide more confidence for investors while providing protections for consumers.

10 To enable this flexibility, the Commission's draft recommendation is that the Australian Energy Regulator (AER) be given the explicit ability to vary the depreciation profile for actionable ISP projects to address financeability challenges, where it considers this would better meet the National Electricity Objective. The AER would be required to develop a guideline setting out how the above arrangements will be applied.

Providing greater clarity around social licence outcomes in the national framework

11 The Commission recognises that building social licence is a significant issue and that obtaining community acceptance of major transmission projects is critical for their timely and efficient delivery. The Commission agrees with stakeholder submissions to the consultation paper that social licence considerations should be a priority area for this Review.

12 The Commission's draft position is that:

- TNSPs should continue to invest in social licence activities, recognising it is vitally important in enabling the energy transformation. Ensuring the needs and perspectives of stakeholders, communities and landowners are appropriately factored into decision-making is necessary to ensure that investments build social licence. Existing work in this area by jurisdictional governments and the Australian Energy Infrastructure Commissioner in identifying key issues and promoting best practice actions remains critical to supporting the timely and efficient delivery of major transmission projects.

- Existing cost recovery mechanisms are largely appropriate and allow TNSPs to recover efficient costs associated with key activities to build and maintain social licence. The Commission seeks stakeholder views on whether any social licence activities are either not captured by or are constrained by the cost recovery arrangements.
- Existing regualtory obligations for TNSPs to build and maintain social licence are largely appropriate. The Commission seeks stakeholder views on whether the NER provides the right balance of flexibility and prescription in relation to stakeholder engagement, and whether there are any barriers to stakeholder engagement taking place earlier in the RIT-T process.

Providing greater clarity on the cost recovery of different types of planning activities

13 The Commission considers that planning activities should be more clearly distinguished in the regulatory framework to provide greater certainty around cost recovery. This uncertainty may lead to delays in investment and/or inadequate levels of planning activities being undertaken. Preparatory activities and 'early works' are not clearly distinguishable in the current framework, and the Commission's draft recommendation is to make changes to distinguish between planning activities for actionable ISP projects based on whether they relate to the *selection* or *delivery* of a preferred option to meet an identified need.

Improving the workability of the feedback loop

14 The feedback loop was introduced as part of the actionable ISP reforms and is designed as a safeguard for consumers by testing if the preferred option remains aligned with the latest ISP. Stakeholders raised concerns that a lack of clarity and practical application difficulties undermine the ability of the feedback loop to operate as an effective safeguard for consumers.

15 The Commission's draft position is that the workability of the feedback loop could be improved by aligning the timing of the feedback loop assessment with the publication of a draft or final ISP to promote timely completion of the feedback loop, while ensuring it draws on the latest available information. This would be enabled by amendments to the AER's Cost Benefit Analysis Guidelines to provide AEMO with the discretion to establish the timeframe for when the feedback loop assessment is to occur, which can be tailored to the circumstances of a particular investment. The draft recommendation a feedback loop and Project Assessment Conclusions Report exclusion window between AEMO's final Inputs, assumptions and scenarios report and draft ISP – the period where undertaking the feedback loop is least workable for AEMO- would be established under this guidance.

Submissions are due by 14 July 2022 with other engagement opportunities to follow

16 Written submissions from stakeholders commenting on the issues and key questions raised in this Draft report are request by **14 July 2022.** Following the receipt of submissions, the

Commission may make use of stakeholder workshops, roundtable meetings and bilateral or multilateral discussions to progress matters requiring further consideration.

17 A public forum on the Stage 2 Draft report will be held by the Commission during the consultation period. Details of the forum will be published alongside this report.

18 The Commission welcomes opportunities to engage with stakeholders on the Review.

19 The Commission intends to publish the Stage 2 Final report in October 2022.

20 Further, the Commission intends to publish:

- an options paper for the contestability workstream on 7 July 2022
- the Stage 3 draft report in mid-September 2022.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

This chapter introduces the focus of this Stage 2 draft report and details:

- the purpose of the Review and the particular focus of Stage 2
- the subsequent stages of the Review and the associated *Material change in network infrastructure project costs* rule change request
- the assessment framework for the Review
- how the remainder of the report is structured
- how to lodge a submission and next steps.

1.1 The Review's purpose is to explore options to support the timely and efficient delivery of major transmission projects

Australia is undergoing a transformation to net zero. A grid that is underpinned by centralised thermal generation is moving to one that is dominated by decentralised renewable generation. There is broad consensus that transmission is a critical enabler for the transition of both the NEM and the broader economy to net zero. An unprecedented level of investment is required. It is vital that we get the right balance between timeliness to meet the needs of the transition and rigour to ensure customers are not paying for more than they should. The speed and scale of decarbonisation of the NEM require substantial investment in and build of transmission infrastructure to bring power from renewable generation and storage to consumers.

The combination of the scale of transmission investment required coupled with the speed of the energy transition, presents unique opportunities and challenges as to whether the existing regulatory framework is fit for purpose to support the scale of investment required for major transmission projects. The current regulatory framework was developed to support incremental growth, not the current level of step-change growth set out in the Integrated System Plan (ISP). It is therefore essential the regulatory framework is sufficiently flexible to support the timely and efficient delivery of major transmission projects, while ensuring these investments are in the long-term interests of consumers.[1] The objective of the Review is therefore to ensure that the regulatory framework can effectively support this transition by striking an appropriate balance between enabling timely investments and ensuring that they deliver beneficial outcomes to consumers.

1.1.1 The priority issues to be addressed via the Review have been separated into several areas given the range and complexity of issues

The prioritisation of issues under Stage 1 drew on the input of stakeholders to identify the issues that are most material in the context of major transmission projects and that will deliver the greatest prospective gains to consumers. Given the range and complexity of

1 For the purposes of this review, the Commission considers major transmission projects to be projects of a significant size, scale and scope such that they are associated with greater uncertainty relative to BAU investments. These can be integrated system plan (ISP) or non-ISP projects.

issues identified through the consultation paper, the priority issues for the Review have been separated into three areas:

- Stage 2 – near-term reforms: This stage focuses on recommendations to help manage uncertainty in the near-term, with solutions to these issues potentially being able to be implemented sooner
- Stage 3 – longer-term reforms: This stage focuses on priority issues that are of considerable complexity, with further consideration required to establish the scope and source of issues prior to considering proportionate solutions
- Contestability workstream: This workstream focuses on delivering a recommendation on whether contestability should be explored in more detail, and if so, in what form

The key milestones for Stage 2, Stage 3 and the contestability workstream are outlined in Table 1.1.

Table 1.1: Key milestones for Stages 2, Stage 3 and the Contestability workstream

MILESTONE	STAGE 2	STAGE 3	CONTESTABILITY WORKSTREAM
Options paper	N/A	N/A	07 July 2022
Submissions on options paper due	N/A	N/A	18 August 2022
Publish draft report	2 June 2022	September 2022	December 2022
Submissions on draft report due	14 July 2022	TBC	February 2023
Publish final report	27 October 2022	Early 2023	Mid 2023

1.1.2 The draft recommendations in the Stage 2 draft report are designed to help manage uncertainty in the near-term and support the timely and efficient delivery of major transmission projects

This report has drawn on stakeholder feedback to prioritise key issues we consider can be addressed in the near-term. The Commission's draft recommendations seek to address these issues by:

- introducing greater flexibility to the regulatory framework to mitigate the foreseeable risk that **financeability** concerns may arise in the future – promoting both the timely and efficient delivery of major projects
- providing greater clarity and seeking feedback on if there are any changes which could improve how the regulatory framework supports **social licence** to facilitate community engagement and the acceptance of major transmission investments – promoting the timely delivery of major projects
- providing greater clarity on how different types of **planning activities** can be distinguished and how the associated costs are recovered – promoting both timely and efficient delivery of major projects

- improving the **workability of the feedback loop** so that it can operate as an effective consumer safeguard and be completed in a timely manner – promoting both the timely and efficient delivery of major projects.

The Commission has also identified a number of issues that will not be taken forward in the Review. Appendix A details the Commission's assessment of these issues.

1.2 The subsequent stages of the Review and the Material change in network infrastructure costs rule change request consider interrelated issues

1.2.1 Stage 3 will focus on issues that may require substantial consideration and/or relate to longer-term reforms

Through consultation with stakeholders and the Stage 1 prioritisation process, the Commission identified a number of complex framework issues that are most appropriately considered via a separate stage to allow for adequate consideration of these issues. These issues are the focus of Stage 3 of the Review and consider:

- whether transmission network service providers (TNSPs) face **suitable incentives and obligations to invest** in major transmission projects. The Commission is exploring the potential for a power to direct or delivery incentive mechanism to address the risk that major transmission projects are not delivered.
- whether there are potential opportunities to improve the balance of timeliness and rigour in the **economic assessment process.** The Commission is exploring whether it is possible to streamline the economic assessment process without compromising its rigour. Issues related to the types of benefits incorporated into the cost-benefit tests that underpin the economic assessment process will also be considered in Stage 3. These include:
    - the existing treatment of **emissions abatement** in transmission planning and how major strategic investments are assessed and selected with reference to decarbonisation objectives
    - whether and how to include **wider benefits** in the RIT-T and ISP assessment.
- whether the ex-ante regulatory framework is fit for purpose to promote timely and efficient expenditure on major transmission projects and the appropriate allocation of risks to parties best able to manage them.

Importantly, the Commission remains cognisant of the interrelationships between issues explored across the Review. For example, some areas of the regulatory framework which have been considered in Stage 2 of the review in relation to a specific priority issue may be explored further under Stage 3 when looking at opportunities to improve the balance of timeliness and rigour in the economic assessment process.

The Commission is currently progressing its policy development for these Stage 3 issues. We intend to publish a draft report at the end of quarter 3 2022 with a final report in mid-2023.

1.2.2 The Contestability workstream will consider whether contestability should be explored in more detail, and in what form

The Commission initially intended to examine contestability as a potential solution to the risk that major transmission projects are not delivered, given that TNSPs have an exclusive right but no corresponding obligation to invest. However, having considered the potential for contestability as a solution to multiple issues considered under the Review, the Commission is of the view than an expanded scope for the contestability workstream is appropriate. The Commission now intends to examine the suitability of contestability in the provision of transmission services as an alternative approach to the existing regulation of major transmission projects. This will involve examining various potential models of contestability to assess their relative costs and benefits through a high-level analysis and comparison.

To help manage the potentially significant volume of work required to explore this issue, the Commission considers it appropriate to progress work on contestability separately (but in parallel) to the issues being examined as part of Stage 3 of the Review. The Commission intends to take a two-part approach to examining contestability:

- **Part 1 – part of Review - developing a recommendation on whether a model of contestability could potentially be a proportionate alternative approach to the existing regulatory model.** Part 1 will involve undertaking an initial high-level analysis of contestability, assessing potential models of contestability. Subsequently, the Commission will recommend whether contestability should be explored in more detail and, if so, what the preferred contestable model is. Part 1 will comprise an options paper in June 2022, a draft report in December 2022 and a final report in the first half of 2023.
- **Part 2 – contestability implementation review.** If the Part 1 final report concludes that it is practical and beneficial to implement a model of competition for major transmission projects, Part 2 would undertake a detailed assessment of the costs and benefits of the preferred model. Detailed law and rule changes required for its implementation may also be developed. If required, this new review would likely commence in mid - 2023 and could run in parallel with the 2025 ISP review.

1.2.3 The Material change in network infrastructure project costs rule change is looking at issues that complement the review including cost estimate accuracy and transparency

The *Material change in network infrastructure project costs* rule change was submitted by the Energy Users Association of Australia (EUAA), Delta Electricity, Major Energy Users, ERM Power Limited and AGL Energy and seeks to amend the material change provisions in the NER to improve consumer confidence in the efficiency of network infrastructure projects. The rule change request proposed changes to:

- amend the NER to require a RIT-T proponent to reapply the RIT-T process if, following completion of the RIT-T, project costs have increased by 10 percent (for larger transmission and distribution projects) or 15 percent (for smaller transmission and distribution projects), unless an exemption is granted by the Australian Energy Regulator (AER)
- improve cost estimate robustness in the RIT-T to identify the preferred option, and

- request a transitional rule requiring reassessment of Project EnergyConnect (PEC) via a requirement to update the PACR (the final Regulatory Investment Test for Transmission - RIT-T report).

Under the existing arrangements, the RIT-T must only be reapplied where, in the reasonable opinion of the project proponent, there has been a material change in circumstances which means the preferred option identified in the final RIT-T report is no longer the preferred option. The rule change proponents consider that this does not adequately protect consumer interests.

The rule change request is being considered alongside the Review and will use the same assessment framework.

1.3 Assessment framework

This section sets out the Commission's assessment framework for the Review and responds to stakeholder comments on the assessment framework proposed in the consultation paper. It discusses the overarching National Electricity Objective (NEO) that guides all of the Commission's work in relation to electricity, including this Review. It then outlines the criteria that we will use in testing whether reforms to the regulatory framework promote the NEO.

1.3.1 National Electricity Objective

This Review is considering potential changes to the NER. As such, the national energy objective relevant to this Review is the NEO:[2]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> a) price, quality, safety, reliability and security of supply of electricity and
>
> b) the reliability, safety and security of the national electricity system.

Consistent with the terms of reference for the Review, the Commission considers that the relevant aspects of the NEO are the promotion of efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, security and reliability.[3]

1.3.2 Assessment framework criteria

The assessment framework criteria summarised in Table 1.2 have been used to assessed whether the Stage 2 draft recommendations promote the NEO. These assessment criteria will also be used for the subsequent stages of the Review. The Commission notes two changes to the assessment criteria which have been made to reflect an internal strategic initiative to support decision-making in the assessment of issues and potential solutions in rule changes

2 Section 7 of the NEL.

3 For a detailed discussion on the Commission's approach to applying these overarching objectives to rule making processes and reviews, such as this one, refer to: AEMC, *Applying the energy objectives: A guide to stakeholders,* 8 July 2019, available on the AEMC's website www.aemc.gov.au.

and/or reviews. The changes include reflecting the Commission's focus on 'Outcomes for customers' as a key criterion and the inclusion of a specific criterion for decarbonisation.

Table 1.2: Assessment framework criteria

CRITERIA	EXPLANATION
Outcomes for consumers	• Assesses whether the regulatory arrangements promote and appropriately balance the timely and efficient delivery of transmission projects.

Economic efficiency	• Assesses whether the solution promotes efficient investment in, and use of, electricity services in the long term interests of consumers with regard to:
	  • **Efficient risk allocation:** allocating risk (and costs) to parties best placed to manage them and who have the incentives to do so will support efficient decision-making.
	  • **Effective price signals/incentives:** effective incentives are needed to support service providers in making efficient and timely investment decisions.
	  • **Information provision/transparency:** service providers require clear adequate information to inform decision-making in an evolving market.
	  • **Clear, consistent, predictable rules:** a stable regulatory environment creates confidence in the market and will encourage investment and innovation through the transition and beyond.
	• Evaluates whether the solution provides service providers with a reasonable opportunity to recover at least their efficient costs.

Implementation	• Considers the complexity of implementing a solution, i.e. whether it will require law and rule changes or other jurisdictional legislative changes. • Assesses the costs of implementing a solution (practical implementation and compliance costs) • Evaluates the timing of costs and benefits.
Flexibility	• Assesses whether the solution is consistent with the long-term direction of energy market reform. • Evaluates whether the solution is flexible enough to accommodate uncertainty regarding unknown technological, policy and other changes that may eventuate.
Decarbonisation	• Considers whether market arrangements will enable the decarbonisation of the energy market.

While a number of stakeholders proposed additional criteria be added to the assessment framework, the Commission considers that the assessment framework adequately captures these.[4] See Appendix B for a more detailed response to stakeholder comments on the assessment framework.

1.4 Lodging a submission and next steps

Written submissions on this draft report must be lodged with the Commission by 14 July 2022 online via the Commission's website, www.aemc.gov.au, using the 'lodge a submission" function and selecting the project reference code EPR0087.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions.[5] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

The final Stage 2 report is expected to be published in October 2022. During that time the Commission will continue to engage both through the formal forums of engagement established for this Review with the market bodies, jurisdictional representatives and investors, and through bilateral and multilateral discussions with stakeholders. Additional public workshops, forums and roundtables may also be undertaken as the Commission finalises its recommendations.

The Commission welcomes opportunities to engage with stakeholders on any aspect of the Review.

All enquiries on this project should be addressed to Rupert Doney on (02) 8296 0668 or rupert.doney@aemc.gov.au

1.5 How the draft report is structured

The remainder of this draft report is structured as follows:

- Chapter 2: describes the potential for **financeability** issues to arise in the future and details the Commission's draft recommendations to ensure that the regulatory framework is equipped to address such issues should they materialise
- Chapter 3: sets out the key areas and activities in the regulatory framework that are relevant to building **social licence**, including cost recovery arrangements and stakeholder engagement with communities
- Chapter 4: describes how **activities to identify and deliver the preferred solution** to meet a transmission system need are currently funded in the regulatory framework and details the Commission's draft recommendations to clarify the cost recovery arrangements for these activities

4 Submission to the consultation paper: Transgrid, p.1; ENA, p.1; PIAC, p.4; EnergyAustralia, p.3; Neoen, p5.

5 See for further information here: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

- Chapter 5: describes the practical difficulties that have been experienced with the feedback loop to date and details the Commission's draft recommendations to improve the **workability of the feedback loop** so that it can operate as an effective consumer safeguard.
- Appendix A: discusses issues that were identified in the consultation paper that the Commission does not intend to progress as part of this Review.
- Appendix B: provides an overview of stakeholder submissions to the consultation paper.

2 THE REVENUE FRAMEWORK SHOULD HAVE SUFFICIENT FLEXIBILITY TO ADDRESS ANY FUTURE FINANCEABILITY CONCERNS

BOX 1: DRAFT RECOMMENDATIONS

The Commission's draft position is that the revenue setting framework would benefit from more flexibility to address the risk of financeability challenges arising in the future.

The Commission's draft recommendation is that:

- A proportionate approach to provide greater flexibility is to give the AER the explicit ability to vary the depreciation profile for actionable ISP projects to address financeability challenges, where it considers this would better meet the NEO.
- The AER would be required to develop a guideline setting out how the above arrangements will be applied. The guideline would include the matters that will be considered when assessing whether a variation from the usual approach to depreciation should be applied, the information that should be provided by the Transmission Network Service Provider (TNSP) in support of its proposal and any other matters the AER considers appropriate.

This chapter describes :

- why financeability challenges may arise in future
- why the current revenue framework may not provide appropriate flexibility for the AER to address financeability challenges
- which options to provide the AER with more flexibility best achieve the NEO.

2.1 The Review is considering whether the revenue framework appropriately supports the financing of major transmission investment programs, with a long-term focus

Financeability refers to the ability of TNSPs to efficiently raise capital to finance their activities. In the consultation, financeability was raised in relation to the concern that transmission investments could be delayed because incumbent TNSPs have an exclusive right to invest, but no clear corresponding obligation. While that broader issue is being considered in Stage 3 of the Review, the Commission has brought forward consideration of financeability concerns to this stage of the Review to enable the earlier implementation of any appropriate changes.

The Commission considered a related financeability issue in the Transgrid and ElectraNet financeability participant derogation rule change requests which were submitted in 2020. In its final determination the Commission recognised that it could not be certain whether financeability issues will arise in the longer term. The Commission decided that financeability, among other issues relating to the timely and efficient delivery of ISP projects, would be taken forward by the Commission in this Review.[6]

This issue is particularly important in the context of a rapidly transitioning power system, which creates significant uncertainty in the timing of transmission needs. The uncertainty in investment timing under successive ISPs is driven by a range of factors, such as the rate of entry of renewable generators and storage, the related economic closure of coal-fired power stations, large scale changes in demand patterns due to distributed energy resources (DER) and the electrification of industry and transport, as well as potential further significant changes in the need to transport energy to support a currently nascent hydrogen industry.

As explained in the following section, the timing of major investments is critical. This is because cash-flow challenges may arise when a large amount of new investment relative to the existing RAB occurs in a short period of time, if businesses are unable to raise funds and adjust capital structures within the required timeframe. Consistent with the findings in the participant derogation rule changes, the Commission finds that there is currently no clear evidence of financeability concerns with specific projects or businesses. However, successive ISP iterations could see major transmission works moved forward or become concurrent, creating a risk of financeability issues arising in the future.

Whether financeability challenges arise in practice will depend on whether the business can raise funds and, if necessary, and adjust its capital structure in the timeframe required. While the magnitude of this task increases with the scale of transmission investment required, it does not mean that financeability challenges will necessarily arise in each case.

Nonetheless, further consideration is warranted due to the foreseeable risk of financeability concerns arising in the future.

2.2 There is a risk that financeability challenges could arise under future investment scenarios

As noted by Transgrid in its submission to the consultation paper, if a project provides the return stipulated for a benchmark efficient entity under the rate of return instrument (RORI) and other arrangements appropriately deal with risks, then, all things being equal, TNSPs will invest.[7] However, there is a concern from stakeholders that for some major ISP projects in the future, even a benchmark efficient entity in the position of an actual TNSP may not be able to invest without adversely impacting credit ratings or requiring re-gearing.

In its determination on the Transgrid and ElectraNet financeability participant derogation rule change requests the Commission noted that financing profiles are expected to change over time. It said that "*there is no expectation that a transmission network business… will adopt the benchmark efficient entity's capital structure*" and that "*in a period of investment and expansion, it is likely that network businesses will need to rely more heavily on finance from*

6 AEMC, *Participant Derogation - Financeability of ISP Projects (TransGrid) and Participant Derogation - Financeability of ISP Projects (Electranet)*, Final Determination, 8 April 2021, pp.34-35

7 TransGrid, submission to the consultation paper, September 2021, p.2.

equity investors relative to the benchmark assumption in order to maintain the benchmark credit rating. In less capital-intensive periods, revenues may support the benchmark credit rating under a structure more reliant on debt relative to the benchmark assumption".[8]

Nonetheless, the Commission recognises that it may be difficult to adjust capital structures quickly.

Financeability concerns for a TNSP may arise from the way that cash flow is impacted by major investments. When a network business invests in a project, it starts receiving a return on the investment based on forecast capital expenditure.[9] However, the business does not start receiving a return of the investment (depreciation) until the investment is commissioned. As depreciation typically occurs on a straight-line basis, this cash flow meets the project's requirements over its lifetime. However, this profile may not match the profile of financing requirements. Specifically, it does not match the requirements to meet the higher levels of debt in early years, but is greater than the debt attributed in later years. In the absence of changes to the business' capital structure, this may in the short term negatively impact some of the financial metrics that form part of the range of factors that are used to assess the creditworthiness of a business. In particular, the ratio of funds from operations (FFO) to net debt (or FFO/net debt).

Where new transmission projects are being developed with similar characteristics to the existing system, and the RAB has a diversity of assets with different lives, new transmission projects can be absorbed without a significant impact on these financial metrics. Accordingly, in the ordinary course of investing, there is little impact on the ability of a business to attract finance to support its activities. Even fairly significant one-off investments can be absorbed, with appropriate changes to capital structure such as shareholders (equity) supporting cash flow in earlier years and receiving higher cash flow in later years.

There are some factors, however, that may lead to financeability concerns for some major transmission projects.

- Firstly, multiple large projects conducted concurrently or in sequence would make new investments a much larger proportion of the RAB. This would likely impact short-term cash flow relative to the RAB more significantly than single large investments or a more gradual accretion of investments. While shareholders can assist by supporting a business with additional equity, reducing the gearing of the business, this does dilute returns to investors in the short term[10] and has the potential in some circumstances to contribute to the delay or avoidance of future investment.
- Secondly, due to the capital intensity of major investments, investors could in practice treat the investments as separate from the transmission business itself. This is because capital is inherently mobile and the opportunity cost of investing in a major transmission

8 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid) and Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021, pp. i-ii.

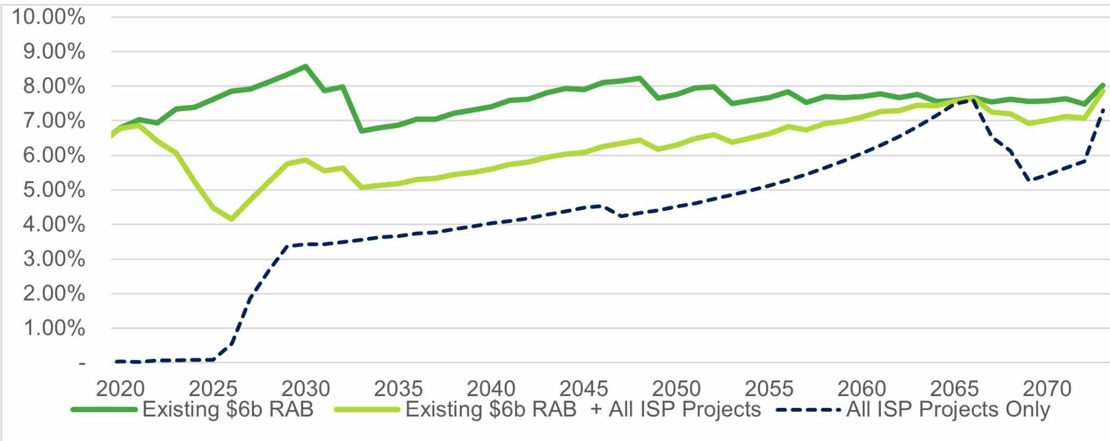
9 Within the regulatory period. At the end of the regulatory period, the RAB is rolled forward on the basis of actual capital expenditure, if the AER considers this prudent and efficient.

10 Returns attributable to the equity portion of the investment may be diluted where equity participants are required to inject additional funds into the business over and above a level that provides them with a target rate of return on the amount of equity capital invested.

project may be too high. If this is the case the decision to invest in a major ISP project that has net market benefits would need to stand on its own financial metrics.

As an example of the impact of a significant investment pipeline on financial metrics, Transgrid has provided the Commission with a projection of its funds from operation to net debt ratio (FFO/net debt) over time. The projection is based on an assumed 60 percent debt gearing to align with the hypothetical benchmark efficient entity and an assumption that Transgrid will invest in all actionable ISP projects from the 2020 ISP.[11] As noted above, the Commission expects that there will be periods in an investment's life where cash flows support gearing levels better than the hypothetical benchmark efficient entity, and periods particularly in the early years where it does not.

Figure 2.1: Transgrid modelled FFO/net debt for RAB + All ISP Projects at 60% gearing.



Source: Transgrid 2021

A range of factors contribute to overall credit scores for a business.[12] While these include financial metrics, such as funds FFO/net debt, they are not determinative. Ratings agencies try to avoid rating volatility with short-term changes in capital structure or investment cycles. Accordingly, they are willing to look through a weakness in some metrics for some time, so long as they see good prospects for future cash flow. The Australian economic regulatory framework and revenue cap for electricity businesses provide a high level of confidence in future cash flow. Even so, a credit rating downgrade could occur if there is expected to be an extended period with weakness in financial metrics. Such an extended period of weakness would show an unwillingness or inability for the business to set a capital structure that can support higher cash flow relative to debt.

11 The economic regulatory framework is designed to regulate the benchmark entity as distinct from individual projects and TNSPs. The framework does not consider actual businesses. Where actual structures differ to the benchmark structure, the impact of major projects on financeability will be different to that shown in Invalid Xref: target figure not found. Please edit or recreate the link.

12 See for example the Moody's scorecard approach described in the Cambridge Economic Policy Associates (CEPA) report supporting the Commission's findings in the participant derogation rule changes: CEPA, Financeability of ISP projects, January 2021, p. 21.

The economic regulatory framework is designed to provide TNSPs with the opportunity to recover returns commensurate with the regulatory and commercial risks involved in providing prescribed transmission services and to promote efficient new investment in the system. The AER achieves this through the construct of a benchmark efficient entity and rewarding all Network Service Providers (NSPs) with a return that reflects the appropriate return for that hypothetical entity. This does not mean that networks will or should always have the same capital structure as that entity. For example, at times of low risk a business may be more highly geared and at times of higher risk, such as when investing in large-scale capital works, it may be appropriate to adopt a capital structure with a lower level of gearing.

In a power system that is relatively stable or undergoing moderate change, the current revenue framework would likely be sufficient to return efficient costs to investors over time and provide appropriate incentives to allow investments to occur in a timely and efficient manner. However, in the context of a rapidly changing power system with significant investment required in new transmission infrastructure, the current arrangements may not provide the right incentives for all businesses for timely and efficient investment. They would still return efficient costs to investors over the longer term, but there may be a short-term disincentive to invest if ratings were negatively impacted. While investors do seek to support their investments in high-quality assets, such as Australian transmission infrastructure, by committing to appropriate capital structures to ensure creditworthiness, the impact on cash flow of multiple major investments has the potential in future to test the willingness of investors to deploy capital in a timely and efficient manner.

Given the analysis above, the Commission considers that while there currently is no clear evidence of financeability concerns with specific projects or businesses, financeability issues could arise in the future under realistic development plans that may arise from the ISP planning framework. This could in turn delay investments and result in outcomes that are more costly for consumers. Accordingly, we consider it is important to ensure that the AER has sufficient flexibility to address this risk on a case-by-case basis, including the ability to shape cash flow for specific projects in a manner that is appropriate to compensate a business for its efficient costs over time as well as incentivise timely and efficient new transmission investment.

We welcome stakeholder views on this finding that financeability challenges could arise in the future under realistic future ISP development plans and that it is appropriate for the AER to have sufficient flexibility to address this issue.

2.3 The current revenue framework is not flexible enough to address the financeability challenges that may arise in the future

As described in Box 2, the AER has some flexibility under current arrangements to adjust cash flow. However, it is not clear that this flexibility extends to varying cash flow for the purposes of supporting the financeability of a TNSP's work program, and addressing the potential concerns of investors in relation to large ISP projects.

Accordingly, we consider the framework would benefit from more flexibility to address any financeability challenges that may arise in the future. Given the issue relates to the specific circumstances of individual businesses that are in the process of investing in a select number of large ISP projects, it is not appropriate that the rate of return for all businesses be adjusted to address this issue. Rather, we consider a bespoke approach should be taken to give the AER the discretion to shape cash flows of specific projects to support financeability through adjustments to depreciation where this would be in the long-term interests of consumers.

BOX 2: ASPECTS OF THE REVENUE FRAMEWORK RELEVANT TO FINANCEABILITY

The revenue framework settings that most impact the ability of businesses to attract finance to support the timely and efficient delivery of major projects are the return on capital (through the rate of return) and the return of capital (through depreciation).

The rate of return is set by the AER through the rate of return instrument, which is required to be set under section 18I of the National Electricity Law (NEL). The rate of return is a forecast of the cost of funds a network business requires to fund investment in its network. This rate of return allowance is determined with reference to a "benchmark efficient entity", which is a hypothetical network business. The benchmark efficient entity framework is intended to provide a long-term efficient return on capital. However, there is no expectation that a transmission network business will adopt the benchmark efficient entity's capital structure – that is, the same distribution of debt and equity assumed by the AER to make up the finances of the benchmark efficient entity (currently 60 percent debt to 40 percent equity).*

The return of capital through depreciation is set by the AER under clause 6A.6.3 of the NER. This requires the AER to set depreciation profiles that reflect the nature of the asset or category of assets over their economic life. Further, the AER is required to set economic lives, depreciation methodologies and rates of depreciation for a given regulatory control period consistently for the same type of assets.**

In addition, clause 6A.6.3(c) requires that assets which (a) are dedicated to one transmission network user (or a small group of them), and (b) have been included in the RAB at a value greater than $20 million, must be depreciated on a straight-line basis. Where this requirement to use a straight line profile does not apply, the AER may adopt a different approach. However, the AER has no such discretion in relation to assets which clause 6A.6.3(c) applies, and in the AER's view even where clause 6A.6.3(c) does not apply, it is unclear as to whether its discretion extends to resolving financeability concerns by adjusting depreciation timing, even when this would best achieve the NEO.

Source: *See AER, Rate of return instrument: explanatory statement, December 2018, p. 64.
Source: **See Clause 6A.6.3(b) of the NER.

We welcome stakeholder views on the finding that the regulatory framework does not currently have sufficient flexibility for the AER to address potential financeability concerns, should these arise.

2.4 It is appropriate to provide the AER with more flexibility to respond to financeability challenges that may arise

There is limited flexibility in current arrangements to shape or vary cash flow to address financeability concerns. The Commission has therefore considered:

- what type of cash flow adjustments could be made by the AER
- how the AER would determine whether such an adjustment is required
- implementation issues if such flexibility is provided to the AER.

2.4.1 A proportionate response is to provide greater flexibility to vary the depreciation profiles for actionable ISP projects

Broadly speaking there are two options for adjusting cash flows:

1. adjust the return *on* capital (through the rate of return instrument), or
2. adjust the return *of* capital (through depreciation).

Option 1: Adjusting the approach to setting the rate of return on capital is likely not an appropriate response to the issue

The AER has some ability within the rate of return instrument to adjust the approach to setting the return on capital in a manner that can help address financeability risks. For example, the AER could change the gearing of the benchmark efficient entity if it considers the risks faced across the industry warrant the change. A decrease in gearing, say from 60 percent to 55 percent, would increase equity returns relative to assumed debt. This should assist a business' ability to maintain higher FFO/net debt ratios.

The AER is currently consulting on its approach to the 2022 Rate of Return Instrument.[13] Among other things, this consultation is considering a potential change from the current trailing average approach to setting the return on debt to a weighted trailing average approach. The current approach assumes equal weighting over ten years (10 percent per year), while a shift to a weighted trailing average would account for the actual weighting when a business raises debt. This change could address risks for businesses arising from a mismatch between the debt allowance and actual costs. For example, this could occur where a business undertaking a major project must raise significant amounts of debt at times when current debt costs are above the 10-year trailing average.

The potential shift to a weighted trailing average return on debt approach could to some degree help address financeability risks. One potential barrier to the timely and efficient investment in major projects is that, under current arrangements, a business compensated on a trailing average with equal weighting of debt could be less willing to raise a significant volume of debt at a time when the cost of debt is increasing. A shift to a weighted trailing average approach would likely remove or reduce this concern but would not address the broader issue of the impact on financial metrics from a significant increase to the RAB in a short period of time.

13 See AER, Rate of return: Information paper, December 2021.

While the AER has some flexibility to manage financeability concerns through changes to the rate of return settings, this approach is not appropriate to address the short-term impact of major investments on financial metrics and financeability. Adjusting the approach to the rate of return would apply across all network businesses, including TNSPs and distributed network service providers (DNSPs).[14] Adjusting the rate of return is, therefore, appropriate to address systemic changes in costs or risks for all businesses.

Financeability concerns on the other hand are likely to arise only for specific projects or businesses and in each case will only persist for a limited time until the financial metrics naturally recover. Adjusting the rate of return to address financeability concerns for some businesses would likely result in higher costs for consumers across the broader system than are efficient to provide appropriate signals to invest in major projects in a timely manner, and would therefore not be in their long-term interests. Accordingly, the Commission considers that other more appropriate and targeted tools to address financeability concerns should be explored.

Option 2: Providing more flexibility to adjust the rate of depreciation is an appropriate and proportionate approach to addressing the issue

The second main setting that can be used to adjust the timing and profile of cash flow to address financeability issues is the return of capital through depreciation. As noted above, the AER currently has limited flexibility in its approach to setting depreciation for businesses and their assets, particularly with respect to flexibility to address financeability concerns.

Shaping depreciation to change the cash flow profile is likely an appropriate and more proportionate way to address financeability concerns for a project or business. Shaping cash flow, while keeping the asset life the same, would increase cash flow in the shorter term and taper cash flow toward the end of the asset life. While the change would be net present value-neutral neutral for TNSPs and consequently consumers would pay the same over the life of the asset, near-term consumers would pay a larger share than later consumers. Shaping depreciation in this way would help support financial metrics for a business, such as FFO/net debt, at more consistent levels over the life of the asset.

The Commission considers that cash flow should only be brought forward when the consumer benefits of more timely and efficient investment in infrastructure outweigh any negative impacts such as less efficient short-term prices and intergenerational inequity concerns. This will not be the case for all projects or all businesses and it should be noted that there are many factors that influence the benefits to consumers from specific assets over time. Indeed, we consider the benefits of shaped depreciation for specific assets will likely only be realised in exceptional circumstances. For example, the intergenerational wealth transfer proposed in the participant derogation rule change requests was not considered to be in the long-term interests of consumers and was opposed by user groups.[15] Given this,

14 The NEL requires a sector wide rate of return instrument (RORI), a weighted average cost of capital (WACC) for different businesses is not possible without changing this requirement.

15 See AEMC, Participant Derogation – Financeability of ISP Projects (TransGrid) and Participant Derogation – Financeability of ISP Projects (ElectraNet), Final determination, 8 April 2021, p68.

the AER is the appropriate body to assess whether shaped depreciation to support financeability is warranted on a case-by-case basis.

There are two principal ways to provide greater flexibility in how the AER can set depreciation to support the financeability of a project or business. The options are:

- to include greater flexibility within the existing arrangements for setting depreciation, and
- to introduce a specific financeability or commercial viability test that can trigger the ability to shape depreciation.

2.4.2 Requirements to adjust depreciation are appropriately considered on a case by case basis

A number of stakeholders support the introduction of a specific financeability or commercial viability test. Energy Networks Australia (ENA) suggest introducing a financeability check into the revenue setting framework.[16] Transgrid suggests introducing either a financeability test or a commercial viability test into the framework.[17] More specifically, TransGrid proposes that:

- A financeability test would involve assessing whether a notional company (in other words, the benchmark efficient entity) with the TNSP's investment profile would be able to achieve and maintain an investment grade credit rating. This would be assessed with reference to the financial metrics used in the Moody's framework for estimating credit ratings, and a range of equity metrics such as dividend yield to ensure sufficient return for equity investors. Transgrid consider this is consistent with the approach taken in the UK, where Ofgem, in the performance of its duties,[18] must have regard to the need for network businesses to be able to finance their activities.[19] Basing the test on a benchmark efficient entity, rather than the actual company is considered to avoid any potential moral hazard concerns that have been raised with financeability tests.[20]
- A commercial viability test would be more specific. This would require the AER to set the allowed revenue such that a benchmark efficient entity with the TNSP's investment profile is able to achieve the credit rating and gearing parameters that are assumed when setting the regulated allowed return.

Introducing a financeability or commercial viability test as suggested by the ENA and Transgrid would be unlikely to promote the long-term interests of consumers in all cases. In particular:

- a broader financeability or commercial viability test required to be performed for all revenue determinations and CPAs would impose a disproportionate administrative burden on the AER and businesses in their proposals
- establishing a finaceability or commercial viability test would require that specific metrics are adopted as a measure of a businesses' financeability, which may not be appropriate

16 See ENA, submission to the consultation paper, p21.

17 See Transgrid, submission to the consultation paper, p12.

18 It should be noted that Ofgems's duty is different to the AER's. Ofgem does vary notional gearing for businesses with different profiles.

19 See section 3A(2)(b) of the Electricity Act 1989 (UK).

20 Moral hazard concerns arise where financeability tests relate to the actual business rather than a benchmark entity. Where they relate to an actual business, there is moral hazard in that poor management of financeability might increase the possibility that the remedy is applied.

for assessing the financeability of a specific project or a notional entity. Moody's and other credit rating agencies combine an assessment of both qualitative and quantitative metrics to arrive at an overall rating. While FFO/Net Debt, for example, is a key factor considered by Moody's, it is not appropriate for an assessment of financeability to rely so strongly on a single metric. Such an approach would also present the key issue of how an appropriate threshold for this credit metric should be determined. Further, there are a range of company-specific factors such as how a company has structured their balance sheet and the risks associated with non-regulated revenues which may lead to such a strongly defined approach to assessing financeability producing unintended consequences.

- a more targeted approach to considering financeability only where this is raised by a business with respect to a specific actionable ISP project would be more appropriate given the issue identified is one that is likely only to arise in exceptional circumstances.

A more proportionate and flexible approach is to allow the AER to consider on a case by case basis whether adjustments to depreciation are in the long-term interest of consumers. This approach would:

- give the AER the explicit ability to disapply the requirement in clause 6A.6.3(c) to use a straight line basis to instead vary the depreciation profile for actionable ISP projects where it considers this would better meet the NEO,[21] and
- require the AER to develop a guideline setting out how the arrangements will be applied, including:[22]
  - the approach the AER proposes to take where it is required to consider whether a different depreciation profile would better meet the NEO
  - the information that should be provided by the TNSP in support of its proposal for a variation from the usual approach to depreciation for the relevant project, and
  - any other matters the AER considers appropriate to include in the guideline.

This approach provides the flexibility to address financeability concerns should they arise, as well as flexibility to address other issues that may arise in the future that require changes to the approach to depreciation. The obligation on the AER to prepare a guideline should also provide some clarity and transparency in how the rule will be applied.

In addition, this approach is relatively simple to implement, forming a part of the ordinary revenue or CPA proposals to which the AER must respond. In practice, this would be comprised of:

1. The TNSP's revenue proposal or CPA setting out, for an actionable ISP project:[23]
   a. the revenue profile if the ordinary approach to depreciation is applied
   b. evidence of the impact this would have on financial metrics and credit ratings for the business over time (i.e. the RAB plus the proposed investment), and

21 See rule 6A.6.3 of the draft rule.

22 See rule 6A.6.3A of the draft rule.

23 See rule S6A.1.3 of the draft rule.

    c. a proposed depreciation profile for the proposed investment that would address the issue
    d. an explanation as to how the proposed depreciation profile would better achieve the NEO as against using a straight line basis.
2. The AER assessing and responding to the proposal, exercising its discretion to set a depreciation profile it considers best promotes the NEO, and taking into account the factors it considers relevant as set out in its guideline.

The Commission's draft recommendation is that this approach is an appropriate and proportionate response to financeability challenges that may arise in the future.

BOX 3: CONSUMER IMPACTS

As noted above, accelerating depreciation in the early years and slowing it down in later years to address financeability concerns would have an intergenerational impact on consumers. The scale of the impact would vary with the needs of the specific business or project at the time, with the impact being no greater than is necessary to ensure the timely and efficient financing of the relevant project.

An acceleration of depreciation for asset with a 50-year economic life would have a material intergenerational impact on consumer prices. This impact would of course flow through to the prices paid by the users of transmission services.

The scale of the impact would depend on the underlying capital structure and scale of the RAB for a business before the proposed investment is made. Given this, we consider it is appropriate for the AER to have the flexibility at its disposal to assess on a case-by-case basis whether adjusting the depreciation profile is in the best interests of consumers over the long term.

We welcome stakeholder views on whether this draft recommendation to increase the AER's discretion to vary depreciation profiles for actionable ISP projects is an appropriate response to financeability challenges that may arise. We also welcome views on alternative approaches that stakeholders consider would better promote the NEO.

2.4.3 Implementation challenges appear to be manageable

A rule could be made to implement the recommended changes immediately after it is made. That is, the AER could apply a new discretion to vary the depreciation profile for actionable ISP projects for determinations made from the date the rule is made and gazetted. It may take some time however for the AER to develop and consult on a guideline. We expect an implementation timeframe of approximately six to nine months from the date a rule is made would be appropriate.

There are also several practical challenges to implementing varied depreciation profiles for actionable ISP projects. These include:

- challenges arising from separating assets from asset classes to apply separate depreciation profiles
- challenges arising from implementing different rates of depreciation across multiple regulatory determinations under the current post-tax revenue model (PTRM) and roll forward model (RFM).

The background to the first of these challenges is that the current approach to depreciation involves the creation of asset classes within the RAB and the depreciation of classes of assets and not individual assets.[24] We understand from the AER that if depreciation rates were able to vary over time for certain major projects there is sufficient flexibility under the current arrangements to allow for the creation of new asset classes (even where similar classes exist) to enable this to occur. We also understand that while there may be some changes required to accounting practices within TNSPs to accommodate varying depreciation over time for specific assets, this would not be too burdensome.

The second challenge noted above relates to the operation of the current PTRM and RFM,[25] which in the AER's view currently only allow for straight-line depreciation for the life of the asset. As a result, if the AER were to be given a wider discretion to adopt a different depreciation profile, the AER considers that it would need to amend the existing PTRM and RFM to allow for shaped depreciation to occur. This could take nine to 12 months to implement following a new rule providing the AER with a wider discretion to vary depreciation profiles.

In the interim, there may be approaches under the current PTRM and RFM that could give effect to a new discretion to shape depreciation profiles. For example, the AER may be able to apply a shorter asset life to an asset under the current PTRM (to increase the near-term cashflow) and then in subsequent determinations change the asset life back to the full economic life. This approach would only be required for determinations that occur up until the PTRM and RFM are updated to accommodate the new discretion to vary depreciation profiles.

Example drafting for a rule to implement these changes is provided for consultation purposes.

We welcome stakeholder views on whether these are practical and workable approaches to implementation and whether there are any further challenges that we have not highlighted in this report.

24 See clause 6A.6.3 of the NER.

25 See AER, Electricity post-tax revenue models (transmission and distribution), April 2019 and AER, Electricity roll forward models (transmission and distribution), April 2020.

3 THE REGULATORY FRAMEWORK SUPPORTS SOCIAL LICENCE ACTIVITIES AIMED AT BUILDING AND MAINTAINING COMMUNITY ACCEPTANCE

BOX 4: DRAFT POSITION

The Commission recognises that building social licence is a significant issue that can have a major impact on the timely and efficient delivery of major transmission projects. Obtaining community and stakeholder acceptance of transmission projects is critical for their timely delivery. As such, the Commission agrees with the numerous stakeholder submissions to the consultation paper that it should be a priority area for this review.

The Commission's draft position is that:

- TNSPs should continue to invest in social licence activities, recognising that securing social licence is vitally important in enabling the energy transformation. Ensuring the needs and perspectives of stakeholders, communities and landowners are appropriately factored into decision-making is necessary to ensure that investments build social licence. Existing work in this area by jurisdictional governments and the Australian Energy Infrastructure Commissioner in identifying key issues and promoting best practice actions remains critical to supporting the timely and efficient delivery of major transmission projects.
- Existing cost recovery mechanisms are appropriate and allow TNSPs to recover efficient costs associated with key activities to build and maintain social licence. The Commission seeks stakeholder views on whether any social licence activities are not captured by the cost recovery arrangements.
- Existing regulatory obligations for TNSPs to build and maintain social licence are largely appropriate. The Commission seeks stakeholder views on whether the NER provides the right balance of flexibility and prescription in relation to stakeholder engagement, and whether there are any barriers to stakeholder engagement taking place earlier in the RIT-T process.

This chapter sets out:

- what we mean by the term social licence for the purpose of this Review (that is, activities that support building and maintaining community acceptance)
- the key elements of the regulatory framework that support activities to build community acceptance, including cost recovery arrangements and engagement with communities
- an overview of the issues raised by stakeholders that fall within the remit of jurisdictional regulatory frameworks. We are working closely with jurisdictions on this Review and note the significant work they are doing to progress social licence outcomes for their renewable energy zones (REZs).

3.1 We are treating social licence as activities that build and maintain community acceptance

Social licence is a broad term used to refer to a range of concepts and activities. It is important therefore to clarify how we are using the term for the purpose of this Review and the specific activities that are relevant under the NER. This is important because several parties and regulatory frameworks (e.g. national and jurisdictional) shape social licence outcomes across the end-to-end process for major transmission projects.

For this review, we are focusing on social licence activities that are (or could be) required under the NER, and which help to build a level of community acceptance for major transmission projects. Building this community acceptance is critical for the timely delivery of major transmission projects and we are interested in stakeholder views on whether changes could be made to the national framework to improve effectiveness and timeliness around building and maintaining community acceptance. Among the issues raised by stakeholders to date, there are two key issues that build/maintain social licence and sit within the NER:

- cost recovery of a range of activities undertaken to build community acceptance such as stakeholder engagement or compensation (e.g. to landowners or communities) and
- stakeholder and community engagement activities.

3.2 The regulatory framework allows TNSPs to recover the costs of activities that contribute to building community acceptance in several ways

The NER provide a number of avenues for cost recovery of social licence activities undertaken by TNSPs for major transmission projects. This includes for activities such as compensation payments (e.g. to landowners or communities) and stakeholder engagement. The three key avenues are:

- preparatory activities, for which forecast operating expenditure (opex) is approved via the revenue determination process
- forecast costs assessed in the RIT-T and recovered under the CPA process
- cost pass-throughs, where TNSPs can seek to amend their revenue determination for specific pass-through events that are beyond the TNSPs reasonable control.

The Commission considers that each of these avenues provides appropriate means for the recovery of costs associated with the numerous and varied activities required to help build and maintain social licence across the end-to-end process of planning and delivering a project. As such, it is the Commission’s view that the existing framework remains fit for purpose to support the recovery of costs associated with activities to build and maintain social licence.

3.2.1 Revenue to fund the costs of some social licence activities is included in forecast expenditure for preparatory activities

As discussed in further detail in Chapter 4, TNSPs have an obligation under the NER to undertake preparatory activities for all actionable ISP projects, as well as for future ISP projects where specified in the ISP.[26] Preparatory activities are activities required to investigate the costs and benefits of actionable ISP projects and, if applicable, future ISP projects to support ongoing improvements to the ISP through the TNSP and Australian Energy Market Operator (AEMO) joint planning process.[27] This includes activities such as engagement with landowners and asset owners on potential transmission routes, local community members and groups, local councils and state planning departments, and First Nations, environmental, and other special interest groups.[28] Some stakeholders suggested that earlier recovery of stakeholder engagement costs would enable TNSPs to carry out stakeholder engagement activities at an earlier stage of the planning process.[29]

Expenditure on preparatory activities is forecast and assessed via the revenue determination process. A TNSP may include in its revenue proposals any operating expenditure and/or capital expenditure (capex) it forecasts as being required to comply with its obligations under the Rules.[30] This can include social licence activities (captured under preparatory activities) that occur in the preliminary stage of investigating and/or planning a major transmission project. The forecast operating and/or capital expenditure submitted by the TNSP is then subject to an efficiency assessment by the AER.[31]

3.2.2 The RIT-T provides a further avenue to seek revenue for the costs of social licence activities, which are then recovered via the CPA process

Under the NER the RIT-T provides proponents the opportunity to identify and quantify the classes of costs they will incur in delivering the major transmission project.[32] This includes costs incurred to comply with laws, regulations, and applicable administrative requirements in relation to the construction and operation of the credible option.[33] For example, jurisdictional planning bodies issue proponents of large infrastructure projects with environmental assessment requirements that need to be undertaken before approval is provided to construct. The environmental assessment requirements normally include activities such as: consulting with community groups and affected landowners; preparing an assessment of the social and economic impacts of the project; developing a community and stakeholder consultation plan; and developing land access plans in consultation with landowners.

Landholder compensation payments are a matter of key concern for stakeholders, and particularly TNSPs when it comes to the management of social licence. Under existing arrangements, the estimated cost of these payments is reflected in a TNSP's RIT-T and is recovered via the CPA process.[34] In the RIT-T, TNSPs include an estimate of land acquisition

26 Clauses 5.22.6(c)-(d) of the NER.

27 Clause 5.14.4(a) of the NER.

28 RE-Alliance, submission to the consultation paper, p.p.2-3.

29 Submissions to the consultation paper: ENA, p.23; AEIC, p.3.

30 Clauses 6A.6.6 and 6A.6.7 of the NER.

31 Note that the Commission is considering clarifying the definition of "preparatory activities" as applying to activities that are carried out in order to identify the preferred option (and not the delivery option). This is discussed in more detail in Chapter 4.

32 Clause 5.15A.2(b)(8) of the NER for actionable ISP projects and clause 5.15A.3(b)(6) of the NER for RIT-T projects which are not actionable ISP projects.

33 Clause 5.15A.2(b)(8)(iii) of the NER for RIT-T projects which are not actionable ISP projects; and clause 5.15A.3(b)(6)(iii) of the NER for actionable ISP projects.

34 Rule 6A.8 of the NER.

costs (negotiated or compulsorily acquired) in accordance with jurisdictional legislative instruments.[35] The AER will then assess the reasonableness of the cost estimate proposed and determine an efficient allowance. Reasonableness is determined with reference to matters such as the market value of the land, any loss attributable to severance or disturbance, or any increase or decrease in value.[36]

Stakeholders have suggested changes which could be made to the compensation arrangements.[37] As described in section 3.4.1, decisions on the quantum of compensation received by impacted parties are the remit of jurisdictional instruments, not the NER. The role of the NER is to allow for the recovery of the efficient costs of meeting jurisdictional legislative requirements. While estimating efficient costs is challenging, as demonstrated in Box 5, the Commission considers that the process is working well.

Beyond costs incurred by TNSPs in complying with jurisdictional laws and regulations, the RIT-T also provides the opportunity for TNSPs to include any other class of costs determined to be relevant by the TNSP and agreed to by the AER in writing before the date the relevant project assessment draft report (PADR) is made available to other parties (noting that the PADR only applies to non-ISP projects).[38] This provides an avenue for TNSPs to recover any costs associated with social licence activities that were not incurred as part of complying with laws, regulations and applicable administrative requirements but were foreseen by the TNSP and agreed to by the AER.

BOX 5: EXAMPLE OF AER ASSESSING THE ESTIMATED COSTS OF ACTIVITIES CARRIED OUT TO BUILD COMMUNITY ACCEPTANCE.

ElectraNet and Transgrid submitted separate CPAs to the AER for the sections of Project Energy Connect that the respective businesses were responsible for building.

The AER's Final Decisions included the following costs in the capital expenditure allowances:

- ElectraNet:
  - $11.1 million for land and easement acquisition
  - $7.2 million for stakeholder and cultural heritage engagement
  - $3.0 million for environmental offsets.*
- Transgrid:
  - $109.6 million for property and easements
  - $125 million for environmental offset costs (including risk). This was $41.6 million less than Transgrid's estimate.**

35 For example, in NSW, compensation arrangements are set out under the *NSW Land Acquisition (Just Terms Compensation) Act 1991.*

36 These matters reflect the *NSW Land Acquisition (Just Terms Compensation) Act 1991* ss 10A, 11, 13, 54, 55.

37 Submissions to the consultation paper: AusNet Services, pp.10-11; Moyne Shire Council, pp.5-7; RE-Alliance, p.3; Energy Grid Alliance, p.21; MEU, p.13.

38 Clause 5.15A.2(b)(8)(iv) of the NER for RIT-T projects which are not actionable ISP projects; and clause 5.15A.3(b)(6)(iii) of the NER for actionable ISP projects.

The AER has demonstrated a balanced approach to assessing efficient costs of negotiated landowner compensation amounts for Transgrid

In its CPA, Transgrid proposed estimates for easement and land acquisition costs that included a market value of land component as well as a forecast contingency for negotiating with landowners to secure easements over and above market rates.

In its revised proposal, Transgrid stated that the ability to negotiate agreements with private landowners would minimise the need to compulsorily acquire property along the route. This is important as the compulsory acquisition of land has the potential to negatively impact TNSPs' relationships with stakeholders and communities. The impact of a deterioration in good relationships between the TNSP and communities is a potential increased risk of delay to the project.***

However, the Public Interest Advocacy Centre (PIAC) disagreed with Transgrid's proposed contingency for negotiating with landowners. While PIAC supported the option of negotiating outcomes, it questioned "...whether it is appropriate for New South Wales (NSW) consumers to bear costs above market price for such negotiated outcomes given the primary direct beneficiary of this relationship building approach is Transgrid."****

The AER recognised that while Transgrid should not be able to recover costs above what is prudently required, negotiated outcomes have the potential to be greater than historical negotiated settlements. The AER concluded that while the allowance proposed by Transgrid was "...likely at the higher end of a reasonable range...", there is a reasonable chance that Transgrid would need to pay higher land values to ensure land is acquired on time, reduce the likelihood of compulsory acquisition of land, and avoid any further route deviations – noting that the avoided time delays and additional costs would benefit consumers.**

Source: *AER, *Final Decision: ElectraNet Contingent Project – Project Energy Connect*. May 2021.
Source: **AER, *Final Decision: TransGrid Contingent Project – Project Energy Connect*. May 2021.
Source: ***Transgrid, *Project Energy Connect: Contingent Project Application – Revised Capex Application*, 30 April 2021.
Source: ****PIAC, *Submission to Project EnergyConnect revised contingent project application*, 17 May 2021.

3.2.3 The cost pass-through mechanism in the rules allows TNSPs to recover unexpected and unavoidable costs

Should TNSPs incur an unexpected or unavoidable material cost associated with carrying out social licence activities, they may seek to recover these costs as cost pass-through events.[39] As is explored in greater detail in Chapter 4, TNSPs can nominate specific activities as a cost pass-through event in the revenue determination. The AER can then decide whether to include the nominated event as a cost pass-through event for the upcoming regulatory period.[40] For example, TNSPs can use the cost pass-through arrangements to manage preparatory activities that are unknown at the time when a regulatory proposal is submitted.

39 Clause 6A.7.3(a1) of the NER.

40 Clause 6A.7.3 (d) of the NER.

In its submission to the consultation paper, Transgrid suggested that the costs associated with building community acceptance, such as changes to the route alignment required by state planning processes, should be a direct cost pass-through (with appropriate third-party verification) as the costs can be significant and largely outside the TNSP's control.[41]

While the Commission recognises that costs incurred as a result of changes to route alignment and/or planning processes are not insignificant, it is the Commission's view that this category of event is not appropriate to treat as a pass-through as there is sufficient information and opportunities available to TNSPs to manage uncertainty associated with such changes. For example:

- Risks of this nature can be quantified, and so managed as part of the risk allowance for major transmission projects
- Uncertainty of these costs could be managed through the staged CPA process (such as earlier and improved engagement with potentially impacted communities).

We welcome stakeholder feedback on the Commission's view that the current cost recovery mechanisms are appropriate and allow TNSPs to recover the costs associated with landowner compensation payments, stakeholder engagement, and other social licence activities associated with major transmission projects.

We also welcome stakeholder feedback on whether there are any other activities undertaken to support building and maintaining social licence that are not captured under the existing cost recovery mechanisms.

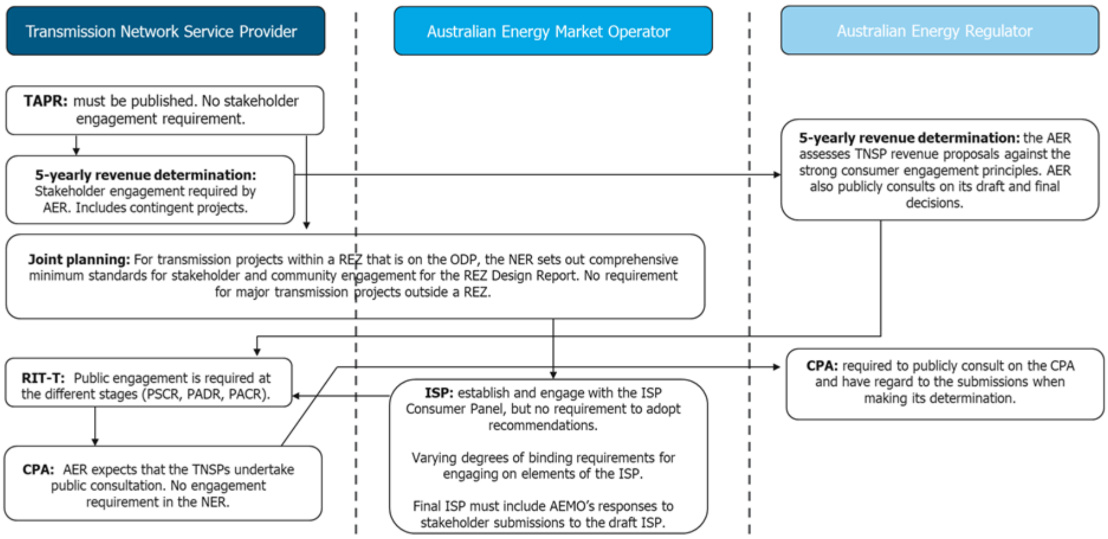
3.3 Stakeholders have suggested further opportunities for TNSPs to improve stakeholder engagement outcomes

The NER places obligations on AEMO, TNSPs, and the AER to support stakeholder consultation as part of the identification and delivery of major transmission projects.

These obligations are indicated in Figure 3.1 below.

41 Transgrid, submission to the consultation paper, p.5.

Figure 3.1: Mapping stakeholder engagement obligations in the NER



Source: Chapter 5 of the NER; Chapter 6A of NER; AER, *Transmission Annual Planning Report Guidelines December 2018;* AER, *Better Resets Handbook December 2021.*

The rules are largely non-prescriptive in how each of these parties meets their obligations. This ensures, for example, that TNSPs can develop stakeholder engagement activities to suit each individual major transmission project.

Some of the stakeholder engagement activities that TNSPs currently undertake at the project identification and delivery stages include:

- Project identification:
  - general consultation on identified need and pathway options during the RIT-T.
- Project delivery:
  - consulting with community groups and affected landowners
  - preparing an assessment of the social and economic impacts of the project
  - developing community and stakeholder consultation plans
  - developing land access plans in consultation with landowners
  - financial compensation of landowners for land needed.

Stakeholders provided feedback to the consultation paper on areas where they considered that stakeholder engagement activities could be improved. Based on stakeholder feedback, the Commission's review of the existing framework has focused on engagement activities carried out by TNSPs. As outlined below, the Commission's initial view is that the obligations within the NER for TNSPs to build and maintain social licence are largely appropriate. Feedback on whether there are any changes which would improve the timeliness and/or efficiency of major project delivery is welcomed. The Commission considers that how the NER is applied and implemented by TNSPs is crucial to obtaining social licence for each major transmission project. The Commission also welcomes feedback on whether further review of the obligations placed on other parties in the NER should be considered.

3.3.1 Stakeholders expect TNSPs to engage with stakeholders in a genuine and collaborative way, as good quality engagement results in better outcomes for consumers

In submissions to the consultation paper, stakeholders provided feedback on opportunities TNSPs can take to improve community acceptance of major transmission projects. Stakeholder feedback indicated there are several ways for TNSPs to improve the quality of stakeholder engagement across the NEM, including opportunities to:[42]

- tailor engagement to meet community needs
- involve stakeholders more and provide greater transparency around decisions, and
- improve the timing of stakeholder engagement, bringing it forward where possible so that stakeholders can engage more effectively.

Stakeholders seek a greater level of tailored and transparent engagement

Some stakeholders considered that TNSPs need to improve the overall quality of their engagement with consumers, landowners and communities, and suggested that this required adaptability due to the diversity of stakeholder views.[43] Energy Grid Alliance considered that establishing and delivering on clear expectations for engagement, as well as providing stakeholders with the opportunity to influence decisions, was key for engagement to be most successful.[44] Referencing the International Association for Public Participation (IAP2) Public Participation Spectrum, RE-Alliance suggests that engagement should move from "inform, consult, or involve" to active collaboration with and empowerment of local communities.[45]

Other stakeholders expressed a need for community supported guidelines and the importance of community involvement and transparency around decisions that impact the preferred options and route selection, which would help build stakeholder confidence in the consultation process.[46] AusNet Services suggested that including social or environmental impacts under clause 5.1.2(a) of the NER when determining a credible option would improve engagement.[47]

In line with this feedback, there has been recent work undertaken, including by the AER, to improve stakeholder engagement. In 2021, the AER replaced the *Consumer Engagement Guideline* with the *Better Resets Handbook – Towards consumer-centric network proposals*, which sets out the AER's expectations for how network businesses should engage with consumers. The handbook was developed to encourage better engagement from network businesses and to encourage network businesses to develop regulatory proposals that are

42 Submissions to the consultation paper: AEIC, p.2; Energy Grid Alliance, p.28; APA, p.8.

43 Submissions to the consultation paper: COTA Queensland, p.2; AEIC, p.2.

44 Energy Grid Alliance, submission to the consultation paper, p.28.

45 RE-Alliance, *Building Trust for Transmission,* 2021, p.11.

46 Submissions to the consultation paper: Energy Grid Alliance, p.6; AusNet Services, p.9; ENA, p.5.

47 AusNet Services, submission to the consultation, p.10.

driven by consumer preferences. Network businesses are incentivised to comply with the handbook as the AER will more likely accept revenue proposals that meet its expectations.[48]

The AER has clearly outlined its expectations and the importance of stakeholder engagement in delivering outcomes that are in the long-term interests of consumers. The factors that the AER will consider include:

- Nature of engagement: whether the engagement approach is sincere, accountable, treats consumers as partners, and equips consumers to engage.
- Breadth and depth: whether the TNSP's engagement is accessible, clear and transparent; whether the TNSP consults on outcomes then inputs, adopts multiple channels of engagement, and allows consumers to influence the regulatory proposal.
- Clearly evidenced impact: whether proposals are linked to consumer preferences, and demonstrate independent consumer support for the proposal.

In 2021, the AER also released the *Guidance Note: Regulation of actionable ISP projects.* In the Guidance Note, the AER clearly articulated its expectations for TNSPs to carry out high-quality, early engagement with local community and consumer representatives, which could result in[49]:

- improved stakeholder and community understanding of the project's costs and risks
- opportunities for the project solution to be designed with input from the local communities impacted by the proposed major transmission project
- TNSPs having a better understanding of community concerns about route selection, which in turn would help the TNSP to manage the associated risks, and
- opportunities for the TNSP to address and manage concerns raised by stakeholders.

Given the recent release of these guiding documents, the Commission notes that the changes in network business behaviour and approaches to engagement may take some time to mature.

Improved timing and earlier stakeholder engagement was seen as beneficial

Stakeholders also provided suggestions around the timing of stakeholder engagement for transmission projects, with some proposing that engagement with stakeholders should start earlier.

The benefits of stakeholder engagement at the RIT-T stage were raised in submissions to the consultation paper. For example, ENA considered that stakeholder engagement at the RIT-T stage helps build community engagement and social licence for major transmission projects.[50] RE-Alliance suggested TNSPs should start their RIT-T engagement early and ensure they engage with:[51]

- landowners and asset owners along potential transmission routes

48 AER, *Better Resets Handbook – Towards consumer centric network proposals*, 2021, p.1.

49 AER, *Guidance Note: Regulation of actionable ISP projects 2021*, p.5.

50 ENA, submission to the consultation paper, p.13.

51 RE-Alliance, submission to the consultation paper, pp.2-3.

- local community members and groups
- local councils and State Planning Departments
- First Nations, environment, and other special interest groups.

Starting stakeholder engagement earlier, such as at the project inception stage or before decisions about route or asset locations are made, was recommended by some stakeholders. These stakeholders suggested that engaging earlier could promote community acceptance and mitigate the risk of project delays.[52] Energy Grid Alliance suggested that engaging early is important for building trust and positive relationships.[53]

ENA suggested that earlier recovery of stakeholder engagement costs will enable TNSPs to start building better social licence.[54] Further information on the recovery of preparatory activity costs is detailed in Chapter 4.

However, early engagement with communities is often challenging when the information most relevant to the community is not available at the time, and the nature of the regulatory process can be difficult for communities to understand. For example, it would be useful to further consider the suitable timing and form of engagement with communities to better capture their views when identifying and determining the preferred route corridor. The Commission considers that it is crucial that communities are involved wherever possible in the design and execution of programs related to major transmission projects. This will require detailed consideration of the effectiveness, or otherwise, of current community/landholder engagement programs, including the types and availability of information sought by communities throughout the design and execution of major transmission projects.

3.3.2 TNSPs are evolving their approaches to stakeholder engagement, with some implementing tools and approaches to lift the standard

The Commission notes that some TNSPs, as well as other parties in the energy sector, are working towards improving stakeholder engagement outcomes. The Commission welcomes initiatives to build and maintain community acceptance to assist in the timely and efficient delivery of major transmission infrastructure.

There is evidence that TNSPs are taking action to improve their engagement with landowners

To improve its engagement with stakeholders, Transgrid appointed a Landowner and Community Advocate for HumeLink. The Advocate made a suite of recommendations for improving stakeholder engagement activities, which Transgrid committed to implementing. This included recommendations to support community input into decisions about route options, to improve communication channels and materials, and to train Transgrid staff on community engagement.[55]

52 Submissions to the consultation paper: APA, p.8; Energy Grid Alliance, p.6, p.28.

53 Energy Grid Alliance, submission to the consultation paper, p.28.

54 ENA, submission to the consultation paper, p.23.

55 Transgrid, *Implementation of the Landowner Advocate's Recommendations on HumeLink*, 2022.

Powerlink has a *Land Access Protocol* which sets out its standards and commitments when entering and using land. This protocol was developed in consultation with stakeholders.

The Energy Charter (which is a joint network and retail business voluntary initiative) has also developed a *Landholder & Community Better Practice Engagement Guide* to help landholders understand what to expect through engagement on project. This was co-designed with landholder and community representatives and launched at a National Farmers Federation event in September 2021.[56]

Some TNSPs are engaging with stakeholders early to ensure their revenue proposals are shaped by consumer preferences

Powerlink's approach to engagement for the development of its 2023-27 Revenue Proposal demonstrates the benefits of earlier engagement for improving the level of stakeholder impact. Stakeholder input helped shape Powerlink's revenue proposal to the AER and this was informed by input from Powerlink's Customer Panel from the initial stages of developing the revenue proposal in 2019. The Customer Panel for the 2023-27 proposal stated that the level of influence it was able to have was "high" and cited five clear examples of where they had been able to have influence – including areas such as depreciation and capital expenditure/operating expenditure treatments and calculations.[57]

We welcome stakeholder feedback on whether the current stakeholder engagement requirements in the NER provide sufficient flexibility for TNSPs to develop and implement appropriate stakeholder engagement plans for major transmission projects.

We also welcome stakeholder feedback on whether greater prescription around stakeholder engagement is needed in the NER, and if so, what would be required.

We welcome stakeholder feedback on whether there are any barriers to TNSPs bringing stakeholder engagement activities forward into the RIT-T stage.

3.4 Stakeholders raised other opportunities for improving community acceptance of major transmission projects that fall within the remit of jurisdictional regulatory frameworks

Stakeholders have made suggestions for improving social licence outcomes for major transmission projects covering a broad range of issues, some of which fall outside of the Commission's remit.

Issues raised by stakeholders relating to jurisdictional frameworks generally fell within two key areas:

- Community benefit sharing and landowner compensation
- Planning, including land use and land access.

56 https://www.theenergycharter.com.au/landholder-and-community-engagement/

57 Powerlink, *Appendix 3.03 – Customer Panel Statement on Engagement*, p.2.

3.4.1 Landowner and community expectations about compensation are changing and stakeholders suggested opportunities to adapt current approaches

Landowner and community expectations about compensation for hosting major transmission infrastructure are changing as they are exposed to different types of compensation approaches from non-regulated entities such as large-scale wind and solar generation proponents. The level of compensation that should be paid to landowners was an issue raised by a number of stakeholders in submissions to the consultation paper. These stakeholders suggested TNSPs should take an approach that is similar to that taken by proponents of wind farm generators.[58] For example, the Australian Energy Infrastructure Commissioner (AEIC) reported the following elements of landowner compensation for hosting wind turbines:[59]

- host landowners are typically paid a fixed amount per turbine under a long-term agreement
- the long-term agreement may be for the life of the turbine (for example, 25 years) and may include an option to renew
- the payment may be an annual flat rate per turbine or a fee based on the turbine's generating capacity
- payment frequency is subject to negotiation but may start at project construction and may cease once the turbine has been decommissioned and the land restored.

Some stakeholders were also of the view that compensation should be extended to include communities impacted by major transmission infrastructure.[60]

While most compensation arrangements apply only to landowners, stakeholder feedback proposes an extension of that compensation should be available to apply to communities. This could be through an extension of existing community development and partnership programs, and to landowners that do not host the infrastructure but are in close proximity to those that do.[61]

One stakeholder suggested that governments could consider developing a strategic government-led social and economic development package for host communities of major transmission and REZ projects, recognising the disproportionate effect of such projects on these communities. This stakeholder considered that the need for development in host communities should be identified in the ISP.[62]

The Commission notes the work that jurisdictions are already undertaking to improve community acceptance of projects within identified REZs.

For example, the New South Wales Electricity Infrastructure Roadmap sets out a number of community-related and social obligations that are embedded in its *Electricity Infrastructure Investment Act 2020* (EII Act). The statutory authority, Energy Corporation of NSW

58 Submissions to the consultation paper: MEU, p.13; RE-Alliance, p.3.

59 AEIC, "Host Landowner Negotiations" in *Commissioner's Observations and Recommendations (updated 2020)*, online.

60 Submissions to the consultation paper: RE-Alliance, p.3; Resist Humelink, p.4; AusNet Services, p.9.

61 Submissions to the consultation paper: Resist Humelink, p.4; AusNet Services, p.9; RE-Alliance, p.3.

62 Moyne Shire Council, submission to the consultation paper, pp.5-6.

(EnergyCo), has a coordination role that includes planning and consultation responsibilities to ensure timely and efficient delivery of the investment needed for REZs in New South Wales. This includes activities such as leading community and stakeholder engagement and promoting local development opportunities.[63]

In Victoria it is proposed that VicGrid would have a planning function in consultation with communities, as well as a role in ensuring REZs provide benefits to local communities.[64]

In relation to landowners, stakeholders suggested that community acceptance of project outcomes would be improved if landowner compensation was negotiated rather than compulsorily acquired by the TNSP. For example, AusNet Services suggested that there is an inherent tension between the goal of negotiated settlements and the incentive framework, which encourages TNSPs to minimise capital costs.[65] Shell was of the view that resorting to compulsory acquisition indicates failed stakeholder engagement.[66] Other stakeholders suggested that TNSPs should consider an approach of ongoing payments to landowners, similar to wind farm developers.[67]

The Commission encourages jurisdictions to consider:

- reviewing jurisdictional frameworks to identify any barriers to faster settlement of land acquisitions, and
- the role of jurisdictions in helping build relationships between TNSPs and landowners. This may include government-led public communications campaigns about the role of major transmission projects in the energy transition and their benefits to consumers and communities.

3.4.2 Better consideration of planning decisions and their impacts on landowners and communities may reduce the risk of land use conflicts delaying the development of major transmission projects

Land use conflicts can delay the development of major transmission projects. Energy Grid Alliance provided a number of suggestions to minimise this risk including using existing transmission corridors or rights of way, avoiding or minimising social-economic impacts, and avoiding or minimising environmental impacts to protect and conserve the environment.[68]

Some stakeholders have also proposed that transmission lines should be installed away from populated areas or productive agricultural land, taking into consideration losses in productive efficiency due to limitations in the types of equipment that can be used near transmission lines.[69] Energy Grid Alliance also suggested improving the governance of planning approvals to ensure optimal design and routing of transmission lines.[70]

63 https://www.energy.nsw.gov.au/renewables/renewable-energy-zones

64 Department of Environment, Land, Water and Planning, *Victorian Renewable Energy Zones Development Plan Directions Paper,* February 2021, p.2.

65 AusNet Services, submission to the consultation paper, p.9.

66 Shell, submission to the consultation paper, p.6.

67 MEU, submission to the consultation paper, p.13.

68 Energy Grid Alliance, submission to the consultation paper, p.12.

69 Submissions to the consultation paper: Energy Grid Alliance, pp.21-22; Resist Humelink, p.5.

70 Energy Grid Alliance, submission to the consultation paper, pp.21-22.

APA considered that there might be benefit in reviewing land access arrangement to ensure TNSPs have certainty of access to land for the purpose of developing major transmission projects.[71]

The Commission encourages jurisdictions to consider:

- reviewing jurisdictional land access protocols to see if changes could be made to improve relationships between TNSPs and landowners, and
- whether coordination activities between energy, environment, and planning portfolios can help to progress the delivery of major transmission projects for the energy transition.

71 APA, submission to the consultation paper, p.8.

4 COST RECOVERY OF PLANNING ACTIVITIES

BOX 6: KEY RECOMMENDATIONS

The Commission's draft position is that there is merit in providing additional clarity to reduce uncertainty around how different types of planning activities can be distinguished and how the associated costs are recovered.

The Commission's draft recommendation is to:

- Make changes to distinguish between planning activities for actionable ISP projects based on whether they relate to the selection or delivery of a preferred option to meet an identified need. This will be given effect through:
  - amending the definition of 'preparatory activities' in the NER to further clarify that their purpose is to inform the *selection* of a preferred option.
  - removing the term 'early works' from AER and AEMO documentation and replacing it with consistent language that characterises activities as either preparatory or not, based on their purpose. That is, whether an activity relates to the *selection* of a preferred option (in which case it is a preparatory activity) or *delivery* of a preferred option (in which case it is not a preparatory activity).
- The above changes will clarify that costs to select a preferred option are recovered through the regulatory allowance, while expenditure to deliver a preferred option is to be recovered through the CPA process.
- In addition, the Commission considers that the existing cost pass-through and project/CPA staging arrangements remain suitable and effective mechanisms to manage material uncertainty over cost recovery for planning activities.

The Commission notes that distinguishing planning activities in this manner will help inform a broader consideration in Stage 3 of the Review of the staging of projects under the actionable ISP framework (where staging is identified in the ISP). Specifically, Stage 3 of the Review will consider which planning activities appropriately comprise a project stage and the appropriate economic assessment process required to justify any expenditure.

The Commission's draft position is that there is merit in providing additional clarity on how different types of planning activities can be distinguished and how the associated costs are recovered.

This chapter sets out the:

- importance of planning activities in the timely and efficient delivery of major transmission projects
- treatment of planning activities within the existing framework,
- Commission's recommendations to clarify the regulatory treatment of planning activities.

4.1 Planning activities to support project selection and delivery help de-risk the transmission planning and investment process

The planning phase of major transmission projects is important to manage uncertainty by helping to identify key project risks and to enable innovative and cost-effective design.

Under the actionable ISP framework, TNSPs incur expenditure related to two distinct types of project planning activities:

1. Activities to *identify and select* the preferred option[72] to meet an identified need. This includes activities to develop project cost estimates in both the ISP and RIT-T stages and assess potential credible options in the RIT-T.
2. Activities to further *refine and deliver* the preferred option. This includes activities to develop firmer cost estimates and obtain a social licence for the preferred option. This also involves purchasing assets with long lead times, which are required before construction begins such as acquiring a slot in a manufacturer's queue for equipment.

Both types of planning activities assist TNSPs in identifying and managing project risks. Identifying key project risks early in the planning process promotes more reliable cost estimates and expenditure forecasts. This reduces the likelihood of cost overruns in the delivery of the preferred option due to poor planning upfront. Effective project planning activities can also help promote the timely and efficient delivery of major transmission projects by reducing uncertainty in project selection and delivery.

4.2 Planning activities can be more clearly distinguished in the regulatory framework

4.2.1 Clearly distinguishing between the different types of planning activities is necessary for cost recovery

Under the NER, different cost recovery arrangements are intended to apply for different types of planning activity expenditure. Generally speaking:

- Costs associated with preparatory activities to identify and select preferred options are typically accommodated within TNSPs' expenditure allowances. TNSPs must demonstrate in their regulatory proposals that the planned expenditure is prudent and efficient.
- Costs associated with substantive project delivery activities are intended to be recovered through the CPA process. TNSPs currently have limited certainty of recovering such expenditure if it is incurred before the CPA is approved.

These arrangements aim to achieve an appropriate allocation of risk between TNSPs and consumers. Specifically, by ensuring that consumers do not bear the cost of delivering a transmission investment that has not yet been confirmed as the preferred option through the application of a RIT-T.

The application of these cost recovery arrangements relies on how categories of planning activities are distinguished. Clarity around how to distinguish types of planning activities

72 'Preferred option' has the meaning given in clauses 5.15A.1(c) and 5.17.1(b) of the NER.

provides TNSPs with certainty around how costs for these activities can be recovered under the regulatory framework. This certainty encourages TNSPs to undertake an efficient level of expenditure on these activities – supporting the timely and efficient delivery of major transmission investments. A lack of clarity may lead to inefficient expenditure decisions.

4.2.2 Preparatory activities and 'early works' are not clearly distinguishable in the regulatory framework

Planning activities are referred to in different ways in the NER and in regulatory documents produced by the AER and AEMO. In particular, the NER refer to 'preparatory activities' while AER and AEMO documents refer to 'early works'.

The existing distinction between the two concepts appears to be one of magnitude (that is, the cost) and the extent to which the activities are project specific. However, as explained further below there are overlaps between the descriptions of these activities. This creates confusion over whether certain planning activities fall into the category of preparatory activities or early works, or both. Stakeholders expressed in their submissions to the consultation paper that it is important to provide additional clarity on the distinction between preparatory activities and what is currently referred to as early works.[73]

TNSPs have an obligation under the NER to undertake preparatory activities for all actionable ISP projects, as well as for future ISP projects where specified in the ISP.[74] Preparatory activities refer to actions taken to investigate the costs and benefits of actionable ISP projects and, if applicable, future ISP projects to support ongoing improvements to the ISP through the TNSP and AEMO joint planning process.[75] Preparatory activities are explicitly defined in the NER as follows:[76]

> "**preparatory activities** means activities to design and investigate the costs and benefits of actionable ISP projects, future ISP projects and REZ stages (as applicable), including:
>
> a) detailed engineering design;
>
> b) route selection and easement assessment work;
>
> c) cost estimation based on engineering design and route selection;
>
> d) preliminary assessment of environmental and planning approvals; and
>
> e)council and stakeholder engagement."

73 Submissions to the consultation paper: ENA, p. 22; Transgrid, p. 13; AEMO, pp. 18-19; AGL, p. 3; AusNet, pp. 13-14; CS Energy, p. 11; EnergyAustralia, p. 10; EUAA, pp. 10-11; Neoen, p. 9; Origin, p. 5; Snowy Hydro, p.2; TasNetworks, p. 7; PIAC, p. 8; and Shell Energy, p. 6.

74 Clauses 5.22.6(c)-(d) of the NER.

75 Clause 5.14.4(a) of the NER.

76 Clause 5.10.2 of the NER.

The term 'early works' is not explicitly defined or referred to in the NER, but is referenced in several regulatory documents including the ISP, the AER's *Cost Benefit Analysis Guideline* and the AER's *Guidance Note on the Regulation of Actionable ISP projects*.[77]

The AER guidelines describe early works as activities that are more substantial and distinct from preparatory activities.[78] AEMO has also used the term early works to describe the actionable first stage of the VNI West and HumeLink projects in the 2022 Draft ISP.[79] The activities comprising early works for these projects include:[80]

- project initiation, including the planning and design activities required to accurately define the projects such as pre-contracting activities for engineering, procurement and construction contracts
- stakeholder engagement with local communities, landowners and other stakeholders
- land-use planning to identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection, easement acquisition and preparation of option agreements with landholders
- detailed engineering design
- cost estimation.

As noted above, there are potential overlaps between the definitions of preparatory activities and early works. Accordingly, the Commission has considered how clarity could be improved.

4.2.3 Project planning activities can be clearly distinguished based on whether they relate to the selection or delivery of a preferred option

The Commission has assessed two potential options to distinguish between various planning activities and to clarify the cost recovery arrangements for these activities in the context of major transmission projects. These are:

- **Option 1:** Distinction based on cost magnitude, the approach implicit in the AER's CBA Guidelines.[81] This option retains the term 'early works', defining these as planning activities that exceed a particular cost threshold. The concept of 'preparatory activities' would then cover planning activities that do not meet the early works definition. The cost of preparatory activities would be recoverable through the TNSP's revenue allowance, while early works expenditure would be recovered through the CPA process.
- **Option 2:** Distinction based on the purpose of the expenditure, which involves:
  - Clarifying, through amending the definition in the NER, that expenditure on preparatory activities relates to the *selection* and *identification* of the preferred option [82]

77 AER, *Cost benefit analysis guidelines,* August 2020; and AER, *Guidance note – Regulation of actionable ISP projects,* March 2021.

78 AER, Guidance note - regulation of actionable ISP projects, March 2021, p. 26.

79 AEMO, *Draft 2022 Integrated System Plan,* December 2021, p. 13.

80 Ibid, p. 66 and p. 69.

81 AER, *Cost benefit analysis guidelines,* August 2020, p. 40.

82 See Clause 5.10.2 of the proposed draft rule.

- Clarifying that expenditure relating to the *delivery* of the preferred option is recovered through the CPA process, as is the intention under existing rules
- Removing use of the term 'early works', which would no longer be required.

The Commission's draft recommendation which has been developed through collaboration with other market bodies, is to adopt option 2. The following sections set out the Commission's assessment of the options.

Option 1: Distinguishing on the basis of cost magnitude is not the recommended approach because it does not appropriately allocate risk

To implement this option, an appropriate cost threshold methodology would need to be developed to define 'early works'. The methodology would need to account for the different scale and scope of actionable ISP projects. It is unclear how a methodology would be developed because there is limited information to benchmark expenditure against.

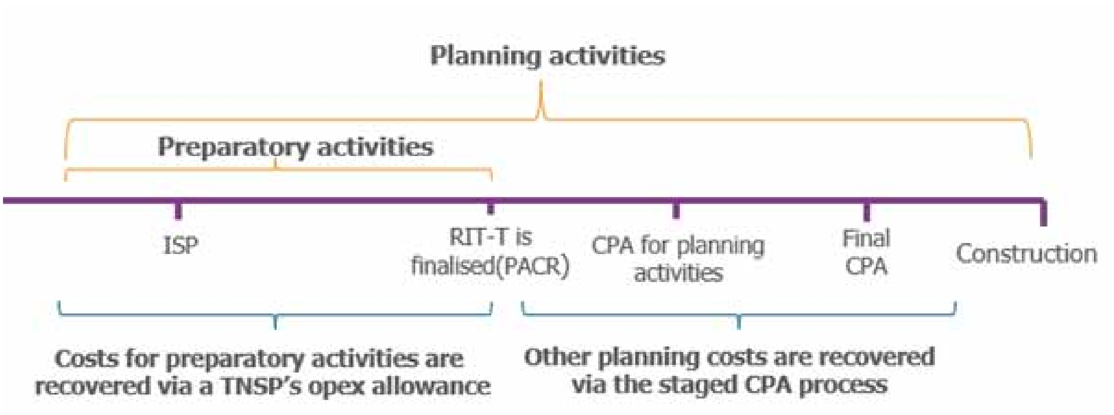
Defining early works by reference to their magnitude, rather than purpose, also risks exposing consumers to inefficient costs. This is because TNSPs would be allowed to recover expenditure associated with delivering a particular option through their regulatory allowance, up to the threshold, before that option is confirmed as preferred via a RIT-T. The cost of delivery activities may be significant in aggregate, even if they do not pass the threshold on an individual basis.

Accordingly, this option could result in consumers bearing significant delivery costs for an option that ultimately does not go ahead. Further, it may incentivise TNSPs to select an option as preferred on the basis of sunk investment costs, rather than because that option maximises net benefits. The Commission therefore considers that this approach may inappropriately place risk on consumers by enabling inefficient expenditure prior to the identification of the preferred option.

Option 2: Distinguishing project planning activities based on the purpose of expenditure is the recommended approach because it promotes clear, consistent and predictable rules

This option seeks to clarify cost recovery arrangements by distinguishing project planning activities based on their purpose, as summarised in Figure 4.1

Figure 4.1: Proposed approach to distinguishing planning activities and relevant cost recovery arrangements



Source: AEMC

The advantage of this approach is that it clearly demarcates when cost recovery risk should be transferred from TNSPs to consumers. Consumers are not best placed to manage the risk of cost recovery for project delivery activities until a preferred option has been published. The recommended changes achieve this by clarifying that:

- cost recovery of expenditure on preparatory activities prior to the selection of a preferred option occurs via the revenue determination process at the outset of the TNSP's regulatory control period.
- cost recovery of expenditure on project planning activities which occur after the selection of a preferred option occurs via the CPA process (for actionable ISP projects).

The Commission's draft recommendation is therefore to distinguish project planning activities based on the purpose of the expenditure. The Commission recommends the following changes to implement this distinction:

- Amend the definition of preparatory activities in the NER to explicitly highlight its purpose by clarifying that preparatory activities occur prior to the identification of the preferred option[83]
- Remove all references to early works and cost thresholds for planning activities in the AER's and AEMO's regulatory documents. Such references will no longer be required, because the NER amendments will make clear that costs should be recovered through the CPA process, unless they relate to preparatory activities. This is clear without the need to use the term "early works".

The Commission considers that the recommended approach is consistent with the NEO. Providing clear, consistent and predictable rules should assist with providing confidence to

83 See Clause 5.10.2 of the proposed amending rule.

TNSPs regarding the recovery of expenditure on planning activities in the selection and delivery of a preferred option.

We welcome stakeholder views on whether this draft recommendation to distinguish planning activities based on their purpose improves clarity in how costs related to project identification and/or delivery are appropriately recovered.

We are interested in views on whether amending the definition of preparatory activities and removing references to 'early works' in regulatory documents is appropriate.

We are also interested in stakeholder views on whether anything further is needed to achieve an appropriate balance between the cost and quality of preparatory activities. We also welcome alternative approaches that stakeholders consider would better promote the NEO.

4.3 The existing framework consists of appropriate tools to manage uncertainty in cost recovery for preparatory activities

4.3.1 Forecasting difficulties may lead to uncertain cost recovery for preparatory activities

Costs of preparatory activities are recovered through TNSPs' regulatory expenditure allowances that are set as part of the revenue determination process at the outset of their regulatory control period. An ISP may specify whether preparatory activities must be carried out and in what timeframe [84] It may be difficult for TNSPs to accurately forecast the expenditure for all preparatory activities that will be required over a regulatory period, as any new obligations set out in future ISPs may be unforeseen at the time of submitting a revenue proposal.[85] This is because there is misalignment between TNSPs' revenue allowances that are set every five years and the development of the ISP that occurs over a two-year cycle.

TNSPs bear most of the risk of overspending if the opex allowance is insufficient to accommodate any unforeseen obligations to complete preparatory activities. TNSPs may therefore undertake less preparatory activities than required to properly assess the credible options to meet an identified network need, if that TNSP perceives that these costs of preparatory activities cannot be accommodated in their opex allowance.

The Commission considers that material unforeseen obligations are unlikely to arise given the ISP joint planning process where TNSPs work closely with AEMO to develop the ISP. Therefore, TNSPs are reasonably aware of potential preparatory obligations for specific projects prior to the ISP being published. Nonetheless, the Commission recognises the potential for unforeseen issues to arise and considers it is prudent to review whether cost recovery arrangements are sufficiently robust and flexible.

84 Clauses 5.22.6(c)-(d) of the NER.

85 Submissions to the consultation paper: ENA, pp. 22-23; and Transgrid, p. 13.

4.3.2 Preparatory activities may be nominated as a cost pass-through event under existing arrangements

The Commission considers that TNSPs can use the existing cost pass-through arrangements to manage any uncertainty in the required level of preparatory activities. This could be achieved by nominating unforeseeable preparatory activities as a cost pass-through event in the revenue determination. A similar approach, currently used to manage a near identical uncertainty that exists in relation to cost recovery for renewable energy zone (REZ) design reports.[86]

The cost pass-through provisions outline specific pass-through events, for example, a regulatory change event or a service standard event.[87] The NER also permits TNSPs to propose a nominated cost pass-through event in their regulatory proposals.[88] The AER can then decide whether to include the nominated event as a cost pass-through event for the upcoming regulatory period.[89] If unforeseeable preparatory activities were to be nominated as a cost pass-through event, cost recovery would involve:

- for known preparatory activities at the time of the revenue determination – the efficient costs of preparatory activities would be considered by the AER when it assesses the opex allowance as part of a revenue determination
- for preparatory activities that could not have been known at the time of the revenue determination – the existing cost pass-through framework could be used to nominate unforeseen preparatory activities as a category of pass-through event for the revenue determination.

For example, TNSPs could propose, and the AER could determine, that the trigger for the nominated cost pass-through event is the obligation to complete preparatory activities in a forthcoming ISP. The precise form of the cost pass-through event is a matter that would be determined as part of the revenue determination process. Provided the AER approves the cost pass-through category, this approach would enable TNSPs to apply to the AER for an adjustment to their revenue determination if they are required to undertake preparatory activities that were not foreseeable at the time of their regulatory determination.

The Commission notes that stakeholders submitted to the consultation paper that it may be appropriate for preparatory activities to be treated as a cost pass-through with no materiality threshold.[90] The Commission's draft recommendation is that the cost pass-through materiality threshold should apply.[91]There is no clear reason as to why costs relating to preparatory activities should be treated differently from other cost pass-through events. Direct cost pass-throughs could also undermine efficiency incentives. However, consistent with the Energy Security Board's (ESB's) decision regarding REZ design reports, it may be

86 It is important to note that a transitional provision was added to clarify that requirements to prepare a REZ Design Report during the current regulatory control period constitute a positive change event.

87 Clause 6A.7.3 (a1) of the NER.

88 Clause 6A.7.3 (a1)(5) of the NER.

89 Clause 6A.7.3 (d) of the NER.

90 Submission to the consultation paper, ENA, p. 22; NSG, p. 9.

91 The definition of 'materially' in Chapter 10 of the NER (for the purposes of the application of a cost pass-through event under clause 6A.7.3) refers to a threshold of 1% of the maximum allowed revenue for the TNSP in any regulatory year of a regulatory control period.

reasonable for TNSPs to group multiple preparatory activities together into a single cost pass-through application to provide an additional degree of confidence that the materiality threshold would be met.[92]

The Commission considers that the recommended approach to account for uncertainty in the cost recovery of preparatory activities is consistent with the NEO. In particular, the existing cost pass-through arrangements provide sufficient flexibility for TNSPs to recover expenditure for unforeseen obligations to complete preparatory activities. The current arrangements should provide TNSPs with certainty that they have a reasonable opportunity to recover efficient costs, which promotes effective and efficient expenditure on preparatory activities.

We welcome stakeholder feedback on the Commission's recommended approach including examples where there has been unforeseeable expenditure on preparatory activities, as well as any rationale for potential changes to the existing cost pass-through arrangements that may be required to accommodate those specific circumstances.

4.4 The existing staged CPA process is appropriate to manage cost recovery uncertainty for planning expenditure to further develop and deliver the preferred option prior to CPA approval

4.4.1 TNSPs are required to manage uncertain cost recovery for planning activities that occur prior to CPA approval

Under existing rules, costs for planning activities, for actionable ISP projects, required to deliver a preferred option, are approved through the CPA process. This process is triggered by the completion of the RIT-T, which confirms the preferred option and satisfaction of the CPA trigger events. However, there may be some circumstances where projects are accelerated and certain delivery activities commence prior to expenditure for these activities being approved through a CPA. For example, jurisdictions may seek to accelerate the delivery of a specific project to support broader jurisdictional outcomes.

In some circumstances, there have also been underwriting arrangements where state governments and the Australian Government pay the network owner for the reasonable cost of expenditure if the project is not approved, or if the recovery of those costs is not ultimately approved as efficient by the AER through the CPA.

The AER introduced the staged CPA process to help TNSPs manage uncertainty in recovering costs for planning activities to deliver the preferred option that occur prior to CPA approval.[93] The staged CPA process allows TNSPs to submit a CPA for project planning and design costs prior to submitting a final CPA for the remaining costs of delivering the project. This process enables earlier approval of efficient and prudent delivery costs.[94] Staged CPAs occur after a

92 ESB, *Renewable energy zones planning | Final recommendations,* February 2021, p. 16.

93 AER, *Guidance note | Regulation of actionable ISP projects,* March 2021, p. 25.

94 The AER guidance note on the regulation of actionable ISP projects describes that a CPA for early works may be submitted as part of the staged CPA process. Therefore, the intention of the staged process is to allow early approval of planning costs to deliver the preferred option. In accordance with the Commission's draft recommendations in section 4.2.3, references to early works should be removed from this guidance note. This does not change the purpose of the staged CPA process, which is to provide early cost recovery approval for expenditure on activities that are required to deliver the project and must occur before

preferred option has been identified through the RIT-T. The AER has developed guidance to provide further clarity on the CPA staging process and enable TNSPs to utilise the process when appropriate. This is set out in the AER's *Guidance Note on the Regulation of Actionable ISP projects*.[95]

4.4.2 The staged CPA process appropriately manages cost recovery uncertainty for actionable ISP projects and will be more effective as the process matures

The staged CPA process is an appropriate mechanism to manage uncertainty in cost recovery for planning activities that are required to further develop and deliver the preferred option before the TNSP seeks full CPA approval. The Commission considers that the existing staged CPA process needs to be given time to apply before changes are contemplated. Guidance on the CPA staging process was issued in March 2021 and has not had an opportunity to be widely applied.[96] The Commission considers that these staging arrangements provide appropriate cost recovery certainty by allowing TNSPs to seek approval for regulatory funding before they are ready to submit a full CPA. This limits the level of cost recovery risk and the period of time that TNSPs are required to manage this risk.

The Commission's draft recommendation is to allow the staged CPA process to mature and be drawn on by TNSPs where appropriate.[97] The Commission considers that the staged CPA process remains fit for purpose to manage uncertainty in cost recovery for planning activities and appropriately balances providing regulatory funding earlier while ensuring consumers do not bear a heightened risk of inefficient expenditure.

The Commission considers that the recommended approach is consistent with the NEO. Staging of CPAs can reduce project risks and increase flexibility to respond to changing market conditions or risks as they arise. This is because each stage can reveal important information about the project, reducing the uncertainty associated with its costs and/or benefits. As such, the existing staged CPA process enables clear, consistent and predictable cost recovery arrangements.

We welcome stakeholder feedback on whether the staged CPA process appropriately manages cost recovery uncertainty for expenditure that occurs before full CPA approval. We welcome views on alternative arrangements to manage this uncertainty.

4.5 Stage 3 of the Review will consider how our proposed approach to distinguish project planning activities interacts with project staging

Section 4.2.3 explains that planning activities can be more clearly distinguished in the regulatory framework by clarifying that:

---

the final CPA is submitted.

95 AER, *Guidance note | Regulation of actionable ISP projects,* March 2021, pp. 25-31.

96 Currently, the staged CPA process has only been developed in the context of Humelink.

97 A TNSP is expected to consult with the AER on its intention to stage CPAs for a project, see AER, *Guidance note | Regulation of actionable ISP projects,* March 2021, pp. 9 and 28.

- expenditure on preparatory activities relates to the *selection* and *identification* of the preferred option and is recovered via a TNSP's opex allowance,
- expenditure relating to the *delivery* of the preferred option is recovered through the CPA process.

The Commission notes that distinguishing planning activities in this manner has implications for the staging of projects under the actionable ISP framework (where staging is identified in the ISP). In particular, it is necessary to consider which planning activities appropriately comprise a project stage and the relevant cost recovery arrangements. For instance, the first stage of a project may comprise:

- solely preparatory activities that assist in managing the uncertainty associated with a proposed investment, or
- a combination of activities required to *identify* the preferred option (preparatory activities) and activities to *deliver* the preferred option (such as easement acquisition).

The specific planning activities included in a project stage will also dictate the economic assessment process required to justify the expenditure. Due to this interaction, the Commission considers it appropriate to assess more holistically how our draft recommendation regarding planning activities interacts with staging as part of the Stage 3 workstream on the economic assessment process.

5 IMPROVING THE WORKABILITY OF THE FEEDBACK LOOP WILL ENABLE IT TO OPERATE AS A TIMELY AND EFFECTIVE CONSUMER SAFEGUARD

BOX 7: KEY RECOMMENDATIONS

The Commission's draft position is that the workability of the feedback loop could be improved.

The Commission's draft recommendation is that:

- Timing of the feedback loop assessment will be aligned with the publication of a draft or final ISP.
- Amendments to the AER's CBA Guidelines will be required to provide the AEMO with the discretion to establish the timeframe for when the feedback loop assessment is to occur, which can be tailored to the circumstances of a particular investment.
- This guidance will establish a feedback loop and PACR exclusion window between the final IASR and draft ISP – the period where undertaking the feedback loop is least workable for AEMO.
- Alignment with a draft or final ISP will promote timely completion of the feedback loop, while ensuring it draws on the latest available information to operate as an effective consumer safeguard – facilitating timely and efficient investment.
- The NER be amended to allow the CPA process and feedback loop assessment to proceed concurrently to manage potential bunching of feedback loop assessments around the publication of a draft ISP.

This chapter sets out the:

- reasons why the workability of the feedback loop is important to address and the practical difficulties with applying the feedback loop under current requirements
- Commission's recommended approach to improve the workability of the feedback loop by aligning the assessment process with the publication of a draft or final ISP.

5.1 Practical application difficulties undermine the ability of the feedback loop to operate as an effective safeguard for consumers

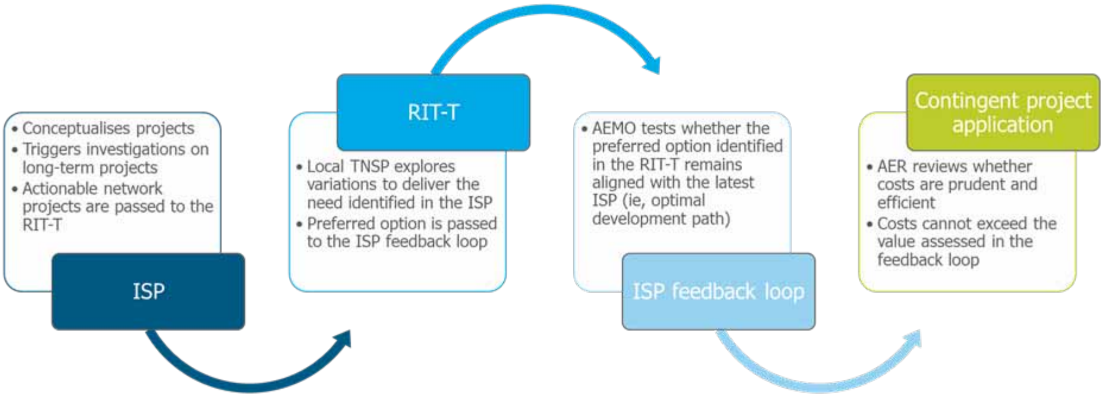
The feedback loop was introduced as part of the actionable ISP reforms and is designed as a safeguard for consumers. It requires the RIT-T proponent to obtain written confirmation from AEMO that:[98]

98 Clause 5.16A.5(b) of the NER.

- the preferred option addresses the relevant identified need specified in the most recent ISP and aligns with the optimal development path (ODP) referred to in the most recent ISP; and
- the cost of the preferred option does not change the status of the actionable ISP project as part of the ODP as updated in accordance with an ISP update.[99]

The feedback loop also caps the costs that can be sought by a RIT-T proponent in the CPA. It provides an important safeguard for consumers by ensuring that only investments that are in their long term interests are eligible for regulatory funding, and that the level of regulatory funding does not exceed the efficient investment level. The role of the feedback loop in the broader regulatory process is summarised in Figure 5.1.

Figure 5.1: the role of the feedback loop in the actionable ISP framework



Source: AEMC

Stakeholders have raised concerns that a lack of clarity and practical application difficulties undermine the ability of the feedback loop to operate as an effective safeguard for consumers. A clear, consistent and predictable regulatory framework is critical to the timely and efficient delivery of major projects. However, AEMO's experience of the feedback loop is that it is poorly defined and unworkable.[100] This unworkability may prevent timely regulatory approval of major strategic projects. ENA expressed the view that the feedback loop was extending the regulatory approval process by up to six months.[101]

The Commission considers that it is important to address these workability issues in the near term so that the feedback loop can be applied as intended and operate as an effective safeguard for consumers. Addressing this issue now will help to ensure that the significant expenditure, expected to be incurred in the short term, is in the long-term interests of consumers. However, we note that the broader role of the feedback loop in the economic

99 ISP updates are set out in clause 5.22.15 of the NER.
100 AEMO, submission to the consultation paper, 1 October 2021, p. 4.
101 ENA, submission to consultation paper, p. 3.

assessment process will also be considered as part of our holistic review of that process during Stage 3 of the Review.

The present workability problem, due to practical application issues, arises as a result of the factors that must be considered by AEMO when performing the feedback loop. If the preferred option, or its cost differs from the ISP candidate option, AEMO must consider:[102]

- removing the ISP candidate option from all development paths where it is featured, and replacing these with the RIT-T preferred option (and associated cost)
- re-running the cost benefit analysis modelling and scenario analysis if practicable, to test whether the ODP referred to in the most recent ISP:
  - still has a positive net economic benefit in the most likely scenario with the RIT-T preferred option, and
  - is still optimal with the RIT-T preferred option under the same decision-making approach, or that any difference is immaterial
- adapting the extent to which AEMO re-runs the CBA modelling and scenario analysis to the size of the difference between the costs and/or market benefits of the ISP candidate option and the RIT-T preferred option.

The requirement for the feedback loop to be assessed against the ODP, identified in the most recent ISP, is a key driver of workability issues. Under the actionable ISP framework, the most recent ISP refers to the latest final ISP, or an ISP update if one has been published.[103] This means that the assessment focuses on the current ODP as opposed to the ODPs that will be included in the publication of the next ISP.

The ODPs in the current and future ISPs will likely be underpinned by different inputs, assumptions and scenarios (as detailed in AEMO's IASR).[104] This means the feedback loop assessment may not be taking into account the latest available information and may be using outdated inputs, assumptions and scenarios.

This approach can create several practical difficulties for the feedback loop assessment, including:[105]

- undermining the value of the result of the assessment due to AEMO using inputs and assumptions underpinning the most recent ISP, because the latest version of the IASR may contain new government policies or changes to inputs that could materially affect the optimal development path of the next ISP and therefore the outcome of the feedback loop
- creating inconsistencies between the inputs underpinning the RIT-T preferred option and the feedback loop assessment, due to the requirement on RIT-T proponents to use the

102 These factors are set out in the AER's CBA Guidelines: AER, *Cost benefit analysis guidelines | Guidelines to make the Integrated System Plan actionable,* August 2020.

103 The ISP is defined in the NER as a plan developed and published under rule 5.22 as amended by an ISP update from time to time.

104 The IASR is developed in consultation with stakeholders and sets out how AEMO will model the future in its forecasting and planning publications (including the ISP). It is updated in each ISP cycle.

105 AEMO, submission to the consultation paper, pp. 4-5 and AER, submission to the consultation paper*,* pp. 9-10.

most recent ISP parameters, i.e., the latest IASR (which will likely differ from those underpinning the most recent ISP which uses the previous IASR) and

- complicating AEMO's development of the next ISP due to the need to simultaneously draw on modelling from the previous and next ISP, which can affect the timeliness of completing the feedback loop assessment.

In principle, the ISP update feature of the actionable ISP framework could be used to address these difficulties.[106] This process requires AEMO to assess the impact of new information on the optimal development path if it considers the new information will materially change the outcome of the RIT-T for an actionable ISP project that has either commenced or is due to commence prior to the publication of the next ISP, or a feedback loop request has been submitted. However, this is unlikely to be a viable approach. The scale and pace of the energy transition is such that developing an ISP update would be akin to developing an entirely new ISP because a number of significant changes are occurring concurrently.[107]

The Commission considers that enabling the feedback loop to use inputs that will underpin the optimal development path in the next ISP, particularly where there are significant differences between the ISP candidate option and RIT-T preferred option, is important for the feedback loop to be an effective consumer safeguard. Providing clarity will also promote timely completion of AEMO's assessment by enabling the feedback loop assessment to be tailored to the circumstances of a particular project.

5.2 Aligning feedback loops with the publication of a draft or final ISP will improve workability

5.2.1 The draft recommendation aligns the feedback loop with a draft or final ISP through an exclusion window

Aligning feedback loop assessments with a draft or final ISP (or final ISP once published) will improve its workability. This position is informed by stakeholder submissions from AEMO and the ENA to the consultation paper that suggested feedback loops were most workable when they aligned with a draft or final ISP.[108] Aligning the feedback loop with a draft or final ISP improves workability because:

- the assessment can be incorporated into the development of the draft ISP i.e., AEMO would not be required to draw on modelling from both previous and next ISPs, and
- the scope for misalignment between the RIT-T and ISP is narrower, reflecting the fact that the RIT-T will have likely used the inputs and assumptions underpinning the next ISP.

Aligning the feedback loop with a draft or final ISP enables AEMO to consider the latest available information from the latest IASR in its assessment – ensuring the feedback loop operates as an effective safeguard for consumers.

106 ISP updates are set out in clause 5.22.15 of the NER.

107 Submissions to the consultation paper : AEMO, p. 5; AER, p. 9.

108 Submissions to the consultation paper: AEMO, p. 4; and ENA, p. 13.

The Commission has assessed two potential options to align the feedback loop with a draft or final ISP:

- **Option 1:** PACR[109] window between the draft ISP and the final ISP, with a feedback loop window opening following publication of the draft ISP
- **Option 2:** feedback loop and PACR exclusion window between the final IASR and draft ISP, with feedback loop requests permitted any other time in the ISP cycle.

The Commission's draft recommendation is to implement a feedback loop and PACR exclusion window between the final IASR and draft ISP (Option 2). Both options 1 and 2 have the common benefit of facilitating alignment between the ISP and RIT-T in terms of the inputs, assumptions and scenarios used. This reflects the fact that they both restrict the publication of PACRs when the feedback loop is least workable for AEMO. Each option promotes confidence that the feedback loop assessment remains valuable because AEMO can consider the latest information when performing it. However, the way alignment is achieved differs between the options. Option 2 is preferred because it enables a more flexible approach that can be tailored to the circumstances of particular projects.

Option 1: PACR window between the draft ISP and final ISP is not recommended as this provides a narrower timeframe for the feedback loop to be applied

In this option, AEMO would be required to provide more prescriptive guidance through the ISP to RIT-T proponents on when the RIT-T is required to be completed. AEMO is currently required to specify the publication date of the project assessment draft report (PADR) in the ISP[110] and would additionally specify a window during which RIT-T proponents must publish their PACRs under this option. This window would open following the publication of a draft ISP and close prior to the publication of the final ISP. Figure 7.2 below shows an example of how option 1 would work in the 2024 ISP cycle.

Establishing a window for PACR publication timed around a draft ISP will mean the RIT-T proponent is required to base the PACR on the inputs and assumptions that will underpin the upcoming draft and final ISP. This will reduce misalignment of the inputs and assumptions used between the ISP and RIT-T, as each would use the latest available information. AEMO would then perform feedback loops during a window that opens upon publication of the draft ISP and closes upon publication of the final IASR that will underpin the next ISP.

The effect of this option is that PACRs would not be published, and feedback loops would not be undertaken, during the period between the final IASR being published and the draft ISP being published. This period is where performing the feedback loop is least workable for AEMO as it is actively preparing the upcoming ISP, but would be required to assess the RIT-T preferred option against the ODP in the last ISP. The result of the feedback loop may have the least value in this period due to the potential for changes to the ODP in the upcoming ISP. This is shown in Figure 5.2 below.

109 The PACR is the final report in the RIT-T process. It builds on the PADR (see footnote below) by refining all matters presented in the PADR and responding to any submissions.

110 Clause 5.22.6(a)(6)(i) of the NER. The PADR is the first report in the RIT-T for actionable ISP projects. It presents an economic net present value assessment of each credible option against a base case that quantifies the costs and benefits under a set of reasonable individual and weighted scenarios.

Figure 5.2: Aligning the feedback loop with a draft or final ISP through a PACR window between the draft ISP and final ISP (option 1)

Source: AEMC

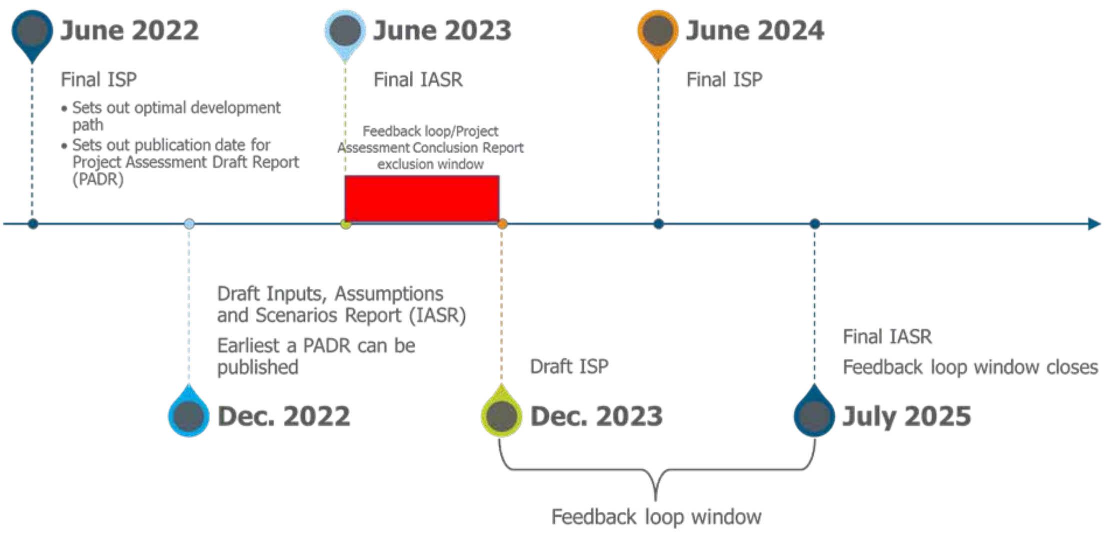
Although this option would improve the workability of the feedback loop, it may have adverse effects on timely investment. Applying the RIT-T to the major strategic projects identified in the ISP is a complex task. A prescriptive publication window for PACRs may create the risk that RIT-T proponents would not be able to complete the RIT-T in time to publish in the required window. This in turn creates uncertainty regarding when the feedback loop assessment would occur. The RIT-T proponent may have to wait for the next window (potentially two years) delaying the CPA and ultimately project delivery.

Option 2: Feedback loop and PACR exclusion window between the final IASR and draft ISP is recommended as it retains the most flexibility for RIT-T proponents and AEMO

Option 2 seeks to explicitly address workability issues by not permitting PACRs to be published and feedback loop assessments to be undertaken during the window between the final IASR and draft ISP. This would result in a four-to-six-month period of the two-year ISP cycle where feedback loops would generally not occur (subject to AEMO's discretion given the particular circumstances of the project, such as the extent of differences between the ISP candidate option and RIT-T preferred option).[111]Outside of this designated window, RIT-T proponents could submit requests for a feedback loop assessment to be carried out. Figure 5.3 shows an example of how option 2 would work for the 2024 ISP cycle.

111 In the current ISP cycle, the final IASR was published on 30 July 2021 and the Draft ISP on 10 December 2021. This would result in an exclusion window of approximately four months, available here.

Figure 5.3: Aligning the feedback loop with a draft or final ISP through an exclusion window between the final ISP and draft ISP (option 2)



Source: AEMC

Prohibiting the publication of PACRs during this period minimises misalignment between the ISP and RIT-T (subject to AEMO's discretion described in section 5.2.3), as this period is when the latest assumptions have been developed in the IASR but are not yet reflected in the ISP for assessment in the feedback loop. This option facilitates alignment between the inputs, assumptions and scenarios used in both the RIT-T and ISP.

Option 2 adopts a less prescriptive approach than option 1 whereby alignment is achieved through an exclusion window where PACRs cannot be published and feedback loop assessment cannot be requested. Outside of this window RIT-T proponents retain the flexibility to carry out the necessary analysis required to progress their project. The Commission considers that option 2 is preferred on the basis that it achieves the necessary alignment to improve the workability of the feedback loop while retaining the most flexibility possible for AEMO and RIT-T proponents.

We welcome stakeholder views on whether the draft recommendation to implement a feedback loop and PACR exclusion window between the final IASR and draft ISP is an appropriate solution. We also welcome views on alternative approaches that stakeholders consider would better promote the NEO.

5.2.2 The Commission is seeking stakeholder input on two elements of our draft recommendation

The Commission is seeking stakeholder views on two features of the draft recommendation to inform the development of its final position. These are:

- whether the feedback loop should be aligned with a draft or final ISP

- enabling the feedback loop and CPA process to run concurrently.

Aligning the feedback loop with a draft or final ISP

Under the draft recommendation, feedback loop windows would commence after the publication of the draft ISP. Stakeholder feedback is obtained on the ODP in the draft ISP which may lead to changes being made to the ODP in the final ISP. For example, the draft ISP includes a call for non-network options that could address the identified need of actionable projects. There is therefore a risk a feedback loop assessment performed by reference to a draft ISP may become outdated by the time the final ISP is published.

The extent to which there may be material differences between a draft ODP and final ODP is unclear. However, restricting the feedback loop assessment to after a final ISP has been published would result in feedback loop assessments not being permitted for half of the ISP cycle. This may delay RIT-T proponents seeking to progress to the CPA stage of the regulatory framework. The Commission therefore considers that commencing feedback loop windows at the draft ISP appropriately balances promoting both the timely and efficient delivery of major transmission projects.

We welcome stakeholder views on whether aligning the feedback loop with the draft ISP or final ISP best balances the timely and efficient delivery of major transmission projects.

Enabling the feedback loop and CPA process to run concurrently to reduce bunching of feedback loop assessments

The draft recommendation may lead to a bunching of feedback loop assessments around the publication of a draft ISP. A consequence of this approach is that it may lead to delays in the regulatory process as RIT-T proponents wait for the feedback loop window to open.

The Commission considers that one approach to managing this delay is amending the NER to allow the CPA process and feedback loop assessment to proceed concurrently. Running these processes concurrently would be unlikely to add a regulatory burden because the costs sought in the CPA are capped at those examined in the feedback loop. It follows that RIT-T proponents will likely have developed their cost estimates to the standard required for a CPA prior to seeking the feedback loop assessment from AEMO.

These changes would be given effect through amending the actionable ISP project trigger event (see proposed rule 5.16A.5(b)), which involves consequential amendments to the making of a contingent project determination. In particular, the AER could not approve a contingent project until the feedback loop is completed and the project passes. [112]

We welcome stakeholder views on whether the potential for delay due to the bunching of feedback loop assessments will have a material effect on timely delivery and, if so, is allowing the CPA and feedback loop to run concurrently the appropriate means of managing this delay?

112 See Clause 6A.8.2(e) of the proposed draft rule.

The Commission notes that this approach may also lead to a bunching of feedback loop assessments prior to the exclusion window commencing. However, as outlined below, the Commission's draft recommendation is to give effect to aligning the feedback loop with a draft or final ISP through amendments to the CBA Guidelines. The CBA Guidelines could therefore be amended to also provide guidance on how the feedback loop will proceed in these circumstances.

5.2.3 The feedback loop and PACR exclusion window would be given effect through the AER's CBA Guidelines

The Commission has assessed three options for giving practical effect to the draft recommendation:

- **Option 1:** informal agreement between RIT-T proponents and AEMO
- **Option 2:** amendments to the AER's CBA Guidelines
- **Option 3:** amendments to the NER.

The Commission's draft recommendation is to amend the AER's CBA guidelines to give effect to aligning the feedback loop assessment with a draft ISP.[113] These amendments will likely involve providing AEMO with the discretion to time the feedback loop assessment to when it is most appropriate given the circumstances of the particular investment. This provides AEMO the flexibility to undertake the feedback loop assessment during the exclusion window if it considers it appropriate to do so (such as in circumstances where there are minimal differences between the ISP candidate option and the RIT-T preferred option). The Commission considers this to be an effective approach because it promotes the feedback loop operating as an effective safeguard for consumers while not unduly delaying progression of major strategic investments through the regulatory process. This approach also provides the necessary flexibility to manage the challenges of the energy transition in approving regulated investments, while providing additional clarity regarding the operation of the regulatory framework with respect to the feedback loop.

We welcome stakeholder views on whether amendments to the AER's CBA Guidelines to give effect to aligning the feedback loop assessment with a draft ISP is suitable.

Option 1: Informal agreement between RIT-T proponents and AEMO is not recommended as it does not provide clear guidance

In section 5.2.1 it was noted that both AEMO and TNSPs consider that the feedback loop assessment is most straightforward when there are minimal differences between the ISP candidate option and RIT-T preferred option, or the assessment aligns with a draft or final ISP.

It may be possible to implement aligning the feedback loop with a draft or final ISP through an informal agreement between RIT-T proponents and AEMO. Under this option RIT-T

113 See Clause 5.16A.2(c)(4) of the proposed amending rule.

proponents would submit feedback loop requests to align with a draft or final ISP of their own accord.

The key advantage of this option is that it achieves the alignment required in the least prescriptive manner i.e., it is at the discretion of RIT-T proponents. However, leaving alignment to the discretion of RIT-T proponents does not provide clear guidance on the timing of feedback loop assessments. Absent additional formal guidance, the issues currently being experienced with the workability of the feedback loop may persist.

Option 2: Amendments to the AER's CBA guidelines is the Commission's draft recommendation

The AER's CBA Guidelines could be amended to provide AEMO with the discretion to determine when it is most appropriate to undertake the feedback loop assessment and align the feedback loop with a draft ISP. AEMO could then issue guidance to RIT-T proponents that it will not undertake feedback loops during the period between the final IASR and draft ISP when there may be material differences between the RIT-T preferred option and ISP candidate option.

A key advantage of this approach is that it provides a basis for the alignment in a regulatory instrument while avoiding the prescription and time associated with the rule change process. It also provides AEMO the opportunity to develop a tailored approach to feedback loop assessments.

Providing AEMO with discretion regarding the timing of the feedback loop will promote the assessment occurring at the appropriate time given the circumstances of the relevant project – ensuring it operates as an effective consumer safeguard while not unduly delaying an investment's passage through the regulatory process.

The Commission notes that our Stage 2 draft recommendations involve a number of amendments to the AER's CBA Guidelines. In light of the scale of required changes, the Commission considers that a holistic amending of the CBA Guidelines is appropriate to avoid multiple consultation periods for the recommended changes.

Option 3: Amendments to the NER is not recommended by the Commission due to the level of prescription

The final option considered by the Commission involved amending the NER to explicitly prohibit the publication of PACRs, and therefore the feedback loop, between the publication of the final IASR and the publication of the draft ISP. This approach would provide clear guidance on the timing of feedback loop assessments by prescribing it in the Rules.

This option is associated with a high degree of prescription and would limit AEMO's flexibility in tailoring the timing of the feedback loop to the circumstances of a particular investment. This option is therefore not recommended by the Commission.

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEIC	Australian Energy Infrastructure Commissioner
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BAU	Business-as-usual
Capex	Capital expenditure
CBA	Cost-benefit analysis
CEC	Clean Energy Council
CEIG	Clean Energy Investor Group
CEPA	Cambridge Economic Policy Associates
CESS	Capital Expenditure Sharing Scheme
Commission	See AEMC
CO2	Carbon dioxide
CPA	Contingent project application
DER	Distributed energy resources
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
EIOG	Emissions intensity of generation
ENA	Energy Networks Australia
ESB	Energy Security Board
EUAA	Energy Users Association of Australia
FFO	Funds from operation
IASR	Inputs, assumptions and scenarios report
IEA	International Energy Agency
IPCC	International Panel on Climate Change
ISP	Integrated System plan
MCE	Ministerial Council on Energy
MEU	Major Energy Users Inc.
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National Energy Market
NEO	National electricity objective
NER	National Electricity Rules
NPV	Net present value
NSW	New South Wales
NTNDP	National transmission network development plan

ODP	Optimal development path
Opex	Operating expenditure
PACR	Project assessment conclusions report
PADR	Project assessment draft report
PEC	Project EnergyConnect
PIAC	Public Interest Advocacy Centre
PSCR	Project specification consultation report
PTRM	Post-tax revenue model
RAB	Regulated asset base
RCP	Representative Concentration Pathway
REZ	Renewable energy zone
RFM	Roll-forward model
RORI	Rate of return instrument
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
SRMC	Short-run marginal cost
SSP	Shared Socio-economic Pathway
TAPR	Transmission Annual Planning Report
TNSP	Transmission network service provider
WACC	Weighted average cost of capital

A ISSUES NOT TO BE PROGRESSED THROUGH THE REVIEW GIVEN LIMITED REFORM OPPORTUNITY AS STAND-ALONE ISSUE

A.1 Overview

This appendix discusses issues that were identified in the consultation paper that the Commission does not intend to progress as part of this review. The Commission makes no recommendations for change. The issues are:

- whether the RIT-T and ISP should be a "market benefits test" – in the interest of all who consume, produce and transport electricity – or a "customer benefits test" – specifically in the interest of those that consume electricity only
- guidance on the treatment of benefits that are hard to quantify in the RIT-T and ISP processes
- the treatment of uncertainty of project benefits in the RIT-T and ISP processes
- the treatment of non-network options as part of the RIT-T and ISP processes.

A.2 A market benefits test remains in the long-term interest of consumers

A.2.1 Overview of issue

The current RIT-T identifies "the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market".[114] This is known as the "net market benefits" test.

As it tests the *net* benefits to producers, consumers and transporters of electricity, the transfer of benefits or costs *between* these parties is not considered. For example, a benefit to a consumer which is directly offset by a cost to a producer is not a net benefit to these parties collectively, and so is ignored for the purpose of the RIT-T analysis. An important implication of this is that:

- contributions made by generators to the cost of a transmission project have limited effect on the overall outcome of the test.[115]
- external funds from any party that is not a producer, consumer or transporter of electricity (for example, a jurisdictional government) will increase the net benefit of an option to all those that produce, consume or transport electricity.

The market benefits test contrasts with a "consumer benefits" test. Under a "consumer benefits" approach, only the benefits and costs to consumers of electricity are considered, meaning that a wealth transfer between consumers and producers or transporters of electricity would count as part of the analysis.

114 Clause 5.15A.1(c) of the NER.

115 The flow-on impact of changes in prices resulting from generator contributions could have a second-order impact on net benefits, and hence impact the outcome of the test.

The consultation paper noted that:[116]

- Prior to the commencement of the NEM, the National Electricity Code described a customer benefits test for transmission investment
- Due to concerns of the Australian Competition and Consumer Commission (ACCC) that such a test was unclear, inefficient and unworkable, the test was replaced by the existing market benefits test.

Given the extensive work done to date on this topic and the compelling arguments in favour of the market benefits test, the Commission noted in the consultation paper that a market benefits test remains fit-for-purpose. However, feedback was sought on whether recent developments in the energy sector warrant further examination of the appropriateness of a market or customer benefits test.

A.2.2 Stakeholder feedback

The majority of stakeholder submissions agreed that the market benefit test is fit for purpose and did not support a reconsideration of a consumer benefit test.[117]In addition, the majority of stakeholders that responded to this issue did not regard it as a priority issue for the Review.[118]

Several stakeholders, including ENA, Shell, CS Energy and Neoen, were of the view that the market benefit test remains fit for purpose and there is no need to reconsider the merits of a consumer benefits test.[119] TasNetworks added that the market benefit test is the appropriate investment test, as it promotes efficient investment in accordance with the NEO.[120] EnergyAustralia considered that the robustness and relevance of the market benefit test has already been debated and settled.[121]

Further, AEMO noted that the net market benefits test is entrenched within the NER and considered that changing this would introduce considerable complexity.[122] Shell and Frank Kiss considered that it would be very difficult to develop a consumer benefits test that is clear, robust, efficient and workable.[123]

A.2.3 Commission analysis and prioritisation

The Commission recommends no change to the existing "net market benefits" test in the RIT-T and agrees with stakeholders that there is no need to take this matter forward in this Review.

116 AEMC, *Transmission Planning and Investment Review*, consultation paper, 19 August 2021, p. 30.
117 Submissions to the consultation paper: AEMO, p. 16; ECA, pp. 6-7; ENA, p. 16; CS Energy, p. 9.
118 Ibid.
119 Submissions to the consultation paper: ENA, p. 16; Shell, p. 4; CS Energy, p. 9; Neoen, p.6.
120 TasNetworks, submission to the consultation paper, p. 5.
121 EnergyAustralia, submission to the consultation paper, p. 9.
122 AEMO, submission to the consultation paper, p. 16.
123 Submissions to the consultation paper: Shell, p. 4; Frank Kiss, p. 5.

The market benefits approach is consistent with standard definitions of economic efficiency. To increase economic efficiency, *net* welfare must increase. Redistributing wealth between consumers and producers does not increase net welfare.

A.3 There are no clear deficiencies in the rules regarding the provision of guidance on hard to monetise benefits

A.3.1 Overview of issue

Some categories of benefits (such as changes in ancillary service costs) are not often estimated due to the complexity and cost of the modelling task. The combination of excluding difficult to quantify market benefits coupled with a desire to complete the regulatory process as quickly as possible may create an incentive for RIT-T proponents to quantify the minimum benefits possible to pass the RIT-T. However, due to the intrinsic uncertainty associated with the capital costs of major projects there are likely to be cost increases, meaning proponents may need to quantify new benefits (including those that are difficult to quantify) later in the assessment process to justify the investment. The consultation paper sought to understand whether particular market benefits are hard to monetise and if guidance on hard to monetise benefits may improve the timeliness in the delivery of projects.

A.3.2 Stakeholder feedback

Some stakeholders identified a range of hard to monetise benefits and ways to account for these.

Network resilience benefits and the avoidance of high impact low probability events were noted by AEMO as being commonly recognised as either being difficult to monetise or immaterial to most assessments based on the method for monetisation.[124]AEMO proposed that hard to monetise benefits could be assessed on a qualitative basis to ensure material costs and benefits are not omitted simply due to quantification difficulties.[125]

The Public Interest Advocacy Centre (PIAC) raised that non-network solutions may have hard to monetise network and market benefits, noting that these technologies (such as, batteries) and the services they enable (for example, system security) are not adequately captured under the current RIT-T assessment.[126] PIAC also noted that these benefits are by their nature difficult to measure and establish value for, and as such if included are vulnerable to manipulation to justify inefficient and/or sub-optimal investment.[127]

Energy Grid Alliance suggested that quantification of benefits to community and environment may provide value and could include costs related to land value impacts or costs of protecting flora and fauna habitats.[128]

124 AEMO, submission to the consultation paper, p. 15.

125 Ibid.

126 PIAC, submission to the consultation paper, p. 10.

127 Ibid.

128 Energy Grid Alliance, submission to the consultation paper, p. 36.

Non-economic benefits for consumers, such as supporting the transition to an energy future that they value and expect, were considered to be the most important hard to quantify benefits by Energy Consumers Australia (ECA). ECA also noted the importance of focusing on hard to monetise benefits that can be calculated with sufficient evidence, data and rigour.[129]

ENA identified option value as a market benefit category which is complex to model and has not been explicitly quantified as part of most ISP/RIT-T assessments to date (outside of its inclusion via scenario analysis). However, ENA did not consider that there is a way in which these benefits could be made easier to quantify, given the nature of how they arise.[130]ENA considers that the current approach, where these benefits are calculated at the point at which they are clearly going to be material to the choice of investment option, strikes the appropriate balance.[131]

Stakeholders had diverse views on whether additional guidance on hard to monetise benefits would improve timeliness

AEMO expressed the view that further guidance on hard to monetise benefits and risk tolerances would reduce uncertainty regarding the evaluation of these benefits, which may allow for projects to be more efficiently assessed via cost benefit analyses using a consistent approach.[132]

Conversely, Shell considered that additional guidance would not better facilitate the inclusion of hard to monetise benefits and presents the risk of being used to justify more network investment than would otherwise be needed, increasing the probability of inefficient investment over the long term.[133]

ENA suggested additional guidance risks increasing the complexity (through restraining the choice of an appropriate and proportionate approach) and therefore adding to the time required to complete the process.[134]

A.3.3 Commission analysis and prioritisation

The Commission does not intend to consider this matter further as part of the review. The Commission does not consider there to be any deficiency in the rules that materially impacts the timely and efficient delivery of major transmission projects.

The existing framework provides adequate guidance on hard to monetise benefits and the AER's Guidelines allow for further guidance to be developed if required by RIT-T proponents

AEMO (in its development of the ISP) and RIT-T proponents are required to consider a very wide range of classes of market benefits (that is, net benefits to those that produce, consume or transport electricity). It is required to consider:

129 ECA, submission to the consultation paper, p. 6.
130 ENA, submission to the consultation paper, p. 15.
131 Ibid.
132 AEMO, submission to the consultation paper, p. 15.
133 Shell, Submission to the consultation paper, p. 4.
134 ENA, submission to the consultation paper, p. 15.

- those classes of market benefits listed directly in the rules,[135] including benefits relating to improved resilience[136]
- other classes that are determined to be relevant by AEMO/the RIT-T proponent and agreed as such by the AER[137]
- any classes specified by the AER in the *regulatory investment test for transmission* (RIT-T)(in the case of RIT-Ts) or the *cost benefit guidelines* (in the case of the ISP)[138]

Only the classes of market benefits deemed to be material in AEMO's or the RIT-T proponent's reasonable opinion are required to be quantified.[139]However, all classes of market benefits must be considered to be material unless reasons can be provided by AEMO or the RIT-T proponent as to why:

- the class of market benefit is not material to the outcome of the assessment, or
- the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate.[140]

AEMO or the RIT-T proponent are required to quantify the material hard to monetise benefit unless the cost of undertaking the analysis is disproportionate. The Commission is not aware of a class of benefit that has been excluded from the above list because it is hard to monetise. To the extent that any such benefit should emerge, then it could be included by the AER in its *regulatory investment test for transmission* and *cost benefit guideline* if deemed appropriate by the AER.

To the extent further guidance is required by RIT-T proponents in estimating hard to quantify benefits, the Commission considers that this is a matter for the AER in developing and updating the guidelines noted above. In this respect, the Commission does not consider there to be any deficiency in the rules.

The rules currently strike the correct balance by requiring RIT-T proponents to justify not quantifying a particular benefit class on a case-by-case basis

Separately to the question of whether a benefit class is hard to monetise, the Commission is aware of a potential problem arising where proponents may determine that a particular class of benefit is immaterial to the outcome of the assessment, and not quantify it. As noted above, they may do this under the rules because:[141]

- the estimated net benefit of the preferred option is already positive even excluding the benefit class in question, meaning that any more benefits are moot to the overall outcome
- the benefit relating to the class is likely to be similar between options

135 Clauses 5.15A.2(b)(4) and 5.22.10(c)(1) of the NER.

136 "Resilience" is not a term used in the NER. The Commission considers that the concept of resilience is captured by the benefit of reduced involuntary load shedding. See Clause 5.22.10(c)(1)(iii) of the NER.

137 Clauses 5.15A.2(b)(4)(x)(A) and 5.22.10(c)(1)(x)(A) of the NER.

138 Clauses 5.15A.2(b)(4)(x)(B) and 5.22.10(c)(1)(x)(B) of the NER.

139 Clauses 5.15A.2(b)(5) and 5.22.10(c)(2) of the NER.

140 Clauses 5.15A.2(b)(6) and Clause 5.22.10(c)(3) of the NER.

141 Ibid.

This approach is problematic if in time, as the RIT-T progresses, the net benefits of the preferred option are lower than originally estimated. This may then necessitate the proponent to go back to quantify previously unquantified classes of benefits to ensure that the preferred option is selected. This is problematic as:

- it may ultimately delay the planning process (despite the class of benefit being excluded in the first place to expedite the process)
- it may give the impression that the cost-benefit analysis is tilted in favour of making investments, as new evidence to support an investment appears to emerge (despite the fact that the "new" class of benefit was explicitly excluded from the original analysis because it was deemed immaterial to the outcome).

The Commission understands that the rationale for the existing rules is to balance:

- the cost and time of undertaking extensive analysis upfront which ultimately proves to be unnecessary, with
- the cost and time of going back to quantify previously unquantified classes of benefits if, in the fullness of time, such analysis was necessary to ensure that the preferred option is selected.

The Commission considers that the rules currently strike the correct balance by requiring RIT-T proponents to justify not quantifying a particular benefit class on a case-by-case basis.

This topic is related to those issues also being considered as part of the *Material change in network infrastructure project costs* rule change which is being progressed in parallel with Stage 3 of this review.[142]

A.4 The uncertainty of project benefits is appropriately factored into the transmission planning process

A.4.1 Overview of issue

The cost and benefits of actionable ISP projects appear to be more uncertain than business-as-usual transmission projects. This is because the larger size and scale of these projects, coupled with the pace of the energy transition, results in intrinsic uncertainty associated with both the benefits and costs of many major transmission projects. In relation to project benefits, this uncertainty stems from various assumptions relating to the energy transition. For example, these assumptions include the:

- evolution of demand for electricity
- future costs of generation and storage technologies
- operation and retirement of the existing thermal generation fleet
- policy direction of federal and state governments.

This greater degree of uncertainty represents a challenge for the regulatory framework, with stakeholders noting that the framework was designed around a mature network characterised by incremental investments. Progressing projects with significant intrinsic

142 See project page here for more information.

uncertainty through a regulatory framework that presupposes reducing uncertainty as a project progresses through the planning stages may result in suboptimal outcomes for consumers.

The Commission notes that the significant intrinsic uncertainty associated with major transmission projects raises the threshold question of whether the existing ex-ante incentive-based regulation approach is appropriate for major discrete transmission projects. This will be addressed separately in Stage 3 of the review.

A.4.2 Stakeholder feedback

Stakeholder submissions generally agreed on the factors identified in the consultation paper to be driving uncertainty in large-scale transmission projects.[143]

CEFC noted that the current framework was intended for incremental network growth and it could be appropriate to consider new regimes for large projects that form part of the energy transition.[144] The EUAA considered that changes are necessary in the current ex-ante framework to reduce uncertainty around project benefits.[145]

A.4.3 Commission analysis and prioritisation

There is intrinsic uncertainty relating to the benefits and costs of transmission investment. The existing framework seeks to account for this intrinsic uncertainty relating to benefits via a range of mechanisms underpinning the transmission planning process, for example the IASR used by AEMO in the ISP. As the ISP and RIT-T should be recognised as forward-looking probabilistic economic cost-benefit assessments the Commission has not identified any deficiencies in respect of how these assessments account for the uncertainty around project benefits.

The appropriate management of this intrinsically higher risk stemming from uncertainty of large transmission projects is a core question for this Review which will be explored further in Stage 3.

A.5 Issues raised by stakeholders about the treatment of non-network options in the context of major transmission investments are not material

Although non-network options play a critical role in the energy transition, in the context of major transmission investments the issues raised by stakeholders provide limited opportunity to materially improve consumer outcomes or have been adequately considered in previous work.[146] Non-network options will not be considered a standalone, priority issue for this

143 Submissions to the consultation paper: Energy Australia pp. 4-6; CEIG, pp. 2-3; Neoen, p. 5; Energy Grid Alliance, p. 2.

144 CEFC, submission to the consultation paper, pp. 2-3.

145 EUAA, submission to the consultation paper, p. 5.

146 See AEMC, *Economic regulatory framework review: Integrating distributed energy resources for the grid of the future*, 26 September 2019 and AEMC, *Demand management incentive scheme and innovation allowance for TNSPs*, final determination, 5 December 2019.

Review. However, consideration will be given to any potential implications for non-network options in the context of broader reform options examined in the Review.

A.5.1 Overview of the issue

Stakeholders perceived several barriers to non-network options in the planning framework for major transmission projects.[147] A significant barrier raised is the perception that TNSPs may have an intrinsic preference for network-focused solutions. This preference may result from three key factors:

- the fundamental purpose of TNSPs is to own and operate the transmission network. Their knowledge and expertise centres around network-based solutions, as opposed to being providers of substitutes for transmission infrastructure
- the structure of the regulatory framework as it relates to the profit-based compensation for additional capex but not equally so for opex
- network and non-network options are not like-for-like with implications for reliability and the TNSP's risk profile, and the differences may shape how they are considered in the assessment process.

A preference for network options may lead to TNSPs taking a relatively optimistic view of the net market benefits of network options when selecting the preferred option to deliver an ISP project. In contrast, inexperience regarding the technical capability of non-network options to cost-effectively meet an identified need may attract a less optimistic assessment from TNSPs. This could lead to a wholly network solution being implemented where a non-network option, or a combination of network and non-network options, may be more efficient.[148] Preserving neutrality between network and non-network options is central to the regulatory framework facilitating the identification of the most efficient solution to an identified need.

A.5.2 Stakeholder feedback

TNSP's may preference network options over non-network options

Several stakeholders expressed the view that TNSPs may have an inherent preference to select network options when meeting a market need that is identified by the ISP. AGL suggested that TNSPs may have a conflict of interest when deciding between investing in an asset that they will own or incurring expenditure to procure non-network services.[149] Origin and ECA considered the issue of bias may be more cultural, given the core expertise of TNSPs revolves around network solutions and therefore TNSPs may lack awareness of the available non-network solutions.[150] Along these lines, TransGrid suggested that adapting the regulatory framework to create incentives for TNSPs to develop expertise in new and emerging technologies may improve engagement with non-network options.[151]

147 The issue of whether non-network options have equal treatment in the transmission planning and regulatory process was recently raised in the context in the AER's review of the regulation of large transmission projects. See: AER*, Final guidance note covering letter — Regulation of large transmission projects*, 31 March 2021, pp. 8-10.

148 Non-network options are unlikely to be substitutes for major transmission investments. Rather, they are more likely to contribute to lowering the overall cost of the investment.

149 AGL, submission to the consultation paper, p. 1.

150 Submissions to the consultation paper: Origin, p. 4; ECA, p. 7.

Several submissions, including from TasNetworks and ENA, considered that the current framework provides sufficient safeguards against the perceived unequal treatment of non-network options.[152]

Assessment of non-network options is not on a like-for-like basis and does not capture the full benefits of non-network options

Some stakeholders considered that the requirements for non-network options under the cost benefit assessment may create a bias against non-network options.

Shell and the EUAA noted that the CBA requirements are such that non-network proponents must provide more detailed cost estimates than capital-based network proposals.[153] They suggested that this may mean that non-network options are not assessed against network solutions on a like-for-like basis.[154]Shell, CEFC and the ENA further suggested that the AER's recent change in guidance on treatment of non-network options,[155] which requires the full cost of non-network options to be accounted for in the CBA further disadvantages non-network proponents. This is because accounting for the full cost ignores the flexibility provided by non-network options.[156]

Fluence and Tesla suggested that the assessment framework should better enable consideration of the full benefits of non-network options such as optionality and the provision of essential system services.[157] Stakeholders suggested greater guidance and transparency in the assessment process for non-network options which would help TNSPs better account for benefits.[158]

Additionally, AEMO noted that further guidance for cases where costs and submissions are confidential would be beneficial.[159] CitiPower, Powercor and United Energy suggested further clarity on how the regulatory framework caters for non-network solutions located on the distribution network that may resolve issues on the transmission network.[160]

The planning framework creates barriers to effectively engage with non-network options

Major Energy Users Inc (MEU) suggested that the current ISP process for selecting credible candidate options limits the extent to which non-network options can be considered.[161] This is on the basis that non-network providers are unable to access sufficient information to submit credible options. In particular, the MEU suggested that "the definition of the need for and the

151 TransGrid, submission to the consultation paper, p. 7.

152 Submissions to the consultation paper: ENA, p 17; TasNetworks, pp. 5-6.

153 Submissions to the consultation paper: Shell, pp. 3-4; EUAA, p. 10.

154 Ibid.

155 AER*, Final Decision – Guidelines to make the Integrated System Plan actionable*, August 2020.

156 Shell, submission to the consultation paper, p. 4.

157 Submissions to the consultation paper: Fluence, p. 3; Tesla, p. 5.

158 Submissions to the consultation paper: CS energy ltd, p. 5; Tesla, p. 5; AEMO, p. 17; CPPALUE, pp. 2-3.

159 AEMO, submission to the consultation paper, p. 17.

160 CPPALUE, submission to the consultation paper, p. 3.

161 MEU, submission to the consultation paper, p. 9.

outcomes from the investment described in the ISP is insufficiently defined for a non-network solution to be readily identified and costed".[162]

Conversely AEMO considered that the existing process of assessing non-network options in the ISP is suitable.[163]

Stakeholders also suggested that the technical requirements established by TNSPs that non-network solutions need to meet are inflexible and limit the potential for hybrid solutions. Tesla and CS Energy suggested that the framework should enable in-market technical demonstrations or joint trials which could be used to demonstrate and understand the technical capacity of non-network options.[164]

Origin suggested that information asymmetry in the submission process run by TNSPs acts as a barrier to non-network options.[165] Tesla suggested this creates unbalanced resource burdens on non-network option proponents, which discourages them from engaging in the process.[166] The ECA also noted that non-network proponents might be discouraged from allocating extensive resources to engage in a process that may not result in a tender and generate revenue.[167]

The importance of engaging non-network providers in pre-RIT processes to ensure and promote a level playing field for network and non-network participants was raised by the AER.[168]In the AER's view, earlier engagement would provide sufficient lead time for non-network businesses to meaningfully contribute to the RIT-T.[169]

Finally, Origin considered that the value of non-network options should be re-assessed where the costs of the preferred option have increased as is the case for network solutions. Origin suggested that this would ensure further optimisation of non-network options is taken into account.[170]

A.5.3 Commission analysis and prioritisation

The Commission recognises the important role of non-network options in the energy transition. However, in the context of efficient and timely delivery of major transmission investments, the issues raised by stakeholders either provide limited opportunity to materially improve consumer outcomes or have been adequately considered in previous work. Non-network options will not be considered a standalone, priority issue for this Review, however the Commission will consider any implications for non-network options in the broader reform options examined in the Review.[171]

162 Ibid.
163 AEMO, submission to the consultation paper, p. 17.
164 Submissions to the consultation paper, Tesla, p. 4; CS energy ltd, p. 10.
165 Origin, submission to the consultation paper, p. 4.
166 Tesla, submission to the consultation paper, p. 8.
167 ECA, submission to the consultation paper, p. 7.
168 AER, submission to the consultation paper, p. 11.
169 Ibid.
170 Origin, submission to the consultation paper, p. 4.
171 The Commission is considering the merits of introducing greater contestability into the delivery of major transmission projects. This may improve the uptake of non-network options.

Previous analysis indicates no capex bias in the treatment of non-network options

In the 2019 *Economic regulatory framework review*, the Commission considered the perceived bias for capex-based solutions over opex -based solutions like non-network solutions.[172]The Commission found there to be no clear bias towards capexover opex.[173]Further, it noted that a bias may only exist where the expected cost of capital is lower than the regulated cost of capital because the financial return of the capex solution is perceived to be greater.[174]This is of low risk in the current low interest environment.[175]The Commission therefore considers the risk of a material capex bias to be limited.

The Commission further considered reform to the transmission incentive frameworks during the demand management incentive scheme (DMIS) and innovation allowance for TNSPs rule change. The rule change request sought to incentivise the uptake of efficient non-network options by applying the DMIS to transmission.[176] The Commission found if the DMIS was applied to transmission, TNSPs would receive incentive payments for undertaking non-network options that they would already have been required to adopt under the RIT-T.[177] On this basis, the Commission was not satisfied that the benefits of applying the DMIS to transmission would outweigh the upfront costs to consumers.[178]

Issues related to the assessment of non-network options in the planning process are not material for major projects

Stakeholders raised concerns related to processes of engagement with non-network proponents and the suitability of the assessment process for non-network options. The Commission finds that these process issues would not significantly impede the efficiency and timely delivery of major transmission projects.

Additionally, the Commission considers that current obligations on AEMO and TNSPs to engage with non-network proponents and consider non-network options during the development and assessment of major projects remain adequate. These obligations are summarised in Figure 1.

172 AEMC, *Economic regulatory framework review: Integrating distributed energy resources for the grid of the future*, 26 September 2019.

173 Ibid, p 64.

174 Ibid.

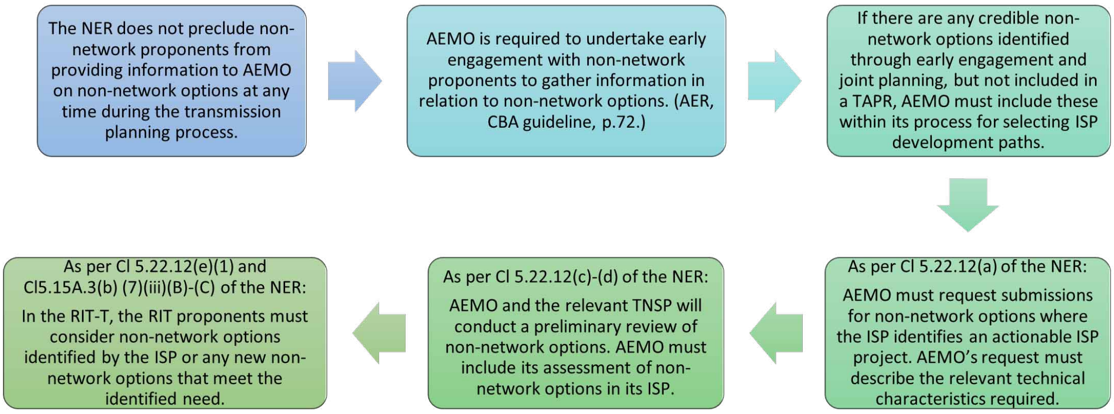
175 Ibid, p. 67.

176 AEMC, *Demand management incentive scheme and innovation allowance for TNSPs*, consultation paper, 23 May 2019, p.4.

177 AEMC, *Demand management incentive scheme and innovation allowance for TNSPs*, final determination, 5 December 2019.

178 Ibid.

Figure A.1: Overview of the requirements to consider non-network options for ISP projects



Source: AEMC

Non-network options will be considered, where relevant, in the context of broader reform

In considering whether to prioritise non-network options as a standalone issue for the Review to address, the Commission considered the extent to which there are opportunities to improve the treatment of non-network options through broader reform options examined under the Review.

Several areas of reform explored in this Review and the *Material change in network infrastructure project cost* rule change request are relevant to the treatment of non-network options.[179]

179 For example, the Commission is considering the appropriateness of current cost estimate requirements more broadly in the rule change. The rule change is also exploring considerations regarding the re-application of the RIT-T where project cost increases which may include a requirement to re-assess non-network options. The Commission is further considering the potential for contestable arrangements in the provision of transmission services which may have implication for the treatment of non-network options.

B SUMMARY OF STAKEHOLDER SUBMISSIONS

This appendix sets out the issues raised in the first round of consultation on this review process and the AEMC's response to each issue. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

B.1 Assessment Criteria

Table B.1: Summary of submissions on the assessment criteria

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
Assessment criteria	ENA and Transgrid	Proposed adding a further criterion of the extent to which reform options are likely to promote consumer confidence in the energy framework and improve social licence for the development of major transmission projects	Consumer confidence and social licence can be captured by the effectiveness criterion of the assessment framework because they are key to promoting timely and efficient delivery of major transmission projects
Assessment criteria	Transgrid	Proposed adding a further criterion of whether the reforms increase the risk to the security and reliability of the energy system	Security and reliability are explicit elements of the NEO and are therefore captured in the assessment framework
Assessment criteria	EnergyAustralia	Proposed adding a further criterion relating to the risks of under and over investment	The risk of under and over investment is captured in the effectiveness and economic efficiency criteria
Assessment criteria	Neoen	Proposed adding a further criterion relating the wider economic and societal impact of effective transmission	Wider economic and societal impacts are not considered in the context of the NEO, which focuses on the long term interests of consumers of

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
		networks	electricity
Assessment criteria	PIAC	Proposed adding a further criterion stipulating that costs are recovered such that the primary beneficiaries from a given investment pay for that investment	Cost allocation arrangements are out of scope for the Review

B.2 Social licence

Table B.2: Summary of submissions on social licence

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
Risk assessment	AEIC	Consider enhancing the regulatory funding framework to include risk assessments for delayed or halted projects due to risks such as stakeholder/ community opposition or legal challenges to the planning process and decisions.	Risk assessment should be captured in BAU activities. Earlier and improved stakeholder engagement, a focus for this review, should be considered a treatment for project risks stemming from community acceptance.
Formalising social licence in the regulatory framework	Energy Grid Alliance	Under an enhanced regulatory framework, acquiring social licence would be a formality. This would provide more certainty at the procurement stage as risks, impacts and community concerns would have been investigated and understood.	The paper recognizes that multiple entities are responsible for social licence for major transmission projects. The focus of the review is on activities that help to build community acceptance and are regulated under the national framework.
Inclusion of social licence in the	Energy Grid Alliance, RE-Alliance, Resist	The economic assessment process	Expanding the economic assessment

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
economic assessment process	Humelink, Tilt Renewables, Transgrid, AusNet Services, Citipower/Powercor/United Energy, CEC.	should include socio-economic, environmental, and community impacts.	test to beyond the market benefits test is inconsistent with the NEO.
Planning	Moyne Shire Council	Underground transmission lines where technically feasible, in line with national best practice	This would be addressed as part of the ISP and TNSP development of major transmission projects and consulted on with stakeholders. Consultation with stakeholders on investment decisions are the focus of the chapter.

B.3 Cost recovery of planning activities

Table B.3: Summary of submissions on planning activities

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
Cost recovery for new entrants	ATCO	Suggested that new entrants are disadvantaged in conducting early and preparatory works because of no means of cost recovery and a lack of access to information. Proposed measures to reduce information asymmetry. Further proposed that bid cost recovery should be considered to ensure that reimbursement of costs is included in	The scope of the stage 2 report addresses issues with cost recovery of early works and preparatory activities as it relates to TNSPs. Issues relating to intending TNSPs or third parties are thus out of scope of the stage 2 report. However, this issue may be considered more broadly as part of the AEMC's work on contestability which is being

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
		response.	progressed as part of the broader Review.
Exclusive right to perform early works and preparatory activities	ATCO	Proposed that preparatory and early works should be independently conducted.	This issue may be considered more broadly as part of the AEMC's work in the stage 3 report and on contestability which is being progressed as part of the broader Review.
Capital contributions and underwriting	Neoen, PIAC, Origin	Expressed concern over the potential for governments to influence decision making on the preferred option. Suggested further transparency.	Proposed amendments in the draft report aim to improve cost recovery certainty for planning activities which may reduce the need for government underwriting.
Cost recovery for projects that do not proceed	Origin, ECA, ENA	Suggested clarity on how planning costs can be recovered should a project not proceed.	Preparatory activities are recovered through a TNSPs opex allowance. For planning costs approved in a CPA prior to the final CPA, where a project does not proceed, TNSPs should treat the costs in line with its capitalisation policy and cost allocation methodology. These costs can be capitalised or expensed so long as the TNSP is consistent with its capitalisation policy and the opex/capex

ISSUE	RESPONDENT(S)	COMMENT(S)	AEMC RESPONSE
			incentives are relatively balanced. (See AER, *Guidance note – Regulation of actionable ISP projects,* March 2021, p. 30.)
Contestability	Ausnet Services, ENA	The introduction of contestable models will have implications for preparatory activities and early works	The contestability work stream as part of this Review will consider the implications for planning activities.