AEMC

REVIEW

Australian Energy Market Commission

DRAFT REPORT

TRANSMISSION PLANNING AND INVESTMENT - STAGE 3

21 SEPTEMBER 2022

INQUIRIES

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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 key feature of this transformation is the replacement of centralised thermal generation with decentralised renewable generation.

2 There is broad consensus that transmission is a critical enabler for the transition to net zero, both in the national electricity market (NEM) and for the economy more broadly. This transition will require an unprecedented level of investment in, and build of, transmission infrastructure to deliver power from renewable generation and energy storage to consumers, and to deliver it quickly.

3 The scale of transmission investment required, coupled with the speed of the energy transition, presents unique opportunities and challenges for the existing regulatory framework. This framework was developed and has evolved over a period of incremental growth of the grid where the framework was weighted to minimise the risk of overbuilding, rather than the current required pace of step-change growth set out in the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP).

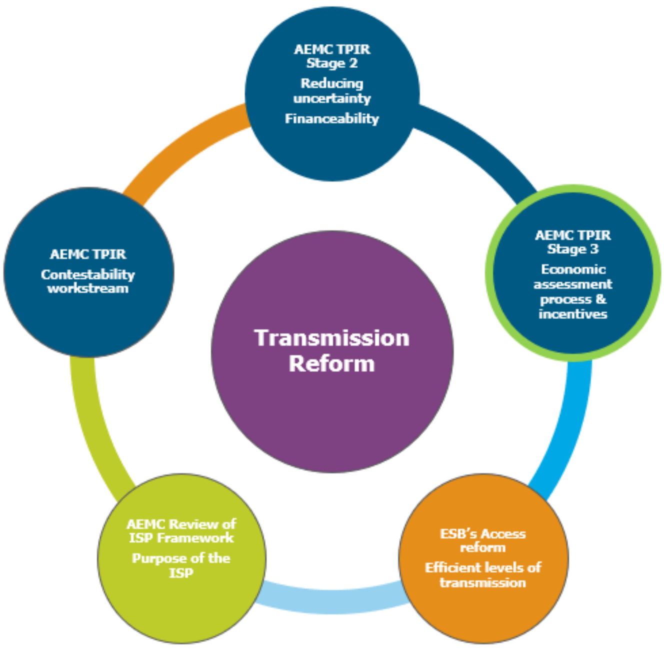
4 The AEMC's Transmission planning and investment review (the Review) was established to consider how to ensure that the regulatory framework supports the timely and efficient delivery of major transmission projects, while ensuring investment in these projects are in the long-term interests of consumers. This document is the draft report on Stage 3 of the Review.

The Stage 3 draft report is part of a larger body of work to support the timely and efficient delivery of major transmission projects to support the transition to net zero.

5 The Review is part of a larger program of work to make sure the national regulatory framework supports the transition to net zero. The program of work seeks to create a national regulatory framework for transmission that ensures major projects that are required are delivered in the most timely possible way with robust consumer protections in place.

6 The upcoming Review of the ISP process is also focused on these issues, while the Energy Security Board's access reform workstream seeks to address increasing congestion in the grid by considering approaches to facilitate efficient use of transmission, generation and storage assets and to assure that consumer processes are appropriate.

Figure 1: Stage 3 of the Transmission Review is part of a larger body of work on transmission reform



Source: AEMC.

7 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.

8 This Review is 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 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.

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

transparency are explored under the rule change.

Stage 3 of the Review considers several areas in the framework where the regulatory treatment for major projects can be simplified, made more timely, and provide more certainty

10 The draft positions in Stage 3 seek to examine several areas in the framework where the regulatory treatment of major projects can be simplified, made more timely, and provide more certainty. A regulatory framework that is sufficiently clear and flexible to support the timely and efficient delivery of major transmission projects is crucial given the scale and significance of transmission investment required to facilitate the decarbonisation of the energy system.

11 The Commission has drawn on stakeholder feedback to prioritise 5 key issues in Stage 3. These are: the economic assessment process for ISP projects, the treatment of emissions abatement and transmission planning, the treatment of concessional finance, the appropriateness of the ex-ante incentive-based regulatory framework and TNSPs' exclusive right but no obligation to invest. These 5 issues are the focus of this Draft report, with the Commission's positions on each issue detailed below.

We are considering a spectrum of alternative options to the current economic assessment process to identify if changes would support the timely delivery of strategically important projects

12 A streamlined economic assessment process could provide greater certainty through a simplified framework and allow for the timely delivery of ISP projects and their associated consumer benefits.

13 We are seeking feedback on three strawperson options, which set out a spectrum of alternatives to the current economic assessment process for ISP projects. We are seeking stakeholder feedback on whether any of these options should be taken forward for further development and assessment or if we should be considering any other options, including variations or hybrids of the three options presented.

14 In light of the ISP review that the AEMC is required to complete by mid-2025, we consider it is appropriate to think broadly about possible alternatives. The work on the economic assessment process in Stage 3 of the Review is a starting point for the ISP review required under Clause 11.126.10 of the NER.

Transmission planning considers the role of transmission in the transition to net zero

15 Recent significant changes indicate an increase in emissions abatement ambitions in Australia. Most notably, there has been a change in the federal government and the introduction of the Climate Change Act which seeks to legislate Australia's greenhouse gas emission reduction targets – a 43 per cent reduction from 2005 levels by 2030 and net zero by 2050.

16 Although these targets are economy-wide commitments and therefore apply to all sectors, the electricity sector is one of Australia's largest emitters and it will also have a key role in

facilitating Australia's decarbonisation through the electrification of other sectors. This role is reinforced by the recent agreement among Energy Ministers to fast-track an emissions objective into the NEO.

17 In this context and in response to stakeholder requests, this report sets out how emissions abatement is currently factored into transmission planning. We will continue to monitor developments with respect to climate legislation and an emissions objective in the national electricity objective (NEO) to ensure that emissions abatement continues to be appropriately factored into transmission planning in the future.

18 However, the Commission notes that determining whether the treatment of emissions abatement in transmission planning is appropriate could be assisted by clear policy direction regarding the expected contribution of the energy sector to Australia's decarbonisation.

Additional guidance is necessary to clarify how benefits from concessional finance are treated in the framework

19 The Commission recognises the increasing potential to use concessional finance to support timely investment in transmission infrastructure, notably in the context of the announcement of the Federal Government's Rewiring the Nation fund.

20 Given the existing National Electricity Rules (NER) do not explicitly recognise the treatment of concessional finance, additional guidance will be beneficial in clarifying its treatment in the regulatory framework and how the benefits can be allocated based on the intended purpose of the concessional finance.

21 We are seeking stakeholder feedback on the key questions we are exploring as we consider the appropriate regulatory treatment of benefits from concessional finance, including:

- how the regulatory framework could be amended to provide additional guidance on processes and information required to facilitate the treatment of concessional finance in the NER? and
- how to recognise these benefits in the economic assessments which inform the ISP as well as the regulatory investment test for transmission (RIT-T)?

A new incentive mechanism may be a suitable response to manage delivery risk associated with TNSPs' exclusive right with no obligation to invest

22 The Commission sees value in a new incentive mechanism to manage delivery risk associated with TNSPs' exclusive right to invest but with no corresponding obligation to invest. A Timely Delivery Incentive (TDI) could provide a way to encourage a timely investment decision and project delivery to align TNSPs' interests with those of consumers.

23 We are seeking stakeholder feedback to inform whether a TDI is proportionate and/or necessary. Detailed design considerations will be put forward if a mechanism is deemed to be considered a proportionate response to the problem.

There are opportunities to build on existing processes to support TNSPs in managing increased cost risk and/or uncertainty associated with major projects

24 Consistent with stakeholder submissions, the Commission recognises the potential for a

higher risk of project cost overruns for large-scale capital projects, relative to more modest projects.

25 The Commission's draft position is that recent developments under the ISP Rules framework – namely ex-ante risk allowances and the staged contingent project application(CPA) process – allow TNSPs to appropriately manage risk and uncertainty around the costs of major projects and that these processes should be given the opportunity to mature.

26 However, the Commission is seeking stakeholder feedback on two specific areas of the regulatory framework that may warrant further consideration: (i) the potential merits of a separate, targeted ex-post review process by the AER that examines expenditure associated with specific ISP projects, and (ii) whether there are circumstances in which it is appropriate to allow the CPA process for a large transmission project to be split into more than two stages.

Submissions are due by 03 November 2022 with other engagement opportunities to follow

27 Written submissions from stakeholders commenting on the issues and key questions raised in this Draft report are requested by 03 November 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.

28 A public forum on the Stage 3 Draft report will be held by the Commission during the consultation period. Details of the forum will be published alongside this report.

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APPENDICES

TABLES

FIGURES

1 INTRODUCTION

This report is the AEMC's draft report on Stage 3 of its Transmission Planning and Investment Review. This chapter outlines:

- the purpose of the Review and the particular focus of Stage 3
- the other stages of the Review and the associated *Material change in network infrastructure project costs* rule change
- the assessment framework for the Review
- how the remainder of the Stage 3 - draft 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 key feature of this transformation is the replacement of centralised thermal generation with 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 and that 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. It is vital that we streamline the process to faciliate the transition to net zero while balancing rigour to ensure customers are not paying for more than they should.

The current regulatory framework was developed and has evolved over a period of incremental growth, not the current pace of step-change growth set out in the Integrated System Plan (ISP). The scale of this investment combined with the speed of the energy transition means that it is appropriate to consider whether the current regulatory framework is sufficiently flexible to support the timely and efficient delivery of major transmission projects, while ensuring the right investments are made and that these are in the long-term interests of consumers.[1] The objective of this Review is therefore to ensure that the regulatory framework strikes an appropriate balance between enabling timely investment in and delivery of major transmission projects, at a time when significant growth is required to facilitate the transition to net zero, 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 their range and complexity

Drawing on the inputs of stakeholders, Stage 1 of the Review identified those issues that are most material in the context of major transmission projects and that could deliver the

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. ISP projects are an example of a major transmission project.

greatest prospective gains to consumers. Given the range and complexity of these issues, they are being considered in the Review in the following ways:

- Stage 2 – near-term reforms: This stage focuses on recommendations to help manage uncertainty in the near-term, with resolution of issues potentially being able to be implemented sooner.
- Stage 3 – longer-term reforms: This stage considers priority issues of greater complexity, requiring more time to consider 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.
- *Material change in network infrastructure project costs* rule change: This rule change project considers amendment of the material change provisions in the NER to improve consumer confidence in the efficiency of network infrastructure projects.

The key milestones for Stage 3 are outlined in Table 1.1 below.

Table 1.1: **Key deliverables**

DELIVERABLE	STAGE 3
Publish draft report	21 September 2022
Submissions due	3 November 2022
Publish final report	March 2023

1.1.2 The draft positions in Stage 3 consider several areas in the framework where the regulatory treatment of major projects can be simplified, made more timely, and provide more certainty

The draft positions in Stage 3 examine several areas in the framework where there is the opportunity for the regulatory treatment of major projects to be simplified, made more timely, and provide more certainty. A regulatory framework that is sufficiently clear and flexible to support the timely and efficient delivery of major transmission projects is crucial given the large scale and significance of transmission investment required to facilitate the decarbonisation of the energy system. These areas are of considerable complexity, relate primarily to longer-term reforms, and include consideration of:

- a spectrum of alternatives to the current economic assessment process for ISP projects and whether any of these options could better facilitate the timely transition to net zero while balancing rigour in the economic assessment process. This is the focus of **Chapter 2** of this report. See **Appendix A** for supplementary information.
- the evolving policy landscape regarding **emissions abatement** and the role of transmission planning in the transition to net zero. This chapter includes consideration of how the current scenario planning approach underpinning the ISP – that flows through to the application of the Regulatory Investment test for Transmission (RIT-T) – factors emissions abatement into transmission planning, including in relation to detailed

jurisdictional environmental and energy policies and broader emission abatement ambitions and/or targets. This is the focus of **Chapter 3** of this report. See **Appendix B** for supplementary information.

- the regulatory treatment of **concessional finance** given the recent announcement of the Rewiring the Nation fund policy and that the NER does not explicitly recognise the treatment of concessional finance. The Review will seek to provide additional guidance to clarify the treatment of concessional finance and how the benefits can be allocated based on the intended purpose of the concessional finance. This is the focus of **Chapter 4** of this report.
- whether transmission network service providers (TNSPs) face **suitable incentives and obligations to invest** to encourage a timely investment decision in major transmission projects. The Commission is exploring whether an incentive to align the interests of TNSPs' interests with those of consumers by encouraging the timely investment in, and delivery of, projects is a proportionate and/or necessary response to the exclusive right with no obligation to invest. This is the focus of **Chapter 5** of this report.
- whether the existing mechanisms to promote and assist management of **cost risk and uncertainty in the ex-ante regulatory framework** remain appropriate for major projects and where changes could be made to support TNSPs in the management of cost risk and uncertainty. This is the focus of **Chapter 6** of this report.

Further, the Commission has made the decision to not further progress one issue related to the types of benefits incorporated into the cost-benefit test that underpins the economic assessment process, namely whether and how to include **wider benefits** in the RIT-T and ISP assessment. **Appendix C** provides a summary of the issue and the rationale for not further progressing this issue as part of this Review.

Importantly, the Commission remains cognisant of the interrelationships between issues explored across the different stages of the Review. For example, some areas of the regulatory framework which have been considered in the Stage 2 draft report in relation to a specific priority issue may be explored further under Stage 3 when looking at alternatives to the current economic assessment process for ISP projects.

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

1.2.1 Stage 2 of the Review focuses on changes that are designed to help manage uncertainty in the near-term and support the timely and efficient delivery of major transmission projects

The Commission published the draft report for Stage 2 of the Review on 2 June 2022. Based on stakeholder feedback to the consultation paper, the Commission identified 4 key issues for Stage 2 of the Review. The draft recommendations under Stage 2 of the Review seek to help manage uncertainty in the *near-term* to support the timely and efficient delivery of major transmission projects by focusing on the following issues:

- introducing greater flexibility to the regulatory framework to mitigate the foreseeable risk that **financeability** concerns may arise in the future

- providing greater clarity and seeking feedback on potential improvements to the regulatory framework to support building **social licence**, i.e. facilitating community engagement and the acceptance of major transmission investments
- providing greater clarity regarding the distinction of **preparatory activities and early works**, along with their respective cost recovery processes
- improving the **workability of the feedback loop** so that it can operate as an effective consumer safeguard and be completed in a timely manner.

1.2.2 The Contestability workstream

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 concluded that an expanded scope for the contestability workstream is appropriate. The Commission is now examining the suitability of contestability in the provision of transmission services as an alternative approach to the existing regulation of major transmission projects. This involves examining various potential models of contestability to assess their relative costs and benefits through a high-level analysis and comparison.

To manage the significant volume of work required to explore this issue, the Commission is progressing work on contestability separately (but in parallel) to the issues being examined as part of Stage 3 of the Review.

The Commission published an options paper on 7 July. Subsequently, the Commission will recommend whether contestability should be explored in more detail and, if so, what the preferred contestable model is.

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 Commission published a more preferable draft rule and draft determination on 7 July 2022.[2]

The draft rule seeks to add clarity to the process for determining whether a material change in circumstances has occurred by requiring certain RIT proponents to develop reopening triggers which, if met, would require the RIT proponent to consider if and how to reconsider the extent to which the previously identified preferred option is likely to remain the most net beneficial option in light of the changed circumstances.

The draft rule additionally seeks to improve cost estimate accuracy by clarifying the rules governing the guidelines for RITs in order to support strengthened guidelines for cost estimate development.

The rule change request is being considered alongside the Review and is using 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:[3]

> 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

2 AEMC, *Material change in network infrastructure project costs,* Draft determination, 7 July 2002 available online at https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs.

3 Section 7 of the NEL.

operation and use of electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, security and reliability.[4]

1.3.2 Assessment framework criteria

The assessment framework criteria summarised in Table 1.2 have been used to assessed whether the Stage 3 draft recommendations promote the NEO. 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 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 major 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: 1. **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. 2. **Effective price signals/incentives:** effective incentives are needed to support service providers in making efficient and timely investment decisions. 3. **Information provision/transparency:** service providers require clear adequate information to inform decision-making in an evolving market. 4. **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

4 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.

CRITERIA	EXPLANATION
	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

Note: While a number of stakeholders proposed additional criteria be added to the assessment framework in response to the consultation paper for this Review, the Commission considers that the assessment framework adequately captures these.[5] For a more detailed response to stakeholder comments on the assessment framework see Appendix B of the consultation paper for this Review.

1.4 Lodging a submission and next steps

Written submissions on this draft report must be lodged with the Commission by 3 November 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.[6] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

The final Stage 3 report is expected to be published in March 2023. 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

5 Submission to the consultation paper: Transgrid, p. 1; ENA, p. 1; PIAC, p. 4; EnergyAustralia, p. 3; Neoen, p. 5.

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

2 ENSURING THE ECONOMIC ASSESSMENT PROCESS FACILITATES THE TIMELY DELIVERY OF MAJOR TRANSMISSION PROJECTS TO SUPPORT THE ENERGY TRANSITION

BOX 1: DRAFT POSITION

The Commission is seeking feedback on three strawperson options, which set out a spectrum of alternatives to the current economic assessment process for ISP projects. The Commission invites stakeholders to comment on:

- Whether any of these options could facilitate the timely transition to net zero while balancing rigour in the economic assessment process, and should be taken forward for further development and assessment.
- Whether the Commission should be considering any other options in this Review, including variations or hybrids of the three options presented.

As indicated in the consultation paper for this Review, the Commission considers that the economic assessment process should provide a robust safeguard for consumers, while not unduly delaying net beneficial projects.

In the context of a forward program of major investments to support the energy transition, it is appropriate to review whether there are opportunities to streamline the process and facilitate the timely transition to net zero while balancing rigour.

The Commission's initial findings are that:

- The current economic assessment process comprises four stages: the ISP, the RIT-T, the feedback loop and the CPA. There is a degree of overlap in the activities and decisions that are being made at each stage. For example, benefits may be assessed in the ISP, RIT-T and feedback loop. However, the process and information revealed at each stage is different, meaning that each stage contributes to the NEO in distinct ways. It is important to be cognisant of how changes would affect the achievement of the NEO.
- To date, all major ISP projects that have completed the economic assessment process have progressed under transitional rules, which may have contributed to some of the concerns raised by stakeholders around the current arrangements.* The Commission expects that as the 2020 actionable ISP rules framework matures, ISP projects may be able to move through the economic assessment process more rapidly than seen to date. Changes proposed in the Stage 2 draft report for this Review and in the *Material change in circumstances* draft rule determination aim to further support the efficiency and robustness of the economic assessment process in the future.

- However, given the scale of potential future investment in the transmission system and the benefits for consumers, it is important to ensure these investments are realised in a timely manner. In this context, the Commission sees value in consulting on further opportunities for improvement. In light of the ISP review that the AEMC is required to complete by mid-2025, the Commission also considers it is appropriate to think broadly about possible alternatives. The work on the economic assessment process in Stage 3 of the Review will provide a starting point for the ISP review.

Note: *HumeLink is a staged ISP project. The AER approved a regulatory allowance for stage 1 early works in August 2022. HumeLink commenced before the 2020 actionable ISP reforms were introduced by the Energy Security Board (ESB). Consequently, some elements of the current ISP framework did not apply to this project.

2.1 This Review's focus in relation to the economic assessment process: timeliness and rigour

The Terms of Reference for this Review tasked the Commission to examine whether the economic assessment process for ISP projects appropriately balances timeliness and rigour. As described in more detail in section 2.2, the economic assessment process comprises four distinct stages:

- The preparation of an **ISP** by AEMO, which determines the optimal development path (ODP). The ODP is the portfolio of network investments that in combination best meet the identified needs of the power system. Projects on the ODP are classed as either **actionable** (to be delivered at the earliest possible date) or **future** (potential actionable projects, subject to testing in a subsequent ISP).
- The **regulatory investment test for transmission (RIT-T)**, in which TNSPs consider more granular technical options addressing the ISP identified need and select the preferred option.
- The **feedback loop** analysis performed by AEMO, which confirms whether the RIT-T preferred option remains on the ODP given the TNSP's estimated cost of delivery.
- The **contingent project application (CPA)**, submitted by TNSPs to seek the AER's approval of a regulatory allowance to deliver the preferred option.

This Review is considering how the economic assessment process facilitates the timely delivery of major transmission projects to support the energy transition, whilst maintaining rigour.

2.1.1 The need for timely delivery of major transmission projects to facilitate the transition to net zero

'Timeliness' relates to how the economic assessment process affects the timely delivery of ISP projects. The time needed to complete the economic assessment process in isolation is not of primary relevance, but rather, how the process contributes to overall project delivery times.

AEMO's 2022 ISP discusses the asymmetric costs to consumers associated with the timely delivery of ISP projects, i.e. the risks of over and under investment, with the costs of delayed investment in ISP projects being significant. With transmission investment occurring earlier rather than later, cheaper renewable energy sources (wind and solar) can be unlocked for consumers. Without transmission, consumers need to pay for more expensive capacity (gas, storage and off-shore wind). Delaying investment in transmission infrastructure would thus come at a cost at consumers. For example, AEMO's 2022 ISP shows that consumers could face a significant increase in wholesale energy costs if HumeLink was to be delayed by two years. Given the importance of these projects to facilitate the energy transition and their benefits to consumers, it is important that improvements to the economic assessment process focus on supporting the timely delivery of these major transmission projects.

'Rigour' in the economic assessment process relates to three elements – cost estimates, benefits estimates, and the transparency of the process to assess those costs and benefits. More specifically:

- In relation to cost estimates, the main determinant of rigour is the level of accuracy around the cost estimates that are an input to each stage of the economic assessment process.[7]
- In relation to benefits estimates, the focus is on how up-to-date the benefits estimate is at the time of making an economic assessment decision. In other words, how much information about the likely future state of the world is available to inform that decision.[8]
- In relation to transparency, the key issue is whether the process to develop options, costs and benefits at each stage of the process is sufficiently consultative.

Against this background, the Commission considers an improved economic assessment process for major transmission projects should:

- **Achieve a material reduction in time**: support the timely delivery of major transmission investments by reducing the time between when an identified need is defined to the start of construction of the solution to meet that need.
- **Maintain an adequate level of rigour**: the process should be transparent and build on high quality information regarding the assessment of costs and benefits, underpinning key decisions in the process.

QUESTION 1: THE NEED FOR TIMELY DELIVERY OF MAJOR TRANSMISSION PROJECTS TO FACILITATE THE TRANSITION TO NET ZERO

a. Do you agree with the Commission's view that improvements to the economic assessment process should focus on facilitating the timely delivery of major transmission projects, given

7 The Commission has also considered the issue of cost estimate accuracy in the *Material change in network infrastructure project costs* draft rule determination published on 7 July 2022.

8 The Commission recognises that the rigour of benefits could consider other dimensions – such as the methodology used to derive the benefits estimate, or the types of benefits that are included in the evaluation. However, the Commission considers that these issues are best taken forward outside this Review. That is because this Review is focused on the overall structure of the economic assessment process and the interaction between each of the stages.

their role in providing benefits to consumers and facilitating the energy transition?

b. What do you think would be a material reduction in time for undertaking the economic assessment process?

2.1.2 Interactions with other elements of the Commission's work program on transmission

The Commission's scope for considering the balance of timeliness and rigour in the economic assessment process is based on three considerations:

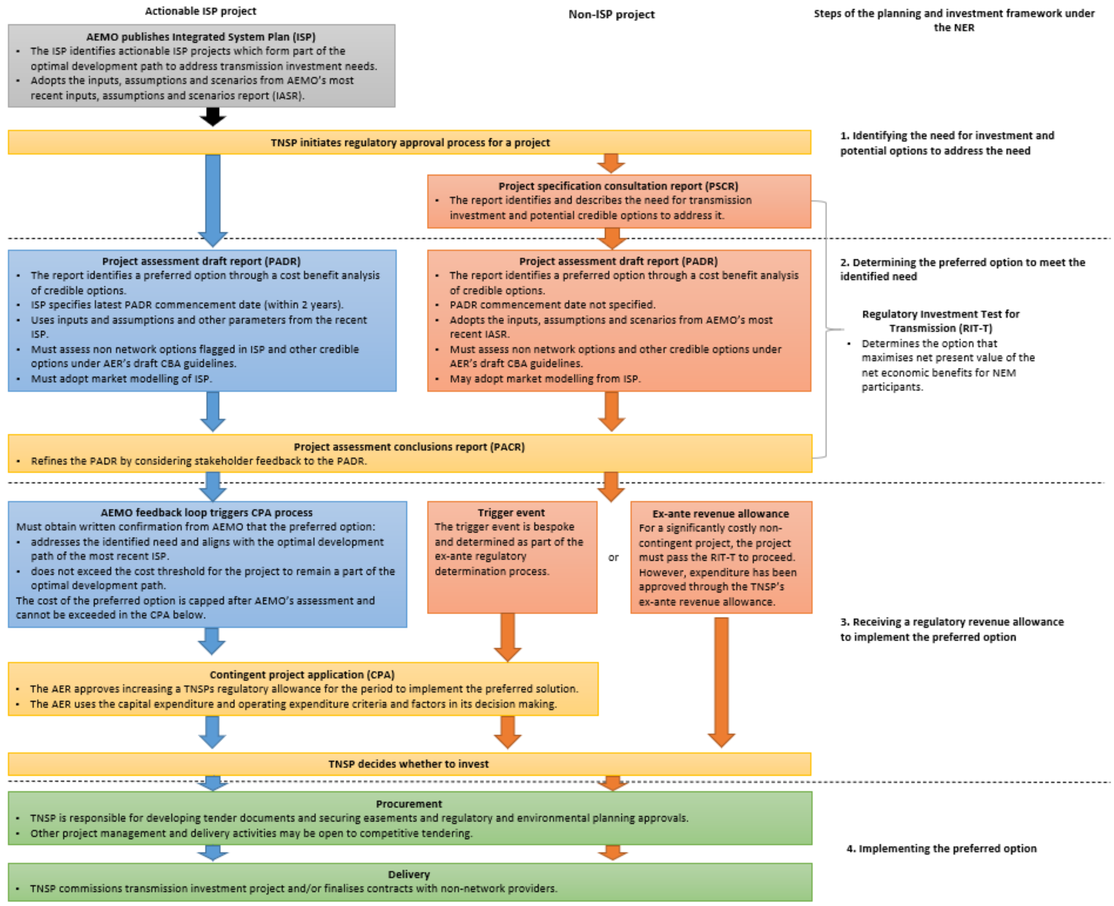
1. **Type of projects:** Whether the Review should consider the economic assessment process for ISP projects only, or also projects outside the ISP framework.
2. **ISP review**: How the Review should interact with the NER requirement for the AEMC to undertake a review of the ISP framework by mid-2025.
3. **Contestability**: What the Review should assume in relation to contestability, noting that this is currently being explored by the Commission as a separate workstream.

We discuss each scope consideration below.

This Review is considering the economic assessment process for ISP projects

The Commission recognises that there are different economic assessment processes for ISP and non-ISP projects. The differences are outlined in Figure 2.1 below:

Figure 2.1: Overview of key steps in the economic assessment process



Source: AEMC.

For this Review, the Commission is focusing on the process that applies to ISP projects. This is because, measured by capital expenditure, ISP projects are expected to comprise the majority of future major transmission system investments. This is shown in Table 2.1 below, which presents data sourced from the 2022 ISP and contingent projects (or potential contingent projects) nominated by TNSPs in their most recent revenue proposals to the AER. Together, the actionable and future ISP projects represent approximately 85 per cent of the total capital expenditure.

Table 2.1: ISP and non-ISP projects

PROJECT	STATUS	FRAMEWORK	CAPEX ($M)
Humelink	Actionable (staged)	National	$3,315m
Sydney Ring	Actionable	NSW	$900m - $2,250m
New England REZ	Actionable	NSW	$1,900m

PROJECT	STATUS	FRAMEWORK	CAPEX ($M)
Transmission Link			
Marinus Link	Actionable	National	$3,780m
VNI West	Actionable	National	$3,565m*
Total actionable ISP projects		National	**$13,460m - $14,810m**
Central to Southern QLD	Future	National	$531m
Darling Downs REZ Expansion	Future	National	$1,203m
South East SA REZ Expansion (Stage 1)	Future	National	$57m
Gladstone Grid Reinforcement	Future	National	$408m
QNI Connect	Future	National/NSW	$1,253m
Facilitating Power to Central QLD (Stage 1)	Future	National	$137m
South West Victoria REZ Expansion	Future	Victoria	$930m
Mid North South Australia REZ Expansion	Future	National	$340m
New England REZ Extension	Future	NSW	$1,237m
Far North QLD REZ Expansion	Future	National	$1,264m
Total Future ISP			**$7,360m**
Non-ISP major projects	**Contingent or future contingent**	**National / jurisdictional**	**$3,444m - $3664m**

Source: AEMO, 2022 ISP, June 2022. ElectraNet, Revenue Proposal 2024-2028, January 2022. AER, Powerlink Queensland Transmission Determination 2022 to 2027, April 2022. TasNetworks, Tasmanian Transmission and Distribution Revised Proposals 2019-2014, November 2018. Transgrid, Revenue Proposal 2023-28, January 2022.

Note: *Weighted average of capex in the PADR.

Limiting the scope of this Review to the economic assessment process for ISP projects means that we will be capturing the bulk of potential future investments. This scope choice is proportionate in the context of the timeframe for this Review. This does not mean that the economic assessment process for non-ISP projects is not important: the non-ISP investments also support reliability and represent a substantial costs to consumers. After this Review concludes, there will be opportunities to consider whether any of the final recommendations have implications for the process that applies to non-ISP projects.

Table 2.1 also highlights that, in the near future, several ISP projects may proceed through jurisdictional planning and investment frameworks, rather than the national framework that is the subject of this Review. These include the NSW regulatory process for Renewable Energy Zone (REZ) projects, and the draft Victorian Transmission Investment Framework (VTIF). This means that these particular projects would not be impacted by any recommendations that this Review might make in relation to the national framework. The Commission will take this into account when considering the potential timing of any recommended changes to the national framework.

As described throughout this chapter, when reviewing the national economic assessment process and considering possible alternatives, the Commission has had regard to the design and objectives of the economic assessment processes that have been developed in New South Wales and Victoria.

AEMC must undertake a review of the ISP framework by 1 July 2025

The NER require the Commission to complete a review of the ISP framework by 1 July 2025. The NER requirements are set out in Box 2 below.

BOX 2: AEMC TO REVIEW THE ISP FRAMEWORK BY MID-2025

Under clause 11.126.10, the AEMC must complete a review of the ISP framework as set out in rules 5.16A, 5.22 and 5.23 of the NER by 1 July 2025.

- Rule 5.16A relates to the application of the RIT-T to actionable ISP projects including: the development and publication of Cost Benefit Analysis Guidelines (CBA Guidelines) by the AER; the exemption for actionable ISP projects to prepare a project specific consultation report (PSCR); and the requirement for an actionable ISP project to complete the feedback loop prior to submitting a CPA.
- Rule 5.22 relates to the requirement for AEMO to publish an ISP at least every two years by 30 June (and the factors relevant to the preparation and publication of the ISP) including: the purpose and content of the ISP; the ISP timetable; the application of the AER's CBA Guidelines and Forecasting Best Practice Guidelines (FBP Guidelines) to the ISP; consultation procedures, including the ISP consumer panel; the AER transparency review of the Inputs, Assumptions and Scenarios Report (IASR); and the process for ISP updates.
- Rule 5.23 sets out arrangements regarding disputes in relation to an ISP.

The scope of the 2025 ISP review overlaps substantially with the issues being considered in relation to the economic assessment process for this Review. This means it is necessary to clarify what is being examined in each of the reviews.

In this Review the Commission is focusing on the key stages of the economic assessment process and the interactions between them, to identify whether there may be opportunities to streamline the process and facilitate the timely transition to net zero while balancing rigour. If potential opportunities are identified, these would inform the scope of the 2025 ISP review. The Commission expects to provide further detail on the scope of the ISP Review as part of the Stage 3 final report, based on stakeholder feedback on the issues explored in this Review.

The Review is considering the economic assessment process independently of the potential future introduction of a national contestability regime

The Commission is currently examining contestability as a separate workstream of this Review. The Commission has recently published an options paper.[9]

The options paper published in July seeks stakeholder feedback on four strawperson contestability models, on a spectrum from early to late-stage competition. Each contestable model is expected to have different implications for the economic assessment process. For example, an early competition model might involve more substantial changes to the ISP than other models.[10]

The Commission is cognisant of the interrelationships between issues explored across the Review. As noted in the contestability options paper, the findings outlined in this report will help inform thinking on whether there is a case for introducing contestability as an alternative delivery model.[11] The Commission is also mindful that contestability is a long-term reform and there may be opportunities to improve the balance of timeliness and rigour in the economic assessment process at an earlier date. This may have an impact on assessing the need for contestability as a means to faciliate the timely delivery of projects. When developing the Stage 3 final report, the Commission will thus further consider possible interactions between the contestability workstream and our recommendations in relation to the economic assessment process.

2.2 The economic assessment process for ISP projects involves four key stages with overlaps in the activities and decisions that are being made at each stage

The economic assessment process that currently applies to ISP projects was established by the ESB through the 2020 actionable ISP reforms. At that time, the ESB's intention was to streamline the regulatory process for key projects identified in the ISP while retaining a rigorous cost benefit assessment.[12]

As illustrated in Figure 2.2 below, the current process revolves around three decisions:

- **Option identification**: What options can potentially meet the needs of the power system?
- **Option selection**: What is the preferred option to meet an identified need (i.e., the option that maximises net benefits)?

9 AEMC, *Options Paper – Transmission Planning and Investment – Contestability*, July 2022.

10 Ibid., p. 27.

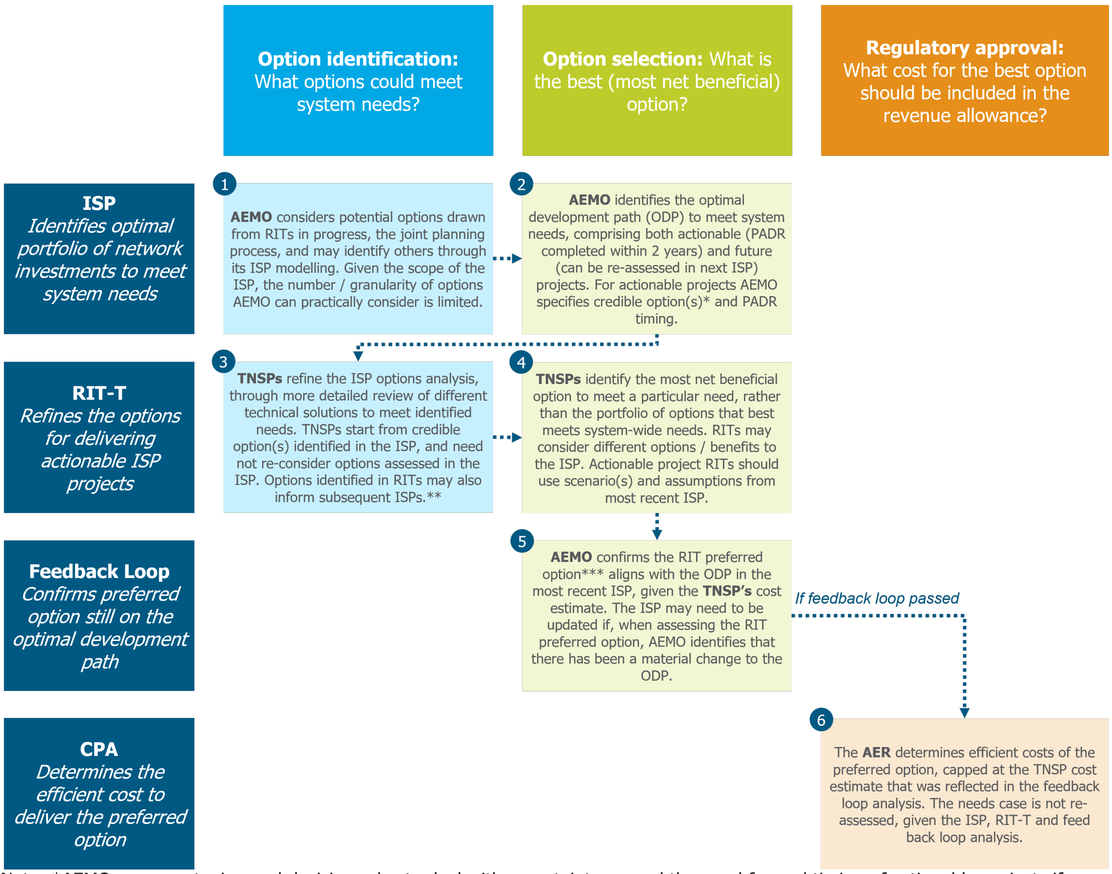
11 Ibid., p. 11.

12 Energy Security Board, *Converting the Integrated System Plan Into Action – Recommendation for National Electricity Amendment (Integrated System Planning) Rule 2020 – Decision Paper*, March 2020, p. 4.

- **Regulatory approval**: What is the efficient cost of delivering the preferred option for inclusion in the TNSP's regulatory allowance?

The three decisions provide 'building blocks' for describing the current economic assessment process and comparing it to alternative options in section 2.6.

Figure 2.2: Purpose of each stage of the current economic assessment process and key decision points



Note: *AEMO can use staging and decision rules to deal with uncertainty around the need for and timing of actionable projects if circumstances change. If a project is identified as staged in the ISP, the first stage and subsequent stages each need to progress through the RIT-T, feedback loop and CPA process. If decision rules are used in the ISP, these need to be satisfied before a feedback loop can be requested.

Note: **In the RIT-T TNSPs can also choose to stage projects to manage uncertainty in the needs case.

Note: ***The TPIR Stage 2 Draft Report proposed timing changes to improve the workability of the feedback loop.

When establishing the current economic assessment process for actionable ISP projects, the new ISP process was combined with the existing RIT-T process, instead of designing an entirely new process. This created challenges based on the differences in scope of the ISP and the RIT-T. Whilst the ISP is a whole-of-system plan, the RIT-T is a project based assessment of different options to identify the transmission investment option which maximises net economic benefits. The scope of the two assessments is thus very different (as described in further detail in Table 2.2**1.2**). This may lead to misalignment between the two processes. At the same time, as two processes were merged, there is also duplication with regard to the analysis undertaken and the decisions made.

For example, the first two decisions – option identification and selection of the preferred option – are progressively refined during the ISP, RIT-T and feedback loop. This means that there is a degree of overlap in the activities and decisions that are being made at each stage. For example, the costs and benefits of alternative options to meet system needs are considered in both the ISP and RIT-T. The cost benefit assessment may also be revisited at the feedback loop stage, in certain circumstances (see section 2.2.3). However, the way costs and benefits are assessed at each stage, and the information revealed, is different. As outlined in the following sections, this reflects that each stage of the economic assessment process has been designed to contribute to meeting the NEO in a distinct way. The Commission considers that it is important to be mindful of the rationale for the existing process when assessing the scope for beneficial change.

In submissions to the TPIR consultation paper, stakeholders expressed a range of views on whether the current balance of timeliness and rigour in the economic assessment paper is appropriate. Several stakeholders saw little need for changes to the economic assessment process.[13] Some submissions highlighted that the ESB's 2020 reforms should provide process efficiencies and considered that the current regulatory framework should be given time to mature.[14] Others suggested that incremental improvements would be more appropriate than wholesale reforms.[15] However, others suggested that there is unnecessary duplication across the process.[16]

Stakeholders supported the removal of unnecessary duplication within the economic assessment process.[17] However, many submissions highlighted the value provided by the checks and balances in the current process to ensure customers do not bear the cost of inefficient investments. These stakeholders emphasised that streamlining should not result in a lower level of rigour.[18] Others noted the distinct purpose of each stage in the current process.[19]

2.2.1 ISP identifies the optimal portfolio of network investments for the NEM

The purpose of the ISP is to identify the ODP for the NEM. The ODP is a portfolio of power system developments that, in combination, are considered to efficiently meet power system needs. Power system needs encompass the market reliability standard, relevant transmission reliability standards and power system security. AEMO may also consider State and Federal

13 Submissions to the consultation paper: EnergyAustralia, pp. 1-2; Shell Energy, p. 2.; TasNetworks, pp. 4-5.

14 Submissions to the consultation paper: EnergyAustralia, pp. 1-2.; Origin, p. 3.; CEC, p. 6.

15 Tilt Renewables, submission to the consultation paper, p. 1.

16 Submissions to the consultation paper: AER, p. 9.; CEFC, p. 3; AEMO, pp. 6-8.

17 Submissions to the consultation paper: AEC, p. 1.; AER, p. 9.; CEFC, p. 3.; CEIG, p. 4.; APA, p. 10.

18 Submissions to the consultation paper: AEC, p. 2.; EnergyAustralia, pp. 1-2.; AGL, p. 1.; Origin, p. 3.; PIAC, p. 5.; MEU, p. 7.; Resist Humelink, p. 1.

19 Submissions to the consultation paper: TasNetworks, pp. 4-5.; Transgrid, p. 6.

government environmental and energy policies when determining power system needs, provided that they meet certain criteria.[20]

The ODP reflects different types of network investments:

- **Committed** and **anticipated** projects, which are fixed inputs to the ISP analysis.[21]
- **Actionable ISP projects**, which are projects on the ODP for which a PADR – the first RIT-T report for actionable ISP projects – must be completed within 24 months of ISP publication (i.e., before the next ISP is published). A project is deemed actionable if AEMO's cost benefit analysis indicates it should be developed no later than one year after its earliest in-service date.
- **Future ISP projects** also address an identified system need and form part of the ODP. Unlike actionable projects, future projects can proceed more than one year after their earliest delivery date (i.e., they may only become actionable in the next ISP).

Once the ODP is determined, AEMO publishes guidance on the development of actionable projects, including:

- Defining the **identified need**, being the reason why an investment in the network is required. This provides a guide for the subsequent RIT-T assessment of options to deliver the actionable project.[22] When describing the identified need, AEMO seeks to provide enough specificity such that options can be narrowed without pre-supposing a particular outcome.
- Specifying a **candidate option** (or options), being a credible project that can meet the identified need.
- Specifying the date by when the **PADR** for the actionable project should be completed.
- Determining whether a project should be **developed in stages**, to protect consumers from the risk of over-investment by enabling some activities to progress without fully committing to the entire project.[23]
- Where appropriate, specifying **decision rules**, which are conditions that must exist in order for actionable projects to proceed from one stage to the next.
- Assigning an **ISP scenario** or scenarios that must be considered by the TNSP in the RIT-T, including likelihood-based weights if there is more than one scenario.[24]

20 Clause 5.22.3(b) of the NER.

21 Committed means that the proponent has: obtained all required planning consents, construction approvals and licences; commenced construction or set a firm commencement date; purchased/settled/acquired land (or commenced legal proceedings to do so) for the purpose of construction; finalised and executed contracts for supply and construction of major components; and finalised the necessary financing arrangements. Anticipated projects meet at least three of the aforementioned criteria. AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 102.

22 For example, the 2022 ISP identified need for the Sydney Ring project is to *"deliver net market benefits for consumers by increasing the power system's capability to supply the Sydney, Newcastle and Wollongong load centres, replacing supply capacity that will be removed on the closure of coal-fired power stations in the Newcastle area"*. AEMO, *2022 Integrated System Plan*, p. 71.

23 Staging could involve: building one part, or a smaller capacity, of the full project in a way that allows the rest to be built later if needed; using a non-network option (which may be reversible) to manage immediate needs and allow the ISP project to be built in future if needed; undertaking initial development activities such that the ISP project can be built more quickly in future if needed (but without committing to the full project).

24 AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 45.

AEMO determines the ODP by assessing a range of candidate development paths. The paths reflect varying combinations of network investments (which may include network and non-network options) that meet system and policy needs under different future scenarios. This involves first **identifying** potential network investments, and then **selecting** the optimal combination. The way AEMO undertakes these economic assessment process decisions is outlined below.

Option identification

Prior to assessing the costs and benefits of network investment options, AEMO publishes the **IASR** which describes the inputs to its ISP analysis. This includes assumptions around future market developments (e.g., demand, costs of generation technologies, fuel costs), as well as potential network investment options.

As part of the IASR development, AEMO consults with TNSPs on credible options and cost estimates through the **joint planning process**. The joint planning arrangements are defined under NER clause 5.14.4, which stipulates that TNSPs and AEMO must take reasonable steps to cooperate and consult with each other to enable preparation of a draft or final ISP. These requirements are set out in Box 3 below. The Commission understands that in practice, TNSPs and AEMO collaborate on the investment options and associated costs feeding into the ISP through a range of working groups and regular engagement.

In its submission to the TPIR consultation paper, AEMO noted that the quality of and confidence in the ISP analysis may be compromised if TNSPs do not provide accurate information to AEMO through the joint planning arrangements, noting that the framework does not include an ability for AEMO to compel TNSPs to provide reliable and accurate information. Similarly, TNSPs may make wide ranging confidentiality claims such that AEMO is unable to use the information provided when publishing the IASR and ISP.[25]

BOX 3: JOINT PLANNING ARRANGEMENTS

To enable the preparation of a draft or final ISP, NER clause 5.14.4 requires AEMO and/or the TNSPs (as applicable) to:

- Provide, and consult on, a Transmission Annual Planning Report (TAPR).
- Provide, in accordance with the ISP timetable, the latest available information in relation to the development of a TAPR required for an ISP.
- Provide information on non-network options and conduct a preliminary review of the non-network options submitted to AEMO following a draft ISP.
- Share a draft ODP to be included in the draft and final ISP, before its publication.
- Consider whether a credible option in a draft ODP is reliability corrective action.
- Share information reasonably necessary to prepare a draft or final ISP.

25 AEMO, submission to the consultation paper, p. 7.

If TNSPs become aware of a material change to information provided to AEMO, they must provide an update as soon as practicable.

Rule 5.12 of the NER sets out requirements for the annual planning process that informs the TAPRs, while rule 5.14B of the NER provides that the AER must develop guidelines that set out the format of the TAPRs, in order to support the consistent provision of information by TNSPs.

Aside from the requirements outlined above, the NER do not otherwise specify the type and quality of the inputs provided by TNSPs into the ISP process.

Note: TAPRs are prepared by the TNSPs and may include information on projects that are already moving through the RIT-T process, and earlier-stage projects that the TNSP has identified to meet the requirements of its network.

To inform the network investment options that feed into the ISP, AEMO may also specify **preparatory activities** and **REZ design reports** that TNSPs must carry out in relation to future or actionable ISP projects:

- **Preparatory activities** inform subsequent ISPs by developing the design of investment options and improving the cost estimates. For example, in the 2020 ISP AEMO identified the Sydney Ring and the New England REZ Transmission Link as future ISP projects, with preparatory activities required to be completed by 30 June 2021. These activities have assisted AEMO in determining that these projects should receive actionable status in the 2022 ISP.[26]
- **REZ design reports** were introduced following the ESB's Review into Renewable Energy Zones. These reports are more extensive than preparatory activities and require the relevant jurisdictional planning body to explore and report on technical, economic or social issues related to REZ development. For example, these elements of the NER require them to: ensure that public consultation is conducted with local councils, community members and other interested stakeholders; and include an assessment of the key community impacts of the REZ in the design report, along with a preliminary estimate of the costs associated with managing these impacts.[27] While AEMO has not called for any REZ design reports in this 2022 ISP, it has determined a need for preparatory activities for some REZ network developments.[28]

Option selection

AEMO undertakes a complex modelling process to select the network investments that make up the ODP, as summarised in Figure 2.3 below.[29]

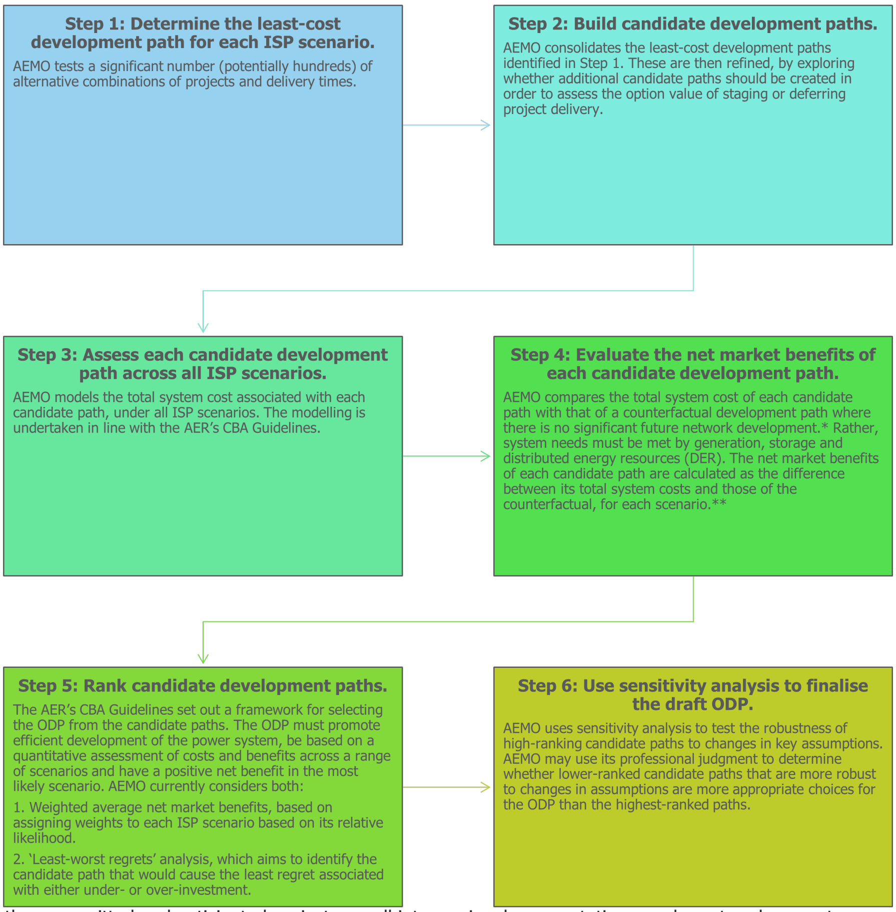
26 AEMO, *2022 ISP*, p. 93.

27 Clause 5.24.1 of the NER.

28 AEMO is continuing to work with State governments to align future REZ design reports with REZ initiatives in each jurisdiction. AEMO, *2022 ISP - Appendix 3 – Renewable energy zones*, June 2022, p. 20.

29 AEMO, *ISP Methodology*, August 2021, Chapter 5.

Figure 2.3: ISP process to select the ODP



Note: *Other than committed and anticipated projects, small intra-regional augmentations, and asset replacements.

Note: **This describes AEMO's approach for the 2022 ISP. The AER's CBA Guidelines provides flexibility for AEMO to consider market benefits that cannot be modelled by comparing total system costs under the counterfactual and candidate development paths. AER, Cost Benefit Analysis Guidelines, August 2020, p. 27.

In estimating the cost of network investments considered in the ISP, AEMO is required to check its estimates against recent CPAs, recent tender outcomes, and/or final project outcomes. If AEMO establishes there is a material degree of uncertainty in the cost estimate, AEMO must adopt a probability-weighted estimate under a range of different assumptions.[30] AEMO described how it meets these requirements in the 2021 Transmission Cost Report.[31]

Staging and option value

An important concept used in the ISP analysis is **option value.** Option value arises when an investment decision can be delayed until more information is available, without the delay removing the option to make that decision in the future. For example, option value may arise

30 AER, *Cost Benefit Analysis Guidelines*, 25 August 2020, p. 18.

31 AEMO, *2021 Transmission Cost Report*, August 2021.

if a network investment can be implemented in stages: implementing the first stage preserves the option to undertake the second stage later if the benefit of doing so is still there, but without making a full commitment to both stages upfront. This protects consumers against the consequences of delayed delivery, while retaining the option to pause or discontinue a project if circumstances change. The AER's CBA Guidelines require AEMO to consider option value in determining the ODP.[32] For example, AEMO may consider option value by analysing different timing and staging of ISP projects, using non-network options to build in flexibility, and staging or deferring projects where benefits occur late in the modelling period.

In the 2022 ISP, AEMO identified that two actionable ISP projects should be developed in stages:

- HumeLink, which is a proposed 500kV transmission link between the Greater Sydney load centre and the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect in South West NSW. Stage 1 is to complete pre-construction activities by mid-2024, while stage 2 is to complete the project by July 2026.[33]
- VNI West, which is a proposed 500kV interconnector between Victoria and NSW. Stage 1 is to complete pre-construction activities by approximately 2026, while stage 2 is to complete the project by July 2031.[34]

To date, stage 1 has typically involved pre-construction activities to deliver the ISP candidate option, such as detailed design, stakeholder engagement, land-use planning and approvals, securing options over easements, and early procurement.

When a staged project is identified in the ISP, the ISP only makes the first stage of that project actionable. Under the current rules, during stage 1 a RIT-T must specify that the RIT-T proponent consider credible options including, the ISP candidate option(s), non-network options that are reasonable likely to meet the identified need and any new credible options.[35] The need for the second stage is then assessed in a subsequent ISP. If the ISP determines that stage 2 should proceed, another RIT-T is required to confirm the preferred option.[36]

Consultation and transparency requirements

The ISP framework provides for a range of measures to support the robustness and transparency of the ISP process. These are outlined in Figure 2.4 below.

32 Ibid., p. 37.

33 AEMO, *2022 ISP*, p. 68.

34 Ibid., p. 74.

35 Clause 5.15A.3(b)(7)(iii) of the NER.

36 AER, *Guidance Note: Regulation of actionable ISP projects*, March 2021, p. 25ff.

Figure 2.4: ISP consultation and transparency requirements

Consultation

- AEMO is required to **consult** on 1) the IASR, ISP cost benefit analysis and modelling methodology, and 2) the draft ISP, with a 30-day submission period for both consultations.
- AEMO must hold a public forum prior to the close of submissions on the draft ISP. AEMO may develop and consult on the IASR in tandem with other AEMO publications (e.g., a reliability forecast).

Clauses 5.22.8 and 5.22.11 of the NER.

ISP Consumer Panel

- The NER provide for the establishment of an **ISP consumer panel** that delivers written reports to AEMO on the IASR and draft ISP.
- AEMO must explain how it has had regard to the report in the draft ISP but is not required to give effect to any recommendations.

Clause NER 5.22.7 of the NER.

AER review

- The **AER** plays a role in ensuring that AEMO has followed the processes and requirements of the NER and associate AER guidelines when developing the ISP.
- This includes publishing an IASR review report and ISP review report within one month of the IASR and ISP publication. Among other matters, these reports considers whether AEMO has adequately explained how it derived key inputs and assumptions, and how these have contributed to the draft ISP outcomes.
- If the AER's reports identify issues, AEMO must provide further explanatory material in an addendum and consult on the issues raised.

Clause NER 5.22.9 and NER 5.22.13 of the NER.

Dispute process

- **Disputes** can be raised on the grounds that AEMO has not followed required procedures when preparing the ISP, including the process for the IASR and ISP methodology, consultation on the draft ISP, and publication requirements for the final ISP.
- AER must review dispute notices within 20 business days of receipt and, if it accepts the dispute notice, must make a determination within 40 business days (subject to extension if additional information is requested from the disputing party or AEMO).

Clause NER 5.23 of the NER.

Source: AEMC.

2.2.2 The RIT-T refines the options for delivering actionable ISP projects

In relation to actionable ISP projects, the role of the RIT-T is to undertake a more detailed assessment of the different options that could meet the identified need specified in the ISP. For actionable ISP projects, there are two RIT-T stages:[37]

- The **PADR**, which sets out the range of options the TNSP has considered and its proposed preferred option to meet the ISP identified need. TNSPs are required to publish the PADR by the date set out in the ISP, unless the AER approves a request for an extension. There is a 6-week consultation period on the PADR.

37 Clause NER 5.16A.4 of the NER provides that the TNSP must re-apply the RIT-T in certain circumstances. These include where an ISP or ISP update identifies a change to the identified need, or where there has been a material change in circumstances that TNSP believes has altered the preferred option. As described in section 2.4 below, the Commission is currently consulting on a change to these provisions of the NER.

- The **PACR**, which sets out the TNSP's final preferred option, taking into account stakeholder feedback on the PADR. The PACR should be published as soon as practicable after the conclusion of the PADR consultation period, having regard to submissions received.[38]

As with the ISP, the RIT-T involves both:

- **identifying** potential options, and then
- **selecting** a preferred option.

However, as described below the scope, the process and analysis is different from the ISP.

Compared to the ISP the RIT-T process provides an opportunity for different technical solutions (including non-network options) to be investigated in greater detail with stakeholders, for cost estimates to be refined, and for benefits to be re-estimated in the event of a material change from the assumptions used in the ISP. The RIT-T can also explore more granular options for staging ISP projects, to preserve option value.[39]

The intent of the current ISP framework is that while the RIT-T process is intended to extend and refine the ISP analysis, it does not seek to duplicate AEMO's analysis. As described below, TNSPs are required to align their RIT-T with the ISP as far as possible.

In response to the TPIR consultation paper, some submissions suggested that the appropriate timing of the RIT-T should be considered. For example, submissions referred to situations where the RIT-T may be completed too early, creating a need to update cost and benefit assessments at the later stages.[40]

Option identification

When considering options that could be included in the RIT-T, the TNSP must use the identified need specified in the ISP. The options considered by the TNSP in the RIT-T must include: the candidate option(s) identified by AEMO, including refinements; any non-network options the ISP considered likely to meet the identified need; and any new credible options not previously identified in the ISP.[41] TNSPs are not required to re-evaluate options that were considered and rejected in the ISP. The range of options assessed in the RIT-T will therefore depend on how comprehensive the ISP options identification process was, and how tightly specified the ISP identified need and candidate option(s) are.

While AEMO makes conceptual design assumptions in the ISP, through the RIT-T the TNSP may need to consider a range of feasible network options to meet the identified need, including credible alternate designs or technologies. For example, these may include:[42]

38 Clause 5.16A.4(n) of the NER provides that the conclusions of a PACR can be disputed on certain grounds. For ISP projects, disputes cannot be raised in relation to the TNSP's use of or reliance on the ISP, given the process that AEMO was required to follow when developing it. Disputes must be lodged within 30 days of PACR publication. Clause 5.16B states that the AER has up to 100 days (40 days, plus an extension of up to 60 days) to make a determination, although this may be extended if the AER requests additional information from the TNSP or disputing party. If the dispute is upheld, the AER may direct the TNSP to amend the PACR.

39 AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 41.

40 Submissions to the consultation paper: AGL, p. 1.; MEU, p. 3.; EUAA, p. 7.

41 Clause NER 5.16A.3(b)(7) of the NER.

42 AEMO, *2021 Transmission Cost Report*, p. 23.

- alternate structure designs, including monopoles, guyed towers, and a variety of lattice towers
- alternate design methodologies, including insulated conductors or cables
- alternate construction methodologies, including helicopter-stringing and direct drilling
- alternate technologies, including high-voltage alternating current (HVAC) and high-voltage direct current (HVDC)
- non-network solutions, including battery services that obviate the need to build new network.

Option selection

When selecting the preferred option for an actionable ISP project, the TNSP must identify the credible option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity. This is similar to the ISP's consideration of net market benefits. However, there are some differences in the analysis, as outlined in Table 2.2 below.

The modelling of benefits was a key focus area in submissions to the TPIR consultation paper around potential areas of duplication.[43] For example, the AER noted that under the current rules, the RIT-T is intended to adopt the benefits modelled by AEMO for the ISP. In the AER's view, this raises the question of whether project benefits need to be re-modelled in the RIT-T.[44] AEMO observed that given the time required to complete a RIT-T, the PACR will inevitably be based on different inputs from the current ISP. This makes it more difficult for RIT-Ts to adopt the market modelling from the ISP, as intended by the current framework.[45] Several submissions commented that the ISP analysis is not sufficiently detailed to replace the RIT-T.[46] Some noted concerns regarding the impartiality and transparency of the benefits assessment conducted by TNSPs.[47] Other stakeholders suggested that opportunities to streamline the economic assessment process should not focus on the RIT-T, but rather on other stages.[48]

Table 2.2: **Comparison of ISP and RIT-T option selection process**

ELEMENT	ISP	RIT-T
Objective	The ISP is seeking to identify an optimal portfolio of actionable and future projects to meet system needs (the ODP).	The RIT-T is seeking to identify the preferred option for a single actionable project that makes a particular contribution to the system-wide ODP.

43 Submissions to the consultation paper: AER, p. 9.; CEFC, p. 3; AEMO, p. 8.
44 AER, submission to the consultation paper, p. 9.
45 AEMO, submission to the consultation paper, p. 6.
46 Submissions to the consultation paper: EnergyAustralia, p. 7.; Shell Energy, p. 2.; EUAA, p. 6.
47 Submissions to the consultation paper: Shell Energy, pp. 2-3; MEU, p. 6.
48 Origin, submission to the consultation paper, p. 3.

ELEMENT	ISP	RIT-T
Criteria for preferred option	While the ODP must have a positive net benefit in AEMO's central (most likely) scenario, AEMO will also consider robustness to sensitivities, weighted outcomes across multiple scenarios, and least-worst regret analysis.	The preferred option is the credible option to meet that need that maximises net economic benefits to all those who produce, consume and transport electricity. The TNSP's assessment must be based on the scenario(s) and weights assigned by AEMO in the ISP. These must reflect the scenario weights used in the ISP (even though AEMO uses other information to inform the ODP).
Inputs, assumptions and scenarios	AEMO develops the IASR, in consultation with stakeholders.	TNSPs are required to use the most recent IASR, unless there is a demonstrable reason to depart from this.***
Cost estimates	AEMO is expected to provide transparency on their methodology for determining the cost of credible options.	TNSPs refine the cost estimates used in the ISP as they develop the RIT-T analysis. RIT-T proponents are required to calculate expected costs for each credible option by taking a weighted-average across cost assumptions.
Benefit estimates	AEMO follows the AER's CBA Guidelines. AEMO does not routinely quantify all benefit classes permitted under the guidelines. For example, AEMO's 2022 ISP notes that assessing competition benefits* would not be feasible when developing a whole of system plan given the many development paths assessed, and may not be a material consideration for this analysis.**	TNSPs are required, if practicable, to adopt the market modelling from the ISP. TNSPs are also required to follow the AER guidelines, which is intended to provide alignment across the ISP and RIT-T. TNSPs may include approved classes of benefits that the ISP did not consider – such as competition benefits.

Source: **AEMO, *2021 ISP Methodology*, p. 74.; ***Clause 5.16A.3(b)(7)(iv) of the NER.
Note: *Competition benefits refer to the increased economic efficiency that may occur from improved competitive behaviours in the market as a result of network investments. These benefits are often not estimated due to the complexity and cost of the modelling task.

As discussed in the *Material change in circumstances* draft rule determination, many stakeholders commented that the Commission should consider whether requiring more accurate cost estimates at the RIT-T stage would better meet the NEO.[49] Some noted that increasing accuracy might also increase the costs of delivering a RIT-T.[50] Others considered that this would merely be bringing forward costs that would be incurred anyway at a later stage of project delivery.[51]

The AER's guidance note on the regulation of actionable ISP projects reflects an expectation that RIT-T proponents will indicate the level of accuracy, or uncertainty, of the forecast costs for the project, noting that the Association for Advancement of Cost Engineering (AACE) cost estimate classification system provides a useful and consistent framework.[52] The RIT-T application guidelines do not specify what level of accuracy cost estimates should have.[53]

AEMO's *2021 Transmission Cost Report* notes that, where possible, AEMO uses AACE classes in the ISP to provide consistency across the cost inputs used. AEMO's understanding of approximate AACE class usage at each stage of the economic assessment process is set out in Figure 2.5 below.

49 Submissions to the consultation paper: AEC, p. 3.; EnergyAustralia, p. 6.

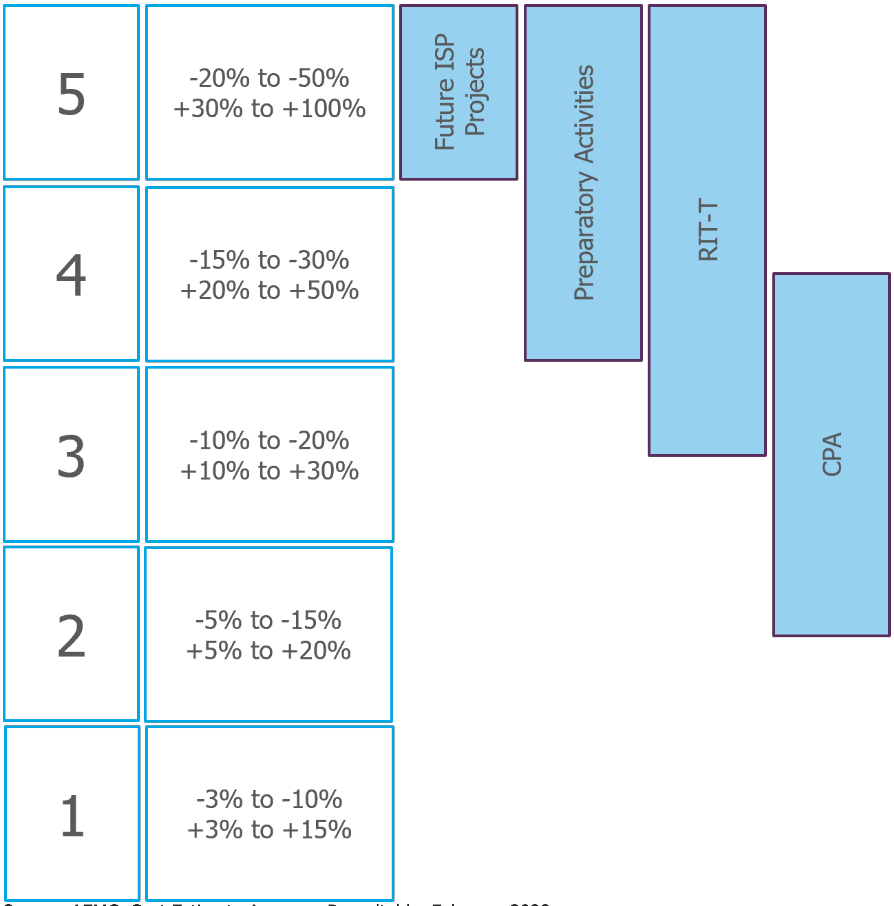
50 Submissions to the consultation paper: AEC, p. 3.; AER, p. 8.

51 MEU, submission to the consultation paper, p. 6.

52 AER, *Guidance Note: Regulation of actionable ISP projects*, March 2021, p. 7. The AACE system is used for defining the level of accuracy in a cost estimate based on the amount of design work that has been completed. Class 5 is the lowest level of accuracy while Class 1 is the most accurate.

53 The AER has noted that while the AACE system provides a useful framework, it is not appropriate to specific an AACE class of cost estimate for CPAs. AER, *Guidance Note: Regulation of actionable ISP projects – Covering letter*, March 2021, p. 16.

Figure 2.5: Approximate usage of AACE classes today



Source: AEMC, Cost Estimate Accuracy Roundtable, February 2022.

Staging

As described in section 2.2.2, to manage uncertainty around need and optimal timing AEMO can specify that a project should be developed in stages. Even if an actionable project is not staged in the ISP, in the RIT-T:

- TNSPs may determine that **staged development** is appropriate and decide to split the preferred option into delivery stages.
- TNSPs may determine that it is appropriate to develop the preferred option as a single unified project. In this case, the TNSP still has the option to submit a single CPA or submit multiple **staged CPAs** as it refines the project scope.[54]

The CPA arrangements under staging, and interactions with other parts of the economic assessment process, are discussed in section 2.2.4.

54 The AER has noted that if a TNSP proposes to submit more than two CPAs for an actionable ISP project, the AER will seek information on why this is appropriate and in the long term interests of consumers. AER, *Guidance Note: Regulation of actionable ISP projects*, March 2021, p. 28.

2.2.3 The feedback loop confirms that the preferred option remains on the optimal development path

Before submitting a CPA for regulatory funding to implement the preferred option, the TNSP must confirm with AEMO that it remains aligned with the ISP. This process is known as the feedback loop. Specifically, TNSPs must obtain written confirmation from AEMO that:[55]

- The RIT-T preferred option meets the identified need set out in the most recent ISP and aligns with the ODP referred to in the most recent ISP.
- The cost of the preferred option does not change the actionable ISP project's status as part of the ODP.

The regulatory allowance the TNSP can seek in its CPA is capped at the cost used in the feedback loop. This provides an important safeguard for consumers by ensuring that, at the maximum allowance the AER could approve, the project remains part of the optimal network investment portfolio to meet future system needs. The possibility of failing the feedback loop also creates an incentive for TNSPs to ensure that the costs used in the feedback loop analysis are not excessive. TNSPs may undertake further work between the RIT-T and feedback loop stages to firm up the cost estimate to the level of certainty required for the contingent project assessment.[56]

The feedback loop can trigger a requirement for AEMO to update the ISP:[57]

- if the preferred option fails to pass the feedback loop, or
- if in the course of undertaking the feedback loop, AEMO considers that there is a material change to the need for, or characteristics of, another actionable ISP project.

In this sense, the feedback loop is another stage of the economic assessment process where a decision is being made to confirm the **selection** of the preferred option. As described in section 2.4 below, in the Stage 2 draft report the Commission proposed changes to improve the workability of the feedback loop.[58]

2.2.4 The AER determines the efficient cost of delivering the preferred option

Under the NER, the contingent project mechanism can be used for large discrete projects where there is uncertainty as to whether or not they will be required during a TNSP's upcoming regulatory control period.[59] Contingent projects are not included in the TNSP's *ex ante* revenue allowance. However, the definition of contingent projects and their accompanying trigger events form part of the regulatory determination. When a trigger event occurs, the TNSP will apply to the AER to amend its revenue determination.

Since the introduction of the ISP, contingent projects include actionable ISP transmission projects that have passed the feedback loop.[60] As explained in the previous section, the cost

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

56 As discussed in section 2.2.3 TNSPs may use staged contingent project applications to seek an allowance for pre-construction activities to firm up costs to deliver the preferred option, before seeking approval to the cost to deliver the entire project.

57 Clause 5.22.15 of the NER.

58 AEMC, *Transmission planning and investment – Stage 2*, Draft report, June 2022, Chapter 5.

59 Clause 6A.8.2 of the NER.

60 The AER has approved CPAs for Project EnergyConnect, QNI and HumeLink (Stage 1).

of the preferred option set out in the CPA cannot exceed the cost included in AEMO's feedback loop assessment. The AER will publish the TNSP's CPA and invite submissions from stakeholders on the application. The AER will then determine, among other things, the total capital expenditure that is reasonably required to undertake the project.

Importantly, the AER's assessment is intended to determine the expenditure reasonably required for the purpose of undertaking the actionable ISP project. It does not revisit the analysis used to determine whether the project would be the most net beneficial option, as this has already been assessed through the ISP, RIT-T and feedback loop.

Staging

As described in section 2.2.1 and section 2.2.2, the economic assessment process provides substantial flexibility around both project delivery and the process to seek regulatory approval of funding.

Firstly, either AEMO or the TNSP may decide that it is optimal to deliver an actionable project in stages, to manage uncertainty around the need for and optimal timing of the investment. For example, HumeLink is proceeding as a staged project, as identified in the 2022 ISP. Following Transgrid's stage 1 CPA, the AER has approved expenditure for Transgrid to refine the project scope, progress activities on the critical path and undertake engagement to retain social licence.[61]

Secondly, where the preferred option is to deliver the actionable project as a single unified development, TNSPs have the option to submit multiple CPAs to seek regulatory funding for the project in stages. The AER introduced this process to help TNSPs manage uncertainty in recovering costs to deliver the preferred option that occur prior to CPA approval.[62] 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. Staged CPAs occur after a 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.[63] Guidance on the CPA staging process was issued in March 2021 and has not had an opportunity to be widely applied.

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 early delivery activities 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 way that staging is undertaken affects interactions between the ISP, RIT-T, feedback loop and CPA. These interactions are summarised in Figure 2.6 below. The figure explains that staging can be applied in three ways:

- through the ISP, whereby AEMO finds that staged delivery is optimal (see column 1),

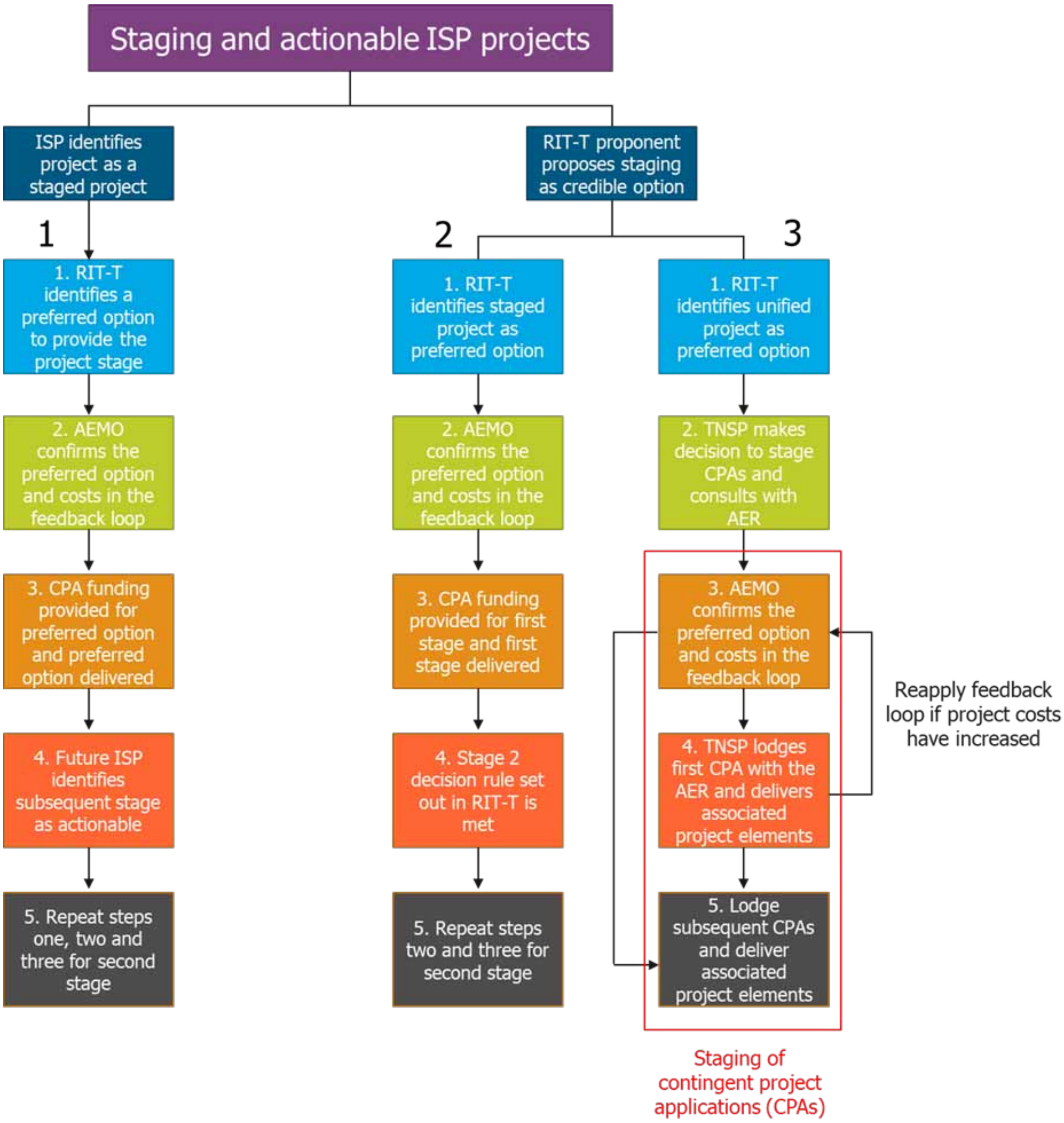
61 AER, *AER Determination – HumeLink Early Works Contingent Project*, August 2022, p. iii.

62 AER, *Guidance note – Regulation of actionable ISP projects*, March 2021, p. 25.

63 Ibid.

- through the RIT-T, whereby a RIT-T proponent finds that the preferred option to address an identified need involves staged delivery (column 2), or
- through the RIT-T, whereby a RIT-T proponent decides to submit CPAs to fund a single unified project in stages (column 3).

Figure 2.6: Regulatory processes for staging actionable ISP project delivery and regulatory approval



Source: Adapted from AER, Cost Benefit Analysis Guidelines, August 2020, p. 68.

2.3 The experience of past ISP projects may not be representative of the current actionable ISP framework

The Commission notes that most actionable ISP projects to date – namely Project EnergyConnect, QNI and Humelink – have been progressed under transitional rules, rather than the ISP framework described in section 2.2.[64] We have reviewed the progress of these three projects through the economic assessment process that applied at the time. Table 2.3 below highlights some of the key milestones for these projects and the time taken to reach them.

Table 2.3: Experience of past ISP projects

STAGE	PROJECT ENERGY CONNECT	QNI	HUMELINK
PSCR published / ISP identifies project as actionable	November 2016	November 2018 *Identified as priority project in inaugural ISP in July 2018.*	June 2019 *Identified as group 2 project in inaugural ISP in July 2018. Deemed actionable with decision rules in the 2020 ISP (July 2020), then a staged actionable project in the 2022 ISP (July 2022).*
PADR published	June 2018 (+19 months)	September 2019 (+10 months)	January 2020 (+7 months)
PACR published	February 2019 (+8 months)	December 2019 (+ 3 months)	July 2021 (+18 months)
CPA completed	May 2021 (+27 months) *Included AER preferred option assessment under clause 5.16.6 of the NER (~4 months) and a dispute following the PACR (~4 months).*	April 2020 (+4 months) *Included AER preferred option assessment (~3 months).*	August 2022 for Stage 1 (+13 months) *Included a dispute process (~6 months, including publication of amended PACR). The feedback loop was undertaken prior to the CPA.* Stage 2 CPA planned

64 VNI West is the first project progressing through the current actionable ISP rules.

STAGE	PROJECT ENERGY CONNECT	QNI	HUMELINK
			for April 2024 (+20 months).
Total duration of the economic assessment process	**4 years, 6 months**	**1 year, 5 months**	**3 years, 2 months (up to Stage 1 CPA), 4 years, 10 months (up to Stage 2 CPA)**
Timing and duration of the route planning and jurisdictional approvals process	**4 years 6 months** **(Q2 2018 – expected end 2022)**	**ca. 1 year** **(Q2 2019 – Q2 2020)**	**ca. 4.5 years** **(early 2020 - June 2024)**
Total combined duration of the economic assessment process jurisdictional planning and approvals process	**ca. 6 years**	**< 2 years**	**ca. 5 years**

Source: AEMC analysis of TNSP RIT-T reports.

This indicates that the more complex projects - Project EnergyConnect and Humelink (Stage 1) – required between 4-5 years to move through the economic assessment process, from the publication of theirPSCR. The PSCR is the first RIT-T report for non-actionable ISP projects; for actionable projects, the ISP now replaces this step. In these earlier projects, the PSCR therefore indicates the point at which these projects may have been identified as actionable under the current rules.

Within this 4-5 year period, a substantial period of time was due to the resolution of disputes raised after the publication of the PACR (ca. 4-6 months) and the AER's preferred options assessment conducted as part of the CPA (ca. 4 months). Further, the Commission understands that within the time required to move from publication of the PSCR to the PADR, the TNSPs required a substantial period of time (i.e., multiple months) to complete the market modelling to assess the benefits of the options being investigated.

Considering overall development timelines, Project EnergyConnect is expected to have required approximately six years from the publication of the PSCR to be ready to commence construction at the end of 2022. Based on the Stage 1 CPA, HumeLink is anticipated to require approximately five years between publication of the PSCR to starting construction once the Stage 2 CPA is approved in mid-2024. As shown above, within the overall period prior to construction starting, there is overlap between the economic assessment process and routing planning/jurisdictional approval activities. In the case of HumeLink, Transgrid is currently progressing detailed design, route planning and environmental approvals through the staged CPA process.

The Commission has drawn two initial conclusions from this analysis.

Firstly, the time required to complete the economic assessment may reduce as the current actionable ISP framework matures, noting that no ISP projects have yet moved through the full process, and that AEMO, the AER and TNSPs are gaining experience in the application of these parts of the rules. This is because:

- Future RIT-T proponents may consider fewer options. For example, in the RIT-T for HumeLink, Transgrid assessed and consulted on 12 credible options in the PADR including route and technical variations.[65] These were the same options that it considered in the PSCR. As discussed in section 2.2.2 under the current ISP rules, RIT-T proponents are not required to re-evaluate options considered and rejected by AEMO in the ISP. This may be more conducive to investigation of social licence issues, which may not be feasible with numerous or widely different options.
- The feedback loop has replaced the need for the AER's preferred option assessment at the CPA stage, which the AER had approximately 4 months (120 days) to complete.[66]
- Future RIT-Ts may draw more heavily on the ISP benefits analysis, potentially reducing the time for preparation of the RIT-T reports. For example, during the HumeLink RIT-T the key inputs and assumptions changed between RIT-T stages.[67]
- TNSPs now have stronger guidance in relation to the estimation of cost and benefits in the RIT-T, as set out in the AER's CBA Guidelines.
- In its submission to the TPIR consultation paper, the AER noted potential interactions between the accuracy of cost estimates and the time required for a project to move through the economic assessment process. Specifically, that if cost estimates are more robust, the time for the AER to assess efficient cost may be shorter.[68] The time required for the AER to assess efficient costs at the CPA stage may therefore improve as TNSPs and the AER gain experience in estimating costs for major projects.

Secondly, the actionable ISP framework may also better support projects in moving through jurisdictional planning and approvals processes in parallel with the economic assessment process, and in securing social licence, relative to previous arrangements. This is because:

- As described in section 2.2.1, under the ISP framework AEMO can require TNSPs to undertake certain preparatory activities. These include route selection and easement assessment work, cost estimation based on route selection, preliminary assessments of environmental and planning approvals, and council and stakeholder engagement.[69]

65 Transgrid, *HumeLink Project Assessment Draft Report*, January 2020, p. 3.

66 Under the now deleted clause 5.16.6 of the NER, the AER would determine that the preferred option satisfied the RIT-T.

67 Transgrid, *HumeLink Project Assessment Draft Report*, January 2020, p. 10.

68 Ibid., pp. 6-7.

69 Clause 5.10.2 of the NER.

- Considering fewer options during the RIT-T may be more conducive to investigation of social licence issues in that process, which may not be feasible with numerous or widely different options.
- The staged CPA arrangements described in section 2.2.4, allow TNSPs to secure early funding for activities to implement the preferred option. This provides funding for the TNSP to work through detailed design, route planning and environmental approvals without waiting for full funding to be awarded. This process also provides an opportunity for the efficient costs associated with securing social licence to be considered on a more informed basis in the full CPA.

The Commission invites stakeholder feedback on our analysis of these projects and how the current ISP framework may apply in future, and whether there are any additional lessons or insights that can be drawn on to inform this Review.

2.4 Recent proposed reforms may further support the timely progression of ISP projects through the economic assessment process

The rigour of the economic assessment process and the timely delivery of ISP projects may be further supported by changes to the current process that have been proposed in this Review and the *Material change in circumstances* rule change.

Firstly, the Stage 2 draft report for this Review noted that there are currently issues around the workability of the feedback loop.[70] Because TNSPs are required to use the latest IASR in the RIT-T, which may be materially different from the IASR used in the current ISP, the feedback loop may not reflect the most recent assumptions and may be inconsistent with the RIT-T. To address this issue, the Stage 2 draft report recommended:

- **Prohibiting feedback loop applications and the publication of PACRs in the window between publication of the most recent IASR and the draft ISP**. This reduces the scope for the RIT-T analysis to diverge from the most recent published draft or final ISP.
- **Allowing the feedback loop application and CPA to run in parallel, to prevent a bunching of feedback loop assessments just after the draft ISP is published**. However, the AER would not be able to approve a contingent project until the feedback loop has been passed.

These changes may reduce the total time required for completion of the feedback loop and CPA, relative to the current rules. The Commission will make final recommendations following consultation with stakeholders.

Secondly, the Commission's draft determination in relation to the 'Material change in circumstances' provisions of the NER provide an additional layer of rigour to the RIT-T

70 These issues are described in more detail in the TPIR Stage 2 draft report, chapter 5.

process. The aim of the draft rule is to improve rigour without adding substantially to the time for project delivery. Among other changes, the draft rule:[71]

- Requires RIT proponents to consider whether there has been a material change in circumstances, including a change in the identified need, subsequent to the completion of the RIT.
- Requires RIT proponents (other than AEMO) of projects with estimated costs greater than $100 million to develop reopening triggers that can be used to identify circumstances in which the preferred option may no longer be the most net beneficial option.
- Requires proponents of contingent projects to explicitly state in their CPA whether or not there has been a change in the identified need or if a reopening trigger has been met, provide supporting analysis, and (if relevant) outline the course of action that has been taken).

The Commission's draft determination also recommends that the AER consider how the guidelines governing RITs could be strengthened to promote the development of more robust cost estimates. Accordingly, the draft rule proposes to:[72]

- Clarify that the AER can provide guidance in relation to any acceptable cost estimate classification systems that should be used for the RIT, and any role for contingency allowances.
- Allow the AER to specify which parts of the RIT-T and RIT-D application guidelines are binding on the RIT proponents.

2.5 The current ISP framework and recent proposed reforms form a 'counterfactual' economic assessment process

It is important to understand how the current arrangements, plus the proposed changes outlined above, will function when we are considering changes to the economic assessment process to facilitate the timely delivery of major projects to support the energy transition. These arrangements form a 'counterfactual' economic assessment process, that we can use to assess whether alternative process would be likely to achieve further improvements.[73] To illustrate the full flexibility of the current framework, the counterfactual reflects two staged CPA applications being made for a single actionable ISP project.[74]

As noted by stakeholders, it is also important to explore linkages between the economic assessment process and jurisdictional planning and approval processes. As a point of reference for the counterfactual process and alternative options, the Commission has developed a stylised representation of the key activities that a proponent could be expected

71 AEMC, *Draft rule determination – Material change in network infrastructure project costs*, July 2022, page ii-iii.

72 Ibid., p. 33.

73 Note, in this context 'counterfactual' is referring to the current economic assessment process plus recently proposed reforms. This differs from the 'counterfactual' that may be used by AEMO and TNSPs in their assessment of market benefits. In that context, the counterfactual is referring to a scenario where the investment being tested is not undertaken.

74 As described in section 2.2.4, the process would look different if a project is identified as staged in either the ISP or RIT-T. In the former case, there would be an additional RIT-T process between each CPA stage. In the latter case, the TNSP would submit the stage 2 CPA after the decision rule set out in the RIT-T was met.

to undertake to develop their project up to the start of construction. In Figure 2.7 below, these activities are mapped to the stage of the economic assessment process at which they typically occur today, alongside the indicative AACE class that may apply to cost estimates at each stage. This mapping of activities provides a starting point for considering how the economic assessment process can most effectively interact with jurisdictional planning and approval processes for ISP projects. The Commission notes that this representation is indicative and will seek to refine its characterisation of these interactions for the Stage 3 final report based on stakeholder feedback.

Figure 2.7: Stylised stages of project planning, design and approval

Project development stage	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7
EAP process	Future ISP project identified	Preparatory activities to refine future project	PADR for actionable ISP project	PACR for actionable ISP project	CPA 1	CPA 2	FID
Project development: activities undertaken before each stage	**High-level scoping of need and options.** • May reflect system needs and initial solutions identified in TNSP TAPRs, and/or AEMO's own analysis during the ISP. • High-level technical specification (e.g., voltage/capacity and conceptual single line diagrams). • Network path may be identified at concept level, or at screening level with some site-specific review and TNSP input.	**Initial preparatory activities to refine future ISP assumptions.** • AEMO may direct TNSPs to undertake preparatory activities for future projects, to refine delivery time, cost and technical scope. Feeds into subsequent ISP, where the future project may become actionable. • Network studies underway. • Desktop geotechnical / ecology / heritage / planning studies. • Generally no consultation with affected communities on options / route.	**Further preparatory activities to refine options and costs.** • Refinement of ISP candidate option / identification of new credible options. • Network studies substantially complete. • Credible network options developed based on geotechnical / heritage / land desktop planning and network studies, potentially with some field work in high-risk areas. • Biodiversity offset liability estimated based on available ecology reports. • May have guide budget estimate from contractors/suppliers. • Generally no consultation with affected communities on options / route.	**Detailed preparatory activities to refine final option selection.** • Further refinement of credible network options in light of stakeholder feedback to select preferred option. • Technical specification completed. • Credible route identified, avoiding significant known risks / sensitivities.	**Start of early works prior to first CPA** • Market engagement underway. • Commenced engagement with affected communities. • Commenced studies for EIS submission. • Further refinement of route, commenced initial consultation with landowners.	**Completion of early works** • Procurement substantially progressed including early contractor involvement and long-lead items. • Finalise studies for EIS submission, EIS approval. • Further refinement of route, secure options over easements, planning for compulsory acquisition.	**Construction activities** • FID, finalise land acquisition, unconditional execution of construction contracts, start construction.
Indicative AACE class	• Class 5	• Class 4 – 5	• Class 4 – 5	• Class 3 – 5	• Class 2 – 4		

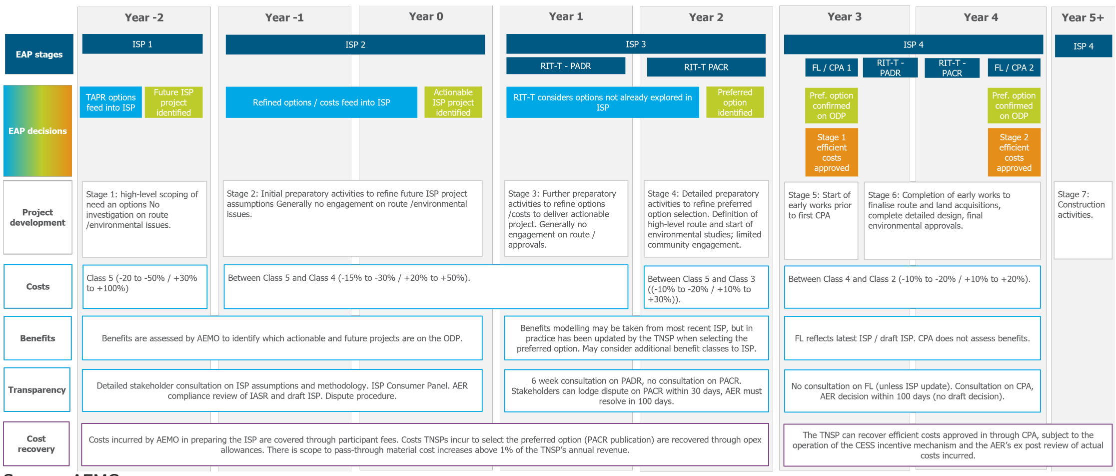
Source: AEMC analysis, based on AEMO's 2020 Transmission Cost Report and Transgrid's first CPA for HumeLink.

Figure 2.7 illustrates the counterfactual economic assessment process. Figure 2.8 indicates the time that may be required for projects to move through the counterfactual economic assessment process, and how this interacts with the stages of project planning, design and approval described above. It is important to note that this is a stylised representation of the counterfactual economic assessment process for future projects. Outcomes for individual projects will depend on factors specific to their development.

Consistent with the analysis in section 2.3 and section 2.4, the counterfactual economic assessment process assumes that in future, it will be reasonable to expect some reduction in the time that is needed to complete the process. The counterfactual reflects an overall duration of approximately 4 years, incorporating a staged CPA. This compares to the anticipated 4-year and 10-month duration timeframe for HumeLink to conclude its Stage 2 CPA. Broadly, the counterfactual reflects potential time savings in relation to:

- A more streamlined set of options being considered through the RIT-T process (as provided for in the current ISP rules).
- Stronger guidance for TNSPs in relation to their estimation of project costs and benefits during the RIT-T (as provided for in the current ISP rules).
- The flexibility provided by the staged CPA framework (as clarified in the Stage 2 draft report).
- The removal of the AER preferred option assessment, combined with the proposed changes to allow the feedback loop and contingent project assessment to proceed in tandem (as proposed in the Stage 2 draft report).

Figure 2.8: Counterfactual economic assessment process



Source: AEMC.

QUESTION 2: COUNTERFACTUAL ECONOMIC ASSESSMENT PROCESS

Do you agree that this is an accurate characterisation of how the counterfactual economic assessment process can be expected to operate in future? If not, what changes would make the counterfactual more accurate?

2.6 We are seeking stakeholder feedback on the economic assessment process to facilitate the timely delivery of transmission projects

The improvements outlined in the preceding sections may address some concerns raised by some stakeholders in relation to the economic assessment process supporting the timely delivery of transmission investment, while balancing rigour.

However, the Commission notes that these developments may not fully address the concerns that stakeholders have raised. In the context of a forward program of major investments to support the energy transition, the Commission considers that it is appropriate to consult on whether there may be opportunities to further improve the balance of timeliness and rigour.

2.6.1 We are seeking input on three strawperson alternatives to the counterfactual

As a starting point for discussion with stakeholders, the Commission has developed three high-level strawperson options that set out alternatives to the current economic assessment process. The three strawperson models and the counterfactual are summarised in Box 4. The strawperson options present a spectrum of approaches, organised around the three key decision points described in the counterfactual: option identification; option selection; and final regulatory approval of an allowance to implement the preferred option. Each strawperson option involves changes to the timing of these decision points, the types of activities that support each decision, and the roles of different parties performing these activities. On this basis we have attempted to quantify the time savings under each strawperson option, relative to the counterfactual economic assessment process. The estimated time savings are indicative only at this stage and will be refined based on the further development of the options. We are interested in stakeholder feedback on the proposed time savings. We also want to note that there is a trade off between time savings and rigour of the process and the size of time savings impacts the level of rigour underlying decision-making. We have set out the trade offs in our discussion of the strawperson options and are interested in stakeholder feedback on our initial views on the appropriate compromise between time savings and rigour.

The Commission developed the following three strawperson options with reference to economic assessment processes applied in other jurisdictions, including Great Britain, PJM (US), the NSW Electricity Infrastructure Roadmap, and the proposed Victorian Transmission Investment Framework (VTIF):

- **Strawperson 1 – Front loading early works** : Existing process remains largely in place with amendments focussing on bringing early works forward. Following a project being deemed actionable in the ISP, the TNSP would submit an early works CPA to seek an allowance for undertaking the efficient level of early works activities and the RIT-T concurrently.

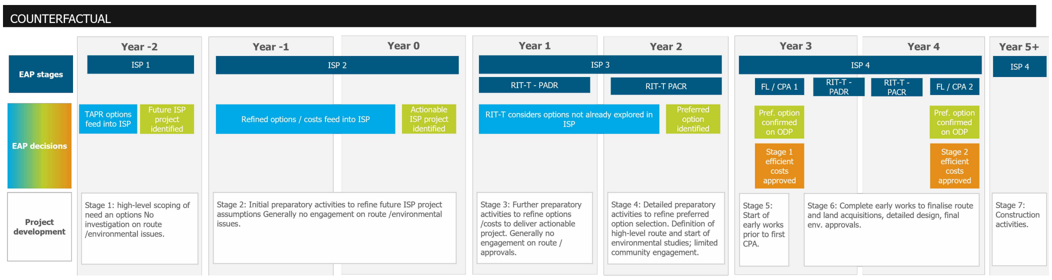
- **Strawperson 2 – RIT-T focusses on option development, AEMO responsible for net benefit assessment through ISP**: Centralising benefits assessment in the ISP process allows TNSPs to focus on exploring credible options and costs in greater detail with stakeholders during the RIT-T.
- **Strawperson 3 – ISP undertakes centralised assessment of costs and benefits, with input from TNSPs**: The ISP process would identify credible options and select the preferred option, rather than the RIT-T. Strengthened joint planning arrangements would improve TNSP input to the ISP analysis.

By providing a broad spectrum of alternative models for consultation, we seek to:

- Identify, at a high level, the possible range of economic assessment processes.
- Incorporate views shared by stakeholders in the consultation paper for this Review in relation to issues around the current economic assessment process (noting that this is different to the counterfactual).
- Explore with stakeholders whether any of the identified alternatives may have the potential to improve the timely delivery of transmission projects while maintaining an appropriate level of rigour, relative to the counterfactual.
- Based on the views and evidence shared by stakeholders, form a view on whether any of the options identified, or alternative options, should be taken forward for further consideration in the Stage 3 final report. We note that the options are not exhaustive or mutually exclusive.

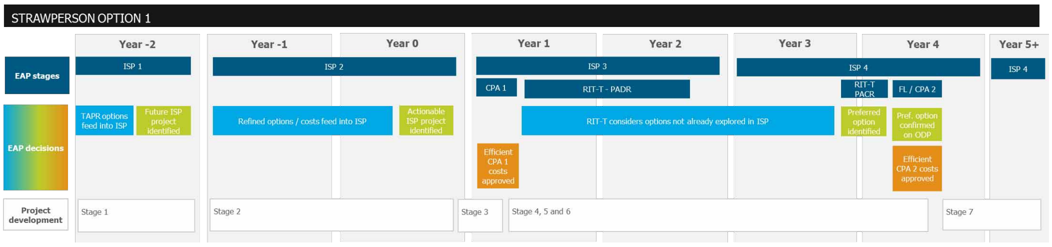
BOX 4: COMPARISON OF STRAWPERSON OPTIONS AND THE COUNTERFACTUAL

Counterfactual: Current arrangements under the NER, plus recent proposed reforms as described in section 2.5. The counterfactual process assumes the economic assessment process (triggered by the ISP identifying a project as actionable) would take approx. 4 years to complete.



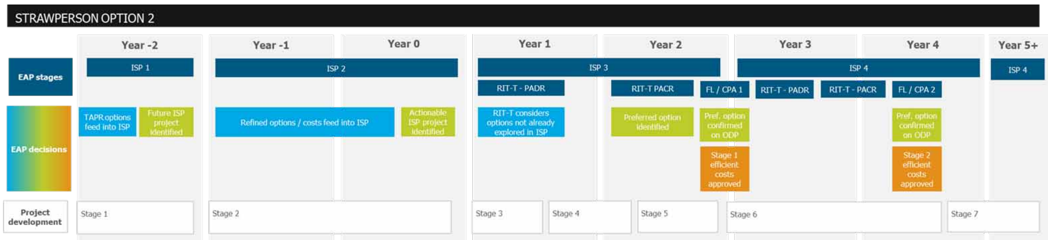
Strawperson 1: Front loading early works

- Following a project being deemed actionable in the ISP, the TNSP would submit an early works CPA to seek an allowance for undertaking the efficient level of early works activities and the RIT-T concurrently. A second CPA (for the full cost of delivery) would be submitted after the preferred option is identified.
- Introduces a longer period between the PADR and PACR, to investigate social licence issues and reflect these in the RIT-T preferred option selection.
- Time savings in the magnitude of 12 months (-50% to +50%) can be expected, compared to the counterfactual.



Strawperson 2: RIT-T focusses on option development, AEMO responsible for net benefit assessment through ISP

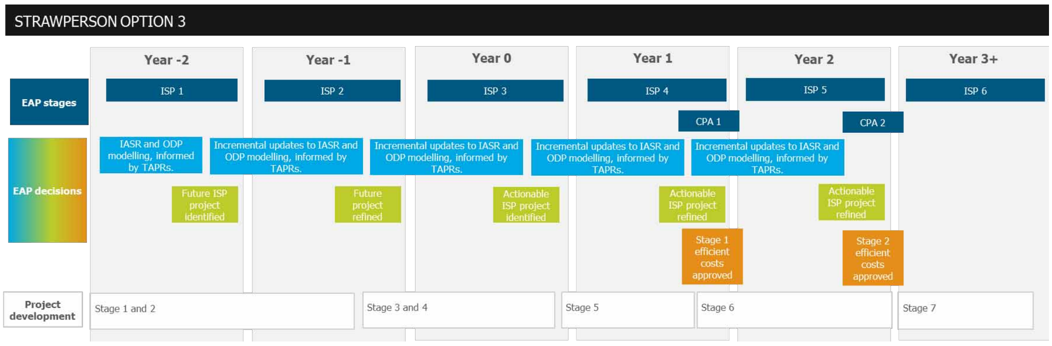
- Centralising benefits assessment in ISP process allows TNSPs to focus on options and their costs during the RIT-T.
- Allowing for a more detailed investigation of options during the RIT, TNSPs could focus on route selection and other social licence issues.
- Time savings in the magnitude of 12 months (-50% to +50%) can be expected, compared to the counterfactual.



Strawperson 3: ISP undertakes centralised assessment of costs and benefits, with input from TNSPs

- The ISP process would identify credible options and select the preferred option, rather than the RIT-T. Accordingly, the RIT-T and feedback loop are removed. The ISP and CPA remain.
- To ensure that decisions on the preferred option are being made with robust information, the ISP would be more frequently updated, e.g. on an annual basis.
- Strengthened joint planning arrangements would improve TNSP input to the ISP analysis.

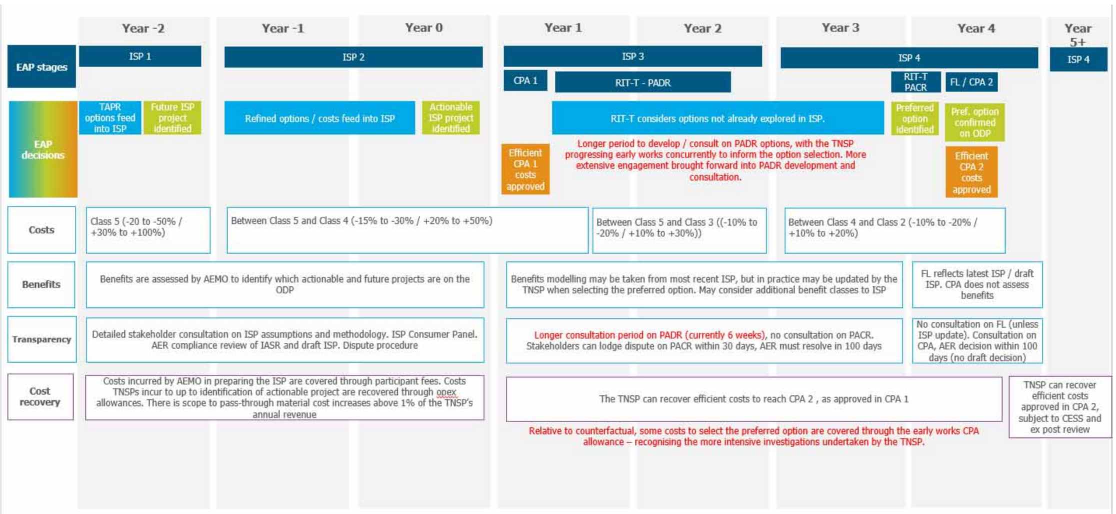
- Time savings in the order of 2 years (-50% to +50%) compared to the counterfactual can be expected, assuming decisions regarding option identification, selection and funding approval are made on the basis of less accurate cost estimates, compared to the counterfactual arrangements.



The intent of consulting on the counterfactual and strawperson options is to provide a concrete point of reference for stakeholders to provide commentary on the advantages and disadvantages of particular economic assessment models. The Commission intends to work collaboratively with stakeholders to gather a greater fact base regarding the potential alternative economic assessment processes we should consider, and the challenges, opportunities and trade-offs associated with each option.

2.6.2 Strawperson 1 – Front loading early works

Figure 2.9: **Overview of strawperson 1**



Note: Strawperson 1 aims to facilitate earlier investigation of social licence issues, by introducing a longer period for developing and consulting on the options identified in PADR, including with affected communities.

Note: TNSPs would refine route selection and environmental impacts (and associated design, timing and cost implications) during the RIT-T, as options are progressively narrowed down through consultation with stakeholders.

Note: The costs of undertaking this more intensive early activity would be funded through an initial CPA, following identification of the project as actionable in the ISP. A second CPA (for the full cost of delivery) would be submitted after the selection of the preferred option (including design changes based on final route and environmental impact assessment).

Key features of Strawperson 1

Figure 2.9 illustrates the detailed operation of strawperson 1.

Under this option, all existing elements of the counterfactual economic assessment process remain in place, namely the ISP, the RIT-T, the feedback loop, and the contingent project assessment.

Table 2.4: **Option identification**

	COUNTERFACTUAL	STRAWPERSON 1
ISP	TNSP/AEMO joint planning identifies credible options for ISP analysis	No change
RIT-T	TNSP identifies credible options not explored in the ISP	No change

The options that inform the ISP would continue to be developed through the AEMO and TNSP joint planning arrangements.

After an actionable ISP project is identified in the ISP, the TNSP would seek to identify any additional options, or refinements of the ISP candidate option, that should be considered in the RIT-T. These options would be set out in the PADR, as is currently the case.[75]

Table 2.5: Option selection

	COUNTERFACTUAL	STRAWPERSON 1
ISP	AEMO identifies candidate option for actionable ISP projects	No change
RIT-T	TNSP identifies preferred option (maximises net benefits)	TNSP identifies preferred option informed by broader stakeholder consultation, including in relation to social licence issues
Feedback loop	Feedback loop confirms preferred option is on the ODP	No change

The ISP process to identify the candidate option for an actionable ISP project would remain as it is today.

The primary difference to the counterfactual is that during the RIT-T process, the TNSP would undertake early works.[76] Examples of early works are outlined in the ISP and include:

- engagement with local communities, landowners and other stakeholders
- community benefits
- procuring equipment with long lead times which are required across all credible options
- pre-contracting activities for engineering procurement and construction contracts such as obtaining binding bids
- obtaining all primary planning and environmental approvals, licences and permits
- substation site selection, easement acquisition and preparation of option agreements with landowners
- construction works necessary to test the design of the physical infrastructure components.

75 This draws on elements of equivalent processes in Great Britain, where the final needs case (similar to the PACR) is assessed when a project has gained planning approval and where determination of the regulatory allowance to deliver the full project (similar to the CPA) takes place when the project is at an advanced stage of procurement (see Appendix A). This option also reflects elements of the NSW Electricity Infrastructure Roadmap, where the Infrastructure Planner is responsible for carrying out preparatory activities and early development works for REZ network infrastructure projects before they are authorised (see Appendix A). The initial design of the VTIF (see Appendix A) also involves extensive project development activities, including stakeholder consultation, at an early stage.

76 In the Stage 2 draft report, the Commission recommended to remove the term 'early works' in AER and AEMO documentation. However, based on stakeholder feedback to the Stage 2 draft report, the Commission is now considering that removing the term 'early works' may not be appropriate. The Stage 2 final report is intending to clarify the use of this term.

As such, the TNSP would undertake detailed investigation of social licence consideration for the proposed options between the PADR publication and the PACR. The intent of undertaking some early works (including activities to build social licence) as part of the RIT-T preferred option selection process would be to:

- De-risk later stages of development for the preferred option that is eventually selected in the PACR. For example, front loading early works may reduce the time required to finalise land acquisition later in the process. As discussed in the Stage 2 draft report for this Review, many submissions to the TPIR consultation paper considered that delays in project delivery relate primarily to difficulties in the proponent securing social licence, such as the time required to finalise the route and acquire the associated easements.[77] A number of submissions suggested that the economic assessment process could better facilitate earlier investigation of social licence issues by TNSPs.[78]
- Reflect the impact of jurisdictional planning and approval requirements on the design, costs and benefits of a project and influence the selection of the preferred option.

To meet these objectives, the appropriate extent of early works undertaken in the RIT-T process may not necessarily include all the activities listed above. There are different options for how this judgement could be made:

- AER guidelines could recommend that certain activities be completed prior to publication of the PACR, or set out principles for how TNSPs should determine what level of activity during the RIT-T would be efficient. The TNSP could propose a scope based on these guidelines in its early works CPA (see below), with the AER assessing whether it is prudent and efficient to undertake the activities proposed during the RIT-T.
- In the ISP, AEMO could specify the extent of the activities to be undertaken in the RIT-T. Guidance for AEMO's decision could be set out in AER guidelines or rules. AEMO already specifies the extent of early works activities for staged actionable projects.

Table 2.6: **Regulatory approval of allowance to deliver the project**

COUNTERFACTUAL	STRAWPERSON 1
• Cost up to stage 1 CPA covered by TNSP revenue allowance • CPAs can be approved in stages	There is no RIT-T before the early works CPA. As under the current arrangements, the early works covers costs up to final CPA, including preparation of the RIT-T for the full project costs

In light of the more extensive investigations and consultation undertaken by the TNSP in the RIT-T, strawperson option 1 envisages that following a project being deemed actionable in the ISP, the TNSP would submit an early works CPA to seek an allowance for undertaking the efficient level of early works activities and the RIT-T concurrently. This is because:

77 Submissions to the consultation paper: Shell Energy, p. 2; AEC, pp. 1-2; MEU, p. 3.

78 Submissions to the consultation paper: AusNet Services, p. 11.; Energy Grid Alliance, p. 9.; MEU, p. 6; CEC, p. 3; RE-Alliance, p. 2; EnergyAustralia, p. 2.

- It may be challenging to estimate the efficient costs of undertaking these activities at the time that a TNSP submits its revenue allowance (for example, this may be before a project has been identified as actionable).
- Under this strawperson model, activities to identify and deliver the preferred option would not be so clearly demarcated as under the current arrangements because of the integration of early works activities within the RIT-T process.

A final CPA for the full cost of delivering the preferred option would be submitted after it is identified in the PACR (including design changes based on the result of the activities funded by the early works CPA).

Further consideration may be required in relation to how bringing the early works CPA forward would interact with other parts of the regulatory framework, including incentive arrangements.

Potential impacts on timeliness

The Commission expects potential time savings of 12 months (-50% to +50%) under option 1 (compared to the counterfactual) based on 1) removing the initial RIT-T before the early works CPA and 2) the reduced likelihood of lack of information and disputes arising as a result of 'front loading' the process by undertaking early works concurrently with the RIT-T. However, the size of time savings is dependent on the specific design of option 1, e.g. the length of PADR consultation under strawperson option 1.

1) **Removing initial RIT-T for early works**: This option removes the need for the TNSP to complete an initial RIT-T before the early works CPA, as is required under the current arrangements. We estimate this could lead to time savings of approx. 6 months. However, we want to note that no RIT-T for early works has been completed to date, hence our estimated time savings are not based on a case study. Our estimate of 6 months is based on the TNSP relying heavily on the ISP analysis when developing their RIT-T for early works. However, the existing consultation requirements would continue to apply, i.e. publication of a PADR and consultation and publication of a PACR.

2) **'Front loading' the process by undertaking early works concurrently with the RIT-T**: This option provides TNSPs with funding to undertake an efficient level of early works concurrently with the RIT-T process and could thereby improve timeliness by de-risking later stages of development for the preferred option that is eventually selected. Bringing early works forward, including more extensive engagement with affected communities and investigation of environmental and other approvals requirements before the preferred option selection, means that TNSPs are able to finalise land acquisition and approvals more efficiently.

As a result, it is expected that the project would proceed more rapidly through the PACR and final CPA decision points. For example:

- If the lengthier period allowed for PADR consultation improves stakeholder confidence in the RIT-T process, leading to a reduced likelihood of disputes arising. Disputes arising after publication of the PACR have substantially contributed to the time required for PEC and HumeLink to move through the economic assessment process (which added approx. 4 months to the process for PEC and approx. 6 months to the process for HumeLink).

- If the AER has improved visibility of the project at the final CPA decision, arising from the early works CPA and the information revealed through the RIT-T.

Our initial estimate is that such 'front loading' of the process, by undertaking early works and building social licence concurrently with the RIT-T, could lead to time savings of approx. 6 months due to de-risking later stages of the process.

Potential impacts on rigour

The Commission's initial analysis suggests that this strawperson option could have the following impacts on consumers and the level of rigour underlying the economic assessment process:

- Removing the RIT-T for early works in order to streamline the process may mean that consumers end up paying more for early works than if a RIT-T would be the basis for the early works CPA.
- In relation to transparency, this option may improve rigour by improving visibility for stakeholders around the impact of jurisdictional planning and approval requirements on the design, costs and benefits of the project. Similarly, increased involvement of stakeholders from outside the electricity sector (e.g., potentially affected landowners and communities) may assist in building early understanding of the benefits that may arise from the actionable ISP project.
- In relation to the rigour of cost estimates, this model envisages that the preferred option determined in the PACR would be based on a more detailed understanding of the project delivery scope (e.g., actions required to mitigate environmental impacts, the likely extent of landowner compensation). This would likely have the effect of increasing the accuracy of the base cost estimates.
- In relation to the rigour of the benefits assessment, this option does not change the process, roles or responsibilities for estimating the market benefits associated with different options. However, it is possible that the PACR and feedback loop analysis would be made on the basis of improved information on project delivery timelines, given the more detailed investigation of planning requirements. If there is more confidence around the likely delivery date, the estimated benefits resulting from implementing the project by that time may be more robust.

QUESTION 3: STRAWPERSON 1

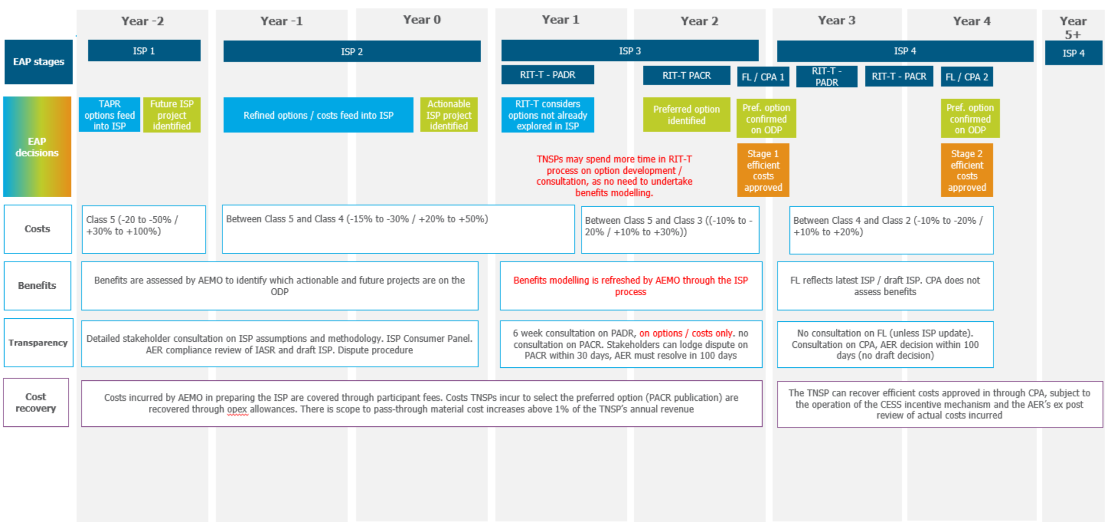
a. Do you agree with our assessment of the time savings of this strawperson option 1 regarding the delivery of ISP projects, relative to the counterfactual?

b. Do you have any suggestions on how this option 1 could be specified differently, to facilitate the timely delivery of major transmission projects while maintaining an appropriate level of rigour?

c. Do you think that this option 1 should be taken forward?

2.6.3 Strawperson 2 – AEMO is responsible for assessing net benefits through the ISP

Figure 2.10: Overview of strawperson 2



Note: Strawperson 2 aims to improve the timeliness of the economic assessment process by changing the current allocation of responsibilities across AEMO and TNSPs.

Note: Specifically, AEMO would become the party responsible for estimating the net benefits of actionable ISP projects through the ISP.

Note: TNSPs would no longer be required to evaluate net benefits when developing their RIT-T. Rather, they would focus on developing credible options to meet the identified need specified in the ISP and assessing the costs of those options. The RIT-T preferred option would be defined as the option that meets the identified need at the lowest cost to consumers.

Note: Removing the need for TNSPs to undertake complex modelling to estimate net benefits may mean that more detailed investigation of options – potentially encompassing route selection and other social licence issues – could take place concurrently with the RIT-T process.

Key features of Strawperson 2

Figure 2.10 illustrates the detailed operation of strawperson 2.

Under this option, all existing elements of the counterfactual economic assessment process remain in place, namely the ISP, the RIT-T, the feedback loop, and the contingent project assessment.

Table 2.7: Option identification

	COUNTERFACTUAL	STRAWPERSON 2
ISP	TNSP/AEMO joint planning identifies credible options for ISP analysis	No change
RIT-T	TNSP identifies credible	No change

	COUNTERFACTUAL	STRAWPERSON 2
	options not explored in the ISP	

The options that inform the ISP would continue to be developed through the AEMO and TNSP joint planning arrangements.

After an actionable ISP project is identified in the ISP, the TNSP would seek to identify any additional options, or refinements of the ISP candidate option, that should be considered in the RIT-T. These options would be set out in the PADR, as is currently the case. [79]

Table 2.8: Option selection

	COUNTERFACTUAL	STRAWPERSON 2
ISP	AEMO identifies candidate option for actionable ISP projects	No change
RIT-T	TNSP identifies preferred option (maximises net benefits)	TNSP identifies the least cost option to meet identified need
Feedback loop	Feedback loop confirms preferred option is on the ODP	No change

The ISP process to select the candidate option for an actionable ISP project would remain as it is today.

The primary difference to the counterfactual is that there is a change in the role of the RIT-T. TNSPs would no longer be required to evaluate net benefits when developing their RIT-T. Rather, they would focus on developing credible options to meet the identified need specified in the ISP and assessing the costs of those options. The RIT-T preferred option would be defined as the option that meets the identified need at the lowest cost to consumers.

The net benefits of actionable projects would instead be assessed by AEMO through the ISP process. This would be based on the options to meet an identified need that were input into the ISP modelling. As described in section 2.2.2, after an actionable ISP project is identified, TNSPs will typically consider further refinements to the design in the RIT-T. The Commission understands that in principle, the granular options considered by TNSPs can each create different benefits. For example, benefits may differ between design options (e.g., due to changes in losses associated with a choice between HVAC or HVDC technologies) or timing

79 This strawperson draws on elements of the NSW Transmission Efficiency Test (TET), where project benefits are assessed in the transmission plan, followed by identification of the least-cost option (see Appendix A). The TET includes a provision that (broadly) the costs approved by the AER to deliver the option cannot exceed the assessed benefits. In this strawperson 2 option, this check is provided by the feedback loop.

options (e.g., staged or deferred delivery). A key question for this strawperson is therefore whether not quantifying differences in the benefits of granular RIT-T options materially impacts the rigour of the preferred option selection. In principle, the RIT-T options that TNSPs develop could be fed back into the subsequent ISP analysis to assess their benefits. However, it is not certain that the timing of the RIT-T and ISP processes would always align.[80] Selecting a preferred option without quantifying differences in the benefits of granular RIT-T options may result in risks for consumers in terms of potentially facing higher costs.

A related question is how this strawperson would provide stakeholders engaging in the RIT-T process with the full picture on the need for the project. A possible solution would be that the TNSPs would need to reference the ISP modelled benefits as part of the RIT-T consultation; this would require the incremental benefit associated with each actionable project to be identified in the ISP.

Table 2.9: Regulatory approval of allowance to deliver the project

COUNTERFACTUAL	STRAWPERSON 2
• Cost up to stage 1 CPA covered by TNSP revenue allowance • CPAs can be approved in stages	No change

There are no changes to the approval of regulatory allowances under this strawperson.

Potential impacts on timeliness

The Commission expects potential time savings of 12 months (-50% to +50%) under option 2 (compared to the counterfactual) based on 1) removing the need for TNSPs to undertake modelling of benefits during the RIT-T, and as a result freeing up the process to allow 2) TNSPs to bring activities like route selection and social licence building forward.

This option could improve timeliness by reducing the time to complete the economic assessment process, allowing the TNSP to proceed more rapidly to construction. This is because:

1) **Removing benefits assessment from the RIT-T**: The strawperson removes the requirement for TNSPs to undertake complex modelling of net benefits, which may allow them to complete the remaining tasks to issue a RIT-T report – developing credible options and cost estimates – more rapidly. The Commission understands that in the past, re-modelling of benefits has incurred months of effort from TNSPs and their consultants. We estimate that removing the benefits assessment from the RIT-T could lead to time savings of approx. 6 months.

80 This also raises a question around the operation of reopening triggers for actionable ISP projects under this strawperson option. Specifically, the TNSP may not be well placed to identify conditions that could change the ranking of options based on their benefits. The operation of reopening triggers in this option would require further consideration.

2) **Bringing route selection and social licence building forward**: The strawperson may reduce the time elapsed between the PACR and CPA stages. This could occur if, with responsibility for benefits modelling removed, the TNSP can undertake tasks in the RIT-T that it would normally complete prior to submitting its CPA, e.g. TNSPs could focus on route selection and other social licence issues.

Similar to option 1, option 2 therefore also has the potential to improve timeliness by de-risking later stages of the process and reducing the likelihood of disputes later in the process by bringing early works forward, including route selection, more extensive engagement with affected communities and investigation of environmental and other approvals requirements. We estimate that in line with option 1, this could lead to time savings of approx. 6 months.

Regarding the potential for combination of the strawperson options, our initial view is that strawperson option 1 and option 2 could be combined to achieve cumulative time savings. This would mean that the ISP identifying a project as actionable would directly trigger an early works CPA (as the early works RIT-T would be removed) and the subsequent RIT-T would only undertake a least cost assessment instead of also assessing benefits. This could lead to cumulative time savings of 18 months (-50% to +50%) (based on our estimated time savings of approx. 6 months from removing the RIT-T, approx. 6 months from removing the benefits assessment from the RIT-T and approx. another 6 months due to the potentially reduced risk of disputes arising later in the process). However, the estimated time savings are dependent on the specific design of a hybrid of strawperson 1 and 2 and the level of rigour underlying decision-making.

Potential impacts on rigour

As outlined above, there could be a concern that this option would reduce rigour, to the extent that variations in the benefits provided by different options to meet an ISP identified need are not captured in the RIT-T process. Variations in benefits would not be quantified – or potentially even identified – if the RIT-T is focussed on exploring least-cost solutions. As explained above, a potential solution might involve requiring AEMO to consider the potential for varying benefits of RIT-T credible options at the feedback loop stage. However, this may introduce complexity to the feedback loop process, and the workability of this approach would require further consideration.

From a rigour perspective, a related concern is the ability of the ISP process to consider all benefits that may be relevant to selecting a preferred option. For example:

- The ISP does not routinely consider competition benefits. Although these are described as a potentially relevant class of benefits in the NER and the AER's CBA Guidelines, as described in section 2.1.1 AEMO has found that it would not be proportionate to undertake the complex modelling associated with quantifying such benefits in the ISP. Further, AEMO considers that competition benefits may not be a material factor in determining the ODP.
- The Commission's engagement with TNSPs during the preparation of this draft report has indicated that during the RIT-T, TNSPs may undertake modelling that represents the electricity network in a more granular way (e.g., more detailed representations of

localised constraints). More granular modelling could potentially change the benefits produced by different options to meet and identified need.

In principle, it is possible that consideration of the types of benefits described above could change the ranking of the more granular solutions identified by TNSPs during the RIT-T. The likelihood of this outcome occurring would need further exploration to understand the potential implications of this option. If it was determined that there are material benefits that the ISP could not feasibly capture, it is possible that TNSPs could – where relevant – contribute their own modelling and analysis to support the ISP through the joint planning arrangements. However, this might have the effect of reducing the timeliness advantages of this option.

A final consideration around rigour relates to the transparency of the economic assessment process, and the ability for stakeholders to engage as options to meet system requirements are explored. The Commission considers that there could be offsetting implications:

- Centralising the assessment of net benefits in the ISP process could potentially increase transparency, in the sense that there would be a single NEM-wide methodology for assessing net benefits that AEMO is required to publish and consult on. This means that stakeholders would not need to spend time understanding the details of multiple modelling methodologies, not grapple with potential discrepancies between AEMO and TNSP modelling approaches. Concentrating benefits analysis in the ISP process may address the concerns raised by some stakeholders regarding the scope for TNSP approaches to benefits modelling to change between the PADR and PACR, without being subject to consultation.
- To the extent that TNSP-led modelling became an input to the ISP process (where the TNSP considered that it would add value), the ISP process may provide a useful framework for ensuring that analysis is prepared on a consistent basis and with a level of oversight provided by AEMO. However, this might have the effect of increasing AEMO's workload.
- On the other hand, the Commission notes that the ISP is already a complex process that involves consideration of many project options across the NEM. Stakeholders may not be able to engage with each actionable project at the level of detail that they would prefer, if there is a requirement to consider multiple projects in parallel.
- Further, the Commission understands that some stakeholders may value information that is currently provided in the RIT-T, but not typically included in ISP reports. For example, the AEMC's Customer Reference Group commented that the RIT-T process currently provides more information on the distribution of costs and benefits across different NEM regions and participants.[81]

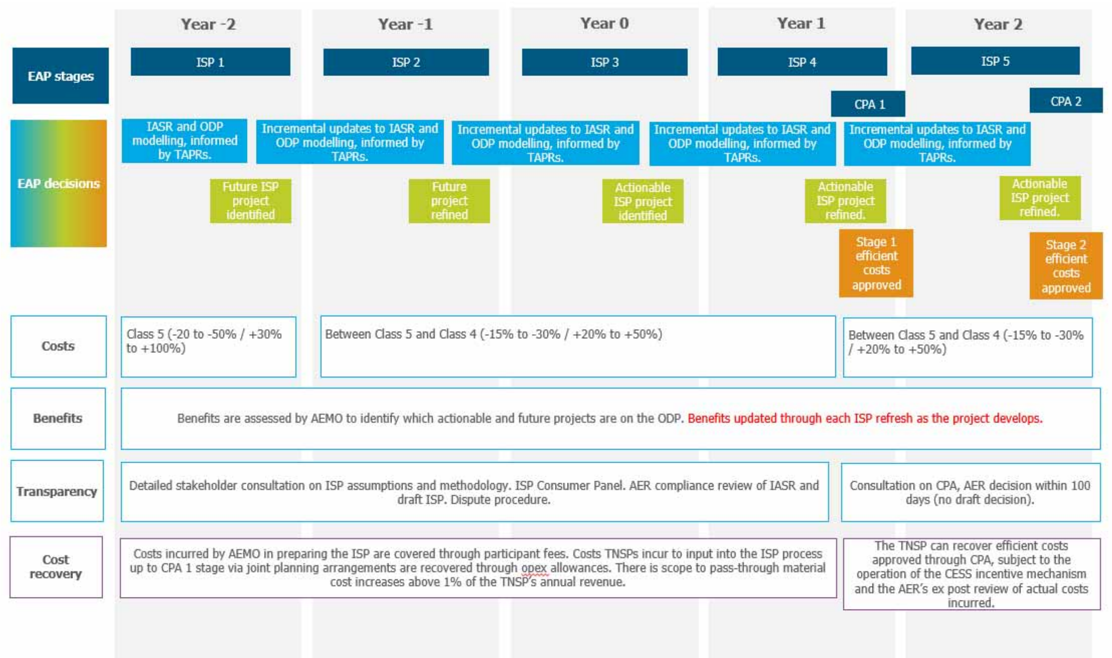
These offsetting factors would need to be carefully explored if this strawperson 2 option is progressed to a more detailed level of specification.

81 Meeting with CRG, 9 August 2022. The AER's CBA Guidelines note that AEMO has flexibility over what information it will present in relation to distributional effects across NEM regions, customer types and market participants. However, these effects do not form part of the ODP selection. AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 34.

> **QUESTION 4: STRAWPERSON 2**
>
> a. Do you agree with our assessment of the time savings of this strawperson option 2 regarding the delivery of ISP projects, relative to the counterfactual?
>
> b. Do you have any suggestions on how this option 2 could be specified differently, to facilitate the timely delivery of major transmission projects while maintaining an appropriate level of rigour?
>
> c. Do you think that this option 2 should be taken forward?

2.6.4 Strawperson 3 – ISP to undertake a centralised analysis of costs and benefits with input from TNSPs

Figure 2.11: Overview of strawperson 3



Note: Strawperson 3 aims to improve the timeliness of the economic assessment process by changing the current allocation of responsibilities across AEMO and the TNSPs.

Note: Under option 3, the identification of options to meet system needs, the selection of the preferred option, and consultation on these decisions would take place solely through the ISP process administered by AEMO.

Note: TNSPs would input into this process by providing updated project information developed through their annual TAPRs. AEMO would have the ability to direct TNSPs to undertake preparatory activities to further refine both actionable and future ISP projects.

Note: To ensure that decisions on the preferred option are being made with robust information, strawperson 3 envisages that the ISP would be more frequently updated, e.g. on an annual basis; however, the optimal timing would require further consideration.

Key features of strawperson 3

Figure 2.11 illustrates the operation of strawperson 3.

Under this option, the identification of options to meet system needs, the selection of the preferred option to deliver an actionable ISP project, and consultation on these decisions would take place solely through the ISP process administered by AEMO. The RIT-T process and feedback loop would no longer apply The contingent project assessment would remain in place, as under the counterfactual process.[82]

Table 2.10: Option identification

	COUNTERFACTUAL	STRAWPERSON 3
ISP	TNSP/AEMO joint planning identifies credible options for ISP analysis	Strengthened joint planning to improve ISP inputs; more frequent ISP
RIT-T	TNSP identifies credible options not explored in the ISP	RIT-T process no longer applies to actionable ISP projects

Under the current ISP framework, a project being granted 'actionable' status triggers a requirement for the TNSP to prepare a RIT-T. The RIT-T then further refines the design specification of the actionable project, contributing to improved cost estimates. Under strawperson option 3, the RIT-T stage is no longer applicable to actionable projects. TNSPs would still continue to input credible options and cost estimates into the ISP process by providing updated project information developed through their annual TAPRs. AEMO would retain the ability to direct TNSPs to undertake preparatory activities to further refine both actionable and future ISP projects.

Under this strawperson 3 model, a possible refinement to the current joint planning arrangements might be to allow AEMO to more prescriptively specify the type of preparatory activities to be undertaken (e.g., more detailed investigation of route options to mitigate delivery risk), and the type of information to be provided (e.g., cost estimates within a particular accuracy range). Other options for ensuring that high-quality information feeds into the ISP analysis could be considered.

Table 2.11: Option selection

	COUNTERFACTUAL	STRAWPERSON 3
ISP	AEMO identifies candidate option for actionable ISP projects	More frequent ISPs progressively refine option selection
RIT-T	TNSP identifies preferred option (maximises net	RIT-T process no longer applies to actionable ISP

82 This option draws on elements of the equivalent process in PJM, where the independent system operator (ISO) has responsibility for identifying the preferred solution to meet system needs through its planning process, based on input from transmission companies and other stakeholders. Unlike the ISP, PJM operates a rolling planning process (see Appendix A).

	COUNTERFACTUAL	STRAWPERSON 3
	benefits)	projects
Feedback loop	Feedback loop confirms preferred option is on the ODP	With a more frequent ISP cycle the feedback loop assessment is no longer required

To ensure that decisions on the preferred option selection are being made with robust information, this strawperson envisages that the ISP would be more frequently updated. For illustration, the strawperson assumes an annual cycle; the optimal timing would require further consideration. The intent of this process would be to progressively refine the definition of the actionable project to meet the identified need. That is, while the need for the actionable ISP project itself might remain relatively constant from one ISP to the next, the detailed technical solution would be refined through successive ISPs.

Given the ISP options and cost inputs are refreshed and consulted on more often as part of a more frequent ISP process, e.g. on an annual basis, the Commission's initial view is that it is no longer practical to retain the feedback loop.

There is a related question as to whether the re-opening triggers for actionable ISP projects proposed in the Commission's *Material change in network infrastructure project costs* draft rule should continue to apply under this option. That is because the net benefits of actionable ISP projects would continue to be refreshed until the point that the project becomes anticipated or committed, as is the case under the current rules. This may provide sufficient comfort that, at the point of the TNSP submitting a CPA, the preferred option decision would still be up to date. This would require further consideration, if this option were to be taken forward for more detailed development.

Table 2.12: Regulatory approval of allowance to deliver the project

COUNTERFACTUAL	STRAWPERSON 3
• Cost up to stage 1 CPA covered by TNSP revenue allowance • CPAs can be approved in stages	Conditions may need to apply before the CPA can occur

This strawperson raises a question around what 'actionable' status would mean in relation to cost recovery. For example, it may not be appropriate for the relevant TNSP to proceed directly to a CPA for an actionable project if the costings for that project are still relatively immature, or if substantial design work is still required before the TNSP could commence the project implementation activities that the contingent funding is intended to support. Therefore, consideration may need to be given as to whether any conditions should be met before a project – or project stage – could be deemed 'actionable', or before a TNSP could submit a CPA for an actionable ISP project. For example, this might include a requirement that certain preparatory or early works activities have been undertaken, or that cost estimates had a particular level of accuracy.

Potential impacts on timeliness

The Commission expects this option is likely to contribute to the timely delivery of actionable ISP projects by concentrating the analysis of and consultation on candidate projects through a single centralised process. Potential time savings under option 3 are in the magnitude of 2 years (-50% to +50%) (compared to the counterfactual). Our estimate of overall time savings is based on removing the RIT-T. This is estimate is based on the length of the economic assessment process for QNI, PEC and HumeLink. However, the length of the RIT-T has varied significantly for these projects, which were also subject to transitional rules.

The magnitude of time savings would largely depend on the specific design of option 3 in terms of the level of rigour underlying the decision-making points in the economic assessment process:

- **Accuracy of cost estimates** that guide decision-making on option identification, option selection and funding approval would determine the level of granularity of the analysis needed and thereby the time needed to perform the analysis. A higher level of granularity and a higher accuracy of cost estimates would impact timeliness of delivery in terms of additional time needed to perform the economic assessment process, i.e. time savings would be less than the indicative 2 years compared to the counterfactual.
- **Transparency in terms of the number of separate reports and consultations for a given project** could be reduced under this option, being required only of AEMO. However, consistent with above, the specific design of the process would have an impact on the time savings under this option 3.

For this strawperson 3 model, there is an important timeliness question around how frequently the ISP could be published and what type of process would be needed to achieve that. For example:

- As the ISP process and AEMO's internal capabilities mature, there may be a degree of 'stabilisation' in the ISP methodology and the approach used to develop assumptions. Under these circumstances, it may be appropriate to consider models where there is more frequent consultation on incremental changes to the process and methodology, rather than major bi-annual reviews.
- In order to achieve more frequent publication of the ISP, it may be necessary to run the development of assumptions and preparation of modelling through overlapping processes. Therefore, when the modelling to inform the next ISP is being finalised, the IASR for the next ISP might already be under development.

Finally, the Commission's early engagement with stakeholders on this option 3 has identified a possible concern that more frequent updates for the ISP could create uncertainty for investors, which may not promote the timely delivery of investments in either the network or power system more generally (e.g., generation, storage). The Commission acknowledges that more regular updates of the ISP may mean that investors could potentially delay decisions until the last possible moment, in order to benefit from the updated information that a subsequent ISP would provide. However, the Commission notes that more frequent ISP updates will not necessarily mean that there are material changes from one ISP to the next. Rather, a shorter cycle might tend to result in more incremental changes and a more stable ISP.

Potential impacts on rigour

In relation to the rigour of the cost estimates and the benefits assessment, the Commission considers that it may be possible to design this strawperson 3 option in a way that has a broadly neutral impact relative to the current arrangements. For example, as described above, it may be appropriate to establish conditions for a project to be given 'actionable' status, or for a CPA to be submitted. This type of approach could potentially act to preserve a level of rigour of cost and benefits estimates that is similar to the counterfactual.

As noted in relation to strawperson 2, the next level of design development for this model would need to evaluate whether the ISP process is (or could be) capable of considering all benefits that may be relevant to selecting a preferred option.

From a transparency perspective, there are important questions around the nature and level of stakeholder engagement undertaken by both:

- TNSPs, in developing technical solutions and cost estimates that feed into the ISP.
- AEMO, in developing the IASR that underpins the ISP analysis.

For example, although TNSPs would not be running the RIT-T consultations process, they would nonetheless need to engage with stakeholders, including on social licence issues, to identify and refine the credible options and cost estimates that inform the ISP. However, it may not be practical for stakeholders to comment in detail on these options and cost estimates during the ISP process, given that many different projects are considered in AEMO's analysis. Accordingly, it may be necessary to reconsider the process through which TNSPs would develop credible options in their annual TAPR.

Similarly, if the ISP is being refreshed more frequently, it may be overly onerous for AEMO and stakeholders to continue to engage through the current process of submissions on draft reports. There may be opportunities for this to potentially take place through less formal processes, such as working groups, advisory panels, or community forums. These arrangements would require careful consideration in order to ensure an appropriate level of transparency and opportunity for engagement in the ISP development.

QUESTION 5: STRAWPERSON 3

a. Do you agree with our assessment of the time savings of this strawperson option 3 regarding the delivery of ISP projects, relative to the counterfactual??

b. Do you have any suggestions on how this option 3 could be specified differently, to facilitate the timely delivery of major transmission projects while maintaining an appropriate level of rigour?

c. Do you think that this option 3 should be taken forward?

2.6.5 Initial assessment of the strawperson options based on the assessment framework for this Review

The consultation paper set out the assessment framework for this Review. The framework described the overarching objective that guides the Commission's work and outlines the criteria that we will use to inform our decision-making, including some of the key trade-offs associated with the criteria.

We have used the assessment criteria to undertake an initial high-level qualitative assessment of the strawperson options and counterfactual presented in (Appendix A). As the strawperson models are high-level, the assessment primarily provides an indication of the types of factors that will be important to consider as these (or other) options are taken forward for further development.

We are seeking stakeholder feedback on this initial assessment. This will inform our decision in the Stage 3 final report on whether there is merit in proceeding to investigate any of the strawperson options in more detail. For simplicity, Table 2.13 below provides a summary of the Commission's initial assessment of how the strawperson options may differ from the counterfactual in relation to both timeliness and rigour.

Table 2.13: **Summary of possible timeliness and rigour impacts**

	IMPACT ON TIMELINESS	IMPACT ON RIGOUR
Strawperson 1	• Early funding to undertake early works concurrently with RIT-T • Early works inform RIT-T preferred option selection, de-risking future project delivery • Estimated time savings: 12 months (-50% to +50%)	• Improves transparency of how jurisdictional planning and approval requirements impact design, costs and benefits • Improves transparency of preferred option selection process for local communities, councils, landowners, etc.
Strawperson 2	• Reduces time for TNSPs to complete RIT-T, as they would not be required to undertake complex benefits modelling • May increase TNSPs' capacity to consider more detailed design and social	• Reduces ability to capture variations benefits between the options assessed in the RIT-T • ISP may not be able to consider all benefits relevant to preferred option selection

	IMPACT ON TIMELINESS	IMPACT ON RIGOUR
	licence issues during the RIT-T process • Estimated time savings: 12 months (-50% to +50%)	• Complexity of ISP process may reduce stakeholder visibility of the benefits assessment for specific projects • ISP may not report on all information stakeholders value in the RIT-T • Centralising the benefits assessment may provide consistency and simplify stakeholder engagement on this issue
Strawperson 3	• Analysis and selection of options centralised in a single process • TNSPs would not be required to undertake complex benefits modelling, allowing them to focus on providing high quality inputs to ISP • Estimated time savings: 2 years (-50% to +50%)	• Potential for design to accommodate similar level of rigour to current process – but needs to be worked through, as substantial process changes would be needed

Note: As set out above, regarding the potential for combination of the strawperson options, our initial view is that strawperson option 1 and option 2 could be combined to achieve cumulative time savings of 18 months (-50% to +50%) based on our estimated time savings of approx. 6 months from removing the RIT-T, approx. 6 months from removing the benefits assessment from the RIT-T and approx. another 6 months due to the potentially reduced risk of disputes arising later in the process. However, the estimated time savings are dependent on the specific design of a hybrid of strawperson 1 and 2 and the level of rigour underlying decision-making.

QUESTION 6: ASSESSMENT OF STRAWPERSON MODELS

a. Do you agree with our initial assessment of the options based on the assessment criteria?

b. Do you think there are alternative strawperson options that should be considered in this Review? This may include alternative specifications and/or combinations of the options presented in this report. If so, how would your proposed alternative better contribute to timeliness and rigour in the delivery of major transmission projects?

c. Do you think there is potential for staging of the strawperson options, e.g. implement one option in the short term and another option in the long term?

d. Do you think the counterfactual is the option that best achieves an appropriate balance between timeliness and rigour? If so, why?

3 TRANSMISSION PLANNING AND THE TRANSITION TO NET ZERO EMISSIONS

BOX 5: DRAFT POSITION

AEMO's current scenario planning approach – that flows through to the application of the RIT-T – factors emissions abatement into transmission planning. This is because ISP planning scenarios reflect the outcomes of emissions abatement policies and targets (as well as broader market dynamics with respect to decarbonisation and the transition to net-zero future), ensuring that transmission investments are compatible with these outcomes being achieved.

There have been recent significant changes, including the change in federal government, the introduction of the Climate Change Act 2022 and agreement for an emissions objective to be incorporated into the NEO. These changes indicate an increase in emissions abatement ambitions and highlight the increasing role of the energy sector in realising these ambitions. While emissions abatement is currently factored into transmission planning, in light of the evolving nature of the policy landscape, the Commission will continue to monitor developments to consider if changes need to be made to ensure that emissions abatement continues to be appropriately factored into transmission planning. However, the Commission notes that determining whether the treatment of emissions abatement in transmission planning is appropriate could be assisted by guidance on sectoral emissions reduction or abatement trajectories in the context of net zero.

This chapter describes:

- the evolving policy landscape regarding emissions abatement and the role of the electricity sector in realising Australia's abatement ambitions
- the purpose of scenario planning within the transmission planning framework
- how detailed jurisdictional environmental and energy policies are included in all ISP scenarios and broader emissions abatement ambitions and/or targets are captured by some scenarios.

3.1 The energy transition has brought into focus the treatment of emissions in transmission planning

Recent significant changes indicate an increase in emissions abatement ambitions in Australia. Most notably, there has been a change in the federal government and the introduction of the Climate Change Act which seeks to legislate Australia's greenhouse gas emission reduction targets – a 43 per cent reduction from 2005 levels by 2030 and net zero by 2050.[83]

83 Section 10(1) of the Climate Change Act 2022.

Although these targets are economy-wide commitments and therefore apply to all sectors, the electricity sector is one of Australia's largest emitters and therefore will have a key role in facilitating Australia's decarbonisation. This role is reinforced by the recent agreement among Energy Ministers to fast-track an emissions objective into the NEO.[84]

In submissions in response to the consultation paper and reflecting the role of the electricity sector in decarbonising the Australian economy, stakeholders indicated that they are keen to understand how decarbonisation objectives are incorporated into the transmission planning process. They had varying perspectives and a wide range of views on the appropriate treatment of emissions (including carbon) in transmission planning, although these views were expressed prior to the recent developments set out above. Views expressed at that time by stakeholders included:

- there is no need for change to the treatment of carbon in transmission planning because AEMO's scenario planning approach adequately captures various assumptions around future emissions reductions levels[85]
- explicitly quantifying carbon reduction benefits may be inconsistent with the NEO, meaning legislative reform may be required before environmental or climate change impacts could be considered as distinct benefits when assessing transmission investments,[86] and
- the current approach of scenario planning is not sufficient – carbon reduction benefits should be included in the planning process and explicitly quantified.[87]

In response to stakeholder feedback and to increase transparency, the Commission has considered how emissions abatement is currently factored into transmission planning. Further, in light of the evolving nature of the policy landscape, the Commission will continue to monitor developments with respect to climate legislation and an emissions objective in the NEO to ensure that emissions abatement continues to be appropriately factored into transmission planning in the future.

For instance, depending on the form of the emissions objective and how it is applied in practice, it may be appropriate for emissions abatement to be explicitly valued in the ISP/RIT-T – even if there is no legislative mechanism that sets a formal price on emissions. The Commission will consider further developments in the stage 3 final report, and will continue this work in the Commission's upcoming ISP Review, due to be completed by July 2025.

Finally, the Commission notes that determining whether the treatment of emissions abatement in transmission planning is appropriate could be assisted by guidance on sectoral emissions reduction or abatement trajectories in the context of net zero.

84 Energy Ministers, *Meeting communique,* 12 August 2022, p. 1.

85 Submissions to the consultation paper: AEC, p. 2; AEMO, p. 15; AGL, p.2; CS Energy, p. 9; EnergyAustralia, p. 8, EUAA, p. 7; and MEU, p. 8.

86 Submissions to the consultation paper: AEMO, p. 14; CEIC, p. 5; MEU, p. 8; and RE-Alliance, pp. 4-5.

87 Australian Energy Market Commission, *Transmission planning and investment review,* submissions to the consultation paper : CitiPower, PowerCor and United Energy, pp. 1-2; Energy Grid Alliance, p. 4; Resist HumeLink, p. 8; Transgrid, pp. 6-7; APA, p. 4; CEC, pp. 2-3; Neoen, p. 7; Tilt Renewables, p. 2; CEFC, p. 5.

3.2 Emissions abatement is currently factored into transmission planning through scenario planning

Transmission investments are made to satisfy an identified need, given the expected evolution of the power system over the long term. Scenario planning, or the development and modelling of multiple future states of the world, is used to account for the uncertainty associated with estimating transmission investment costs and benefits over lengthy periods of time. Jurisdictional environmental and energy policies – as well as emissions abatement ambitions – are factored into these different scenarios. Broader market dynamics with respect to decarbonisation are also reflected. The question examined in the ISP and RIT-T is then how to meet identified needs most efficiently under these states of the world.

Currently, the ISP and RIT-T implicitly value emissions abatement through the scenario planning framework. Jurisdictional environmental and energy policies are explicitly reflected in all scenarios where there is sufficient detail for AEMO to model their impact on the power system. In many cases, broader abatement targets are not accompanied by this level of policy detail. However, the objectives of these targets are reflected in some planning scenarios through the application of carbon budgets, i.e., caps on the level of emissions. These caps on emissions place an implicit value on emissions. This approach reflects a compromise between the need to reflect emissions abatement in transmission planning without a clear policy mechanism guiding the electricity sector's contribution to Australia's emission abatement ambitions. Changes to the NEO may enable a different way to reflect emissions abatement.

These current arrangements are described in greater detail below.

3.2.1 Scenario planning is a necessary feature of the transmission planning process to account for and help manage uncertainty

The ISP and RIT-T serve distinct purposes in the transmission planning framework. The purpose of the ISP is to:[88]

> "...establish a whole of system plan for the efficient development of the power system that achieves power system needs for a planning horizon of at least 20 years for the long term interests of the consumers of electricity."

Reflecting its purpose of assessing a single identified need(such as delivering market benefits),[89] the purpose of the RIT-T is to:[90]

> "...identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option)..."

88 Clause 5.22.2 of the NER.

89 The identified need is defined in the NER as the objective a network service provider or a group of network service providers seeks to achieve by investing in the network in accordance with the Rules or an ISP.

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

Despite serving distinct purposes, the analysis underpinning both the ISP and RIT-T requires a forward-looking assessment of the costs and benefits of transmission investments.[91] An inherent challenge of this forward-looking approach – particularly in the context of long assessment periods – is the uncertainty around how the energy market will develop.[92] This uncertainty is heightened during periods of significant change such as the current energy transition.

A scenario planning approach is used in transmission planning to manage this uncertainty. AEMO develops scenarios or future states of the world that outline how the energy market may develop, which are modelled when assessing transmission investments. To ensure that these future states of the world are consistent across the ISP and RIT-T, AEMO develops the IASR. Consistency is achieved by the requirement for RIT-T proponents to adopt the most recent ISP parameters, from the latest IASR (if the RIT-T proponent varies, omits or adds a new parameter it must provide demonstrable reasons why the addition or variation is necessary),[93] and the modelling from the ISP as far as practicable.[94]

The IASR is developed in consultation with stakeholders and is subject to a transparency review by the AER.[95] It sets out how AEMO will model the future in its forecasting and planning publications – most notably the ISP – and comprises a range of plausible futures for:[96]

- growth in electricity demand
- decentralisation as businesses and household consumers manage their own energy
- the pace of decarbonisation (described in greater detail in Section 1.2.3).

These inputs, assumptions and scenarios in turn form the basis of the electricity market modelling that underpins the ISP. The development of the wholesale electricity market is modelled– with and without the proposed transmission investment(s) – and includes the type, quantity and timing of future generation investment. These modelled outcomes inform the estimation of particular categories of market benefits that are associated with a development path or credible option, including:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in costs for parties other than the RIT-T proponent due to:
  - differences in the timing of new plant
  - differences in capital costs and
  - differences in operating and maintenance costs.

Due to the requirement for RIT-T proponents to adopt the most recent ISP parameters and the market modelling used in the ISP (to the extent practicable), the IASR also forms the

91 Candidate development paths in the case of the ISP, and credible options in the case of the RIT-T.

92 Although the NER are not prescriptive with respect to the assessment period applied in the RIT-T, the AER's Cost Benefit Analysis Guidelines state that RIT-T proponents must consider using the ISP modelling period. AER, *Cost benefit analysis guidelines | Guidelines to make the Integrated System Plan actionable,* August 2020, p. 67.

93 Clause 5.15A.3(b)(7)(iv) of the NER.

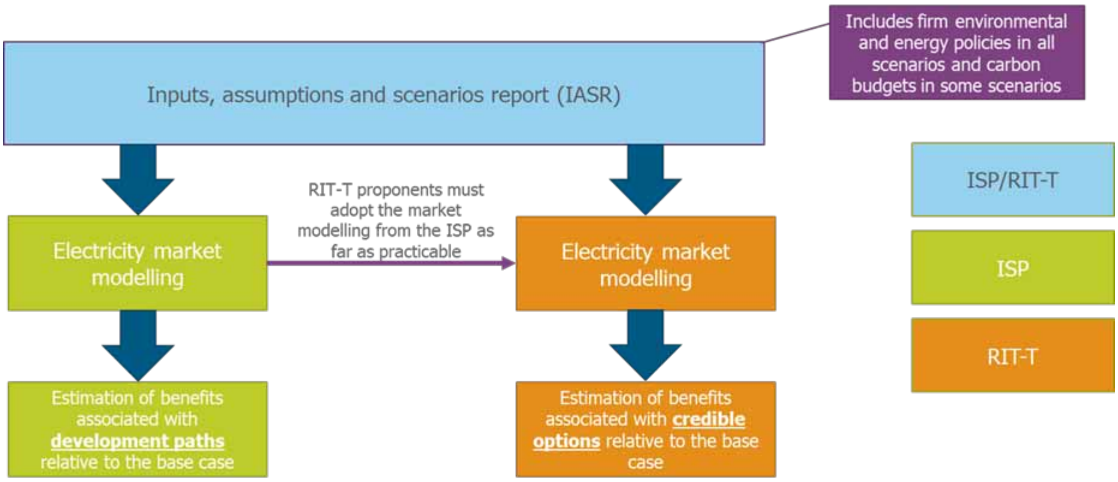
94 Clause 5.15A.3(b)(7)(vi) of the NER.

95 Clauses 5.22.8 and 5.22.9 of the NER.

96 AEMO, *2021 inputs, assumptions and scenarios report,* July 2021, p. 4.

basis of how the RIT-T models the future. Figure 3.1summarises this relationship between the IASR, ISP and RIT-T.

Figure 3.1: Relationship between the IASR, ISP and RIT-T



Source: AEMC

3.2.2 Environmental and energy policies that meet the public policy clause can be included in all scenarios

The transformative scale of the energy transition is such that numerous jurisdictional environmental and energy policies have been introduced to facilitate the decarbonisation of the energy sector. Effective planning of the power system requires these policies to be taken into account because their associated commitments will fundamentally shape the future of the NEM.

The IASR and therefore the ISP/RIT-T takes into account numerous jurisdictional policies. This occurs through what is referred to as the 'public policy clause' of the NER.[97] Under this clause, AEMO is permitted to consider a current environmental or energy policy of a participating jurisdiction when determining power system needs, provided that:

- the policy has been sufficiently developed to enable AEMO to identify the impacts of it on the power system, and
- at least one of the following is satisfied:
    - a commitment has been made in an international agreement to implement that policy
    - that policy has been enacted in legislation
    - there is a regulatory obligation in relation to that policy
    - there is material funding allocated to that policy in a budget of the relevant; participating jurisdiction or
    - the Ministerial Council of Energy (MCE) has advised AEMO to incorporate the policy.

97 Clause 5.22.3(b) of the NER.

AEMO consults on the public policy settings to be included in the scenarios as part of the development of the IASR.[98] Where AEMO considers that a particular policy meets the public policy clause and applies that policy to a scenario, it is applied to all states of the world included within that scenario. In other words, the commitments associated with these policies occur in each state of the world modelled to assess transmission investments within a scenario. For example, a legislated state-based renewable energy target can be included in all states of the world modelled for every scenario. To illustrate the application of the public policy clause, the policies incorporated into the 2021 IASR – which underpins the 2022 ISP – are summarised in Figure 3.2 below. In future ISPs it is likely that the Climate Change Act would be included in all scenarios , (and meets the other conditions set out above) reflecting the fact that Australia's 2030 emissions reduction target is already incorporated. Other policies, such as emission reduction ambitions, are not included under the public policy clause but can still be captured in some of the scenarios via scenario settings.

Figure 3.2: Jurisdictional environmental or energy policies included in the 2021 IASR

Jurisdictional environmental or energy policies included in the 2021 IASR

Source: AEMC
Note: A detailed overview of how each of these policies are captured in AEMO's modelling is provided in the 2021 IASR.[99]

98 As part of the development of the 2021 IASR, AEMO sought stakeholder inputs on whether the approach to including government policies across the scenarios was appropriate and whether there were any additional energy or environmental policies that needed to be considered. See: AEMO, *Draft 2021 inputs, assumptions and scenarios report,* December 2020, p. 47.

99 AEMO, *2021 inputs, assumptions and scenarios report,* July 2021, pp. 27-31.

The objectives of the policies set out in Figure 3.2 are not explicitly translated as a benefit in the ISP or RIT-T. They are implicitly captured because the policy objectives are reflected in each state of the world modelled. The policies shape the scenarios that are possible and/or likely to represent the future state of the world, rather than directly contributing to the assessment of net market benefits – they are not a line item in the RIT-T analysis.

The role of the modelling underpinning the ISP and RIT-T is to identify the transmission investment(s) that meet states of the world in a way that optimises net market benefits (in the case of the ISP) and delivers the greatest net market benefits (in the case of the RIT-T). This is reflected in both the ISP and RIT-T because particular transmission investment(s) may meet these states of the world more efficiently, that is, at a lower resource cost. For example, in the context of a renewable energy target, an interconnector investment may deliver market benefits in the form of avoided investment costs in generation, storage and unrelated transmission. Absent the interconnector, significant new investment in generation, storage and transmission may be required to ensure the renewable energy target is met. Investing in the interconnector may be able to defer, or negate the need entirely, for some of this expenditure and therefore more efficiently meet the target.[100]

3.2.3 Emissions reduction ambitions are captured in some scenarios through carbon budgets

In addition to specific policies that contribute to decarbonisation objectives, many jurisdictions in Australia have a specific policy or policy ambition that targets emissions reduction. These policies are typically framed in the context of achieving net zero emissions. Emissions reduction ambitions are not included in the IASR under the public policy clause. This is because they do not meet the first element of the clause, ie, AEMO cannot determine their impact on the power system. This point is explained in the 2021 IASR:[101]

> "…in most cases, these policies [state-based emissions targets] have limited detail, funding, or underpinning legislative framework to enable assessment of how they will impact the power system."

While these policies are not explicitly incorporated into the IASR, their objectives are captured in the IASR scenarios that achieve Australia-wide net zero emissions. The process for developing emissions and climate related assumptions is set out in detail in the 2021 IASR and involves significant stakeholder engagement.[102] At a high-level it involves two steps:

1. Each scenario is mapped to the International Energy Agency World Energy Outlook, and the International Panel on Climate Change's Shared Socioeconomic Pathways and Representative Concentration Pathways.[103] Linking AEMO's IASR scenarios to global

100 For this market benefit to be realised, the capital costs of the interconnector investment must be less than the avoided capital costs of the generation, storage and unrelated transmission investment.

101 AEMO, *2021 inputs, assumptions and scenarios report,* July 2021, p. 31.

102 AEMO, *2021 inputs, assumptions and scenarios report,* July 2021, p. 35.

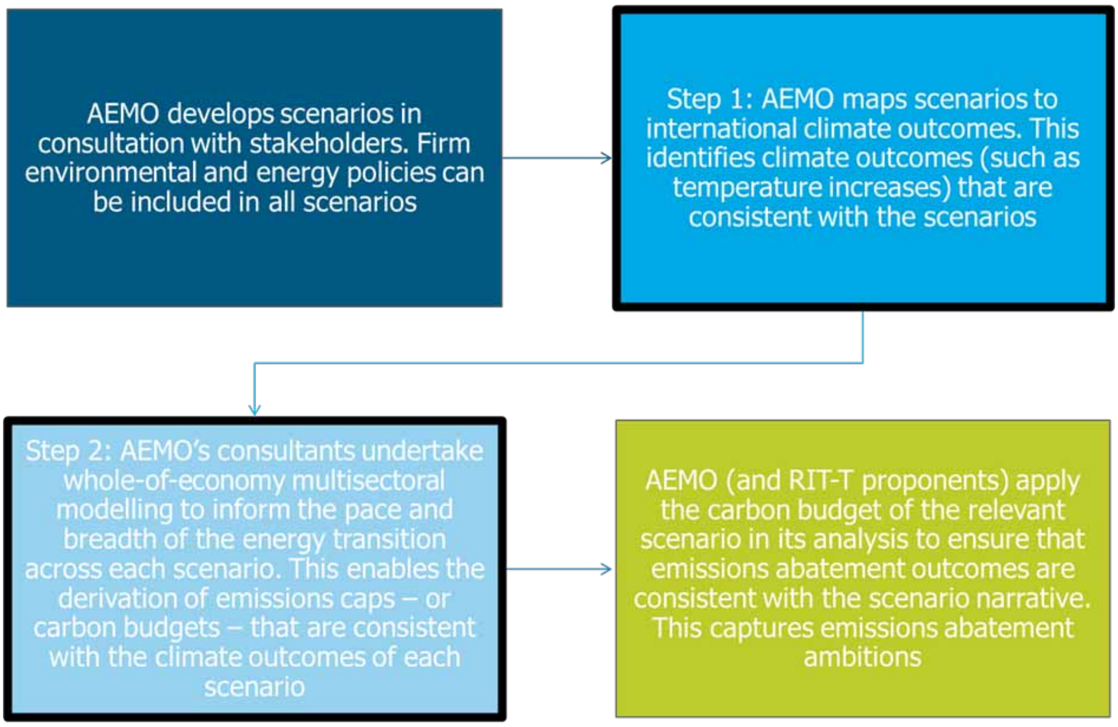
103 AEMO explicitly consults on whether its mapping of the scenarios to international narratives in appropriate. For the 2021 IASR, AEMO sought stakeholder input on whether its proposed alignments were appropriate as well as the global temperature pathways associated with each scenario. See: AEMO, *Draft 2021 inputs, assumptions and scenarios report,* December 2020, p. 51.

narratives enables them to be framed to consider broader energy, social, economic and demographic trends across the world.

2. Whole-of-economy multi-sectoral modelling is (undertaken by CSIRO and ClimateWorks) to inform the pace and breadth of the energy transition across each scenario. This modelling enables electricity sector carbon budgets (caps on emissions) to be imposed in the analysis to ensure that the scenarios adopt emission abatement outcomes that are consistent with the relevant scenario. For instance, the Step Change scenario is consistent with a temperature increase of less than two degrees by the end of the century, and the carbon budget imposed in this scenario ensures emission abatement outcomes consistent with this level of warming.[104]

The general role of climate and emissions-related assumptions, as well as the high-level process for deriving them, is summarised in Figure 3.3.

Figure 3.3: Role and development of carbon budgets in the ISP and RIT-T



Source: AEMC

The carbon budgets developed through the multi-sectoral modelling undertaken by AEMO's consultants, and consulted on as part of the development of the IASR, are applied in the market modelling that underpins the development of the ISP and application of the RIT-T.

104 AEMO explicitly consults on whether the proposed carbon budgets are appropriate and whether there is an alternative methodology for deriving them. See: AEMO, *Draft 2021 inputs, assumptions and scenarios report,* December 2020, p. 54.

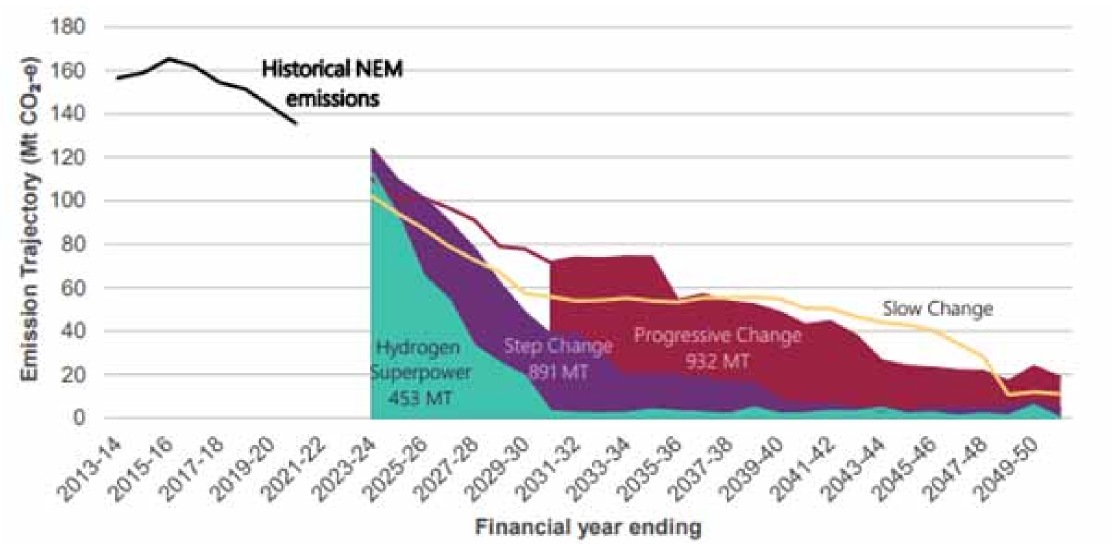
They represent a cap on the level of emissions that are permitted in a given scenario for the electricity sector. In other words, they are a modelling constraint.

For a given scenario, the outcome of the modelling cannot lead to emissions that exceed the carbon budget. Capping the level of emissions can influence the analysis by affecting the retirement of fossil-fuelled generation, selection of technologies to replace this generation, and/or out-of-merit-order dispatch. Carbon budgets affect each of these areas because market modelling is concerned with minimising total system costs given a set of constraints. This equates to minimising dispatch and investment costs (both generation and network investment) in a way that is consistent with the carbon budget (and all other constraints).

Many of these effects of the carbon budget reflect the same outcomes that would arise were an explicit value placed on emissions. Indeed, a carbon budget is equivalent to a value on emissions in a modelling sense – the same modelling outcomes occur. Appendix B presents a simplified dispatch model to illustrate the modelling equivalence of the two approaches.

Thee carbon budgets underpinning the 2022 ISP, as well as indicative emissions trajectories to achieve them, are highlighted in Figure 3.4.

Figure 3.4: 2021 IASR NEM carbon budgets and indicative emissions trajectories that achieve them



Source: *AEMO, Draft 2022 Integrated System Plan, December 2021, p. 29.*

As can be seen in Figure 3.4 each scenario in the 2022 ISP is underpinned by a different cumulative carbon budget. This is due to each scenario mapping to slightly different climate outcomes (such as temperature increase outcomes). For instance, the Hydrogen Superpower scenario has the lowest total emissions (and therefore the highest level of required carbon abatement), with a cumulative carbon budget of 453 million tonnes. Much of this budget is exhausted between 2023-24 and 2031-32, with minimal emissions in the following years. In contrast, the Slow Change scenario has no carbon budget and therefore represents the unconstrained carbon path appropriate for the circumstances of that future scenario.

A carbon budget provides a means of ensuring that emission abatement outcomes are consistent with the relevant scenario. The IASR carbon budgets are based on international evidence that quantifies the scale of emissions reduction required to meet climate-related objectives.

3.2.4 Major non-ISP projects capture emissions abatement consistent with the approach for ISP projects

The preceding sections have focused on how emissions abatement is factored into transmission planning for major projects identified through the ISP. However, emissions abatement is similarly captured in the planning of major non-ISP investments.

Under the RIT-T instrument, a RIT-T proponent for non-ISP projects:[105]

- must adopt the inputs and assumptions from the most recent IASR unless it provides demonstrable reasons for why an addition, omission or variation from those inputs and assumptions is necessary
- must base its cost benefit analysis on an assessment of reasonable scenarios for future supply and demand if each credible option were implemented compared to the situation where no option is implemented, and
- may, in so far as practicable, adopt the market modelling from the ISP.

RIT-T proponents must include any of the ISP scenarios from the most recent IASR that are relevant in developing reasonable scenarios.[106] A consequence of this approach is that non-ISP projects factor in environmental and energy policies, as well as emissions abatement ambitions, in a manner consistent with the approach for ISP projects (described above) provided that these are captured in the scenario(s) relevant to the RIT-T. For non-ISP projects the relevant scenario is determined by the RIT-T proponent, whereas for ISP projects the ISP assigns scenarios (and the relevant weightings) to be assessed in the RIT-T.

105 AER, *Regulatory investment test for transmission,* August 2020, paragraph 3.

106 AER, *Application guidelines | Regulatory investment test for transmission,* August 2020, p. 40.

4 APPROACH TO THE REGULATORY TREATMENT OF CONCESSIONAL FINANCE IN THE NER

BOX 6: DRAFT POSITION

The Commission recognises the increasing potential to utilise concessional finance to facilitate timely investment in transmission infrastructure, notably in the context of the Federal Government's Rewiring the Nation.* It is therefore timely to consider the potential treatment of concessional financing in the NER.

In particular, the Commission considers that additional guidance is necessary to provide the AER, AEMO, TNSPs, investors and financiers with clarity on how consumer benefits (and benefits that do not accrue to consumers) from concessional finance are treated in the regulatory framework. In turn, this would improve investor confidence and assist in the timely delivery of transmission infrastructure.

The Commission seeks stakeholder feedback on the considerations outlined in this chapter.

Note: *The Rewiring the Nation policy is focused on updating the electricity network and transitioning towards renewables by providing $20 billion of low cost financing to deliver the ISP. See here.

With an unprecedented level of investment required, concessional finance[107] can be offered to facilitate timely investment in transmission infrastructure.

Concessional finance may be provided by a government funding body to achieve a range of different objectives, such as to:

- benefit energy consumers through lower prices, and/or
- support the acceleration and delivery of a transmission project that may not otherwise be undertaken by the TNSP in the absence of concessional finance.[108]

These purposes are not necessarily mutually exclusive.

The Commission is considering how concessional financing provided by governments and agencies, such as the Clean Energy Finance Corporation (CEFC), should be treated for regulatory purposes when some of the benefits may be intended to flow to consumers.

Given the NER does not explicitly recognise the treatment of concessional finance, additional guidance is required to clarify the treatment of benefits (both to the consumer and/or the TNSP) from concessional finance and how the benefits can be recognised in the ISP as well as in the RIT-T where appropriate.[109]

107 Concessional finance may be provided to a TNSP in the form of below-market rate finance as well as finance over a longer term, higher gearing and additional debt capacity, or possibly other forms for the same level of risk to below market rate loans.

108 Concessional finance, under certain conditions, could also minimise financeability concerns arising by improving project cash flows in instances where revenue profile adjustments are coupled with back-loaded debt payments.

109 Under the current regulatory framework concessional financing will benefit TNSPs while consumer benefits, if intended, may not be realised other than through benefits associated with a project being built that otherwise would not be.

This will enable funds such as Rewiring the Nation to be applied for the benefit of consumers when intended. It would also clarify the intended purpose of the concessional finance arrangement and provide clarity in the treatment of concessional financing to improve investor confidence and assist in the timely delivery of transmission infrastructure.[110]

The focus of this chapter is on the appropriate regulatory treatment of benefits from concessional finance in the national regulatory framework as it applies to major transmission projects, and the potential implication this may have for how the benefits of concessional financing are then incorporated into the ISP and the RIT-T assessment processes and into the determination of maximum allowed revenue for the provision of prescribed transmission services.

This chapter sets out:

- The current treatment of funding from external parties in the national regulatory framework.
- The key questions we are exploring as we consider the appropriate regulatory treatment of benefits from concessional finance.
- How the regulatory framework could be amended to provide additional guidance on the treatment of benefits from concessional finance including how to recognise these benefits in the economic assessments which inform the ISP as well as the RIT-T.

The Commission is liaising with the Commonwealth Government and market bodies on the future provision and appropriate treatment of concessional finance in the regulatory framework.

The Commission has also recently considered the treatment of concessional financing in the context of the National Gas Rules (NGR) as part of the *Review into extending the regulatory frameworks to hydrogen and renewable gases*. The final report recommended that the NGR be amended to provide the regulator with discretion to treat concessional finance in the same manner as user capital contributions and government grants, where appropriate. In practice, the regulator would treat concessional finance as a capital contribution by deducting an amount from the capital base when determining scheme pipeline revenue and prices.

The Commission notes the similarities in the policy considerations between the two reviews. However, in light of the differences in the NER and NGR regulatory regimes, the Commission recognises that the treatment of concessional finance will need to be fit-for-purpose and targeted to each framework. In this chapter, the Commission seeks stakeholder views on the appropriate regulatory treatment of consumer benefits from concessional finance in the NER, and similar to the Commission's recommendations for the NGR, whether it should be treated as a capital contribution or through another means. This is discussed in further detail in section 4.3

110 For example, the Commission understands one of the key objectives of the Rewiring the Nation program is to upgrade the transmission network to benefit consumers through lower energy costs.

4.1 The NER does not currently set out how concessional finance is to be treated

Concessional finance may take a range of forms, for example loans with lower than market rate pricing, loans with different tenor or security requirements than the market may provide or they may be in the form of guarantees for the same level of risk to below market rate loans. If the concessional finance is provided to reduce customer prices, the provider may expect that the benefits of the lower cost finance are passed to the relevant customer. If the concessional finance is intended to facilitate investment, then it will be required that at least for a limited period TNSPs would need to retain sufficient benefits of the lower interest so that financial ratios are flattered by the arrangement.

Part J of Chapter 6A of the NER specifies how user contributions to new capital expenditure are to be treated for regulatory purposes.[111] However, this part of the NER does not specify how capital contributions from non-users and concessional financing is to be treated for regulatory purposes. Similarly, the revenue and pricing principles that apply to the economic regulation of transmission services in Chapter 6A provide no direct guidance on these matters.

Clause 6A.28.2 'Capital contribution or prepayment for a specific asset' states:

Where the Transmission Network Service Provider is required to construct specific assets to provide connection service or Transmission Use of System (TUOS) service to a Transmission Network User, the provider may require that user to make a capital contribution or prepayment for all or part of the cost of the new assets installed and any contribution made must be taken into account in the determination of transmission service prices applicable to that user.

Under this clause, non-users are not prevented from offering concessional finance or making capital contributions to TNSPs, whether in respect of the assets contemplated by clause 6A.28.2 or other assets that form part of a TNSP's regulated asset base. However, it is unclear as to the application of a concessional finance arrangement to the project assessment framework and capital expenditure program as well as the treatment of the concessional finance by the AER in its revenue determination process.

4.2 Providing additional guidance for the regulatory treatment of benefits from concessional finance is required to align the allocation of benefits with the intent of the concessional finance

Given the current rules are silent on the treatment of concessional finance from a government funding body, there is a risk that such funding could result in TNSPs solely benefiting from circumstances where the government funding body intended that some or all the benefit of the lower cost of finance would flow through to energy consumers.

111 Clause 6A.28.2 of the NER.

Where some or all of the concessional finance for a transmission project is intended to benefit consumers, the regulatory framework should enable the TNSP, the AER and AEMO to take it into account in the assessment of the project.

However, where some or all the concessional finance is provided to support a transmission project that would not otherwise occur, there is a need to clarify when the regulatory treatment of consumer benefits from concessional finance would apply.

In considering these factors, the Commission considers that further regulatory guidance would:

- Provide the AER, AEMO, TNSPs, investors, and financiers with clarity on the regulatory treatment of benefits from concessional finance.
- Enable the intent of the financier to be reflected in the regulatory treatment of the concessional finance.
- Enable benefits to flow to energy consumers, where intended.

The Commission's view is that additional regulatory guidance would contribute to the achievement of the NEO by promoting outcomes for consumers and economic efficiency through providing clarity and transparency in regulatory arrangements that will enable market participants and investors to make efficient investment decisions.

4.3 Additional regulatory guidance would provide the AER, AEMO, TNSPs, investors and financiers with clarity on how benefits from concessional finance can be treated in the regulatory framework

The following section outlines the Commission's initial views on the additional regulatory guidance which may be required to provide clarity on how benefits from concessional finance should be treated in the regulatory framework.

The Commission welcomes stakeholder views on these issues and on other matters which should be considered to facilitate the appropriate regulatory treatment of benefits from concessional finance.

4.3.1 The regulatory framework requires additional guidance on the treatment of benefits from concessional finance in the economic assessment process for a transmission project

The net impact of the benefits from concessional finance may need to be considered in the development of the economic assessments, including those informing the ISP and the RIT-T, to ensure the intent of the concessional finance is appropriately treated in the regulatory framework.

This will require consideration of the form that this takes including whether it is appropriate for the benefits from concessional finance to be treated as:

- a reduction in the capital expenditure amount,
- a reduced rate of return in the economic analysis of different solutions, or
- through other means.

Given the number of ways the benefits from concessional finance could be treated, the regulatory framework including the AER's cost-benefit analysis guidelines and RIT-T assessment guidelines may benefit from additional guidance to inform the treatment of benefits from concessional finance in the economic assessment undertaken by the AER, AEMO and TNSPs.[112]

Further consideration may also be required to accommodate the different arrangements amongst jurisdictions of the NEM (for example, in Victoria), and how benefits from concessional finance yet to be committed should be treated in the assessment of the project (if at all).

The Commission welcomes stakeholder views on the additional guidance that may be required to clarify the appropriate treatment of benefits when concessional financing is applied to a project.

4.3.2 The regulatory framework requires additional guidance on the processes and information required to facilitate the treatment of concessional finance in the NER

The Commission has considered several key questions, outlined in further detail below, including[113]:

- Who should notify the AER about a concessional finance arrangement and the type of information that should be provided?
- How the AER determines the intent of the concessional finance and who the beneficiaries are (ie the consumer, TNSP or both)?
- How the AER determines the value of the benefit to the consumer and/or TNSP and the mechanism by which it is treated in the revenue determination process?

> QUESTION 7: NOTIFYING THE AER
>
> Who should notify the AER about the existence of a concessional finance arrangement?

To consider the treatment of concessional finance, the AER needs to be made aware of its existence. The NER could specify an obligation on a related party to the concessional finance to inform the AER that concessional financing has been provided for the project.

In determining whether it is the TNSP or financier (or another party, such as AEMO) who should inform the AER of a concessional finance arrangement, an important consideration is the potential information asymmetry that may arise for the AER when a TNSP receives concessional finance from a government funding body. For example, to assess the purpose of

112 Currently, the AER's cost-benefit analysis guidelines are silent on the treatment of concessional finance and calculation of associated benefits, and the AER's Regulatory investment test for transmission application guidelines treats contributions from non-participants solely as a reduction in the cost of a project (as detailed in example 21 on pages 57-58 of the guideline).

113 The key questions listed have also been considered in the context of the NGR. Whilst the Commission's initial views on application to the NER are largely consistent with its recommendations for the NGR, stakeholder views are sought on whether this is fit for purpose in the context of the regulatory framework in the NER.

concessional finance, the AER would need information from both the TNSP and the government funding body.

To overcome this information asymmetry, the Commission considers that the TNSP may be best placed to inform the AER of a concessional finance arrangement.

An alternative option could include the financier informing the AER of the concessional finance arrangement. However, there is no certainty that a financier will be aware of the requirements under the NER and act on them. Further, under the NER, a TNSP can be required to inform the AER whereas a financier cannot.

The Commission welcomes stakeholder views on the question of who should inform the AER of the existence of a concessional finance arrangement.

> QUESTION 8: INFORMATION REQUIREMENTS
>
> What types of information about the concessional finance arrangement should be provided to the AER and by whom?

The AER will need certain information to consider the regulatory treatment of the benefits from concessional finance. For example, this may include:

- The name of the government funding body that provided the concessional finance and contact details for that body.
- A description of the amount and type of concessional finance provided and the capital expenditure to which it relates.[114]
- A copy of the funding agreement.
- A statement as to whether the government funding body intended some or all of the concessional finance to benefit consumers.

Several parties to the concessional finance arrangement may be in a position to inform the AER, including the TNSP, financier and AEMO when applying it to the ISP.

The Commission considers that the TNSP may be best placed to provide the required information about the concessional finance arrangement to the AER. If the AER considers the information provided to be deficient, it could use its existing powers to obtain certain information about the concessional finance arrangement from the TNSP. This approach has the benefit of utilising an existing and relevant decision-making process.[115]

The Commission welcomes stakeholder views on (i) what types of information about the concessional finance arrangement should be provided to the AER? and,

114 There is a potentially wide set of financial arrangements that might be considered concessional including loan facilities, grants, guarantees and waivers. The AER may consider the information provided, together with the financier's intent (further discussed under Question 3), to determine whether the concessional finance provided should be assessed for consumer benefits.

115 For example, the AER indicates at page 204 of its Draft Rate of Return Instrument Explanatory Statement (June 2022) that since 2021 it has been using RINs to require NSPs to provide information about their debt issuances. The AER may prefer to take a similar approach to information gathering about concessional finance arrangements.

(ii) who may be best placed to provide additional information about the concessional finance arrangement to the AER?

> QUESTION 9: **FINANCIER'S INTENT**
>
> How should the AER determine the financier's intent?

Concessional finance may be provided with the intention of reducing the cost of energy to consumers as well as supporting the TNSP to undertake a transmission project of priority. In some cases, this may be apparent from the concessional finance documentation itself, while in others, it may not.

To appropriately treat the benefits from concessional finance, the regulatory framework should also enable the AER to consult with the government funding body with the purpose of determining:

- Whether the intention was for consumers and/or the TNSP to benefit from some or all of the concessional finance, and
- If so, what proportion of the concessional finance was intended to benefit each party?

Such a requirement would also enable the AER to be informed of any other relevant aspects of the financing arrangement in place.

Under this approach, the AER would be required to treat some or all of the concessional finance as a consumer benefit if it is satisfied that the government funding body's intention was for that benefit to flow through to energy consumers. However, if the financier's intent was for some or all of the concessional finance to support the TNSP's delivery of a transmission project of priority, then those benefits would be expected to flow to the TNSP.

The Commission welcomes stakeholder views on how the regulatory framework can facilitate the communication of the intent of the concessional finance to the AER.

> QUESTION 10: REGULATORY TREATMENT OF CONCESSIONAL FINANCE
>
> How should the AER determine the amount of the concessional finance to be treated as a benefit to consumers and/or TNSPs? How should this amount be treated in the revenue determination process?

When deciding whether to treat some or all the concessional finance as a benefit to consumers and/or TNSPs there is a need for the AER to determine the value of the benefit, having regard to the information provided by the TNSP, the government funding body, and any other information the AER considers appropriate.

If the government funding body's intention was for some or all the benefits to flow to the TNSP (e.g. to support investment that would not otherwise occur including by addressing financeability concerns), the AER may not be able to treat the concessional finance, or a component of it, as a consumer benefit. For example, if the government funding body's intention was for 20 per cent of the benefit to flow to the TNSP, then the AER may not be able to treat that 20 per cent as a consumer benefit.

The Commission considers the regulatory framework could provide the AER with discretion in deciding where the intended benefit of the finance should flow and determining a value. This may be required in the event the information does not specify a value to be treated as a benefit to consumers and/or TNSPs.

The Commission's initial position is that the regulatory framework could be clarified to facilitate the AER determining the value of the benefit to consumers and/or TNSPs from the concessional finance.

The Commission also considers the regulatory framework could benefit from additional guidance on how the determined value can be treated by the AER in the revenue determination process.

There are a number of ways the revenue determination process could treat the consumer benefits (largely a reduction in network charges) from concessional finance including as a capital contribution with a corresponding adjustment to the Regulated Asset Base (RAB), as an adjustment to the Maximum Allowed Revenue (MAR) or through another mechanism. In determining which mechanism to use, regard needs to be given to both providing certainty to consumers of their benefits from the concessional finance, where appropriate, as well as to the TNSP and financier of the project's treatment in the RAB.

Similarly, there may be a number of ways to treat benefits from concessional finance intended to flow to the TNSP. As concessional finance may be provided via different structures[116], additional regulatory guidance on the treatment of concessional finance may be required to realise the benefits. The additional regulatory guidance could consider detailing the methodology to be used to price any discounted return afforded by the concessional finance and mechanisms to improve the financeability and cash flow impacts. This could include how projected cash flows could be improved when revenue profile adjustments are coupled with concessional finance terms that include back-loaded debt payments and the continued calculation of a regulatory allowance based on the market cost of capital.[117]

The Commission welcomes stakeholder views on how the value of the benefit to the TNSP and/or consumer should be determined and treated by the AER in the revenue determination process and whether the NER should specify the mechanism or provide discretion to the AER to determine the mechanism?

116 For example through the provision of standard senior unsecured debt, subordinated debt, hybrid debt, equity or by way of a capital grant.

117 The AER currently sets a benchmark return that does not take into account the actual cost firms incur in raising finance.

5 INTRODUCING A TIMELY DELIVERY INCENTIVE IS AN EFFECTIVE WAY TO ENCOURAGE TNSPS TO MAKE TIMELY INVESTMENT DECISIONS

BOX 7: DRAFT POSITION

The Commission's draft position is that a new incentive mechanism may be a suitable response to manage investment decision and delivery risk associated with a TNSP's exclusive right with no corresponding obligation to invest. A Timely Delivery Incentive (TDI) could provide a mechanism to encourage a timely investment decision by a TNSP, as well as timely project planning and delivery. It may also better align costs and benefits to consumers with costs and benefits to TNSPs.

The Commission seeks stakeholder feedback to inform whether a TDI is proportionate and/or necessary, and to inform high-level design principles. Detailed design considerations will be put forward if a mechanism is considered a proportionate response to the problem.

The Commission's draft position is that:

- the exclusive right with no corresponding obligation to invest imposes a risk that strategic projects may not proceed in a timely manner and the benefits to customers may not be realised
- recommendations in other workstreams of this Review and existing jurisdictional levers will go some way to managing the uncertainty and risks that may lead to the exercise of the exclusive right and delays in investment
- a national power to direct is not recommended and introducing a national contestability regime solely to address the exclusive right is not a proportionate or practically implementable solution
- an incentive mechanism may be a proportionate and rapidly implementable response to incentivise TNSPs to plan, make investment decisions and deliver projects, in a timely manner, in accordance with the timing of benefits identified to consumers in the planning of major transmission projects.

The Commission seeks stakeholder feedback on this draft position.

This chapter sets out:

- why the exclusive right to invest with no obligation presents risks of late or non-delivery of major transmission assets
- how complementary recommendations in other workstreams of the Review/existing jurisdictional levers go some way to managing the uncertainty and risk that may lead to delays in TSNP's decision to invest

- the potential responses considered by the Commission to manage the exclusive right and limit delays in investment, including:
    - introducing a power to direct
    - contestability
    - creating a new incentive mechanism
- some of the possible features of a TDI that the Commission is interested in stakeholders' views on should such a mechanism be considered appropriate.

5.1 The exclusive right to invest with no obligation to deliver may impose a risk that strategic projects may not proceed in a timely manner and limit or delay the benefits to consumers

In the consultation paper, the risk of non-delivery of major transmission projects was raised as an issue in the current investment framework and considered a priority for the Review.

TNSPs have an exclusive right to build, own and operate transmission solutions in the NEM but no obligation to deliver transmission projects under the national regulatory framework, creating an environment of uncertainty around the delivery of future transmission projects.[118] This has emerged in the context of:

- the evolution of drivers of investment in network infrastructure (i.e. to match the need for, and rapid development of, renewable generation as compared to the long lead times associated with the historical build of thermal generation units), and
- the shift towards centralisation in planning to better coordinate and facilitate investment in transmission networks via AEMO's development of the ISP.

The convergence of these factors highlights that the framework does not appear to fully consider the risks of new major transmission projects being seriously delayed or halted as a result of actions taken or lack of investment decisions by TNSPs.

Under the national framework, there are currently no alternatives to ensure delivery of major transmission projects if TNSPs decide not to deliver projects and there are also no regulatory consequences for the TNSP should it choose to delay or not invest in a major transmission project.

The implication of this is that major strategic projects that offer net market benefits may not proceed in a timely way, even where the revenue and pricing principles are met for the TNSP as a whole, because of a misalignment between the long-term interests of consumers, and the commercial considerations of investors.

Stakeholders had varying views on whether the exclusive right presented a risk to the delivery of projects and what may be an appropriate means for TNSP's to manage risk as part of investing in a major project. Views expressed included:

118 The NEL and NER do not expressly provide that the primary TNSP (PTNSP) has the exclusive right to implement major transmission projects in its region. There are several examples of transmission projects in the NEM that have been undertaken by a person other than the PTNSP, such as BassLink, MurrayLink, DirectLink and the proposed CopperString 2.0 project. However, there is currently no regulatory process to facilitate the contestable procurement of transmission projects, and the proponent of a contestable project would face considerable regulatory uncertainty.

- TNSPs are obliged to invest for compliance and service standard reasons, and for projects not driven by those reasons there is no reason that a TNSP would not proceed with a project if it were commercially viable and in consumers interests.[119]
- allocating external risk differently, for example, by allowing cost pass-through and removing the ex-post review or setting the rate of return (ROR) at a higher level.[120]
- the existing ability for jurisdictions to impose obligations on TNSPs, such as obligations to undertake specific investments, already exists in some jurisdictions' legislation including NSW and Victoria and is an adequate backstop.[121]

In light of stakeholder feedback, the Commission considers that there are several reasons why a TNSP might choose not to invest in a particular project or delay investment, including:

- <u>Project portfolio</u>: under the NEL revenue and pricing principles a network service provider should be provided with a reasonable opportunity to recover at least the efficient costs that the operator incurs. However, the revenue and pricing principles are cast in terms of the TNSP, not in terms of individual projects.
  - Some projects may be commercially attractive, and some may be commercially unattractive for the TNSP. For example, a project may be less commercially attractive based on the assumed risk that costs may escalate
  - All else being equal a TNSP, in the absence of additional incentives, may pursue only those projects that are commercially attractive.
- <u>Interest rate cycle:</u> It may be attractive to tilt investments towards periods where interest rates are below the trailing average used in setting the WACC, or to use the TNSP's investment profile to commercially optimise other credit metrics such as free cash flow
- <u>Variability of cash flows</u> – Efficient costs are recovered over the life of an asset, but not necessarily evenly. During construction and early in the life of an asset, cash flows may be less attractive. TNSPs may seek support in the early years, even where cash flows are forecast to become attractive later in an asset's life.
- <u>Investor specific:</u> Different cash flow profiles may suit different investors. Superannuation funds for example may prefer capital growth now and cash later, while a listed or wholly owned company may prefer regular dividends. TNSP owners may also face short-term cash constraints, which may impact on their willingness to invest in a timely manner.

It is important for consumers that TNSPs make their investment decisions, commit to projects and deliver projects in a timely manner regardless of the above issues. It is also important that, subject to meeting the revenue and pricing principles, consumers do not pay a surplus.

119 TasNetworks, submission to the consultation paper, pp.6-7.
120 Submissions to the consultation paper: ENA, p. 4; TasNetworks, pp.6-7.
121 ENA, submission to the consultation paper, p.22.

5.2 Recommendations in other workstreams of this review and existing jurisdictional levers go some way to managing risk and uncertainties that may delay TNSPs' investment decisions

Several workstreams under Stage 2 and Stage 3 of the Review consider changes to the framework in ways that are intended to help TNSPs manage the uncertainty and risk that may lead to delays in their decision to invest.

These include the:

- Stage 2 draft recommendation to allow the AER flexibility in setting price controls to vary TNSPs' cash flows to address any possible future financeability concerns. Introducing this flexibility in the framework should provide more confidence for investors while providing protections for consumers.[122]
- Stage 2 draft recommendations to clarify the definition and cost recovery pathways for early works. Clarity here is important to manage uncertainty in investments by helping to identify key project risks early in the planning process.[123]
- Stage 3 draft recommendations to manage increased cost risk and/or uncertainty in the ex-ante framework through examining the potential merits of a separate, targeted ex-post review process by the AER, and whether there are circumstances in which it is appropriate to allow the CPA process for a large transmission project to be split into more than two stages.[124]

Collectively these proposed changes should clarify key sources of uncertainty within the existing framework, as identified by stakeholders, and provide additional ways to support TNSP's in identifying and managing risks associated with major projects. A reduced level of uncertainty and a greater understanding of the risks involved with major projects should provide confidence for TNSPs when making investment decisions.

In addition, several existing jurisdictional arrangements provide powers to direct investment in certain circumstances. Both NSW and Victoria have state-based powers to direct investment,[125] while state ownership arrangements in Queensland and Tasmania of transmission businesses allow for more direct control of the investment decision-making processes. In contrast, in South Australia, there is currently no existing arrangement for a power to direct TNSPs in the way that the other jurisdictions could require a TNSP to undertake new network or transmission infrastructure projects.

Further, contestability arrangements in both NSW and the existing and proposed arrangement in Victoria provide a regulatory process to facilitate the contestable procurement of

122 AEMC, Transmission Planning and Investment Review, Stage 2 draft report, pp.9-20.

123 Ibid, pp.35-45.

124 See Chapter 2.

125 In NSW, the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act) gives power to the NSW Minister to direct the delivery of certain transmission projects. In Victoria, the *National Electricity (Victoria) Amendment Act 2020* gives the Minister the power to order the carrying out certain transmission projects.

transmission projects.[126] The ability for major projects to be undertaken by parties other than the incumbent may reduce uncertainty in circumstances where a TNSP may delay or choose not to invest in a particular project.

5.3 A national power to direct is not recommended and introducing a national contestability regime solely to address the exclusive right is not a proportionate response

The Commission has considered the suitability of introducing a national power to direct and/or contestable arrangements to manage the issue of exclusive right and limit delays in investment. Neither of these options is considered a suitable or proportionate response to the issues they seek to solve on a standalone basis. This section sets out the rationale for this assessment.

5.3.1 A national power to direct is not recommended due to complexity of implementation and lack of proportionality

The Commission is of the view that establishing national power to direct arrangements is not appropriate or proportionate on the basis that:

- the majority of jurisdictions already have legislated or implicit powers to direct under existing jurisdictional arrangements,[127] and
- the introduction of a power to direct in the national framework would have significant implementation issues.

As outlined in the previous section, existing jurisdictional arrangements to direct investment exist in NSW and Victoria whereby a TNSP can be directed to deliver certain transmission projects as an obligation as part of a Ministerial Order or state licensing condition. Although there is no explicit power to direct in Queensland or Tasmania, the state ownership of transmission businesses allows for more direct control of the investment decision-making processes.

In addition, establishing a national power to direct would present several implementation issues, including that

managing interactions between a national power to direct instrument and jurisdictional arrangements (for example, managing non-compliance may be related to the transmission licence, which is a jurisdictional licence (potential to cancel the licence, step in rights, cure periods etc)) may present coordination complications.

Given the existing arrangements in most jurisdictions and implementation complexities associated with introducing a national power to direct, the Commission's draft position is to

126 In NSW, new arrangements are currently being implemented for REZ network infrastructure projects and priority transmission infrastructure projects under the *Electricity Infrastructure Investment Act 2020 (NSW)*. In Victoria, existing arrangements are based on AEMO's current declared network functions in an adoptive jurisdiction under the NEL and NER. In addition, the Department of Environment, Land, Water and Planning's proposed new Victorian Transmission Investment Framework is currently under consultation in Victoria.

127 The Commission considers Queensland and Tasmania to have implicit power to direct as incumbent TNSPs with a majority market share in these jurisdictions are state-owned enterprises.

not recommend the introduction of a 'power to direct' in the national regulatory framework to address the risk of non-delivery.

5.3.2 National contestability is not a proportionate solution to the exclusive right issue as a standalone response

The Commission does not consider the option of implementing national contestable arrangements to be a proportionate response to address the exclusive right. However, contestability is being considered more broadly in a standalone workstream, to assess whether it could be a more efficient alternative to the delivery of major transmission projects by monopoly TNSPs under the existing ex-ante incentive based regulatory framework. In this separate workstream, contestability is being examined as a potential solution to multiple issues that are being looked at across the Review.[128]

5.4 The Commission is seeking feedback on whether introducing a timely delivery incentive (TDI) is a proportionate and effective way to encourage timely investment decisions

Existing incentives such as the Capital Expenditure Sharing Scheme (CESS) and the Service Target Performance Incentive Scheme (STPIS) emphasise the efficiency of investment while meeting the required service level, or the reduction of costs for an agreed service level, rather than committing to and developing assets on time. Changes to these existing incentives to encourage timely investment decisions by TNSPs was raised by some stakeholders.[129] The Commission considers these incentive arrangements are not well suited to address the risk of delayed investment decisions and/or late delivery of projects, however, we consider an incentive to encourage a timely investment decision may be a credible option but needs further consideration.

The output delivery incentives included in Ofgem's latest network price control may provide a useful starting point when considering what specifications could apply to a timely delivery incentive in the NER (see Box 8).

As a starting point, the Commission considers that a TDI could impose a financial incentive on a TNSP to make a financial investment decision and deliver a project in a timely manner. This could be achieved by establishing milestone dates for projects and providing incentives for a TNSP to meet those milestones, or could simply be by providing one incentive around the final delivery date. At present, consumers bear all the consequences of late project delivery, even though TNSPs have more control over the timely delivery of projects. A new incentive could see TNSPs sharing in the benefits to consumers if projects are delivered early and sharing in the costs to consumers if projects are delivered late. These benefits and costs could include the impact on wholesale energy prices from continuing transmission constraints, and the value of unserved energy. This incentive mechanism could address delays in investment decisions and the timely delivery of large transmission projects and

128 An options paper exploring contestable models for further consultation was published by the Commission on 7 July 2022.

129 Submissions to the consultation paper: EnergyAustralia, pp. 2-10; ATCO, p. 4.

provide confidence that the regulatory framework can facilitate investment in important transmission projects.

We welcome stakeholder views on whether a new incentive mechanism is considered a proportionate and effective response to manage delays in the decision to invest and in the delivery of a project.

BOX 8: OFGEM'S PROJECT DELIVERY INCENTIVES

Ofgem's 2021-26 network price controls (RIIO-2) included a financial output delivery incentive (ODI) framework. The Large Project Delivery (LPD) output forms part of this framework. It will be applied to large projects (£100m +) on a project-by-project basis. Under the LPD, either re-profiling or the milestone mechanism will be applied to network companies.

Re-profiling involves changes to a network company's allowances to reflect project delays. This mechanism prevents a network company from benefitting from delayed expenditure.

Milestone-based approach involves setting project allowances based on the delivery of specific and agreed upon milestones. Allowances are only granted once a milestone had been delivered.

A **Project Delay Charge (PDC)** may also be applied to reduce consumer detriment caused by a delay. The PDC is also part of the LDP framework and penalises network companies for each day that a project is delivered late. The funds collected from the project delay charge would then be used to compensate consumers for the late delivery of the project.

Threshold level and benchmark dates

Every project that qualifies for this incentive would be identified by the Electricity System Operator who also specifies the year when the project must be delivered.

Basis of the charge or reward and symmetry of design

Ofgem considers that:

- an incentive mechanism that rewards early delivery and penalises delay could align the interests of consumers and Transmission Operators (TOs).
- the size of the penalty or reward imposed on the TO should be set based on the size of an individual project and proportionate to the expected detriment or benefit caused from the later/earlier delivery deadline. This design allows TOs to prioritise projects with the biggest impacts to consumers.
- the financial parameters should also not create excessive financial risk for the TO. To this end, Ofgem suggests that a penalty and reward incentive be set at 50% of the estimated detriment or benefit. Additionally, penalties and rewards should be capped at 15% of the estimated value of the project.

Risk pass-through contracts

The TO would be aware of the financial parameters of the incentive at the early stages of the project. When engaging with potential suppliers, TOs would have certainty on the financial parameters of the incentive and time to put in place appropriate risk management measures. Ofgem considers that the incentive should target actions that TOs can reasonably take to expedite delivery. It should not penalise or reward a TO for delays or early delivery caused by factors beyond of their reasonable control.

The Commission is also seeking to gather stakeholders' initial views on the design of this mechanism in this draft report. Detailed design considerations will be put forward to stakeholders if a TDI is deemed to be a proportionate and effective response to the problem.

The Commission is interested in stakeholder views on possible features of a TDI, including:

- A threshold level for the application of the TDI
- Setting of a benchmark date
- Basis of the charge
- Symmetry of the TDI
- Application to TNSP decision to invest
- Risk pass-through contracts
- Implementation considerations

5.4.1 Threshold level

One option for the application of the TDI is for it to be used for major transmission projects with costs above a monetary threshold. The intent is to capture projects that impose large costs on consumers and have the potential to deliver significant consumer benefits. This option provides certainty to the market on which projects will be subject to this incentive.

An alternative option is to apply the TDI to projects identified as actionable projects under AEMO's ISP. These are projects for which work should commence at the earliest planned time.[130] AEMO identifies actionable projects by selecting candidates according to the AER's Cost Benefit Guidelines. This option provides confidence to the market that projects that have been identified to be progressed urgently will be delivered in a timely manner.

We welcome stakeholder views on whether a TDI should exclusively apply to large projects based on a threshold, on whether a TDI should exclusively apply to actionable ISP projects, or if there is an alternative threshold that should be considered?

5.4.2 Benchmark dates

TDI milestone delivery dates could potentially be proposed by a TNSP and set by the AER.

One option for setting a delivery date is to use the identified dates in the ISP. The ISP identifies actionable and future transmission projects that are needed to efficiently deliver

130 AEMO, 2022 Integrated System Plan ISP, p. 12.

firmed renewable energy to consumers and identifies dates by which these projects should be delivered.[131]

Benchmarking delivery dates based on the ISP provides cohesiveness between the projected optimal timing identified to deliver benefits to consumers with the actual delivery of a large transmission project. A risk with this option is that benchmark dates for the delivery of a project may change in future iterations of ISP publications. Depending on the design features of the TDI, if the identified delivery date in future ISPs changes, the TDI delivery times will need to be adjusted to reflect this change. See section 5.4.4for more details.

Project timeline accuracy would be anticipated to improve over time, as TNSPs respond to incentives and communicate achievable timelines with AEMO and the AER.

We welcome stakeholder views on how benchmark dates should be set - whether benchmark dates should be based on the latest ISP and whether the AER could be given a role or discretion in shifting milestone delivery dates where a delay occurs due to reasons outside of a TNSPs control?

5.4.3 Basis of the charge or any benefit

The intent of the TDI is to align TNSP revenue incentives with the benefits that consumers receive from the timely delivery of large transmission projects. It follows that the consumer benefit or cost should inform the magnitude of the charge, however the cumulative penalty amount that a TNSP is charged for project delays could be capped, or the incentive could be profiled, to reduce a TNSP's revenue risk where a project encounters significant delays. A cap may differ from project to project. The level of the cap should be pre-determined by the AER. The corollary is that customers would bear a progressively higher proportion of the consequences of the delay.

We welcome stakeholder views on whether the cumulative amount of TDI should be capped and whether the same cap should apply for all projects or should vary on a project by project basis?

5.4.4 Symmetry design

A further consideration for the design on a potential TDI is the symmetry of the application of rewards and penalties. A symmetric design for the TDI would reward a TNSP if a large transmission project is delivered ahead of time and penalise the TNSP if delivery delays occur. This design feature acknowledges the added benefit of delivering a project ahead of time and rewards TNSPs for achieving project start up in advance of an agreed date.

The symmetric design also provides consistency with existing incentives in the regulatory framework where efficiency gains and losses are shared between consumers and network service providers.[132]

131 AEMO, 2022 Integrated System Plan ISP, p. 12 and p. 67.

132 Australian Energy Regulator, Review of incentive schemes for networks, Discussion paper, December 2021, p. 31.

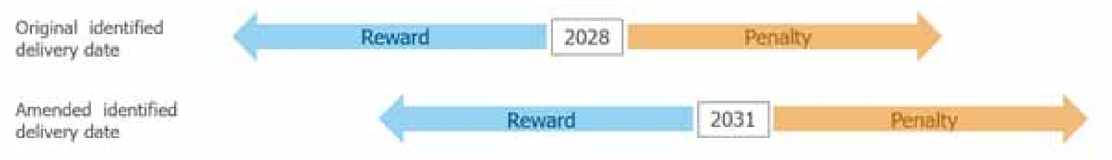
However, this design could prove complex to adjust if the delivery date for a project is amended. For example, if the identified delivery date for a project is brought forward significantly as shown in Figure 5.1 below, the application of the TDI would need to be amended. A delivery date that would have originally incurred a reward, may change to incur a penalty.

Figure 5.1: Bringing forward the delivery date

Source: AEMC

If the identified delivery date for a project is brought back significantly as shown in Figure 5.2 below, the application of the TDI would need to be adjusted. A delivery date that would have originally incurred a penalty, may change to incur a reward.

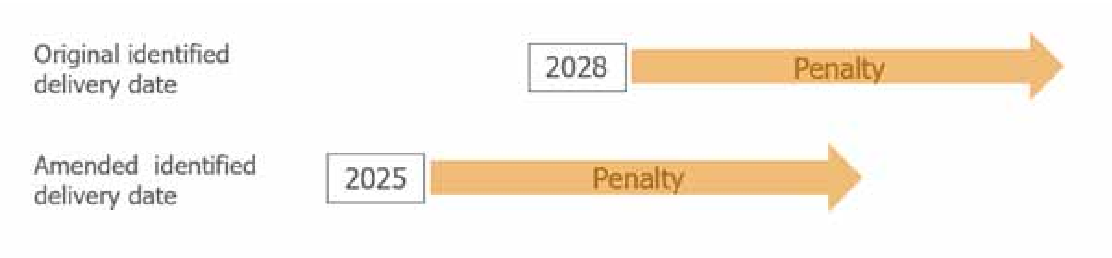
Figure 5.2: Pushing back the delivery date



Source: AEMC

Alternatively, an asymmetric design would solely penalise a TNSP for the late delivery of a project which allows for flexibility and simplicity if there is a change in the identified delivery date.[133] If a delivery date is brought forward, penalties could be reduced to acknowledge a revised earlier delivery.

Figure 5.3: Asymmetric design



Source: AEMC

133 If for example, a new iteration of the ISP identifies a different delivery date compared to previous iterations.

We welcome stakeholder views on whether the application of the TDI should be symmetrical or asymmetrical and/or whether the value of an incentive should vary over time based on expected benefits and disbenefits to consumers?

5.4.5 Application to TNSP decisions to invest

The incentive as proposed would apply to the project commissioning date, and potentially to milestone dates along the way. By extension, this means that TNSPs would need to plan and make final investment decisions early enough to meet those dates.

As outlined in section 5.1, there are a number of reasons that, in the absence of an incentive, a TNSP may choose not to make, or to delay, an investment decision. For instance, investors have linked final investment decisions on particular projects to t additional financial support. [134]

The Commission appreciates that uncertainty and risk could also impact a TNSP's ability to recover its efficient costs in accordance with the revenue and pricing principles, and section 5.2 summarises recommendations for managing uncertainty and risk, including financeablity concerns, where they arise.

The Commission is considering whether and how a TDI could be designed to incentivise a TNSP to make timely investment decisions (as well as to incentive timely delivery) to address the issue of exclusive right.

We welcome stakeholder views on whether applying the TDI to investment decisions is proportionate, and/or whether there are circumstances where a TNSP should not be subject to the TDI if a TNSP fails to make a decision to invest.

5.4.6 Risk pass-through contracts

The Commission is interested in stakeholder views on whether contractual arrangements that pass on costs are a concern. A TNSP could use contracts with a project's developers to pass through the risk of incurring a penalty if a project is delivered late or a milestone is not achieved. This provides the TNSP with a way to mitigate the risk of being penalised by passing on some of the risk to the party that has control over delays.

This approach is likely to lead to higher project costs due to higher contract costs. However, the Commission considers that the benefits of timely delivery are likely to outweigh any additional costs incurred. Existing mechanisms such as the CESS, should also incentivise appropriate risk allocation, so that costs are optimised.

We welcome stakeholder views on the role of risk pass through in contracts and whether existing arrangements can mitigate potential high project cost outcomes.

134 For example, Spark Infrastructure said that project EnergyConnect would have been unable to proceed without CEFC support. Spark Infrastructure ASX release Monday, 31 May 2021.

5.4.7 General design consideration

We welcome stakeholder views on the identified design considerations and any other design considerations that have not been included but stakeholders deem worthy of consideration.

5.4.8 Implementation considerations

For current incentives, the AER tends to develop the scheme after considering high-level principles in the rules.[135] A similar approach for the TDI would likely be appropriate.

We welcome stakeholders view on whether the principles-based approach used in the NER for other incentives would be appropriate for the TDI.

135 For example see for STPIS Rule 6A.7.4 of the NER.

6 MANAGING INCREASED COST RISK AND/OR UNCERTAINTY ASSOCIATED WITH MAJOR PROJECTS THROUGH RISK ALLOWANCES AND STAGING

BOX 9: KEY RECOMMENDATIONS

The Commission's draft recommendation is that the existing ex-ante incentive-based regulation framework generally remains appropriate to promote timely and efficient investment in major transmission projects. The Commission considers that recent developments under this framework – namely ex-ante risk allowances and the staged CPA process – allow TNSPs to appropriately manage risk and uncertainty around the costs of major projects. These processes should be given the opportunity to mature.

However, the Commission also considers that incremental change to two specific areas of the regulatory framework may warrant further consideration:

- The potential merits of a separate, targeted ex-post review process by the AER that examines expenditure associated with specific ISP projects.
- Whether there are circumstances in which it is appropriate to allow the CPA process for a large transmission project to be split into more than two stages, to further assist TNSPs with managing uncertainty in project delivery.

The Commission seeks stakeholder feedback on these two areas.

The Commission's analysis indicates that the level of risk and uncertainty around delivery costs for major transmission assets is higher relative to business-as-usual activities. Therefore, it is appropriate to review whether the regulatory framework is appropriate to:

- effectively promote efficient and prudent expenditure on major transmission projects, and
- allocate risks associated with major projects to the parties best placed to manage them.

The focus of this chapter is on the transmission revenue determination framework under Chapter 6A of the NER, as it applies to major transmission projects. The planning framework, including the RIT-T, is being considered as part of the economic assessment process workstream in stage 3.

This chapter sets out:

- the reasons why cost risk and cost uncertainty materially increase for major transmission projects relative to business-as-usual investments, and the risks this can present for consumers
- how risk and uncertainty are currently managed under the regulatory framework and why the Commission considers these arrangements to be broadly appropriate, and

- the Commission's views on incremental adjustments to the existing arrangements that could potentially improve the management of cost risk and uncertainty for major projects.

6.1 Major transmission projects present increased cost risk and uncertainty relative to business-as-usual investments

The Commission notes the potential for a higher risk of project cost overruns for large-scale capital projects, relative to more modest projects.[136] This is consistent with stakeholder submissions to the consultation paper, which reflected a general consensus that large scale greenfield transmission projects have greater cost risk and/or cost uncertainty relative to business-as-usual investments.

When examining the issues associated with the delivery of large transmission projects, it is important to distinguish between uncertainty and risk. A risk refers to situations where both the impact and probability of an event are generally understood and can be estimated. In contrast, uncertainty refers to events where either the impact and/or the probability of occurrence cannot be calculated.[137] In other words, risks refer to 'known unknowns', while uncertainties relate to 'unknown unknowns'. Sources of cost uncertainty and risk for major transmission projects are described below.

6.1.1 Sources of cost risk are typically associated with route selection and supply chain issues

Based on stakeholder feedback and our analysis, the Commission has identified that the increased cost risk associated with large scale transmission projects arises from:

- the line route being undetermined at the revenue determination (contingent project assessment) stage, and
- risk of supply chain issues.

Several network service providers noted the cost risk associated with undetermined line routes.[138] At the time when TNSPs forecast project expenditure for their regulatory proposals, there are generally outstanding activities still needed to finalise the line route. These activities include land and easement acquisition, stakeholder and community engagement related to land and environment,[139] and meeting obligations under state and federal laws. The TNSP must reach reasonable estimates of the expenditure required to complete these activities. Further, the outcomes of these activities may change the final transmission line route, which may in turn impact the original estimates for other cost categories. For example, a change to the line route may require additional materials for the transmission line structures and conductors, and more extensive earthworks.

136 PwC, Managing capital projects through controls, processes, and procedures, 2014, p. 4; KPMG, Managing risk in the Australian construction industry, May 2020; Grattan Institute, Cost overruns in transport infrastructure, October 2016; McKinsey & Company, A risk-management approach to a successful infrastructure project.

137 Toma, Chiriţă, and Şarpe, *Risk and Uncertainty,* Procedia Economics and Finance, Vol 3, 2012, pp. 975-980.

138 See submissions to *Transmission Planning and Investment Review* consultation paper: AusNet Services, p. 12; ENA, p. 2; TasNetworks, p. 7 and Transgrid, pp. 5 and 13.

139 A separate workstream is being progressed under the Review to promote obtaining social license for a project at the RIT-T stage, which may assist in reducing the associated cost risk at the revenue determination stage.

Stakeholders have also identified supply chain issues as another source of significant cost risk.[140] Due to the worldwide growth in renewable generation and emission reduction targets, competition is increasing for labour and materials. Combined with broader global supply chain pressures caused by COVID-19, this can result in material cost increases as the project is developed. The potential for supply chain cost risk is arguably heightened where there is a lengthy period of time between the initial estimate of project costs and commencing project delivery. This is likely to be the case for major transmission projects, due to the time needed to consult communities or navigate state land approval processes.

The costs associated with the transmission line route and supply chains risk are considered cost risks. This is because they are identifiable factors that have the potential to change the outturn costs from the forecasts, even though the extent of any change is unknown.

The degree of the risk of cost overruns is project specific. The unique characteristics of a project inform the degree of cost risk. For example, new larger ISP projects may have a much larger line construction component than stations. Other factors that may shape the cost risk associated with a project include where significant greenfield assets are required and the line route is subject to both community acceptance and local government approvals.

6.1.2 Source of cost uncertainty relates to a lack of comparable projects

TNSPs may make allowances to account for uncertainty when estimating costs for transmission projects. Generally, information asymmetry can present a challenge for the AER in assessing TNSPs' cost forecasts, but the Commission understands the AER has developed techniques to mitigate its effects and continues to improve them. The unprecedented scale and complexity of major transmission projects makes the assessment task more difficult, due to a lack of comparable project information that both the AER and the TNSP can rely on to accurately forecast efficient delivery costs. This is reflected in ENA's submission to the consultation paper, which considered that a large proportion of observed cost increases have stemmed from a general lack of understanding of the drivers of major project costs.[141]

The Commission notes that uncertainty relating to a lack of experience is expected to decline as more major projects are delivered. Over time, TNSPs and the AER will gain access to better data, tools and processes that can be used to more accurately identify and assess costs. This point was also raised by Ausnet Services.[142]

140 Infrastructure Australia, *Market Capacity for electricity generation and transmission projects* (October 2021) cited by EUAA, Shell Energy, MEU, AGL and Delta, Presentation to AEMC Roundtable on Material Cost Rule Change, slide 15; see also AEMO, Presentation to AEMC Roundtable on Material Cost Rule Change, slide 38.

141 ENA submission to *Transmission Planning and Investment Review* consultation paper, 30 September 2021.

142 AusNet Services submission to *Transmission Planning and Investment Review* consultation paper, 30 September 2021.

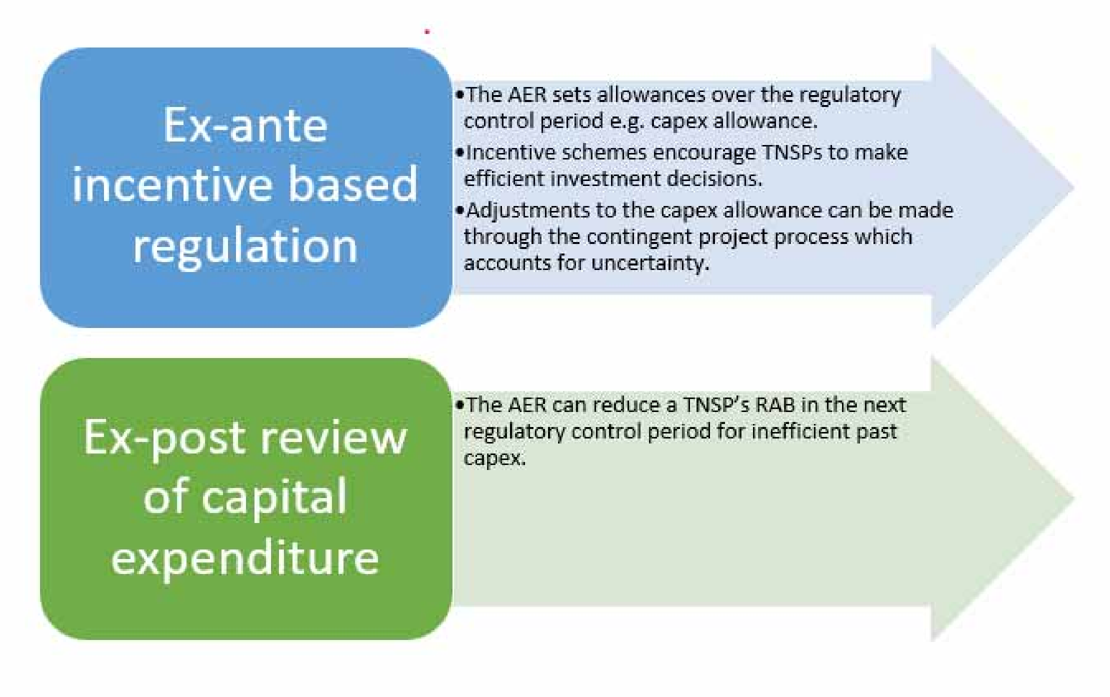
6.2 The ex-ante incentive-based regulatory framework is considered appropriate for major transmission projects

6.2.1 The existing regulatory framework provides a range of mechanisms to promote efficient management of cost risk and uncertainty that should be allowed to mature

Under the existing regulatory framework, the AER approves an ex-ante revenue allowance by scrutinising the prudency and efficiency of the forecast expenditure included in TNSPs' regulatory proposals. Once allowances are approved, the AER then relies on incentives, such as the CESS, to put downward pressure on a TNSP's actual expenditure. Under the incentive arrangements, TNSPs are rewarded or penalised based on their outturn performance against their revenue allowance.

Finally, if a TNSP's actual capex exceeds their approved allowance, the ex-post review process allows the AER to assess whether the overspend is prudent and efficient. The AER may exclude capex that does not meet this test from the RAB, under certain conditions.

Figure 6.1: Features of the economic regulatory framework



Source: AEMC.

Within this existing framework, the AER and TNSPs have worked to improve processes for estimating large project costs, including through the better estimation of project risks and the use of tender processes to estimate project-specific costs.[143] The AER's guidance note for the regulation of actionable ISP projects (the Guidance Note) set out two new approaches that assist TNSPs to appropriately manage cost risk and cost uncertainty: the use of risk allowances for major projects and the staged CPA process.

Firstly, the Guidance Note clarifies that the AER can accept a project risk allowance in a contingent project determination. The risk allowance is based on the AER's assessment of residual project risks[144] identified by the TNSP and the efficiency of the associated cost estimates (i.e., the cost impact if the risk eventuates, adjusted to reflect the likelihood of occurrence).[145] This approach to quantifying risk is a key difference between business-as-usual investments and major projects.

As cost overrun risk for business-as-usual projects can generally be managed by network operators, the AER does not typically consider that risk allowances will be incorporated into forecasts for these projects. However, for major greenfield projects a specific risk allowance allows the TNSP to better manage the risk of significant cost overruns that may occur. The inclusion of a risk allowance therefore provides appropriate incentives for a TNSP to proactively and transparently identify and manage these risks and can be calculated according to a methodology in which the AER has confidence.

Secondly, the Guidance Note sets out how TNSPs can stage the regulatory process for actionable ISP projects by lodging multiple CPAs with the AER.[146] The staging of CPAs is another tool for TNSPs to manage both cost risk and uncertainty associated with major transmission projects. Lodging an initial CPA allows prudent and efficient planning costs to be granted ex-ante approval before a CPA for the total project costs is ready for submission. This promotes comprehensive planning activities by providing TNSPs with certainty that they will recover the associated costs. Staging CPAs also provides flexibility for TNSPs to respond to changing market conditions or project risks as they arise. Overall, as each project stage progresses, it can reveal important project information that leads to more accurate expenditure forecasts and reduces the likelihood of cost overruns in delivery. Multiple stakeholders consider staging CPAs to be an effective approach for managing the increased cost risk and uncertainty associated with major projects.[147]

143 AER, Project EnergyConnect contingent project site, see under https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-%E2%80%93-project-energyconnect-contingent-project. See also Transgrid letter to the AER, regarding Humelink project – staging of the Contingent Project Application process, 14 September 2020; and Australian Energy Regulator responding letter to Transgrid, 13 October 2020.

144 Not all project risks need a separate allowance in the contingent project determination. Many project risks can be efficiently mitigated, transferred or avoided by the TNSP. Residual risks refers to those risks that cannot be efficiently mitigated, transferred or avoided. Section 2.6 of the Guidance Note sets out the AER's expectations on TNSPs in quantifying and justifying the residual project risks that comprise the proposed risk allowance for a major project; See AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p. 16.

145 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p. 18.

146 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, Section 3. This is based on the intended two-stage approach to the CPA process for HumeLink, as agreed between the AER and Transgrid in 2020.

147 Submissions to the *Transmission Planning and Investment Review* consultation paper, 30 September 2021: ENA, p. 2; Transgrid, p. 4, Society of St Vincent de Paul (SVDP) and the Council on the Ageing Queensland (COTAQ).

There is potential for the use of risk allowances and the staged CPA process to become more sophisticated over time as TNSPs and the AER gain experience with forecasting the costs of, and delivering, major transmission projects. For example, it is expected that both parties will become more familiar with the specific cost components of major projects that present forecasting challenges and with using the risk allowance and staged CPA processes to address these.

The following section explains why the Commission considers that the existing arrangements, including the approaches recently adopted by the AER, are largely appropriate and should be allowed to mature before considering additional changes.

6.2.2 The interaction of ex-ante incentives and ex-post review promotes efficient management of cost risk

The increased cost risk and/or uncertainty associated with major transmission projects increases the likelihood that outturn costs will depart significantly from the forecast costs used to set regulatory allowances. This increases the risk that consumers could pay more than necessary for transmission network investments as a result of:

- Overstated expenditure forecasts – which inefficiently increase costs to consumers in the short term as the TNSP receives a return on allowed capex during the regulatory period, and/or
- Inefficient actual expenditure in project delivery – which inefficiently increases costs to consumers in the long term, as actual capex is rolled into the TNSP's RAB and is recovered over the life of the asset (subject to incentive scheme rewards or penalties, and the outcome of the AER's ex-post review).

The scale of major transmission projects means that the CESS and ex-post review process provide a strong incentive for TNSPs to spend less than their approved capex allowance. However, to ensure that the regulatory framework only rewards and penalises genuine efficiencies and inefficiencies, it is important that expenditure forecasts are set at reasonable levels.

As noted above, the cost uncertainty associated with major projects incentivises TNSPs to over-forecast project costs to avoid cost overruns and an associated CESS penalty. While the incentive for TNSPs to minimise project costs remains, there is the potential for the incentive to be diluted as they are less likely to spend over that forecast amount and face a CESS penalty, relative to a scenario where their cost allowance reflects their best risk-adjusted cost estimate.

Disapplying the CESS for major projects would reduce the incentive for TNSPs to overstate expenditure forecasts for these projects. However, this would also remove the incentive for TNSPs to achieve efficiencies in delivery.

The Commission notes that the AER has commenced a review of the expenditure incentive schemes, including the CESS.[148] Submissions to the review's December 2021 discussion paper

148 AER, Review of incentive schemes for regulated networks, initiated 2 December 2021, see https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-incentive-schemes-for-regulated-networks.

closed in mid-March 2022. While the review of the CESS is largely focused on distribution network expenditure outcomes, it may provide insight into the success of the CESS more broadly. Accordingly, it may not be appropriate to consider changes to the application of the CESS to major projects until the findings of the review are published.

The Commission considers there are other elements of the regulatory framework that limit the likelihood of over-forecasting, counteracting concerns raised in relation to the CESS. These include:

- the introduction of ISP rules requiring TNSPs to assist in the identification and selection of a preferred option for priority projects, which supports improved forecasting for large projects
- project costs are capped by the amount submitted to AEMO for assessment as part of the feedback loop process
- TNSPs must convince the AER of the reasonableness and efficiency of identified costs as part of the contingent project application process
- the inclusion of a risk allowance provides appropriate incentives for a TNSP to proactively and transparently identify and manage these risks and mitigates the incentive for the TNSP to over-forecast in their cost estimates, and
- the staged CPA process encourages TNSPs to undertake efficient planning activities that help to identify project risks and allows time for previously unforeseen risks to arise.

6.2.3 The existing regulatory framework is generally appropriate to manage risk and uncertainty for major projects

On balance, the Commission considers that the ex-ante incentive-based regulatory framework appropriately encourages TNSPs to undertake prudent project planning and to efficiently manage actual delivery costs. Based on the analysis set out above, the Commission's draft recommendation is that the current arrangements should be given the opportunity to mature before considering additional changes.

The Commission has considered whether the expectations in the Guidance Note for TNSPs' preparation of CPAs should be made binding through an amendment to the NER. This would promote TNSPs providing robust CPAs in the first instance and mitigate the need for the AER to make follow up information requests during its assessment. However, the Commission considers that there is no need to make the guidance binding at this stage. TNSPs are incentivised to follow the expectations in the Guidance Note to convince the AER that their proposed expenditure is efficient and prudent. The Commission considers it is appropriate to ensure TNSPs retain flexibility to tailor their approach to preparing the CPA as is appropriate and efficient for the specific project.[149] Making the guidance binding via a rule change is a medium to long-term solution that may be appropriate in the future if there is evidence that TNSPs' information provision requires improvement.

149 In their submissions to the draft Guidance Note, ENA and TasNetworks raised concerns around the flexibility of the expectations in the Guidance Note. Specifically, they noted that the efficient level of activities in preparing a CPA will change depending on the size and complexity of the project, and so the Guidance Note should retain sufficient flexibility to allow for these activities to be tailored accordingly. In the final Guidance Note, the AER clarified that the expectations are principles-based to support such flexibility.

We welcome stakeholder views on the draft recommendation that the overarching regulatory framework is appropriate in the context of major projects and that the recently adopted approaches of providing risk allowances and staging CPAs should be given the opportunity to mature.

6.3 The Commission is seeking stakeholder input on two options for further consideration

Stakeholder submissions to the consultation paper indicated the view that while the existing ex-ante incentive-based regulatory framework is largely appropriate, incremental changes are required to improve the accuracy of forecast costs.[150] The Commission has considered a number of options for incremental improvement including two options that it is seeking stakeholder views on for further consideration. These are:

- enabling a targeted ex-post review process by the AER that examines specific ISP projects,[151] and
- whether there may be circumstances associated with a specific major transmission project that warrant allowing additional stages in the CPA process.

The Commission notes that further consideration of these options will require balancing the trade-offs involved between the benefits of minimising outturn costs, which are passed on to consumers, with providing more certainty for TNSPs (and the corresponding transfer of risk to consumers that this creates).

6.3.1 Consideration of the potential to tailor the ex-post review for ISP projects

The Commission is seeking stakeholder feedback on whether to consider further the potential for the AER to tailor its ex-post review to be project- or cost-specific, and in what circumstances this may be appropriate. At the end of a regulatory period, the AER is required to produce a statement on the efficiency and prudency of all capex that is to be rolled into the RAB. If total capex incurred by the TNSP over the regulatory period exceeds its total capex allowance, the AER may review whether to exclude certain types of capex from being included in the roll forward of the RAB. The AER can only exclude capex up to the amount of the overspend (i.e.total capex incurred less the total capex allowance). This process is known as an ex-post review.

The ex-post review is triggered by an overspend against the TNSP's total capex allowance for the previous regulatory control period. However, the AER has flexibility to focus on individual projects within that allowance, such as actionable ISP projects.[152] As detailed in the AER's Guidance Note, when considering actionable ISP projects in the ex-post review process it will have regard to whether the TNSP:

150 Submission to the consultation paper: ENA, pp. 9-10; TasNetworks, pp. 3-4; NSG, p. 4; ECA, pp. 4-5; Transgrid, p. 5.

151 Submission to the consultation paper: ENA, pp. 9 -11; Transgrid, p. 5.

152 The NER provide the AER with the flexibility to undertake ex-post reviews in the manner that it considers appropriate, given the circumstances of the NSP. See AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, November 2012, p. 145.

- Actively monitored the actionable ISP project and notified stakeholders and AEMO of any material cost overruns, and any other material changes in their cost forecasts or expectations for the project.
- Delivered the actionable ISP project in accordance with project governance structures, and project and risk management plans/processes demonstrated in its CPA. Efficient outturn project costs can differ from estimated costs, and some risks may eventuate that are unforeseen or are larger than expected or costed for at the time of the CPA.
- Controlled and minimised any cost overruns through project controls and other processes demonstrated in its CPA.

When conducting an ex-post review, the AER only takes into account information and analysis the TNSP could reasonably be expected to have considered at the time it incurred the relevant capex.[153] The AER's decision on whether to exclude capex from the RAB will be informed by any assessment it undertakes in the ex-post review, and other requirements of the NER.[154]

The ex-post review provides an important safeguard for consumers against clear cases of capex inefficiency. This safeguard is particularly important for major transmission projects where there is an increased risk of cost overruns, which could lead to higher network costs for consumers. The ex-post review operates in tandem with the ex-ante incentives of the economic regulatory framework to promote efficient project delivery and capex. It is designed to be a 'last resort' check and incentive to promote efficient and prudent capex.

However, in its submission to the consultation paper, Transgrid has suggested that "any ex-post review triggered by a major transmission project should be confined to that project."[155] It may be appropriate to consider applying the ex-post review in a manner that allows for a more targeted application for ISP projects. For example, the ex-post review could separately, in a proportionate manner, consider just the expenditure associated with a specific ISP project. Given the timing of this review, it is timely to consider a clarifying rule to allow a specific ex-post review of ISP project capex separate to the broader ex-post review. This would allow a targeted approach while ensuring the integrity of the AER's ex-post review statement on the broader RAB.

Would stakeholders support exploration of a separate, targeted ex-post review process that examines the expenditure associated with specific ISP projects, where the capex allowance for those projects is exceeded?

6.3.2 Consideration of the potential merit of additional CPA stages during project delivery

The Commission is seeking stakeholder feedback on whether there may be circumstances associated with a specific major transmission project that warrant the use of additional stages in the CPA process.

153 Clause S6A.2.2A(h)(2) of the NER.

154 Clause 6A.2.2A(a1) of the NER.

155 Transgrid submission to the consultation paper, p. 2.

The AER's Guidance Note proposes that staging CPAs occurs in two stages: the first for project design and planning activities, and the second for delivery of the project.[156] However, there may be project-specific circumstances that warrant separating the CPA process into additional stages to allow greater flexibility for TNSPs to respond to changes in both costs and benefits. In the right circumstances, additional CPA stages may better promote the outcomes of the ISP and address concerns around ensuring investments remain net beneficial in a continuously evolving sector. With each staged CPA, the updated total project costs (where they have increased) must be submitted through the feedback loop for AEMO to assess that the project remains on the optimal development path. Subsequent CPAs in a staged regulatory process are also subject to the other ISP trigger events. Increasing flexibility for TNSPs to respond to evolving information could also reduce the likelihood of cost overruns, improving certainty of cost recovery for TNSPs and thereby promoting investment in major transmission projects.

There are risks of additional CPA staging which should be balanced against the benefits. Creating additional stages could result in duplication of activities and/or scope creep including multiple feedback loop assessments. More stages would also likely increase the level of AER oversight in approving incremental project costs. This duplication and increase in oversight could increase costs and add time to the process, potentially leading to delays in project delivery. Further, more stages would increase the AER's involvement in approving incremental project costs, moving more towards a cost-of-service regulation approach,[157] and so consideration must be given to the impact on the effect of the incentives that exist for a TNSP under the regulatory framework. A further consideration is the impact on certainty for investors in new generation or storage assets, who need to know which transmission investments will proceed to plan their own projects.

The Commission is interested in stakeholder views on whether additional staging of CPAs to promote flexibility in project delivery could be appropriate. Are there project-specific circumstances that may warrant additional staging, noting the associated risks?

6.4 The Commission considered other options to manage cost risks and/or uncertainty which are not recommended

The Commission has considered three other options for incremental change, which are not recommended for further investigation. These are:

- adjusting the strength of or disapplying the CESS,[158]
- creating additional cost pass-through categories,[159] and
- additional regulatory monitoring of TNSP delivery expenditure.

156 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p. 28.

157 Under pure cost-of-service regulation, prices are set to cover the business's *actual* expenditure (plus a return).

158 NSG submission to the consultation paper, pp. 8-9.

159 Submission to the consultation paper: ENA, pp. 10 -11; Transgrid, p. 13; NSG, pp. 8-9.

6.4.1 Adjusting the strength of or disapplying the CESS for major transmission projects is not considered appropriate

The CESS provides an incentive for TNSPs to undertake efficient capital expenditure during the regulatory control period, to increase confidence that only efficient costs are being rolled into the RAB. Given the size and scale of ISP projects, the CESS provides an additional incentive for TNSPs to spend less than their approved capex allowance on large projects. Currently, the CESS provides the TNSP a 30 per cent reward where it underspends against its capex allowance over a regulatory period, or a 30 per cent penalty where it exceeds its approved capex allowance. In other words, 70 per cent of any overspend or underspend is passed onto consumers. The CESS also recognises that circumstances arise where capex may be deferred within the regulatory control period by a NSP, leading to the delay of project planning approvals. Where this occurs, the NSP will not receive the CESS benefit of what could otherwise be considered an underspend, when it is associated with a project delay.

Adjusting the existing 30:70 sharing ratio of the CESS alters the behavioural incentive for TNSPs and impacts the risk of overspends that is borne by consumers:

- Decreasing the ratio (e.g., 20:80) would dilute the incentive for the NSP to undertake efficient capex as it bears less cost in the event of an overspend of the capex allowance, with the additional forecast risk being transferred to consumers.
- Increasing the sharing ratio (e.g., 40:60) would increase the incentive for an NSP to overstate its capex forecast, especially late in the regulatory period, and reduce expenditure to achieve an underspend and receive a reward or avoid a penalty due to an overspend.

If the CESS was removed from major transmission projects, the incentive for TNSPs to minimise costs would be diluted and consumers would expect to bear more risk in the event of capex overspends as the costs would no longer be shared with the TSNP.

Given no major ISP projects have been delivered, resulting in the limited availability of expenditure data for analysis, it is not possible to determine whether consumers would benefit from changes to the CESS ratio applying to these major transmission projects. However, the Commission considers the current ratio of the CESS is likely to provide sufficient incentive to undertake efficient expenditure.

Further, the AER's ongoing review of the expenditure incentive schemes may provide further insights on the broader application of the CESS. Accordingly, the Commission does not recommend considering changes to the strength or application of the CESS for major projects until the findings of the Review are published.

6.4.2 Additional cost pass-through categories are not appropriate

The incentive-based regulatory framework encourages TNSPs to undertake prudent project planning. TNSPs are expected to proactively manage project risks, and identify risks that are uncontrollable and/or not economic to mitigate.[160] This includes establishing and maintaining a risk management framework for all project risks as well as risk monitoring, control and

160 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, pp. 17-18, 20.

reporting policies and processes.[161] Importantly, the revenue determination process is not intended to completely de-risk a project, as investment projects always contain project-specific risks and financing arrangements account for this.[162] As such, project risks should be held by the party best able to manage them.

Cost pass-throughs are a mechanism that allow TNSPs to manage costs associated with events that are beyond their reasonable control. To recover efficient costs through the cost pass through mechanism, costs must relate to certain classes of events and meet a materiality threshold.[163] The NER also permits TNSPs to propose a nominated cost pass-through event in their regulatory proposals.[164]

The Commission considers that the pass-through mechanism should, as a matter of principle, be reserved exclusively for costs that are outside of the TNSP's control. This is because there is no incentive on TNSPs to find efficiencies under a cost pass-through arrangement, as risk is entirely allocated to consumers.

The Commission does not consider that the identified sources of increased cost risk for major projects – the transmission line route and supply chain risk – are appropriate for inclusion as cost pass-through events. TNSPs are expected to be able to mitigate, to an extent, the costs associated with any changes to the transmission line route. For example, a TNSP may be able to adjust the route to avoid certain land parcels that are costly to acquire, or which contain protected flora and will therefore increase the environmental offset costs. Such a circumstance would require a trade-off to be made between environmental costs with a particular line route, and additional equipment costs that may be required to avoid or reduce these. Similarly, TNSPs are expected to proactively identify and manage supply chain risks. The unexpected delays and price increases associated with supply chain issues, including material shortages, are some of the most common risks that face construction projects. As with all other known project risks, a prudent business is expected to identify the risks within its supply chain and develop strategies to manage them.

The Commission therefore does not consider it appropriate to allow these costs to be directly passed through to consumers. Rather, the efficiency incentives under the existing regulatory framework should apply to these costs to encourage TNSPs to mitigate the extent of cost overruns that may arise in project delivery.

6.4.3 Additional regulatory monitoring of TNSPs' spending throughout project delivery is not recommended

As explained [**in section x**], under the existing regulatory framework, the AER relies on efficiency incentive schemes to put downward pressure on TNSPs' actual expenditure:

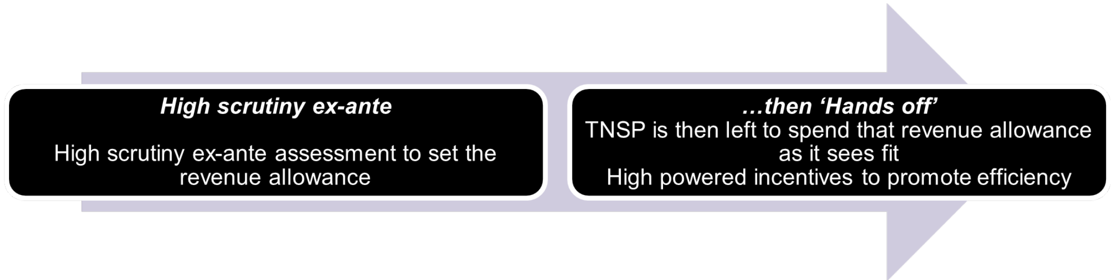
161 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p. 20.

162 AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p. 17.

163 Clause 6A.7.3 of the NER.

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

Figure 6.2: Impact of TNSPs' actual expenditure



Source: AEMC.

An alternative approach to achieving efficiencies in actual expenditure would be, for example, to require the AER to more closely monitor TNSPs' spending decisions.[165] Under such an approach, information could be provided to the AER on a periodic basis (such as quarterly) with the purpose of:

- keeping the AER aware of changes to factors that drive project costs as they arise; and thus
- providing the regulator with an improved ability to make decisions as to:
  - the abandonment or delay of a project or project stage; or
  - the application of an ex-post review of project costs.

In the absence or dilution of efficiency incentives, such an approach may be warranted. However, the Commission recommends retaining the existing incentives – namely, the CESS and ex-post review – for large transmission projects. Increasing the AER's involvement in the delivery of a TNSP's project would likely delay project timelines and compound the challenges arising for the AER from information asymmetry. Further, such an approach is likely to result in increased administration costs for the TNSP to prepare the periodic information disclosures and for the AER to assess the ongoing information.

Accordingly, the Commission does not recommend further consideration of this approach.

165 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020.

ABBREVIATIONS

AACE	Association for Advancement of Cost Engineering
ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
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
FBP	Forecasting Best Practice
FFO	Funds from operation
HVAC	high voltage alternating current
HVDC	high voltage direct current
IASR	Inputs, assumptions and scenarios report
IEA	International Energy Agency
IPCC	International Panel on Climate Change
ISP	Integrated System plan
LPD	Large Project Delivery
MAR	Maximum Allowed Revenue
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
NEVA	National Electricity Victoria Act
NPV	Net present value
NSP	Network service provider
NSW	New South Wales
NTNDP	National transmission network development plan
ODP	Optimal development path
ODI	Output delivery incentive
Opex	Operating expenditure
PACR	Project assessment conclusions report
PADR	Project assessment draft report
PDC	Project delay charge
PEC	Project EnergyConnect
PIAC	Public Interest Advocacy Centre
PSCR	Project specification consultation report
PTNSP	Primary transmission network service provider
PTRM	Post-tax revenue model
RAB	Regulated asset base
RCP	Representative Concentration Pathway
REZ	Renewable energy zone
RFM	Roll-forward model
ROR	Rate of return
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
STIPIS	Service Target Performance Incentive Scheme
TAPR	Transmission Annual Planning Report
TDI	Timely Delivery Incentive
TNSP	Transmission network service provider
TO	Transmission Operators
TUOS	Transmission use of system
VTIF	Victorian Transmission Investment Framework
WACC	Weighted average cost of capital

A ECONOMIC ASSESSMENT PROCESSES - LEARNINGS FROM OTHER JURISDICTIONS

A.1 Economic assessment processes from other jurisdictions

This appendix provides a summary of the economic assessment processes from other jurisdictions that the Commission has considered in developing the strawperson options.

A.1.1 Ofgem's Large Onshore Transmission Investment Reopener

The onshore transmission network in GB is currently planned, constructed, owned and managed by three regional monopoly electricity transmission owners (TOs). Ofgem's Large Onshore Transmission Investment Reopener (LOTI) reopener is a price control uncertainty mechanism that provides TOs with a route to apply for funding for large investments that were not included in the revenue allowance due to insufficient certainty regarding their need, scale and/or timing. In this sense, the LOTI process is similar to the RIT-T and CPA for actionable ISP projects in the NEM.

As shown in the figure below, the LOTI process involves four stages, designed to fit within the TOs approach to project delivery:[166]

- An **eligibility assessment**, confirming that the project meets certain criteria (principally, that the expected cost exceeds GBP100 million).
- An **Initial Needs Case,** submitted at least 12 months before the final statutory planning consultation. At this stage, Ofgem will review the technical and/or economic justification for the project, the options under consideration, and the justification for the preferred option.
- A **Final Needs Case,** submitted after the TO has secured all material planning consents.[167] At this stage, Ofgem confirms the needs case by checking that there have been no material changes in the technical and/or economic drivers used select the preferred option in the Initial Needs Case.
- A **Project Assessment Direction**, where Ofgem sets the efficient cost allowances that can be recovered from consumers for delivery of the project. At this stage, Ofgem also assesses the TO's proposed delivery plan, including detail on the technical design, delivery strategy and risk management approach. While Ofgem engages with TOs on a case-by-case basis to determine the timing of the Project Assessment, it typically requires that the TO has: confidence in its cost estimates;[168] received its final procurement offers from suppliers;[169] and can provide evidence of negotiation with suppliers.

166 Ofgem, *Large Onshore Transmission Investment (LOTI) Re-opener Guidance and Submissions Requirements Document*, March 2021.

167 For a number of LOTI projects, Ofgem has been open to receiving the Final Needs Case submission before the decision on planning consents in order to support timely delivery. However, in these cases Ofgem will still publish its decision after the planning consent decision, as that is critical to the design of the project. For example, see Ofgem, *Yorkshire GREEN – Consultation on the project's Initial Needs Case and initial thinking on its suitability for competition*, October 2021, p.30.

168 For the Project Assessment, Ofgem requires the TOs to specify the 'firmness' of cost estimates in line with a classification system determined by Ofgem. Ofgem, *Large Onshore Transmission Investment (LOTI) Re-opener Guidance and Submissions Requirements Document*, March 2021, p. 37.

169 The expectation is that negotiations would have reached the final stages, rather than a requirement for contracts to actually have

Figure A.1: Overview of the LOTI process

Source: AEMC.

The TOs costs to move through the LOTI process (i.e., to reach the start of construction) are funded through a pre-construction funding (PCF) allowance set at the time of the price control determination. The PCF allowance comes with associated price control deliverables. For example, if planning consent is never applied for and the Final Needs Case is not approved by Ofgem, the TO can only recover 20% of the allowance. In addition, there is a PCF re-opener so that TOs can request additional funding if a previously unanticipated need arises. The re-opener can be requested at the time of the Initial Needs Case.

LOTI projects are informed by the annual Network Options Assessment (NOA) conducted by the Electricity System Operator (ESO). While TOs are expected to consider future energy scenarios (FES) in their needs case – and Ofgem may consider the ESO's recommendations in its decision – the linkages are currently less formal compared to the ISP and RIT-T for actionable projects. However, Ofgem has recently published a proposal to introduce an approach close to the ISP model.[170] Under the proposed approach, the system operator would lead a 2-3 year centralised strategic network planning process, with responsibility for selecting the strategic option to meet system needs. Ofgem expects that the LOTI re-opener would continue to apply as described above, with the difference being that new projects would come forward via the CNSP rather than being proposed by TOs.

In August 2022, Ofgem published a consultation on potential changes to the LOTI process for selected strategic projects that are needed by 2030 to meet the UK government's decarbonisation targets.[171] While Ofgem does not consider that the current LOTI arrangements cause delays to transmission projects, they consider TOs may not be able to expedite delivery of the strategic projects without changes. Ofgem is therefore proposing to:

- Provide early certainty on project approval, by accepting the need for certain strategic projects without an Initial and Final Needs Case.
- Providing early certainty on funding approval by splitting the Project Assessment into two stages: early construction funding in advance of planning permission; full funding after final planning permission.
- Providing targeted, programmatic exemptions from onshore competition.

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been signed.

170 Ofgem, *Consultation on the initial findings of our Electricity Transmission Network Planning Review*, November 2021. Ofgem, *Consultation on our minded-to decision and draft impact assessment on the initial findings of the Electricity Transmission Network Planning Review*, July 2022.

171 Ofgem, *Accelerating onshore electricity transmission investment*, August 2022.

- Using strong financial incentives (including penalties for delivery delay) and licence conditions to protect consumers and hold TOs accountable for delivery.

Ofgem plans to take a relatively cautious approach to implementing these reforms, stating that they will only apply the new framework where there are clear and binding commitments from the TOs to deliver on time.

A.1.2 The NSW Electricity Infrastructure roadmap

The NSW *Electricity Infrastructure Investment Act 2020* (NSW EII Act) established a new framework for the development of REZ network infrastructure projects.

Under this model, a Consumer Trustee (AEMO Services) is responsible for preparing an Infrastructure Investment Objectives Report (IIOR) every 2 years, including a 20-year Development Pathway for generation, storage and firming infrastructure and a 10-year tender plan for the competitive tender of Long-Term Energy Service Agreements (LTESAs). The IIOR also sets out network projects that are required to give effect to the Development Pathway, informed by a network investment strategy prepared by the Infrastructure Planner (EnergyCo), with input from AEMO and the jurisdictional planning body (Transgrid).

The Infrastructure Planner then assesses and makes recommendations to the Consumer Trustee on the network investments that are required to deliver a network infrastructure project. The regulations state that to *"avoid delays that can arise under the national framework, certain preparatory activities and early development works (including planning studies and community consultation) may be undertaken by the Infrastructure Planner prior to the authorisation of a network project."*[172] These activities are intended to further scope a project and gain the social license for the project through community engagement. Once a Network Operator is authorised or directed to undertake the network infrastructure project, the Network Operator will be required to reimburse the Infrastructure Planner for its costs in undertaking such activities and works. Amounts for those costs will be included in the revenue determination, and recovered through transmission use of service charges.

The Consumer Trustee will decide whether to authorise the network investments recommended by the Infrastructure planner.[173] The authorisation decision will be based on a cost-benefit analysis, where the benefits are those that accrue to NSW electricity customers. Benefits will be assessed relative to a counterfactual scenario where the network project is not developed.

The AER has a role in making a determination on the amounts to be paid to a Network Operator for carrying out a network infrastructure project, through a Transmission Efficiency Test (TET). Where the AER is satisfied that the competitive procurement process is likely to have produced an outcome that reflects prudent, efficient and reasonable costs and is otherwise consistent with the EII Act, its determination may adopt the relevant amounts payable to the Network Operator as agreed between the Infrastructure Planner and Network

172 *NSW Office of Energy and Climate Change, Regulatory framework for the Transmission Efficiency Test and Regulator's determinations for network infrastructure projects – Policy paper, April 2022, p. 10.*

173 This is the process for REZ network infrastructure projects (RNIPs). The process is different for priority transmission infrastructure projects (PTIPs) that are directed by the Minister.

Operator through that competitive process. There are important differences between the NER Chapter 6A framework and the competitive procurement process contained in the EII framework:

- The focus for the AER in the EII framework is on reviewing the potential of the competitive procurement process to produce an outcome that reflects prudent, efficient and reasonable costs rather than a detailed review of the components of a proposed revenue allowance.
- Where the AER is satisfied with the procurement process, the AER's determinations in the EII framework will reflect the amounts payable in the Project Deed that has been negotiated and agreed to by the Infrastructure Planner and the successful proponent, until the end of the concession period.
- Network Operators in the EII framework are paid by the Scheme Financial Vehicle using monies collected through a Jurisdictional Scheme Obligation on the NSW distributors rather than through the NER pricing arrangements.

When the Consumer Trustee authorises an investment, it also sets a 'maximum capital amount', which places a ceiling on the amount that the AER can approve it its determination of efficient capital costs under the Transmission Efficiency Test. The maximum capital amount will reflect the capital cost above which the network project would no longer deliver benefits to consumers, relative to the counterfactual without the project. The draft Network Authorisation Guidelines issued by the NSW Government note that the benefits considered will include those that are materially different between the proposed project and the counterfactual scenario. Further, where benefits require resource-intensive or time-consuming analysis to robustly quantify, these would only be included if the effort required is proportional to the likely impact on the maximum capital amount.

A.1.3 The Victorian transmission investment framework

The Victorian Government has released a consultation paper setting out its proposed VTIF and a new Victorian Transmission Planning Objective. A final report incorporating stakeholder feedback is expected in late 2022.[174] The key driver behind the proposal is to create an integrated and targeted approach to electricity transmission and REZ developments focusing on early, inclusive and ongoing community engagement and integrating land use and environmental impacts early in the transmission planning process.

The VTIF planning process has seven stages with the majority undertaken by VicGrid.[175]

- Stage 1: Development of future electricity system scenarios over a 25 year planning horizon, focused on Victoria and Victorian energy policies in consultation with stakeholders including AEMO.
- Stage 2: Development of REZ development pathways that will describe how new transmission capacity could be allocated across REZs, the most acceptable corridors

174 Department of Land, Water and Planning, *Victorian Transmission Investment Framework – Preliminary Design – Consultation Paper*, July 2022.

175 The consultation proposes that VicGrid be established as separate body or independent authority, governed by legislation enacted by the Victorian Government.

where that capacity could be situated, and the technical requirements needed to meet security and reliability standards. This stage is expected to harness opportunities for early engagement with local communities and stakeholders.

- Stage 3: Establishing optimal REZ pathway that would set out the preferred amount, location and timing for transmission investment over 25 years. It would be consulted on with diverse stakeholders including engagements with impacted local communities. Priority REZs would be declared where projects would be developed within the next 10 years. Declaring a REZ would include specifying its intended transmission hosting capacity, access arrangements, geographic boundary and indicative development timing.
- Stage 4: Identifying and assessing transmission projects to be delivered. A new investment test for REZ transmission projects is proposed, the Victorian Network Investment Test (VNIT). VNIT could be applied either as a least net cost test or a maximum net benefits test. In cases where a project is necessary to deliver the level of capacity required by the optimal REZ path, the least net cost form would apply. In cases where the project is not needed for this but may produce operational and economic benefits, the maximum net benefits form (similar to the RIT-T) would be used. This may mean that the 'critical path' would be delivered under a least net cost test, and other projects under the maximum net benefits test.
- Stage 5: Approvals. The project proponent, in partnership with VicGrid, would commence heritage, environmental and land use planning assessments as required ahead of project delivery. As part of this, the project proponent would propose a preferred route, within the REZ location previously identified in the optimal REZ pathway. It is noted that the project's land approvals applications would be expected to be significantly informed by early work to integrate land use, environmental, Traditional Owner and community values into the transmission planning process. VicGrid would maintain a role in planning approvals such as the Environmental Effects Statement (EES), to ensure continuity in community engagement throughout the development of Victoria's REZs.
- Stage 6 & 7: Delivery and Review. The recommended projects will then be constructed and commissioned by the successful TNSP. The proposed framework includes an annual review of the optimal REZ pathway and proposed projects, to check if underlying assumptions or costs have changed, or if any projects should be brought forward or delayed.

A.1.4 Pennsylvania-New Jersey-Maryland Interconnection's (PJM) Regional Transmission Expansion Plan (RTEP)

Through the RTEP process, PJM identifies system upgrades and enhances to provide for the operational, economic and reliability requirements of PJM customers. The identification of RTEP projects to meet reliability and economic needs is performed sequentially:

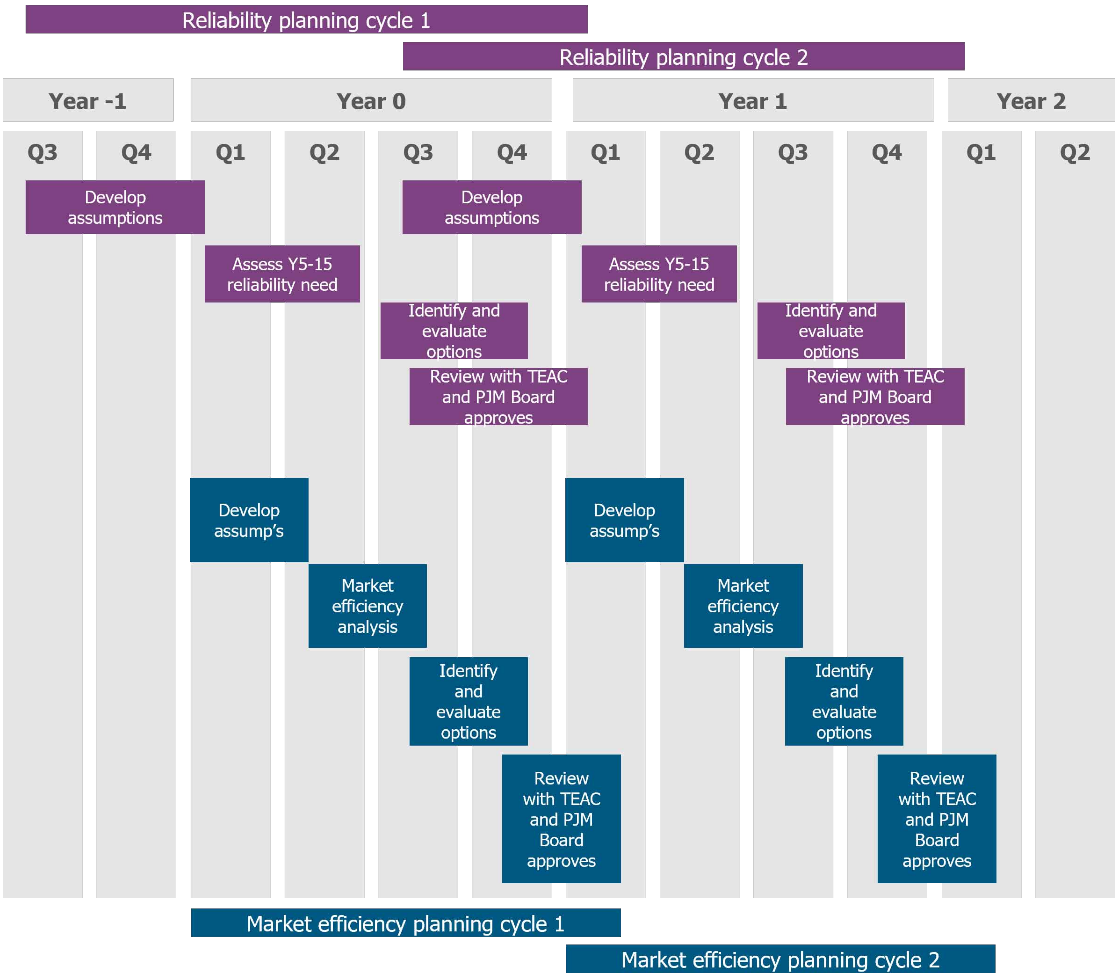
- PJM first identifies transmission constraints and other reliability concerns over a 15-year horizon. Transmission upgrades to mitigate identified needs are then examined for their feasibility, impact and costs, culminating in one plan for the entire PJM footprint.

- Once investments to support reliability are identified, PJM will then consider investments to support economic needs (e.g. to alleviate congestion cost or generate wholesale market benefits).

While the RTEP is published annually, it is developed through longer overlapping cycles of planning. For example, PJM and PJM Transmission Owners' processes for reliability projects occur through an 18-month planning cycle which begins in September of the previous calendar year and extends through a full calendar year to the February of the next calendar year (see figure below). This sits alongside a separate 24-month cycle for considering projects that are required to deliver economic benefits. This means that planning assumptions and modelling are refreshed at different stages, allowing for confirmation the RTEP projects are still needed. PJM has in the past cancelled projects that were previously included in the RTEP and assigned to designated entities (e.g., the Potomac-Appalachian Transmission Highline in 2012).

The RTEP process includes ongoing engagement with stakeholders through a Transmission Expansion Advisory Committee (TEAC) and consideration of more localised issues through Subregional RTEP Committees. PJM's website indicates that there are around 13 TEAC meetings each year.

Figure A.2: Simplified representation of PJM's rolling RTEP cycle



Source: AEMC.

Transmission investments that are approved by the PJM Board are developed by the designated entity. PJM staff will notify the entity of the required in-service date and the date by which all necessary state approvals should be obtained. Cost recovery for new investments is dealt with through that entity's rate case approved by Federal Energy Regulatory Commission (FERC).

A.2 Strawperson options against the assessment criteria

This appendix sets out the Commission's initial high-level qualitative assessment of the strawperson options and counterfactual against the assessment criteria for this Review.

Table A.1: High-level assessment of the counterfactual and strawpeople

MODEL	ADVANTAGES	DISADVANTAGES
Assessment Criteria: Outcomes for consumers *Assess whether the regulatory arrangements promote and appropriately balance the timely and efficient delivery of transmission projects.*		
Counterfactual	• Streamlining of processes was introduced through the 2020 ISP reforms and will be further addressed through the proposed changes to the feedback loop; these elements of the process may require time to mature. • Flexibility to pursue actionable ISP projects at different speeds is provided through staging, which can be proposed by AEMO in the ISP or the TNSP through the RIT. Staged CPAs allow efficient expenditure to implement the preferred solution to be funded ahead of the full CPA application. • Requirements for TNSPs to undertake preparatory activities to inform the ISP may provide for appropriate early investigation of social licence issues, with clarification through guidelines.	• The current arrangements may not be sufficient to incentivise TNSPs to undertake an efficient level of preparatory activities or make full use of the flexibility in the staged CPA process; these arrangements are still maturing and there may be uncertainty around their application in practice. • Currently, there are no defined links between the economic assessment process and the jurisdictional planning and approval processes. This may create a lack of transparency around how the two processes are interacting (or should interact).

MODEL	ADVANTAGES	DISADVANTAGES
Strawperson 1	• Aims to introduce a more defined link between economic, planning and approval processes, to provide clarity around how TNSPs should integrate activities across these areas. • Aims to improve timeliness of project delivery by requiring earlier investigation of social licence issues that could impede timely progression of projects through jurisdictional planning and approval processes.	• The current specification of strawperson 1– which envisages that some degree of early investigation into social licence issues would be required for all actionable ISP projects – may introduce a level of rigidity. This may not be necessary or appropriate for all actionable projects. • Further consideration is needed in relation to how, and how prescriptively, the appropriate level of investigation is determined.
Strawperson 2	This option recognises that it may be impractical for TNSPs to make substantive use of ISP benefits modelling in their RIT-T, given the pace at which the inputs, assumptions and scenarios may continue to change. A more timely progression of projects through the economic assessment process is therefore envisaged by centralising the benefits assessment in the ISP.	Further consideration is required in relation to the arrangements to support transparency and opportunities for stakeholder engagement under this model.
Strawperson 3	Similar to Strawperson 2, with the potential for additional streamlining of the process achieved through concentrating the assessment of costs and benefits through a centralised process and more frequent ISP updates.	A key challenge for this option is whether the ISP process can appropriately capture differences in the benefits provided by the more granular options that TNSPs identify.
Assessment criteria: Economic efficiency		

MODEL	ADVANTAGES	DISADVANTAGES
Assess whether the solution promotes efficient investment in, and use of, electricity services in the long term interest of consumers with regard to: efficient risk allocation; effective price signals/incentives; information provision/transparency; clear, consistent and predictable rules. Evaluates whether the solution provides service providers with a reasonable opportunity to recover at least their efficient costs.		
Counterfactual	Checks and balances of the efficiency of actionable ISP projects and the preferred option are provided at multiple stages, including: the ISP, the RIT-T, the feedback loop, the CPA, and the proposed reopening triggers.	Checks and balances of the efficiency of actionable ISP projects and the preferred option are provided at multiple stages, including: the ISP, the RIT-T, the feedback loop, the CPA, and the proposed reopening triggers.
Strawperson 1	Retains the checks and balances on efficient investment that exist in the current process.	Further consideration may be required in relation to how bringing the stage 1 CPA forward would interact with other parts of the regulatory framework, including incentive arrangements.
Strawperson 2 Strawperson 3	A single NEM-wide methodology for assessing net benefits may better promote a consistent approach across all projects.	A key challenge for these options is whether the ISP process can appropriately capture differences between the benefits provided by the more granular options that TNSPs identify, and consider all benefits relevant to selecting a preferred option.
Assessment criteria: 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		
Counterfactual	Lowest level of cost and complexity. Would require relatively straightforward rule changes	

MODEL	ADVANTAGES	DISADVANTAGES
	and/or modification of AER guidelines as described in the Stage 2 draft report.	
Strawperson 1	Moderate level of cost and complexity. Would likely require rule and guideline changes that impact multiple elements of the current economic assessment process.	
Strawperson 2		
Strawperson 3	Highest level of cost and complexity. Would likely require rule and guideline changes that impact multiple elements of the current economic assessment process. Requires substantial reconsideration of the ISP process and potentially the TAPR / joint planning processes.	
Assessment criteria: 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.		
Counterfactual	At this early stage of development, the Commission has not assessed whether any of the high-level strawperson options are more compatible with other changes that may eventuate. As consideration of alternative options progresses, the Commission will be mindful of consistency relation to broader policy developments.	
Strawperson 1		
Strawperson 2		
Strawperson 3		
Assessment criteria: Decarbonisation Considers whether market arrangements will enable the decarbonisation of the energy market.		
Counterfactual	The assessment for this factor is driven by the impact of the options on the timely delivery of actionable ISP projects that will facilitate decarbonisation. Refer to the 'outcomes for consumers' criterion.	
Strawperson 1		
Strawperson 2		
Strawperson 3		

B MODELLING OUTCOMES ARE EQUIVALENT UNDER A CARBON BUDGET OR VALUING EMISSIONS APPROACH

Chapter three explained that carbon budgets represent the total cumulative emissions that are permitted in a given scenario for the electricity sector – acting as a constraint on the modelling assessing transmission investments. It also explained that the constraint can influence the analysis by affecting the retirement of fossil-fuelled generation, selection of technologies to replace this generation, and/or out-of-merit-order dispatch.

This appendix introduces a single-hour dispatch market model to illustrate the effect that a carbon budget can have on financial and physical outcomes in electricity market models, and to demonstrate the modelling equivalence of a carbon budget and explicitly valuing emissions. However, the Commission notes that this example abstracts away from the complexities of ISP and RIT-T market modelling.

Specifically, the modelling underpinning the economic assessment process of major transmission investments is principally seeking to solve capacity expansion problems, that is, what, how much and what type of generation and transmission investment is needed to meet future demand. The single-hour dispatch model discussed in this appendix is only intended to demonstrate the effects of a carbon budget that equally apply to the more complex analysis undertaken for the ISP and RIT-T. Further, the value on emissions used in this example is illustrative only and does not represent the Commission's view of an appropriate value on emissions.

B.1 Carbon budgets can affect market modelling outcomes

Under a single-hour dispatch model, total system costs are equal to total dispatch costs. Absent a carbon budget, the objective of the market model is to minimise dispatch costs while ensuring energy demand is met. The generation capacity in the market model is summarised in Table B.1 and includes the:

- capacity of each generator in megawatt hours (MWh) for the dispatch period (in this case, one hour)
- short-run marginal cost (SRMC) of each generator, reflecting the cost of each MWh of generation
- emissions intensity of generation (EIOG) of each generator, reflecting the tonnes of CO_2 that are emitted per MWh of generation

Table B.1: **Generator characteristics for the single-hour dispatch market model**

GENERATOR	CAPACITY(MWH)	SRMC($/MWH)	EIOG(TONNES OF CO2/MWH)
Solar	50	0	0

GENERATOR	CAPACITY(MWH)	SRMC($/MWH)	EIOG(TONNES OF CO2/MWH)
Coal 1	30	30	1.50
Coal 2	20	40	1.50
Gas	50	90	0.50

Source: AMEC

To minimise total dispatch costs, the market model dispatches generators from lowest to highest SRMC until sufficient capacity has been dispatched to meet demand. Assuming demand of 120MWh for the dispatch period, the following dispatch profile would occur:

- the solar generator dispatches all of its capacity because it has the lowest SRMC
- the first coal generator dispatches all of its capacity because it has the second-lowest SRMC
- the second coal generator dispatches all of its capacity because it has the third-lowest SRMC
- the gas generator dispatches 20MWh of its capacity despite having the highest SRMC because it is required to ensure demand is met.

This dispatch profile leads to modelled dispatch costs of $3,500 with 85 tonnes of CO_2 emissions. These outcomes are summarised in Table B.2.

Table B.2: **Single-hour dispatch market model outcomes assuming no carbon budget**

GENERATOR	QUANTITY DIS-PATCHED(MWH)	COST OF DIS-PATCH($)	QUANTITY OF EMISSIONS(TONNES)
Solar 1	50	0	0
Coal 1	30	900	45
Coal 2	20	800	30
Gas	20	1,800	10
Total	**120**	**3,500**	**85**

Source: AEMC

The single-hour dispatch market model can be extended by introducing a carbon budget of 65 tonnes for the period. When the carbon budget is introduced, the objective of the market model remains minimising dispatch cost while meeting demand. However, there is the additional constraint that the dispatch profile does not exceed the carbon budget.

It follows that the outcomes in Table B.2 are no longer a solution to the market model – the dispatch outcomes breach the carbon budget (85 tonnes versus a budget of 65 tonnes). To simultaneously meet demand and the carbon budget, the market model must substitute low-cost but emissions intensive coal capacity for high cost but less emissions intensive gas capacity. This substitution has the effect of raising the dispatch cost to $4,500 (from $3,500) while lowering the level of emissions to 65 tonnes (down from 85) –Table B.3 .

Table B.3: **Single-hour dispatch market model outcomes assuming a carbon budget of 65 tonnes**

GENERATOR	QUANTITY DIS-PATCHED(MWH)	COST OF DIS-PATCH($)	QUANTITY OF EMISSIONS(TONNES)
Solar	50	0	0
Coal 1	30	900	45
Coal 2	0	0	0
Gas	40	3,600	20
Total	**120**	**4,500**	**65**

Source: AEMC

The above example highlights how a carbon budget can lead to out-of-merit order dispatch. In particular, the gas generator is more expensive than the second coal generator, but it is preferred in dispatch because of the requirement to meet the carbon budget.

Although the carbon budget affects modelling outcomes, emission abatement benefits are not explicitly captured in the ISP or RIT-T – they are not a line item in the net market benefits assessment. Similarly to the treatment of public policies set out in section 1.2.2, these benefits are implicitly captured by the fact that the carbon abatement outcomes are reflected in the relevant state of the world modelled.

Further reflecting the treatment of public policies, decarbonisation can also influence the estimation of market benefits if the transmission investment facilitates decarbonisation more efficiently. For instance, in the context of an interconnector investment, its contribution to decarbonisation may lead to market benefits through:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in costs for parties other than the RIT-T proponent (such as investment costs relating to generation and storage)
- differences in the timing of other transmission investment (for example, offsetting the need for significant investments to connect renewable energy zones - REZs).

B.2 A carbon budget is equivalent to an explicit value on emissions

The previous section demonstrated how carbon abatement assumptions – in the form of carbon budgets – influence the outcomes of electricity market modelling in a simple constrained dispatch market model. This section explains that the carbon budget approach provides equivalent dispatch and financial outcomes to using an explicit value on emissions provided that the value is set at the level implied by the carbon budget.

Starting from the position that price and quantity in a market are effectively two sides of the same coin, it follows that:[176]

- when a price is set, there is a corresponding way in which to fix quantity to achieve the same outcome and equally
- when quantity is set, there is a corresponding way in which to set the price to achieve the same outcome.

The ability to yield an equivalent outcome using either price or quantity has been previously recognised in relation to the discussion of policy mechanisms for carbon abatement. For example:[177]

> "Cap-and-trade [systems] sets an aggregate quantity, and through trading, yields a price of emissions, and is effectively the dual of a carbon tax that prices emissions and yields a quantity of emissions as firms respond to the tax's mitigation incentives."

In other words, the same level of carbon abatement can be achieved through either fixing the quantity of emissions (cap-and-trade, or a carbon budget) or placing a value on on carbon.

The equivalence of these two approaches can be further demonstrated using the single-hour dispatch market model introduced in above. In particular, it can be shown that the carbon budget approach places an implicit value on carbon emissions. This implicit value is determined by answering the following question: what would be the change in the total cost of dispatch if the carbon budget was increased by one tonne, holding all else constant?

In practice, determining the value on carbon implied by the carbon budget requires comparing dispatch costs when the carbon budget is 65 tonnes versus 66 tonnes. The outcome of this comparison is summarised in Table B.4, which highlights that total dispatch costs are $50 lower when the carbon budget is increased by one tonne. This reflects the fact that more low-cost but emissions intensive coal can be used to meet demand – replacing a small amount of high-cost gas to reduce dispatch costs.

Table B.4: Effect on total dispatch costs of increasing the carbon budget by one tonne

GENERATOR	CARBON BUDGET OF 65 TONNES			CARBON BUDGET OF 66 TONNES			DIFFERENCE		
	Quantity dispatched (MWh)	Cost of dispatch ($)	Quantity of emissions (Tonnes	Quantity dispatched (MWh	Cost of dispatch ($)	Quantity of emissions (Tonn	Quantity dispatched (MWh	Cost of dispatch ($)	Quantity of emissions (Tonn

176 Martin L Weitzman, *Prices vs. quantities,* The Review of Economic Studies, 1974, 41(4), p.477.

177 Joseph E Aldy and Robert N Stavins, *The promise and problems of pricing carbon: Theory and practice,* The Journal of Environment and Development, 2021, 21(2), p.157.

GENERATOR	CARBON BUDGET OF 65 TONNES			CARBON BUDGET OF 66 TONNES			DIFFERENCE		
			)	)		es)	)		es)
Solar	50	0	0	50	0	0	0	0	0
Coal 1	30	900	45	30	900	45	0	0	0
Coal 2	0	0	0	1	40	1.5	1	40	1.5
Gas	40	3,600	25	39	3,510	19.5	-1	-90	-0.5
Total	**120**	**4,500**	**65**	**120**	**4,450**	**66**	**0**	**-50**	**1**

Source: AEMC

The $50 reduction in dispatch costs can be interpreted as the value on carbon, in dollars per tonne. This interpretation reflects the fact that the electricity system as a whole would be willing to spend $50 to produce one more tonne of carbon, because this is the corresponding reduction in dispatch costs from an additional tonne of emissions. The market outcomes associated with a carbon budget of 65 tonnes are summarised in Table B.5. It is important to emphasise that the $50 value on carbon is not the value on carbon implied by the carbon budgets used in developing the ISP. Rather, it is the outworking of an illustrative example. Further, it does not represent the Commission's view of an appropriate value on carbon.

Table B.5: Summary of single-hour dispatch market model outcomes assuming a carbon budget of 65 tonnes

MARKET CHARACTERISTIC	OTCOME
Total supply (MWh)	120
Total emissions (tonnes)	65
Cost of supply ($)	4,500
Implied cost of emissions ($)	3,250
Total implied cost of supply ($)	7,750

Source: AEMC
Note: Implied cost of emissions is calculated by multiplying the total tonnes of emissions by $50/tonne.

Having determined the value on carbon implied by the carbon budget in the example, it is possible to reapply the single-hour dispatch market model using a carbon value (rather than budget) to demonstrate the equivalence of the two approaches.[178]

178 Noting again that this example abstracts away from the significant complexity involved in the market modelling underpinning the ISP and RIT-T.

Table B.6: **Generator characteristics for the single-hour dispatch market model with carbon price incorporated into SRMC**

GENERATOR	CAPACITY(MWH)	SMRC($/MWH)	EIOG(TONNES OF CO2/MWH)	CARBON COST($/MWH)	CARBON INCLUSIVE SRMC($/MWH)
Solar	50	0	0	0	0
Coal 1	30	30	1.50	75	105
Coal 2	20	40	1.50	75	115
Gas	50	100	0.50	25	115

Source: AEMC
Note: The carbon inclusive SRMC is calculated by multiplying each generator's EIOG by the carbon value of $50 (carbon cost) and adding it to the original SRMC.

Absent a carbon budget, the objective of the market model is again to minimise dispatch costs while ensuring energy demand is met. Similarly to the example in section 1.2.4, the market model dispatches generators from lowest to highest SRMC (inclusive of carbon cost) until sufficient capacity has been dispatched to meet demand. Again assuming demand of 120MWh for the dispatch period, the following dispatch profile would occur (Table B.7):

- the solar generator dispatches all of its capacity because it has the lowest SRMC
- the first coal generator dispatches all of its capacity because it has the second-lowest SRMC
- the gas generator dispatches all of its capacity because it has the same SRMC as the second coal generator but a lower emissions intensity.[179]

Table B.7: **Single-hour dispatch market model outcomes with carbon price incorporated into SRMC**

GENERATOR	QUANTITY DISPATCHED(MWH)	COST OF DISPATCH($)	LEVEL OF EMISSIONS(TONNES)
Solar	50	0	0
Coal 1	30	4,150	45
Coal 2	0	0	0
Gas	40	4,600	20
Total	**120**	**7,750**	**65**

Source: AEMC

179 Strictly speaking, the market model would be indifferent between the gas generator and second coal generator because they have an identical SRMC inclusive of the cost of carbon. Indeed, any combination of gas and coal that meets the remaining demand would lead to the same total system costs. However, the breakdown of those costs between energy costs and emissions costs would differ. The purpose of this example is to demonstrate that one solution corresponds exactly to the solution that arises with a carbon budget.

An important result demonstrated by this example is that the physical and financial outcomes of the market are equivalent whether a carbon budget or carbon value is used – provided the value used corresponds to that implied by the carbon budget. This result is summarised in table 8, which shows that the total cost of energy supply under each approach is equivalent. Although this example abstracts away from the complexity of ISP and RIT-T analysis – such as excluding features of capacity expansion and using multi-period constraints – the principle that a carbon budget and carbon value are equivalent remains.

Table B.8: Comparison of single-hour dispatch market model using a carbon budget versus a carbon price

MARKET CHARACTERISTIC	CARBON BUDGET	CARBON PRICE
Total supply (MWh)	120	120
Total emissions (tonnes)	65	65
Cost of supply ($)	4,500	4,500
Cost of emissions ($)	3,250	3,250
Total cost of supply ($)	7,750	7,750

Source: AEMC

C THE INCLUSION OF WIDER BENEFITS IN THE RIT-T WILL NOT BE PROGRESSED THROUGH THE REVIEW GIVEN LIMITED REFORM OPPORTUNITY AS A STANDALONE ISSUE

C.1 Overview of issue

This appendix discusses that an issue 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 stage 2 draft report discussed why a market benefits test is preferable to a consumer benefits test.[180] However, there is a third approach: a test of the benefits not just to all those that produce, consume and transport electricity ("the market") but also to wider society. Such a test might include benefits relating to employment growth or environmental considerations.

The consultation paper noted a variety of earlier reviews that concluded that wider economic benefits should not be included in the RIT-T.[181]

C.2 Stakeholder feedback

Stakeholder feedback on this issue was diverse. However, most stakeholder submissions mentioned that the realisation of wider benefits is supported by broader elements of the transmission planning process beyond the regulatory investment test, such as environmental and safety regulations.[182] CS Energy and Origin outlined possible issues that could arise from including wider benefits, such as the potential for duplication of benefits already captured by the market benefit test[183]

Other stakeholders supported the inclusion of wider economic benefits within the regulatory tests.[184] CEFC and RE-Alliance proposed including employment, social, and environmental benefits.[185] AEMO considers that the timely delivery of transmission projects requires changes to the current framework to include wider economic benefits and additional classes of benefits.[186]

180 AEMC, Transmission planning and investment review - stage 2, draft report, 02 June 2022, pp. 58 - 60.

181 AEMC, *Transmission Planning and Investment Review*, Consultation paper, 19 August 2021, p. 26.

182 Submissions to the consultation paper: EUAA, p. 7; PIAC, pp. 5-6; Shell, pp. 4-5; Energy Australia, p. 7.

183 Submissions to the consultation paper: CS Energy ltd, p. 9; Origin, p. 4.

184 Submissions to the consultation paper: NSG, p. 2; Neoen, pp. 6-7; Energy Grid Alliance, pp. 3-4.

185 Submissions to the consultation paper: CEFC, pp. 4-5; RE-Alliance, p. 3.

186 AEMO, Submission to the consultation paper, pp.13-14.

C.3 Commission analysis and prioritisation

Consistent with the findings of previous reviews, the Commission does not recommend that the RIT-T, or the planning process for transmission more generally, should be changed to include wider economic benefits.[187]

The NEO is restricted to considering the long-term interest of *consumers*, not the wider benefits to the economy. Including benefits such as increased employment would likely increase input costs to the sector by allowing investments that do not increase net benefits to consumers to pass the regulatory test, and hence flow through to worse outcomes for consumers.

Incorporating wider economic benefits in the RIT-T would also increase computational complexity, which may raise issues regarding transparency and increase the likelihood of delays and disputes. For example, if inclusion of increased employment resulting from a transmission investment allows that investment to pass the regulatory test, the costs of that investment would result in higher energy prices which would have subsequent flow on impacts throughout the economy – including to employment.

Governments have legitimate objectives that are wider than economic efficiency and the long-term interest of consumers. These are incorporated into the planning process via a variety of approaches, including as:

- third party capital contributions to a project, since these increase the net benefits to those that produce, consume and transport electricity (i.e., increase net *market* benefits) at the expense of taxpayers (who are outside of the market as defined for the purpose of the test)
- the wide range of environmental and safety regulations that already exist.

An underlying rationale for the NEO is that a "single objective has the benefit of being clear and avoiding the potential conflict that may arise where a list of separate, and sometimes disparate, objectives is specified."[188] It is appropriate that elected representatives make these trade-offs, rather than unelected officials within the market bodies when applying the NEO, or the RIT-T proponent. The national framework, as encapsulated by the NEO, then requires transmission to be planned to maximise net benefits to consumers given any regulatory requirements or investments determined by elected representatives.

187 COAG Energy Council, *Review of the Regulatory Investment Test for Transmission*, 6 February 2017, pp. 34-45.

188 SA, parliamentary debate, House of Assembly, 9 February 2005, p. 1452.