ENERGY SECURITY BOARD

Transmission access reform

Project initiation paper

November 2021

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List of Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COGATI	Coordination of Generation and Transmission Investment
CMM	Congestion management model
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
GW	Gigawatt
ISP	Integrated System Plan
MW	Megawatt
NEM	National Electricity Market
NEO	National Electricity Objective
PFR	Primary frequency response
PV	Photovoltaic
REZ	Renewable Energy Zone
TNSP	Transmission Network Service Provider
VRE	Variable renewable energy

Executive Summary

In its Post 2025 Market Design Review, the Energy Security Board (ESB) recommended a congestion management model with REZ adaptations (CMM[1]).[2]

National Cabinet subsequently instructed the ESB to progress detailed design work on the CMM and to bring back a proposed rule change to Energy Ministers by the end of 2022. The design process should include a comprehensive consultation process and should take into consideration value for money, providing locational signals, and ensuring sufficient flexibility for jurisdictional differences.[3]

This project initiation paper provides more detailed information on the matters summarised in the ESB's CMM scope of works document. The purpose of this paper is to initiate a comprehensive consultation process to engage with stakeholders on the design of the CMM. It has two key functions:

- To provide stakeholders with more clarity about the approach and process that we intend to use to give effect to National Cabinet's decision on transmission access reform, and
- To give stakeholders the opportunity to submit alternative mechanisms. The paper articulates the challenges that the CMM seeks to solve, so that stakeholders know the criteria that their model will be assessed against.

For convenience, the paper also outlines the CMM and provides an overview of the key matters requiring further consideration.

Nature of the challenge

Transmission access reform is concerned with designing a market that encourage generators, storage providers and demand response providers to connect to the grid and utilise the system in a way that minimises total system costs. The energy transition can be delivered more cheaply and quickly if generators connect in places where we can get the most benefit from all the renewables coming into the national power system.

At the moment, some generators are connecting in locations where, a lot of the time, they are not adding new renewable energy to the power system; instead, they are displacing the renewable generators that were already there. This is resulting in overall system costs being unnecessarily high: unnecessary capital expenditure in generators that are poorly located to be dispatched, additional transmission expenditure to accommodate these poorly located generators, and storage not being incentivised to locate where it can most add value. In operational timeframes, we end up with more expensive combinations of generation and storage being used in real time to meet demand than is necessary.

The objective of the transmission access reform program and its associated CMM design process is to address the challenges set out below.

1 For convenience, this document uses CMM to refer to the model previously referred to as CMM(REZ).

2 ESB, Post-2025 market design: Final advice to Energy Ministers – Part A. Available at: https://www.datocms-assets.com/32572/1629944958-post-2025-market-design-final-advice-to-energy-ministers-part-a.pdf.

3 A summary of the final reform package and corresponding ESB recommendations is available at: https://www.energy.gov.au/sites/default/files/2021-10/Summary%20of%20the%20final%20reform%20package%20and%20corresponding%20Energy%20Security%20Board%20recommendations0.pdf

1. Better signals for generators to locate in areas where there is available transmission capacity – including, but not necessarily limited to, in the REZs that are being delivered through the ISP and state government policies.
2. Better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.
3. Establishing a framework that rewards storage and demand side resources for locating where they are needed most and operating in ways that benefit the broader system.
4. Measures to give investors confidence that their investments will not be undermined by inefficient subsequent connections.

Scope of the review

In order to progress the detailed design of the CMM, the ESB will seek to address the problems that prompted National Cabinet to ask the ESB to conduct the review, namely, the problems associated with the current access regime. We will also work with stakeholders to understand their concerns and respond to them where appropriate, including by considering alternative mechanisms, and ensure sufficient flexibility for jurisdictional differences.

While the ESB recognises that there are critical interdependencies between transmission access and transmission investment, they are distinct issues, and this review is focussed on the former.

Next steps – call for alternate models

The ESB's priority at this stage is to understand any alternative models that stakeholders are working towards so that they can be given due consideration as part of the detailed design process.

Submissions on this project initiation paper are due by 28 January 2022.

To assist stakeholders with their submissions, the ESB will hold a webinar on 26 November 2021.

Alternative models should build on previous work and seek to address the objectives identified above, noting the range of conceptual models that have already been considered in the post 2025 market design project. . Models that are substantially the same as models previously considered by the ESB are unlikely to be assessed differently unless there is evidence of a material change in circumstances.[4] We encourage stakeholders who wish to provide an alternative model to get in touch with us to informally discuss their thinking.

In parallel, the ESB will progress the detailed design of the CMM such that a proposed rule change can be submitted by the end of 2022, as required by National Cabinet. We will publish a consultation paper in March 2022 where stakeholders will have an opportunity to provide feedback on a more detailed iteration of the CMM (or an alternative model) which incorporates issues raised by alternative models put forward by stakeholders in response to this project initiation paper.

4 ESB, Post 2025 Market Design Options Paper, Part B, Chapter 4, April 2021. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf

1. Introduction

1.1. Background

The NEM has an open transmission access regime; that is, parties may connect to the grid at any point subject to meeting technical requirements and funding only the cost of the assets required to connect to the shared grid. Generators are not required to contribute towards the cost of the shared transmission network, and they receive no assurance that the transmission network will be capable of transporting their output to load centres.

The NEM's access regime has been contentious ever since the market started in 1998. Over the past 20 years, various bodies responsible for the design of the NEM[5] have each expressed concern about the lack of locational signals and the imbalance between those who benefit from, and those who pay for, the transmission network. During the 2015 Optional Firm Access review, the Australian Energy Market Commission (AEMC) noted that "the issues that have been contemplated in this review have been considered, in at least eleven reviews… These reviews have shown:

- solving these issues is technically complex;
- stakeholders have different views about the importance of these issues, and their solutions; and
- the importance of these issues to stakeholders changes as market conditions change."[6]

Since then, these issues have emerged again in four more major reviews (see Figure 1).

Generators, on the other hand, have defended the current open access regime. It gives them flexibility to connect where they want, and they do not need to pay to access the transmission network.

More recently, the downsides of the NEM's access regime have become more apparent. An investment boom in renewable energy has meant that new generation investment exceeds the capacity of the transmission network to host it. The energy transition can be delivered more cheaply and quickly if new generators connect in places where we can get the full benefit of all the renewables coming into the national power system.

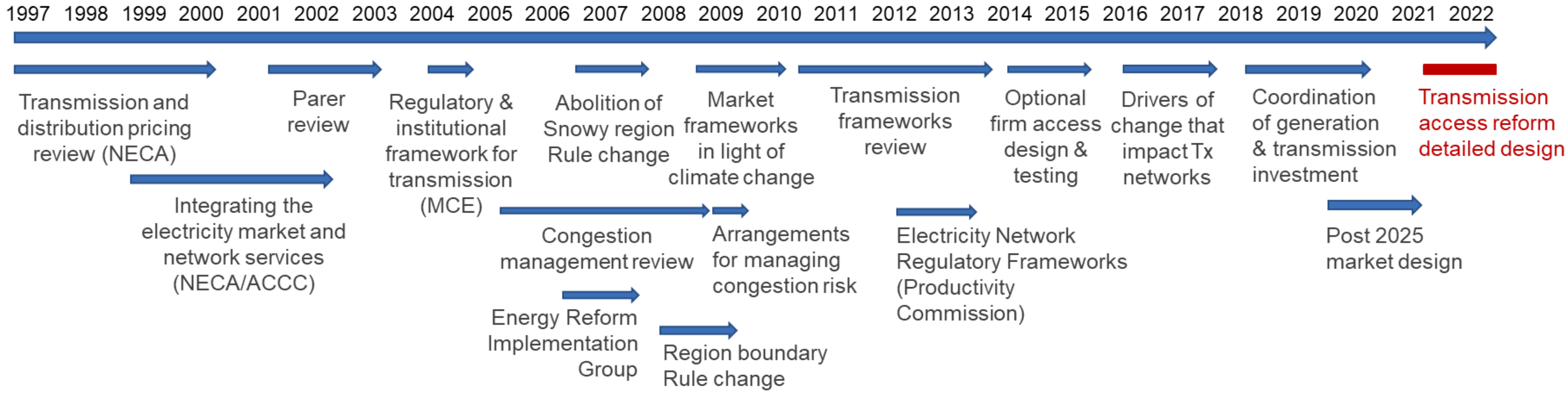
In some cases, generators are connecting in locations where, a lot of the time, they are not adding new renewable energy to the power system. Instead, they are displacing the renewable generators that were already there. This is resulting in overall system costs being unnecessarily high: unnecessary capital expenditure in generators that are poorly located to be dispatched, additional transmission expenditure to accommodate these poorly located generators, and storage not being incentivised to locate where it can most add value. We also end up with more expensive combinations of generation and storage being used in real time to meet demand than is necessary.

Furthermore, investors are facing unpredictability and delays during the connections process, volatile marginal loss factors and the unexpected curtailment of operational projects. Ultimately, customer bear additional costs if investing in the NEM is riskier than it needs to be, particularly if poor generator location decisions result in transmission investment that would not be needed if the generators had located elsewhere.

5 These include the Australian Competition and Consumer Commission, the National Electricity Code Administrator, the Australian Energy Market Commission and the Energy Security Board.

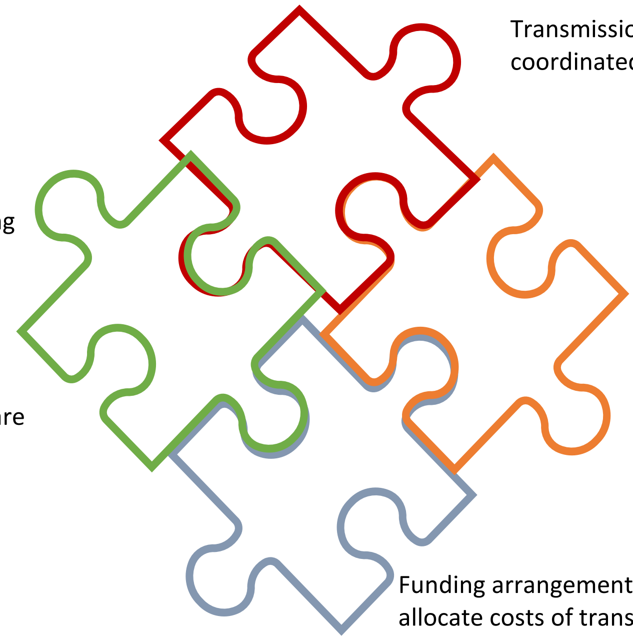
6 AEMC, Optional Firm Access Draft Report, Volume 1, pg vi. Available at: https://www.aemc.gov.au/sites/default/files/content/e3455d5c-4492-4ab4-a212-03b9da989928/Optional-Firm-Access-Draft-Report-Volume-1.pdf

Figure 1 Timeline of NEM access reform reviews



1.2. Access reform within the broader regulatory context

The National Electricity Market has a range of inter-related market design features that seek to deliver coordinated transmission and generation investment. Transmission access and transmission investment are each key parts of the puzzle.



This paper is focussed on transmission access. The ESB recognises that there are critical interdependencies between transmission access and transmission investment. The ESB's package of transmission and access reform include a range of measures to get transmission built when and where it is needed. These reforms are described in Appendix D.

Recent enhancements to the planning regime in the NEM include the development of the Integrated System Plan (ISP) and changes to support transmission investment in accordance with the ISP (the actionable ISP reforms).[7] Among other things, the ISP identifies renewable energy zones (REZs) as part of the optimal development path. These seek to provide the most efficient means to connect the additional renewable energy capacity required as the power system transitions away from fossil fuels.

Several State governments have initiated schemes to expedite the development of REZs. In an interconnected power system, developments in one location can have significant flow on consequences elsewhere, including in other jurisdictions. To promote coordinated development, the ESB has recently completed a two-stage process to develop an interim REZ framework. The REZ Planning Rules and the Interim REZ Recommendations build on the ESB's rules to action the ISP:

1. **REZ Planning Rules.**[8] The ESB developed an improved REZ planning framework that among other things, provides for greater alignment of the needs of developers and communities, while ensuring REZs leverage and contribute to the efficient development of the broader power system provided for in the ISP. These new rules have now been implemented.

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7 ESB, Actionable ISP Final Rule Recommendations, 27 March 2020. Available at: https://energyministers.gov.au/publications/actionable-isp-final-rule-recommendation.

8 ESB, Renewable Energy Zone Planning Final Recommendations, February 2021. Available at: https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/ESB%20final%20recommendations%20REZ%20Planning%20Rules.pdf

2. **Interim REZ Recommendations**.[9] Ministers have adopted the ESB's recommendations for a set of overarching principles for the development of REZs, together with practical guidance on how to implement these principles. These principles relate to planning a REZ, connecting to a REZ, funding, and access within a REZ.

The REZ principles will help jurisdictions looking to resolve urgent issues in the short term to do so in a way that builds towards long term improvements the national framework.

A key finding from the ESB's process to develop an interim REZ framework is that REZs need whole-of-system access reform to be viable in the long term, particularly if governments want generators to contribute to the cost of REZ transmission infrastructure. The CMM supports and strengthens state REZ schemes by:

- Strengthening incentives for new entrants to locate and participate in REZ investments,
- Giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investment decisions inside or outside the REZ,
- Removing opportunities for subsequent connecting generators to free ride on REZ investments without contributing to them, and
- Promoting the efficient use of REZ infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

If the current access regime is retained, there is a risk that parties outside the REZ may degrade the level of access available to generators within a REZ. As electricity flows consistent with the laws of physics, generators outside of the REZ physically utilise the REZ infrastructure and non-REZ infrastructure required for a REZ generator to get to load. Consequently it is not feasible to physically honour the access rights of a REZ generator without changes to the access rights of REZ generators elsewhere.

In this context, the CMM detailed design process is focussed on transmission access, namely, how generators, storage and demand side resources can gain access to the transmission network to provide services to load.

The REZ schemes, together with the ISP reforms, aim to provide efficient overall development of the power system. However, there should also be viable opportunities for market participants to develop projects outside the planned framework, so long as the investment does not detract from the efficient development of the power system. The consultation process will seek to design a framework that retains the dynamism and innovation of the competitive market, while addressing the anomalies in the current market design that cause sub-optimal outcomes.

9 ESB, Interim Framework for Renewable Energy Zones – Final Recommendations, June 2021. Available at: datocms-assets.com/32572/1631503418-esb-decision-document-renewable-energy-zones-recommendations-final-1-june-2021-to-encrc.pdf

2. Scope of review

National Cabinet has instructed the ESB to progress detailed design work on the CMM and to bring back a proposed rule change to Energy Ministers by the end of 2022. The design process should include a comprehensive consultation process and should take into consideration value for money, providing locational signals, and ensuring sufficient flexibility for jurisdictional differences.[10]

To deliver on this task, the ESB will seek to:

- Address the problems that prompted National Cabinet to ask the ESB to conduct the review, namely, the problems associated with the current access regime,
- Work with stakeholders to understand their concerns and respond to them where appropriate, including by considering alternative mechanisms proposed by stakeholders, and
- Ensures sufficient flexibility for jurisdictional differences.

While the ESB recognises that there are critical interdependencies between transmission access and transmission investment, they are distinct issues, and this review is focussed on the former.

2.1. Addressing the problems associated with the current access regime

Transmission access reform is concerned with designing a market that encourages generators, storage providers and demand response providers to connect to the grid and utilise the system in a way that minimises total system costs.

The NEM's open access regime is unusual by international standards,[11] and gives rises to adverse consequences in both operational and investment timeframes. Ultimately, customers bear additional costs relating to poorly located generation, storage, and load; resulting inefficient transmission investment; and higher cost dispatch. They also ultimately bear additional costs if investing in the NEM is riskier than it needs to be.

While the ISP reforms are an important step forward in delivering needed transmission investment, they cannot solve these problems without changes to the access regime. The ISP identifies the optimal development path, including optimal generation development opportunities, based on minimising the underlying costs. In practice, generation investors respond to market signals and will invest when they consider it most profitable to do so. If the electricity market design does not signal to generators (and other resources) the "right" place to invest from a system perspective, actual investment outcomes are likely to diverge from the ISP.

This framework potentially exposes consumers to higher wholesale and network costs than optimal as there is no assurance that the overall development of the power system through this approach will deliver the most efficient outcome. There have been instances where ad hoc generation developments have triggered major transmission investments. This happens because once an investment has occurred, its capital cost is treated as "sunk" for transmission planning purposes.[12]

10 A summary of the final reform package and corresponding ESB recommendations is available at: https://www.energy.gov.au/sites/default/files/2021-10/Summary%20of%20the%20final%20reform%20package%20and%20corresponding%20Energy%20Security%20Board%20recommendations0.pdf

11 FTI Consulting, Final report on forecast congestion in the national electricity market, 5 August 2021. Available at: https://www.datocms-assets.com/32572/1629773972-fti-esb-forecast-congestion-in-the-nem-final-5-august-2021.pdf

12 For more information on the regulatory investment test, see the AER's Cost Benefit Analysis Guidelines. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable

As the transmission access regime is at the heart of the design of the NEM, any shortcomings have a diverse range of consequences. The CMM is intended to overcome a number of distinct, but related, problems that arise because of the design of the NEM's access regime, as set out in Table 1.

Table 1 Challenges to be solved

No.	Issue	Description	Objective
1	Locational signals	There are inaccurate locational signals for generation and storage, ultimately driving a larger, costlier set of generation and transmission investments than would be required if investment was more accurately targeted.	Better signals for generators, storage and load to locate in areas where it is efficient – including, but not necessarily limited to, in the REZs that are being delivered through the ISP and state government policies. This will result in lower costs for consumers.
2	Congestion management	Congestion is a permanent feature of a high VRE power system, however, the current regional pricing model creates a divergence between what happens on the power system and what happens in the wholesale market in operational timeframes. In the event of congestion, the current market design applies simplified rules that reward market participants for acting in ways that result in higher costs.	Better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.
3	Enabling new technologies	The market design does not reward emerging technologies for providing services that enable the efficient integration of renewables. In particular, measures to promote the efficient location and operation/use of network for storage and new large flexible loads (e.g., hydrogen) is critical given the potential for these technologies to both alleviate and worsen transmission congestion. Better price signals are needed to support new business models so these technologies work with, and not against, a high variable renewable energy power system.	Establishing a framework that rewards storage and demand side resources for locating where they are needed most and operating in ways that benefit the broader system.
4	Risk management tools	Investing in the NEM is riskier than it should be. The current access regime can make it profitable for new projects to proceed in parts of the network that are already full. For most of the time these projects don't add usable new megawatts - they survive by eroding the profits of their neighbours.	Give investors confidence that their investments will not be undermined by inefficient subsequent connections.

Each of these challenges are a substantial issue in their own right. What they have in common is that they are all closely connected to transmission access regime. It is necessary to address these challenges now, more than ever, as the NEM transitions from centralised large-scale generation to one where demand is largely to be met by decentralised variable generation. It is crucial that the significant volume of new generation entering the NEM, including through jurisdictional REZ schemes, is incentivised to locate and operate in the network efficiently, to minimise the costs of the NEM transition to consumers over the long-term.

Ministers have instructed the ESB to develop a detailed design to solve these problems. The challenges that transmission access reform seeks to solve have been discussed in detail in previous reviews, most recently the Post 2025 Market Design Review. Table 2 lists resources for stakeholders seeking more background on these issues. The core concepts of the previously considered alternate models discussed in these documents are set out in Appendix C.

Table 2 Case for reform – key documents

Document	Date
ESB's Post 2025 market design: Final Recommendation – Part C	July 2021
ESB's Post 2025 market design: Options paper – Part B	April 2021
ESB's Post 2025 market design: Directions paper – Chapter 6	January 2021
FTI Consulting's Forecast congestion in the NEM: Final report	August 2021
AEMC's Coordination of generation and transmission infrastructure (COGATI): Directions paper – Section 3.2	June 2019
AEMC's Optional Firm Access: Final report – Appendix B	July 2015

2.2. Working with stakeholders

The ESB has developed the CMM based on feedback received during the Post 2025 Market Design process, as well as learnings gained during numerous previous reviews. We hope to use the upcoming collaborative process to further develop and improve upon the CMM in a way that allows this issue to resolved.

This section describes preliminary stakeholder feedback on the CMM, including in relation to the final advice, and sets out how the ESB intends to respond to it.

The Post 2025 Market Design Review options paper[13] proposed that the CMM with REZ adaptations[14], or CMM plus connection fee, could be applied in the medium term as a stepping-stone to a long term solution of locational marginal pricing and financial transmission rights (LMP/FTRs). While a number of generator and investor representatives were opposed to LMPs in any form, a range of customer, generator, network, academic and other stakeholders expressed support for LMP in some form.

Among those that supported some form of LMPs, support was fairly evenly spread between LMP/FTRs, CMM(REZ) and CMM plus connection fee. However, only a small group expressed support for a stepping-stone approach involving both LMPs/FTRs and CMM. Additionally, a number of

[14] As noted previously, this paper refers to the "CMM with REZ adaptations" as CMM for succinctness.

respondents who were not ready to express a preference for any specific model were willing to support further work to explore the options.

In light of concerns about the potential for disruption caused by changing between access regimes, the ESB's final recommendations moved away from a stepping-stone approach and instead recommended the CMM(REZ). Subsequent stakeholder briefings highlighted three key concerns:

- The potential for projects outside REZs, which are otherwise efficient, to be disadvantaged as they would not receive access to congestion rebates and hence would be subject to greater risk and uncertainty,
- The lack of detail, which prevents a full assessment of the model, and
- The reliance of the model on the planning framework rather than market signals.

The ESB's next stage of work will consider these concerns. In particular, the detailed design process will develop the model in sufficient detail to allow market participants and other stakeholders to assess how the reforms are likely to affect them. It will also consider further the treatment of projects outside REZs and provide greater certainty around the future costs of congestion for investors.

With respect to the final concern, the ESB notes that CMM was developed in response to previous stakeholder concerns about a market-based solution (see Appendix C). The consultation process will seek to design a CMM that retains the dynamism and innovation of the competitive market, while addressing the anomalies in the current market design that cause sub-optimal outcomes.

The ESB notes that when transmission investment follows the generation, it becomes something of a lottery for developers and existing generators who may be substantially affected in either a positive or negative way. The REZ schemes, together with the ISP reforms, aim to provide efficient overall development of the power system. However, there should also be viable opportunities for market participants to develop projects outside the planned framework, so long as the investment does not detract from the efficient development of the power system. The ESB particularly welcomes alternative solutions that have not been previously considered and that use effective market-based approaches to provide accurate locational signals and operational incentives.

2.3. Consideration of appropriate alternative models

As part of its comprehensive stakeholder engagement strategy, the ESB will consider alternative models that appropriately address the challenges the CMM seeks to solve. To this end, this paper asks stakeholders who are developing, or have developed, an alternative model to provide a description of their proposed approach. These models will then be considered for how to best incorporate the model, or issues arising from the model, as part of the detailed design process.

An example of an alternative model is the Congestion Relief Market proposed by Edify Energy in the submission to the Post 2025 market design options paper.[15]

The ESB has developed a set of assessment criteria that will be used to assess the detailed design decisions of any mechanism put forward by stakeholders. The criteria are based on National Cabinet's decision , the four core objectives for transmission access reform, and the ESB's statutory duty to make recommendations that are consistent with the national electricity objective (NEO).[16]

15 Edify Energy, Submission to Post 2025 market design options paper, 9 June 2021. Available at: https://web.archive.org.au/awa/20211005080356mp_/https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/28.%20Edify%20Energy%20Response%20to%20P2025%20Market%20Design%20Consultation%20Paper_0.pdf

16 Section 90F(4)(b) mandates that for South Australian Minister made Rules on recommendation from the ESB the ESB must is satisfied that the Rules are consistent with the national electricity objective (NEO).

Table 3 Assessment criteria

No.	Criteria	Description
1	Efficient market outcomes – investment	• Better incentivises for generators, storage such as batteries, and load such as hydrogen electrolysers to locate in areas that are efficient. In the case of generation this is most likely to be where there are low levels of congestion, such that transmission assets are better utilised. In the case of storage and load, this may be areas that are congested, in order to help alleviate that congestion and utilise otherwise wasted renewable electricity that was unable to reach load.
2	Efficient market outcomes - dispatch	• Better incentives for generation, storage such as batteries, and load such as hydrogen electrolysers to bid in a fashion that best reflects its underlying costs, resulting in more efficient dispatch outcomes and reducing fuel costs across the NEM. In turn, this may also reduce emissions.
3	Appropriate allocation of risk	• The allocation of risk arising due to congestion in the NEM should be done as efficiently as possible noting the practical limitations on exposing parties to risk without appropriate mitigation tools and measures.
4	Appropriately allocation of the cost of transmission investment	• The efficient allocation of the cost of transmission between consumers and generators.
5	Implementation considerations	• Cost and complexity: cost and complexity of implementation and ongoing regulatory and administrative costs to all market participants, consumers and market bodies, across all potential solutions (consider timing, nature of issue) • Timing and uncertainty: uncertainty of outcome, and the likely timing of benefits versus costs.
6	Flexibility to enable consideration of jurisdictional differences	• As requested by Minsters, the proposed rules must provide flexibility such that differences between jurisdictions, such as those without REZ schemes, can be appropriately adapted.

Stakeholders should have regard to these criteria when preparing alternate models. To provide context and to assist stakeholders who are considering putting forward an alternative model, Appendix C contains a summary of previously considered alternative models and a description of why they were not pursued. Models that are substantially the same as models previously considered by the ESB are unlikely to be assessed differently unless there is evidence of a material change in circumstances.

2.4. Flexibility in light of jurisdictional differences

Several State governments have initiated schemes to expedite the development of REZs. National Cabinet has instructed the ESB to continue to collaborate with state governments to explore different REZ models and ensure that these parallel processes deliver a cohesive overall framework.

Minsters have also instructed the ESB to design the CMM in a way that ensures sufficient flexibility for jurisdictional differences. For instance, some jurisdictions might wish to allocate congestion rebates to new generators via a state-based scheme, while others may prefer to rely on a Rules based scheme.

This will be a key focus for the detailed design process.

2.5. Matters that are beyond scope

Transmission access reform is not about how to build the transmission infrastructure required to support the transition of the power system to renewables. The ESB understands this is an important and pressing question for stakeholders. Some of the processes that are directed towards delivering transmission include:

- the development of Renewable Energy Zones,
- AEMC's Transmission Planning and Investment Review and dedicated connections assets and systems rule changes, and
- the ISP framework, including new rules to deliver the transmission projects identified in the ISP.

This work is described in Attachment D.

While transmission investment is an essential component of the task of delivering the energy transition, it does not replace the need for transmission access reform. For the power system to develop in way that efficiently provides secure and reliable electricity to consumers, it is also necessary for generators, storage and load such as hydrogen electrolysers to make efficient decisions about where and when to invest, and how to operate their plant. Not only do we need to build a transmission system that supports the energy transition, we also need to use it effectively.

Outside REZ schemes, the NEM relies on the decisions of commercial investors to determine where and when generators should be built. While investors can be relied upon to efficiently respond to the commercial incentives put before them, investment outcomes are dependent on having a market design that sends the right signals in the first place. If the market design is flawed, the investment decisions made in response to the market design will not align with the long-term interests of consumers.

3. Approach going forward

Effective stakeholder engagement will be critical to the detailed design process. To this end, this project will be informed by an advisory panel and a technical working group, each comprised of a diverse set of stakeholders with appropriate experience and expertise.

The ESB will also undertake a formal public stakeholder consultation process, consisting of submissions on consultation documents, stakeholder briefings and public forums/webinars as appropriate.

Advisory panel and working groups

The Technical Working Group will include representatives of each of the key stakeholder groups nominated by their peak bodies, including customers, generators, storage providers and network representatives. This group will act as a sounding board for the ESB's thinking on the detailed design of the CMM (and/or alternative solution). Relevant Technical Working group papers will be made publicly available as part of the design process.

Access reform is inevitably complex, irrespective of the model. The ESB will prepare working group papers that discuss the detailed issues and rely on the working group as a key vehicle to receive feedback. Papers and minutes will be published on the ESB's website.

Additionally, the ESB's Advisory group as well as a jurisdictional working group will be utilised to gain industry and jurisdictional feedback on the TAR work. All workshops with these groups will be by invitation only and will be scheduled throughout 2022.

The Senior Officials Reference Group established for the Post 2025 project, comprised of senior officials from each of the NEM jurisdictions, will continue to provide the focal point for feedback from jurisdictions throughout the process.

An overview of these panels and working groups as they relate for all ESB projects progressing P2025 reforms can be found on the ESB's post 2025 market design microsite.[17]

Stakeholders who are not part of these groups are welcome to reach out to the ESB at any point if they would like to discuss or provide feedback on the detailed design process. Please contact us at info@esb.org.au.

Timing and deliverables

National Cabinet has instructed the ESB to prepare a proposed rule change setting out the design of a congestion management model and necessary regulatory changes to Energy Ministers by December 2022.

Due to the large amount of work to cover to meet this deliverable, the ESB plans to progress the project in two streams that will interact with, and inform, each other. Stream 1 will work with stakeholders to understand their concerns and explore different solutions to the identified problems, and Stream 2 is focussed on the detailed design of the CMM – consistent with the requirements laid out by National Cabinet. The ESB's proposed forward work program is set out below. It includes meetings with Energy Ministers to seek guidance on the progression of the congestion management model. These meetings have been given indicative dates for planning purposes.

17 See https://esb-post2025-market-design.aemc.gov.au/

Table 4 Forward work program – key milestones

Milestone	Indicative timing
Project initiation paper	**18 November 2021**
Public webinar on project initiation paper	26 November 2021
Submissions due on project initiation paper	28 January 2022
(Indicative) Ministerial meeting: CMM update	March 2022
Detailed design consultation paper	**March 2022**
Public webinar on consultation paper	March 2022
Submissions due on consultation paper	April 2022
(Indicative) Ministerial meeting: draft recommendations for detailed design	August 2022
Draft recommendations for detailed design	**August 2022**
Public webinar on Draft recommendations	August 2022
Submissions due	September 2022
Submit proposed rule change to Energy Ministers	**Early December 2022**
Ministers consider proposed rule change	**December 2022**

3.1. Matters for consultation

The ESB invites comments from interested parties in response to this project initiation paper by 28 January 2022. While stakeholders are invited to provide feedback on any issues raised in this paper, the ESB's priority is to understand the alternative options that stakeholders wish to put forward so that they can be given due consideration. Stakeholders will have further opportunities to consider and provide feedback on more detailed iterations of the CMM during subsequent stages of the consultation process.

3.2. How to make a submission

Submissions will be published on the COAG Energy Council's website, following a review for claims of confidentiality. All submissions should be sent to info@esb.org.au.

Submission information	
Submission close date	28 January 2022
Lodgement details	Email to: info@esb.org.au
Naming of submission document	[Company name] Response to Project Initiation Paper on Congestion Management Model
Form of submission	Clearly indicate any confidentiality claims by noting "Confidential" in document name and in the body of the email.
Publication	Submissions will be published on the Energy Ministers website, following a review for claims of confidentiality.

Following consideration of submissions made to the paper, the ESB will prepare a detailed design consultation paper that considers various options and design choices for addressing the identified problems. This paper will give stakeholders the opportunity to provide feedback on a more detailed iteration of the CMM which incorporates issues raised by alternative models put forward by stakeholders in response to this project initiation paper.

The ESB intends to hold a webinar on the material covered in this paper on 26 November 2021, 9:45-10:30 am AEDT. Interested parties are invited to register their interest by email to info@esb.org.au.

A. Description of the CMM

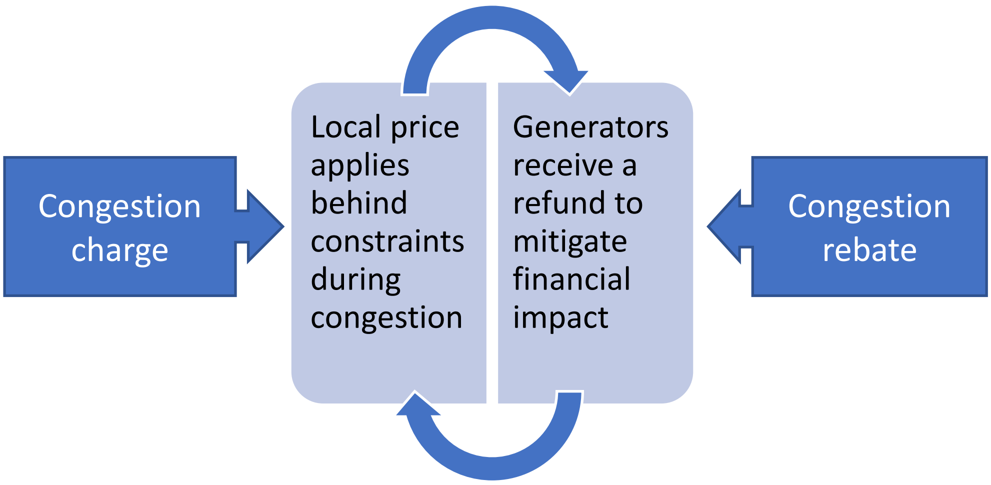
This appendix explains the basic concepts that underpin the CMM and outlines the detailed decisions that will are still under consideration.

A1 Overview of CMM

Under the CMM, all wholesale market participants would be settled for their energy at their regional reference price (multiplied by an annually determined marginal loss factor) as is currently the case.

The CMM additionally introduces a dual mechanism of congestion charges and congestion rebates:

1. All scheduled and semi-scheduled market participants would face a **congestion charge**, calculated each dispatch interval on a $/MWh basis reflecting the generator's impact on congestion in the dispatch interval. Specifically, this charge is calculated as the change in the cost of dispatch were a binding constraint to be relaxed by a small degree, multiplied by the generator's participation factor in the constraint. When the market participant is not participating in a binding constraint, its congestion charge will be zero.
2. Eligible scheduled and semi-scheduled generators would receive a **congestion rebate**, calculated each dispatch interval, funded from the collective revenue received from the congestion management charges in that dispatch interval. The size of the rebate would be determined in accordance with a pre-determined allocation metric, most likely a generator's availability and participation factor in the binding constraints in comparison to other generators' availabilities and participation factors.



Existing generators would automatically qualify for receipt of rebates. New market participants that connect as part of a REZ scheme would also be eligible to receive rebates. The ESB is considering the treatment of new market participants who connect outside of REZs as part of the detailed design process (see discussion below).

The CMM is intended to achieve the following benefits:

- By exposing market participants on the margin to the congestion charge, market participants, including storage or scheduled loads such as hydrogen electrolysers, will be incentivised to bid more reflectively of their underlying costs[18], improving the efficiency of dispatch
- By allowing new market participants to purchase the right to receive the rebate, they should factor the cost of congestion into their investment decisions (either through the cost of purchasing the rebate, or by facing the congestion charge unhedged), improving the efficiency of scheduled and semi-scheduled generation, load and storage placement in the network.
- For incumbent generators, receipt of the rebate substantially mitigates the financial impact of the introduction of the congestion charge.
- For new generators, the rebate allows them to better manage the risk of congestion.

Worked examples of the basic CMM mechanism are set out in Appendix B.

A2 Rationale for the design of the CMM

Congestion charge

Under the current regional pricing arrangements, dispatch outcomes can be affected by generator bids that do not have a commensurate impact on price outcomes. In the presence of congestion, the profit maximising strategy of a generator is to bid to the market floor price in order to maximise the amount that they are dispatched for. Because the dispatch engine selects the lowest *as-bid cost* combination of generators (as opposed to the lowest combination of generators given their underlying *actual cost*), this bidding behaviour can result in higher cost generators being dispatched instead of lower cost generators: inefficient dispatch.

Under the CMM, a market participant that bids at the market floor price risks setting its own congestion charge to a very high level. Instead, the profit maximising strategy given the congestion charge is to bid more closely to their true costs of generation (that is, they bid in line with their short run marginal cost). This in turn will reduce the cost of dispatch, because by selecting the lowest cost combination of generators based on their bids, the dispatch engine will select the actual lowest cost combination of generators.

The net effect of scheduled and semi-scheduled market participants receiving the RRP for energy and then paying the congestion charge is that they face their locational marginal price. Indeed, the dispatch engine already calculates shadow locational marginal prices in this way - by deducting the marginal impact of congestion from the regional reference price.

Congestion rebate for incumbents

Incumbent market participants would automatically receive a rebate to compensate them for the financial impact of the introduction of the congestion change. Significant changes to market design, such as the introduction of the congestion charge, creates regulatory risk. This in turn could increase the cost of capital for future investors which all else equal would delay future investments, and so not be in the interest of consumers. The allocation of rebates to incumbents addresses this concern, by protecting sunk investments from significant financial impacts arising from regulatory reform.

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18 In the case of storage, their opportunity costs. In the case of storage, the opportunity cost include the forgone benefit that would have been derived had the storage unit chosen to discharge later, when prices are different.

Under the current arrangements, in the presence of congestion and disorderly bidding, a generator's dispatch, and so revenue, is a function of:

- the generator's availability in comparison to the availability of other generators participating in the binding constraints. This is because tie-breaking of bids which have identical impacts on the cost of dispatch as calculated by the dispatch engine[19] is done on the basis of generators' availability
- the degree to which the generator contributes to the binding constraints in comparison to other generators, based on generators' participation factors in binding constraint equations
- the available transmission capacity.

The design of the rebate is to make incumbent market participants broadly financially indifferent to the introduction of the congestion management charge compared to the status quo arrangements (while the congestion management charge, described above, improves dispatch efficiency because market participants would continue to be exposed to it *on the margin*). It does this by allocating the collective revenue received from the congestion management charge between rebate holders, with each holder's individual share being determined as a function of the factors listed above.

The ESB will consult on the exact design of the rebate allocation metric during the next stage of the ESB's consultation process. Alternative options were discussed in the post 2025 market design final advice to Ministers.[20]

Congestion rebate for new market participants

In the absence of a congestion rebate, the introduction of the congestion charge creates a risk for new market participants that the size and occurrence of the charge differs from expectations over time. This could happen as the prevalence, and cost, of congestion changes unexpectedly. This risk, if unmanaged, could increase the cost of capital for new investors, delay investments, and not be in the interest of consumers.

To address this risk, new market participants who connect within REZs would be entitled to participate in a process to purchase access to rebates, most likely through a competitive process such as an auction.[21] This may be an auction separate to the jurisdictional REZ schemes, or in effect be a part of the processes currently being developed by jurisdictions which not only allocates access to rebates, but other rights such as financial contracts for energy.

Generators outside of a REZ, and potentially those within[22], would be entitled to connect without rebates, which would then expose them, unhedged, to the congestion charge. Of course, in some areas of the grid, the congestion charge would be expected to be low, because there is ample spare capacity both now and forecast in the future. In making this decision, the cost of congestion is borne directly and fully by them. Other market participants who have purchased rebates would be hedged

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19 The dispatch engine minimises the cost of dispatch based on the offers of generators, not the actual underlying costs. Regional pricing means that generators are incentivised to bid inconsistent with their underlying costs (in a "disorderly" manner), meaning that the dispatch optimisation based on these inputs is inefficient.

20 ESB, Post 2025 market design final advice to Energy Ministers - Part C, July 2021, pg 53-54. Available at: https://www.datocms-assets.com/32572/1629945838-post-2025-market-design-final-advice-to-energy-ministers-part-c.pdf

21 The same concern – that freely available rebates would negatively impact new investments – does not apply to existing investments which are sunk.

22 The ESB envisages that generators could connect to a REZ after the initial tender process to establish/fill the REZ, however, in this case, they would not receive congestion rebates.

against the cost of congestion caused by the non-rebate holding market participant, via a larger rebate pool being divided between the same number of rebate-holding market participants.

Some stakeholders have expressed concern about the version of the CMM recommended by the ESB to Ministers on grounds that if congestion rebates are only made available inside REZs, then this may make it difficult for projects to proceed outside REZs. The intent of the original model was to provide an incentive to locate within REZs by rewarding REZ generators with a congestion rebate. However, this is a relatively blunt tool, as there may be locations outside REZs which may also efficiently support new generation, for instance, in places where thermal generators have retired. The "bluntness" of the recommended CMM-REZ was a design choice intended to simplify the access model.

The ESB will consult further on this issue as part of the detailed design process. Stakeholders who plan to submit alternative models are encouraged to consider the circumstances in which might be appropriate for participants outside a REZ to gain a rebate right. The ESB is cognisant that a more finely tuned mechanism for allocated rebate rights can lead to models more similar to the LMP/FTR model, which some stakeholders have opposed in the past. An alternative potential outcome would be a model along the lines of the vanilla CMM[23], which does not provide locational signals, and hence leaves REZ generators exposed to the risk that their access will be degraded by inefficient subsequent connections.

In designing the details of the CMM, the ESB would like to actively balance previous industry feedback and limit unnecessary complexity while providing meaningful investment signals that reward investors for choosing locations that confer maximum benefit from our generation and storage fleet.

Consequences of limiting the availability of rebate to certain areas

The collective payout of the rebates is equal to the revenue from the congestion charges. This means that the more market participants that hold an entitlement to receive rebates, the lower their individual payouts will be on average. In turn this means that the rebates will be less good congestion risk management tools for their holders.

There is therefore a trade-off along a spectrum between:

- making the rebates abundantly and widely available, so that many prospective generators can have relatively low quality congestion risk management tools, and
- making the rebates available in limited numbers at specific areas of the network where there is network capacity, so that generators connecting early and in those areas have high quality congestion management tools.

The ESB proposes to use the selective availability of congestion rebates to incentivise generators to connect in locations with spare transmission capacity available such as REZs. The model supports and strengthens the REZ framework by rewarding generators who locate in the 'right' place with access to better congestion risk management tools, while enabling generators to also manage congestion risk is connecting in other seemingly favourable areas.

By limiting the number of rebates available to these areas, holders will receive greater certainty relating to the impact of congestion on their profits.

The ESB will closely work with the jurisdictions to ensure that the design and availability of the rebates are compatible, and complementary to, their REZ schemes.

Generators would still be entitled to connect where they wish (subject to meeting agreed technical standards). However, if they wish to connect in a location that where there are no rebates available,

23 ESB, Post 2025 market design final advice to Energy Ministers - Part B, July 2021, pg 110-112. Available at: https://www.datocms-assets.com/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf

then they would face the associated congestion risk. As such, the model allocates the risk of congestion (which is an inherent feature of any appropriately sized transmission network) to those new generators who do not purchase access to rebates.

The revenue from the sale of the rebates would be returned to consumers, and therefore be of direct benefit to them compared to the status quo.[24] This could be used to offset some of the cost of new transmission investment. In the case of REZs, this means that new generators connecting to areas that have had additional transmission capacity will pay, in part, for that new investment.

Storage and scheduled load may take advantage of payments for alleviating congestion

Load (and storage when acting as load, which from now on will simply be called load for simplicity of explanation), alleviates congestion when it is behind a constraint. Consequently, the congestion management charge for load will be negative, meaning that the load pays the regional price and then receives the marginal reduction in the cost of congestion it alleviates. In combination, the load will therefore pay its locational marginal price – which will be lower than the regional price.

This sends the appropriate and efficient signal in investment and operational timeframes with regard to storage and load, such as hydrogen electrolysers.

The ESB is considering the appropriate availability and design of the rebate for storage and load. If rebates were to be made available to load, the cashflows may typically be reversed compared to that for generators:

- the load would often be paid a congestion charge because it alleviates a constraint
- the load would then be paid to access the rebate
- the rebate would mean the load makes a payment.

Alternatively, scheduled storage and load could be subject to LMPs and hence able to benefit from the low prices that could be expected to arise in the presence of congestion. When the network is uncongested, the LMP would be equal to the RRP. **Transmission investment**

The CMM relies on complementary reforms, such as the actioning the ISP rule changes and those being contemplated through AEMC's Transmission Investment and Planning Review are designed to improve the transmission investment process. The ESB acknowledges that the CCM, by itself, does not solve all issues relating to transmission in the NEM.

Having said this, the CMM would be expected to improve transmission investment outcomes. As it is a least cost engineering assessment, the ISP (and hence the RIT-Ts) assumes efficient investment and bidding behaviour by market participants. That is, our existing transmission plan is in effect predicated on the introduction of congestion charges. Not introducing congestion charges, but continuing to make transmission investments regardless, is likely to result in misalignment between the ISP and actual market outcomes. Over time, this misalignment has the potential to result in inefficient transmission investment as the ISP is updated to include new generation investment.

The CMM also increases the value derived from new transmission investments because congestion across the grid is managed efficiently.

A3 Key issues for further consideration

Substantial further work and consultation is required to develop the CMM detailed design and Rules. As noted above, there is a trade-off between giving market participants access to risk management tools everywhere, and the quality of those risk management tools for each individual market participant. Further work is required to define the circumstances in which generators will be eligible

24 Customers would also indirectly benefit from more efficient generation investment and dispatch outcomes.

to receive congestion rebates, and how CMM fits with State based REZ schemes. Table A1 sets out the ESB's initial view of the key outstanding issues.

Table A1 Overview of key issues requiring further consideration

Issue	Description
Where rebates will be made available	The process used to determine which locations on the network will be eligible to receive rebates (e.g. locations that are defined as REZs, as well as any other appropriate locations)
Methodology used to calculate caps	The methodology used to calculate the caps on access to the pool of congestion rebates in each of the locations where rebates are available.
Rebate allocation scheme	The form of the rebate allocation process - e.g. tender, auction, first come first served, or part of a wider jurisdictional scheme to allocate other instruments such as financial energy contracts
Allocation of roles and responsibilities	Who is responsible for administering various aspects of the framework
Allocation metric	The exact metric used to allocate congestion rebates among eligible generators in each dispatch interval.
Nature of rebate entitlements	Whether rebate entitlements can be traded, and whether use is or lose it provisions are required in the event that a project falls through or is delayed.
Grandfathering arrangements	Whether grandfathered rebates received by incumbent generators should be treated the same as rebates purchased by new entrants.
Distribution level generation	Whether (and how) the access regime should apply to distribution level scheduled generation. Ideally, the regime should seek to avoid preferential treatment for either transmission or distribution-connected plant.
Interconnectors and constrained on generators	It will be necessary to reach a view on how to calculate interconnector "availability" for the purposes of allocating the revenue from the congestion charge between interconnectors and generators. This will have consequences for the firmness and design of inter-regional settlement residues. There is also a question as to whether generators who are constrained on (ie, have a negative congestion charge) should receive a negative rebate.
Impact on contractual arrangements	Stakeholders have suggested that there may be additional implementation costs if the reforms trigger the market disruption clause of a contract (particularly power purchase agreements), with the effect that the contract needs to be renegotiated. It will be particularly important to work with State governments to consider the impact on jurisdictional schemes.
In-train developments	It will be necessary to establish a mechanism to determine which developments are treated as incumbent and hence eligible to receive congestion rebates. The approach should seek to avoid disrupting genuine projects that are being developed under the current access regime, while also ensuring that it does not incentivise gaming behaviour.

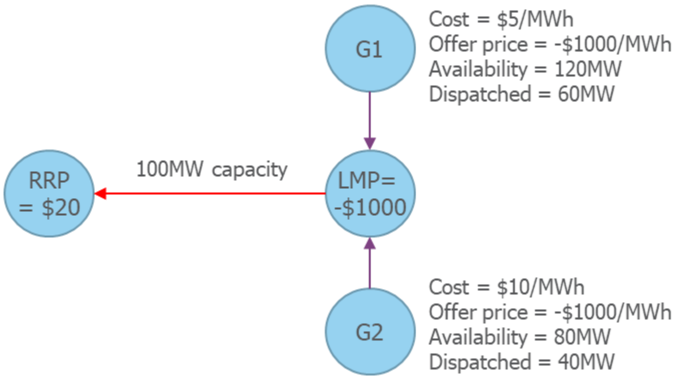
B. Worked examples

This appendix provides a simple example for a radial line, below, which ignores the effect of losses for ease of explanation. It shows outcomes under four scenarios:

- the status quo,
- under the CMM where both parties receive rebates,
- under the CMM when some generators receive rebates and some do not, and
- under the CMM where a storage facility is present.

B1 Status quo

Figure B1 Current arrangements with disorderly bidding



Under the current arrangements, it is privately profit maximising for both generator 1 and generator 2 to offer at the market floor price: -$1,000/MWh. As the dispatch engine is unable to distinguish between the underlying costs of the generators, it pro rates their dispatch quantities in proportion to their availabilities. There is 200MW of available generation behind the constraint, of which generator 1 has 120MW (60%) and generator 2 has 80MW (40%). Given the limit on the radial transmission line is 100MW, generator 1 is dispatched for 60% of this (60MW) and generator 2 for 40% (40MW) - in proportion to their availability.

This dispatch pattern is inefficient and so creates costs for consumers. Generator 1 has lower underlying costs and so it would be more efficient for the system as a whole for generator 1 to be dispatched for 100MW and generator 2 dispatched for nothing. But this is not profit maximising for generator 2, who would prefer to be dispatched and be paid the RRP. Depending on the relative carbon emission intensity of the generators, this outcome is also likely to be more carbon intensive, as thermal generators tend to have higher variable costs than variable renewable generators. The profitability of each of the generators is provided in the table below.

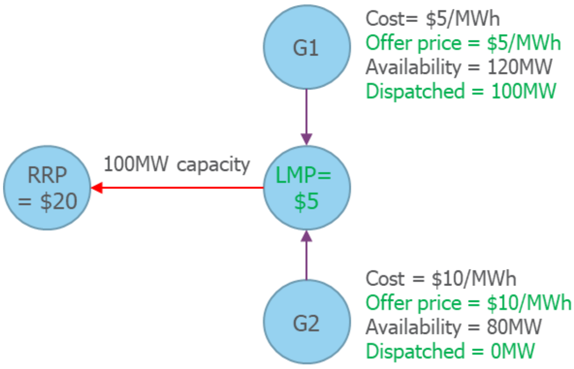
Table B1 Financial outcomes under status quo arrangements

	Price received ($/MWh) (A)	Cost incurred ($/MWh) (B)	Quantity generated (MW) (C)	Profit ($/h) (A – B) x C
Generator 1	20	5	60	900
Generator 2	20	10	40	400

B2 Both parties receive rebates

Figure B2compares the outcomes for under the congestion management model where both parties receive rebates.

Figure B2 Outcomes under the congestion management model (both with rebates)



Because the generators each face a congestion management charge which reflects the local marginal price, they offer reflective of their marginal costs (changed outcomes shown in green in Figure B2). To do otherwise would risk either not being dispatched or being dispatched for a price that is lower than their costs if their bid is too low. This is of course simplistic, but a useful assumption for illustrative purposes.

Given these offers, the dispatch engine dispatches 100MW of generator 1 and zero MW of generator 2. However, the financial impact on generator 2 is mitigated by the congestion management rebate.

The marginal cost of congestion, and hence the congestion management charge, is equal to the change in the cost of dispatch if the constraint was slightly less stringent. If there were 101MW of transmission capacity, rather than 100MW, then the lost cost combination would include another MW of generator 1 at a cost of $5/MWh, and a MW less of the generator setting the regional reference price at a cost of $20/MWh: a $15/MWh difference. Hence the rebate is $15/MWh. This results in total rebates paid by the generators (in this case all by generator 1) of $1500/h, because there is 100MW of flow on the transmission line.

This is then divided between generator 1 and generator 2 in the ratio of their availability behind the constraint: 60% to generator 1 ($900/h) and 40% to generator 2 ($600/h).

The overall financial outcomes for the generators are outlined in Table B2.

Table B2 Financial outcomes under congestion management model

	Price received ($/MWh) (A)	Cost incurred ($/MWh) (B)	Congestion management charge ($/MWh) (C)	Quantity generated (MW) (D)	Rebate (E) ($/h)	Profit ($/h) (A – B – C) x D + E
Generator 1	20	5	15	100	900	900
Generator 2	20	10	15	0	600	600

The following results arise:

- Under the congestion management model generator 2 is better off: because the total cost of dispatch collectively across all the generators has decreased but the revenue received from all consumers is the same, so the collective profitability of the generators has increased. In this case the benefits have accrued to generator 2, who has been

compensated for not being dispatched and avoided costs associated with physical dispatch.
- Settlement balances. All the revenue collected from the congestion management charge is exactly allocated back to the generators as rebates.
- The dispatch efficiency has improved under the congestion management model compared to status quo.

It appears to be always the case that the incentives for dispatch efficiency will be improved, and that generators will be collectively more profitable (or no worse off) under the congestion management model.[25]

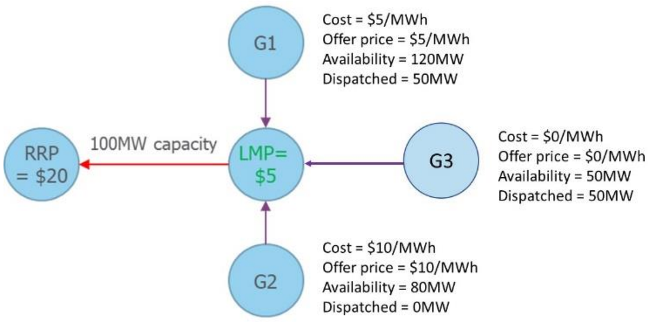
Under the simple example above, which has a radial constraint (i.e., a single route for power to travel from generation to load) the allocation is on the basis of availability alone. More complicated situations which include meshed networks and where there are multiple constraints binding simultaneously require a more sophisticated approach, which also takes into account the participation factors of the generators in the constrained transmission lines.[26] Participation factors represent the proportion of a generators' output which flows across a constrained transmission line and are already used by the dispatch engine.[27]

While the example above resulted in no individual generator being worse off than the status quo, this is not always the case on a meshed network, nor when the cost of the generators exceeds the RRP. More detailed quantitative assessment is required to understand the circumstances when this arises. Nevertheless, the sharing approach to determining the rebate for individual generators attempts to broadly replicate the existing way in which congestion risk is shared between generators (as occurs under disorderly bidding), while at the same time attempting to create efficient dispatch incentives.

B3 Some generators receive rebates and some do not

Under the following example, an additional generator is added to the right hand node, but this generator does not receive a rebate.

Figure B3 Outcomes under the congestion management model (one generator without rebates)



25 At least in the short run. Over time, we would expect that competition would erode the increase in profit to generators, to the benefit of consumers.

26 This more sophisticated settlement algebra is found here https://www.aemc.gov.au/sites/default/files/content/bd0bae75-0d9a-4c14-a2db-de275ab88209/International-Power%2C-AGL%2C-TRUenergy%2C-Flinders-Power%2C-Loy-Yang-nbsp%3B-4-April-2008.pdf pp.9-11.

27 On meshed networks, participation factors vary between -1 and +1. On radial parts of the grid, the participation factor is always exactly 1 (or minus 1). Because all the generators behind the constraint have exactly the same participation factor, this simplifies the more complicated settlement algebra discussed in the footnote above to give the simple result that the revenue received from the congestion management charge in allocated in proportion to just the generators' availabilities.

Generator 3's capacity is less than the capacity of the transmission constraint, and its bid price is less than that of generator 1, so it is dispatched in place of some, but not all, of generator 1. The congestion charge remains at $15/MWh.

The financial outcomes for the three generators are presented below, nothing that generator 3 pays the congestion charge but does not receive a rebate.

Table B3 Financial outcomes where one generator is without rebates

	Price received ($/MWh) (A)	Cost incurred ($/MWh) (B)	Congestion management charge ($/MWh) (C)	Quantity generated (MW) (D)	Rebate (E) ($/h)	Profit ($/h) (A – B – C) x D + E
Generator 1	20	5	15	50	900	900
Generator 2	20	10	15	0	600	600
Generator 3	20	0	15	50	0	250

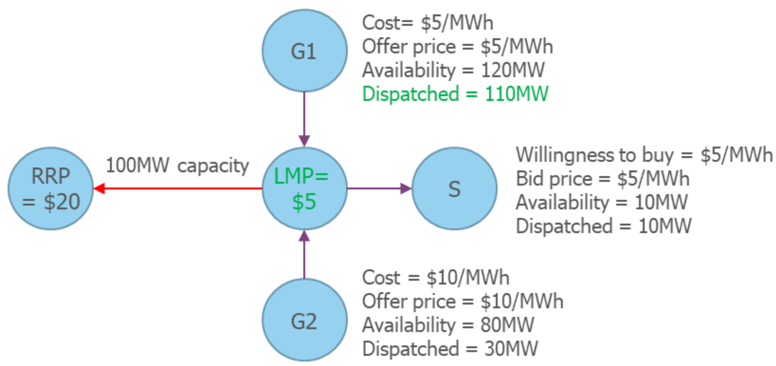
The following outcomes are observed:

- Total system costs are reduced by $250/h, because generator 3 is cheaper than generator 1 by $5/MWh and is offsetting 50MW of generator 1.
- This reduced total system cost is entirely captured by generator 3. Generator 3 therefore faces the appropriate price signals: it is rewarded for the benefit it provides to the system
- The profit of generators 1 and 2 are unaffected by the new generator in the dispatch interval in question. The risk of congestion that arises due to the future investment of generators has been mitigated by the rebate.
- Settlement balances. All the revenue collected from the congestion management charge is exactly allocated back to the generators as rebates.

B4 Storage and load

The example below describes the operational incentives for storage under the CMM.

Figure B4 Outcomes under CMM in the presence of storage



Both generator 1 and 2 are solar generators, and the dispatch interval is in the middle of the day. As a result, both generators are capable of generating a combined output of 200MW, absent of transmission congestion. The introduction of a storage unit, S, means that 10MW more generation is dispatched, all of which is from generator 1 as it is the cheapest and still has sufficient capacity. Less renewable generation is spilt.

The storage unit pays the RRP, but then pays the (negative) congestion management charge of \$15/MWh. There is still \$1500/h of total revenue received via the rebate, and this continues to be allocated on the basis of the two generators' availabilities (i.e., 60% and 40%, respectively) (as we have assumed that the storage unit does not have an entitlement to the rebate). The financial outcomes of each of the generators and storage is provided below.

Table B4 Financial outcomes under CMM in the presence of storage

	Price received (\$/MWh) (A)	Cost incurred (\$/MWh) (B)	Congestion management charge (\$/MWh) (C)	Quantity generated (MW) (D)	Rebate (E) (\$/h)	Profit (\$/h) (A – B – C) x D + E
Generator 1	20	5	15	110	900	900
Generator 2	20	10	15	0	600	600
Storage	20	0	15	-10	0	-50

Storage would pay \$50/h or \$5/MWh, whereas under the current arrangements it pays \$200/h or \$20/MWh (the regional reference price). When the sun sets, and the constraint is alleviated, the storage can then discharge and receive the regional price at that later time, with a higher arbitraged profit as a result.

The result incentivises for storage to operate and invest efficiently, based on the principle that prices should reflect marginal costs. In contrast, under the current arrangements, storage may be incentivised to not locate behind the constraint in the first place (because it is unable to financially capture the economic benefit it provides to the system) or may even engage in disorderly bidding in competition with generators 1 and 2 to export to receive the RRP – exacerbating the constraint and causing yet more renewables to be spilt.

C. Previously considered alternative models

A key part of the ESB's upcoming consultation process will be to engage with stakeholders regarding alternatives to the CMM.

Transmission access reform has a long history in the NEM and many models have been considered over time. As with other types of regulatory policy, the coordination of transmission and generation can be delivered via a market-based approach, a planning-based approach, or a hybrid. In addition to CMM-style models, the leading models are:

- Locational marginal pricing and financial transmission rights
- Generator transmission use of service charges (TUOS)
- Deep connection charges.

This section outlines in broad terms the options that have been considered in the past and summarises why they have not been pursued. Most recently, the ESB's post 2025 market design review discussed the pros and cons of each of the main models.[28] A survey of earlier reviews can be found in the Optional Firm Access Draft Report, Volume 1, Appendix B.[29]

C1 Locational marginal pricing and financial transmission rights

This model (also known as nodal pricing) represents a market-based approach to transmission access. This market design is common and well-established for decades overseas in a variety of different settings, including in North America and New Zealand. This model was proposed by the AEMC as part of the Coordination of Generation and Transmission Investment review[30], and the ESB during earlier stages of the Post 2025 Market Design Review.

This model involves two key changes:

- locational marginal pricing, which involves large-scale generators and storage receiving a spot price that varies based on their local supply and demand conditions – rather than the regional price;
- financial transmission rights, which participants can purchase to hedge against the differences in wholesale market prices that arise due to network congestion and transmission losses.

International experience suggests that LMPs/FTRs will send better locational signals and information to participants, enabling them to make better investment and operational decisions, and use the transmission network more effectively. However, stakeholders raised a number of concerns, including:

- Exposure to basis risk that generation investors would face if they were subject to lower, more volatile LMPs;
- High implementation costs, including system costs and the impact on contractual arrangements; and
- Uncertainty arising as a result of such a substantial change to the market design.

28 ESB, Post 2025 Market Design Options Paper, Part B, Chapter 4, April 2021. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf

29 https://www.aemc.gov.au/sites/default/files/content/e3455d5c-4492-4ab4-a212-03b9da989928/Optional-Firm-Access-Draft-Report-Volume-1.pdf

30 https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

C2 Generator transmission use of service charges (TUOS)

Under this model, generators would pay an administratively calculated TUOS charge, with this attempting to reflect the incremental cost of using the network at various locations. The charges would vary by location because the cost of using the transmission system varies by location. These charges could be updated on an annual basis.

The two main options for determining generator TUOS include:

- Using administratively determined estimates of the long run marginal cost of transmission at each connection point, which is similar to the locational charges that loads currently face.
- Using administratively determined estimates of the short run marginal cost of congestion over the course of a year, which is similar to the current process used for marginal loss factors.

Where generator TUOS frameworks are used internationally they are often accompanied by a generator reliability access standard. Typically, this applies on an averaged basis throughout a generator reliability region, similar to the reliability standard that already exists for load. While this does not provide a specific access right to individual generators it would deliver some assurance as to the average level of congestion.

Generator TUOS models involve setting a price signal that is calculated administratively in advance and which seeks to provide effective locational signals for investment. That is very difficult, especially in a more complex power system with a mix of variable renewable energy, conventional generation and storage using the transmission system in different ways and at different times. In particular, a generator TUOS charge would not reflect the dynamic, short run marginal cost of the transmission network. This means that in operational timescales, generators and storage would not be sent the appropriate price signals and is likely to result in inefficient dispatch.

For any generator TUOS model that would include a generator reliability standard:

- This standard would lack flexibility by mandating a uniform level of access for generators – generators would have to pay the administrative set price and receive the administratively set level of access in return. There would be no flexibility or optionality for generators in this.
- Consumers would bear the risk that the regulated standard is inappropriate. This may result in an inefficiently high amount of transmission (high TUOS charges for load without commensurate reductions in wholesale prices), or an inefficiently low amount of transmission (high wholesale prices without a commensurate reduction in TUOS charges for load), or a combination of the two in differing locations.
- Generators would also need to bear the risk that the regulated standard is inappropriate. For generators, an inefficiently high amount of transmission could lead to high TUOS charges without providing substantial reductions to their volume risks because the increased transmission leads to increased access for their broader area rather than for an individual generator specifically.

C3 Deep connection charges

Under this model, a new generator pays for both cost of the physical connection to the grid (its shallow connection costs, which it already pays for) along with the costs of any transmission network reinforcement, over that already committed, required to maintain access for all existing network users. These costs are often referred to as a “deep connection charge.”

The need for reinforcements is assessed by reference to the impact of the new generator connection on the ability of the TNSP to meet the transmission reliability standard. Under a deep connection charging model, the transmission reliability standard typically includes standards that relate to the ability of the network to export generator output as well as standards that relate to load.

This new charge calculated at the time of their connection based on the estimated cost of the network reinforcement required to accommodate them. The payment can be set as a one-off upfront payment, or it can be converted into $/MWh over a long period of time (e.g. 20 – 30 years), or it could be paid based on some other arrangement that could be negotiated between the generator and their TNSP. If converted into a $/MWh charge, the forecast of the output of the generator in question is needed over the same period in order for the calculation to be made and the potential impacts on the efficient dispatch of the plant needs to be considered.

A variant option of this model would be to determine an estimate of the long run marginal cost when a generator first connects to the transmission network and leave it unchanged afterwards. In this case, the estimate of long run marginal cost would be calculated by reference to the forward-looking plan for transmission investment as set out in the ISP. If a generator's location decision aligns with the ISP, they would face a lower connection charge that a generator whose location decision does not align with ISP.

Under an LRMC deep connection charging model, the charge is calculated on a case by case basis as part of each generators' connection process, and the cost is known up front. This is contrasted to generator TUOS described above, where the LRMC is recalculated on an annual basis.

The application of deep connection charges is complex as it needs to consider:

- The definition of the access of existing plant that needs to be maintained by any augmentation funded through deep access charging including which generators and storage providers, to where, under what conditions and at what times
- A baseline transmission plan needs to be adopted to calculate the incremental deep connection charge
- The lumpy nature of transmission investment meaning that deep connection charges could move over a wide range and can induce strategic queuing behaviour.

Under deep connection charging, there is a risk that new connecting generators might be obliged to pay for inefficient investment as the access standard may not necessarily align with the use of the network. As with generator TUOS, it also does not provide a solution to inefficiencies in dispatch because the price they face in operational timescales would not reflect the marginal cost of congestion.

Despite these issues, deep connection charges would provide locational signals to potential investors and deliver a level of certainty. For example, by setting the charges prior to connection, generators would be able to include these in their investment decisions with no risk of change, which may decrease their overall risks.

The deep connection charging model does not give rise to the grandfathering issues that arise in relation to generator TUOS, since legacy generators have already connected to the network.

D. Reforms to deliver efficient transmission investment

Substantial transmission investment is needed to accommodate the forecast 26-50 GW of new low-cost large-scale variable renewable energy expected by 2040. These relatively smaller and geographically dispersed renewable generators need to connect in windy or sunny parts of the grid. Historically the transmission network was built to transport energy from coal fuelled and hydro generation to load centres. The current networks have not required large amounts of transmission capacity in the areas where this new generation now needs it.

A wave of new transmission investment is underway to develop committed and actionable ISP projects. However, challenges are emerging in getting the new network built. These include planning issues, community concerns, biodiversity, indigenous heritage, difficulties getting access to land and reluctance by networks to take risk and cope with financing very large projects. There are also questions over whether the network planning framework, including the role of the ISP and Regulatory Investment Test for Transmission (RIT-T), could be streamlined and whether large transmission projects could be delivered more efficiently through competition rather than by incumbent transmission network service providers. These emerging challenges create risk that the new network is not built in a timely manner and at least cost.

In this context, a number of reform processes seek to deliver efficient transmission investment. These issues have been a key focus of several ESB projects, including new rules to convert AEMO's Integrated System Plan (ISP) into action, and the development of an interim framework for Renewable Energy Zones (REZs).

D1 Development of Renewable Energy Zones

In parallel to the ESB's package of reforms, major programs to develop REZs are being undertaken by State governments. To promote coordinated development, the ESB has recently completed a two-stage process to develop an interim REZ framework. The REZ Planning Rules[31] and the Interim REZ Recommendations[32] build on the ESB's rules to action the ISP. The framework is intended to complement and support the work of State governments.

Energy Ministers have adopted the ESB's recommended principles for an interim REZ framework - including access within a REZ. The principles relate to four key issues: planning, connections, funding and economic regulation, and access. These principles provide flexibility to enable jurisdictions to pursue REZ schemes in accordance with required timeframes, while also maintaining consistency across the NEM with respect to core aspects of the market design. The interim REZ framework is designed to align with key areas of market reform that should ultimately form part of the Rules, including the transmission access regime and system security frameworks.

In an interconnected power system, developments in one location can have significant flow on consequences elsewhere, including in other jurisdictions. The interim REZ principles seek to ensure that REZ developments avoid costly ramifications from a whole of system perspective.

The planning and implementation of priority REZs is an important step to the efficient connection of generation to the enhanced grid. Some form of transmission access reform, such as the CMM, is required to support the integration of REZ. The CMM complements the interim REZ framework and addresses the emerging congestion management needs of the system. Together these changes are

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31 ESB, Renewable Energy Zone Planning Final Recommendations, February 2021. Available at: https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/ESB%20final%20recommendations%20REZ%20Planning%20Rules.pdf

32 ESB, Interim Framework for Renewable Energy Zones – Final Recommendations, June 2021. Available at: datocms-assets.com/32572/1631503418-esb-decision-document-renewable-energy-zones-recommendations-final-1-june-2021-to-encrc.pdf

intended to encourage new generation and storage to locate in REZs, lessen the likelihood that their access to the grid is degraded by the connection of other generators outside the REZ, and also lessen the impact of other REZs. A detailed design needs to be developed enabling comprehensive consultation with stakeholders and interested parties.

D2 Transmission Planning and Investment Review

In this context, the AEMC is conducting a review to determine whether changes are required to the regulatory framework in order to maximise benefits to consumers through the timely and efficient delivery of major transmission projects (including ISP projects). The scope of the review may include, but is not limited to:

- Implications of TNSPs having the monopoly right but no obligation to build critical major transmission infrastructure.
- Consideration of whether existing frameworks support and provide sufficiently strong incentives for TNSPs to deliver major transmission projects in a timely and efficient way, including examination of potential improvements and alternatives such as the introduction of contestability in transmission planning and delivery.
- Opportunities to improve the RIT-T and the ISP processes.
- Related rule changes that could be run concurrently with the Review.

Stage 1 of the review will focus on identifying and testing issues associated with the frameworks for planning, funding, financing, and delivering major transmission projects. Stage 2 will focus on identifying and developing solutions to address the issues identified in Stage 1. A consultation paper was published in August 2021 and the AEMC is currently considering issues raised in submissions.

D3 AEMC's dedicated connections assets and system strength rule changes

On 8 July the AEMC made a final rule on its Dedicated Connection Assets rule change, which establishes new opportunities for a generator, a group of generators, merchant investors or governments to develop a radial REZ on a commercial basis. The AEMC has also recently published its final determination on the system strength rule change.[33] The reformed system strength regime uses the transmission planning regime to identify and deliver system strength investments that align with the efficient development of the power system. As such, the system strength reforms complement and builds on the coordinated process used to deliver REZs. Both of these reforms complement the ESB's reform pathway.

D4 Actionable ISP framework

The actionable ISP framework introduced whole of system planning rather than the previous transmission-centric, project-by-project approach to transmission planning. This has consequences for the funding of REZs.

The Rules have always permitted TNSPs to build new transmission for the purpose of connecting new generation. However, under the previous RIT-T framework, it was problematic for a TNSP to justify such investments due to the scale of the modelling exercise involved. The TNSP is required to demonstrate that the proposed investment maximises net market benefits, recognising that there are any number of alternative locations elsewhere in the NEM where the generation might locate.

For this reason, under the previous RIT-T framework, TNSPs found it necessary to wait until the relevant generation projects became committed before they could be formally included in a RIT-T

33 https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

assessment. This gave rise to the “chicken and egg” problem, whereby generation could not become committed before the transmission was committed and vice versa.

Under the actionable ISP framework, the scale of AEMO’s modelling exercise has increased to an extent that the Rules requirements can now be met before generation projects become committed. The ISP models plausible combinations of generation and transmission solutions required to meet power system needs over the 20-year outlook period. It provides a whole of system plan that includes the optimal generation mix, and the transmission required to support it. The ISP identifies the optimal development path, which is the suite of projects (including generation projects) that efficiently meets a defined set of power system needs, where power system needs are:

- the market reliability standard
- relevant transmission reliability standards
- power system security.

These needs must be achieved having regard to economic efficiency, public policy and good electricity industry practice.

This change of perspective towards whole-of-system planning means that if a transmission investment associated with a REZ is classified as an actionable ISP project and it passes the RIT-T, it is able to proceed on a regulated basis – i.e., the assets would be built, owned and operated by the local TNSP and funded entirely or in part by customers.

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