ENERGY SECURITY BOARD

Transmission access reform

Consultation paper

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List of abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CEC	Clean Energy Council
CEIG	Clean Energy Investor Group
CRM	Congestion relief market
CRMP	CRM price
DC	Direct current
DP	Dispatch priority
DUID	Dispatchable unit identifier
ECMC	Energy and Climate Change Ministerial Council
EN	Energy market
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
GW	Gigawatt
IESS	Integrating Energy Storage Systems
IRP	Integrated Resource Provider
IRSR	Inter-regional settlement residue
ISP	Integrated System Plan
LHS	Left hand side of a constraint equation
LP	Linear program
MNSP	Market network service provider
MFP	Market floor price
MPC	Market price cap
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objectives
NER	National Electricity Rules
OSM	Operational security mechanism
PPA	Power purchase agreement
REZ	Renewable Energy Zone
RHS	Right hand side of a constraint equation
RRN	Regional Reference Node
RRP	Regional Reference Price
SCADA	Supervisory control and data acquisition
SRA	Settlements Residue Auction
SRMC	Short run marginal cost
TNSP	Transmission Network Service Provider
VRE	Variable renewable energy

Executive Summary

The Energy Security Board (ESB) is developing a transmission access reform package to address market design issues in response to congestion.

Transmission access reform is key to deliver an orderly energy transition that supports the long-term interests of consumers. Congestion will become more common as we transition to net zero and adopt a higher level of variable renewable energy (VRE). We are at a critical juncture to influence where we build our generation and storage fleet of the future. It is vital we use our generation, storage and transmission infrastructure efficiently to protect consumer interests.

The ESB has worked closely with industry stakeholders to develop a preferred model design. It is needed to ensure that congestion on the network is efficiently managed and the network is used effectively. On 24 February 2023, Ministers accepted the ESB's draft recommendations and agreed a way forward on this complex issue.

> "…Ministers agreed to immediately implement 'enhanced information' reforms to provide east-coast market participants with better information on the optimal location for new generation and storage.
>
> Ministers requested that the Energy Security Board (ESB) work with Senior Officials and stakeholders to develop the voluntary congestion relief market (CRM) and the priority access model ['the hybrid model'] and to bring forward a detailed design for consideration by the Energy and Climate Change Ministerial Council (ECMC) in mid-2023."[12]

'Enhanced information' will be developed as a rule change request.

'Enhanced information' is intended to promote more informed investment and siting decisions. To action this task efficiently, the ESB is developing an enhanced information rule change which is expected to be progressed by the Commonwealth Government. The draft rule change request builds on stakeholder submissions previously received.

'Enhanced information' is not included in the scope of this consultation paper. We will continue to notify stakeholders of its progress. Stakeholders will have the opportunity to provide input and feedback on this proposal as part of the rule change process.

We seek stakeholder feedback on key design choices that will inform the ESB's final policy recommendations.

We need stakeholder inputs to assess the risks and opportunities for the model's detailed design against the transmission access reform objectives and assessment criteria.

The ESB recognises that these reforms would represent a significant change to the NEM's bidding and dispatch processes and this creates operational risk for both AEMO and market participants. While this paper does not seek stakeholder feedback on technical changes to AEMO's systems, we have provided a status update on the technical investigations for shared visibility.

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1 Refer to Energy Ministers' communique, 24 February 2023: https://www.energy.gov.au/sites/default/files/2023-02/ECMC%20Communique%20-%2024%20February%202023.docx

In parallel, we are engaging closely with jurisdictions. Transmission access reform is intended to support and strengthen jurisdictional schemes. In particular, priority access provides a clear mechanism to support the delivery of renewable energy zones (REZs). Priority access can be reserved for REZs to support the coordination of generation and transmission investments. It also can protect REZ generators from the financial impact of congestion caused by generators located outside the zone (and free-riding on investments intended for REZ participants). It enables us to use the REZ developments and associated resources effectively and minimise costs for consumers.

This paper confirms the status of design choices raised in the previous directions paper.

The directions paper was released in November 2022 with submissions received in December 2022.

Design choices raised in the directions paper for priority access remain open. The Ministers' decision allows stakeholders to focus on one hybrid model design, rather than multiple model variants. This consultation paper re-presents model options with clarifications on their design and the critical questions for stakeholder input. This will inform the development of the priority access model.

Design choices raised in the directions paper for the CRM design have broadly been resolved. The ESB has proposed initial preferences which will apply as a working assumption going forward. The ESB is broadly aligned with stakeholder views. Based on stakeholder feedback and inputs from the ESB's technical team, the initial preference is to adopt design choices which retain the existing energy market arrangements and maintain the optionality of the CRM.

Our consultation with stakeholders continues beyond the final policy recommendations.

The detailed design (to be submitted to Ministers in mid-2023) is intended to confirm key policy principles. It represents an important project milestone but does not mark the end of the design process, nor of stakeholder input and consultation.

Assuming Ministerial approval for the policy recommendations in mid-2023, there will be subsequent details to be discussed and resolved. This will occur through the process of drafting amendments to the National Electricity Rules (NER) and finalising the technical specification for implementation into AEMO's systems. There will be at least one round of consultation on these draft rules. We will provide details of this future consultation following the Ministers' decision in mid-2023.

We also suggest that the rules put in place a review of the priority access and the CRM model 3 years after implementation. This review should include consultation with stakeholders. It will have the benefit of real data points to consider the operation of the scheme and any refinements that may be required at that time.

Written submissions are due by 12pm AEST, Friday 26 May 2023.

Written submissions must be lodged by email to info@esb.org.au. Stakeholders can also use this email address to lodge any queries.

The ESB will hold a webinar on the material covered in this paper on Monday 8 May 2023, 1.30 - 3pm AEST. Interested parties are invited to register here.

1 Introduction

1.1 Purpose of document

Ministers have tasked the ESB to work with Senior Officials and stakeholders to develop the detailed design of the transmission access reform package which includes:

- A hybrid model comprising the voluntary congestion relief market (CRM) and priority access
- 'Enhanced information' to provide better information to market participants.[3]

The consultation paper focuses on the detailed design for the hybrid model. Design choices and consultation questions are detailed in chapter 3 and 4.

1.1.1 Congestion relief market and priority access

This consultation paper:

- confirms the status of design choices published in the directions paper (November 2022)
- seeks stakeholders' feedback on open and new design choices
- outlines the status of technical considerations
- outlines next steps in the model's design and development.

Stakeholder feedback will guide the ESB as it develops its detailed design and final policy recommendations to Ministers in mid-2023.

1.1.2 Enhanced information

'Enhanced information' is not included in the scope of this consultation paper.

The ESB is developing an enhanced information rule change which is expected to be progressed by the Commonwealth Government. It will build on stakeholder submissions previously received. The rule change request will be submitted to the AEMC and progress through the AEMC's rule change process.[4] The ESB will continue to notify stakeholders of its status.

There are linkages between the scope and nature of 'enhanced information' and the priority access reforms. The priority access reforms will build on the enhancements to information. To make more efficient decisions, investors will need information relevant to the priority access mechanism including how hosting capacity assessments translate to a priority level of access. The ESB project teams are collaborating on these issues and will also collaborate with the AEMC once the request is submitted.

1.2 Process to date

In October 2021, National Cabinet instructed the ESB to progress detailed design work on transmission access reform for the National Electricity Market (NEM). The design process should include a comprehensive consultation process and take into consideration value for money, locational signals and ensuring sufficient flexibility for jurisdictional differences.[5]

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3 Refer to Energy Ministers' communique, 24 February 2023.

4 Refer to https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request

5 Refer to Summary of the final reform package and corresponding Energy Security Board, published October 2021

1.2.1 Consultation process

The ESB has engaged extensively with stakeholders on the detailed design. This includes public consultation, regular meetings with a technical working group and bilateral and peak body briefings. Ministers requested that the ESB develops a hybrid model combining concepts proposed by industry including Edify Energy, the Clean Energy Council (CEC) and the Clean Energy Investor Group (CEIG).

Key points of consultation have included:

- Project initiation paper, released November 2021: in response, stakeholders submitted alternative models to the ESB's preferred model at the time (congestion management model (CMM) adapted for REZs). The ESB engaged with stakeholders to understand their proposals and identify the best features of the proposed model designs.
- Transmission access reform consultation paper, released May 2022: The ESB shortlisted four out of the ten models in a consultation paper. The paper outlined the ESB's access objectives and assessment criteria developed in collaboration with the ESB's technical working group.
- Directions paper, released November 2022: the ESB proposed a preliminary hybrid model which included the congestion relief market (CRM) and two key variants based on priority access or congestion fees. The paper sought stakeholder views on 23 design choices that would form part of the future detailed design.
- Technical working group, ongoing meetings (March 2022 to present day): membership includes representatives from industry and consumer groups. Papers and minutes from the meetings are published on the ESB's website.

The ESB has undertaken a joint consultation process with Senior Officials since October 2022.[6] This has included a series of joint public and industry forums in parallel with the ESB's stakeholder engagement. Details of the ESB's consultation plan for this paper are provided in chapter 5.

1.3 Process going forward

Publication of this consultation paper marks an interim project milestone. There is an ongoing process of consultation required before and after the ESB submits its final policy recommendations.

1.3.1 Education initiative

The ESB recognises the need to establish an education workstream to familiarise stakeholders with the access reform changes. This includes presenting technical information in an accessible way so that stakeholders can familiarise themselves with the proposed reforms.

The ESB has previously published worked examples based on a simplified intra-regional looped flow network limited to 4-5 nodes. Stakeholders have specifically requested in their submissions for real-world examples. AEMO has developed a prototype to develop and test the detailed design of the energy market with priority dispatch and the CRM dispatch. Initial results from this NEMDE CRM prototype are introduced in section 4.3.1 and expanded in **Appendix E**.

6 Energy Ministers tasked Senior Officials to jointly undertake stakeholder consultations with the ESB on the options for transmission access reform in preparation for the Energy Ministers' meeting on 24 February 2023. Refer to communique, 28 October 2022. Available at: https://www.energy.gov.au/sites/default/files/2022-10/Energy%20Ministers%20Meeting%20Communique%20-%2028%20October%202022.docx

The ESB is working on a platform to visualise scenarios from the NEMDE CRM prototype. The ESB will notify stakeholders of updates and schedule specific webinars to support users' understanding of the proposed model options during the consultation period.

1.3.2 Engagement with jurisdictions

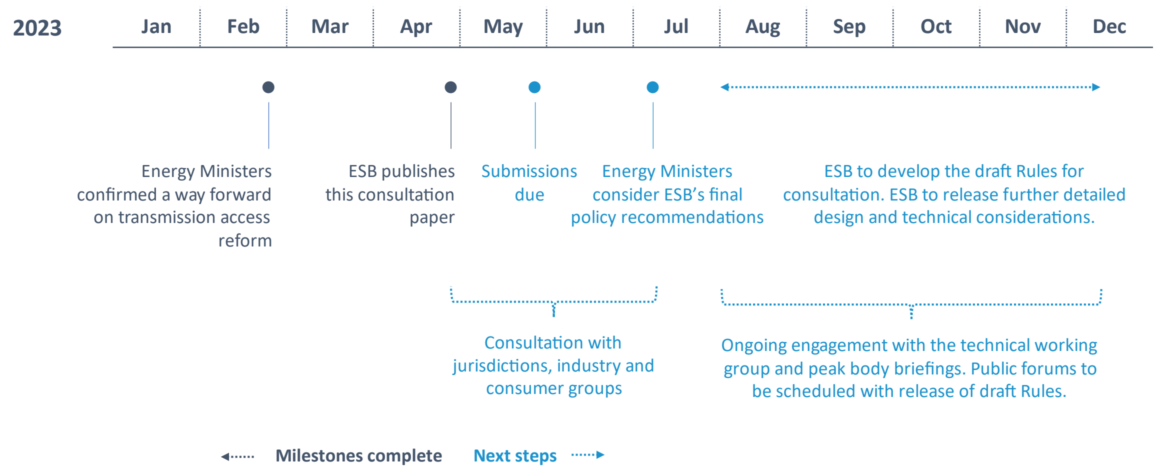
Transmission access reform is intended to support and strengthen the jurisdictional schemes. The ESB is undertaking close engagement with each of the jurisdictions before it submits its final policy recommendations. One of the assessment criteria specifically requires an assessment of the model design in this regard. As requested by Ministers, the proposed rules must provide flexibility such that differences between jurisdictions' access schemes, including those without REZ schemes, can be appropriately integrated.

The ESB will consult with industry, consumer groups, the public and the jurisdictions in parallel. Feedback from all sources will guide the ESB's final recommendations to Energy Ministers in mid-2023.

1.3.3 Draft Rules and consultation

Assuming Ministers accept the ESB's final policy recommendations, we will develop and consult on the draft Rules later in 2023. Figure 1 shows the key project milestones.

Figure 1 Project milestones and next steps



Source: ESB

The ESB will release details of the consultation plan to accompany the draft Rules following the Energy Ministers' meeting. Next steps are captured in chapter 5.

1.4 Drivers for reform

Transmission access reform is key to deliver an orderly energy transition that supports the long-term interests of consumers.

With a 9-fold increase in utility-solar and wind, and 16GW of utility-scale storage expected under the ISP Step-change scenario by 2050, we are at a critical juncture to influence where we build our generation fleet of the future. It is vital we use our infrastructure efficiently to protect consumer interests.

The ESB has published detailed papers on the case for change including the directions paper, a cost benefit analysis of the hybrid model variants and detailed modelling on the CRM design. These were supporting materials for the ESB's draft recommendations to Ministers in February 2023. Key insights from these materials include:

- The recommended model combination (CRM and priority access) results in:
    - quantified net benefits estimated at $2.1-5.9 billion
    - a reduction in emissions by 23 million tonnes over 20 years.[7]
- The hybrid model supports and strengthens REZ schemes and is likely to have a downward impact on cost of capital.[8]
- Detailed modelling of dispatch shows the complexity and risks to efficiency of operating the market under the current design into a low carbon future.
- In the absence of reform, it will be increasingly necessary for AEMO to clamp the interconnectors to avoid customers having to fund revenue shortfalls. Given that the forecast cost of interconnector investments is over $11 billion, it is important that our ability to use them is not undermined by shortcomings in the market design. Counter-price flows, and hence the need for interconnector clamping may be mitigated by the proposed reforms.

This paper does not re-prosecute the case for change but it does discuss key risks in today's energy market, the objectives of the model options and how their design seeks to address congestion issues in investment and operational timeframes.

1.4.1 Transmission access reform objectives

The ESB has developed objectives and assessment criteria as critical parameters. Figure 2 sets out the four transmission access reform objectives. Our detailed design process seeks to identify the design options that best promote these objectives.

Figure 2 Access reform objectives

Investment timeframes *The level of congestion in the system is consistent with the efficient level.*	Operational timeframes *When congestion occurs, we dispatch the least cost combination of resources that securely meets demand.*
1. Investment efficiency: Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, taking into account the impact on overall congestion. 2. Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.	3. Operational efficiency: Remove incentives for non-cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.

4. Incentivise congestion relief: Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.

Source: ESB

7 We note that the CRM and priority access model will also have resourcing implications on the AER to perform its functions to monitor the market and ensure compliance with the reforms.

8 The ESB commissioned a report by Cambridge Economic Policy Associates (CEPA) on the cost of capital impacts.

1.4.2 Assessment criteria

The ESB will apply an agreed set of criteria to assess the design choices. The assessment criteria are set out in Table 1.

The criteria draw upon 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).[9]

Table 1 Access reform assessment criteria

	Criteria	Description
1	Efficient market outcomes – investment	• Better incentives for generators, storage such as batteries, and load such as hydrogen electrolysers to locate in efficient areas. In the case of generation, this is most likely where there are low congestion levels, such that transmission assets are better utilised. In the case of storage and load, these may be congested areas to help alleviate that congestion and use otherwise wasted renewable electricity that could not reach the 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	• Risk arising due to congestion in the NEM should be allocated, to the extent possible, to the party that is best placed to manage or otherwise bear that risk, noting the practical limitations on exposing parties to risk without appropriate mitigation tools and measures.
4	Manage access risk	• Lower risk to investors, where the benefits of doing this outweigh the costs (from a consumer perspective), by addressing the features of the current market design that amplify access risk. • Facilitate market participants' ability to manage access risk. • Managing the risk arising from regulatory change, i.e. consider whether there are strategies to mitigate the impact of the changes on market participants.
5	Effective wholesale competition	• Any changes should promote an effectively competitive wholesale market by avoiding creating barriers to new entry; any additional costs to new entrants associated with their transmission connection reflects a benefit(s) they receive in return.
6	Implementation considerations	• Cost and complexity: cost and complexity of implementation, including the impact of the system's physical complexities and ongoing regulatory and administrative costs to all market participants, consumers and market bodies, compared to the expected benefits of the option, and as compared to the status quo. • Timing and uncertainty: uncertainty of outcome, the likely timing of benefits versus costs.
7	Integration with jurisdictional REZ schemes	• As requested by Ministers, the proposed rules must provide flexibility such that differences between jurisdictions' access schemes, including those without REZ schemes, can be appropriately integrated.

9 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).

2 Outline of the hybrid model design

2.1 Introduction

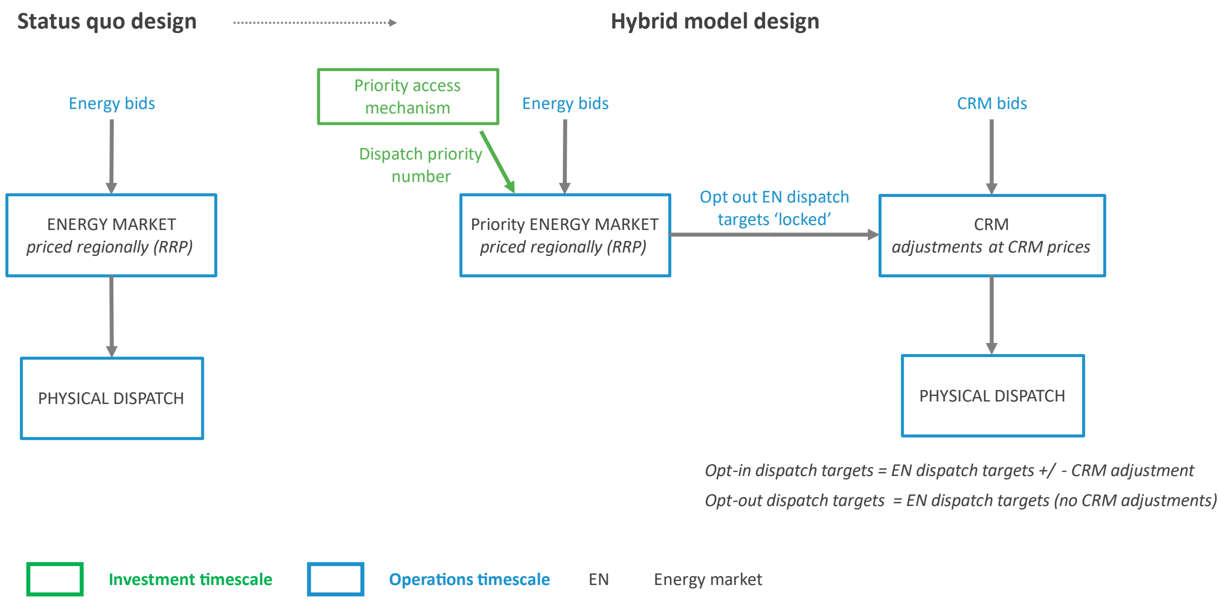
In February 2023, Ministers requested that the ESB provide a detailed design for the voluntary CRM and priority access model for consideration in mid-2023. This consultation paper builds on the design proposal and choices released in the directions paper (November 2022).[10] New terms are defined to describe the model options and consolidated in the Glossary for reference.

This chapter provides a recap of key concepts in today's market design and clarifies the key components of the hybrid model design which include:

- priority access:
    - priority access mechanism
    - priority dispatch in the energy market (EN)
- congestion relief market (CRM).

Detailed design choices are introduced and assessed in subsequent chapters. Figure 3 illustrates the change in market architecture as a result of the hybrid model design.

Figure 3 Change in market architecture



Source: ESB

2.2 Key concepts in today's market design

Today's energy market design creates key risks for investment and dispatch efficiency, and the ability of investors to manage congestion risk effectively. This section provides a recap of issues explored in detail in the directions paper so that readers can understand key concepts, the objectives of the model

10 ESB, Transmission access reform directions paper, November 2022. Available at: https://www.datocms-assets.com/32572/1667984730-tar-directions-paper-final-for-web.pdf

options and how their design seeks to address congestion issues in investment and operational timeframes.

2.2.1 Current access mechanism

The current access regime does not use a market to ration access to constrained parts of the transmission network.

In operational timeframes, the volume that a generator[11] may sell into the market is determined via the NEM's dispatch engine (NEMDE). NEMDE is a co-optimised dispatch algorithm. It determines the output of each generator that leads to the overall lowest cost dispatch (as reflected by generators' bids) to meet demand while maintaining system security and avoiding violations of constraint equations.

These constraint equations represent the physical limits of the system:

- The right-hand side (RHS) of constraint equations represents the physical limit of the system or piece of equipment to which the constraint equation relates. The limits can be represented by a mix of fixed numbers and measured parameters, the formulation of which is determined in advance by AEMO for each constraint equation.
- The left-hand side (LHS) of constraint equations contains all the inputs that can be varied by NEMDE to avoid violating the constraint, such as output from scheduled and semi-scheduled generators and flows on interconnectors.

Each generator or interconnector on the LHS of a constraint equation is "participating" in the constraint. Changes in their output changes the flow of energy across the piece of equipment to which the constraint equation relates. Each generator that participates in a constraint has a constraint coefficient (also known as a contribution factor or participation factor).[12] The constraint coefficient reflects the impact of a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector) on the relevant piece of equipment. Typically, the further away a generator or interconnector is located from the constrained line the less it uses that line. If a one MW change in generator output only results in a small MW impact on the constraint, this is reflected by a smaller constraint coefficient.

The formulation of constraints is designed to reflect the physical realities of the power system. This approach gives rise to efficient dispatch outcomes, providing that generators are incentivised to bid in a manner reflecting their costs.

When a constraint is "binding", more generation is trying to access a piece of equipment than can be accommodated. Access must be *rationed* between the generators participating in the constraint. Some generators must be "constrained off" and their dispatch is reduced.

NEMDE calculates the lowest cost dispatch solution that satisfies the constraints i.e. lowest cost based on generator bids. It is priced regionally i.e. every generator is paid RRP for their output, no matter where they are located within a region and whether or not their output is causing congestion. When a constraint binds and the RRP is above a generator's marginal cost (factoring in contract

11 In the context of priority access, generator is often applied as a shorthand for market participants including scheduled and semi-scheduled generators and market network service providers.

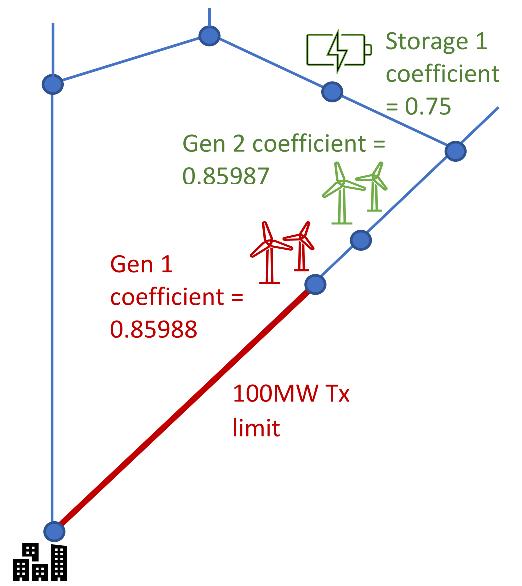
12 AEMO, Constraint Implementation Guidelines, June 2015

arrangements), generators participating in the constraint are likely to bid to the market floor price. This maximises their chances of being dispatched and paid the RRP.

In these circumstances, the generators' coefficients in the binding constraints become determinative. For example, in the case of a single binding constraint, NEMDE dispatches those generators "competing" in the constraint at the market floor price in ascending order of constraint coefficients.[13]

Bidding at the market floor price erodes dispatch efficiency. The bid no longer reflects the generators' costs but NEMDE continues to operate as though it does. The bidding also gives rise to "winners take all" outcomes when a single network constraint affects the dispatch of generators even where the coefficients of those generators have only minor differences. Figure 4 shows how access is rationed between generators competing in a binding constraint.

Figure 4 Illustrative example of "winner takes all" outcomes in the NEM dispatch



Consider 3 market participants, each with availability of 50 MW, that are subject to a transmission limit of 100MW.

If all constrained parties bid at the market floor price -$1000/MWh, NEMDE will maximise the output of low as-bid cost generation by dispatching the market participants that contribute least to the constraint, even if the coefficients are virtually identical. The constraint equation would be:

0.85988 x G1 + 0.85987 x G2 + 0.75 x S1 <= 100

Where G1, G2 and S1 are the dispatch quantities (MW) of Gen 1, Gen 2 and Storage 1 respectively where Storage 1 is acting as a generator.

This results in a dispatch as follows, assuming -$1000/MWh bidding:

- 22.69 MW – G1
- 50 MW – G2
- 50 MW – S1.

Generator 1 is curtailed despite having a negligible difference in coefficient compared to Generator 2.

Source: ESB

2.2.2 Key risks

Today's market design, and the bidding behaviours it incentivises, can result in dispatch which is higher cost than is necessary. Constraint coefficients, rather than the underlying generation costs, become determinative in dispatch. NEMDE's algorithm reflects the outcomes of participant bids and constraints and does not explicitly consider emissions. But the knock on effect is also higher emissions since the higher cost generators are also fossil fuel.

It can also incentivise inefficient investment decisions and increase risk for investors. If a new generator chooses a location where it is assigned a lower constraint coefficient than other existing generators, it will displace existing generators whenever the constraint binds. If the constraint

13 When a generator is competing in more than one binding constraint then the constraint coefficients and the relative marginal cost of the constraints influence dispatch outcomes.

coefficients – of the existing and new generators – are similar, the new generator is largely offsetting ("cannibalising") the output of an existing generator. The new generator gets paid RRP on its output, making the investment privately profitable, but at the expense of the existing generator, whose output and profitability are correspondingly reduced. The *net* increase in low-cost and low-emission generation can be modest due to the reduction in output of the existing generators, compared to the new generator locating in an uncongested area.

While new investors might, in the first instance, be the party who cannibalises the output of its predecessors, over time they face the risk of subsequent investments cannibalising them.

This behaviour can also prompt transmission investment to alleviate the costly constraint, paid for by consumers. But if the generator had instead located in an uncongested area, the transmission investment may not have been needed.

2.3 Priority access

The primary benefits of priority access reform are to improve:

- the locational decisions of generation investments
- the ability of investors to manage congestion risk.

It is designed to complement and leverage jurisdictional schemes, but could also work on a standalone basis.

This section introduces:

- priority access mechanism: how access priority levels are assigned to existing and incoming generators
- EN priority dispatch: how energy market dispatch will be designed to give effect to priority dispatch i.e. higher dispatch levels for generators assigned a higher priority, other things being equal.

It provides context for chapter 3. A more detailed technical explanation is found in section 3.3.1.

2.3.1 Priority access mechanism

Introduction

The priority access model introduces a mechanism by which generators are assigned a priority level in the energy market. The mechanism occurs during the investment time period, and the priority level is given effect in dispatch during operational timeframes.

The concept was originally introduced by the Clean Energy Investor Group (CEIG) as the 'transmission queue model'.[14] Key principles and features have been adopted and developed into the priority access options shared in this consultation paper.

The priority access model addresses the issue of cannibalisation that reduces locational efficiency and creates additional congestion risk for legacy generators. The concept is that the EN priority dispatch is designed to limit the amount of cannibalisation of higher priority generators by lower priority

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14 Clean Energy Investor Group, https://ceig.org.au/news-resources/?_post=submissions including Castalia, Rethink of the Open Access Regime, February 2022.

generators. Locational efficiency of incoming generators can be improved and the cannibalisation risks for existing generators can be reduced.

The priority access model, on its own, may result in even less efficient energy dispatch than today. However, the priority access mechanism only applies to the EN priority dispatch, not the CRM dispatch. We expect the overall physical dispatch to be efficient because the CRM dispatch provides a mechanism to correct both existing and newly created inefficiencies in the EN priority dispatch.

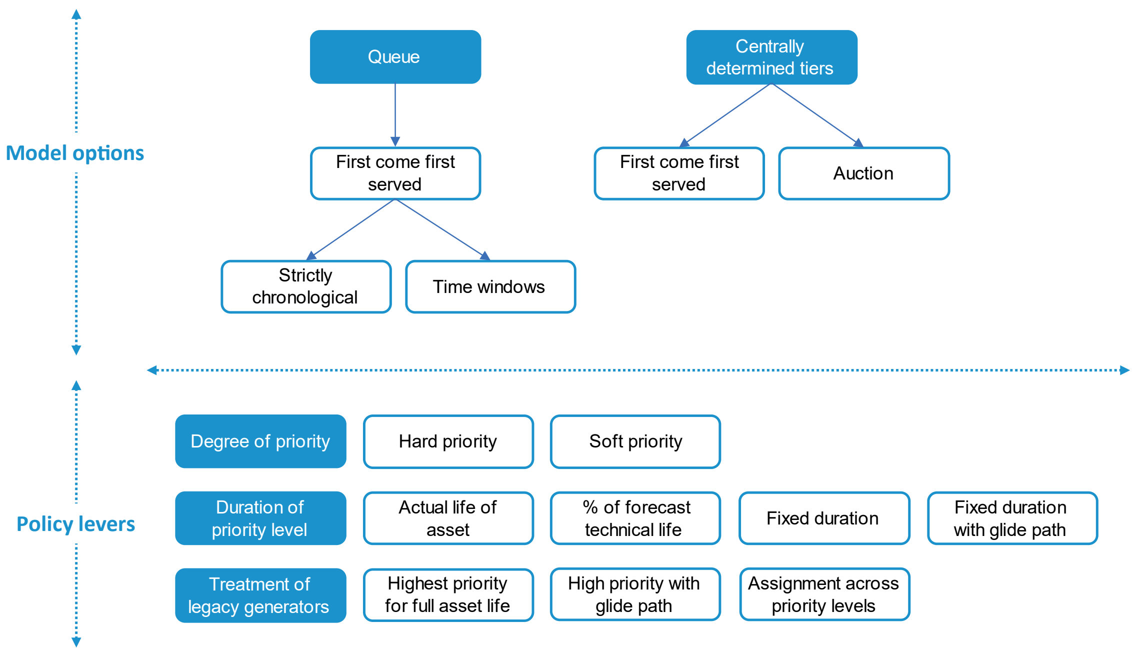
Design choices

The directions paper proposed a number of options for assigning a priority level for access. This document re-presents these as two key model options:

- queue
- centrally determined tiers.

Within these model options, there are a number of more detailed design sub-options and policy levers illustrated in Figure 5.

Figure 5 Hierarchy of key design choices for the priority access mechanism



Source: ESB.

The queue option adopts the principle that a future generator receives a lower level of priority in dispatch, compared to existing generators trying to access the same congested transmission equipment. Assigning queue numbers would be mechanical. The rules would clearly lay out the process, and no judgement would be required by AEMO or any other central agency in determining a generator's or REZ's queue number and MWs of priority.

The centrally determined tiers option would assign generators to a tier. Each tier represents a different level of priority. Generators in tier 1 would have a higher priority level than generators in tier 2 who would, in turn, have a higher priority level than tier 3.

This option requires a central agency or agencies – for example AEMO, TNSPs and/or jurisdictional bodies responsible for planning and delivering network augmentations – to determine:

- geographic zones to which the tiers would apply
- the delineation of tiers
- the hosting capacity of the network and available hosting capacity of the tiers in each zone
- the assignment of new entrant generators to those tiers.

Generators within the same tier would not have priority over one another. Within a tier, the usual dispatch algorithm order applies e.g. dispatch behind a single binding constraint is in ascending order of coefficients.

There are risks and opportunities identified for each of the model options. The model options and sub-options are defined and assessed in section 3.2.1.

Terminology

Terms are defined in this consultation paper which include clarifications for previously used terms or definitions for new terms.

Readers should be aware:

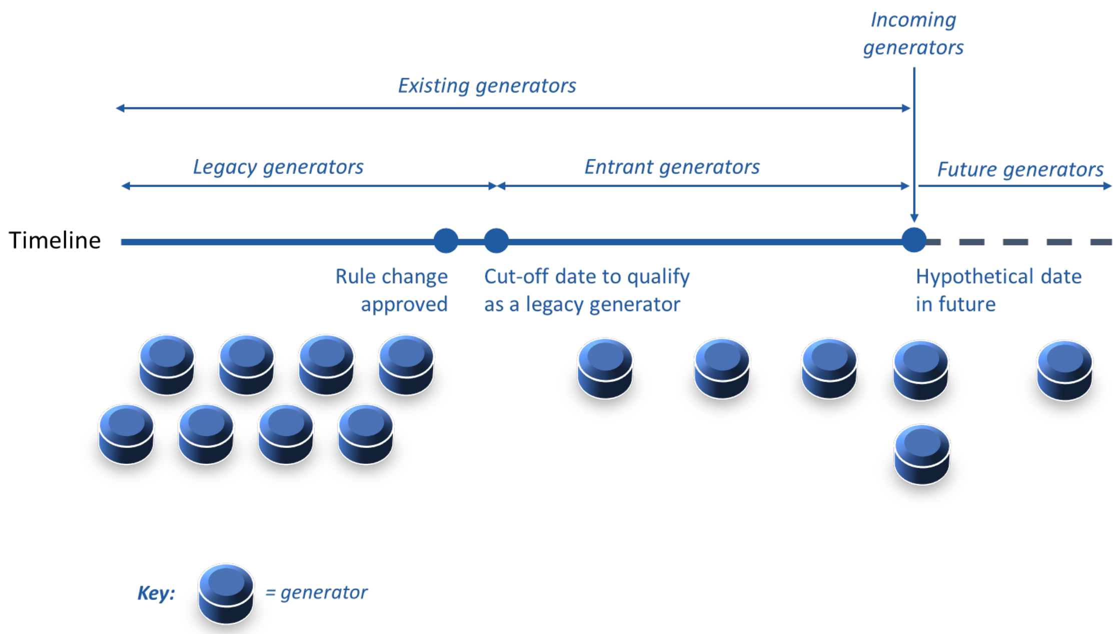
- *Queue number* is a number assigned to each generator under the queue model. These numbers are ordinarily assigned in chronological order of entry (the later the entry date, the higher the queue number) with some important exceptions:
    - Legacy generators could have a shared number, for example '0'.
    - REZ coordinators could reserve a single queue number for all generators in a certain REZ (before they connect) up to a defined MW total quantity.
    - Incoming generators could have a shared number if they connect in the same time window.
- *Tier* reflects the tier that a generator is assigned to in the centrally determined tier model.
- *Dispatch priority* (DP) number is the number that EN priority dispatch uses to prioritise dispatch in AEMO's systems. The lower the DP number, the higher the dispatch priority, other things being equal. Queue numbers and tiers are linked to a DP number and MW quantity depending on the framework of each model option.

This distinction is helpful to clarify:

- The similarities and differences of the model options and to separately distinguish technical considerations; queue, tier and DP number were used interchangeably in the directions paper.
- A high queue number is not necessarily unfavourable. A well-located new entrant with a high queue number could have a good level of access and/or be mapped to a good DP number, because priority is conferred between generators participating in the same binding constraint.
- An individual generator's queue number can identify and rank generators eligible for promoting into a better DP number e.g. when there is new transmission capacity or a generator retires.

In addition, new terms are used to describe generators at different stages of their project life cycle relative to the introduction of the reform. They are illustrated in Figure 6 and explained overleaf.

Figure 6 Terms for generators relative to the adoption of the reform



Source: ESB

- *Legacy generators* means a generator in existence at the date the reform is adopted e.g. the date that the rule change is approved, or a date specified in that rule change. Grandfathering arrangements may apply to legacy generators.
- *Entrant generators* means any generator that is not a legacy generator. The priority access mechanism applies to these generators without any grandfathering provisions.
- This paper considers behaviours and impacts at hypothetical future dates with the new arrangements under way, at which date generators will be classified as:
  - *Existing generators*, which will likely be a combination of legacy generators and entrant generators.
  - *Incoming generators* refer to generators that are undergoing their development and connection processes at that date.
  - *Future generators* refer to generators entering after that date.

This distinction is helpful to clarify:

- Separate arrangements may be required for legacy generators compared to entrant generators regarding the mechanism to assign a priority level and duration of priority access.
- Careful consideration will be required to define the cut-off point during the reform process to determine whether a generator is a legacy generator.
- Priority access provides a locational signal at a point in time for incoming generators. Their connection will have some level of congestion impact on existing generators (a combination of legacy and entrant generators).
- Priority access helps legacy and entrant generators to manage their congestion risk since they are protected (to some level) against future generators.

2.3.2 Priority dispatch in the energy market

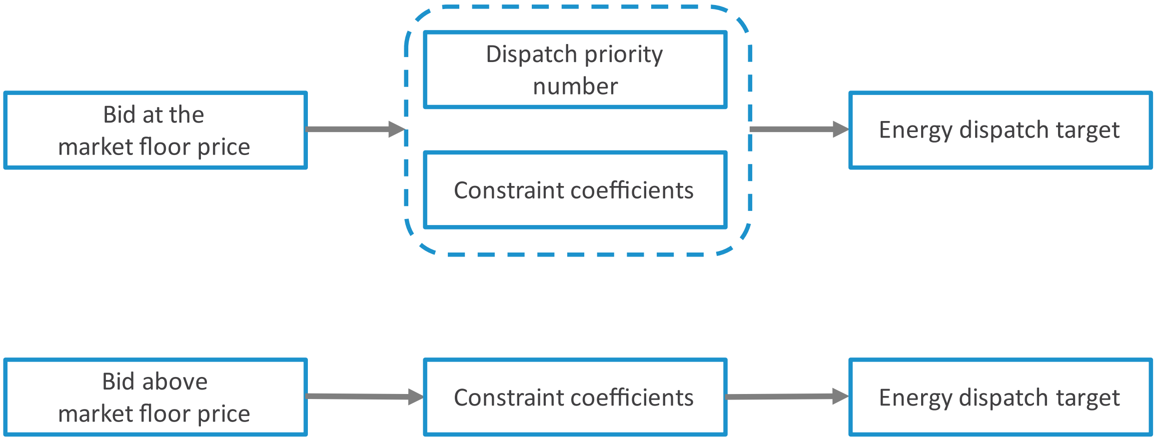
Introduction

It is proposed that the priority level is nominated as a DP number; the lower the DP number, the higher the priority level. When two or more generators bid at the market floor price, the EN dispatch would factor in the DP number to give a level of preference to generators with the higher priority.

The DP number is linked to a queue number or tier, depending on the option selected.

Figure 7 illustrates how DP numbers would be factored into the EN priority dispatch. It is only triggered for generators bidding at the market floor price. The dispatch algorithm is unchanged for generators bidding above the market floor price.

Figure 7 Illustration of EN priority dispatch



Note: Constraint coefficients is a simplification for the set of constraint coefficients and the relative marginal cost of those constraints.

Source: ESB, note that this figure was previously represented in the directions paper. The update from 'queue position' to 'dispatch priority number' reflects the clarified definition of terms.

EN priority dispatch is the same as today's dispatch, except where two or more generators are bidding at the market floor price and competing for dispatch i.e. to access the same constrained piece of transmission infrastructure. In this case, the higher priority generator will have a greater chance of being dispatched in preference to the lower priority generator (compared to today's unprioritized dispatch). Constraint coefficients would no longer be the only factors rationing access between generators competing in the same set of binding constraints.

One important choice is whether the priority offered is 'hard' or 'soft' which affects the degree to which a generator's priority level supersedes its constraint coefficients in determining dispatch outcomes. This design choice affects both model options; the queue and centrally determined tiers.

Some market participants will share the same DP number. If they are also competing in the same binding constraint, the current method for determining dispatch outcomes is applied. The dispatch algorithm will favour those generators that have a lower constraint coefficient.

Technical considerations

There are technical considerations as to how the policy design is given effect in AEMO's systems. Section 5 provides stakeholders with an update on these considerations. There are no questions posed for stakeholder consultation at this time. Achieving preferences on the design choices will help to refine the design specification and ongoing technical investigations.

The ESB is investigating a number of implementation issues including technical feasibility, solve times, feasible dispatch and the impact of EN priority dispatch on the regional reference price (RRP). The number of queue numbers and the number of tiers may be limited by the technical feasibility to implement into AEMO's systems and the level of priority (hard or soft). It is a complex area of investigation, and we propose to revert to stakeholders with updates following this consultation period.

2.4 Congestion relief market design

The primary drivers for the CRM design are to:

- improve dispatch efficiency by incentivising bidding behaviours in the CRM that achieve a lower system cost compared to today's market design
- optimise the use of the transmission network that avoids overspend of the network and maximises the value of investment in interconnectors
- create market opportunities for storage and flexible demand by rewarding bidding behaviours that maximise wind and solar investments.

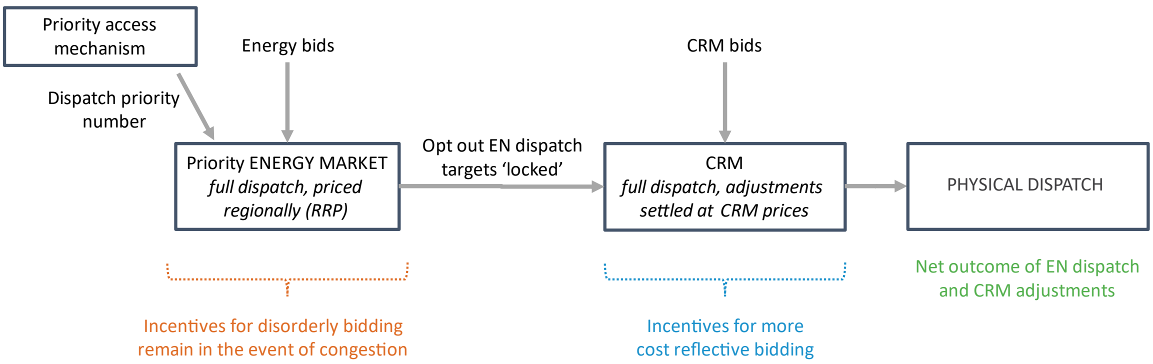
These drivers are aligned to the long-term interests of consumers to efficiently use the generation, storage and transmission infrastructure that customers (or taxpayers) ultimately pay for.

2.4.1 Overview

The CRM design refers to the introduction of a new voluntary spot market (the CRM) and its interactions with the energy market (EN).[15] The CRM can achieve a lower cost dispatch by encouraging more cost reflective bidding behaviours than today's energy market design. CRM participants are rewarded from the efficiency gain (increased profits). It also provides financial incentives for storage and scheduled load to charge when surplus power is generated during windy or sunny periods.

Figure 8 visualises the bidding incentives for the two markets.

Figure 8 Bidding incentives in the CRM design



Source: ESB

15 In the context of the CRM design, generator is often used as a shorthand for market participants including scheduled and semi-scheduled generators, scheduled load and storage and market network service providers. The scope of parties eligible to participate in the CRM are discussed in section 4.2.1..

The EN dispatch continues to be priced at the RRP from the EN dispatch.[16] Bidding incentives are (largely) consistent with today's energy market e.g. generators that are constrained often engage in 'disorderly bidding'. The net outcome of the EN dispatch and CRM adjustments is the final physical dispatch. The CRM helps to 'unwind' any inefficiencies in the EN dispatch.

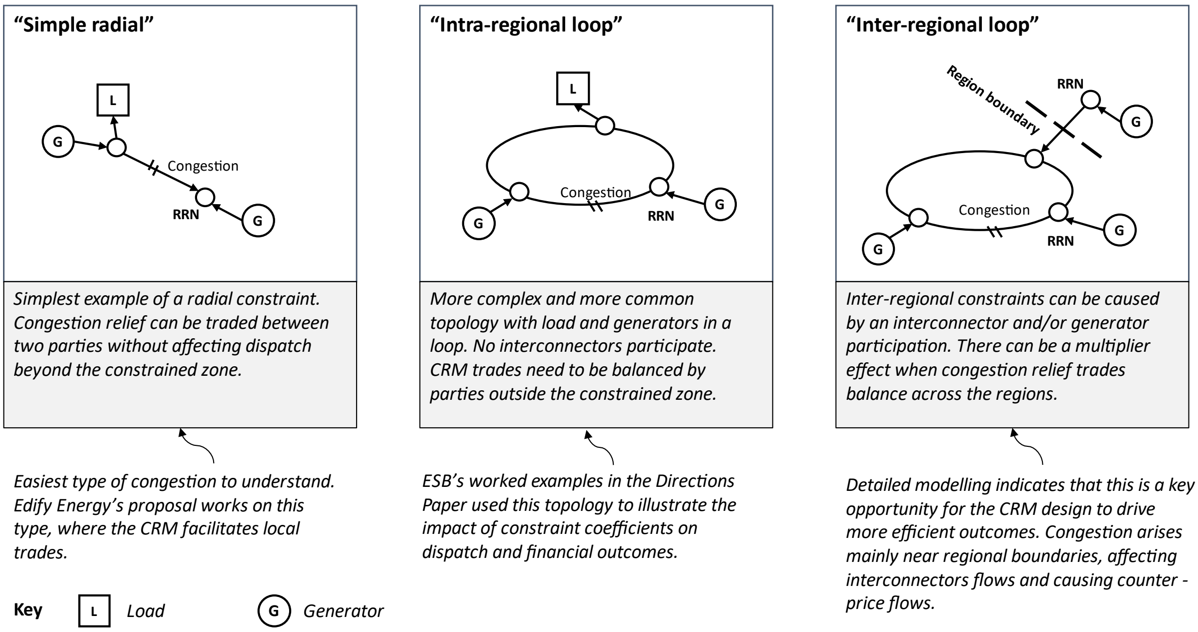
Scope of CRM trading

The CRM design was originally conceived by Edify Energy[17] as a mechanism to encourage bilateral trades between parties behind a constraint. It was more limited in scope involving local trades. The CRM design has evolved into a broader market solving multiple and multi-lateral constraints across the network.

This evolution increases the scope of the potential efficiency gain that can be achieved and the scope of participation into the CRM. It creates trading opportunities for generators providing the balance of energy outside of the immediate area affected by the constraint.

Figure 9 illustrates the different network topologies and their impact on the scope of CRM trades.

Figure 9 Different types of network topology affect the scope of CRM trades



Source: ESB, adapted from Modelling the congestion relief market' February 2023.

The "simple radial" network typology exemplifies the situation when generators are behind a constraint and bidding to the market floor price, then their constraint coefficient is determinative of the dispatch outcome.

The "intra-regional loop" and "inter-regional loop" figures only illustrate one binding constraint. But they indicate that multiple constraints may be binding in different areas of the network. When

16 This is consistent with section 4.2.1 which confirms the status of design choices raised in the directions paper.

17 Edify Energy, Consultation response to Post 2025 Market Design Options - Transmission and access reform, June 2021. Available at Response to ESB's Project Initiation Paper.

multiple constraints are binding, a generator's dispatch is affected by its set of coefficients and the relative marginal costs of those constraints.

2.4.2 Clarifying key concepts of the CRM design

This section clarifies key concepts for the CRM design. It provides context for chapter 4.

Opt-in and opt-out

Stakeholders have previously expressed concerns that the directions paper referred to participants wishing to 'opt-out' of the CRM can elect to do so. The CEC submitted that this "contradicts the key foundation of the proposed CRM, which is strictly opt-in by design to allow participants to manage their exposure to congestion changes over time."[18]

For clarity, the CRM is a voluntary market. If a party chooses not to participate in the CRM, they do not have to submit CRM bids. They will simply participate in the EN. Section 4.3.2 confirms that the CRM is strictly opt-in given the requirements to register. AEMO will need to maintain an opt-in database to record the registration status of dispatchable unit identifiers (DUIDs). Participants that have not registered to opt-in, are referred to as "opt-out" as a shorthand in this paper.

Sequential dispatch

The CRM is a second dispatch run that is executed immediately after the EN dispatch. It preserves the optionality of the CRM. For participants that do not participate in the CRM, it is intended that dispatch outcomes from the energy market would be 'locked' for the purpose of the CRM dispatch immediately after. Section 4.3.2 provides technical details on this matter.

Scope of constraints

The CRM dispatch adopts all of the constraint equations as the EN dispatch.[19] This means it is solving for multiple constraint types i.e. thermal, voltage, stability, FCAS constraints etc.

If NEMDE can achieve a more efficient (lower cost) dispatch in the CRM, it will have considered the same scope of constraint equations as the EN dispatch, and co-optimised with FCAS. The difference between the two dispatch outcomes arises because of different bids from opt-in generators (CRM bids). Dispatch outcomes for opt-out generators remain 'locked' from the EN dispatch targets.

There are issues already present in today's dispatch. NEMDE cannot always ensure a secure dispatch solution which requires AEMO to intervene by directing units on. A separate rule change request called the operational security mechanism (OSM) is considering ways to avoid this outcome. The reforms (if implemented) would have different objectives:

- The OSM as outlined in the AEMC's draft determination aims to value and schedule security services.
- The CRM as outlined in this paper aims to allow participants to trade between themselves to better manage congestion.

18 CEC, Submission in response to ESB Transmission access reform directions paper, 22 December 2022

19 AEMO, Constraint Formulation Guideline, effective 24 October 2021. Available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/wholesale-demand-response/first-stage/constraint-formulation-guidelines.pdf?la=en,

If implemented, both mechanisms would use similar inputs but operate over different timeframes. **Appendix B** outlines the interaction between the CRM and OSM.

CRM prices

For those participating in the CRM, adjustments between the CRM and EN are settled at local CRM prices (CRMPs). Local pricing creates new opportunities for trades that did not exist in the EN. CRM prices vary by location on the transmission network. This is a key feature because congestion is localised. For instance, there is no point in paying generators in north NSW to relieve congestion in south NSW.

The ESB's directions paper used the term locational marginal prices or "LMPs" to describe the local prices within the CRM. However, this has unhelpful connotations given LMPs are used to describe nodal markets common in the United States and many other countries, The CRM is different from a US LMP-style market because it separates trading in the energy market from trading in the CRM. The CRM is a voluntary market with market clearing prices. This is the model that Ministers have requested the ESB to develop and not LMPs. We have therefore used the term "CRM price" here to represent the local CRM price.

Given its pricing signal, CRM participants are more likely to bid the value they put on their output, referred to as 'cost reflective' bidding. As with any market, participants will bid strategically in the CRM but the bids are expected to be closer to their marginal or opportunity costs (inclusive of contract positions).

Terminology of CRM buyers and sellers

In this paper, the term of buyer and seller is applied as follows:

- CRM buyers:
  - consume energy (scheduled load) or
  - reduce energy outputs (generators or storage).
- CRM sellers:
  - sell energy (generators or storage) or
  - reduce consumption (scheduled load).

This consultation paper adopts terminology which is consistent with the formula for settlement and enables stakeholders to understand how they would develop their bidding strategy (including a design choice on CRM bidding structures in section 4.2.4.). We note it applies different terminology to the original Edify Energy proposal which is explained below.

2.4.3 Evolution of the CRM design

The CRM is a model design that has evolved over time:

- June 2021: Edify Energy introduced key concepts of a voluntary congestion relief market.[20]
- June 2022: the CEC retained the intent of Edify Energy's proposal but model design updates were needed to resolve implementation issues.[21] The model was developed in response to the complexity of the NEM including its network topology, range of constraints, operating

20 Edify Energy, Consultation response to Post 2025 Market Design Options - Transmission and access reform, June 2021. Available at Response to ESB's Project Initiation Paper.

21 Clean Energy Council, Response to ESB's Consultation Paper, June 2022.

requirements etc.

- November 2022: The ESB adopted the implementation solution proposed by the CEC with a modification for a sequential dispatch of the EN and CRM. The ESB introduced design choices in the directions paper as potential adaptations to the CEC's base.

There have been challenges for stakeholders to keep track of these modifications over time.

Appendix C provides the context and rationale for the evolution of the CRM design from the original concept proposed by Edify Energy to the model design proposed by the CEC and ESB.

2.5 Technical considerations

The hybrid model will require changes to the dispatch process and systems. AEMO is providing key technical inputs as part of the reform's detailed design. This includes identifying potential technical solutions and helping to assess their implementation risks including a NEMDE CRM prototype to test design options.

The hybrid model creates some additional operational risk for AEMO to manage which are discussed in more detail in chapter 5. The main risks are:

- Increased solve time – the CRM doubles up the number of bids for AEMO to process and adds an additional run for NEMDE to solve so is expected to increase the overall dispatch time.
    - Indications from initial NEMDE CRM prototype testing is that the solve time (even without tuning) is manageable but the full end to end process from loading SCADA and bids to publishing dispatch instructions and prices cannot be tested at this time.
    - Incorporation of priority access could further complicate the dispatch process so this design needs to be carefully considered.
- Increased risk of infeasible dispatch outcomes – adding in the CRM and catering for priority access and opt-out participants could lead to NEMDE struggling to find a feasible dispatch solution within the required time.
    - This could be the case if the solution becomes overly constrained and would require AEMO to intervene to relax the violation penalties so that NEMDE could solve.
    - There is an existing process for this eventuality but the risk is that it becomes more common in the CRM design.

Updates on technical considerations are provided in chapter 3 and 4 relating to priority access and the CRM design respectively. We will continue to update stakeholders as this work progresses.

3 Priority access

3.1 Introduction

This chapter:

- outlines two broad options for assigning priority access; via a queue or centrally determined tiers
- assesses the pros and cons of these two options
- discusses policy levers including design changes that may address concerns with the two model options
- discusses the treatment of legacy generators
- assesses the pros and cons of these policy levers.

Many design details of the priority access model remain open, including the overall choice between a queue and centrally determined tiers. We seek stakeholder feedback on this choice and the detailed design of each of the options. We are also engaging directly with jurisdictions on these choices given that this supports jurisdictional schemes.

3.2 Design choices

3.2.1 Model options

We have identified two broad options to assign priority access to generators.

- Queue: Incoming generators are assigned a priority level based on the time at which they (or the REZ in which they are participating) reach some defined stage in the connection process (or REZ development process).
- Centrally determined tiers: A central agency assigns a priority level to incoming generators. There would only be a few (two or three) priority levels, called “tiers”. A central agency specifies the delineation between the tiers. Generators are assigned to these tiers either on a first-come-first-serve basis or auctions.

A summary of these options is provided in Table 2 with explanatory details provided afterwards.

Table 2 Outline of two model options: queue and centrally determined tiers

	Option 1: Queue	Option 2: Centrally determined tiers	
		First come first serve	Auction
How is priority access organised?	A relatively large number of queue numbers.	A small number of tiers determined by a central agency.	
How are queue numbers or tiers delineated?	Either strictly chronological, or by time-windows.	By central agency, based on efficient hosting capacity.	
How is priority access assigned?	Based on time of connection / REZ reservation. Mechanical, with little to no judgment required.	Based on time of connection / REZ reservation, with central agency determining which generators fit in each tier.	Via an auction, with central agency determining which generators can fit in each tier.

	Option 1: Queue	Option 2: Centrally determined tiers	
		First come first serve	**Auction**
What happens to incoming generators?	Join the back of the queue. Receive good access if locating in an uncongested area.	Assigned to the highest priority tier with available hosting capacity.	Assigned to a tier via an auction.
Can a generators' queue or tier number change?	No	Yes – as available hosting capacity becomes available (see below).	Yes – but only via purchasing higher priority access in the auction (see below).
What happens when a generator exits the market or transmission is built which alleviates constraint?	Existing generators implicitly move up the queue – but retain their queue number.	Additional available hosting capacity within a tier is assigned to existing generators on a first-come-first-serve, who shuffle into higher priority tiers. Available hosting capacity in lower priority tiers is assigned to incoming generators.	Additional space in a tier is sold in auction to incoming and existing generators who are in lower priority tiers.
How are REZs accommodated?	REZ coordinators are assigned a queue number at the back of the queue. Extra transmission capacity means this queue position is valuable.	Extra transmission investment creates available hosting capacity in priority tiers. Central agency reserves capacity in priority tiers for the REZ when it reaches a stage in the REZ process.	Extra transmission investment creates space in priority tiers. Extra space sold via auction.

Option 1: Queue

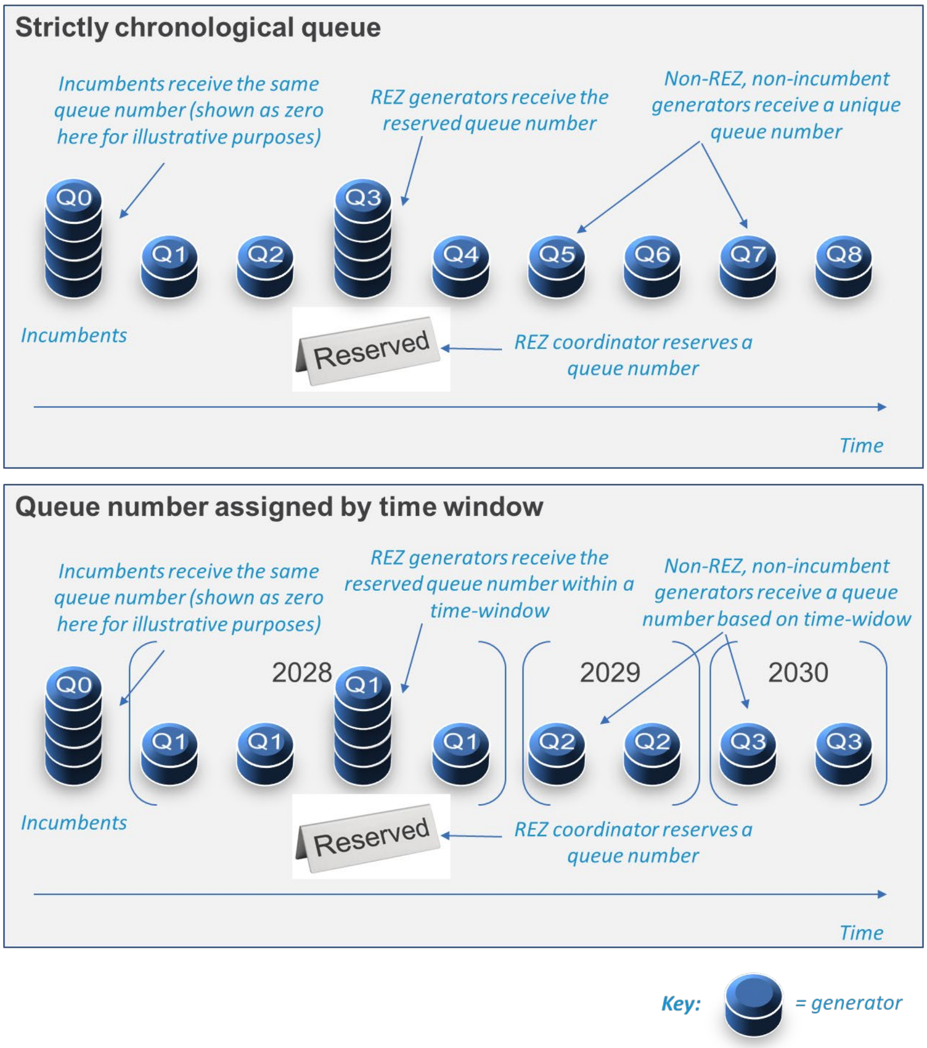
In the queue model, each non-REZ generator or REZ is assigned a "queue number" for a specified MW of capacity. Each generator's queue number determines a generator's priority in the energy dispatch for those MWs.

Each queue position corresponds to a MW capacity. Existing generators wishing to expand their capacity would have to join the back of the queue for their capacity expansions. Each generator may have multiple queue positions, received over time as their capacity changes.

No judgement is required by AEMO or any other central agency to determine a generator's or REZ's queue number.

A summary of the queue option is outlined in Figure 10. In the top panel, a strictly chronological queue order is implemented. In the bottom panel, queue numbers are grouped by time-windows.

Figure 10 Queue model (strictly chronological and by time-window)



Source: ESB

There are two determinants of a generator's queue number:

- *Timing of connection*: when an incoming generator (or the REZ in which they are participating) reaches some defined stage in the connection process (or REZ development process).
- *Type of generator*: whether a generator is a legacy generator, REZ generator, or other.

Each topic is discussed in turn.

Timing of connection

There are two approaches being considered as to how the timing of connection determines the queue number:

- strict chronological order
- time-windows (grouped by calendar year/s or similar).

In the former, incoming generators (or the REZ in which they are participating) would be assigned a queue number in strict chronological order of when they reach some defined stage in the connection process (or REZ development process). Generators that reach that stage simultaneously (for example via a batched connection process) would receive the same queue number.

Queue numbers would be:

- assigned indicatively in response to their connection application
- finalised upon completion of the connection agreement for the relevant number of MW of capacity, or earlier qualifying criteria to be determined e.g. technical and/or financial criteria (which might include the lodgement of a bond).

This balances the need of incoming generators to have certainty of their priority access as early as possible while maintaining the integrity of the queue. If queue numbers were assigned too early, priority could be given to projects that do not proceed or even encourage strategic behaviours – such as lodging speculative connection enquiries. This would create associated uncertainty for other, bona fide, entrants.

Another option to protect the integrity of the queue relates to use-it-or-lose-it provisions. Incoming generators might lose their queue position if they do not proceed to a subsequent stage in the connection process (e.g. commissioning) within a certain timeframe of being assigned it (e.g. two years). At this point, the incoming generator would forgo its queue position and go to the back of the queue. If the incoming generator proceeds to commissioning but with a smaller project than specified for its queue number, it will forego the remaining MWs relating to its queue number.

Assigning queue numbers in strict chronological order would likely best allow a generator to manage the risk of congestion caused by future generators. This is because each generator would have a better queue number – and so priority in energy dispatch – than future generators.

A downside of assigning priority in strict chronological order is that it could create an inefficient rush to reach the relevant stage in the connection process. Incoming generators could instead be assigned a queue number based on time-windows in which they complete their connection agreement. For example, each generator that connects in 2028 could be assigned the same queue number. Generators with the same queue number would be assigned the same priority in dispatch.

Compared to the strictly chronological assignment of queue numbers, this approach may:

- diminish the ability of generators to manage the risk of congestion caused by other incoming or future generators
- result in a different rush to reach the relevant stage before the time-window closes, which would create peaks in demand for connections
- incentivise generators to wait until the end of the time-window to better assess the quality of the priority access it may receive.

The level of these risks depends on the breadth of the time window.

Type of generator

A generator's queue number also depends on whether it is participating in a jurisdiction's REZ scheme (a "REZ generator"), a legacy generator, or other.

Legacy generators at the time the reforms are adopted (noting that the exact definition of 'adoption' needs to be determined) will have the same queue number as one another, defined at the time of the reforms. This reflects that they do not currently have priority over one another. The treatment of legacy generators is discussed in section 3.2.3.

For **non-REZ, incoming generators**, the queue number represents the time that the generator reaches a connection agreement (either in strict chronological order or by time-windows). When the generator reaches a connection agreement, it is assigned either the next available queue number (in the case of strictly chronological queuing) or the queue number associated with the time-window.

REZ generators are managed as part of the relevant jurisdictional arrangements. REZ coordinators – such as government agencies responsible for administering REZ schemes – are assigned a queue number. This must be at the back of the queue at the time the reservation occurs. One queue number would be assigned to each REZ.

The REZ coordinator would only be assigned a queue number when some pre-determined stage in the REZ's development occurs, analogous to an individual generator reaching a connection agreement (or other qualifying criteria).

The REZ queue number would correspond to a quantity of generation capacity within the REZ. That quantity might be based on the hosting capacity created by the REZ's transmission infrastructure.

The queue number would apply to all generators that are participating in the REZ, up to the allocated quantity. It would be the REZ coordinator's responsibility to assign the reserved quantity between the generators participating in the REZ.[22]

A generator participating in a REZ may receive a lower (i.e. better) queue number even if a non-REZ incoming generator connects earlier because the former's queue number is part of its REZ access rights. Consequently, the reserved queue position and the good network location may be valuable to generators. REZ coordinators could sell the reserved quantity to incoming generators as part of their REZ processes.

Implementation issues

A generator's queue number and allocated MW determines its priority in the EN dispatch.

Too many priority levels may make the dispatch algorithm infeasibly slow, given it needs to solve in substantially less time than the five-minute dispatch interval. Incorporating different MW allocations for a DUID will also complicate bidding and bid validation. Assigning queue numbers by time-window may diminish this concern, but over time the number of priority access levels will still increase, potentially infeasibly high.

The ESB is assessing both the design choices and technical considerations to determine the preferred number of queue numbers, the degree of priority and its implementation into the dispatch engine. Refer to section 3.2.2 for an assessment of the degree of priority (hard or soft) and section 3.3.1 for technical considerations.

Option 2: Centrally determined tiers

Under this option, a central agency would be tasked with establishing and managing tiers. The ESB has not yet decided which institution or institutions would perform these roles. It might be AEMO, TNSPs, jurisdictions (or a representative of them), jurisdictional planning bodies or even a new agency set up for this purpose.

The central agency or agencies would:

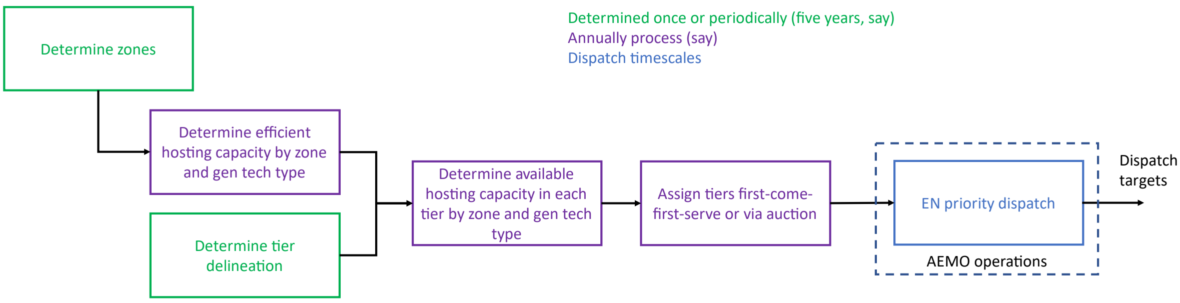
22 In the context of the NSW REZ schemes, this would refer to REZ access rights holders. The terminology and arrangements may differ by jurisdiction.

- determine zones within each region to which the tiers relate
- determine the delineation of a small number of tiers of priority access (about two or three)
- assign generators to those tiers.

The tier corresponds to a level of priority in the EN dispatch.

The central agency would undertake detailed system modelling to estimate, by zone, the "efficient hosting capacity" in MW of different generation types (wind, solar etc). This would build on the ISP's analysis.

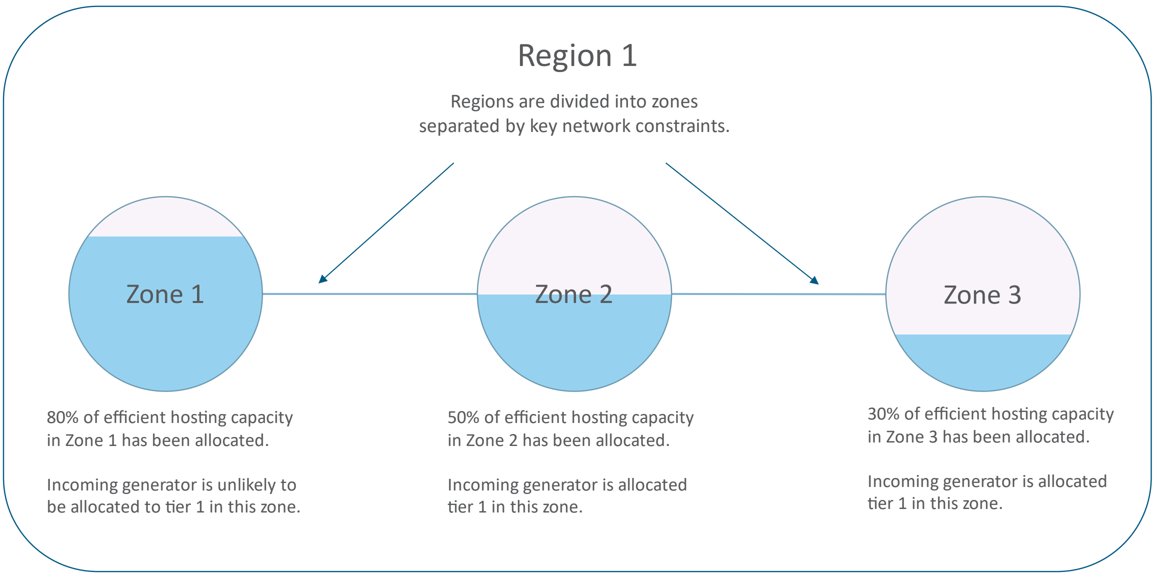
Figure 11 Illustrative process map to delineate tiers and assign generators



Source: ESB

Regions would be divided into zones determined by the agency which are relatively uncongested internally and capture the key intra-regional constraints at their boundaries. Zones similar to those envisaged in this option are used by AEMO in the development of the ISP and most TNSPs use similar zones in their planning. One or more REZs could be within a zone, or a zone could correspond to a REZ. The hosting capacity in each such zone at each tier or level of access would be determined. Taken together, the determination of zones and MWs available in each tier within each zone would aim to capture the efficient location of generators across the NEM given the existing and planned network transfers capabilities. Figure 12 shows diagrammatically how that process would apply.

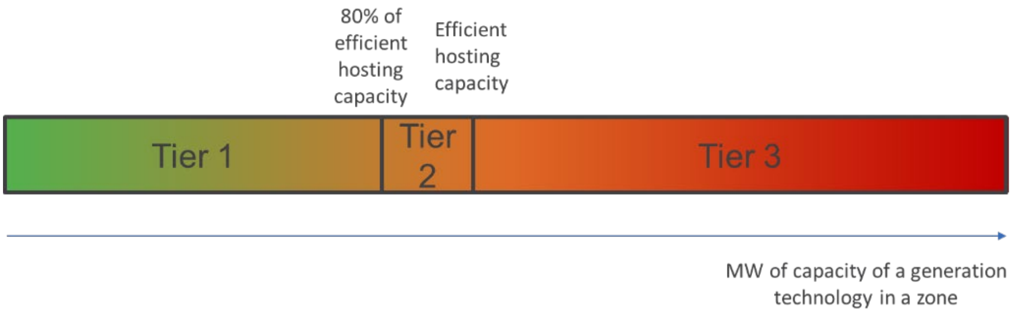
Figure 12 Assessment of hosting capacity and delineation of tiers by zone



Source: ESB

The delineation between two of the tiers would be based on the efficient hosting capacity. If there are more than two tiers, the delineation between these extra tiers would be a fraction of the efficient hosting capacity (say, 80%), as outlined in the figure below.

Figure 13 Illustration of tiers definition based on 'efficient hosting capacity'



The delineation between tiers could be specified as volume or value based e.g. MW of generation or maximum targeted expected revenue lost to congestion for each individual generator within the tier. If the latter type of metric was used, it would be a target, not a guarantee. There would be no financial compensation for generators suffering a level of congestion worse than the target.

While hosting capacity would be specified zonally and by technology, there would only be a few tiers. Generators assigned to the same tier because there was available hosting capacity for them would enjoy the same priority in dispatch, even if they are in a different zone or a different generation technology.

In some locations, the presence of legacy generation may already exceed efficient levels. Clearly, legacy generators cannot receive a higher level of access overnight upon the implementation of the reforms. In this case, the tier would be overfilled. Legacy generators in the same tier and competing in the same binding constraint would continue to be dispatched based on constraint coefficients, as now. Incoming generators could not be added to the tier until the tier was no longer overfilled.

The efficient hosting capacity of a zone will change continually, as more transmission is built or simply because of changing demand. This means that space in tiers could become available over time.

The percentage of hosting capacity used to delineate the tiers (e.g. 80% in the example above) could be set forever, or redetermined periodically. The former would provide the most certainty to generators that their access will not be affected by a change that allows incoming and future generators into their tier and erodes their access. Conversely, redetermining the delineation of the tiers may enable the central agency to better meet the evolving needs of the power system.

"Available hosting capacity" is the difference between the efficient hosting capacity and the hosting capacity already assigned to generators (and REZs) in that tier. Like the efficient hosting capacity, the available hosting capacity would be specified zonally and by technology type.

The governance arrangements will be important to ensure the success of the option. One or more agencies will have the crucial roles of:

- determining (and potential re-determining) the appropriate delineation of the tiers
- assigning generators into tiers. This will require judgement of the quantity of generation that can be accommodated in each tier (based on load flow modelling of the location and technology of the generation connecting).

Generators' EN dispatch – and ultimately their business case – will be influenced by these decisions. This affects not only incoming and future investors, but also existing generators (including legacy and entrant generators). Consequently, investors will need confidence that the processes involved in making these decisions are rigorous.

We have identified two sub-options for how this model might assign generators into tiers:

a) *First come first serve*: Generators are assigned into tiers on a first-come-first-serve basis.
b) *Auction*: An auction determines which generators are assigned to tiers.

Each sub-option is explored below.

First-come-first-serve

Generators would be assigned into the highest tier with "available hosting capacity" for their technology in their zone on a first-come-first-serve basis.

Incoming generators are assigned to the highest tier with available hosting capacity. The oldest existing generator in the lower tier would gain automatic promotion to the higher tier when hosting capacity was available.

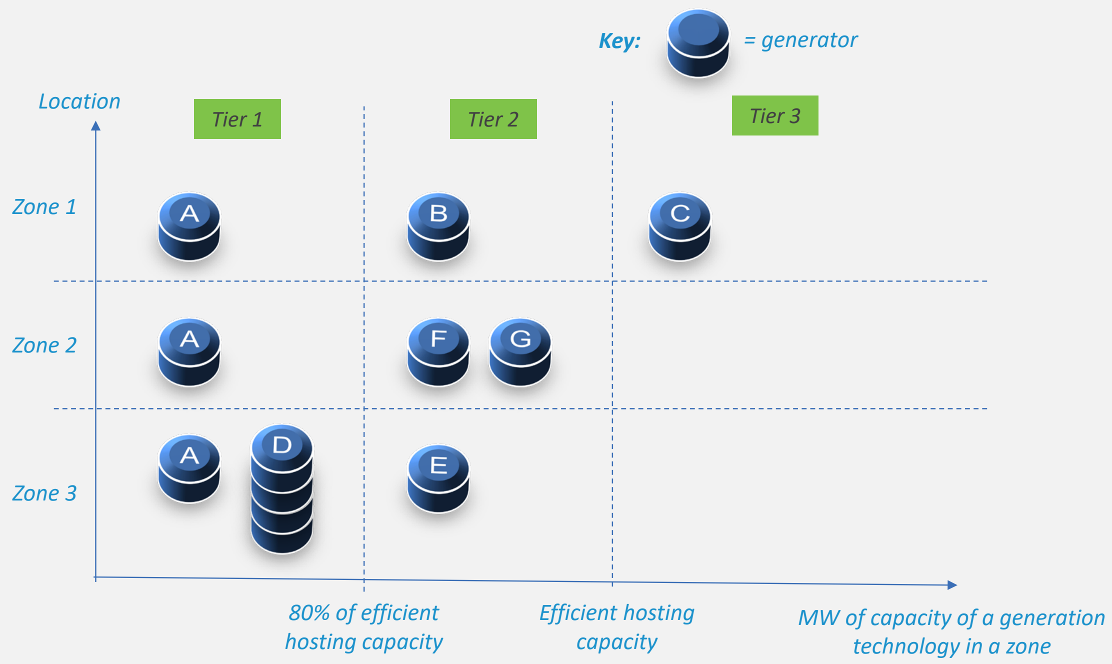
The same considerations would apply as the queue model i.e. timing of assigning a generator to a tier in the connections process, use-it-or-lose it provisions and qualifying criteria. Again, to manage a rush to proceed through the connection process, time-windows could be employed, as with the queue. Promotion into higher tiers might be allocated on a pro-rata basis where incoming generators connect within the same time window.

Generators participating in REZs could be assigned into higher priority tiers, on the basis that the associated REZ transmission infrastructure increases the efficient hosting capacity of the tier, despite the increase in generation. This would, in effect, breach the first-come-first-serve concept in the specific case of REZ generators. But existing generators would be no worse off to the extent that the associated REZ infrastructure made additional hosting capacity available.

Similarly, generators who fund transmission investment (or participate in run-back schemes which have the effect of increasing transmission capacity) could be assigned to a higher priority tier on the basis that their investment creates space in the tier. Again, this would breach the first-come-first-serve concept. But existing generators would be no worse off to the extent the incoming generator had funded appropriate transmission investments.

An overview of this sub-option is provided in the illustration below and accompanying example.

Box 1. Illustration of first-come-first serve assignment into tiers



The central agency specifies that there will be three tiers. The delineation between those tiers is:

- 80% of the estimated efficient hosting capacity
- the estimated efficient hosting capacity.

For simplicity, we assume there is only one generation technology type.

Legacy generators, labelled A, are in each zone. Incoming generators B to G connect in alphabetical order.

In zone 1, the legacy generators already exceed 80% of the efficient hosting capacity.

The next incoming generator, Generator B, is assigned into the next highest priority tier with available hosting capacity: tier 2. There is no longer any available hosting capacity in tier 2.

Next, generator C connects in zone 1. As there is now no available hosting capacity in zone 1, it is assigned to tier 3.

Next, a REZ is created in zone 3. This increases the efficient hosting capacity, and now all the REZ generators D can be accommodated in tier 1.

There is enough available hosting capacity for generator E to be assigned to tier 2, but not tier 1.

Over time, as more generators (F and G) connect they are assigned to the next tier with available hosting capacity.

Comparison of sub-options between centrally determined tiers (first-come-first serve and queue (grouping)

When discussing the queue option, we noted that it may be necessary to group generators with different queue numbers for the purpose of EN dispatch priority.

The queue (with grouping) option and tiered (first come first serve) option share some similarities. Both assign access by chronological order in which generators reach a stage in the connection process, and both award a shared priority in EN dispatch to multiple generators (those within the same group or tier).

However, there are important differences:

In the queue model with grouping, the grouping is intended to address:

- design concerns: to avoid a 'rush' to connect, in which case the grouping is mechanical e.g. based on time windows, and/or
- technical considerations: to enable dispatch to solve in time i.e. the grouping is intended to approximate the dispatch outcomes that would arise if priority were based on queue numbers.

In either event, the grouping intends to respect the principle that existing generators are protected from cannibalisation by future generators. As a result:

- An incoming generator must assess its congestion risk based on its queue number relative to existing generators and its network location.
- The grouping respects the chronology of the queue numbers, to the extent possible.
- If based on time-windows, the grouping process is mechanical.
- If based on an algorithm to give effect to the chronological queue numbers, congestion modelling may be required but the relativities of the queue position are key, rather than upholding the delineation of the tiers (and sharing congestion risk between generators within those tiers).

In the first-come-first-serve version of the tier model, the delineation of tiers and grouping are:

- a deliberate design feature
- designed to provide locational signals based on estimates of efficient hosting capacity and coordinate transmission and generation investments.

As a result:

- The central agency assesses the congestion impact of an incoming generator.
- The central agency gives the incoming generator an indication of its congestion risk based on the definition of the tier to which it is assigned.
- The incoming generator assesses its congestion risk based on the tier to which it is assigned and the existing generators with which it shares that tier.
- The determination of the delineation of the tiers, and the subsequent allocation of generators into tiers, requires more judgement by a central agency.

Auction

This section discusses auctions that could be accommodated in parallel or in addition to the REZ schemes. The design of the REZ schemes will be determined by each jurisdiction.

In this sub-option, entry to tiers (other than the lowest priority tier) would be sold via auctions. The auction would be open to incoming generators and any existing generators in a lower priority tier wishing to be promoted into a higher priority tier. Unlike the first-come-first serve sub-option, any existing generators in lower priority tiers would not otherwise be promoted into higher priority tiers. Success in an auction is the only way to be 'promoted' to a higher priority tier. Any generator that does not purchase priority access (and is not otherwise awarded it, for example as a legacy generator) is assigned for free into the lowest priority tier.

Providing the auction is well-functioning and competitive, the auction prices would reveal the market's view of the expected benefits of a higher priority tier. All else equal, in a congested part of the network, being in a high priority tier would be valuable and so command a high price. This disincentivises incoming generators from connecting in this congested part of the network. If the auction is functioning well, it would be expected to send an efficient price signal to investors.

The auction sub-option reinforces the locational signal of centrally determined tiers. The central agency's delineation of tiers (and estimates of available hosting capacity) delivers a locational signal to encourage efficient investment. The auction reinforces this with a price signal to locate in uncongested parts of the network. As a result, this sub-option is only partially reliant on the accuracy of the central agency's planned approach and modelling to deliver efficient outcomes.

The auction may also ration scarce transmission access more efficiently to generators than via the first-come-first-serve model, because it is based on willingness to pay rather than speed to connect.

The auctioneer would assign generators into tiers based on the bids of participating generators and the quantity, type and location of generation that it considers can be accommodated into a tier.

Auctions would need to be scheduled only periodically, rather than every time an incoming generator connects to the network, to ensure there is sufficient competition. The timing of these auctions would be important. Too far apart could delay investment; too close could mean there is insufficient competition and make the auction dysfunctional. Generators could still connect and enter the lowest priority tier until the next auction, but they would risk not winning priority access in that auction or having to pay a high price.

In assessing various options for locations to invest, investors might observe:

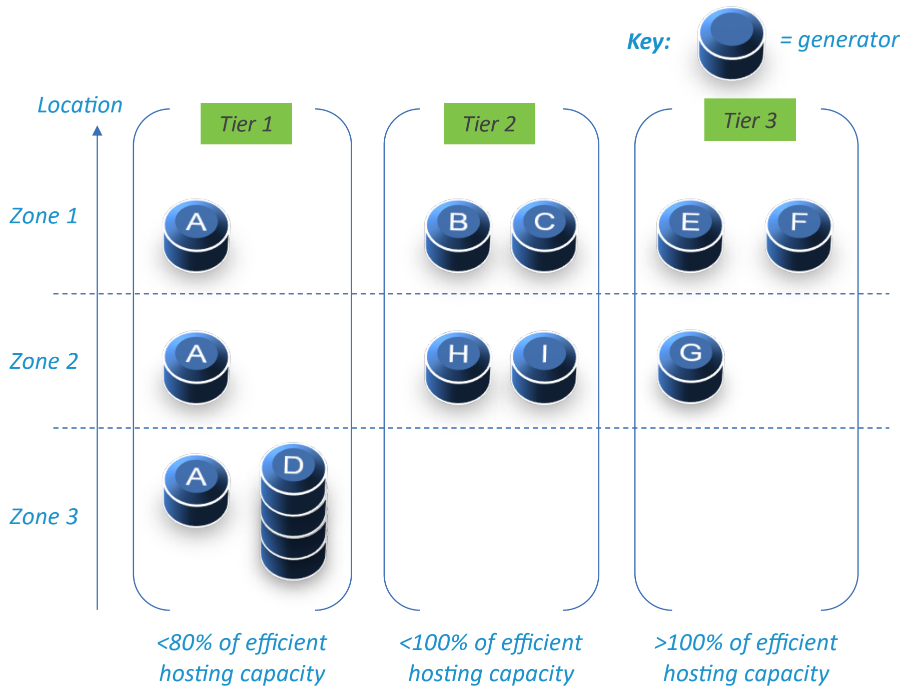
- In some locations, the higher value tiers are full because the network is congested. There is little or no prospect of a forthcoming auction, and investors are disincentivised from connecting in this area.
- In other locations, there is available hosting capacity in the highest priority tier but the network is nevertheless congested (or expected to become congested). The level of competition in an auction from existing and incoming generators is likely to be high. This competition – and the high value of priority access in this location - is expected to increase the price in the auction. In turn, this may disincentivise the investor from connecting at this location.
- In yet other locations, there is available hosting capacity in the highest priority tier and relatively uncongested. The price of access is likely to be low, incentivising connection in this location.

An auction may not require the equivalent use-it-or-lose it provisions or qualifying criteria as the queue model. If generators purchase priority access, they have a strong incentive not to forego the priority access they have purchased. These provisions may nevertheless be a useful safety net, giving greater confidence to subsequent investors.

Generators who fund transmission investment (or participate in run-back schemes which have the effect of increasing transmission capacity) could be assigned to a higher priority tier on the basis that their investment creates space in the tier. This would be in lieu of paying via the auction.

A summary of this sub-option is shown in Figure 14. The generator's labels are in chronological order i.e. A represents the legacy generators, I is the last to connect.

Figure 14 Illustration of auction sub-option in Option 2 centrally determined tiers



Source: ESB

The diagram illustrates some key features of the model:

- In zone 1, the highest priority tier was already full (tier 1). No more generation could be accommodated without breaching the tier. Generators B, C, E and F competed in an auction for entry to tier 2. Generators B and C were successful in that auction. There was insufficient space for generators E and F, who were assigned to tier 3.
- In zone 2, the highest priority tier was already full. Generators G, H and I competed for tier 2. Generator H and I were assigned to tier 2. Generator G was unsuccessful and assigned to tier 3.
- Generators in a REZ (labelled D) were accommodated in the highest priority tier. The REZ coordinator allocated reserved capacity in the tier to incoming generators (perhaps through its own auction process).

The treatment of legacy generators is discussed in section 3.2.3.

Assessment of the options

Consistent with the access reform objectives, the primary rationale for implementing the priority access model is to promote investment efficiency and manage access risk. Under the access reform assessment criteria, this must be achieved while promoting effective wholesale competition, minimising implementation challenges, and integrating with jurisdictional REZ schemes.

Table 3 provides a summary assessment of the options.

Table 3 Initial assessment of the two model options

<table>
<tr><th rowspan="2"></th><th rowspan="2">Queue</th><th colspan="2">Centrally determined tiers</th></tr>
<tr><th>First come first serve</th><th>Auction</th></tr>
<tr><td rowspan="2">How is efficient investment incentivised?</td><td rowspan="2">In congested areas, the back of the queue would have less value, incentivising investment in less congested areas.</td><td colspan="2">Central agency estimates efficient hosting capacity and refers to this analysis to delineate tiers.</td></tr>
<tr><td>Incoming generators are disincentivised from investing in congested areas that lack available hosting capacity since they would be assigned a lower priority level.
Efficiency depends on assessments made by central agency</td><td>Incoming generators are disincentivised from investing in congested areas that lack available hosting capacity since they would be assigned a lower priority level.
Efficiency depends on assessments made by central agency. Furthermore, the auction price sends signal to invest in uncongested areas, and rations access based on auction results.
Potential delays to the connection process could forestall otherwise efficient investment.</td></tr>
<tr><td>How is congestion risk reduced?</td><td>There may be a reduced risk that an existing generator’s access is diminished by an incoming or future generators. The level of reduced risk is subject to implementation considerations e.g. grouping generators to a DP number.</td><td colspan="2">A generator’s risk of congestion from incoming or future generators would be limited. If an incoming generator cannot be accommodated in a tier, it must be assigned to a lower priority tier. This reduces the risk of degrading access for existing generators within the tier.
Governance arrangements are crucial. Reliance on the central agency to preserve the expected value of priority access.</td></tr>
<tr><td>How might competition be affected?</td><td>Incoming generators may be able to block access to future generators, increasing their congestion risk.</td><td>Incoming generators may be able to block access to future generators, increasing their congestion risk.</td><td>Incoming generators may be able to block access to future generators, but incoming generators can compete with existing generators for available space in a tier.</td></tr>
<tr><td>Implementation issues</td><td>Grouping may be required to enable the EN priority dispatch engine to run quickly.</td><td>Determining the efficient hosting capacity based on load flow modelling may be challenging.</td><td>Determining the efficient hosting capacity and running the auction, based on load flow modelling, may be challenging.
Auction complexity may drive inefficient assignment of priority access.</td></tr>
<tr><td>How are REZs accommodated?</td><td>REZ coordinators reserve queue number at back of the queue. Extra transmission capacity makes the back of the queue valuable.</td><td>REZ coordinator reserves space in high priority tier.</td><td>REZ coordinator reserves space in high priority tier</td></tr>
</table>

Conclusion

The ESB has identified two broad design choices for the implementation of the priority access model - a queue or centrally determined tiers. A key design difference between them is the extent to which central agencies are involved in assigning priority levels, and in turn influencing the incentives on generators to invest.

Under the queue model, generators are assigned priority access based on the time they (or the REZ in which they are participating) reach some defined event in the connection process (or REZ development process).

In the centrally determined tiers model**,** a central agency delineates tiers based on its expectations of efficient investment, and then assigns generators into those tiers on a first-come-first serve basis or via an auction.

Our next step is to gather feedback on the options and their specific design, to progress to a detailed design for consideration by Energy Ministers in mid-year. We will continue to analyse the options and engage with our technical working group.

QUESTION 1: PRIORITY ACCESS MODEL OPTIONS

The ESB welcomes feedback on the two options (and sub-options) for the priority access model, as well as any other options not considered here. Some specific questions are:

1. Key design choice
    a. Do you prefer the queue option or the centrally determined tiers option? Why?
    b. At what point in the connection process should queue numbers or tiers be assigned?
2. Queue model
    a. Do you favour queue numbers being assigned in strict chronological order or in time-windows?
    b. If grouping is necessary for practical reasons, how substantially do you think the benefits of the queue model might be diminished? What is the minimum number of groups to make the model preferable?
3. Centrally determined tier model
    a. Which sub-option do you prefer; first-come-first-serve or auction? Why?
    b. What is the preferred metric to delineate the tiers?
    c. Should the tier delineations be set forever or redetermined periodically?

3.2.2 Policy levers

The intent of the priority access model is to limit the cannibalisation by incoming generators of the access of existing generators (legacy and entrant). The ability to cannibalise creates risks for existing generators and provides inefficient investment signals for incoming generators.

However, giving incoming generators priority over future generators may create new incentives for inefficient investment. Because incoming generators are protected from the future congestion that they bring forwards in time, but do not immediately cause, they may connect in areas of the grid which “use up” most of the spare capacity. This leaves less access for future generators.

Assigning less priority access to future generators limits their ability to access the RRP. The risk of congestion will increasingly be borne by newer generators.

These concerns can be addressed by adjusting “policy levers” within the priority access model design:

- implementing soft, instead of hard, priority access
- limiting the duration of priority access.

The levers are discussed below.

Hard or soft priority

As noted in chapter 2, the priority conferred to a generator could be designed as “hard” or “soft”:

- Hard priority means that the dispatch priority number will play a larger role than constraint coefficients in determining dispatch when a constraint binds. It is not fully absolute given it is still subject to conditions to ensure that overall EN priority dispatch is physically feasible.
- Soft priority means that the dispatch priority number will overcome some but not all constraint coefficient differences in determining dispatch when a constraint binds. With soft priorities, generators would have priorities over units in proximate locations (meaning similar coefficients in a range of constraints) but not necessarily priorities over generators in distant locations (meaning quite different coefficients in a range of constraints).

Soft priority lies on a spectrum, anywhere between hard priority and almost no priority at all. For example, very soft priority could only confer priority over generators in very similar locations, with very similar constraint coefficients.

The advantage of hard priority is that it confers greater protection to existing generators from cannibalisation from incoming generators across a wide geographical area, and so may better address the problem that priority access is attempting to address. Hard priority disincentivises inefficient investment decisions which in part are based on cannibalisation and increases the ability of generators to manage congestion risk.

Under the current regime, to cannibalise, generators must connect in parts of the grid that have relatively low constraint coefficients compared to their competitors in the constraint. Similarly, a relatively low coefficient protects them – somewhat – from subsequent cannibalisation. Only generators with an even lower coefficient can cannibalise when that constraint binds (noting that other constraints may become binding over time). This sends a signal to avoid connecting in locations with high constraint coefficients, which use much of the capacity.

However, hard priority reduces this incentive. Providing that a location is not *currently* congested, an incoming generator need not consider how much of the constraint it uses. It will be a future generator that *immediately* causes a constraint to bind that bears the cost, not all the other generators who have contributed to bringing forward the point in time when the grid is congested.

There may be two countervailing impacts on investment efficiency.

On the one hand, hard priority may increase investment efficiency by reducing incentives to invest in parts of the grid which cannibalise the access of *existing* generators. This also enables investors to manage the congestion risk caused by future generators. But on the other hand, it may decrease investment efficiency by allowing generators to locate in areas of the grid which use spare transmission capacity wastefully. This will more quickly bring forward binding constraints .

It is difficult to know where the balance lies between these competing effects. Softer priority would partially address the newly created problem of incoming generators ignoring the impact of their decisions on future generators. This is because coefficients would continue to play a role in determining priority. But, the trade-off would be that the original problem – cannibalisation resulting in inefficient investment and risk – would not be as thoroughly addressed.

Soft priority may also have other advantages.

- It is easier to implement, as discussed in section 3.3.
- It may avoid the possibility of substantial changes to the RRPs arising from implementing priority dispatch.
- It reduces the inefficiencies arising in the priority energy dispatch. Under soft priority, less reliance is placed on the CRM to rectify these newly created inefficiencies in order to arrive at an overall efficient physical dispatch. While we consider that the CRM provides strong incentives for participation, if generators are assigned hard priority and choose not to opt in to the CRM, physical dispatch efficiency may be reduced compared to the status quo.

Table 4 Summary of hard and soft priority

Level of priority	Pros	Cons
Hard	• Improved investor confidence; maximises the ability of generators to manage congestion risk • Improved locational signal to avoid inefficient investment in congested parts of the network.	• Weaker locational signal to locate efficiently in uncongested parts of the network • May be difficult to implement • May have a significant impact on the RRP • High reliance on CRM to unwind inefficiencies in priority dispatch
Soft	• Stronger locational signal to locate efficiently in uncongested parts of the network • Easier to implement • May have a less significant impact on the RRP • Less reliance on CRM to unwind inefficiencies in priority dispatch	• Limited impact on investor confidence; does not maximise the ability of generators to manage congestion risk • Weaker locational signal to avoid inefficient investment in congested parts of the network

Duration of priority access

This section discusses the duration of priority access assigned to newly connecting generators after the reform has been implemented. The treatment of legacy generators is discussed below.

Options

Four options are considered:

1. Actual life of asset i.e. when the generator exits the market. This could relate to the full or part of the asset's total capacity e.g. one stakeholder suggested [90%] of the asset's capacity is assigned to the highest available priority level.[23]
2. Proportion of the asset's forecast technical life e.g. one stakeholder submission suggested a minimum of 2/3 of the asset's technical life.[24]

23 Hydro Tasmania, Response to ESB Transmission Access Reform – Directions Paper, 21 December 2022

24 Australian Energy Council, Submission to ESB Transmission Access Reform – Directions Paper, 21 December 2022

3. Fixed duration e.g. in line with typical PPAs (~5 – 15 years) or aligned with jurisdictional access schemes. The fixed duration may need to be adjusted depending on the intent of the policy lever e.g. to account for different asset lives by technology particularly hydro.
4. Fixed duration with a glide path whereby a generator's priority adjusts following a predictable glidepath e.g. fixed for [10] years, decreasing thereafter based on a proportion of the asset's capacity assigned to a lower priority level.

Assessment

The choice between long-lived and short-lived priority access has many of the same trade offs as the choice between hard and soft priority access.

Long-lived priority access best protects existing generators from cannibalisation, enabling them to manage their risk and deterring inefficient investment that would currently be profitable due to cannibalisation. But it means that incoming generators have less regard to the impact of their decisions on future generators, potentially incentivising them to connect in locations which use up much of the available capacity. This may block future investments (depending on the duration of priority access rights).

Under the centrally determined tiers model, shorter-lived priority access may make the auction more competitive, as existing generators are required to re-compete for priority access.

If generators are receiving considerable value from a priority access, this may, all else equal, delay otherwise efficient *dis*investment if priority access is conferred until the generator chooses to exit the market. In practice, many generators that are expected to retire in the near future may be in relatively uncongested parts of the network, and so the value of a position at the front of the queue or in a priority tier is low. The distortions to efficient behaviour, and impact on other generators and consumers, may only be modest.

Conclusion

Adjusting the firmness or length of priority access could address the concern that investors will disregard the impact they have on congestion brought forward, but not immediately prompted, by their investment.

Softer priority access may also be easier to implement, have less impact on the RRP, and place less reliance on the CRM to deliver efficient physical dispatch.

QUESTION 2: POLICY LEVERS

1. Where on the hard versus soft spectrum should priority access be?
2. What is the preferred basis for the length of priority access?
3. If a glide path is taken, what should its shape be?

3.2.3 Treatment of legacy generators

To encourage investment, it is a common principle in public policy that regulatory changes does not substantially impact the value of sunk investments. By doing so, this may discourage future investments, who perceive future regulatory changes may impact the value of their investments. This concept is commonly known as "regulatory risk".

This principle has been a feature of the decision to progress the CRM, rather than the CMM, as the mechanism to improve dispatch efficiency.[25] It has also featured prominently in informing many of the CRM design decisions (discussed in section 4.2), such as the voluntary basis of the CRM.

This suggests that existing arrangements may need to "grandfathered".

On the other hand, if investors perceive that the grandfathered arrangements for legacy generators are more profitable to arrangements for generators that connect after the reforms are implemented there may be a rush to connect. Given that the current arrangements provide incentives for inefficient investment, this rush may be inefficient. Similarly, if grandfathered arrangements are perceived to be less profitable, there may be an investment strike.

Both the queue model and the centrally determined tiers model will have to consider the treatment of legacy generators.

Options

Three options for the treatment of legacy generators are considered here:

1. Highest priority level for life: legacy generators automatically assigned the highest priority level which lasts for the life of asset.
2. Initial assignment to the highest priority with glide path: access for legacy generators could be set at the highest priority level initially, but degrade over time by:
    a. reallocating towards the back of the queue or to lower priority tiers
    b. reallocating a proportion of capacity or availability to the back of the queue/into lower priority tiers.
3. Split a legacy generator's capacity across priority levels: access for legacy generators could be proportioned across queue numbers or tiers.

Assessment

Whatever approach is taken is likely to be controversial as it may create winners and losers compared to the status quo arrangements (i.e. what will happen in the future given the current access regime).

Under the status quo arrangements, a generator's access can change over time as:

- incoming generators connect with lower constraint coefficients, decreasing access
- generators with lower constraint coefficients exit the market, increasing access
- new transmission capacity, load or storage is constructed which alleviates constraints, increasing access.

Depending on the design, the priority access model could inadvertently increase or decrease a legacy generator's access compared to the status quo arrangements. This is particularly material for legacy generators who are in – or are likely to be in the future – parts of the grid that are congested. NERA's analysis suggests that this is often a legacy renewable energy generator, rather than fossil fuel generators, that will be most affected by this decision. Many fossil fuel generators are currently in uncongested parts of the grid. In general, the treatment of legacy generators in the priority access model is not a choice between old high emission generators and new low emission generators, but between older and newer low emission generators.

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[25] Energy Security Board, *Transmission access reform Cost benefit analysis*, February 2023, p.12.

A brief overview of options and summary of their pros and cons is outlined below.

Table 5 Summary of options for treatment of legacy generators

Legacy generators	Pros	Cons
Highest priority level for the full asset life	• Simple • Limits regulatory risk and so promotes future investments	• Likely to result in a windfall gain to legacy generators, resulting in a rush for inefficient investments
Initial assignment to the highest priority with glide path	• Seeking to replicate that legacy generator access can fall over time in the status quo arrangements	• By demoting legacy generators through the queue/tiers, the access of new generators is promoted even in parts of the grid that are already congested – potentially incentivising inefficient investment. • Complicated to calibrate to replicate status quo. If unsuccessful, may create a rush or investment strike, and increase regulatory risk
Split a legacy generator's capacity across priority levels	• Simple and transparent, once initially set up.	• By reserving high priority access for new comers, entry is incentivised even in parts of the grid that are already congested – potentially incentivising inefficient investment. • Complicated to calibrate to replicate status quo. If unsuccessful, may create a rush or investment strike, and increase regulatory risk

Conclusion

Regardless of whether the centrally determined tiers approach or queue model is implemented, the treatment of legacy generators will have to be carefully considered. Assigning legacy generators the highest priority access may be a windfall gain, prompting an inefficient rush to connect. Conversely, assigning low value priority access to legacy generators may create regulatory risk and prompt a rush to invest before the cut-off that defines legacy generators takes effect.

We welcome feedback on these issues and will take it into account as we continue our detailed design of the priority access model.

QUESTION 3: LEGACY GENERATORS

1. How should legacy generators be assigned priority access?
2. How should legacy generators be defined i.e. how should the demarcation date be set?

3.3 Technical considerations

This section introduces technical considerations for the implementation of priority access into AEMO's systems. There are no specific questions posed for stakeholder consultation at this time. We are sharing information about potential technical options for stakeholders' visibility. Achieving preferences on the design choices will help to refine the design specification and ongoing technical investigations.

3.3.1 Implementing priority access

Background

This section considers how EN priority dispatch is calculated. Dispatch calculations are undertaken by NEMDE. Priority dispatch would require some changes to the algorithms that NEMDE uses which is discussed more fully in section 5.

Each generator with a DUID will be assigned a DP number which reflects its access priority – relating to either its queue position or tier. The lower the DP number, the higher the priority.

Depending upon the prioritisation approach there may be:

- a few different priorities e.g. tiering may only use 2 or 3 DP numbers; or
- many different priorities e.g. queueing may have a different priority for each new REZ and each new non-REZ generator.

The ESB is investigating two possible approaches to implementing priorities in the dispatch process:

- market floor price (MFP) adjustments
- sequential-solve.

Market floor price (MFP) adjustments

MFP adjustments would apply a different market floor price to different DP numbers. Two simplified examples are shown in Table 6 for a single binding constraint. These are indicative only. The values for MFP have not been chosen and will depend on how many DP numbers need to be accommodated. There is also the possibility that some MFPs could be greater than -$1,000/MWh, for instance - $500/MWh.

Table 6 Examples of adjusted MFP

DP number	MFP in Design 1	MFP in Design 2
1	-$100,000	-$4,000
2	-$10,000	-$2,000
3	-$1,000	-$1,000

Source: ESB, illustration purposes only

Consistent with today, no generator is *required* to bid to the MFP. A generator can bid to the MFP if it wishes and is likely do so if behind a binding constraint. A generator with DP=1 could bid to a lower MFP than a generator with DP=2 and it is likely to be dispatched in preference.

However, this is not guaranteed. In the case of a single binding constraint, generators with equal bids will be dispatched in ascending order of coefficient: the "*a* value". When bids are *not* equal, a different dispatch order arises, based on a different "*b* value" variable which combines the coefficient and bid values. This variable is determined using the following formula:

$$b = (a \times MPC) / (RRP – bid)$$

Generators are dispatched in order from lowest to highest *b* value. It will be seen from this formula that, where bids are equal (e.g. all generators bid at the same MFP), the ordering of *b* is the same as the ordering of *a*. Strictly speaking, the market price cap (MPC) multiplier on the numerator is not needed, but helps to make the b-values similar in order of magnitude to the a-values.

Table 7 and Table 8 show examples of how the different MFPs in the two example designs affect *b*, and so the order of dispatch, for different values of RRP. To make the example interesting, the order of the DP number is the opposite of the order of the coefficients. If the ordering had been the same, the correct prioritisation would occur even under the usual dispatch algorithm.

Table 7 b-values under an adjusted MFP (Design 1)

Generator Details					b-values under RRP Scenarios		
Gen	DP #	a-value coefficient	MFP $/MWh	Bid $/MWh	RRP=$0	RRP=$1000	RRP=$15,000
A	1	1	-100,000	-100,000	0.15	0.15	0.13
B	2	0.2	-10,000	-10,000	0.30	0.27	0.12
C	3	0.07	-1,000	-1,000	1.05	0.53	0.07

Table 8 b-values under an adjusted MFP (Design 2)

Generator Details					b-values under RRP Scenarios		
Gen	DP #	a-value coefficient	MFP $/MWh	Bid $/MWh	RRP=$0	RRP=$1000	RRP=$15,000
A	1	1	-4000	-4000	3.75	3.00	0.79
B	2	0.2	-2000	-2000	1.50	1.00	0.18
C	3	0.07	-1000	-1000	1.05	0.53	0.07

Source: ESB, for illustration purposes only

Normal dispatch (where generators can bid down to -$1000/MWh) would be in ascending order of coefficient i.e. *"<CBA>"* meaning that C is dispatched first, then B then A.

Under 'Design 1' in Table 7, the dispatch (based on the b-value ordering) is usually in order of DP number i.e. <ABC>. However, at very high RRP levels, the order reverses i.e. back to <CBA>. The DP number dominates at low levels of RRP and the coefficient dominates at high levels of RRP.

Under 'Design 2' in Table 8, dispatch prioritisation is not maintained even at low values of RRP.

It can be seen from these examples that a *higher* ratio between the consecutive MFP values (10 in example A, just 2 in example B) helps to ensure prioritisation during high (but not *very* high) RRPs. A lower ratio means that prioritisation might not be ensured even under low RRPs. Section 2.3.2 introduced the concept of hard and soft prioritisation. It is seen that the greater the MFP ratios, the harder the prioritisation becomes.

Where a high ratio is preferred, the MFP for the highest priority level quickly becomes extreme as more priority levels are added. In this respect, there is a limit to how hard the prioritisation can be made when there are many levels e.g. under the queue approach.

The very high RRP in the final column of Table 7 and Table 8 would typically indicate a shortage of generation e.g. during a critical demand peak. In such circumstances, a fully prioritised dispatch may be infeasible. In such situations, dispatch feasibility must take precedence over dispatch priority. Dispatch priority must be relaxed, where necessary, to ensure feasibility. The MFP adjustment method does this automatically, as the dispatch ordering in the final columns of Table 7 and Table 8 indicate.

Sequential-solve for EN priority dispatch

Section 2.4.2 confirms that the CRM is a second dispatch run that is executed immediately after the EN dispatch i.e. the CRM will be implemented via a sequential dispatch. In addition, this section discusses a sequential-solve approach to implement priority levels into the energy market dispatch.

The sequential-solve approach would use a sequence of dispatch runs to ensure that generators bidding at the market floor price are dispatched in order of DP number and the balance by their offer price. For example, if there are three DP numbers then there would be four dispatches in the sequence:

- Dispatch 1: only gens with DP=1 and bidding MFP
- Dispatch 2: only generators with DP= 1 or 2 and bidding MFP
- Dispatch 3: all generators bidding MFP
- Dispatch 4: all generators and all bids.

Dispatch 4 is the final energy dispatch that is used for in settlements.

In all but the final dispatch, only a portion of the offered generation is eligible for dispatch, which will typically be inadequate to meet the demand for energy and FCAS.

The technical considerations of implementing market price floor adjustments and sequential-solve are discussed in section 5.

Grouping

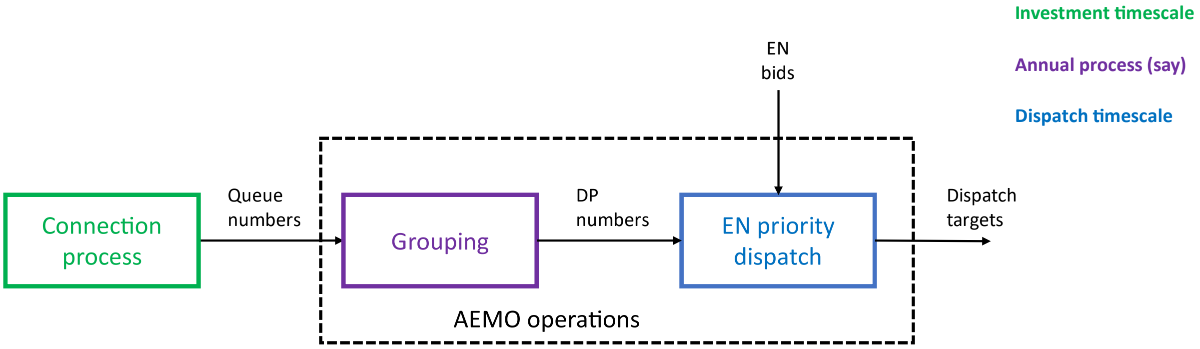
If the queue model is chosen and each queue number has a unique DP number, there will eventually be many different priority levels. This may cause problems for priority dispatch:

- For the MFP adjustments method:
    - MFPs must be extreme, or
    - prioritisation becomes soft, or
    - a mixture of both
- For sequential-solve:
    - the process might take an impractically long time to complete.

These problems do not arise in the tier model where there will likely be only two or three priority levels.

One way to address these difficulties would be through grouping priorities within the queue model. Generators would have different queue numbers and be grouped to a DP number for priority dispatch. The highest priority group would have DP number ‘1’ etc. This system is illustrated in Figure 15 below.

Figure 15 Grouping architecture



Source: ESB analysis

The objective of grouping is to reduce the priority levels to a manageable number whilst maintaining, as far as possible, the degree of prioritisation required.

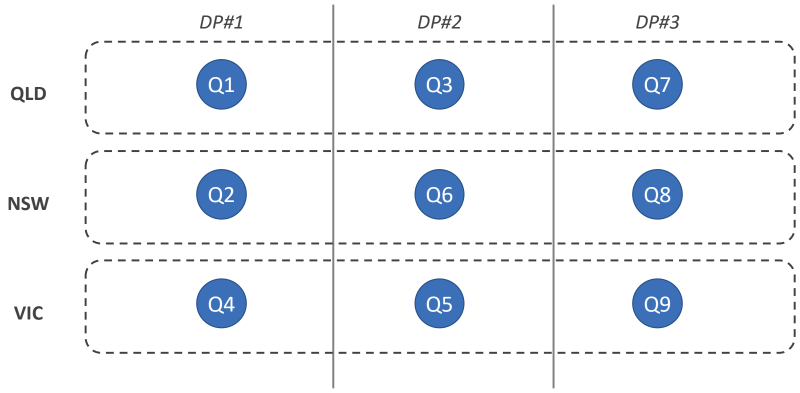
To achieve this, the location of generators will need be factored in.

Assume an example where:

- 9 generators have unique queue numbers.
- The exigencies of priority dispatch require these 9 generators to be placed in no more than 3 groups.
- The generators happen to be located in 3 different states.
- The generators in different states are not competing for the same access.[26]

Given the above assumptions, the generators in different states can be placed in the same group without affecting priority dispatch outcomes. Generators in the same state must be placed in different groups as far as possible. A likely grouping is shown in Figure 16.

Figure 16 Illustrative grouping of queue numbers to DP numbers, accounting for location



Source: ESB, for illustration purposes only, DP refers to dispatch priority number, Q refers to queue number

In this simple example, the outcome of the grouping is the same as if a separate queue had been established in each state. In more complex examples – e.g. with many generators within a state –

26 This is not always true in reality given the interconnected nature of the NEM, and because a number of constraints cross regional boundaries.

interactions between generators become more complex and dynamic and a single queue with grouping is preferred.

In this example, because of the limited interaction between states, priority dispatch using DP numbers will likely give similar outcomes to that using queue numbers. With more generators and queue numbers, the grouping problem will become harder and priority dispatch is likely to be affected.

Because grouping is essentially an implementation issue – part of designing the dispatch process to reflect priorities – it would be undertaken by AEMO, subject to the objective stated above. The intent is to speed up dispatch times so grouping would be done *prior* to dispatch rather than within dispatch. Groups would probably only need to change when generators entered or exited, or when new transmission was built. Therefore, grouping might be undertaken annually, say.

Discussion

Both algorithms may be feasible when there are only a few DP numbers but they will both be less effective or practical when there are many DP numbers.

For the adjusted MFP method, many DP numbers will either require extremely low MFPs for the highest priority generators, or require smaller ratios between consecutive DP numbers, giving a softer prioritisation than might be intended. This will particularly be the case when there are high RRPs when generators would most want access. Extreme MFPs are liable to lead to extreme RRPs, interfere with the use of constraint violation penalties in NEMDE, and could create calculation difficulties.

For the sequential-solve method, many DP numbers will require many dispatch runs. There may be insufficient time to solve in real-time dispatch.

These practical difficulties could potentially be addressed by grouping to reduce the DP numbers. However, grouping will itself create complexities and may soften priorities. For example, two generators in the same network location may be grouped to the same DP number and hold the same prioritisation, despite having different queue numbers.

If tiering is used, rather than queueing, these practical difficulties are unlikely to arise given there are already a small number of DP numbers.

An illustrative example of the queue model, with the MFP method, is provided in **Appendix D**. As previously noted, the ESB plans to share more worked examples (at varying levels of complexity) to facilitate stakeholder's understanding of the proposed model options including how it would apply in real-world scenarios.

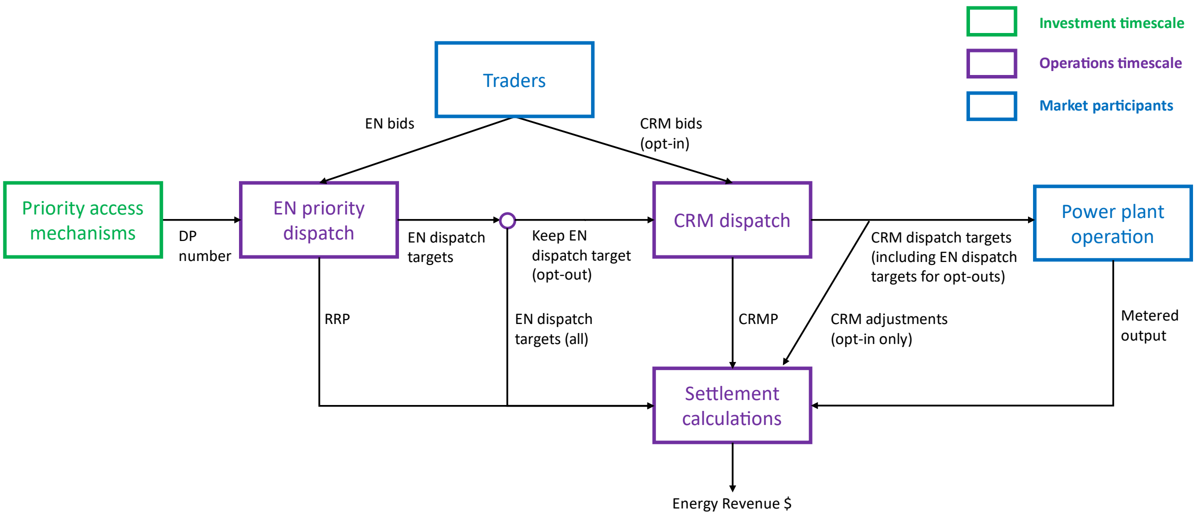
4 Congestion relief market

4.1 Introduction

The CRM architecture is presented in Figure 17. There are four high-level processes in the hybrid model:

- priority access mechanism
- EN priority dispatch
- CRM dispatch
- settlement calculations.

Figure 17 CRM architecture



Source: ESB analysis

The priority access mechanism is carried out in the investment timescale and was discussed in the previous chapter 3. The three other processes are carried out in the operation timescale and discussed below.

4.1.1 EN priority dispatch

The EN priority dispatch algorithm was discussed in section 3.3.1. Inputs include the DP numbers (assigned during the connections process for each DUID) and the EN bids submitted by traders for each generator.

Similar to today's dispatch, there are two key outputs from this process: EN dispatch targets and RRPs. These outputs feed into the settlements calculation and also, for opt-out generators, into the CRM dispatch.

4.1.2 CRM dispatch

The CRM dispatch is a second dispatch. It is subject to the same constraints as the EN dispatch i.e. transmission constraints, demand forecasts etc. Opt-in generators provide a second set of bids into the CRM dispatch. For opt-out generators, the CRM dispatch is set equal to their EN dispatch.

Unlike the EN dispatch, the CRM dispatch is not prioritised. The DP numbers play no role in deciding who is dispatched, except indirectly through the EN dispatch targets of opt-out generators. The CRM dispatch also calculates CRMPs for the nodes of each opt-in generator.

4.1.3 *Energy settlement calculations*

CRM settlement uses the price and quantity information determined by the two dispatch processes, and the metering of actual output. Based on stakeholder feedback the ESB has determined to use the "option 1" settlements formulation from the directions paper where dispatch variations are settled at RRP as is currently the case in the NEM:

$$\text{Energy Revenue} = G_{MET} \times RRP + (G_{CRM} - G_{EN}) \times (CRMP - RRP):$$

Where:

G_{EN} = EN dispatch target

G_{CRM} = CRM dispatch target

G_{MET} = metered output or load

This can also be shown as three components:

$$\text{Energy Revenue} = \underbrace{G_{EN} \times RRP}_{1.} + \underbrace{(G_{CRM} - G_{EN}) \times CRMP}_{2.} + \underbrace{(G_{MET} - G_{CRM}) \times RRP}_{3.}$$

1. settled at the RRP for energy dispatch
2. additionally settled on the difference between the CRM and EN dispatch targets at the CRMP
3. additionally settled at the difference between metered output and the CRM dispatch target at the RRP.

Readers should note that G_{EN} was previously referred to as G_{NEM} in the directions paper. This update is designed to flag the policy decision to pursue priority access. G_{EN} refers to EN priority dispatch.

For opt-out generation the settlement formulas are unchanged from today given $G_{CRM} = G_{EN}$ so:

$$\text{Energy Revenue} = G_{MET} \times RRP$$

Non-dispatchable load and opt-out dispatchable load continues to be settled at the RRP i.e.

$$\text{Energy Payments} = G_{MET} \times RRP$$

Dispatchable load that has opted in is analogous to opt in generation:

$$\text{Energy Payments} = G_{MET} \times RRP + (G_{CRM} - G_{EN}) \times CRMP + (G_{MET} - G_{CRM}) \times RRP$$

4.2 Design choices

This section:

- confirms the status of design choices from the directions paper
- introduces new design choices for stakeholder consideration.

4.2.1 *Status of design choices from the directions paper*

The directions paper sought feedback on six key topics for the CRM design. Five are shown in Figure 18 below, and the sixth relates to the parties eligible to participate in the CRM.

The ESB is broadly aligned with stakeholder views. Based on stakeholder feedback and inputs from the ESB's technical team, the initial preference is to adopt design choices which retain the existing energy market arrangements and maintain the optionality of the CRM. **Appendix G** provides further detail on the design choices, stakeholder views and the ESB's response.

Outcomes are summarised below in Figure 18.

Figure 18 Initial preferences for the CRM design

Consistent with status quo ⟷ Change to status quo

Design choice	Option		
1. Rounding coefficients	Keep the existing energy market dispatch.		Round the constraint coefficients in the energy market.
2. Do we modify the energy market design in response to the new bidding incentives?	Keep the existing market design.	Modify the bidding guidelines.	Introduce automated rules into the energy market to exclude 'out of merit' bids i.e. if CRM bid > energy market bid.
3. Do we introduce additional rules for storage?	Apply the same rules to storage as a generator as to other generators (see above).		When storage is acting as a generator, exclude 'out of merit' bids i.e. if energy market bid > assigned strike price (+ availability profile).
	Apply the same rules to storage as load as to storage as a generator (see above).		When storage is acting as load, only settle storage at the CRM price.
4. How do we calculate RRP?	RRP_{NEM} - calculate the RRP based on the energy market (as per status quo).		RRP_{CRM} - calculate the RRP based on the final dispatch including CRM adjustments.
5. How do we settle metered output?	Differences (metered output vs dispatch targets) are priced at RRP.		Differences (metered output vs dispatch targets) are priced at the CRM price.

Key — Initial design preference (green) — Under investigation (blue)

Source: ESB

Note RRP_{EN} was previously referred to as RRP_{NEM} in the directions paper.

Parties subject to the arrangement

- All market participants with scheduled and semi-scheduled generating units, scheduled loads and wholesale demand response units can participate in the CRM including market network service providers.
- Non-market participants and non-scheduled units of market participants will not be able to participate in the CRM.
- The level of participation will be at a dispatchable unit (DUID) level. Scheduled generating systems comprising multiple DUIDs will need to opt in for all DUIDs to participate in the CRM.

Rounding constraint coefficients

- The decision to pursue priority access already addresses key risks identified in today's energy market and has a significant impact on the allocation of congestion risk.
- Depending on the number of parties with a shared queue number or tier, rounding coefficients may still be a useful addition to address the residual risk of 'winner takes all' outcomes for parties with the same DP number.

- However, the ESB does not propose to pursue rounding constraint coefficients at this time. There are key design choices to be finalised for priority access which affect this residual risk. There is also a significant technical work plan to implement both priority access and the CRM design. A rule change request could be considered at a later date, when we can better assess if there is incremental benefit and its technical feasibility.

Bidding incentives and additional rules for storage

- The ESB (with the AER leading on this item) is exploring the potential for market manipulation arising from the CRM design and potential options to address this issue. The current working assumption is that the same rules for other generators will apply to storage (as a generator or load). Storage forms part of the broader considerations of market bidding incentives.
- Potential options being considered include (but are not limited to) amendments to the rules and/or bidding guidelines to ensure the prohibition on false and misleading bids also applies to bids into the CRM.
- We note that post-implementation monitoring of market participant behaviour and bidding incentives created by the CRM will be important. Behaviour will evolve with a new market and it is important that the rules and/or guidelines are reviewed to ensure the reforms enable effective functioning of energy markets.

Calculation of RRP

- This was a key focus for stakeholders. On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to keep RRPs from the energy dispatch (rather than the CRM).
- This choice maintains the optionality of the CRM and avoids potential disruption to financial markets and the costs of re-opening contracts.

Settlement of differences between metered output and dispatch targets

- For similar reasons, the preference is to settle differences between metered output and CRM dispatch targets at the RRP, rather than CRM prices.

We suggest that the rules require a review of the priority access and the CRM model 3 years after implementation. This review could be conducted by the AEMC with inputs from AEMO, the AER, and consultation with stakeholders. It will have the benefit of real data points to consider the operation of the scheme and any refinements that may be required at that time. This review will likely have resourcing implications for the market bodies.

Stakeholders also requested more information on the interaction between the transmission access reform and other recent and upcoming reforms. **Appendix B** provides details on the interactions with:

- Operational security mechanism (OSM)
- Scheduled lite
- Integrating energy storage systems (IESS) which introduced a new market participant category; the Integrated Resource Provider (IRP).

The ESB continues to monitor the parallel progress of reform changes to ensure they are consistent and complementary. We will notify stakeholders of key changes and interactions as part of our ongoing stakeholder engagement.

The design choices overleaf represent new design choices for stakeholder feedback in response to this consultation paper.

4.2.2 Settlement residues

Background

Settlement residue is the difference between payments made *to* AEMO by retailers and payouts made to generators *by* AEMO. The market design needs to decide who receives this residue. In the case of negative residues (settlement deficits), a funding source must be identified.

In the current market design, inter-regional settlement residues arise due to interconnector flows and loss factors. For simplicity, losses are ignored here but will be factored in for drafting Rules.

In the absence of losses, settlement residues only arise across interconnectors where RRPs in the adjacent regions diverge due to inter-regional congestion. The residue associated with each interconnector is referred to as the Inter-regional Settlement Residue (IRSR). In a dispatch interval, the IRSR (in $/hour) can be derived using the formula:

$$IRSR = IC \times (RRP_M - RRP_X)$$

Where:

IC is the MW flow on the interconnector

RRP_M is the RRP in the importing region

RRP_X is the RRP in the exporting region

The IRSR can be negative due to $RRP_M < RRP_X$. This condition is referred to as a *counter-price flow*. AEMO manages these deficits and prevents them from becoming too large through *negative residue management*. This is informally referred to as *clamping*. Constraints are added in NEMDE to block the interconnector flow and reduce the IRSR to zero.

The accumulated IRSR is auctioned through regular settlement residue auctions (SRAs) where auction units relate to each *directional* interconnector i.e. each interconnector in each flow direction.[27] The IRSR is paid to the winning bidders (SRA holders). Each TNSP receives the SRA proceeds relating to directional interconnectors flowing *into* its region. Negative residues (settlement deficits) are not recovered through the SRA process but instead from the relevant TNSP directly. SRA proceeds paid to TNSPs, and settlement deficits paid by TNSPs are ultimately paid to, or paid by, consumers respectively.

Residues in the CRM

The CRM settlement algebra for generation and load was shown in section 4.1.3.

For the purposes of analysing settlement residues, generator payments can be split into 3 components and retailer payments (relating to load) remain as a single payment:

Payment to generators = EN$ + CRM$ + DEV$

Payments to retailers = RET$

Where:

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27 Refer to AEMO's Guide to Settlements Residue Auction, version 4.0 final as at 1 Oct 2019. Available at: https://aemo.com.au/-/media/files/electricity/nem/settlements_and_payments/settlements/2019/guide-to-the-settlements-residue-auction.pdf?la=en&hash=FF4564280891B22874B65060013A48D0

$EN\$ = RRP \times G_{EN}$

$CRM\$ = CRMP \times (G_{CRM} – G_{EN})$

$DEV\$ = RRP \times (G_{MET} – G_{CRM})$

$RET\$ = RRP \times G_{MET}$

For opt-out generators, $G_{CRM} = G_{EN}$ by definition and so CRM$ equals zero.

The settlement residue can then be calculated and grouped into two components, as follows:

Settlement Residue = total retailer payments – total generator payments

= total RET$ - (total EN$ - total CRM$ - total DEV$)

= (total RET$ - total EN$ - total DEV$) + (0 - total CRM$)

= SR_{EN} + SR_{CRM}

Where:

SR_{EN} = total RET$ - total EN$ - total DEV$

SR_{CRM} = 0 – total CRM$

EN$ and DEV$ payments are at the RRP which is similar to today's market. This gives rise to an SR_{EN} that is similar to today's residue. However, there is a subtle difference.

Today's RRP payments are made on metered quantities of generator output and retailer load.

In the CRM, the EN$ payments are made on EN dispatch targets and the DEV$ payments are based on dispatch deviations.

Correspondingly, the SR_{EN} – being the sum of these two quantities – is based on the interconnector EN dispatch targets and deviation. That is:

$IRSR = (IC_{EN} + IC_{DEV}) \times (RRP_M – RRP_X)$

Where:

IC_{EN} is the dispatched interconnector flow in EN dispatch

IC_{CRM} is the dispatched interconnector flow in CRM dispatch

IC_{MET} is the metered interconnector flow

$IC_{DEV}= IC_{MET} – IC_{CRM}$

The two residues (and the associated IRSRs) relating to EN and to DEV could potentially be calculated and allocated separately.

Because the IRSR calculation in the CRM is very similar to that seen today, it is anticipated that the allocation mechanism – involving SRAs and TNSPs – will continue unchanged. To the extent that EN dispatch under the CRM is similar to today's dispatch, the IRSR and SRA values will also be similar.

Clamping in the CRM

There remains the possibility of counter-price flows leading to negative IRSRs. In this case the relevant "flow" relates to the EN dispatch. Whilst the deviation component could also be counter-price, deviations and their associated deficits is generally expected to be small. In any case, it is not possible to clamp deviations. This means that, to manage these deficits, AEMO will need to clamp the EN dispatch from time to time, similar to what it does today.

Unlike the EN residue, the CRM residue is new because there is no CRMP settlement today. Whilst it will not be immediately apparent, the relationship between congestion, CRMPs and dispatch means that the CRM residue will rarely be negative. It could occur where, for some reason, the EN dispatch is infeasible (*over-constrained*). In particular, counter-price flows in CRM dispatch do *not* lead to negative residues and therefore do not need to be clamped.

Allocating the CRM dispatch residue

Three approaches are considered regarding the allocation of the CRM residue:

1. Add some or all of the residue to the IRSRs from the EN dispatch. These enhanced IRSRs would be paid to SRA holders.
2. Allocate the residue to TNSPs in each region.
3. Allocate to retailers via the settlements process.

Assessment

Under Option 1, it is not clear how to allocate the CRM residue to interconnectors.

Unlike with the EN residue, there is no direct relationship between the CRM residue and interconnector flows – or changes in interconnector flows – in the CRM dispatch. Indeed, CRM residue can arise even with no changes in such flows e.g. if CRM trading is based around an intra-regional constraint.

Furthermore, because the residue depends on CRMPs – not RRPs – it would not provide a useful RRP hedge; indeed, adding it to the EN IRSRs could be detrimental by adding an extraneous factor that worsens the hedging value of the IRSR. For these reasons, it is proposed not to allocate it to the IRSRs.

Under Option 2, there is a question about the allocation *between* TNSPs.

There is a similar problem of no obvious allocation of the residue between regions. CRM trading can happen within regions or between regions. Since there is no hedging objective here, the main issue is one of equity i.e. how to distribute the CRM residue fairly between consumers in different regions. To meet this objective, the allocation method should be fair and transparent. A suggested approach would be to allocate in proportion to the load in each region.

Under Option 3 there is a question as to how to allocate to retailers. This could be achieved by allocating the total CRM surplus to retailers based on their proportion of load consumed in the billing week. This would then be revised through the standard settlement process. This would provide a quicker way of redistributing the CRM surplus

Conclusions

The settlement residue arising under the CRM market design is divided into two components:

- *IRSR from EN dispatch and deviations*: this is disposed of in the same way as today i.e. through the SRA with SRA revenue paid to TNSPs in the importing region.
- *CRM residue from CRM trading*: this is a new residue, which would be allocated between TNSPs, or to retailers using a simple approach such as pro rata to region load.

QUESTION 4: SETTLEMENT RESIDUE

1. Do you have any feedback on the alternative approaches to allocate the CRM residue?
2. Do you have any suggestions on the metric to allocate the CRM residue between TNSPs or between retailers?

4.2.3 Treatment of MNSPs

Background

A market network service provider (MNSP) is a market participant that trades a merchant interconnector in the NEM. Like a normal, regulated interconnector, a merchant interconnector interconnects two regions. However, unlike a regulated interconnector, it is not permitted to levy transmission charges but rather earns its revenue by trading in the NEM.

The trading, dispatch and settlement of an MNSP is analogous to an equivalent generator-load pair: for example, a 500MW flow on Basslink (an MNSP) from Tasmania to Victoria is analogous to a combination of a 500MW scheduled load in Tasmania and a 500MW scheduled generator Victoria. It is settled in line with this analogy i.e. ignoring losses:

$$MNSP\$ = \text{gen payout} - \text{load payment} = 500MW \times RRP_{VIC} - 500MW \times RRP_{TAS}$$

It is seen that this is similar to the IRSR that is "paid" to a regulated interconnector.

Rules need to be developed for settlement of MNSPs in the CRM design. There will also need to be consideration of how to determine the relevant CRMPs given these are not currently produced by NEMDE.

CRM settlement of MNSPs

For scheduled generators and loads, settlement is based on EN and CRM dispatch targets and any dispatch deviations. It is proposed to settle MNSPs in line with the analogy of a generator-load pair described above. Note that the payment to scheduled load under the CRM design for opt-in scheduled load can be split into 3 components, analogous to the payment to opt-in generators, discussed in section 4.1.3.

$$Load\$ = Load\_EN\$ + Load\_CRM\$ + Load\_DEV\$$$

Where:

$$Load\_EN\$ = RRP \times Q_{EN}$$

$$Load\_CRM\$ = CRMP \times (Q_{CRM} - Q_{EN})$$

$$Load\_DEV\$ = RRP \times (Q_{MET} - Q_{CRM})$$

Where the quantities, Q, refer to the load.

The payment to an MNSP, using the generator-load pair analogy, is simply the difference between the generator and load payments:

$$MNSP\$ = Gen\$ - Load\$$$

$$= (Gen\_EN\$ + Gen\_CRM\$ + Gen\_DEV\$) - (Load\_EN\$ + Load\_CRM\$ + Load\_DEV\$)$$

These six payments can be grouped into two components, similar to how the settlement residue was analysed in section 4.2.2:

MNSP$ = MNSP_EN$ + MNSP_CRM$

Where:

MNSP_EN$ = (Gen_EN$ + Gen_DEV$) – (Load_EN$ + Load_DEV$)

MNSP_CRM$ = Gen_CRM$ - Load_CRM$

Now the EN component is simply settled at RRP, giving a payment similar to the existing arrangements:

MNSP_EN$ = (RRP_M – RRP_X) x (IC_EN + IC_DEV)

This is identical to the IRSR formula for interconnectors discussed in section 4.2.2. Although the formulas will not be identical once losses are incorporated, due to different application of loss factors between regulated interconnectors and MNSPs. IC terms have similar meanings:

IC_EN is the EN dispatch target for the MNSP
IC_DEV is the dispatch deviation for the MNSP

However, unlike for regulated interconnectors, a further payment is made to MNSPs:

MNSP_CRM$ = Gen_CRM$ - Load_CRM$

Now recall that CRM$ is paid at CRMP on the dispatch delta: the difference between the EN and CRM dispatches. So:

MNSP_CRM$ = delta_IC x ($CRMP_M$ – $CRMP_X$)

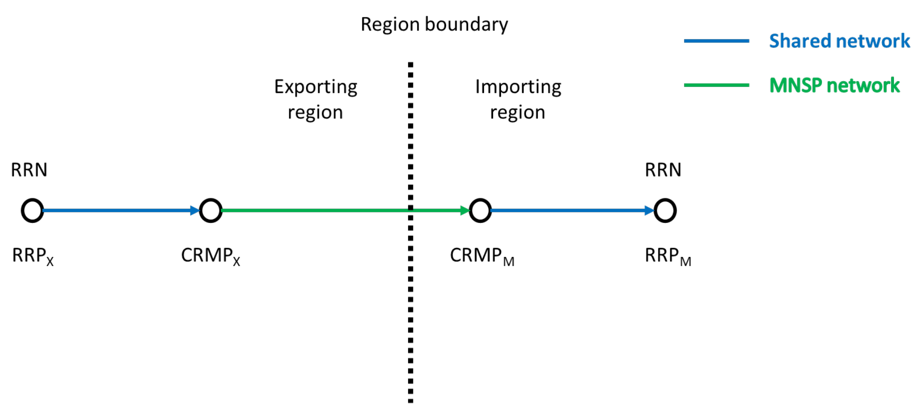
Where:

Delta_IC = IC_CRM – IC_EN

$CRMP_M$ = CRMP at the importing node of the MNSP
$CRMP_X$ = CRMP at the exporting node of the MNSP

This is illustrated in Figure 19. Note that the CRMP will differ from the RRP where there is congestion between the MNSP node and the RRN.

Figure 19 MNSP prices



Source: ESB analysis

Conclusions

Under the CRM design, MNSPs will be settled similar to an analogous generator-load pair, equivalent to their treatment in the current design. This means they earn an "IRSR" payment similar to regulated interconnectors and similar to how they are paid today. In addition, they receive a CRM payment – based on their CRM prices – similar to scheduled generators and loads.

QUESTION 5: TREATMENT OF MARKET NETWORK SERVICE PROVIDERS

1. Do you have any feedback on the proposed approach for the settlement of MNSPs?
2. Are there any special considerations in determining the CRM price for an MNSP?

4.2.4 CRM bidding structures

Background

The CRM design introduces a second dispatch run which settles CRM adjustments at the CRM price. This provides the incentive for CRM participants to bid close to their short run marginal cost (SRMC) so they should be more profitable whatever their CRM dispatch outcome.

EN and CRM dispatch involves full runs of NEMDE and includes the same physical inputs i.e. SCADA values, system constraints and demand forecasts.

It is proposed that traders would submit bids into the CRM and EN dispatches that had similar structures to today's dispatch i.e. 10 offer bands, with a MW quantity and $/MWh price for each band. The process of bidding in the CRM should replicate as much as possible the current process so that participants can leverage their existing bidding tools and systems. The bid type will need to be clearly delineated as either an EN or CRM bid.

However, given the different settlement treatment for CRM dispatch, a question arises whether there should be additional features for CRM bids which will provide traders with more control and certainty over CRM outcomes. Two features are considered:

- *Quantity limits*: setting the maximum quantity that can be bought from, or sold into, the CRM in a dispatch interval; and
- *Buy/sell spreads*: setting a $/MWh spread between the minimum price to sell into the CRM and the maximum price to buy from the CRM.

These two features are discussed in turn below.

Quantity limits

Under this feature, a CRM trader would specify:

- The maximum quantity they would buy from the CRM; and
- The maximum quantity they would sell into the CRM.

Given that the CRM trade is defined as the difference between the EN and CRM dispatches, this is equivalent to setting limits on the CRM dispatch:

EN dispatch – max CRM buy quantity ≤ CRM dispatch ≤ EN dispatch + max CRM sell quantity

Generators can effectively set minimum and maximum values for their CRM dispatch through their bid. However, because they do not know their EN dispatch in advance (i.e. when bids and rebids occur), this does not allow them to set these trading limits with any certainty.

These CRM trading limits would allow traders to "dip their toes" into the CRM. With increased confidence over time, a trader might decide to relax or remove these limits. It would also allow traders to manage contract positions which may allow for a proportion of output not to be sold via the PPA.

Buy/sell spread

The nature of CRM clearing (based on quantities and CRM prices from the CRM dispatch) means that a trader can be more confident (subject to FCAS considerations) that:

- Any purchases from the CRM will be at a price no *higher* than the relevant CRM offer price.
- Any sales to the CRM will be at a price no *lower* than the relevant CRM offer price.

Because the CRM is a physical dispatch, any payments from the CRM will need to be offset against the SRMC of generating more or less than indicated by the EN dispatch target.[28] A CRM trade will be profitable for the generator, so long as:

- The price paid for any CRM purchases is no higher than SRMC.
- The price received for any CRM sales is no lower than SRMC.

Putting these two sets of inequalities together, we have:

- For CRM sales: offer price ≥ SRMC.
- For CRM purchases: offer price ≤ SRMC.

The problem for a trader is that they cannot know for certain in advance whether they will be buying from, or selling into, the CRM. Pre-dispatch may give them some indication but cannot necessarily be relied upon. Given this uncertainty, the only way that a trader can ensure that it never trades at a loss is to bid in at cost i.e. offer price equals SRMC.

There is no policy difficulty with traders bidding at cost. Indeed, to maximise dispatch efficiency, it is necessary to have such cost-based bidding. However, there will be some CRM trades where a CRM bid is at the margin and consequently will set the local CRM price. In these cases, there will be no profit or loss on this bid band. With this possibility, traders may prefer simply to opt-out of the CRM.

A suggested approach to encourage participation is that the CRM bid would include two additional quantities:

- An offer spread (in $/MWh)
- A bid spread (in $/MWh)

The offer spread parameter would in effect automatically raise the CRM offer prices above the EN dispatch target. Similarly the bid spread parameter would in effect automatically lower the CRM offer prices below the EN dispatch target. The offer and bid spreads would be managed by putting a price on deviations in the CRM from the EN dispatch target.

With the spread, the trader can be confident that CRM trades will be profitable for them whichever side of the trade they are on. On the other hand, it might be that they do not trade at all. Indeed, the larger the spread they submit, the less likely that a trade is cleared and consequently a greater chance of foregone profits. Like the trading limits, this feature provides an opportunity for traders to "dip their toes" into the CRM, rather than simply opt-out.

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28 For the purpose of the discussions we will assume that the SRMC accounts for any opportunity costs.

Traders who do not wish to make use of this spread feature can set their bid and offer spreads to zero.

Assessment

Quantity limits have been considered as part of the NEMDE CRM prototype. Including bidding spreads will add some complexity to the design and implementation of the CRM bidding and dispatch processes. However, CRM traders may find these features useful; and generators may be encouraged to opt in and use these features to limit their CRM exposure initially.

Conclusions

We are seeking stakeholder feedback on whether to consider a quantity limit and/or buy/sell spread as part of the design for the CRM dispatch and pricing process.

QUESTION 6 CRM BIDDING STRUCTURES

1. Do you agree with the proposed approach to modify the CRM bidding structure?
2. Do the benefits of this proposed approach outweigh potential internal costs to traders to modify their bidding systems?
3. If there are technical challenges with this proposed implementation, do you have alternative suggestions to facilitate CRM engagement?

4.2.5 FCAS bids and settlement

Background

Notwithstanding its name, the "energy" dispatch (or EN dispatch) is actually a complete dispatch which sets dispatch targets for both energy and FCAS. Similarly, the CRM dispatch also covers both energy and FCAS. Whilst the CRM design is focussed on incentivising incremental *energy* dispatch it will invariably lead to changes in FCAS dispatch. Hence, the two dispatch runs will lead to two different dispatch quantities and two different prices for each FCAS service.[29]

FCAS settlements would be similar in structure to energy revenue settlements except that FCAS is paid on dispatch quantities so there are no deviations to consider. Hence:

$$\text{FCAS revenue} = FQ_{EN} \times FP_{EN} + (FQ_{CRM} - FQ_{EN}) \times FP_{CRM}$$

Where:

FQ_{EN} = FCAS quantity dispatched in the EN dispatch

FQ_{CRM} = FCAS quantity dispatched in the CRM dispatch

FP_{EN} = FCAS price dispatched in the EN dispatch

FP_{CRM} = FCAS price dispatched in the CRM dispatch

Similar to energy settlements, generators who have different FCAS dispatch targets between the EN and CRM dispatches will have exposure in settlements to a second FCAS price i.e. FP_{CRM}. However, because FCAS constraints are specified regionally, the CRM prices for FCAS will be regional, not nodal as they are for energy.

29 Initial insights are shared in **Appendix E** as part of results from the NEMDE CRM prototype. Further insights will be shared with the stakeholders as the ESB develops additional real-world scenarios.

Options

There are two design choices to consider for FCAS:

- FCAS bids: whether generators should be able to submit a second set of FCAS bids to the CRM dispatch, or whether there should be only one set of FCAS bids which apply to both dispatches;
- FCAS opt-in/out: whether generators should be able to opt-out of the CRM for FCAS, as they can do for energy.

FCAS bids

The options are simplified as:

One set of FCAS bids which will be co-optimised for each dispatch run in turn:

- FCAS bids are first co-optimised as part of the EN dispatch
- Same set of FCAS bids are co-optimised as part of the CRM dispatch

Two sets of FCAS bids which are specific to each dispatch run:

- FCAS-EN bids are co-optimised with the EN dispatch
- Second set of FCAS-CRM bids are co-optimised with the CRM dispatch.

The regional nature of FCAS dispatch means there are less incentives for disorderly bidding of FCAS in EN dispatch than there are for energy. However, the complex interaction and co-optimisation between energy and FCAS dispatch means that there might still be some forms of disorderly bidding which generators would then wish to undo (i.e. bid cost-reflective instead) in CRM dispatch. In this case, allowing two separate sets of bids – and so allow cost-reflective bidding into CRM dispatch – might improve the efficient of physical dispatch.

FCAS opt out

To avoid the complexity associated with being settled at two different sets of prices for FCAS, a generator might wish to "opt-out" of FCAS. Analogous to energy, this opt-out would mean that the FCAS CRM dispatch targets are automatically set equal to the FCAS EN dispatch targets.

Since the FCAS opt-out generators would typically also be opting out of the CRM energy trading, this linking could be made automatic i.e. any generator opting out of CRM energy trading is also opted out of CRM FCAS trading. Alternative, this could be a separate decision e.g. a generator would be allowed to opt out of the CRM for energy but opt in for FCAS.

Assessment

Two sets of FCAS bids would complicate bidding and impose additional costs on participants for possibly no significant efficiency gain.

Whilst participants can opt-out of exposure to CRM prices, the ESB believes they should not need to avoid exposure to CRM FCAS differences. FCAS prices and dispatch quantities can vary between the EN and CRM dispatches. However, given FCAS bidding is already likely to be at SRMC for the majority of the time there is no reason to avoid exposure to CRM FCAS outcomes. Limiting participants' exposure to CRM FCAS outcomes would limit the amount of CRM energy trading and so reduce the benefits of the reform.

Conclusions

It is proposed that only one set of FCAS bids is required in the CRM design. This approach accounts for the bidding incentives of the FCAS markets and the financial outcomes from the CRM design. This approach also reduces the impact on participant bidding systems and reduce costs.

It is proposed that both opt in and opt out generators are settled on their FCAS EN dispatch outcomes and FCAS CRM dispatch outcomes according to the settlement formula above.

> **QUESTION 7: FCAS BIDS AND SETTLEMENT**
>
> 1. Do you have any comments on the proposed approach for FCAS bids and participation in the CRM design?

4.3 Technical considerations

4.3.1 NEMDE CRM prototype

On behalf of the ESB, AEMO has developed a NEMDE CRM prototype. The objectives are to:

- test the validity of the CRM design – does it work on a NEM-wide scale?
- inform design decisions for the CRM design e.g. how to deal with opt-out, IRSR formulation etc.
- determine the impact on NEMDE for implementation cost purposes.

NEMDE is a scalable solver so the prototype has been developed in stages:

- simple 4 node Excel model
- 7 node 2 interconnector 1 FCAS service model
- full NEM based on historic dispatch intervals.

The full NEM model simulates EN and CRM dispatch outcomes using historic dispatch intervals as scenarios. The historic dispatch intervals provide a reference for energy requirements and EN bids.

Lessons learned from the prototype have been incorporated into the proposed design choices in section 4.2. In addition, the scenarios have highlighted:

- There are important interactions between energy and FCAS dispatch which affect CRM adjustments. This is particularly pertinent for batteries given they are a key provider of FCAS in the NEM. Participants will need to consider the interaction between energy and FCAS when they submit offers (as they do today).
- Coefficients play a key role in determining dispatch outcomes when constraints are binding and, in the absence of priority access, it is often not efficient or profitable for a high coefficient unit to significantly change its output in the CRM when it is effectively trading with a low coefficient unit.
- Trading behind loop flow constraints requires units outside the constraint to participate in the CRM to balance the energy flows. Therefore, realising the benefits of the CRM depends on maximising participation of both generators impacted by constraints but also those that can play the role in balancing the energy flows. The CRM provides incentives for these generators to participate in and profit from CRM trades.

Appendix E provides detail on the development of the prototype and two scenarios. The ESB will share further real-world scenarios as part of its education initiative. The ESB is working on a platform to visualise scenarios from the prototype to help facilitate stakeholder's engagement. The ESB will notify stakeholders of updates and schedule specific webinars to support users' understanding of the proposed model options during the consultation period.

4.3.2 CRM participation and non-participation

The ESB recognises that opt-out participants do not want to be exposed to CRM prices and prefer not to have to make changes to their systems and processes. Therefore, opt-out participants will be able to submit a single set of bids as they do currently. AEMO will duplicate their EN energy bids in the CRM dispatch to ensure that CRM prices can be formed for all locations. However, this would not achieve the intended outcome to avoid dispatch differences. Instead, the dispatch process will "fix" the CRM dispatch to match the EN dispatch. This will be subject to a small MW tolerance (e.g. 0.001 MW) to ensure that dispatch can solve without creating degeneracy issues.[30]

To facilitate this process, AEMO will maintain an opt-in database to record the status of eligible dispatchable units. Participants are assumed to not participate (i.e. "opt-out") until they explicitly opt-in. Once they opt-in, they will be required to submit two sets of energy bids. Once opted in they cannot opt-out again. This simplifies the management of the opt-in/opt-out process and participants will always be able to use bidding strategies to limit their exposure to the CRM e.g. bid a quantity limit of zero as described in section 4.2.4.

Based on the FCAS settlement proposed in section 4.2.5, FCAS dispatch deviations should not be limited between the two runs even for opt-out participants and so there is no need for a delta limit to be applied to FCAS dispatch.

4.3.3 Pre-dispatch processes and forecasting

Pre-dispatch

The existing pre-dispatch process will continue in the CRM but the quantity of information published will effectively double with one set for the EN run and one for the CRM run.

ST PASA

The ST PASA system is in the process of being upgraded with the new system to be operational when the new rules commence on 31 July 2025. The primary focus of ST PASA is to provide stakeholders with information on the supply-demand outlook over the next 7 days. In addition, the new ST PASA system will use participant bids to provide information on relative price distributions between nodes of the full network model.

Therefore, the key input from participant bids is their maximum availability. Bid PASA availability, energy limits, fixed loading and ramp rates will also be used in the new PASA. Provided all these are the same in the EN and CRM run then either the EN or CRM bid can be used in ST PASA. If they are allowed to be different then the CRM bid quantities should be used for opt-in units and the EN bid quantities would be used for opt-out units.

To determine the relative price distributions it is proposed to use the EN bid price bands only as these will provide information on the location and degree of network congestion which is of greatest interest to participants using the PASA.

MT PASA

There will be no changes to the MT PASA process.

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30 Degeneracy is a term used in optimisation where there can be multiple equivalent solutions.

5 Technical implementation in dispatch

The ESB recognises that the CRM and priority access represent novel reforms that have not been tried in other markets and which fundamentally change the dispatch process in the NEM. Consequently, AEMO will need to go through a very rigorous process of design, testing, education and implementation to deliver these reforms.

In addition to the overall TAR assessment criteria (section 1.4.2), there are three key requirements to consider for the dispatch solution as part of the 'implementation considerations'. The dispatch solution refers to the set of dispatch instructions and prices produced by NEMDE:

1. **No material impact on timing of dispatch instructions**. A five-minute dispatch window requires that the dispatch solution has to be disseminated as close as possible to the start of the interval. The end-to-end dispatch process includes a number of steps including receiving and loading bids, forecasts and SCADA data, optimisation by NEMDE and publication of results. Hence, CRM and priority access need to be designed so that they do not lead to an unacceptable deterioration in the publication of dispatch instructions.
2. **Maintenance of power system security.** Chapter 3.8.1 of the NER requires that the outcome of the central dispatch process should allow AEMO to use its reasonable endeavours to maintain power system security. This means that the dispatch solution needs to be feasible and satisfy the technical system constraints. In some circumstances this may create a conflict with the hybrid model (e.g. if scheduling according to dispatch priority order produces an infeasible outcome) and so the dispatch solution will need to address this.
3. **Maximising the value of spot market trading** The other leg of 3.8.1 is to maximise spot market trading which facilitates meeting the NEO. This is achieved in NEMDE through the minimisation of cost in the objective function subject to the constraints. Again there may be circumstances where implementing the hybrid model would conflict with this objective and the solution will need to address this.

Implementation of CRM

As discussed in more detail in Appendix E, AEMO has developed a NEMDE prototype to test the CRM design. This has been trialled on a small set of real-life dispatch intervals with a very limited number of bidding and CRM participation scenarios. The results of the prototype development are encouraging in that NEMDE solve times have been reasonable (albeit end to end testing has not been possible).

The prototype has delivered some useful insights for the CRM design. However, the extent of testing has been very narrow and there remains considerable uncertainty as to the uptake of the CRM and how participants will bid. Consequently, further testing is required to ensure that the CRM design can be implemented in a way that can mitigate all three requirements noted above.

Implementation of priority access in the EN dispatch

As discussed in section 3.3, there are two potential options for implementing priority access in the EN run. These include:

- **Market floor price (MFP) adjustments**. Different dispatch priorities receive different bid price floors that can be used for bidding in the EN dispatch run. The highest dispatch priority group would be able to bid at the lowest price floor. The number and separation of bid price floors is a function of the number of tiers or queue numbers and the degree of dispatch priority required, which is a design choice for the EN priority dispatch.

- **Sequential-solve.** The dispatch process solves the EN run sequentially according to dispatch priority order. The dispatch priorities could be grouped to reduce the number of iterations. Once the highest priority solution is locked in the dispatch process then moves to the next highest priority and continues until the solution balances supply and demand whilst meeting the technical constraints.

Of these options the MFP adjustments method is much lower risk to implement and is much more likely to meet the three requirements above for the dispatch design. Clearly, a single pass will have no impact on solve times for the EN run whereas a multiple, sequential-solve process will inevitably take longer and delay the timing of receiving dispatch instructions. Hence, sequential-solve can only really handle a small number of queue positions whereas MFP adjustments can handle many.

The other major concern with the sequential-solve process is that it locks in dispatch solutions too early for high priority generators and by doing so it misses out on better solutions. In some situations this may mean that the dispatch solution has “painted itself into a corner” and may not be able to find a feasible technical solution or a low-cost solution (e.g. if the only option for the last generator is one with a very high bid price). Clearly, the solution needs to be feasible and technically acceptable so there would have to be a process for revisiting the locked-in dispatch outcomes which would add more time to finding a dispatch solution and create further operational risk.

Given these considerations the NEMDE prototype has been developed to test the MFP adjustments approach in the EN dispatch run. Three tiers were selected with very widely separated bid price floors (-$1000, -$10,000 and -$100,000/MWh) which equates to a hard priority implementation i.e. where the price floor separation should overcome most of the difference in constraint coefficients between generators. In most test cases that were run the dispatch solution appeared reasonable and consistent with the dispatch priority order. However, in one case the dispatch solution was counterintuitive in that the highest priority dispatch group actually got dispatched less. The cause of this was that the large difference in bid price floors was interacting with the constraint violation penalties and leading NEMDE to violate constraint penalties in its search for the lowest cost solution. In this case there was also a large increase in the RRP as a result of priority access. Whilst AEMO believes that the prototype could be changed to alleviate this outcome this illustrates the complexity of NEM dispatch and the risk associated with of implementing a new approach. It also suggests that using soft priorities with smaller separation of bid price floors is likely to have less unintended consequences in dispatch.

Timeline for implementation

The ESB expects that several years would be required to implement the reforms after the rule changes have been adopted. A previous project update indicated the earliest implementation date for changes to the dispatch solution by the end of 2027.[31] The implementation timeline will be reviewed and updated as we continue our technical investigations. The timeline will be influenced by a range of factors including:

- the detailed design of the final models
- any unforeseen technical challenges from the detailed design and implementation process
- the broader portfolio of concurrent systems changes for other energy market reform processes.

We will continue to update stakeholders on our implementation progress and plans as part of future consultation.

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31 ESB, Project update – transmission access reform, February 2023. Available at: https://www.datocms-assets.com/32572/1677794660-transmission-access-reform-project-update.pdf

6 Next steps

The ESB invites comments from interested parties in response to this consultation paper by 12pm AEST, Friday 26 May 2023. While stakeholders are invited to provide feedback on any issues raised in this paper, the key questions for consultation are summarised in **Appendix A**. Submissions will be published on the Energy Ministers' website, following a review for claims of confidentiality.

Submission information	
Public webinar	1.30–3pm AEST, Monday 8 May 2023
Submission close date	12pm AEST, Friday 26 May 2023
Lodgement details	Email to: info@esb.org.au
Name of submission	[Company name] Response to transmission access reform consultation paper
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.

The ESB will hold a webinar on the material covered in this paper on Monday 8 May 2023, 1.30-3pm AEST. Interested parties are invited to register here.

In parallel, the ESB will continue to engage through a number of forums, including public webinars, stakeholder briefings, the transmission access reform technical working group, jurisdictional advisory group, the Post 2025 advisory group and bilateral exchanges. Parties wishing to contact the ESB's transmission access reform project team should email info@esb.org.au.

The ESB will review submissions to this paper in order to prepare final policy recommendations. Stakeholders will have an opportunity to comment and make submissions on the draft Rules later in 2023. The next steps in the ESB's forward work program are set out below.

Milestone	Indicative timing
Final policy recommendations for detailed design	Mid 2023
Publish draft Rules for consultation **(assuming Ministerial approval of policy recommendations)**	Timing to be confirmed 2023

If Ministers adopt the ESB's recommendations, then the timelines for implementing any reforms will be developed having regard to the urgency of the need for change, the scale of changes required, and the broader industry reform program.

Glossary

Clamping	Clamping refers to AEMO's response to a situation when electricity is flowing from a high-priced region to a low-priced region (also known as a counter-price flow). Clamping reduces or stops the flow of electricity during these periods avoid or reduce negative inter-regional settlement residues and to reduce transmission charges for consumers.
Congestion	Electrical equipment being operated to its technical limit, meaning electricity cannot be dispatched to meet demand at the lowest possible cost.
Constraint coefficient (coefficient)	Reflects the proportion of a generator's output or interconnector's flow which "uses" the equipment to which the constraint relates – it measures how much each generator contributes to each constraint.
Counter price flow	Counter-price flows is the name for the situation where electricity is flowing from a high-priced region to a low-priced region across an interconnector.
Congestion relief market	The congestion relief market (CRM) represents a component of the CRM design. It is a new market in addition to the energy market and ancillary services markets operated by AEMO. Participants submit CRM bids. The market is priced nodally i.e. participants are paid their CRM price for the cleared amounts.
CRM design	The CRM design refers to the overall design concept which includes the CRM and its integration with the existing markets (energy market and ancillary services).
CRM dispatch	The CRM dispatch is a second dispatch. It is subject to the same constraints as the EN dispatch i.e. transmission constraints, demand forecasts etc. Opt-in generators provide a second set of bids into the CRM dispatch. For opt-out generators, the CRM dispatch is set equal to their EN dispatch. Unlike the EN dispatch, the CRM dispatch is not prioritised. The DP numbers play no role in deciding who is dispatched, except indirectly through the EN dispatch targets of opt-out generators. The CRM dispatch also calculates CRM prices (CRMPs) for the nodes of each opt-in generator.
CRM price	The CRM price is a market clearing price based on the bids and offers of CRM participants. CRM prices vary by location on the transmission network. The price represents the change in the cost of dispatch if an additional unit is supplied at that location.
Disorderly bidding	Refers to the situation when generators bid to the market floor price to maximise their individual dispatch quantities. In the presence of congestion, generators participating in constraints may bid to the market floor price in the knowledge that their bids are unlikely to impact the regional reference price. This bidding strategy arises because of the regional pricing regime in today's energy market.
Dispatch solution	The set of dispatch instructions and prices produced by NEMDE.

Energy market (EN) priority dispatch	The EN priority dispatch algorithm takes inputs including the DP numbers (assigned during the connections process for each DUID) and the EN bids submitted by traders for each generator. The process has key outputs of EN dispatch targets and RRPs. These outputs feed into the settlements calculation and also, for opt-out generators, into the CRM dispatch.
Entrant generator	Any generator that is in existence and is not a legacy generator.
Existing generator	A combination of legacy generators and entrant generators.
Future generator	Generators that are entering after a specified point in time.
Incoming generator	Generators that are undergoing their development and connection processes at a specified point in time.
Legacy generator	A generator in existence at the date the reform is adopted e.g. the date that the rule change is approved, or a date specified in that rule change.
Market price cap	A limit to how high the regional reference price can be in settlement. In the NEM, it is currently set at $15,500/MWh.
Market floor price	A limit to how low the regional reference price can be in settlement. In the NEM, it is currently set at $-1000/MWh.
Net present value	The difference between the present value of cash inflows and the present value of cash outflows over a period of time. It is a method for standardising costs and revenues over multiple periods of time for comparison at a single point in time.
Opportunity cost	The cost of the best foregone opportunity e.g. the cost of a later opportunity that is no longer available due to a decision being made.
Prioritisation	The dispatch of a high priority generator in preference to a low priority generator where this is feasible.
Dispatch priority (DP) number	The number applied in EN priority dispatch in AEMO's systems to give effect to prioritisation when a generator bids to the MFP.
Queue number	The chronological number assigned to an incoming entrant at some point of the connection process. Queue numbers are unique to a DUID except for shared queue numbers which could apply to: • Legacy generators • REZ up to a defined MW total quantity • Incoming generators if they connect in the same time window.
Regional reference node	The network node where the regional reference price is determined. Usually, this is a node located at the capital city of each region, with the exception of Tasmania, where the regional reference node is in the north of Tasmania where the Basslink interconnector connects to the island.
Regional reference price	The price representing the change in the cost of dispatch if an additional unit of load is supplied at the regional reference node.
Short run marginal cost	The cost of producing an extra unit of electricity from a resource.
Tier	Corresponds to a level of priority in the EN dispatch.
Transmission curtailment	Curtailment happens when generation is constrained down or off due to operational limits.

Appendix A. Summary of consultation questions

Section	Questions
QUESTION 1: PRIORITY ACCESS MODEL OPTIONS	The ESB welcomes feedback on the two options (and sub-options) for the priority access model, as well as any other options not considered here. Some specific questions are: 1. Key design choice a. Which option do you prefer? The queue option or centrally determined tiers option? Why? b. At what point in the connection process should queue numbers or tiers be assigned? 2. Queue model a. Do you favour queue numbers being assigned in strict chronological order or in time-windows? b. At what point in the connection process should queue numbers be assigned? c. If grouping is necessary for practical reasons, how substantially do you think the benefits of the queue model might be diminished? What is the minimum number of groups to make the model preferable? 3. Centrally determined tier model a. Which sub-option do you prefer; first-come-first-serve or auction? Why? b. What is the preferred metric to delineate the tiers? c. Should the tier delineations be set forever or redetermined periodically?
QUESTION 2: POLICY LEVERS	1. Where on the hard versus soft spectrum should priority access be? 2. What is the preferred basis for the length of priority access? 3. If a glide path is taken, what should its shape be?
QUESTION 3: LEGACY GENERATORS	1. How should legacy generators be assigned priority access? 2. How should legacy generators be defined i.e. how should the demarcation date be set?
QUESTION 4: SETTLEMENT RESIDUE	1. Do you agree with the proposed approach to allocate the CRM residue to TNSPs? 2. Do you have any suggestions on the metric to allocate the CRM residue between TNSPs e.g. pro rata to region load?
QUESTION 5: TREATMENT OF MARKET NETWORK SERVICE PROVIDERS	1. Do you have any feedback on the proposed approach for the settlement of MNSPs? 2. Are there any special considerations in determining the CRMP for a market network service provider ?
QUESTION 6 CRM BIDDING STRUCTURES	1. Do you agree with the proposed approach to modify the CRM bidding structure? 2. Do the benefits of this proposed approach outweigh potential internal costs to traders to modify their bidding systems? 3. If there are technical challenges with this proposed implementation, do you have alternative suggestions to facilitate CRM engagement?
QUESTION 7: FCAS BIDS AND PARTICIPATION	1. Do you have any comments on the proposed approach for FCAS bids and participation in the CRM design?

Appendix B. Interaction with recent and ongoing reforms

Stakeholders have proactively requested more information on how the proposed transmission access reform interacts with recent and proposed rule changes. The ESB continues to monitor the parallel progress of reform changes to ensure they are consistent and complementary.

This appendix provides detail of three specific reforms.

Operational security mechanism

The AEMC is currently considering a rule change request for the operational security mechanism (OSM).[32] The draft determination for this rule change sets out a proposed new process for scheduling and remunerating provisions of system security services. The AEMC is currently considering stakeholder feedback on the draft determination.

- The ESB notes stakeholder feedback querying the interaction between the CRM and the OSM. If the OSM was to be implemented, the ESB considers that both the OSM and the CRM could work alongside the energy market dispatch. This is because:
- The OSM and CRM have different purposes: the OSM aims to value and schedule security services, whereas the CRM aims to allow participants to trade between themselves to better manage congestion.
- Both mechanisms would use similar inputs, but operate over different timeframes:
    - the OSM would use all the pre-dispatch constraints from NEMDE as well as system configurations, and potentially other service requirements, which can't be represented in NEMDE (and which are required for a secure solve)
    - the OSM would run *ahead* of real time and use its own parallel algorithm to produce schedules (using all the constraints described above)
    - the CRM would run immediately after the energy market dispatch using the NEM inputs and constraints, allowing participants to buy / sell energy to manage congestion.

If both the CRM and the OSM were to be implemented, then resources would use their OSM position to consider how to participate in the CRM.

For example, consider a resource that provides a security service when operating at a minimum level, and can also increase its output above that level:

- The resource could be cleared under the OSM ahead of time for its minimum stable generation level (X) in order to maintain system security in the NEM.
- Constraints would be invoked to reflect this status and so the X MW would always be cleared in both the EN and CRM runs. There is therefore no need for the unit to bid the X MW into the CRM.
- The unit could bid MW above its minimum level into the CRM.

The ESB will continue to monitor developments on the OSM closely and work with the AEMC on this.

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32 Refer to rule change request available at: https://www.aemc.gov.au/rule-changes/operational-security-mechanism. Open as at April 2023.

'Scheduled lite'

"Scheduled lite" is a proposed new market reform to enable distributed energy resources to provide visibility and to participate in dispatch. [33] Under the option set out in the rule change proposal that AEMO has submitted to the AEMC and that is currently being considered, light scheduling units would enable distributed resources to be represented in market scheduling processes and systems, including portfolios of smaller facilities in a similar geographic area with a combined output greater than 5 MW.

Light scheduling units in dispatch mode would be able to bid into NEMDE, participate in constraints and have to follow dispatch instructions, subject to non-conformance monitoring. They would need to provide information to AEMO in SCADA format (expected to be enabled via "SCADA lite") and would be settled on revenue quality metering through the central settlement process.

In principle, if the solution is adopted, light scheduling units should be able to participate in the CRM on the basis that they would be scheduled in energy dispatch and are participating in the energy market. However, the units may be too dispersed or too small to impact on NEM constraint equations. If they cannot be incorporated into a constraint equation they would not receive a constraint coefficient or local price adjustment. However, just as for other generators not participating in binding constraints, AEMO would be able to calculate the CRM price from the regional energy balance equation. Light scheduling units could be settled in the CRM at their CRM price for their CRM deviations.

Integrating energy storage systems (IESS)

The recent rule change completed by the AEMC introduces a new participant category into the NEM: the Integrated Resource Provider.[34] This provider will be able to classify a wide range of unit types. If an IRP classifies a scheduled generator, semi-scheduled generator, scheduled load they will be able to participate in the CRM.

IESS also introduces the concept of a bidirectional unit which can be scheduled, non-scheduled or "small". Scheduled bidirectional units will be able to submit energy offers with 20 bid bands, 10 which are similar to a scheduled generator and 10 which are like a scheduled load. Consequently, scheduled bidirectional units should be able to participate in the CRM but non-scheduled and small units will not be able to.

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33 Refer to AEMO consultation papers available at: https://aemo.com.au/initiatives/trials-and-initiatives/scheduled-lite and rule change request submitted to the AEMC available at: https://www.aemc.gov.au/rule-changes/scheduled-lite-mechanism. Open as at April 2023.

34 Refer to original rule change request completed: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem. A new rule change request has been submitted for some amendments to the IESS rule which aim to reduce implementation costs, improve clarity and reduce uncertainty in its implementation. Available at: https://www.aemc.gov.au/rule-changes/implementing-integrated-energy-storage-systems

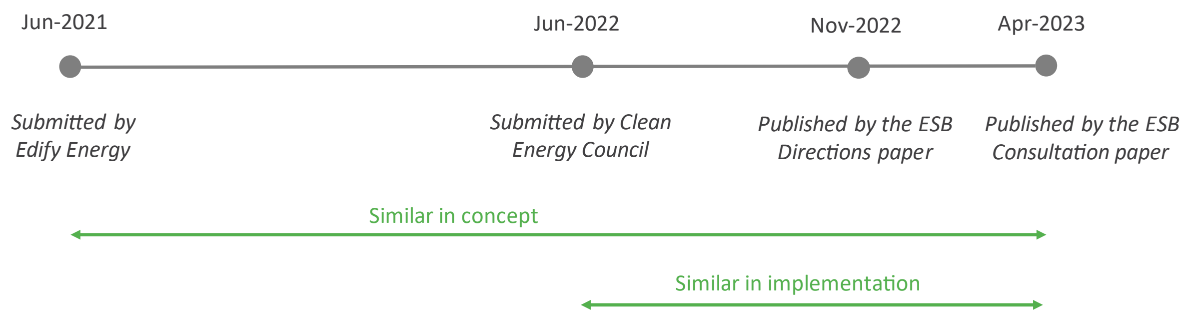
Appendix C. Evolution of the CRM design

There have been four key milestones in the development of the CRM design to date:

- Original proposal proposed by Edify Energy
- Modified version submitted by the CEC
- Version developed by the ESB in the directions paper
- Current version presented by the ESB in this consultation paper.

Figure 20 shows the key milestones in its evolution.

Figure 20 Evolution of the CRM design



Source: ESB

All models are similar in concept. The CRM design includes:

- An additional voluntary market whereby participants can trade dispatch adjustments and share in the efficiency gains.
- Energy market transactions are settled at the RRP.
- CRM transactions are settled at a market clearing price from the CRM.

The more significant step change was from the Edify concept to the CEC modified version. It needed to scale up to work across multiple constraints accounting for the complex network topology and to be able to solve in AEMO's systems. The CEC proposed amendments to implement the concept in practice.

In the directions paper, the ESB adopted the CEC solution as a baseline; 'Option 1' design choices were consistent with the CEC and 'Option 2+' were introduced as potential design choices to adapt this baseline.

This consultation paper, section 4.2.1, confirms that the ESB has mostly proposed to adopt design choices which are consistent with the CEC's modified version.

However, the changes in model design and terminology are challenging for stakeholders to track. This appendix highlights some key changes for reference.

Dispatch solution for the EN and CRM

Edify Energy and CEC proposed that the energy market and CRM would be co-optimised as a 'single pass'. EN and CRM bids/offers would be concurrently considered, co-optimised, and dispatched.

Two key challenges were subsequentially identified:

- A co-optimised solution would involve more substantial changes to NEMDE and increase the solve time; there would be technical challenges and costs associated with this approach.
- A co-optimised approach has the potential to result in disorderly bidding in the CRM for the units which had chosen no deviations between the EN dispatch and the CRM dispatch in order to get a better outcome in the EN dispatch. In this case, even though these units would not be practically participating in the CRM their behaviour in the CRM could distort the outcomes in the EN dispatch.

The CRM design in this paper (and the previous directions paper) assumes a sequential dispatch:

- first run for the EN priority dispatch
- second run for the CRM dispatch.

This allows NEMDE to solve and gives confidence that it replicates the same NEMDE structure and algorithms and minimises changes required. The cost benefit analysis assumed this solution for the purpose of estimating implementation costs into AEMO's systems, and the effective date of implementation. The NEMDE CRM prototype is based on this design (refer to section 4.3.1).

The sequential dispatch preserves the optionality of the CRM. For participants that do not participate in the CRM, it is intended that dispatch outcomes from the energy market would be 'locked' for the purpose of the CRM dispatch immediately after. Section 4.3.2 provides technical details on this matter.

Terminology of buyers and sellers and products

In Edify Energy's proposal,[35] bids/offers are received from buyers (receivers) and sellers (providers) of congestion relief. For example, a seller could be a generator behind a constraint that reduces its output. They would be paid for congestion relief as compensation for lost RRP revenue.

Under the CEC and ESB's design, the CRM instead clears adjustments in dispatch quantities, compared to the dispatch outcomes of the energy market. A generator or storage that reduces output does not lose any RRP revenue, but it now pays to buy energy from the CRM. This framework changes the terminology of buyers and sellers. Table 9 summarises this change.

Table 9 Comparison of terms for buyers and sellers

Term	Edify Energy	ESB
Buyer	Buys congestion relief (increases output)	Buys energy (decreases output)
Seller	Sells congestion relief (decreases output)	Sells energy (increases output)

Source: ESB

The net effect of these payment structures is the same; a generator or storage that reduces its energy output profits from avoided costs, just like the Edify proposal.

The original concept of buying and selling congestion relief has been helpful to explain the policy principles and economic concepts. But it is less helpful for parties to determine how they might optimally trade and to determine their settlements in the modified CEC and ESB version.

35 Edify Energy, Response to ESB's Project Initiation Paper, attachment originally submitted in June 2021.

This consultation paper adopts terminology which is consistent with the formula for settlement and enables stakeholders to understand how they would develop their bidding strategy (including a design choice on CRM bidding structures in section 4.2.4.).

CRM pricing

There is an associated change with the definition of the CRM pricing.

Under Edify Energy's proposal, the congestion relief price (CRP) is determined for each binding constraint by a clearing process matching bids and offers. It assumes that only one constraint will bind at a time, each constraint can be solved one at a time and no FCAS co-optimisation is required.

Under the CEC and ESB's model, the congestion relief market price (CRMP) adopts a holistic approach so that CRM constraints are all those constraints whose costs can be relieved through the changes to the energy dispatch targets of dispatchable generation and loads.

The formulas below show the revenue calculations for the two approaches. For ease of comparison, they ignore differences between metered output and dispatch deviations.

Edify Energy: Energy revenue = G_{CRM} x RRP + (G_{CRM} – G_{EN}) x CRP

ESB: Energy revenue = G_{EN} x RRP + (G_{CRM} – G_{EN}) x CRMP

Where

CRMP = marginal cost of meeting another MW of load at the RRN – $sum_{constraints}$ (marginal cost of constraint x constraint coefficient)

CRP = 0 – (marginal cost of constraint x constraint coefficient)

G_{EN} = EN dispatch target; previously referred to as G_{NEM} in the directions paper.

G_{CRM} = CRM dispatch target

Table 10 provides a description of the revenues depending on whether the generator is increasing or decreasing its output as a result of the CRM adjustments.

Table 10 Description of revenue formula for Edify and CEC/ESB

Generator	Edify formula	CEC/ESB formula
Increases its output with positive CRM adjustment (G_{CRM} – G_{EN} > 0)	• gain revenue at the RRP, and • pay for congestion relief at the CRP	• keep revenue at the RRP, and • gain revenue at the CRM price
Decreases its output with negative CRM adjustment (G_{CRM} – G_{EN} < 0)	• forfeit revenue at the RRP, and • receive payment for congestion relief at the CRP	• keep revenue at the RRP, and • pay for other market participants to dispatch on your behalf at the CRM price

The total settlements for the two proposals are identical assuming an efficient market. In an efficient market, the market clearing congestion relief price would be *RRP-CRM price* and this results in exactly the same total settlements as for the ESB's CRM.

Appendix D. Worked example of the queue model

This appendix provides an example of the queue model.

It uses the market floor price adjustments method discussed in section 3.3.1. Throughout this example, assume:

- There are no losses.
- There are no frequency control ancillary services.
- Generators always follow their dispatch instructions (to simplify the settlement equations and we can ignore metered dispatch quantities).
- There is only one region and no interconnectors.
- Generators bid at cost in the CRM.
- Generators that do not participate in a binding constraint bid at cost in the EN dispatch.
- Generators that participate in a binding constraint bid at their respective MFPs in EN dispatch.
- Each incoming generator is provided a unique priority dispatch number equal to their queue number i.e. there is no grouping of generators.

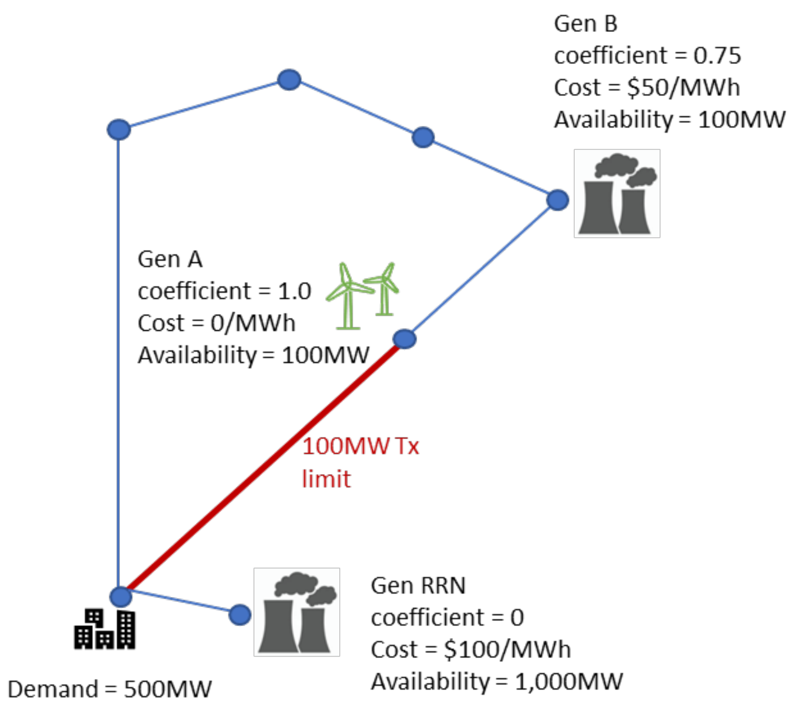
The example begins with only legacy generators connected to the network. Two more generators will then be added successively to show how the queue influences outcomes.

This example focuses on outcomes in a single dispatch interval.

Legacy generation fleet

Below, there is a simple looped network with a single transmission constraint of 100MW shown in red.

Figure 21 Legacy generator fleet



There are three legacy generators, with their costs, constraint coefficients and availabilities shown in the diagram.

Demand is 500MW.

Under the existing arrangements, Gen A and Gen B would be incentivised to bid at -$1,000/MWh. The RRP would be set by Gen RRN's offer at $100/MWh. The physical and financial outcomes would be as follows:

Table 11 Status quo dispatch with legacy generators

Status quo dispatch				
	Quantity (MW)	**Cost ($/h)**	**Revenue ($/h)**	**Profit ($/h)**
Gen RRN	375	37,500	37,500	0
Gen A	25	0	2,500	2,500
Gen B	100	5,000	10,000	5,000
Total	**500**	**42,500**	**50,000**	**7,500**

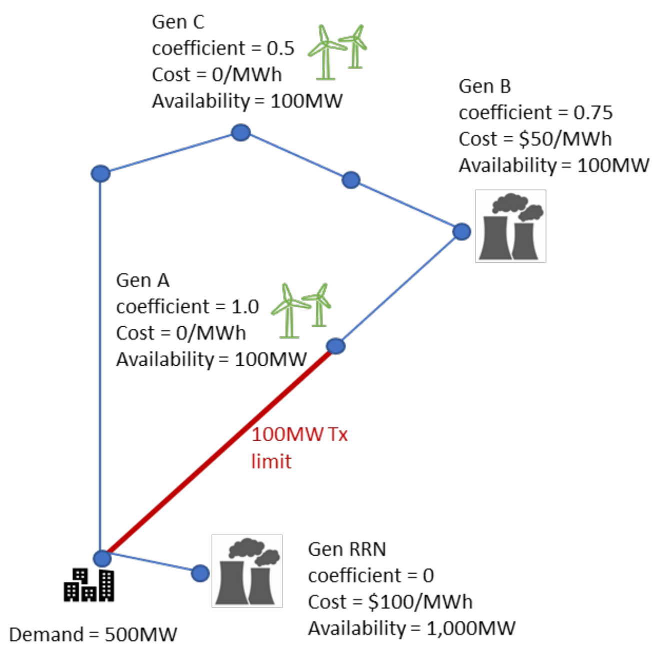
From the perspective of NEMDE, the lowest cost combination of generation (as revealed by bids) to meet demand is to maximise Gen B's output because it has the lowest coefficient in the binding constraint. Gen A is constrained down despite costing less than Gen B.

Because all legacy generators will be allocated the same dispatch priority number, these outcomes would be the same under the priority access model.

Incoming generator participating in the constraint

Gen C now chooses to connect to the network. It participates in the constraint but with a lower coefficient than Gen A and Gen B.

Figure 22 Legacy generator fleet plus Gen C



Under the existing arrangements, Gen A, Gen B and Gen C would all be incentivised to bid at -$1,000/MWh. The RRP would continue to be set by Gen RRN's offer at $100/MWh. The physical and financial outcomes would be as follows:

Table 12 Status quo dispatch when Gen C connects

	Status quo dispatch			
	Quantity (MW)	Cost ($/h)	Revenue ($/h)	Profit ($/h)
Gen RRN	333.33	33,333	33,333	0
Gen A	0	0	0	0
Gen B	66.66	3,333	6,667	3,333
Gen C	100	0	10,000	10,000
Total	**500**	**36,667**	**50,000**	**13,333**

The dispatch engine allocates access in ascending order of constraint coefficients.

Table 13 compares the outcomes of Table 12 (with Gen C) and Table 11 (before Gen C's connection):

Table 13 Change in status quo dispatch outcomes and profit when Gen C connects

	Change in quantity (MW)	Change in cost ($/h)	Change in revenue ($/h)	Change in profit ($/h)
Gen RRN	-41.7	-4,167	-4,167	0
Gen A	-25	0	-2,500	-2,500
Gen B	-33.3	-1,667	-3,333	-1,667
Gen C	100	0	10,000	10,000
Total	**0**	**-5,833**	**0**	**5,833**

Gen C cannibalises Gen A and Gen B. The total cost of the system has only been reduced by $5,833/h, yet Gen C profits $10,000/h. Gen C's profits arises not just from reducing total system costs but from cannibalising the profits of Gen A and Gen B. This provides Gen C an inefficient signal to connect in this location of the network, and is a risk for Gen A and Gen B.

Now, we examine what happens under the priority access model. The dispatch priority number and MFP of each of the generators is provided in Table 14.

Each of the legacy generators is given a dispatch priority number of 0, which provides them an MFP of -$12,000/MWh. Gen A and Gen B bid at that price. Gen RRN continues to bid at cost because it does not participate in the binding constraint. Gen C is given a dispatch priority number of 1, which provides it an MFP of -$4,000/MWh. It bids at this price.

Table 14 DP numbers and MFPs of generators under priority access model

	DP#	MFP ($/MWh)	Bid ($/MWh)
Gen RRN	0	-12,000	100
Gen A	0	-12,000	-12,000
Gen B	0	-12,000	-12,000
Gen C	1	-4,000	-4,000

The priority EN dispatch would be as follows:

Table 15 EN priority dispatch with Gen C

	Priority EN dispatch			
	Quantity (MW)	**Cost ($/h)**	**Revenue ($/h)**	**Profit ($/h)**
Gen RRN	375	37,500	37,500	0
Gen A	25	0	2,500	2,500
Gen B	100	5,000	10,000	5,000
Gen C	0	0	0	0
Total	**500**	**42,500**	**50,000**	**7,500**

Now, Gen C is not provided access because the dispatch engine prefers the lower MFP bids of Gen A and Gen B to Gen C's, despite Gen C's lower coefficient.

Comparing Table 15 and Table 11 we see that Gen A's and Gen B's priority EN dispatch is unaffected by Gen C's connection. Gen C is unable to cannibalise Gen A or Gen B.

Comparing Table 12 and Table 15 we see that overall, the cost of dispatch has increased in the priority EN dispatch (to $42,500/h) compared to the status quo ($36,667/h). Gen A and Gen B were provided access over Gen C despite Gen C utilising less of the congested network and being lower cost than Gen B.

However, because Gen C has a lower constraint coefficient than Gen A and Gen B it is able to trade with them in the CRM in a way that it profitable for all and results in efficient physical dispatch.

The CRM dispatch outcomes and final financial outcomes are provided in Table 16 below:

Table 16 CRM dispatch and financial outcomes

	CRM dispatch						
	Quantity G_{CRM} (MW)	**CRM adjustment ($G_{CRM} - G_{EN}$) (MW)**	**CRMP ($/MWh)**	**Change in cost ($/h)**	**Change in revenue ($/h)**	**Change in profit ($/h)**	**Overall profit ($/h) (priority EN profit + CRM Profit)**
Gen RRN	350	-25	100	-2,500	-2,500	0	0
Gen A	50	25	0	0	0	0	2,500
Gen B	0	-100	25	-5,000	-2,500	2,500	7,500
Gen C	100	100	50	0	5,000	5,000	5,000
Total	**500**	**0**	**N/A**	**-7,500**	**0**	**7,500**	**15,000**

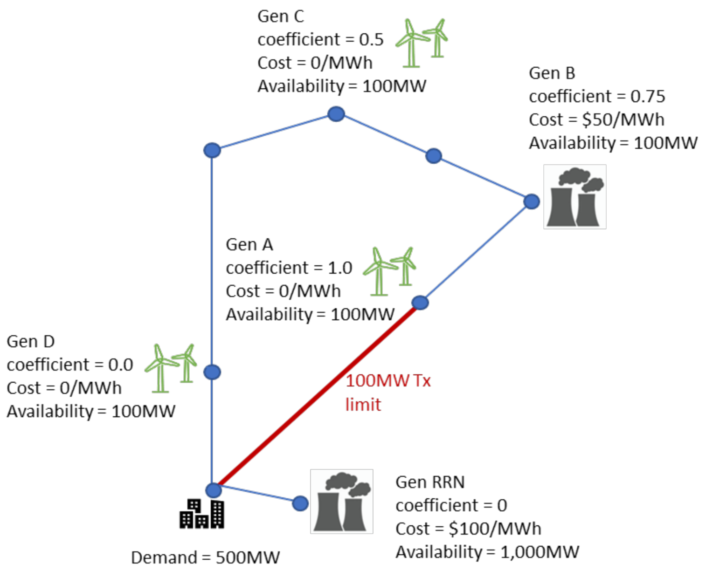
Overall, each of generators faces the efficient price signal in operational timescales via the CRM. Assuming the generators act on these signals, physical dispatch is efficient. Costs have been reduced by $7,500/h compared to the priority EN dispatch, down to $35,000/h, which is lower than the dispatch under the status quo arrangements.

Each of the generators other than the marginal generator at the RRN is profitable. Gen A's profits derive from its priority access. Gen C faces efficient investment signals under the priority access model, and Gen A and Gen B have been protected from the risk of congestion caused by a subsequently connecting generator.

Incoming generator not participating in the constraint

Next, Gen D connects in an unconstrained part of the network:

Figure 23 Legacy generator fleet plus Gen C and Gen D



Because it is uncongested, its coefficient in the constraint is 0.0: it does not participate in the binding constraint. It is allocated dispatch priority number 2 – the lowest priority of all the generators, which provides it an MFP of -$1,000/MWh. But because it does not participate in the constraint it does not have an incentive to bid at the MFP – it gets dispatched bidding at cost, as shown in Table 17.

Table 17 EN priority dispatch with new Gen D

	Priority EN dispatch			
	Quantity (MW)	**Cost ($/h)**	**Revenue ($/h)**	**Profit ($/h)**
Gen RRN	275	27,500	27,500	0
Gen A	25	0	2,500	2,500
Gen B	100	5,000	10,000	5,000
Gen C	0	0	0	0
Gen D	100	0	10,000	10,000
Total	**500**	**32,500**	**50,000**	**17,500**

Comparing Table 11 and Table 17 we see that Gen D does not impact the priority dispatch of Gen A or Gen B. It gets dispatched regardless of its high queue number because it is not participating in the constraint. Gen D's profit of $10,000/h is exactly equal to the amount by which it reduces system costs, which is an efficient signal.

Gen D would also be protected from the congestion caused by subsequently connecting generators in its part of the network.

The generators would also be incentivised to trade via the CRM (results not shown here in the interest of brevity).

Conclusion

Overall, this example highlights the following:

- The status quo arrangements result in cannibalization of legacy generators by incoming generators participating in the same constraints (Table 13). This provides inefficient price signals and creates risks for generators
- Under the priority access model, incoming generators are unable to cannibalise the access of existing generators (compare Table 16 and Table 11). Incoming generators connecting in a congested part of the network may nevertheless be profitable, even at times of congestion, by trading via the CRM.
- Incoming generators connecting in an unconstrained part of the network enjoy unrestricted access despite having a high queue number. They are protected from congestion caused by subsequently connecting generators.

Appendix E. NEMDE CRM prototype

This appendix provides insights from two case studies when the NEMDE CRM prototype simulated the introduction of the CRM dispatch. The ESB plans to release further worked examples and real-world scenarios to facilitate stakeholder's understanding of the reform changes and design options. This education initiative was referred to in section 1.3.1.

Overview

To test the validity of the CRM design and to inform design choices, the ESB requested that AEMO develop a CRM prototype using the NEM dispatch engine (NEMDE).

NEMDE is the optimiser that AEMO runs every 5 minutes to determine the least cost security constrained dispatch solution for the NEM based on participant bids and physical inputs (SCADA meter readings, demand forecasts, and system constraints). NEMDE is the software that AEMO uses to implement the central dispatch requirements of the NER 3.8.1 and the spot pricing requirements of NER 3.9.2. The key outputs of NEMDE are the dispatch instructions for generators/scheduled loads and the market prices that are used to determine the financial outcomes for participants.

AEMO's approach to the prototyping exercise was to:

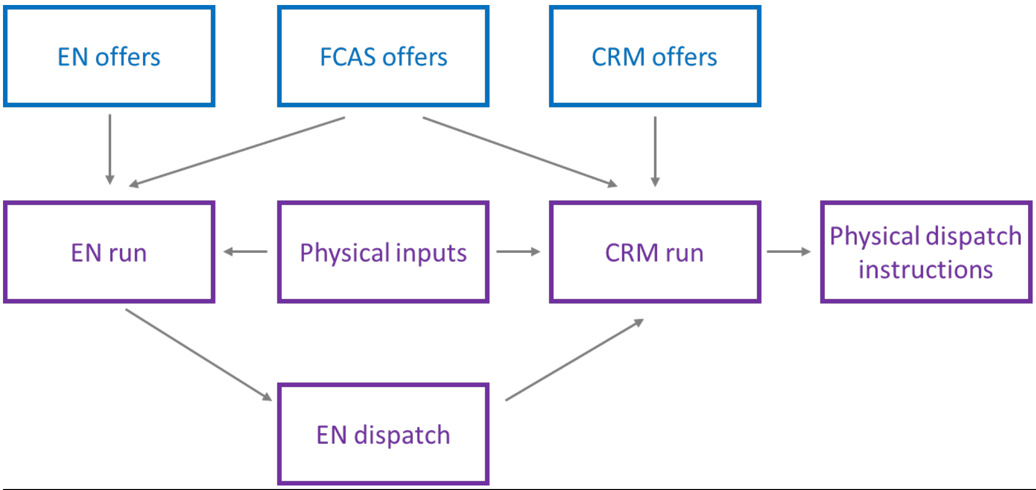
- develop the CRM model on small scale networks
- validate results using an independently developed model
- extend the model (once validated) to larger models until the whole NEM was being modelled.

CRM prototype design

There are various alternatives for implementing the CRM. The one chosen for the CRM prototype was to leverage the existing NEMDE formulation as much as possible and so the CRM prototype was based on two full sequential dispatch runs – the EN run (equivalent to today's NEM energy dispatch run) and the CRM run.

Figure 24 shows the design adopted for the NEMDE CRM prototype.

Figure 24 NEMDE CRM prototype design



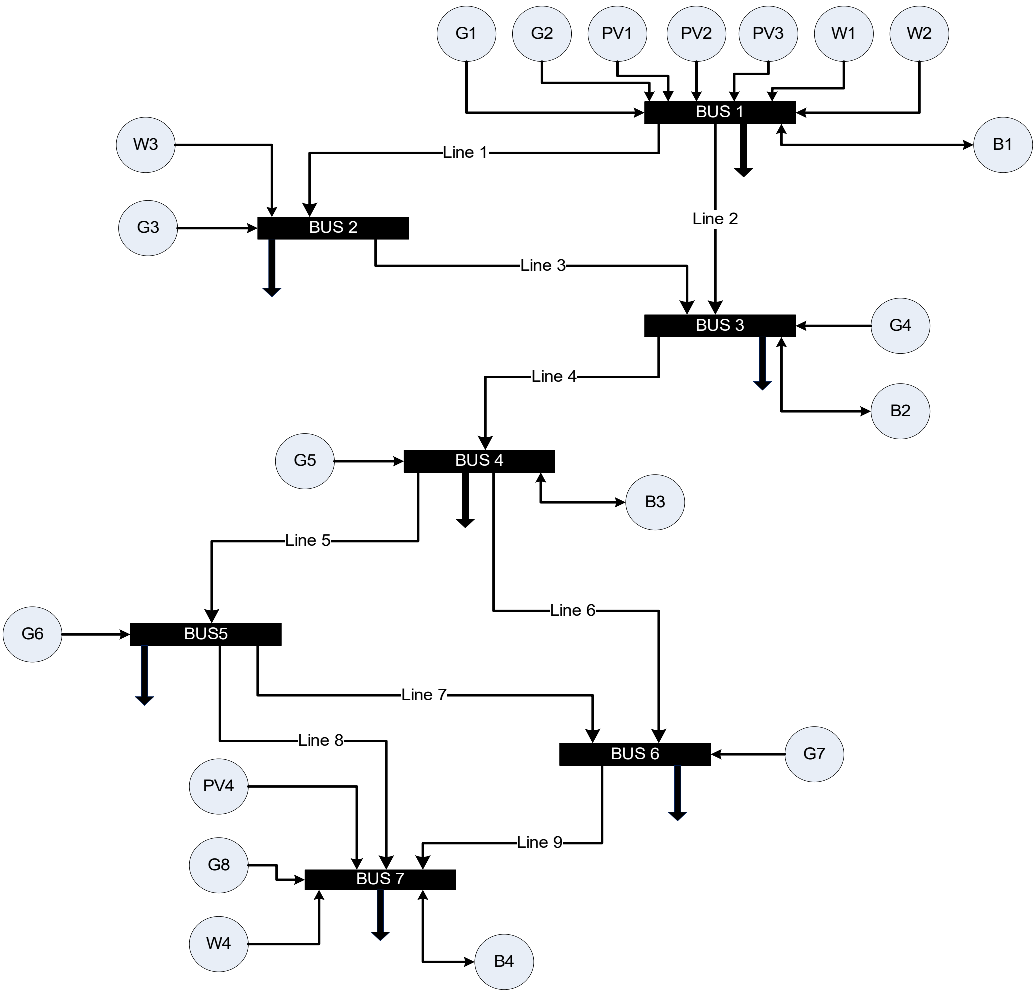
Both runs use the same physical inputs and the same FCAS offers but use two different energy offers. The two runs are sequential with separate objective functions and some of the outputs of the first run are fed into the second run e.g. to ensure that opt-out dispatchable units are dispatched identically in the CRM run to what these units were dispatched to in the EN run.

Development of the prototype

The NEMDE software adopts a data driven design and so is very scalable. The starting point was a simple 4 node direct current (DC) load flow model of the CRM implemented as a linear program (LP) in Excel. Power system shift factors for the LP formulation were calculated and the Excel LP model solution was verified against the DC load flow model at each stage. The Excel LP formulation was then coded in NEMDE and the resulting NEMDE solution was compared against the Excel solution to ensure matching objective functions, dispatch outcomes and locational and regional reference prices.

Once the NEMDE solution was confirmed as accurate additional complexity was added into the Excel model and the process was repeated. Gradually the model was expanded from 4 nodes to 7 nodes as shown in Figure 25 and from 0 to 2 interconnectors and eventually a single FCAS service was included.

Figure 25 Network topology for the 7-node model



Source: ESB

The next stage of the prototyping process was to test the CRM NEMDE prototype on actual historical dispatch intervals. A set of interesting historical dispatch intervals was selected with input from the TWG and the actual NEMDE dispatch input and output files were retrieved. These were then modified to add in the additional information required to perform a CRM dispatch run such as the CRM offers and the additional solver parameters such as “fixing tolerances” and constraint violation penalties that ensure the CRM dispatch matches the EN dispatch for opt-out units. The modified input files could then be solved by NEMDE and the results analysed. Initially, only a small set of CRM offers were included in the CRM run so that the impact of the change could be properly understood. As confidence increased the extent and complexity of CRM bidding was extended to the full set of participants.

Non-participation in the CRM

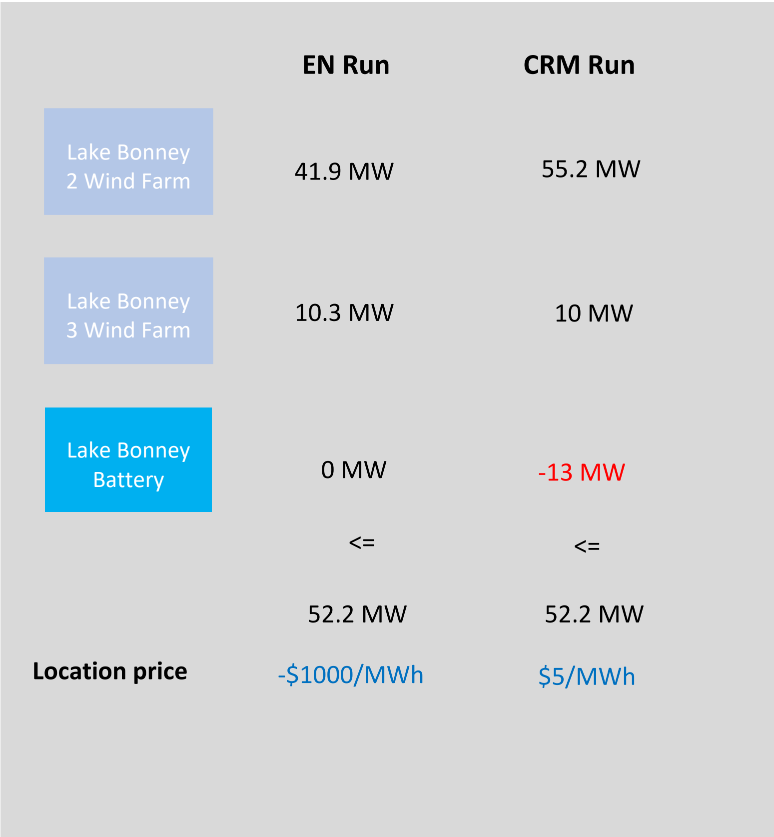
The first issue to resolve was how to ensure that the CRM prototype would solve even where there were no or few CRM participants. Given the CRM prototype is based on two full, sequential NEMDE runs it requires a set of offers for both the EN run and the CRM run so that both objective functions can be minimised. The design objective for the CRM is to not expose opt-out participants to the CRM so this can be achieved by taking their dispatch results from the EN run and constraining the model so that it produces the same dispatch outcome in the CRM run (in practice a small tolerance between the runs of say 0.001 MW is allowed to ensure that the LP model will solve without creating "degenerate" prices).

The solution adopted for the CRM prototype was to use the same the offer prices from the EN run for the CRM run. This did not impact their dispatch outcome because of the tolerance threshold (0.001MW) for differences between the EN and CRM dispatches. The result was that CRM prices in parts of the network where there was no or scarce participation tended to align with the locational prices produced in the EN run.

Case study 1: Battery

The first case study for the CRM prototype was to test the potential for trading behind a radial constraint. The case study selected was a May 2021 dispatch interval where a radial constraint was binding to limit the output of Lake Bonney 2 & 3 wind farms to 52.2 MW. The aim of the case study was to change the CRM bids so that it became economic for Lake Bonney battery to start charging and so allow the two wind farms to increase their generation whilst still satisfying the constraint.

Figure 26 Battery case study



In the actual NEM dispatch run Lake Bonney 2 and 3 bid at -$1000/MWh in order to get access to the RRP and hence tie breaking was required to allocate the total dispatch of 52.2 MW between the two wind farms. The resultant locational price was -$1000/MWh but both wind farms received the South Australian RRP of $57/MWh for their output. This RRP was above what the battery was prepared to pay to charge so it was not dispatched.

In the case study the wind farms were assumed to have an SRMC of close to $0/MWh and to bid into the CRM so their EN dispatched quantity was bid at slightly below SRMC and their remaining availability slightly above SRMC. The battery bids were constructed so that the battery would charge its full 25 MW if the price was below $10/MWh, 10 MW if the price was between $10/MWh and $20/MWh and zero above this.

Table 18 CRM energy bids in the battery case study

Unit	Band 1	Band 2
Lake Bonney 2	42 MW @ -$5/MWh	91 MW @ +$5/MWh
Lake Bonney 3	10 MW @ -$7/MWh	14 MW @ +$7/MWh
Lake Bonney Battery Load	10 MW @ $20/MWh	15 MW @ $10/MWh

Source: AEMO analysis

The outcome of the CRM dispatch is shown in Figure 26. The CRM price is $5/MWh which is set by Lake Bonney 2's second band being partially dispatched. The battery is dispatched to charge at 13 MW which allows an additional 13 MW of wind farm output. There is a slight reduction in Lake Bonney 3 output as it moves from a tie breaking outcome in the EN run to one driven by only its first band being dispatched in the CRM run.

The interesting aspect of this case study is that even though the CRM price is $5/MWh the battery isn't fully scheduled i.e. it bid to charge up to 25 MW if the price was below $10/MWh. So why hasn't it been fully dispatched?

The answer is to do with FCAS dispatch. In the EN run the battery is being dispatched for Lower Regulation for its full offer of 25 MW (i.e. if frequency rises during the dispatch interval it will be called on to charge and so restore the frequency). Hence, the dispatch solution has to replace Lake Bonney's Lower Reg quantity with the next most expensive offer which is Gladstone at $7.73/MWh. In this case it can replace the first 13 MW at an additional cost of $7.73-$3.70=$4.03/MWh but then for the next 12 MW the additional cost is $7.73-$0 = $7.73/MWh. This outweighs the energy benefit of increasing charge $10/MWh less the additional cost of Lake Bonney output $5/MWh and so NEMDE only schedules 13 MW of battery charging.

Table 19 FCAS bids in the battery case study

Unit	Band 1	Band 2
Lake Bonney Battery Lower Reg	12 MW @ $0/MWh	13 MW @ $3.70/MWh
Gladstone Lower Reg	30 MW @ $7.73/MWh	

Source: AEMO analysis

This apparently simple case study illustrates the important interaction between energy and FCAS dispatch which is particularly pertinent for batteries given they are a key provider of FCAS in the NEM.

Participants will need to consider the interaction between energy and FCAS when they submit offers (as they do today).

Another observation here is that Gladstone's FCAS dispatch is changed even though it is not participating in the CRM. This is because opt-out has been interpreted as avoiding exposure to CRM prices in energy settlement. It would be possible to also limit the exposure to CRM FCAS prices but given that participants are already incentivised to bid FCAS at SRMC they should be no worse off if their FCAS dispatch is changed. Besides, limiting FCAS variations in the CRM for opt-out customers would reduce the scope for CRM trading. In this case study Lake Bonney battery would not be able to charge if it could not find an opt-in counterparty to change its FCAS dispatch and so there would be no change in the dispatch outcome in the CRM.

Case study 2: Loop flow constraint

The next case study focussed on a dispatch interval in April 2021 when a loop flow constraint was binding. The constraint N^^N_NIL2 is a voltage stability constraint that includes 25 dispatchable units across Victoria and NSW and the Murraylink interconnector.

This constraint is quite typical of loop flow constraints and comprises a wide range of coefficients ranging from Ararat wind farm with a coefficient of 0.0931 to Darlington Point solar farm with a coefficient of 1.000. The actual dispatch outcome on the day was that Darlington Point bid -$1000/MWh but was only dispatched to 105.6 MW out of 161 MW available due to its poor coefficient (i.e. high). Darlington's locational price was -$1000/MWh and the NSW RRP was $23.68/MWh.

In the CRM run the aim was to increase Darlington Point output by getting the battery (at Gannawarra) to increase its charging from 2 MW to 25 MW. However, as with the first case study the increase in battery charge was limited by FCAS impacts and so only an additional 13.5 MW of charging was dispatched. This allowed just 2.4 MW of additional Darlington Point generation being dispatched.

The reason for this is to do with the coefficients used in the left-hand side of the constraint equation which is binding. Gannawarra's coefficient is 0.1749 whilst Darlington Point's is 1.000 so this means that each additional 1 MW increase in Darlington Point dispatch needs to be offset by 1/0.1749 = 5.72 MW of additional Gannawarra charging.

Apart from balancing the constraint the dispatch solution needs to balance the energy dispatch. Hence, if there is 13.5 MW of additional battery charging but only 2.4 MW of Darlington Point output the 11.1 MW difference must be sourced outside the constraint. In this case Murray is dispatched for the additional energy.

This case study highlights a couple of important learnings:

- Coefficients play a key role in determining dispatch outcomes when constraints are binding and it is often not efficient or profitable for a high coefficient unit to significantly change its output in the CRM when it is effectively trading with a low coefficient unit.
- Trading behind loop flow constraints will invariably require units outside the constraint to participate in the CRM so as to balance the energy flows. Therefore, realising the benefits of the CRM will depend on maximising participation not just of generators that are impacted by constraints but also by those that can play the role in balancing the energy flows.

Appendix F. Priority access – submissions to the directions paper

Introduction

As at 13 January 2023, the ESB received 32 submissions to the transmission access reform directions paper. This appendix summarises the stakeholder feedback specific to the design choices for priority access.

The ESB notes that the directions paper included a significant number of design choices. It is understandable that stakeholders focused the detail of their submissions on their preferred options. We have received thoughtful feedback on the priority access options but it represents only a sub-set of submissions. For instance, many of the stakeholders that opposed the priority access model did not respond to questions relating to its detailed design. This tendency may introduce bias to the feedback received to date. Further consultation, including submissions to this document, will be required to obtain a more comprehensive understanding of stakeholder views on the various design choices within the priority access model.

One exception was RES, who provided feedback in relation to detailed design choices associated with the priority access model even though they strongly opposed the model. RES proposed an alternative design of the CRM by pro-rating access to generators with tied bids in the initial energy market run based on constraint equation coefficients. RES considered that requiring new generators to share a portion (but not all) of the additional congestion caused by their location decision best replicates outcomes in a competitive market.

This Appendix does not provide an 'ESB view' at this time. The design choices remain open for ongoing consultation. Section 3 redefines and clarifies the design options.

This consultation paper also clarifies terms for the model options, particularly in section 2.3. Where appropriate, we have updated the terminology from the directions paper and stakeholder submissions so it is consistent with this paper.

Form of queue right (model option)

Directions paper

The directions paper sought stakeholder feedback on whether the ESB should work towards providing as many DP numbers as is feasible (given implementation challenges) or whether a tiered approach would be preferable.

Stakeholder views

Of the nine respondents that commented on this issue, six preferred a higher number of DP numbers as it provides greater certainty to investors. However, there was widespread recognition that there may be a need for a tiered or grouping approach given implementation challenges.

Origin Energy and the Clean Energy Investor Group (CEIG) preferred a tiered approach, with CEIG preferring Castalia's original approach to assigning queue positions i.e. with respect to the available hosting capacity.

Of the options available, RES preferred queue numbers to be assigned within time-windows on the basis that it would lessen pressure on developers to race for connections and avoids problems with tiered access.

Shell suggested that generators finalising their connection agreements in a similar part of the network within a time window (e.g. same month or quarter) should receive a shared queue number.

Allocation mechanism

Directions paper

The directions paper sought stakeholder feedback on how queue or tier positions should be allocated to generators. The paper described three options (first-come first-served, auctions or a combination) and sought views on whether other approaches could be considered.

Stakeholder views

Six submissions favoured first-come, first serve. Within this, two respondents considered that there may be situations where auctions are appropriate, such as in the case of jurisdictional auctions in REZs (Hydro Tasmania), or when multiple entrants connecting to shared network with interacting impacts (AEC).

RES considered that both first-come first-served and auctions would be problematic. Regarding the former, RES considered that it would increase the strain on an already stressed connection process. On the latter, it considered that the auction process would be problematic because it relies on a static assessment of transmission capacity and introduces a new process to the project development cycle which would increase the timeframe and costs for new entrants.

Duration of rights

Directions paper

The directions paper sought stakeholder feedback on whether priority levels be set for the life of the participant's asset, a fixed duration, or a fixed duration with a glide path. The paper also sought views on the length of time that a priority level should last for if a fixed duration was adopted.

Stakeholder views

Six submissions favoured priority levels for the life of the asset. Within this group, three provided pragmatic alternatives. Hydro Tasmania suggested that a proportion of capacity should be assigned with queue position and remainder at the back. Engie suggested a minimum duration of 10 years with a glide path. AEC suggested that priority levels should be available for at least two thirds of the technical life of the asset, with a glide path whereby early entrants are progressively brought to the front alongside the original legacy generators. The AEC also considered that original legacy generators should retain queue number '0'.

RES preferred fixed duration aligned with average PPA duration or project debt tenor (or preferably, no priority access mechanism). Similarly, Ergon Energy/Energex suggested that the duration should be aligned to current PPA terms e.g. 5-10 years. Energy Australia suggested a duration of 10-15 years.

Interaction with the connections process

Directions paper

The directions paper sought stakeholder feedback on the point within the connection process that the priority level should be locked in. Stakeholder submissions refer to both the timing of the priority level and congestion fees (which was the alternative hybrid model variant proposed in the directions paper, and excluded from this consultation paper).

Stakeholder views

Six submissions encouraged finalising the priority level late in the connection process e.g. at the connection agreement. Several respondents recommended that an indicative priority level (i.e. queue number or tier) is provided earlier.

The CEC and RES raised concerns that the priority access model would increase the risk of the connection process and/or incentivise developers to race to connect with associated poor quality connections. The CEC stated that:

"The ESB has identified that either establishment of a queue position, or final determination of the connection fee, will need to occur at some point within the connection agreement process. At the latest, this could occur close to the execution of the connection agreement itself, at the time the 5.3.4a approval process is finalised and FID is reached.

The problem is that leaving such a material factor undecided until so late in the connection process will tend to massively increase the degree of risk in the process, or may very well make it impossible to reach FID. The only real alternative would be to lock queue position or connection charge into place very early on in the process, perhaps at connection enquiry. However, this creates the risk of perverse incentives and strategic behaviours – such as lodging multiple speculative connection enquiries with a view to locking in a lower cost connection fee or preferable queue position."

Managing multiple simultaneous connection applications

Directions paper

The directions paper sought views on whether:

- there should be a process for batching connection applications and jointly establishing connection requirements, and
- an expression of interest process, combined with auctions, could be used to manage multiple simultaneous connections.

The term 'batching' was designed to align to a separate reform headed by the Connections Reform Initiative. It is now referred to as the "Streamlined Connection Process".

Stakeholder views

Four respondents addressed this issue. Finncorn suggested that a batching process could help to reduce uncertainty and encourage efficient deployment when new capacity becomes available. AEC suggested that batching may have a role when generators finalising connection agreements at the same part of the network at the same time, although first-come first-served should be the default. Shell suggested there is a case for generators finalising connection agreements in the same part of the network at a similar time (e.g. same month or quarter) should be able to receive a common queue position.

RES suggested that batching could only be used where there are similarly timed projects in congested areas that overbuild the ISP forecast, as it could incentivise developers to collaborate with each other on technology selection, connection arrangement design and generation runback schemes to minimise the overall congestion impact of the batched projects. However, any process should be designed having regard to the strain it would put on the connections process, and the risk of incentivising developers to rush the applications process.

The ENA considered that the relative costs and benefits of a batching process were unclear, and whether it would apply to all new connections. They suggested that lessons learned from state REZ batching should be considered before adopting across the NEM.

Qualifying criteria

Directions paper

The directions paper sought views on whether there should be conditions precedent which must be met before a queue position or congestion fee is finalised and accepted.

Stakeholder views

Few respondents addressed this issue. AEC expressed support for some form of qualifying criteria, and RES suggested that if priority access was implemented then the queue position should be provisionally identified at the time a connection application was made and confirmed at the time the connection agreement was signed.

Use it or lose it

Directions paper

Use it or lose it provisions involve the introduction of time limits or expiry dates to ensure that projects that have been assigned a priority level under the priority access framework proceed in a timely fashion. They are designed to ensure that available capacity is efficiently utilised by limiting opportunities for under-prepared projects to use up network access that could be assigned to others.

Stakeholder views

Four submissions supported use it or lose it provisions. The AEC suggested 2 years may be appropriate duration. Hydro Tasmania encouraged discretion should apply so that projects are not unduly penalised for unavoidable delays and force majeure events.

RES noted that if priority levels were not confirmed until execution of the connection agreement, then use it or lose provisions would be unnecessary.

Treatment of legacy generators

Directions paper

The directions paper sought views on the treatment of legacy generators (referred to as incumbents) under the priority access variant. For instance, legacy generators could receive:

- full grandfathered access for the life of the asset or a fixed term
- partial grandfathered access for the life of the asset or a fixed term
- no grandfathered rights for either all or certain types of legacy generators.

Stakeholder views

The ESB notes, for this issue in particular, not all respondents answered the question and consequently the summary below does not reflect the full range of stakeholder views on the issue. Legacy generators were more likely than other stakeholders to respond to this question.

Of those that responded, five submissions prefer a full grandfathering approach whereby the priority level awarded to legacy generators expires at retirement or a specified date. Variations on this preference include:

- Hydro Tasmania suggested that there should be indefinite priority access, but only for a proportion of their capacity.
- The AEC suggested a glide path whereby early entrants are progressively brought to the front alongside the original legacy generators, and the original legacy generators retain the highest priority level i.e. DP number '0'.

If a fixed duration for grandfathered rights was to be adopted, submissions suggested the appropriate duration should be between 10-30 years. Hydro Tasmania suggested a bespoke term to avoid disadvantaging technologies with longer asset lives.

Tilt expressed concern that if legacy generators were granted grandfathered rights, this could limit the amount of incoming investment during the period that the grandfathering applies. RES considered that any protection of legacy generators is unacceptable due to the barrier this creates for new entrants.

Options to reduce congestion impact

Directions paper

The directions paper sought views on whether the ESB should develop proposals to give generators options to reduce their congestion impact (in return for a better priority level) as part of its congestion management reform package.

Stakeholder views

Shell suggested that generators that invest in network augmentations should receive the highest priority level. Origin Energy suggested that there was a potential role for AEMO or the TNSP to coordinate generator fees for upgrades, including existing constrained generators that may wish to opt in (on a voluntary basis) to reduce any current curtailment level through network augmentation.

Neoen suggested that new entrants should have an obligation to amend their project to mitigate excessive curtailment (and this should be a substitute for other reforms including a priority access regime). RES suggested that options to enable new entrants to move up the priority levels is incompatible with priority access as it would reduce confidence in the queue. RES suggests that by exposing generators to constraint coefficients, generators already have an incentive to minimise congestion and efficiently utilise the network via technology selection, connection arrangement design and implementation of generation runback schemes.

The ENA noted the potential for interactions between the reforms under consideration and the Dedicated Network Assets (DNA) framework. They considered that the DNA framework should have precedence.

Governance

Directions paper

The directions paper outlined a set of proposed governance arrangements, whereby AEMO would be responsible for developing a congestion forecast methodology and congestion impact assessment guidelines. In the event that auctions form part of the access framework, the paper suggested that auctions should be conducted by either the jurisdictional planning bodies (where this role can be assimilated into State government REZ schemes) or in the absence of jurisdictional schemes, by AEMO.

The ESB is subsequently reviewing the governance arrangements in light of the enhanced information rule change request and the role of the central agency or agencies.

Stakeholder views

Few respondents commented on this issue. AEC supported the suggested approaches in the directions paper. Origin Energy supported the governance approach whereby AEMO sets out the forecast methodology and TNSPs apply the methodology for proponents connecting to their network. RES noted that if this framework were be to adopted, it would be important that the party responsible preparing congestion forecasts has experience of the Plexos software program.

Appendix G. CRM design – ESB preferred choices and summary of submissions to the directions paper

The directions paper sought feedback on six key topics for the CRM design. This appendix summarises the design choices, stakeholder views and the ESB's response.

Parties subject to the arrangement

Directions paper

The directions paper proposed that parties eligible for CRM participation would include; scheduled and semi-scheduled market participants including (scheduled and semi-scheduled) generators, scheduled load and scheduled storage. This would be valid regardless of whether they connected at the transmission or distribution level.

Non-scheduled market participants do not bid into the energy market and so cannot participate in the CRM. They would automatically be settled at the RRP, as they are now.

Stakeholder views

Stakeholders were broadly agreed that the CRM would apply for scheduled and semi-scheduled generators that are transmission or distribution connected.

Stakeholders requested that the ESB confirm the proposed treatment for:

- scheduled lite generators
- network demand response providers (contracted with NSPs)
- wholesale demand response providers

Three stakeholders also requested that the ESB reconsider:

- relatively large non-scheduled generators registered before there was a semi-scheduled generator classification (Shell)
- 5 – 30MW capacity threshold (AEC, Alinta)
- non-energy market participants e.g. synchronous condensers, runback schemes (AFMA).

ESB response

In principle, all parties that submit an *energy* bid into NEM dispatch today should be able to participate in the CRM if they choose to. This approach would mean market participants with scheduled and semi-scheduled generating units, scheduled loads and wholesale demand response units could participate. It also means that market network service providers (Basslink) will be able to participate in the CRM.

Market participants with non-scheduled units will not be able to participate in the CRM even if AEMO currently requires them to participate in central dispatch e.g. Wattle Point wind farm etc. In addition, non-market participants will not be eligible to participate in the CRM.

The level of participation will be at a dispatchable unit (DUID) level. Scheduled generating systems comprising multiple DUIDs will need to opt in for all DUIDs.

A non-scheduled market participant would be able to participate in the CRM if it became scheduled. The classification of generators as scheduled is a separate consideration to the CRM design, and is governed by chapter 2 of the NER.

Rounding constraint coefficients in the energy market

Directions paper

The directions paper proposed to round constraint coefficients to 1 or 2 decimal places in the energy market. Participants with different coefficients (e.g. Gen A has 0.7935 and Gen B has 0.7512) could have common coefficients after rounding to 1 decimal place (0.8). Rounding the coefficients partially socialises congestion risk and represents a 'buffering' of volatile outcomes. In the case of a REZ, participants are likely to have similar but not identical coefficients for constraints applying remotely from that REZ. This option promotes the socialisation of congestion risk between these parties locating in the same area.

This rounding would only apply to EN dispatch. Rounding would not be applied in the CRM i.e. it does not interfere with achieving a more efficient dispatch through CRM adjustments.

Stakeholder views

10 stakeholders provided feedback on this design choice, of which:

- 3 were supportive of rounding constraint coefficients
- 4 were supportive of the concept, but were uncertain whether rounding would have the intended effect on sharing congestion risk
- 3 were not supportive of the proposal.

Most stakeholders expressed a view that they were reserving judgment on rounding constraint coefficients until further technical investigation was completed.

There were some concerns that rounding constraints could introduce new inefficiencies into the energy market with a requirement for new safety margins to ensure a secure feasible dispatch. RES questioned whether this inefficiency might then increase the RRP (and energy costs for consumers) if additional energy was required from the marginal generator.

RES also suggested that it could introduce uncertainty for developers and investors who would need to consider the *absolute* value of coefficients more accurately rather than considering the *relative* ranking of coefficients today.

Origin Energy recommended pursuing this concept as a separate workstream. CEIG supported the proposed design choice including as a standalone reform if needed.

ESB response

The ESB is currently pursuing the hybrid model which combines priority access and the voluntary CRM. The decision to pursue priority access already addresses key risks identified in today's energy market and has a significant impact on the allocation of congestion risk.

Depending on the number of parties with a shared queue number or tier, rounding coefficients may still be a useful addition to address the residual risk of 'winner takes all' outcomes for parties within the same dispatch group. The benefits are highest if there are a large number of parties within the same priority dispatch number.

However, the ESB does not propose to pursue rounding constraint coefficients at this time. There are key design choices to be finalised for priority access which affect this residual risk. And there is a significant technical work plan to implement both priority access and the CRM design. A rule change request could be considered at a later date, when we can better assess if there is incremental benefit and its technical feasibility.

Response to new bidding incentives

Directions paper

The directions paper identified new bidding incentives for "out-of-merit" (OOM) generators in the energy market, that are not incentivised in today's market design. OOM generators refers to those with costs higher than RRP. In the CRM design, they face incentives to:

- bid disorderly in the energy market at the market floor price (-$1000/MWh) to secure access to the RRP; this is new bidding behaviour that is not incentivised today
- bid at cost into the CRM to avoid physical dispatch.

The directions paper proposed to keep the existing energy market design, or introduce new design elements such as modifying the bidding guidelines to deter unwanted bidding behaviour or introducing an automated measure into the EN dispatch that would filter out inconsistent bids (between the EN and CRM) deemed to be from OOM generators.

Stakeholder views

10 stakeholders provided feedback on these topics of which:

- 6 submissions recommended keeping the existing market design. A number of these submissions suggested monitoring post-implementation to determine the materiality of the issue and its ability to self-resolve.
- 1 submission proposed modifying the bidding guidelines (Hydro Tasmania).
- 1 submission suggested deferring the decision and re-assessing once the detailed design is developed (ACCIONA).
- 2 submissions favoured introducing automated rules into the energy market based on participants bids in the CRM relative to the forecast RRP (RES and ACEN).

A number of stakeholders acknowledged the potential risks identified by the ESB. RES identified that wealth transfers away from in-market generators would introduce investment uncertainty and hinder the business case for new entrant renewables.

But a number of stakeholders were unclear whether these would eventuate and their level of materiality. Shell noted that if participants are allowed to dynamically opt out of the CRM via rebids, participants observing OOM generators seeking to arbitrage the CRM and EN could withdraw from the CRM, removing any inefficient arbitrage payment and providing a strong disincentive to the OOM generator.

The majority of stakeholders preferred to keep the existing market design. ENGIE suggested that the AER's existing market surveillance powers allow it to identify any egregious bidding.

Some stakeholders suggested monitoring post-implementation to determine the materiality of the issue and its ability to self-resolve.

ACCIONA submitted that this is a complex issue and further analysis of design choices and bidding approached is required. RES also suggested further work is required to develop a detailed design.

ESB response

The ESB (with the AER leading on this item) is exploring the potential for market manipulation arising from the CRM design and potential options to address this issue. Potential options being considered include (but are not limited to) amendments to the rules and/or bidding guidelines to ensure the prohibition on false and misleading bids also applies to bids into the CRM.

We note that post-implementation monitoring of market participant behaviour and bidding incentives created by the CRM will be important. Behaviour will evolve with a new market and it is important that the rules and/or guidelines are reviewed to ensure the reforms enable effective functioning of energy markets. We suggest a review of market manipulation in the CRM be required 3 years after implementation. This review will likely have resourcing implications for the market body undertaking the review.

The ESB will release further information for consultation through its technical working group and consultation on draft rule changes.

Additional rules for storage when acting as a generator and as load

Directions paper

The directions paper recognised that the OOM issue can be harder to identify for storage (i.e. hydro, pumped hydro, batteries) because they bid based on the marginal value of their stored energy and contract positions. Additional design choices were considered for storage:

- as a generator: a potential "strike price" to determine whether the storage unit is in-merit
- as a scheduled load: settling storage at its CRM price.

Stakeholder views

8 submissions provided views:

- 6 recommended keeping the existing market design
- 2 recommended energy limits on storage assets in the energy market which might address some of the issues for short-duration storage
- No submissions favoured:
    - introducing a 'strike price' for storage
    - settling storage at the CRM price only when acting as load.

RES and Hydro Tasmania agreed with the underlying assumptions in the Directions Paper. However, RES noted that a further scenario should be considered where LMP>RRP due to a load driven transmission constraint such as the forecast Gladstone load area constraint driven by the retirement of Gladstone Power Station. In this scenario, storage would seek to access the LMP for generation.

Most stakeholders preferred to keep the existing market design. Similar to the previous OOM issue, some stakeholders suggested monitoring the issue post-implementation. EDL suggested that caution should be taken in applying bidding guidelines or price rules to storage given that this technology is varied and relatively new so the way it would operate under the CRM is not well understood. Instead, EDL submitted that the ESB should monitor storage participation in the CRM to determine whether there is an issue that needs addressing.

Most stakeholders preferred that the rules were technology neutral, rather than applying different rules for storage compared to other generation technologies.

ENGIE also submitted that there is insufficient merit to justify treating storage differently from load (when charging) and generation (when discharging). The AEC submitted that it is unlikely that storage acting as a load would be exposed to a LMP in excess of RRP.

RES offered a different view that the same design choices cannot be applied to storage as other generators because strategic bidding is likely to lead to wealth transfers and allow storage proponents to achieve financial returns on the energy market that do not reflect the limitation on their storage depth.

Both Hydro Tasmania and RES opposed the use of a “strike price”. RES suggested it would not be appropriate for merchant revenue maximising storages that respond purely to estimated opportunity cost. Hydro Tasmania similarly submitted that it was a blunt instrument which does not capture the fluctuating values of energy in storage for hydropower and other storage assets. Hydro and storage assets price their supply based on the opportunity cost of supply rather than input costs and will frequently change bid prices and volumes.

Hydro Tasmania instead suggested placing energy limits on storage assets in the energy market (e.g. a battery with 2 hours of storage could be limited to 4-6 hours of dispatch in the energy market assuming that it cycles 2-3 times per day). RES submitted that an automatic daily energy constraint should be considered further. However, RES noted the need to ensure that new entrant storage is not disincentivised.

Hydro Tasmania proposed that, if necessary, the amended bidding guidelines, and monitoring practices of the AER could have specific reference to storage assets and outline how these assets should respond during periods of thermal constraint.

ESB response

As noted above, the ESB (with the AER leading) is exploring the potential for market manipulation arising from the CRM design and potential options to address this issue. The current working assumption is that the same rules for other generators will apply to storage (as a generator or load). Storage forms part of the broader considerations of market bidding incentives and the ESB will release further information for consultation through its technical working group and consultation on draft rule changes.

Calculation of RRP

Directions paper

The directions paper included a design choice on the calculation of RRP referred to as RRP_{NEM} and RRP_{CRM}. This choice arises because the CRM design is based on two sequential NEMDE dispatch runs for each five minute dispatch interval including:

- energy market dispatch based on energy market bids
- CRM dispatch based on CRM bids.

This means that the CRM dispatch is a full dispatch but for settlement purposes, only adjustments between CRM and energy market are settled at the CRM price. The RRP can be calculated from the CRM in the same way as it is in today’s energy market. The RRP may differ between the two markets given:

- differences in bids
- changes in demand from storage acting as load, or scheduled loads choosing to participate in the CRM
- changes in interconnector flows.

The paper noted that there may be technical challenges that affect which RRP calculation can be adopted in practice.

Stakeholder views

14 stakeholders provided feedback on this design choice, of which:

- 10 submissions supported RRP_{NEM}

- 3 submissions recommended deferring the decision for a better explanation of how RRP may be calculated under the two options and how/why the two RRPs may vary
- 1 submission supported Option 2 RRP_{CRM}

The majority of stakeholders preferred to retain RRP_{NEM} from the energy market because:

- it preserves the principle that the CRM is voluntary, and parties that do not want to participate in the CRM remain unaffected
- contract arrangements may be affected if the formulation of the RRP was changed.

ACCIONA submitted that the benefits of retaining the current definition of RRP_{NEM} (avoiding impacts of existing long-term energy contracts) outweighed the potential downsides (including residual differentials between RRP_{NEM} and RRP_{CRM} and a potentially more complex settlement for FCAS). RES had an alternative assessment that the long-term benefits RRP_{CRM} outweighed the risks and retained consistency with the concept that RRP is based on physical dispatch. However, RES recognised that further analysis and transitional arrangements may be required to reduce the requirement to reopen existing contracts.

ESB response

On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to keep RRPs from the energy dispatch (rather than the CRM).

One of the key aspects of the CRM is that participation in the CRM is voluntary. Thus, even though we expect that most dispatchable units will participate in the CRM over time, there may be occasions when only a small number of units participate in the CRM and the RRP_{CRM} may not be very representative of a region's demand and supply balance. However, in these circumstances, the local prices produced by the CRM where trading actually takes place will still provide accurate information on the willingness of participants to increase or decrease generation or consumption and at these locations the market will clear at logical prices.

An advantage of the CRM is its compatibility with the existing NEM arrangements and contracts. The use of RRP_{CRM} increases the risk that it is necessary for market participants' contracts to be reopened.

The directions paper included the RRP_{CRM} as a design choice because it was considered that it may result in lower RRPs for customers. However, our work to date has not identified a compelling reason to move to the RRP_{CRM}. Instead, it appears likely that if there is full participation in the CRM then arbitrage opportunities will force the RRP_{NEM} and RRP_{CRM} to converge over time. Ultimately, the market will require high enough spot prices to get new investments and the larger portfolio generators with some market power will ensure that, in the long term, prices are high enough to support new investments.

Settlement of metered output (differences between dispatch targets and metered output)

Directions paper

In today's energy market, participants' metered energy (adjusted for losses) is settled at the RRP. The CRM introduces two different prices into the settlement equation and the single metered energy value must be allocated in some way to the two prices.

The directions paper introduced a design choice for the settlement of differences between metered output and dispatch targets at RRP or CRM prices.

Stakeholder views

All nine submissions on this design choice preferred to price differences at RRP given:

- the principle of the CRM is a voluntary market and participants can opt out of local price exposure
- it would avoid potential impacts on financial contracts and the cost of reopening of long term contracts
- the risk of proponents not following dispatch instructions could continue to be managed via AEMO's non-conformance monitoring.

Shell also proposed there were impacts to be carefully considered and balanced between the energy market, CRM, FCAS markets and the mandatory narrow band primary frequency response (MNBPFR). Paying differences at the CRM price might create a disincentive for generators including BESS to participate in FCAS markets and changes to unit operation that would minimise the provision of MNBPFR, as it would at times receive the (presumably) lower CRM price rather than the RRP. The proposed change could also lead to an imbalance between market customer (load) and generation settlement amounts which may not balance over time and require ongoing settlement adjustments by AEMO to correct this inefficiency.

ESB response

On the basis of stakeholder feedback and analysis by the ESB's technical implementation team, the preference is to settle differences between metered output and dispatch targets at the RRP.

The rationale is equivalent to the previous design choice for the calculation of RRP. On balance, the potential risks of moving to a new settlements arrangement outweighed the potential benefits.

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