AEMC

AUSTRALIAN ENERGY MARKET COMMISSION

REVIEW

Consultation paper

Transmission access reform

24 April 2024

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Citation

To cite this document, please use the following:
AEMC, Transmission access reform, Consultation paper, 24 April 2024

Summary

1 The transition to a net zero energy system will require investment in a significant amount of transmission and generation capacity at an unprecedented rate. The 2024 Draft Integrated System Plan (ISP) forecasts a seven-fold increase in grid-scale wind and solar capacity and 19-fold increase in storage capacity between 2024 and 2050. This pipeline of large-scale renewable generation and storage is driving a wave of major new transmission projects to transport the electricity produced to market. This is particularly important as the national electricity market (NEM) replaces most of its ageing power stations over the next 20 years. Governments are:

- getting involved to deliver some of this new investment over the next several years via Rewiring the Nation, the Commonwealth Capacity Investment Scheme (CIS) and various jurisdictional government initiatives,
- seeking to promote more co-ordinated development by establishing renewable energy zones (REZ) and accompanying reforms within their regions.

2 Issues regarding the current transmission access arrangements in the NEM have been evident for several years. Over time, significant work has been undertaken by various bodies to address current problems.

3 It is in this context that Energy Ministers have had an active program of work to explore transmission access reform.

4 In an electricity system “access arrangements” refer to the arrangements that govern how generators “access” or dispatch electricity into the grid and what they get paid for. The NEM’s current “open access” arrangements permit any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to, or causes congestion on - the broader power system. Under the current arrangements “access” (i.e. the megawatts you can sell at the regional reference price (RRP)), is equal to your physical dispatch every five minutes. If a generator is not dispatched, it gets no access and is not paid.

5 The linkage between access and physical dispatch contributes to various operational and investment inefficiencies in the NEM increasing costs for consumers. These include:

- **Increasing congestion risk:** Current NEM arrangements mean the costs of congestion are often borne (at least in part) by pre-existing generators, rather than fully by a new entrant that causes the congestion. This can increase congestion and create a risk of “cannibalisation” (when a new generator locates in a congested area and displaces, or cannibalises, the dispatch of an existing generator). This means that investors may be exposed to unnecessary risk.
- **Investment inefficiencies:** The regional pricing arrangements of the NEM mean that locational signals are not as clear as they could be for participants on where to build assets and best utilise the network. There could be stronger commercial drivers for investors to choose locations in order to minimise congestion. This means that REZ schemes may not deliver their expected benefits.
- **Inefficient dispatch:** When congestion occurs, the current wholesale pricing arrangements can create dispatch outcomes that do not minimise outcomes for customers over time. Flexible resources such as storage and demand response are also not encouraged to operate in a manner that recognises how they can add value to the system.

6 Transmission access reforms seek to address these inefficiencies so that we invest in the right places, and operate effectively to achieve a least cost transition for customers.

7 In February 2023, Energy Ministers agreed that the Energy Security Board (ESB) should develop a "hybrid model" made up of a voluntary congestion relief market (CRM) and a priority access model. At the time, it was noted that the reforms would yield net benefits for industry and consumers of up to $5 billion NPV and lower emissions by 23 million tonnes by 2050.[1]

8 This was further reinforced after considering advice from the Energy Advisory Panel (EAP - which replaced the ESB in mid 2023) as well as the stakeholder feedback to the ESB and EAP processes. Energy Ministers asked the Australian Energy Market Commission (AEMC or Commission) to continue to progress the design of the hybrid model.

9 Accordingly, the AEMC initiated a transmission access reform review and will make final recommendations to the Energy Ministers in accordance with Terms of Reference published on 7 March 2024.

10 The AEMC is working collaboratively with the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO), and building on the work done by the ESB and EAP and the feedback provided by stakeholders over the course of 2023 to undertake this work.

11 The purpose of the AEMC's review is to address four transmission access objectives, which have been agreed by Energy Ministers and which were developed by the ESB in consultation with stakeholders:

- **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.
- **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.
- **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.
- **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.

12 This consultation paper is an important next step for considering transmission access reform. It will facilitate stakeholder input on key elements of the design of the hybrid model that have not yet been settled. This paper also outlines and seeks stakeholder feedback on previous work, including the 2023 cost benefit analysis (CBA) and prototyping results of the hybrid model, and our responses to key stakeholder concerns. Stakeholder submissions are due by **Thursday 6 June 2024**.

13 The AEMC has published a project plan that sets out a number of other activities we intend to progress over the course of the review, including:

- modelling to explore how priority access may inform investment decisions,
- the development of a stylised network model to be shared with stakeholders,
- technical working group to act as a sounding board for our thinking on the design of the hybrid model,
- jurisdictional workshops to seek views and ensure alignment with government initiatives.

14 These activities will assist the AEMC in progressing development of the hybrid model to the fullest

1 Energy and Climate Change Ministerial Council, Meeting Communique, Friday 24 February 2023.

extent possible before reporting back to Ministers with final recommendations in September 2024.

15 If a decision is made to proceed, a detailed implementation phase including the development of draft rules and consultation would commence in 2025.

Problems and drivers for reform

16 The transition to net zero means a physical transformation of the electricity system.

17 Congestion is a normal, everyday feature of an efficiently sized transmission infrastructure system to accommodate variable renewable energy (VRE). We need to upgrade and augment our transmission network to meet our future energy needs. However, eliminating all congestion would involve building a huge transmission system. Instead, it is more cost effective to build a smaller system and manage congestion by efficiently rationing which generators get to use the system. This is the best way to make sure that the transmission infrastructure is used effectively, ensuring that consumers get the best value from it.

18 As we move to a weather dominated power system, congestion will continue as a feature - we are seeing this worldwide in other energy systems. Active management of congestion in the system (rather than eliminating all congestion) is the best way to make sure that the transmission infrastructure is used effectively, and that consumers get the best value from it.

19 AEMO's 2024 draft ISP forecasts that congestion will continue to increase as part of its optimal development path, even after the actionable ISP projects are built. This modelling does not take into account problems with the current access regime and assumes people bid at their costs, so in practice the levels of congestion in the ISP can be considered to the best case scenario. In addition, we expect that congestion will be further exacerbated by a number of matters in the future, such as increasing costs of transmission and supply chain challenges that may make it more challenging to build new transmission that is required to connect the new generation to the grid.

20 Congestion needs to be carefully managed. Having a transmission planning and investment framework that is effective, timely and provides checks and balances for consumers is an important component of managing congestion. So too is providing information to the market about where congestion is occurring so that this can be taken into account by participants. Recent reforms on transmission planning and investment as well as enhancing locational information have sought to improve these arrangements. However, neither of these are substitutes for broad transmission access reform.

21 Without reforms to transmission access, as recognised by Energy Ministers, the following problems will continue as the transition to net zero progresses, increasing costs to consumers:

- Solar and wind investments will face increased congestion and not be effectively utilised, meaning that emissions reductions from renewable resources are not fully realised.
- REZs may be undermined by generators located outside the zone, free riding on investments intended for REZ participants.
- Storage (e.g. batteries) and flexible demand (e.g. hydrogen) will not be rewarded for congestion-alleviating behaviour that benefit customers, and their use case will be diminished.
- The value of investment in interconnectors may not be fully realised.
- Customers (or taxpayers) may pay extra for additional transmission to be built.

The hybrid model is the preferred model to address these issues

22 In February 2023, Energy Ministers agreed to a lead 'hybrid' model, that combines the congestion relief market (CRM) (originally proposed by Edify Energy and supported by the Clean Energy Council (CEC)) and the priority access model (originally proposed by the Clean Energy Investor Group (CEIG)).

23 The CRM aims to improve operational efficiency while priority access aims to improve investment efficiency. By integrating the two, the hybrid model addresses the transmission access reform objectives:

- Priority access provides a locational signal for investment efficiency and enables investors to manage congestion risk more effectively. A generator or storage facility would be assigned a priority level up front which is factored into the project's investment and siting decision.
- The CRM allows for operational efficiency and congestion relief by providing voluntary incentives to generators to bid more cost-reflectively. Storage and demand response providers are incentivised to locate and operate where they can relieve congestion with benefits to the whole system. The CRM also ensures that the access of existing generators is broadly unchanged.

24 This hybrid model forms the basis for the AEMC's continued work on transmission access reform. The hybrid model seeks to resolve stakeholder concerns with the previous models, including by:

1. Designing the CRM as an opt-in mechanism: If access quantities and physical dispatch are different, then generators are exposed to two different prices. This increases complexity and creates implementation and transaction costs. These may be particularly acute for generators that hold contracts that hedge against the current regional price which therefore might need to be reopened. The hybrid model is designed so that participants opt-in, meaning that they can *choose* if they want their access and physical dispatch quantities to be different.
2. Allocating access consistent with the status quo: moving to a different access model may lead to generators' level of access may be set differently compared to the status quo and they may be required to pay for this access, creating winners and losers. To encourage investment, the hybrid model is designed to allocate access to the transmission network in the same way as the status quo, so as not to substantially disrupt the allocation of value between existing market participants.

25 As a standalone solution, priority access may introduce new dispatch inefficiencies to the energy market. The CRM balances this by incentivising participants to effectively trade congestion relief and produce a more physically efficient dispatch (compared to both the status quo and the priority energy dispatch).

26 While each model could be implemented individually, the two are currently being considered together as benefits from their combined implementation exceed either of their individual benefits. It will mean participants have more control over their revenues at the same time as being incentivised to deliver system-wide benefits. Ultimately this leads to more efficient outcomes and prices for customers.

27 We welcome stakeholder comments on how their views may change if only one, rather than both, reforms were to be implemented.

Priority access

28 The introduction of priority access seeks to address the issue of cannibalisation, by introducing a mechanism where generators are assigned a priority level in the energy market. Cannibalisation is

when a new generator locates in a congested area and displaces (or cannibalises) the dispatch of an existing generator.[2] Cannibalisation can increase investment uncertainty, as new entrants may be subsequently cannibalised (and thereby lose revenue) by even newer entrants.

29 The priority level would be assigned to a new entrant generator during its planning and investment period, with the priority level given effect in dispatch, during operational timeframes. Generators assigned a higher priority would be given preference in dispatch over generators assigned a lower priority, improving the access for higher priority generators to be dispatched and paid at the regional reference price (RRP). Importantly, priority access would only have an effect in the presence of congestion, when competing generators bid to the market floor price in order to be dispatched.

30 Priority access would improve investment certainty by protecting generator access to the RRP from cannibalisation by newer entrants, as well as reducing incentives for new entrants to efficiently locate in congested areas.

31 Priority access also provides a clear mechanism to support the delivery of 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.

32 In determining a preferred model for priority access, the ESB decided to progress investigation of a bid price floor (BPF) adjustment approach, where participants with different dispatch priorities would be assigned different bid price floors that set the minimum bid they can make. Higher priority generators would have lower (more negative) bid price floors, meaning they may get dispatched ahead of lower priority generators with higher (less negative) bid price floors.

33 As part of the ESB's most recent work on priority access, AEMO used a NEMDE prototype to test the bid price floor adjustments approach. The key takeaway from AEMO's work was that the bid price floor adjustments approach can be implemented in the national energy market dispatch engine (NEMDE). However, we are unlikely to be able to implement a large number of meaningful dispatch priority levels. This is because dispatch priority levels require sufficiently large bid price floor ratios between generators with adjacent queue positions, for priority access to have meaningful impacts.

34 A key design question, then, is how to assign participants to a smaller number of priority levels whilst maintaining most of the benefits of a full sequential queue. To this end, we have identified several priority access model options we consider to be credible options under the bid price floor adjustment implementation approach.

- **Option 1 – Grouping by time-window:** Generators would be grouped by year for the duration of prioritisation, before rolling them up into a higher priority group as the number of available priority levels was met. Each priority level would have a corresponding bid price floor.
- **Option 2 – Grouping by time-window REZ model:** As with option 1, generators would be grouped by year. Jurisdictions would also be provided with the ability to grant REZs the highest level of priority, irrespective of the timing of REZ planning, declaration, specification and operation.

2 Due to congestion, there are limits on the total dispatch of generators in the congested area (meaning for someone to increase output, someone else will have to decrease output). With knowledge of the existing network configuration, a new entrant is able to select a more preferable location that gives them an advantage to get dispatched instead of existing generators.

- **Option 3 – Two tiers approach:** Under this model, legacy generators, committed generators (at the time the reform is implemented) and generation participating in REZs, would all be grouped into a priority tier. Other new entrant generators who have chosen not to participate in a jurisdictional REZ, would be given a lower level of priority in dispatch. Using two levels of priority means that only two bid price floors would be needed. As a result, the bid price floors can be set far apart to harden priority access.
- **Option 4 – Dynamic grouping algorithm:** An algorithm would be run close to, but before real-time, and would run sequential dispatches to progressively prioritise or deprioritise generators, based on when they connect and whether their dispatch would need to be constrained to avoid constraint violations. Effectively, the algorithm assumes higher priority generators get 'dispatched' ahead of lower priority generators, and allocates prioritisation accordingly. The results from the dynamic grouping algorithm, groups generators for access dispatch and determines their corresponding bid price floors.

35 At this stage, model option 1 (grouping by time-window) is our preferred priority access model. We consider that there could be theoretical merit in dynamic grouping delivering priority access that is stronger, however this option has not been tested yet, or developed in any detail.

36 The Commission is particularly interested in views as to whether stakeholders would see merit in option 4 relative to option 1. There are a number of more detailed priority access design options where we are also seeking stakeholder views.

Congestion relief market (CRM)

37 The CRM is a voluntary, opt-in mechanism, where market participants can seek to revise their initial dispatch outcomes that set how much they can sell at the regional price (RRP). It can be more profitable for CRM participants to revise their position by increasing or decreasing their dispatch, as revisions are paid at CRM prices (CRMP), that may differ from the regional price.[3]

38 These revisions would occur between market participants, such that this effective trading in the CRM can be seen as buying and selling 'congestion relief'.

- Prospective buyers would generally be high cost and high emission generators behind a constraint that are dispatched under the status quo, and who are willing to reduce their output (or loads/storage behind a constraint that increase their consumption)
- Prospective sellers would generally be lower-cost, lower emission generators located behind the same constraint willing to increase output (or loads/storage behind a constraint that decrease their consumption).

39 Typically, buyers of congestion relief are generators who are dispatched to sell energy at the regional price, but instead choose to pay another generator through the CRM to meet their sale obligation, to avoid the cost of generating themselves. This decision effectively reduces the generation that is contributing to the congestion, i.e. it 'relieves congestion'.

40 Over the course of 2023, the ESB developed a specific design for the CRM component of the hybrid model, which involved two-stage dispatch. First, a prioritised access dispatch would determine access quantities and regional prices. Immediately after, a physical dispatch would determine physical dispatch targets (and any corresponding revisions from the access dispatch) and CRMPs.

41 The CRM model addresses some of the issues and stakeholder concerns, compared to both the

3 For constrained-down generators, their CRMP will be lower than the RRP.

status quo arrangements and previous access reform models considered in the NEM – most notably in allowing market participants to voluntarily opt-in to participating in the CRM. For participants that do not opt-in to the CRM, their dispatch and settlement would be similar to the status quo arrangements, and they would not be subject to revision in their access dispatch outcomes.

42 At a high level, the CRM changes three components of the existing market design: the way market participants bid/offer, the dispatch process, and settlement. There are opportunities for participants in the CRM to improve individual positions as well as delivering system-wide benefits.

43 Market participants would continue to submit bids into the wholesale energy market. These bids would be used as an input to access dispatch, which determines “access quantities” for each market participant. For those market participants that choose to opt-in to the CRM, they would additionally submit a second set of bids, which would be an input into the physical dispatch. The physical dispatch can differ from the access dispatch and physical dispatch targets and would be sent to market participants as dispatch instructions, who currently have regulatory obligations to conform with them.

44 Participants in the CRM would be paid for the energy they produce at the regional price, with an adjustment to account for a change in dispatch outcomes and the difference between the CRMP and regional price. This creates an incentive for generators to maximise profits by bidding more cost-reflectively, producing system-wide benefits by improving dispatch efficiency.

45 Through the CRM, batteries (among other storage assets and scheduled load) located in constrained areas will be able to buy energy for prices below the regional price. This can provide incentives for batteries to locate in constrained areas, as this can increase their intra-day price spread and consequential profit. If storage locates in congested areas, this has system-wide benefits as excessive low cost energy can be stored and used at a later time when it is needed, instead of not being generated.

Regional price and dispatch implementation options

46 The two-staged dispatch model means that two sets of regional prices are generated, presenting a choice of which to use for settlement:

- access RRP - calculated in priority access dispatch,
- physical RRP - calculated in physical dispatch

47 The ESB considered that the access RRP was the preferred RRP choice, and this remains the AEMC’s preference between the two options. However, using the RRP from either dispatch can have downsides. Therefore, while the access RRP is preferred over the physical RRP, the ESB began considering in late 2023, whether an alternative implementation option could provide an RRP option that avoided issues with the two-stage dispatch RRPs.

48 This consideration has led to the identification of co-optimisation as an alternative implementation method for the CRM, which may provide a regional price that carries neither of the issues with the access RRP or physical RRP. We note that this co-optimised method has not been developed to the level of detail as the two-stage dispatch.

49 Co-optimisation refers to the two dispatches being carried out at the same time. This means that access dispatch can be set taking account of physical dispatch, and vice versa. In the current two-stage design, this influence only goes one way: access dispatch can affect physical dispatch but not vice versa.

50 Co-optimisation is used in today’s dispatch for energy and frequency control ancillary services

(FCAS). It is a conventional optimisation problem, with a single objective function which minimises the combined cost of the access dispatch targets and physical dispatch targets, and a set of constraints.

51 Under the co-optimised design, there is no choice of RRPs: there is just one RRP for settlement, which overcomes the problems with either choice of RRP from the two-stage dispatch.

52 Our view is that the theoretical benefits of co-optimisation do seem to have significant promise. In particular, it would mitigate the impacts of the access RRP (the preferable two-stage dispatch RRP) from priority access while also avoiding issues associated with the physical RRP, such as pricing inconsistencies for opt-out generators.

53 However, we also acknowledge that implementation costs would be higher than the current sequential dispatch method. AEMO have confirmed this with us, and so the benefits of the model would need to be higher to offset these costs.

54 We also recognise that there could be a perception that co-optimisation is less voluntary than the current lead model as CRM bids could affect or set the RRP that all participants face, including participants who do not opt into the CRM. We recognise that the voluntary nature of the lead model is a key benefit of the reform. Alongside this, there is the potential that bidding could be more involved. We are interested in stakeholder views on these issues.

55 The Commission is particularly seeking stakeholder views on these two alternative implementation options for the CRM. We are also seeking stakeholder feedback on detailed design choices for the CRM, noting that many of these have already been explored by the ESB.

Testing and modelling of transmission access reform

56 As for any major reform, it is appropriate to undertake quantitative analysis to assess whether the reform would have net benefits and so promote the long-term interests of consumers and contributing to emissions reduction targets.

57 There are three key exercises that have been undertaken, or we are currently undertaking, with this in mind. We are interested in stakeholder feedback on these three pieces of work, and we intend to discuss them with our technical working group members.

The ESB's cost benefit analysis showed greatest benefits come from a hybrid model

58 The ESB conducted a CBA to quantify the net benefits of transmission access reform, which was published in February 2023. The CBA found that the introduction of the hybrid model would result in quantified net benefits estimated at $2.1-5.9 billion. It also results in a reduction in emissions by 23 million tonnes over 20 years, which is quantified as a benefit of $1.6 billion. This results in an estimated total net benefit of $3.7-7.5 billion. The hybrid model also has the potential to reduce the cost of capital for generators.

59 The cost benefit analysis was undertaken at a point in time for the purposes of informing an assessment of access reform options against each other and the status quo. Concerns with specific elements of the cost benefit analysis in isolation have not, to date, provided sufficient evidence to suggest that:

- the broad, directional costs and benefits were not accurate,
- another access reform model should have been progressed ahead of the hybrid model,
- access reform in general should not be explored further.

60 The AEMC has consulted with and sought advice from government officials on key work items for

this review. Based on this advice the AEMC will not be undertaking a new cost-benefit analysis of the hybrid model for the reasons set out above. The high level analysis undertaken provides clear directional benefits, and we consider that redoing the cost benefit analysis would not provide significant, new information.

61 **We are seeking stakeholder views on the cost benefit analysis to the extent that it may inform the AEMC's recommendations for Ministerial consideration on a hybrid model that best meets the reform objectives.**

AEMO's testing with a NEMDE prototype shows an indication of potential outcomes from priority access if this was in place

62 In 2023, to understand the impact of implementing priority access in the NEMDE, a testing program was set up using AEMO's CRM prototyping. This is a full version of NEMDE that can be used to study how actual dispatch outcomes would have changed under different bidding regimes.

63 Previous testing results highlighted that a 'hard' priority approach could, in certain circumstances, lead to significant moves in the RRP and undesirable system outcomes like increased counter price flows.

64 The recent phase of testing shows that it is technically possible to use a soft priority approach. The findings show that soft prioritisation may allow for reduced cannibalisation compared to the status quo without significantly increasing the RRP. It also showed that there could be several unintended consequences including some increases in the access RRP relative to the current arrangements where new entrants cannibalise existing generators. It is worth noting that this testing was limited to considering historical dispatch intervals and treating certain existing generators as 'new entrants' by deprioritising them. The 'new entrants' were assumed to have connected in the congested area regardless of any reductions in dispatch and revenue due to priority access. In reality, they may have located in less congested parts of the network which could have resulted in different system outcomes (e.g. a lower RRP).

65 The AEMC is using this review to explore the extent to which the unintended consequences are cause for concern or could be addressed through alternative design choices.

66 Despite the unintended consequences appearing in the prototyping results, the AEMC considers the testing demonstrated that given the large expected "size of the prize" in terms of better investment efficiency, as well as improvements to the way generators can manage congestion risk, even capturing a small proportion of the benefit could be worthwhile.

67 **We are interested in stakeholder feedback on the prototyping results and views on how "firm" priority access needs to be in order to be effective and drive locational investment efficiencies.**

A current piece of work assessing how priority access may impact investor decisions

68 During the ESB's work on TAR, stakeholders noted that for priority access to achieve the reform objectives, prospective investors will need to be able to take account of the mechanism when building the business case for new investments. To answer this question, the AEMC has engaged ACIL Allen to complete a piece of work, investigating how congestion modelling contributes to the investment case of an intending participant. ACIL Allen will complete this work in two stages. The first stage of work will involve a written explanation of how congestion modelling is currently undertaken, and how priority access could be included in this modelling. The second stage of work will be the development of a simplified prototype model that compares generation development plans over a 20-year horizon with status quo arrangements and priority access and

the CRM.

69 We are interested in stakeholder's initial views on how modelling priority access would impact investment decisions.

We are also considering a number of key concerns with the model previously raised by stakeholders

70 There are a number of specific issues previously raised by stakeholders, which we are considering in the further development of the hybrid model. These include:

- **What is the impact of the hybrid model on PPAs?** Several stakeholders have expressed concern that introducing the hybrid model will result in participants having to reopen and renegotiate existing power purchase agreements (PPAs). Stakeholders have also expressed a concern that certain behavioural clauses commonly found in some PPAs may mean that introduction of the CRM could have unintended outcomes for some generators.
- **What is the impact of the hybrid model on financial markets?** Throughout the course of the ESB's consultation on the hybrid model, stakeholders including the Australian Financial Markets Association (AFMA), have raised questions around the impact of the proposed reforms on financial contracts and, more broadly, on financial markets. AFMA noted that its key concern related to proposals that could reduce the importance of the RRP as a price signal, or reduce liquidity in the market.
- **How will the priority access design incorporate constraints?** In response to the ESB's previous consultation on priority access, several stakeholders recommended that certain constraints – for example, outage, system strength or suddenly emerging stability constraints – be excluded from prioritisation to avoid unmanageable risks for investors. In the event prioritisation is introduced, it would no longer be the case that affected generators would 'share the pain' of these constraints equally. Rather, those generators who enter the market later and are assigned a lower level of prioritisation would be impacted to a greater degree than generators assigned a higher level of priority. These arrangements could increase investment risk compared to the status quo.

71 We have set out our initial views in relation to each of these questions as part of this consultation paper.

72 We are interested in stakeholders views on these questions and our initial responses.

Submissions are due by 6 June 2024 with other engagement opportunities available

73 Feedback from stakeholders on the proposed transmission access reforms will be crucial to informing and shaping our recommendations to Ministers in September 2024. There are multiple options to provide your feedback throughout the review process.

74 Written submissions responding to this consultation paper must be lodged with Commission by 6 June 2024 via the Commission's website, www.aemc.gov.au.

75 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. Interested stakeholders are also invited to participate in our transmission access reform technical working group (TAR TWG). The TAR TWG has been established with the first meeting held on 26 March 2024. The members list, meeting papers and

minutes are published on the TAR project page.[4] If you are not already a member, and would like to join the TAR TWG please contact the project team (details below).

76 Formal submissions received in response to this consultation paper, as well as stakeholder feedback gathered through the TWG and stakeholder meetings will inform our next stage of work. This includes making detailed design choices to recommend a hybrid model we consider best meets the reform objectives, as well as ongoing testing and implementation planning.

77 As noted in section 1.4.1, the AEMC will also be collaborating with the AER and AEMO to progress the detailed design of this reform, and we intend to continue engaging broadly with stakeholders beyond those in our TAR TWG as we develop our final recommendations for Ministers.

How to read this document

78 Transmission access reform has been the topic of discussion in the NEM for many years. There have been a number of processes led by a different organisations over that time and we note that stakeholders have had different levels of engagement in each of these processes. We also acknowledge that stakeholders have diverse views, and that these may have evolved over time.

79 This review, requested by Energy Ministers, builds on the work and stakeholder engagement undertaken by the ESB and EAP over the course of 2023. This consultation paper seeks to outline the work to date and current design with the purpose of seeking meaningful feedback from stakeholders to progress a design of the hybrid model that best meets the reform objectives.

80 The paper is written for a range of audiences and aims to provide information for stakeholders engaging at all different levels. To help stakeholders in navigating the paper, below is a summary of what each chapter seeks to achieve:

- **Chapter 1 – Problem and drivers for reform:** This chapter outlines the problem with current access arrangements in the NEM, the benefits that can be achieved by reforming them, the task that the AEMC has been asked to do with this review, how it links with related reforms and the forward work plan.
- **Chapter 2 – The hybrid model is the current preferred option for access reform:** This chapter provides some of the history of access reform discussions in the NEM, and explains the differences between previous models and the hybrid model that is the focus of this review. Specifically, the key role stakeholders have played in proposing and informing the design of the hybrid model.
- **Chapter 3 – Testing and modelling access reform:** This chapter summarises the ESB's cost benefit analysis, and AEMO's prototyping work to test priority access in NEMDE.
- **Chapter 4 – Priority access:** This chapter outlines the priority access model and seeks stakeholder views on grouping options that could be used to allocate priority.
- **Chapter 5 – Congestion relief market:** This chapter outlines the CRM and seeks stakeholder views on two different implementation approaches - a two stage dispatch and co-optimised dispatch.
- **Chapter 6 – We are considering a number of key concerns raised by stakeholders:** This chapter responds to three key stakeholder concerns with the hybrid model; impact on power purchase agreements (PPAs), impact on financial markets, and how the model incorporates wide-reaching constraints. It seeks stakeholder feedback on these.

4 The Transmission access reform project page can be accessed here.

- **Chapter 7 – Each variant raises detailed design questions:** This chapter seeks stakeholder feedback on a range of more detailed design options for both priority access and the CRM, noting that the ESB already consulted on some of these.
- **Chapter 8 – Making our recommendations:** This chapter reiterates the transmission access reform objectives developed by the ESB in consultation with stakeholders and agreed by Ministers and links these to the national electricity objective (NEO) which guides the AEMC's work overall. The hybrid model we recommend to Ministers must achieve these objectives.
- **Appendix A – Case for reform:** This appendix sets out the issues caused by the current NEM transmission access arrangements, the reasons reform is needed and the benefits that will flow from reforms.
- **Appendix B – Testing priority access using a prototype:** This appendix outlines the approach to testing priority access using a NEMDE prototype. It details the results of this testing.
- **Appendix C – Detailed CRM design decisions in the two-stage model:** This section explains the options and preferences for a number of design details for the CRM, many of which have been consulted on previously by the ESB.
- **Appendix D – Worked examples of the hybrid model:** This section sets out several worked examples of dispatch outcomes in the existing market arrangements and under the hybrid model. These are simplified examples to illustrate the broader impacts on dispatch outcomes.
- **Appendix E – Glossary and abbreviations:** This glossary includes information on a number of key terms that are important when explaining transmission access reforms. Some of these terms have changed compared to previous processes and the reasons for this are explained. A list of relevant abbreviations is also included.

Full list of consultation questions

Question 1: Feedback on cost-benefit analysis conducted in 2023

What are stakeholder views on the cost-benefit analysis?

Question 2: Feedback on prototyping

What are stakeholder views on the result of the prototyping analysis? Is there any additional analysis that would be useful?

Question 3: Feedback on modelling the hybrid model

Noting that this work is still being completed, do stakeholders have any initial views on how modelling priority access would impact investment decisions?

Question 4: Assessment of priority access allocation models

Each model option outlined in this section addresses the problem and reform objectives to different degrees.

Which model option do you prefer and why?

Question 5: Assessment of CRM implementation approaches

What are the relative advantages and disadvantages of each design?

Do stakeholders have a preferred design and if so, why?

Question 6: Feedback on impact of the hybrid model on PPAs

What are stakeholder views on the observations and AEMC initial views regarding impacts of the hybrid model on PPAs?

Question 7: Feedback on impacts of the hybrid model on financial markets

What are stakeholder views on the impacts of the hybrid model on financial markets? Specifically:

- How the proposed access model, or particular aspect(s) of the model, may impact their ability to manage price risk in the market?
- The subsequent impact that a reduced ability to manage price risk may then have on participants' hedging costs.

Question 8: Feedback on wide-reaching constraints

Do stakeholders consider that priority access could increase investment risk due to wide-reaching constraints?

Do stakeholders consider that there is value in implementing the dynamic grouping option for priority access to mitigate this concern?

Question 9: Feedback on detailed priority access design choices

What are stakeholder views on the detailed priority access design questions and the AEMC's preferred positions?

Question 10: Feedback on detailed CRM design choices

Do stakeholders have further views on the detailed design choices for the CRM that were explored by the ESB? Are these views related to a preference for a two-step or co-optimised implementation approach discussed in chapter 5?

What are stakeholder views on tethering, including the relative advantages and disadvantages of each design and any preference?

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the recommendations by participating in the review process. Engaging with stakeholders helps us understand the potential impacts of our recommendations and, in so doing, contributes to well-informed, high quality review recommendations.

We have included questions in each chapter to guide feedback, and the full list of questions is above. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by **Thursday 6 June 2024**.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **EPR0098.**[5]

Tips for making submissions are available on our website.[6]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[7]

For more information, you can contact us

Please contact the project leader with questions or feedback at any stage.

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5 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

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

7 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission

Contents

Appendices

Tables

Figures

1 Problem and drivers for reform

The 2024 Draft Integrated System Plan (ISP) forecasts a seven-fold increase in grid-scale wind and solar capacity and 19-fold increase in storage capacity between 2024 and 2050.[8] A significant pipeline of large-scale renewable generation and storage is driving a wave of major new transmission projects to transport the electricity produced to market. This is particularly important as the National Electricity Market (NEM) replaces most of its ageing power stations over the next 20 years. Governments are:

- getting involved to deliver some of this new investment over the next several years via Rewiring the Nation, the Commonwealth Capacity Investment Scheme (CIS) and various jurisdictional government initiatives,
- seeking to promote more co-ordinated development by establishing renewable energy zones (REZs) and accompanying reforms within their regions.

Issues regarding the current transmission access arrangements in the NEM (described further below and in appendix A) have been evident for several years. Over time, significant work has been undertaken by various bodies to address current problems.

It is in this context that Energy Ministers have also had an active work program over the past several years on the complex issue of transmission access reform. In February 2023, Energy Minsters agreed that the Energy Security Board (ESB) should develop the voluntary congestion relief market (CRM) and the priority access model, noting that (at the time) the reforms would yield net benefits for industry and consumers of up to $5 billion NPV and lower emissions by 23 million tonnes by 2050.[9] This was further reinforced by Energy Ministers in November 2023, when they agreed to continue to progress the agreed transmission access reform work through further design, having considered advice from the Energy Advisory Panel (EAP) and stakeholder engagement.[10]

To progress this work, it was agreed by Energy Ministers that the Australian Energy Market Commission (AEMC or Commission), working collaboratively with the Australian Energy Regular (AER) and Australian Energy Market Operator (AEMO), will progress the agreed transmission access reform and congestion management initially progressed by the ESB, through further design work. Accordingly, the AEMC has initiated a review to progress the design of the hybrid model for transmission access reform to make final recommendations to the Energy Ministers in accordance with the Terms of Reference published by the AEMC.[11]

This chapter outlines:

- the benefits to be achieved with transmission access reform by effectively and efficiently managing congestion as the NEM transitions,
- the objectives for transmission access reform to provide benefits over investment and operational timeframes,
- the current preferred model that the AEMC will continue to develop, as agreed by Energy Ministers,
- how transmission access reform is complementary with other policy mechanisms,
- the forward work plan for this review.

8 An overview of the 2024 Draft ISP can be found here.

9 Energy and Climate Change Ministerial Council, Meeting Communique, Friday 24 February 2023.

10 Energy and Climate Change Ministerial Council, Meeting Communique, Friday 24 November 2023.

11 The Terms of Reference can be found here.

1.1 There are large benefits to be achieved by transmission access reform

The transition to net zero means a physical transformation of the electricity system.

Congestion is a normal, everyday feature of an efficiently sized transmission infrastructure to accommodate variable renewable energy (VRE). We need to upgrade and augment our transmission network to meet our future energy needs. However, eliminating all congestion would involve building a huge transmission system, which would be prohibitively expensive. Instead, it is more cost effective to build a smaller system and manage congestion by efficiently rationing which generators get to use the system.

As we move to a weather dominated power system, congestion will continue as a feature - we are seeing this worldwide in other energy systems. Active management of congestion in the system (rather than eliminating all congestion) is the best way to make sure that the transmission infrastructure is used effectively, and that consumers get the best value from it.

AEMO's 2024 draft ISP forecasts that congestion will continue to increase as part of its optimal development path, even after the actionable ISP projects are built.[12] By 2050, the economic spill and curtailment of the approximately 126 GW of available VRE is forecast to be between 10% and 20% annually.

Modelling by AEMO and transmission network service providers (TNSP) does not take into account the problems with the current access regime[13], so in practice these levels of congestion can be considered the best case scenario. In the absence of reform, actual levels of curtailment are likely to exceed the levels forecast in the ISP. Higher than expected congestion will increase costs for consumers by requiring more transmission build than is necessary, as well as increasing the operational inefficiencies in the system.

We expect that congestion will be further exacerbated by a number of matters in the future, including the following:

- **Increasing costs of transmission:** As transmission costs rise, it will become more expensive to upgrade and build new, large-scale transmission assets. The changing economics may result in the efficient level of congestion in the NEM increasing in the future (i.e. when incurring more congestion is cheaper than expanding the network).
- **Supply chain challenges:** The NEM is experiencing challenges regarding timely transmission build, with global supply chain constraints, skilled labour shortages and social license issues leading to delays in the delivery of projects. These delays can result in higher congestion.
- **Planning frameworks and generator incentives:** The ESB has also previously noted the disconnect between current transmission planning frameworks and generator investment incentives without transmission access reform, meaning that generators may not coordinate their locational decisions with planned transmission investment. This may result in congestion being higher than forecast.
- **Recent changes in generation and storage costs:** Battery storage is becoming a leading option for firming in the NEM, and it has always been a technology that benefits substantially from efficient locational investment signals, which are not provided under the current market design. Similarly, large pumped hydro projects are being progressed by governments, and these need the dispatch price signals provided by access reform to operate efficiently. With the current arrangements, these technologies are not rewarded for alleviating congestion and

12 AEMO's webpage for the 2024 ISP can be found here.

13 It typically assumes bidding at cost, rather than disorderly bidding, which is likely to underestimate the scale of the problem.

delivering system benefits, and as such investment in, and build-out of, these technologies may be inefficient.

Congestion needs to be carefully managed when it prevents the least cost combination of generation resources from being dispatched. Congestion arises when a higher cost generator in one location must be used instead of a lower cost one at another location, because of the physical limits of the transmission network and the relative locations of the generators. Dispatching higher cost generation often has a dual disbenefit of higher costs and higher emissions, since they are sometimes non-renewable generators.

In today's market design, generators do not face the costs they impose on third parties, when, because of their use of the transmission network, another generator is curtailed. The party taking the action has no reason to ensure costs are minimised, because the costs are borne by somebody else. Similarly, because storage and flexible loads are not paid for the benefits they provide when charging and helping to alleviate congestion, their incentive to do so is diminished. The inefficiencies created by the current regime are described further in appendix A.

Having a transmission planning and investment framework to build new transmission that is effective, timely, and provides additional checks and balances for consumers, is an important component of the NEM. The AEMC recently completed a comprehensive review of this regime and recommended several proposed changes, some of which have been implemented and others still being progressed via AEMC rule changes.[14] However, once the transmission network is built, it is important that the infrastructure is used effectively, and congestion is best managed.

Also, it is important to effectively manage congestion is having information available about congestion, so that this can be taken into account by market participants as well as network service providers, when considering what new transmission infrastructure is required, and where. Recent reforms on enhancing locational information – as discussed further below – have sought to increase information to the market about transmission congestion.

However, while both of these reforms – to transmission planning and investment, and transparency of information – are important for the transition, neither are substitutes for broad transmission access reform.

Without reforms to transmission access, as recognised by Energy Ministers, the following problems will continue as the transition to net zero progresses:

- Solar and wind investments will face increased congestion and not be effectively utilised, which may mean emissions reduction from renewable resources are not fully realised.
- Renewable energy zones (REZs) may be undermined by generators located outside the zone, free riding on investments intended for REZ participants.
- Storage (e.g. batteries) and flexible demand (e.g. hydrogen) will not be rewarded for congestion-alleviating behaviour that benefit customers, and their user case will be diminished.
- The value of investment in interconnectors may not be fully realised.
- Customers (or taxpayers) may pay extra for additional transmission to be built.

Ultimately, these problems and inefficiencies will increase costs to electricity consumers.

14 AEMC, Transmission Planning and Investment Review, found here.

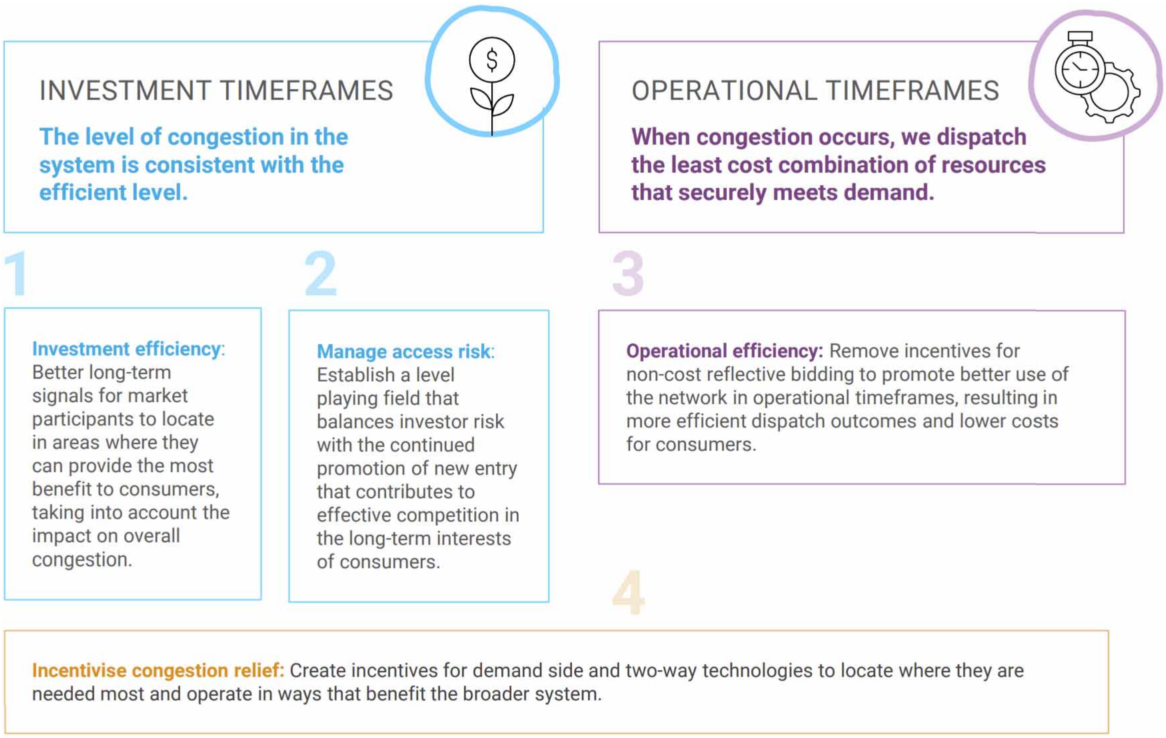
1.2 Transmission access reform objectives

The ESB, in consultation with stakeholders developed four transmission access reform objectives, which have been agreed by Energy Ministers and which continue to underpin the AEMC's work to progress development of the hybrid model:

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. **Access risk:** Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to efficient competition in the long-term interest of consumers.
3. **Operational efficiency:** Provide incentives for 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. **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.

These reform objectives will provide benefits over investment timeframes as well as operational timeframes.

Figure 1.1: Transmission access reform objectives



1.3 The hybrid transmission access model is the preferred model

Transmission access reform has been considered by the ESB over the past few years. In February 2023, Energy Ministers agreed to a lead model – a hybrid model combining the CRM originally proposed by Edify Energy and the priority access model originally proposed by the Clean Energy Investor Group. At the same time, Ministers decided not to further develop or consider the congestion management model and congestion fee options, ruling out any models using locational marginal pricing.

The CRM model aims to improve operational efficiency while priority access aims to improve investment efficiency. The hybrid model, by integrating the two, address the transmission access reform objectives:

- Priority access provides a locational signal for investment efficiency and enables investors to manage congestion risk more effectively. A generator or storage facility would be assigned a priority level up front which is factored into the project's investment and siting decision.
- The CRM provides voluntary incentives for generators to bid more cost effectively and achieve a more efficient dispatch. It also incentivises storage and demand response providers to locate and operate where they can relieve congestion, with benefits to the system. The way the CRM operates ensures that the access of existing generators is broadly unchanged.

As a standalone solution, priority access does not address today's issues of dispatch inefficiency and it may introduce new inefficiencies to the energy market where priority levels override constraint coefficients. The hybrid model achieves a net efficient outcome. The CRM is key to incentivise trades between participants and achieve an efficiency gain (compared to both the status quo and the priority energy dispatch). While each model could be implemented individually, the two are being considered together at this stage. We welcome stakeholder comments on how their views may change if only one, rather than both, reforms were to be implemented.

1.4 Drawing on previous ESB and EAP work, the AEMC has been asked to further develop the hybrid model

In late 2024, Ministers agreed that the AEMC should continue development of the hybrid model in 2024, drawing on all previous work from the ESB and Energy Advisory Panel (EAP). Under section 45 of the National Electricity Law (NEL), the AEMC initiated a review to underpin this work by publishing Terms of Reference and project plan.[15]

The purpose of this review is to provide final recommendations to Energy Ministers on a design of the hybrid model that best meets the reform objectives.

In undertaking the review, the AEMC will do the following in line with the Terms of Reference:

- build on the design of the model that was developed by the ESB,
- consult with market participants, industry, consumers, the AER, AEMO, and government officials, as appropriate to form these final recommendations,
- develop final recommendations that comprise design specifications for a hybrid model that best meets the reform objectives as articulated above.

The matters that the AEMC will specifically consider and progress in developing its final recommendations are:

- the development and final design recommendations for both the priority access and CRM components of the hybrid model,
- in relation to priority access, consideration of four approaches for priority access could be allocated:
    - queue allocated by time with annual grouping
    - queue allocated by time with annual grouping and preferential treatment to REZs

15 The TAR project page can be found here.

    - two-tiers with prioritisation allocated by jurisdictions or a central body
    - queue allocated by time with grouping into two-tiers determined dynamically
- whether a further modification to consider a co-optimised dispatch model for implementing the hybrid model would better meet the objectives, and if so, what the implications would be for key design components
- the development of a simple, stylised network model for stakeholders to interact with and improve their understanding of the hybrid model
- key stakeholder concerns and issues, including:
    - the timing of priority access allocation to generators and how this would impact investment decisions and the connection process
    - the ability to meaningfully model priority access to support an investment case
    - setting out the prototype testing and work to date
    - prioritisation and the impact of certain constraints
    - power purchase agreements (PPA) impacts from the implementation of the hybrid model
    - financial market impacts of the hybrid model.

Stakeholders have diverse views on these issues and, to be fully informed, stakeholders need to have access to clear information on the reforms and their impacts, uncovered by existing and ongoing analysis and modelling. This consultation paper seeks to outline the work to date and current design, with the purpose of seeking meaningful feedback from stakeholders to progress a design of the hybrid model that best meets the reform objectives.

The AEMC will also be collaborating with the AER, AEMO, jurisdictions and the TAR TWG throughout the process, and we intend to continue engaging broadly with stakeholders beyond those in our transmission access reform technical working group (TAR TWG), as we develop our final recommendations for Ministers.

1.4.1 Ministers have tasked the AEMC to collaborate with the AER and AEMO and consult with stakeholders

As agreed by Ministers, the AEMC will collaborate closely with the AER and AEMO in the development of the reforms. To this end, the AEMC:

- is updating the EAP at each of its quarterly meetings with an update on key areas of work and key themes it is hearing from stakeholders, in order to receive feedback,
- will accompany its final advice with letters from heads of AEMO and AER setting out their views on the final recommendations,
- has set up executive-level and staff working groups that comprise market bodies to facilitate productive collaboration.

We are also undertaking public consultation on this review. This includes:

- seeking stakeholder feedback in this consultation paper on the current design of the hybrid model by setting out test case analysis, current design and design options of priority access and the CRM,
- consulting through regular meetings with the TAR TWG,
- providing regular updates to senior officials through the National Energy Transformation Partnerships transmission working group.

We will provide a report to Energy Ministers with our final recommendations on the design of the hybrid model by September 2024, including a summary of stakeholder feedback.

1.5 Transmission access reform is complementary with other policy mechanisms

If implemented, transmission access reform (TAR) would be complementary with other policy mechanisms. In particular, TAR would:

- complement the enhanced information reform, agreed by Ministers in February 2023 to collate existing locational information for improved clarity of locational signals,
- provide long-term investment signals that extend beyond the timeframe of other short-term policy mechanisms such as the CIS.

Importantly, TAR will need to complement jurisdictional REZ schemes. TAR should help facilitate the development of, and investment in, REZs. On investment timescales, TAR should help promote investment certainty and manage access risk in REZs, while simultaneously ensuring dispatch efficiency on operational timescales.

We are working with jurisdictions so that jurisdiction-specific initiatives to support the development of REZs can dovetail with any national transmission access reforms that are progressed. We do not consider that there would be any overlap or conflicts between TAR and other policy mechanisms or reforms. This further enforces the need for TAR to address the previously discussed drivers for reform.

1.5.1 Transmission access reform would complement the consolidation of existing locational information

In February 2023, Energy Ministers agreed to immediately implement 'enhanced information' reforms to provide NEM participants with better information on the optimal locations for new generation and storage. This enhanced information reform came from the ESB's work program on transmission and access, which simultaneously developed the hybrid model.[16]

The ESB published a final decision paper in June 2023 that proposed AEMO will consolidate existing sources of locational information.[17] These sources of locational information include Transmission Annual Planning Reports, system strength charges, Marginal Loss Factors, and REZ scorecards from the ISP. Locational information and an accompanying dataset would be published annually in an enhanced locational information report. AEMO is expecting to publish their first enhanced locational information report in May 2024.[18]

The development and implementation of the hybrid model for TAR would be complementary to the enhanced information reform. The enhanced locational information report will be useful at collating locational information for investors to initially consider where the optimal locations might be to build assets. However, TAR is needed to provide stronger incentives for, and directions to, investors to build in the optimal locations.

1.5.2 Transmission access reform will provide long-term investment signals

TAR would provide long-term market signals to drive more efficient locational investment decisions and operational outcomes. We consider that this would be complementary to other policy mechanisms such as the Commonwealth's Capacity Investment Scheme (CIS). The CIS is designed to provide revenue underwriting to successful CIS tender projects, thereby helping provide new investment in renewable capacity and clean dispatchable capacity.

16 The ESB project page for transmission access reform can be found here.

17 ESB, Transmission access reform - enhanced locational information, June 2023, found here.

18 AEMO's webpage for enhanced locational information can be found here.

The CIS currently involves the running of competitive tenders until 2027 and, without a further expansion of the CIS, would only provide investment signals for new investment in the short-term. As outlined in DCCEEW's recent CIS design paper, part of the assessment for CIS projects will consider system benefits, including the delivery of renewable energy where a project's technology type, capacity factor and (notably for transmission access reform) location will be relevant.[19]

Transmission access reform would provide long-term investment signals and is unlikely to be implemented before 2027.[20] Furthermore, priority access and the CRM would provide investment signals to all market participants in the NEM.

Therefore, we consider that transmission access reform and the CIS would complement each other, without significant overlap, to incentivise and coordinate new investment in the NEM. As flagged in the DCCEEW CIS design paper, any access reform will apply to any projects supported by the CIS.[21]

1.5.3 Transmission access reform would support and prioritise jurisdictional REZs

Transmission access reform is aimed at complementing the introduction of REZs in the NEM. Priority access provides a clear mechanism to support the delivery of REZs. Priority access can be reserved for REZs to support the coordination of generation and transmission investments. It can also 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 will enable REZ developments and associated resources to be used effectively and minimise costs for consumers.

The role of a central planner involved in managing connections within a REZ means that priority access may not be needed to manage the risk of cannibalisation between generators participating in the same REZ.

Overall, transmission access reform would help provide certainty to investors locating in REZs, while also providing an incentive to locate in a REZ and 'skip the queue' by inheriting the REZ priority level.

A number of jurisdictions are pursuing jurisdiction-specific access schemes or other arrangements to manage investment risk in REZ's in the near term. However, the AEMC is working closely with all jurisdictions so that any reforms recommended to Ministers would complement and support such jurisdictions-specific arrangements.

1.6 Forward work plan

At the November 2023 Energy and Climate Change Ministerial Council meeting, Energy Ministers agreed to progress the agreed transmission access reform and congestion management through further design work, having considered advice from the EAP and stakeholder engagement.

The AEMC has published a project plan outlining how we intend to progress the work and thinking already done by the ESB and EAP.[22] Key activities include the following:

- **This consultation paper:** We are seeking stakeholder feedback on:
  - key elements of the design of the hybrid model where these have not yet been settled,

19 DCCEEW, Implementation Design Paper: Capacity Investment Scheme, February 2024, p.29.

20 Previous indication by the ESB in February 2023 suggested that the earliest implementation date was the end of 2027, however this will need to be reviewed and updated to reflect the current progress and design of the hybrid model.

21 DCCEEW, Implementation Design Paper: Capacity Investment Scheme, February 2024, p.11.

22 The project plan, published on 7 March 2024, can be found here.

    - previous work including the 2023 cost benefit analysis and prototyping results,
    - our responses to stakeholder concerns raised in the previous stages.
- **Modelling priority access:** We have engaged ACIL Allen to model priority access and investigate how it would impact on investment decisions. See more in section 3.3.
- **Stylised network model of the reform:** We will be developing a stylised network model to be shared with stakeholders. This will be a relatively simple model of the network incorporating the hybrid design for priority access and the CRM. Stakeholders will be able to interact with it, to test how dispatch and settlement outcomes can vary under different circumstances. We consider that this network model will be important in improving stakeholder understanding of the proposed reform. This would allow stakeholders to better consider the impact of the reform and how it might affect the NEM. We will engage with the TWG and other interested stakeholders as we have more information to share in coming months.
- **Technical working group:** We have established through an open expression of interest process, a TWG comprised of diverse stakeholder representatives. This group has been established to act as a sounding board for our thinking on the design of the hybrid model. The AEMC meets monthly as set out in the project plan and more often as required.[23]
- **Jurisdictional workshops:** We are engaging with jurisdictional officials regularly to seek views and ensure alignment with government initiatives seeking to support a smooth transition.

These activities will assist the AEMC in progressing the hybrid model to the fullest extent possible, before reporting back to Ministers with final recommendations.

Following consideration of these final recommendations, Energy Ministers will make a decision as to whether to implement the hybrid model.

If a decision is made to proceed, a detailed implementation phase including the development of draft rules and consultation on these, would commence in 2025.

23 See TAR project plan on the AEMC website here.

2 The hybrid model is the current preferred option for access reform

Over the last decade, the AEMC and ESB have explored many alternative designs to reform the NEM's access regime, including the model known as Coordination of Generation and Transmission Investment (COGATI) after the name of the review which developed it, and the Congestion Management Model (CMM).

To understand why the hybrid model is now favoured by Energy Ministers, it is useful to compare it to these historically considered models. Chapter 3 also explores the most recent work undertaken by the ESB and EAP to test the hybrid model.

2.1 Previously considered reform options were based around a generic access model

At their heart, the prior transmission access reform models previously considered share many common features. For scheduled market participants, they *decouple* access from physical dispatch. For unscheduled market participants (e.g. most load) settlement would remain unchanged.

In each case, scheduled market participants' physical dispatch would be settled at the local price (known as the congestion relief price, or CRMP), while access would be purely financial, settling at the difference between the RRP and CRMP. RRPs and CRMPs differ in the presence of congestion.

1. Revenue (current NEM) = physical dispatch x CRMP + physical dispatch x (RRP – CRMP), becomes
2. Revenue (access reform) = physical dispatch x CRMP + *financial access* x (RRP – CRMP)

Settling physical dispatch at the local price removes the incentive for disorderly bidding, and so, corrects the inefficient dispatch problem.

The quantity of financial access would be allocated through a process that is separate from physical dispatch. By design, existing generators' financial access would not be reduced (cannibalised) by an incoming generator, which provides generators with a hedge against congestion. Incoming generators would have to (or would have had the option to) pay for financial access. Access in congested areas – where the difference between the RRP and CRMP is high and/or frequent – would command a higher price than access in an uncongested area, incentivising generators to locate in uncongested areas.

As a result, all these alternatives solved the fundamental problems with the existing regime: inefficient dispatch, inefficient investment and congestion risk.

2.1.1 Some features present in generic access models have raised concerns from stakeholders

However, each alternative was deeply controversial with stakeholders. Accordingly, in response to stakeholder feedback, Energy Ministers dismissed these options, including locational marginal pricing and the congestion management model, and the ESB further developed two models proposed by industry. The hybrid model seeks to resolve stakeholder concerns with the previous models, being:

1. Designing the CRM as an opt-in mechanism: If access quantities and physical dispatch are different, then generators are exposed to two different prices. This increases complexity and creates implementation and transaction costs. These may be particularly acute for generators

that hold contracts that hedge against the current regional price which, therefore, might need to be reopened. The hybrid model is designed so that participants opt-in, meaning that they can choose if they want their access and physical dispatch quantities to be different or not.

2. Allocating access consistent with the status quo: moving to a different access model may lead to generators' level of access being set differently compared to the status quo. They may be required to pay for this access, creating winners and losers. To encourage investment, it is a common principle in public policy that regulatory interventions do not substantially disrupt the allocation of value between existing market participants. The hybrid model is designed to allocate access to the transmission network in the same way as the status quo, so as not to substantially disrupt the allocation of value between existing market participants.

2.2 The current era of access reform has been underpinned by stakeholder proposals

The ESB's development of the hybrid model was underpinned by stakeholder proposals for access reform models. The CRM was proposed by Edify Energy and the Clean Energy Council (CEC), while priority access was proposed by the Clean Energy Investor Group (CEIG).

2.2.1 Edify Energy and the Clean Energy Council (CEC)'s congestion relief market

In 2021, Edify Energy proposed an alternative to the then front-running congestion management model for transmission access reform, known as the congestion relief market (CRM). This model was refined by the CEC.

As originally described, generators would bid into the existing energy market as now, and then be able to voluntarily trade 'congestion relief', settled at the CRMP, to profitably increase the efficiency of physical dispatch. Physical dispatch would be the original energy dispatch, plus or minus any change as a result of congestion relief trades.

What Edify labelled as the existing energy market, we now call the 'access dispatch', to accurately reflect that it is determining financial access. Physical dispatch, settled at the CRMPs, is separately determined as a consequence of congestion relief trades.

Critically, the CRM's design also seeks to address the two long-standing concerns with previous access reform models:

1. The operation of the CRM is voluntary, meaning that generators can opt-in to the CRM which allows their physical dispatch (the amount AEMO requires them to produce) to be different to their access dispatch. If a generator does not opt-in to the CRM, then their physical dispatch will be identical to their access dispatch, meaning that all of their output is settled at RRP, and none at CRMP. This means that generators who choose not to participate in the CRM, can reduce implementation costs (including costs associated with renegotiating contracts) for those generators who choose not to participate (albeit they miss out on the incremental trading opportunities afforded by the CRM).
2. Because access is allocated in a process similar to today's (coupled energy + access) dispatch, the financial access is allocated in broadly the same quantity as today. This reduces the winners and losers arising from the reforms.

2.2.2 Clean Energy Investor Group (CEIG)'s priority access model

The priority access model has its roots in a proposal from the CEIG. CEIG proposed that generators would receive prioritised access depending on their chronological order of entry to the market. This would address the cannibalisation problem by ensuring the access of prioritised generators is not impacted by generators connecting later.

This idea was proposed independently of the CRM. A key issue with this concept (when considered in isolation from the CRM) is that *access* is currently coupled to physical dispatch. Prioritisation of access under the status quo would also come with linked prioritisation of physical dispatch, which would likely reduce dispatch efficiency.

2.2.3 ESB's hybrid model

The ESB worked with stakeholders to develop a hybrid model that combines priority access with the CRM to improve both operational and investment outcomes.

- **The priority access model:** This prioritises financial access to RRP (without prioritising physical dispatch), based on chronology of entry, and so addresses the "cannibalisation" problem, whereby entrants can profitably locate in congested areas, by taking access from incumbents.
- **The CRM:** This provides grandfathering of existing access to RRP, incentives for cost-reflective bidding and efficient dispatch, and the voluntary opt-in nature allows management of exposure to local prices (congestion relief market prices or CRMPs) if it is problematic for existing trading or contractual arrangements.

This hybrid model forms the basis for the AEMC's continued work on TAR. The hybrid model has been chosen by Energy Ministers as the lead model for transmission access reform in the NEM.

2.3 Stakeholders have also informed the design of the hybrid model

The ESB sought stakeholder feedback throughout the development of the hybrid model. The most recent public consultation was through a consultation paper published by the ESB in May 2023.[24] That consultation paper outlined the current status of the hybrid model and sought stakeholder views on design choices for both priority access and the CRM. Stakeholder submissions to the consultation paper informed the EAP's development of the hybrid model over the second half of 2023.

At the end of 2023, the EAP also conducted a round of stakeholder engagement sessions with peak bodies, jurisdictions and individual stakeholders. The AEMC and the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW) also held a stakeholder forum in early December 2023. These sessions aimed to provide an update on the current status of the reforms, as well as to inform stakeholders about the next steps for the reform.

At these sessions, the EAP discussed five key questions that stakeholders had on the reform regarding the hybrid model. These were:

- Can investors meaningfully model priority access to support investment cases consistent with the reform objectives?
- How would prioritisation interact with unforeseen and wide-reaching constraints compared to the status quo?
- How would the hybrid model impact existing power purchase agreement (PPA) contracts?
- How would the hybrid model impact the broader financial market for electricity?

24 ESB, Transmission access reform - consultation paper, May 2023, found here.

- How would the specific timing to allocate priority access impact investment decisions and the connections process?

Seeking meaningful answers and resolution to these questions is a clear priority for this stage of work.

2.4 The hybrid model has the potential to deliver a range of benefits

In theory, the hybrid model should deliver benefits against the reform objectives. We consider that it has the potential to:

- improve locational signals for new investment,
- address cannibalisation,
- stimulate operational efficiency,
- incentivise scheduled storage and load to alleviate congestion.

Worked examples of how the hybrid model could deliver these benefits are shown in appendix D.

2.4.1 The hybrid model would improve locational signals for new investment

The hybrid model would provide clearer locational signals for new investment, such that assets are incentivised in locations where they are valuable and contribute to minimising the total cost of the energy transition. Both priority access and the CRM would contribute to this outcome. This would lead to a more efficient build-out of generation and load assets, and transmission infrastructure by ensuring that:

- participants face corresponding costs if their investment decisions cause inefficient congestion,
- participants, who locate when and where spare capacity is available, are protected from later connection and cannibalisation risks.

2.4.2 The hybrid model would address cannibalisation

The hybrid model would address investment risks to new generation from cannibalisation in congested areas.

In particular, priority access is aimed at offering protections to generators from being cannibalised by subsequent investment. This means that newer generators would be less able to cannibalise incumbent generators and may locate elsewhere, such as uncongested areas of the grid.

This would provide greater investment certainty to generators at risk of cannibalisation that they will be protected from cannibalisation risk, while also providing greater certainty and incentives for investors to enter and connect in less congested areas of the network. The result is longer-term cost efficiency for stakeholders.

2.4.3 The CRM would stimulate operational efficiency

The hybrid model, particularly the CRM, would incentivise participants to bid for physical dispatch in a way that reflects their underlying cost of generation. While bidding to the floor price to maximise dispatch is a common strategy under the current arrangements for congested generators (because it is unlikely to materially affect the RRP), the CRM would encourage generators to bid more cost-reflectively in the CRM to trade congestion and have profit-maximising outcomes.

As a result of more cost-reflective bidding, operational efficiency would be improved as the dispatch engine would be able to physically dispatch a mix of generation and storage that is closer to the least-cost generation mix in each trading interval. A more operationally efficient dispatch will ultimately lower prices for consumers.

2.4.4 The CRM would incentivise scheduled storage and load to alleviate congestion

The hybrid model, in particular the CRM, would incentivise and reward storage and load who wish to participate in the CRM for alleviating congestion when and where it is most valued. Scheduled loads participating in the CRM can be exposed to their local CRM prices, which would be lower than the RRP if and when they are located in a congested area. Therefore, scheduled load can pay less for their consumed energy while alleviating congestion. This would improve system-wide efficiency compared to the current arrangements, as extra low-cost energy in a congested area can be generated and consumed by load/storage instead of not being produced at all.

For two-way technologies such as batteries and pumped hydro, if they choose to participate in the CRM they could increase their potential intra-day price spread and subsequent profit. For example, these technologies could charge at low CRM prices when their local transmission network is congested (e.g. in the middle of the day near multiple solar farms away from a load centre), then discharge at higher RRPs when demand is high and transmission is uncongested (e.g. during the evening peak or night).

2.5 Achieving these benefits would in turn achieve the reform objectives agreed by Ministers

In the ESB’s previous papers on transmission access reform, these benefits have been described as the case for change. Whether described as benefits, or a case for change, these points demonstrate the benefits that could be delivered by transmission access reform to support an orderly transition by providing optimal investment signals to facilitate efficient investment in, and operation of, generation, storage, and transmission.

It will be important to balance the need to provide improved revenue certainty for current investments against the need to incentivise cheaper, new entrant technology in the future, to promote effective competition in the wholesale market over the long-term. Access reform options all require difficult trade-offs. However, failing to act means accepting that the energy transition will be less orderly and more expensive for customers.

Furthermore, transmission access reform would contribute to the NEO by promoting efficient investment in, and efficient operation and use of, electricity systems for the long-term interests of consumers and contributing to emission reduction targets. TAR would also benefit investors and governments at reducing investment and operational inefficiencies.

3 Testing and modelling of transmission access reform

A key question in any reform in the NEM, is whether the reform would have net benefits and promote the long-term interests of consumers and contributing to emission reduction targets. Both qualitative and quantitative analysis can be used to inform this assessment. It is important to consider any such analysis both in the theoretical sense (as described in chapter 2), as well as in the practical.

In relation to quantitative analysis, there are three key exercises that have been undertaken, or are currently being undertaken, with this in mind. Each exercise provides some – but not all – of the information that is required to assess this, and so the information should be assessed as a whole, bearing in mind the information and limitations that each modelling approach provides.

This chapter sets out this modelling for stakeholder feedback, notably:

1. the ESB's cost benefit analysis showed greatest benefits come from a hybrid model,
2. AEMO's prototyping that shows an indication of potential outcomes from priority access if this was in place,
3. an overview of a current piece of work assessing how priority access may impact investor decisions.

3.1 The ESB's cost benefit analysis showed greatest benefits come from a hybrid model

The ESB conducted a cost benefit analysis (CBA), to quantify the net benefits of transmission access reform, which was published in February 2023.[25]

The CBA found that the introduction of the hybrid model would result in quantified net benefits for consumers estimated at $2.1-5.9 billion, excluding emissions reductions. It also found that the hybrid model would reduce emissions by 23 million tonnes over 20 years, which can be quantified as a net benefit of $1.6 billion.[26] This results in an estimated total net benefit of $3.7-7.5 billion. The hybrid model also has the potential to reduce the cost of capital for generators.[27]

The key drivers of the benefits were:

- efficiency savings arising from efficient congestion management in operational timeframes ($0.5 billion mid-point estimate), plus 23 million tonnes of emissions ($1.6 billion),
- reduced capex and fuel costs arising from more efficient investment decisions ($3.8 billion mid-point estimate).

The hybrid model was assessed against six alternative designs – various combinations of options in the investment timescale (priority access or a congestion fee) and operational timescales (the CRM or the congestion management model).[28]

The key findings were:

- the benefits of the hybrid CRM-priority access model are significant versus doing nothing,

25 Energy Security Board, Transmission access reform Cost benefit analysis, February 2023, found here.

26 The quantitative assessment of emissions reductions was in line with the AEMC's guidance for valuing emissions reductions as of April 2024. For more information, refer to the AEMC webpage here.

27 CEPA, Transmission access reform - Cost of capital impact, February 2023, found here.

28 At the time of the cost-benefit analysis, design details of the hybrid model had not been fully established. Indeed, the preferred hybrid model was one of the alternative models assessed, none of which had been worked up in detail. Given this, the cost-benefit analysis was based on the high-level, conceptual designs of the models. Since then, we have continued to develop the design of the preferred hybrid model but consider the broad outcomes of the CBA remain relevant.

- the benefits of a hybrid model (combining either reform in the operational timeframes with either reform in the investment timeframes), are significantly higher than reform in one or the other; the investment benefits arising from implementing the priority access model in addition to the CRM are significantly higher than the benefits from implementing the CRM alone,
- there was only a small difference in *quantified* benefits of the CRM (in combination with priority access) versus the benefits of the alternative congestion management model (also in combination with priority access),
- market participants can choose not to opt into the CRM, meaning that they are not exposed to the congestion relief market price; this reduces transaction costs associated with market participants setting up new systems and reduces the costs of renegotiating contracts that might otherwise be required due to compulsory exposure to a local price.

The ESB instead drew upon the *non-quantified* benefits of the CRM versus the congestion management model, to establish the CRM as its preferred model:

- In comparison to the congestion management model, the CRM distributes benefits between generators in a manner which more closely reflects the status quo arrangements; as a result, the CRM better avoids "winners" and "losers" among market participants arising from the reforms.
- The CRM has potential to reduce the cost of capital for generators, while the effect of the congestion management model on the cost of capital is more ambiguous; this may lower prices for consumers in the CRM design.

The CBA was undertaken at a point in time for the purposes of informing an assessment of access reform options against each other and the status quo. Concerns with specific elements of the cost benefit analysis in isolation have, to date, not provided sufficient evidence to suggest that:

- the broad, directional costs and benefits, that the reform would lead to net benefits from efficient congestion management and locational decisions, were not accurate,
- another access reform model should have been progressed ahead of the hybrid model
- access reform in general should not be explored further.

The AEMC has consulted with, and sought advice from, government officials on key work items for this review. Based on this advice, the AEMC will not be undertaking a new cost-benefit analysis of the hybrid model, for the reasons set out above. We consider that the high level analysis that has been undertaken provides clear, directional benefits, and we consider that redoing the cost benefit analysis would not provide significant, new information. Instead, we consider it is more important to test the practical outcomes of the reform – through the two below pieces of work.

However, we recognise that quantitative cost-benefit analysis on a reform of this nature is challenging. There were elements of the analysis that were, and likely remain, controversial.

Stakeholders are invited to provide feedback on the cost benefit analysis to the extent that it may inform the AEMC's recommendations for Ministerial consideration on a hybrid model that best meets the reform objectives.

We understand some stakeholder have concerns with the assumptions used, which we provide an overview of in Table 3.1 below. We welcome feedback on these assumptions or any other aspect of the cost-benefit analysis.

Table 3.1: CRM and priority access cost-benefit analysis assumptions queried by stakeholders

Assumption	Description	Source
Costs – AEMO reform implementation and ongoing costs	Upfront costs: $21-54m. Ongoing costs: $3-7m per annum. Total AEMO costs (NPV midpoint): $76m. Uncertainty range of -/+ 50%.	2022 AEMO and EY estimates, based on analysis of which systems are likely to be impacted by the reforms.
Costs – Market participant reform implementation and ongoing costs	NEM-wide upfront legal costs (NPV): $24m. NEM-wide upfront IT costs (NPV): $37-105m. NEM-wide ongoing IT costs (NPV): $59-118m. Total NEM-wide participant costs (NPV midpoint): $183.5m. IT costs (e.g., for system upgrades necessary to submit CRM bids) were assumed to grow over time in line with assumed CRM participation. Legal costs relate to contract updates/renegotiations triggered by the reforms. The lower bound estimate provided by participants was adopted for the CRM, because it was expected to result in fewer contract reopeners compared to the congestion management model and/or that participants would not participate in the CRM if it triggered contract reopeners.	Estimated costs per participant were based on 2021 interviews with participants on the COGATI reforms. These were combined with AER/AEMO estimates of participant numbers to derive estimated NEM-wide costs.
Benefits – Extent of generator CRM opt-in	The benefit estimates assumed partial participation in the CRM in 2028, rising linearly to full participation by 2030. The partial participation starting point assumed 50% non-participation by renewable generators, who were considered most likely to hold existing PPAs that would disincentivise CRM participation (see note 2).	ESB assumption.
Benefits – Reform operational benefits	Operational benefits relate to the more efficient use of existing generation and transmission assets, resulting in lower generation costs to meet demand.	The cost-benefit analysis relied on two main sources:

Assumption	Description	Source
	In the low benefit case, the cost-benefit analysis assumed: • A $31m reduction in generation costs in 2028, rising linearly to $40m by 2030 (and then holding constant until 2050). • These assumptions reflected NERA's 2023/24 estimates with partial (2028) and full (2030) CRM participation. • NERA's 2023/24 estimates were considered to be a credible lower bound, as they align with other studies. In the high benefit case, the cost-benefit analysis assumed: • A $59m reduction in generation costs in 2028, rising linearly to $76m by 2030 (and then holding constant until 2050). • The 2030 assumption reflected Triolo and Wolak's (2020) estimates of the benefits of comparable reforms in Texas (3.9% generation cost reduction), a market with similarities to the NEM. The 2028-2030 transition reflected assumed growth in CRM participation. NERA's (much higher) 2033/34 estimates were not used in the cost-benefit analysis, because these were not consistent with the international studies.	• Market-modelling undertaken by NERA in 2023. NERA modelled two years (2023/24 and 2033/34), assuming both partial and full CRM participation. Under full participation, NERA estimated generation cost savings of 1.4% (2023/24) and 28.3% (2033/34). • Previous studies on introducing LMPs in the NEM and international markets. The cost-benefit analysis considered thirteen data sources. These demonstrated that the operational cost savings identified by NERA in 2023/24 (with full CRM participation) were within the ranges observed elsewhere.
Benefits –Reform carbon benefits	Carbon benefits relate to the more efficient use of renewable generation resources. The cost-benefit analysis assumed: • A 0.8m tonne per annum reduction in CO_2 emissions in 2028, rising linearly to 1m tonnes per annum by 2030 (and then holding constant until 2050). • The 2030 assumption reflected NERA's 2023 modelling of the CRM impact with full participation. The 2028-30 trajectory mirrored the assumed growth in CRM benefits (due to growth in CRM participation).	NERA's 2023 modelling indicated that the CRM would support a substitution of thermal generation for renewables, reducing CO_2 emissions by approximately 1 million tonnes per annum in both 2023/24 and 2033/34, with full CRM participation.

Assumption	Description	Source
	With the current values of emissions reduction (see note 3), this corresponds to $1,550m in benefits.	
Benefits - Capital and fuel cost savings from more efficient locational decisions	By addressing cannibalisation, the reforms will mean that less generation investment is needed to deliver the desired level of reliability and emissions reduction. The cost-benefit analysis estimate of investment benefits was drawn directly from NERA's 2020 study (converted to 2022 prices). The cost-benefit analysis assumed: • In the low benefit case, NERA's estimated annualised investment saving over 2026-2040 (NPV $2,130m). • In the high benefits case, NERA's annualised savings extended to 2050 (NPV $5,470m).	NERA's March 2020 study modelled generation investment to 2040 under the status quo arrangements and compared this to an efficient level of generation investment. NERA found that by 2040, the reforms would enable reliability and emissions targets to be achieved with approximately 20GW less generation capacity than the status quo.

Note 1: Net present value (NPV) estimates were calculated over the period 2023-50. All estimates are in $AUD 2022 terms. For more information on the assumptions, refer to the ESB's and NERA's report on the cost-benefit analysis, found on the ESB project page here.

Note 2: To model the partial participation benefits, NERA first identified the top 50% of generators with the highest profit gain from participating in the CRM, then added wind and solar generators until 50% of wind/solar generation output was accounted for. Remaining generators were assumed not to participate in the CRM.

Note 3: AEMC, Guide - How the national energy objectives shape our decisions, March 2024, Table A.1, p.16.

We have also undertaken a qualitative assessment of how the current design may impact on the original cost-benefit analysis – see below.

Table 3.2 discusses the benefits and costs that were quantified in the cost-benefit analysis. Table 3.3 discusses the qualitative costs and benefits from the cost-benefit analysis. We note that these were material in the decision to recommend the hybrid model over the alternative options also considered in the cost-benefit analysis. In both tables, we highlight the assessment criteria to which each benefit or cost relates.

We therefore consider that the benefits estimated earlier, are unlikely to be significantly changed.

Table 3.2: Impact of the current hybrid model design on the benefits and costs quantified in cost-benefit analysis

Benefit or cost	Assessment criteria	$bn (2022) NPV from CBA	In principle assessment of the hybrid model	Assessment of specific design
Operational benefits	Efficient market outcomes - dispatch	0.49	CRM provides incentives for cost-reflective bidding and so efficient dispatch. See note.	Benefits may be reduced due to: • "Tethering" of access and energy dispatch by ramp rates. • Higher RRPs driving inefficient operational decisions by non-scheduled market participants (noting these are offset by benefits from better locational decisions) Materially likely to be small.
CO_2 emissions reductions (23m tonnes)		1.55	Because low short run marginal cost generation also tends to be low emission generation, a more efficient dispatch also tends to lower emissions. The modelling undertaken by NERA demonstrated this expected outcome, with approximately 1m tonnes of emission reduction in both years studied (2023/4 and 2033/4), summing to approximately 23m tonnes over the study period.	
Capital and fuel cost savings from more efficient locational decisions	Efficient market outcomes - investment Effective wholesale competition	3.80	Priority access solves the existing "cannibalisation" problem. New entrants would no longer be able to profitably locate in congested areas by taking access from legacy generators. This improves incentives for efficient investment. Not a "solar stopper". Reforms limit *inefficient* investment. The reduction in renewable generation capacity does not result in a reduction in renewable generation output nor	Assessments suggest that a softer priority may address cannibalisation.

Benefit or cost	Assessment criteria	$bn (2022) NPV from CBA	In principle assessment of the hybrid model	Assessment of specific design
			an increase in emissions. Rather, we build a smaller renewable generation fleet that is better utilised, and we avoid building projects that cannot be used due to network congestion (or building otherwise unnecessary transmission to "save" poorly located projects).	
AEMO costs	Implementation considerations	0.08	The costs are relatively low compared to previous CRM cost estimates because of the design to sequentially run access and then physical dispatch. Sequential dispatch means that each stage of this dispatch process is largely the same as the status quo, limiting implementation costs. This estimate has a range of uncertainty of ± 50%.	No change. Bid Price Floor (BPF) method simply changes the lowest possible bids of generators, further limiting system changes relating to priority access. Further analysis is required to firm up cost estimates.
Participant costs (IT and legal)		0.18	Lower than other models (such as the CMM) because of the voluntary nature of the reforms. Legal costs lower because the CRM does not disrupt the operation of the existing energy market.	No change.
Net quantified benefits		**5.58**		**Net benefits down, perhaps immaterially.**

Table 3.3: Impact of the current hybrid model design on the qualitative assessment of the costs and benefits from the cost-benefit analysis

Benefit or cost	Relevant assessment criteria	In principle assessment of the hybrid model	Assessment of specific design
Market disruption; redistribution of wealth between existing generators	Appropriate allocation of risk Manage access risk	Risk arising from regulatory change significantly reduced by features of the CRM compared to alternative models. By allocating access via the existing dispatch process, CRM is a mechanism to grandfather incumbent generators. Generators can opt-in if they want to participate in the CRM.	No change.
Cost of capital for generators		Potential to reduce the cost of capital for generators because: • The CRM generally increases individual generators' profits, because it is optional. • The priority access model provides protection against later cannibalisation by a new entrant.	The risk of access cannibalisation may be addressed under the design even with a softer priority access.
Integration with jurisdictional REZ schemes	Integration with jurisdictional REZ schemes	Priority access will support and strengthen REZ scheme by limiting the ability of non-REZ generators to cannibalise the access of generators within a REZ.	The risk of access cannibalisation may be addressed under the design even with a softer priority access.
Wealth transfers from consumers to generators arising from higher RRPs	Not explicitly considered as an assessment criterion as this disbenefit had not yet been identified	Not considered as part of the cost-benefit analysis as this disbenefit had not yet been identified.	Wealth transfers from consumers to generators could occur from possible RRP impacts by priority access.

Question 1: Feedback on cost-benefit analysis conducted in 2023

What are stakeholder views on the cost-benefit analysis?

3.2 Prototyping of the hybrid model

A key question relates to the practical implementation and operation of the priority access, including whether it will realise the intent of the reforms. In 2023, to understand the impact of implementing priority access in the NEM dispatch engine (NEMDE), a testing program was set up using AEMO's CRM prototyping. This is a full version of NEMDE that can be used to study how actual dispatch outcomes would have changed under different bidding regimes.

Previous testing results had highlighted that a "hard" priority approach could, in certain circumstances, lead to significant moves in the RRP and undesirable system outcomes like increased counter price flows (in the access dispatch, noting that there are incentives for efficient physical dispatch under the CRM). The 2023 prototype testing by AEMO therefore sought to test whether priority access could be implemented in NEMDE using a "soft" priority approach sufficiently to meet the reform objectives without creating undesirable dispatch outcomes.

The recent phase of testing shows that it is technically possible to use a soft priority approach. The findings show that soft prioritisation may allow for reduced cannibalisation compared to the status quo without significantly increasing the RRP. It also showed that priority access generally:

- delivered the desired directional change in dispatch but the magnitude of the change was variable,
- delivered some counter-intuitive results against some test criteria,
- as predicted by theory led to an increase in the RRP in some cases.

It is worth noting that, while useful to consider possible outcomes from priority access, the results of this testing should be taken in mind, being:

- highly congested areas of the NEM with multiple binding constraints were considered,[29]
- historical dispatch intervals were considered,
- particular existing generators were chosen to be 'new entrants',[30]
- a range of bid price floors (BPFs) were tested.[31]

Based on testing of different BPFs and grouping approaches, the ESB undertook testing of this with the high level findings of this set out in Box 1. See appendix B for a detailed overview of the outcomes of this work.

Extrapolating the testing results for policy implications requires careful consideration. Future power system outcomes will depend on many factors such as investment in transmission and generation, the implementation of constraints, and bidding behaviour. The testing results do not

29 Priority access will likely have more predictable and intuitive impacts in less congested areas.

30 The 'new entrants' were assumed to have connected in the congested area regardless of any reductions in dispatch and revenue due to priority access. In reality, they may have located in less congested parts of the network which could have resulted in different system outcomes (e.g. a lower RRP).

31 Typical BPFs used in the case studies were -$800/MWh, -$650/MWh and -$400/MWh but some scenarios tested higher values above -$250/MWh to see when dispatch outcomes changed.

predict the future. Some test cases would not occur in the future under different policy settings, such as a generator with a poor coefficient locating in a congested area.

Box 1: Overview of AEMO prototyping work for priority access

The objective of AEMO's prototyping program of work was to test the implementation of priority access in NEMDE using separated BPFs. The experiment compares:

- the base case – the actual historical dispatch outcome in the NEM for the chosen dispatch intervals,
- the test case – the rerun of dispatch with a select group of generators assigned 'new entrant' status and allocated higher BPFs to represent lower priority.

The results were collated and a range of statistics collected including:

- MW changes in dispatch,
- RRP changes,
- profitability changes.

AEMO's test case work reveals that we are likely only to be able to implement a very limited number of meaningful priority levels in NEMDE using the bid price floor method (see section 4.2 on this method).

The outcomes of AEMO's test case work is summarised against the three test criteria:

- **Criteria 1 - direction of change:** In the vast majority of cases tested, priority access leads to the expected direction of change in dispatch. Where AEMO observed outcomes that were not as expected, the cases often involved interactions between generators in the same queue position with closely similar constraint coefficients. In 86% of cases, priority access leads to the expected direction of change in dispatch. However, 30% of all cases and 62% of the 94T sets (one of the two data sets) showed an unexpected dispatch change. In particular, there can be unexpected interactions between generators in the same queue position where a generator with priority is dispatched more but at the expense of another generator with priority.
- **Criterion 2 - predictability:** Whilst the incumbent and new entrant metrics show the right trends as the BPF is raised, there was a wide dispersion of results for different generators. For example, the size of the change in dispatch for individual generators could be large or small, which makes the results somewhat unpredictable. We are keen to understand from investors how such an outcome as a result of the reform would be factored in and whether this would be an improvement compared to the status quo, noting that current dispatch outcomes may also be unpredictable.
- **Criterion 3 - change in RRPs:** Priority access leads to less efficient dispatch which can impact RRPs (specifically the access RRP). Overall 31% of cases showed a >5% rise in at least one NEM region. 13% of cases showed a >25% rise in at least one region.

While this testing has some limitations, these relate to the technical feasibility of the model. The testing undertaken described above was not designed to measure the benefits of the reform.

The findings show that soft prioritisation may reduce cannibalisation outcomes compared to the status quo without significantly increasing the RRP. However, the question is whether investors would be able to quantify the costs and benefits of their expected queue positions in a way that would influence their investment decisions - this is the subject of section 3.3. Given the large expected "size of the prize" of better investment efficiency, as well as improvements to the way generators can manage congestion risk, even capturing a small proportion of the benefit could be worthwhile.

These results show that generally the outcomes of priority access are as expected, however, there are some unexpected outcomes. The AEMC is using this review to:

- explore the extent to which the unintended consequences are cause for concern or could be addressed through alternative design choices, such as alternative implementation approaches
- seek stakeholder views on how "firm" priority access needs to be in order to be effective and drive locational investment efficiencies.

Question 2: Feedback on prototyping

What are stakeholder views on the result of the prototyping analysis? Is there any additional analysis that would be useful?

3.3 Understanding practicalities of priority access for investors

During the ESB's work on TAR, stakeholders noted that for priority access to achieve the reform objectives, prospective investors will need to be able to take account of the mechanism when building the business case for new investments. The priority access prototyping results were not intended to provide an answer to the question of how priority access may change future investment decisions. To answer this question, the AEMC has engaged ACIL Allen to complete a piece of work addressing the following questions:

1. How is congestion modelling currently completed in the NEM, and how does it contribute to the investment case of an intending participant?
2. Could priority access be included in this type of modelling that is usually completed for investors in new generation, and if so, how?
3. Whether the inclusion of priority access in congestion modelling (if possible) would likely have the desired impacts on outcomes for an individual new generator? The desired outcomes would be that:
    a. A generator could model the cash flow effects of priority access relative to the status quo due to the priority access mechanism providing protection against congestion caused by new entrants.
    b. A generator could anticipate where its access would be limited/reduced by higher priority generators at certain points on the grid.
4. Whether, in ACIL Allen's opinion, priority access could provide more certainty (relative to the status quo) to intending investors about the revenues a project would earn over its lifetime?
5. Whether modelling of this nature would likely improve over time (for example, like modelling of marginal loss factors)?

ACIL Allen is addressing this work in two stages. The results from both stages of work will be published in a report following the consultation paper. The AEMC will discuss the detailed findings of the work with the technical working group (TWG).

The first stage of the work involved ACIL Allen providing a written explanation setting out:

- how congestion modelling is currently completed,

- why ACIL Allen considers priority access could be included in this modelling,
- how priority access would be included.

ACIL Allen's findings are set out at a high level in the table below. These will be published in ACIL Allen's report in more detail.

Table 3.4: How current congestion modelling would change to incorporate priority access and the CRM

Element of model	Current approach	Required changes
Dispatch and pricing	Dispatch pricing in models of this nature reflect the current, single-stage dispatch process.	To model the effect of priority access and the CRM, dispatch and pricing will need to include the two-stage dispatch process, where: • the first stage access dispatch is modelled the same as the current NEM dispatch, • the physical dispatch is modelled using a new set of CRM bids for those participating in the CRM, and includes a new set of CRM deviation constraints which can be used to limit the deviation of a dispatchable resource's physical dispatch from its access dispatch. The model will also need to calculate the CRMPs for each dispatchable resource as the local marginal prices. This could either be calculated directly from a DC load flow model, or calculated as the shadow prices of the binding network constraints as is currently done with NEMDE.
Participant bidding	Participant bidding approximates current participant bidding in the NEM. This includes: • in an unconstrained sub-region, participants will bid to maximise profits, considering any impact their dispatch may have on RRPs, • for dispatchable resources in constrained sub-regions, participants bid at MFP if the RRP is greater than the opportunity costs of generating/not generating; if RRP is less than	Participants would be assumed to bid in the access dispatch in the same way the bid under the status quo, with the key change that the MFP/BFP would reflect their priority access queue position. In the CRM, participants would assume to bid at their opportunity costs.

Element of model	Current approach	Required changes
	their opportunity costs, they would bid at their opportunity cost.	
Network constraints and security constrained dispatch	Network and security constraints are developed through power flow modelling.	Constraints are modelled the same in the CRM dispatch as in the status quo.
Market-based new generation investments	Opportunities for new investment are indicated by small generic investments at certain grid locations. To the extent these investments are profitable, there is the potential for larger investments to be made at these locations.	New entry would be modelled in a similar way, with the key change being that the small generic investments would be impacted by the presence of the queue. Indications of profitable new entry will therefore reflect locations that are still profitable even with the presence of priority access.

The second stage of work aims to answer questions 3-5 above about the effectiveness of priority access in changing investment decisions. To answer these questions, ACIL Allen is developing a simplified prototype model that compares generation development plans based on generators making profit-maximising investments over a 20-year horizon with:

- the status quo arrangements,
- priority access and the CRM.

The results of this modelling work will be presented in ACIL Allen's report, which will be published following the consultation paper. This work will also be discussed at an upcoming technical working group meeting.

Question 3: Feedback on modelling the hybrid model

Noting that this work is still being completed, do stakeholders have any initial views on how modelling priority access would impact investment decisions?

4 Priority access

This section sets out an overview of the priority access mechanism, including the current design of the mechanism and potential alternative options for how this could be implemented for stakeholder feedback.

The introduction of priority access seeks to address the issue of cannibalisation by introducing a mechanism by which generators are assigned a priority level in the energy market. The priority level would be assigned to a new entrant generator during its planning and investment period, with the priority level given effect in dispatch during operational timeframes. The concept is, that generators assigned a higher priority would be given preference in dispatch over generators assigned a lower priority. Importantly, priority access would only have effect in the presence of congestion when competing generators bid to the market floor price in order to be dispatched.

The concept was originally introduced by the CEIG as the 'transmission queue model'.[32] Key principles and features have been adopted and developed into the priority access model and options shared in this consultation paper.

The mechanics of priority access are outlined in Box 2.

Box 2: Priority dispatch in the NEM

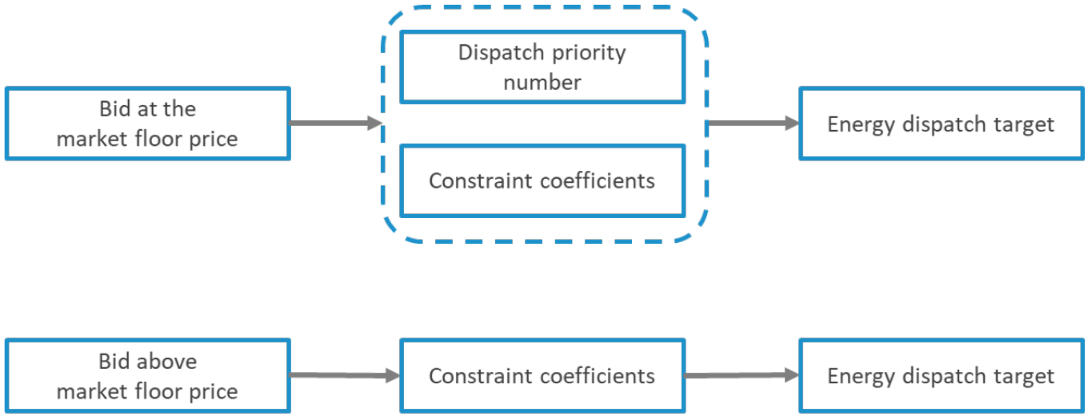
Under priority access, generators would be allocated a priority level which would be given effect through a nominated Dispatch Priority (DP) number: the lower the dispatch priority number, the higher the priority level.

When two or more generators bid at the market floor price to access the same constrained piece of transmission infrastructure, the dispatch engine would factor in the dispatch priority number to give a level of preference to generators with higher priority. Constraint coefficients would no longer be the only factors rationing access between generators competing in the same set of binding constraints and bidding at the same price. Generators bidding above the market floor price would have their dispatch process be unchanged.

The figure below illustrates how dispatch priority numbers would be factored into the access dispatch.

32 CEIG, Submission to the ESB Transmission access reform May 2022 consultation paper, 10 June 2022, found here.

Figure 4.1: Dispatch priority numbers in dispatch



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

One important element of the model is whether the priority offered is 'hard' or 'soft' which affects the degree to which a generator's priority level overrides its constraint coefficients in determining dispatch outcomes. While the degree of priority is a design choice, it is also subject to technical considerations, including the approach to implementing priorities in the dispatch engine.

Some market participants may share the same priority level. 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 in the binding constraint.

There are several options for organising generators and linking them to a dispatch priority number. These options – termed 'priority access model options' – are described in more detail in section 4.3. Under our priority access lead model, the dispatch priority number would be linked to the year in which a generator or REZ meets the defined point in the connection or REZ development process.

The introduction of a mechanism to prioritise the dispatch of certain generators (or groups of generators) over others will deliver two key outcomes:

1. Where existing generators are assigned a level of priority in dispatch that is higher than the level of priority assigned to new entrant generators, priority access will reduce the extent to which new generators are able to cannibalise the access of existing generators. This mitigates some of the additional congestion risk facing investors who entered the market first, while continuing to promote new entry in less congested areas of the network.
2. Priority access will create an investment locational signal that encourages investors to site new generation in less congested areas of the network. This locational signal originates from the effect of prioritisation on the dispatch outcomes, and hence on the profitability, of new entrant generators relative to outcomes under the existing arrangements. To be effective and deliver the most benefit to consumers, this signal must be long-term and dependable.

The priority access model, on its own, may result in even less efficient energy dispatch than today. However, the priority access mechanism only applies in the access dispatch, not the physical 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 prioritised dispatch.

4.1 The market-based queue model

In its early work to develop the original priority access model put forward by the CEIG, the ESB explored two broad options for assigning priority levels to generators: a queue model; and a centrally determined tiers model.[33]

A key design difference between these options was the extent to which central agencies would be involved in assigning priority levels, and the extent to which the options would influence the incentives on generators to invest:

- In the queue model, generators would be assigned priority access chronologically, 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) relative to others.
- In the centrally determined tiers model, a central agency would delineate several tiers based on its expectations of efficient investment. Generators would then be assigned into those tiers on a first-come-first serve basis or via an auction. This option would require the hosting capacity of areas within the national grid to be determined on a regular basis as part of planning processes.

Having regard to stakeholder feedback, the ESB determined that while there may be potential benefits associated with a centrally determined tiers model, it would be challenging to realise the benefits in practice given the dependence on central decision-making to determine efficient investment levels in different locations and over time.[34]

In contrast, the queue model would leverage a market-based approach and would allocate forecasting risk to investors. It would allow investors to determine the level of network congestion that is acceptable in the context of their project, and has the potential to better address the cannibalisation risks, which would improve investor confidence and enhance the value of the REZs.

At the Ministers meeting in July 2023, the ESB was tasked with progressing the detailed design of the market-based queue model, in preference to the centrally determined tiers model. The ESB's recent work has therefore focused on progressing the more detailed design aspects of the preferred queue model.

A more detailed overview of the market-based queue model is provided in Box 3 below.

Box 3: Market based queue model

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.

Under a pure sequential queue, a queue number would be assigned to generators in strict chronological order of entry (the later the entry date, the higher the queue number) with some important exceptions:

33 For a fulsome discussion on the two broad options for allocating priority access, see ESB 2023, Transmission access reform consultation paper, May 2023.

34 The determination of hosting capacity would require the central agency to undertake detailed forecasting and load flow modelling, which is likely to be challenging. The efficiency of the locational signal assumes a greater degree of accuracy than what may be possible. It is also likely to be costly to administer and could complicate the connections process, delaying and deterring investment.

- existing generators (and potentially other groups of generators) could have a shared queue number (for example '0'),
- REZ coordinators could reserve a single queue number for all generators participating in a certain REZ (before they connect) up to a defined MW total quantity.

It would also be possible to assign generators a queue number based on time-windows in which they enter the market. 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.

Queue numbers would be mapped directly to a dispatch priority number (where the DP number ultimately determines access) and a specified MW of capacity. 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 MW of priority.

Existing generators or REZs wishing to expand their capacity would have to join the back of the queue for their capacity expansions. This means that each generator (or REZ) may have multiple queue positions, received over time as their capacity changes.

A high queue number would not necessarily be 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 only conferred between generators participating in the same binding constraint.

Investors would be responsible for assessing their effective level of access and making their entry (or expansion) decisions on that basis. Investors would carry out this assessment having regard to:

- the queue number they would expect to be assigned,
- the queue numbers assigned to all existing and committed plant in an area,
- the queue numbers assigned to all existing and committed REZs in a jurisdiction,
- the outcome of their own modelling undertaken to assess the congestion risk associated with locating in a specific area of the network.

The investor could undertake this assessment with a degree of confidence that their project will not be cannibalised by future generation investments.

The market based queue model of priority access is illustrated below, either as a strictly chronological queue number or a queue number based on grouping by time-window.

Figure 4.2: Strictly chronological queue

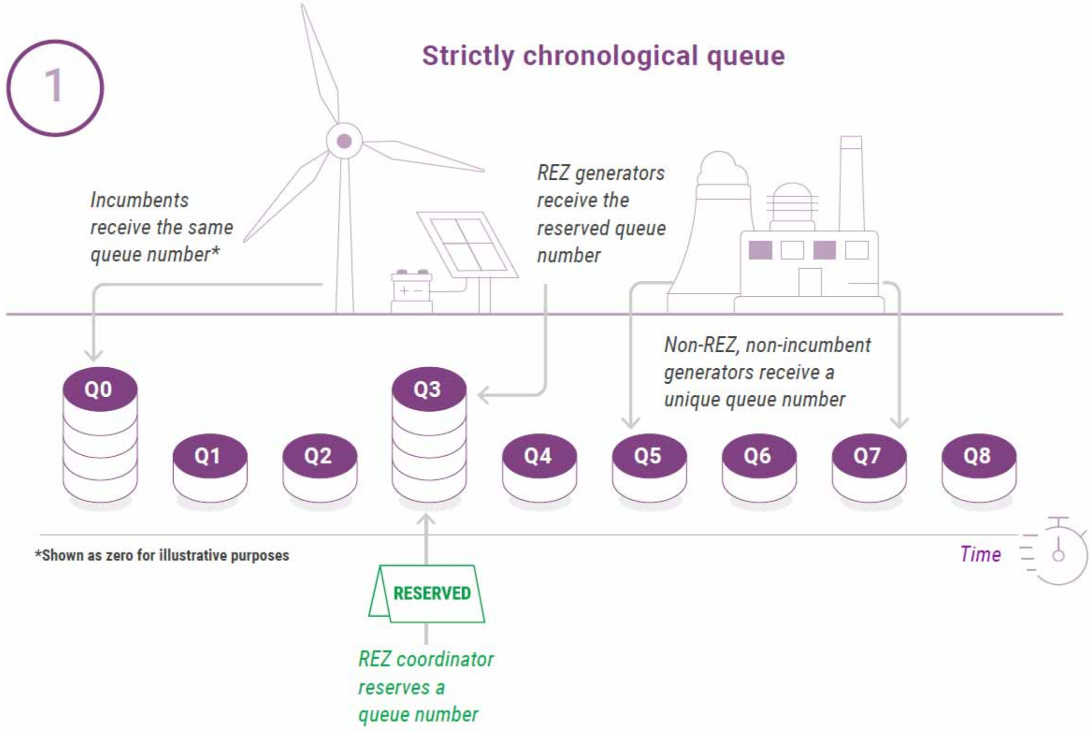
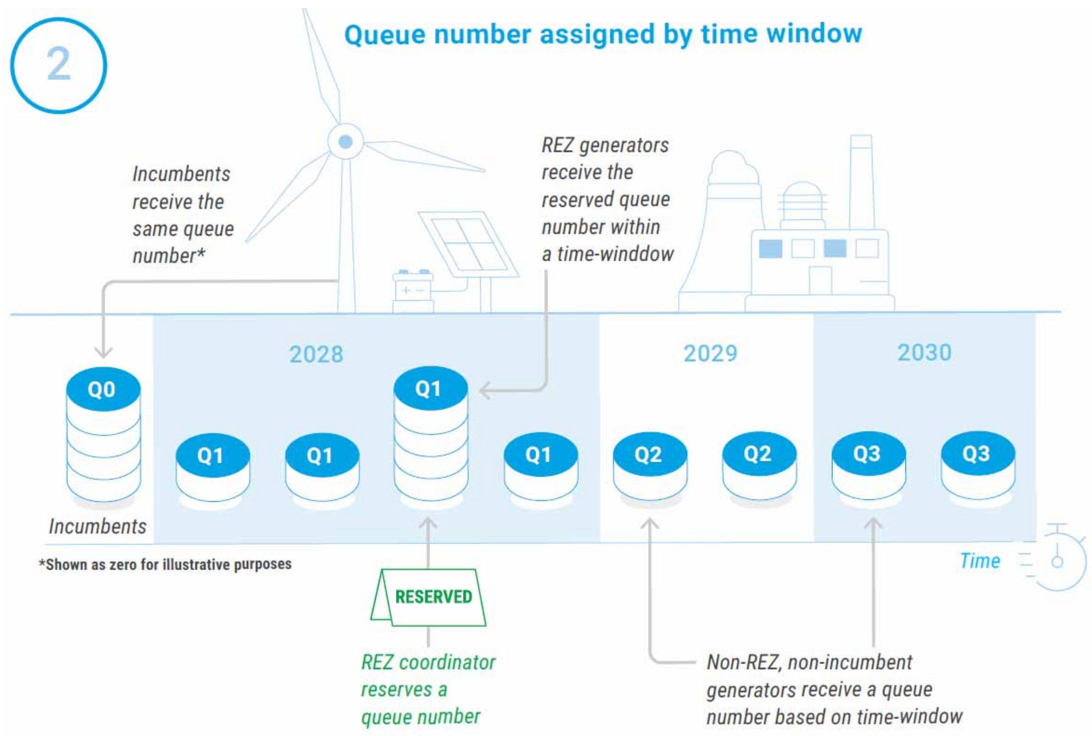


Figure 4.3: Queue number assigned by time-window



4.2 Implementing prioritisation using a bid-price floor approach

As noted above, priority access would involve a new entrant generator being assigned a priority level during the investment period, with the priority level given effect in dispatch during operational timeframes.[35] The ESB identified two potential options for giving effect to prioritisation in dispatch:

- **Bid price floor adjustments:** Participants with different dispatch priorities would be assigned different BPFs that set the minimum bid they can make in the access dispatch run. Those with the highest dispatch priority (lowest dispatch priority number) 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 dispatch priority (DP) levels made available, which is a design choice for the access priority dispatch.
- **Sequential-solve:** The dispatch process would solve the access 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 would then move to the next highest priority and continue until the solution balances supply and demand whilst meeting the technical constraints.

Of these options, the ESB decided to progress investigation of the BPF adjustment method in the first instance, on the basis that this would be lower risk to implement than the sequential-solve process. Among other things, the ESB considered that a single pass would have no impact on solve times for the access dispatch run, whereas a multiple, sequential-solve process would take longer, delaying the timing of the physical dispatch run and receipt of dispatch instructions relative to the status quo. A sequential solve process could also lead to situations where it does not solve, requiring manual intervention which would be undesirable.

As part of the ESB's most recent work on priority access, AEMO used a NEMDE prototype to test the BPF adjustments approach in the access dispatch run. The key takeaway from AEMO's work was that, if the BPF adjustments approach is pursued as the method of implementing priority access, then we are unlikely to be able to implement a large number of meaningful dispatch priority levels. This work was previously discussed in section 3.2 with further detail included in appendix B. This is because meaningful dispatch priority levels require significant ratios between the BPFs of generators with adjacent queue positions.[36]

A worked example in appendix D.2.1 shows how implementing priority access with BPF adjustments can lead to the desired outcome of dispatching higher priority generators ahead of lower priority generators.

4.3 We are seeking feedback on four priority access variants

Given only a limited number of priority levels can be implemented while maintaining effective, although not outright, prioritisation between each level. This then means that a pure sequential queue as described in section 4.1 cannot be implemented given the number of generation projects expected to connect in the next decade and the very limited number of discrete levels of priority able to be successfully implemented.

A key design question then is how to assign participants to a smaller number of priority levels whilst maintaining most of the benefits of a full sequential queue. To this end, we have identified

35 Dispatch calculations are undertaken by AEMO's NEM dispatch engine (NEMDE).

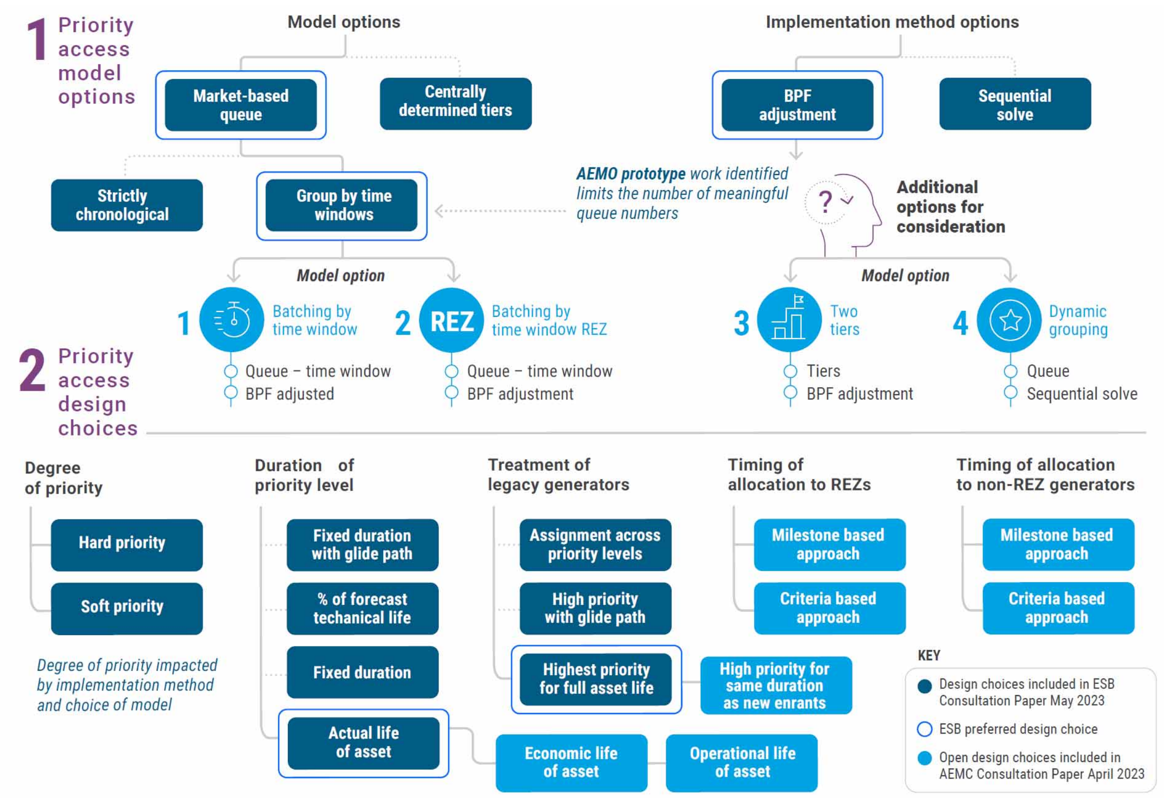
36 With a ratio of 2 (for example), the ratio between the highest and lowest BFP with 10 levels is 2^{10} = 1,024. If the highest (least negative bid price was -$200/MWh, then the lowest (most negative) would be –$204,800/MWh. More levels and higher ratios quickly result in astronomically large BFPs.

several priority access model options which we consider to be credible options under the BPF adjustment implementation approach. These are:

- **Option 1:** grouping by time-window,
- **Option 2:** grouping by time-window REZ model,
- **Option 3:** two-tiers approach,
- **Option 4:** dynamic grouping algorithm.

Figure 4.4 below maps the ESB's considerations on the priority access model and highlights the model options that remain open and are the focus of this consultation.

Figure 4.4: Priority access model options and design choices



For the reasons outlined in this section, option 1 is our currently preferred model – that is, the lead model. However, to facilitate further discussion and feedback from stakeholders, we have described each of the model options below. An initial assessment of the pros and cons associated with these models is also provided in section 4.3.5.

4.3.1 Model option 1: Grouping by time-window

We consider that the approach of grouping generators, likely on an annual basis, could deliver many of the benefits of a pure time sequential queue while being simpler to implement.

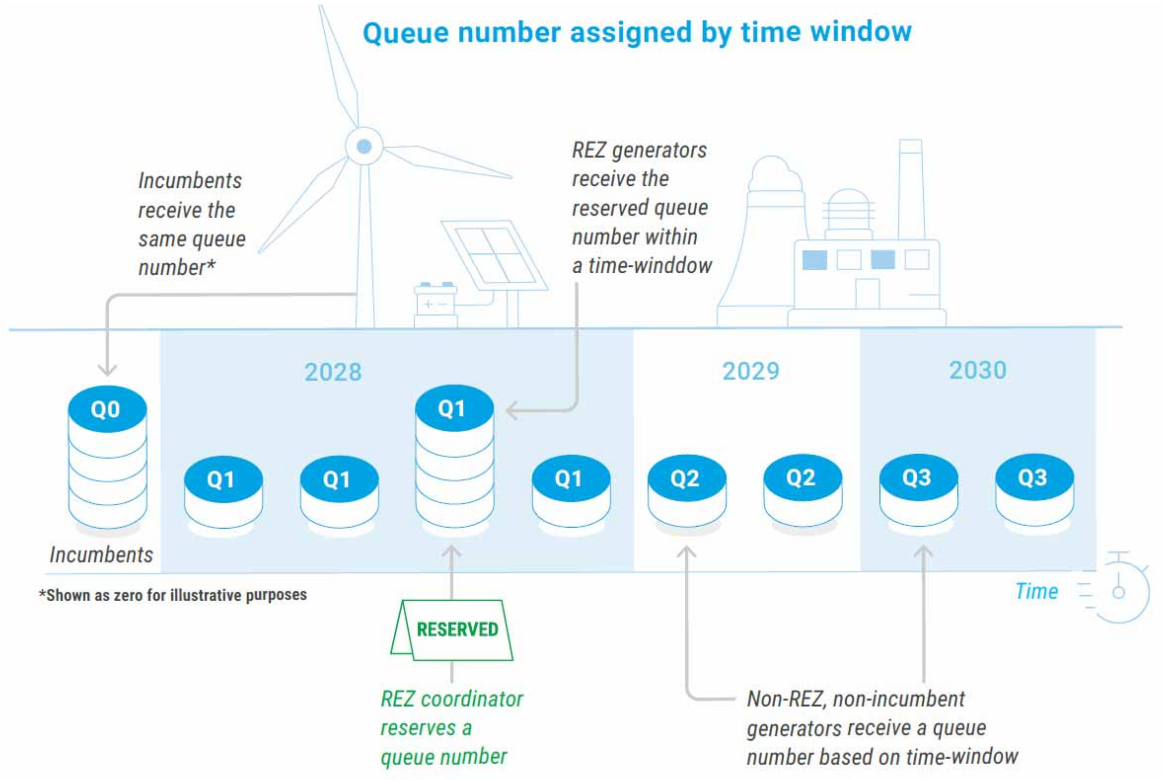
In this option, the approach would be to group generators by year for the duration of prioritisation (discussed in section 7.1.1), before rolling them up into a higher priority group as the number of available priority levels was met.

We consider that 10 priority levels would be implemented, with the specific BPFs to be decided. Based on the prototyping results, our initial view is that the BPFs could range from -$200/MWh for the lowest priority to -$1000/MWh for the highest priority. Within the range, the BPFs could follow a geometric sequence such that the level of firmness between adjacent dispatch priority is somewhat constant.[37]

While the separation between adjacent BPFs may not be sufficient to provide the ideal level of effective priority, this model would be more effective at prioritising generators as the difference in priority levels (and BPFs) increases. In other words, the longer the time difference between two generators connecting in the same constrained part of the network, the more effective priority access will be at protecting the generator who connected first.

An example of the 10-year annual grouping model is provided in Figure 4.5 below.

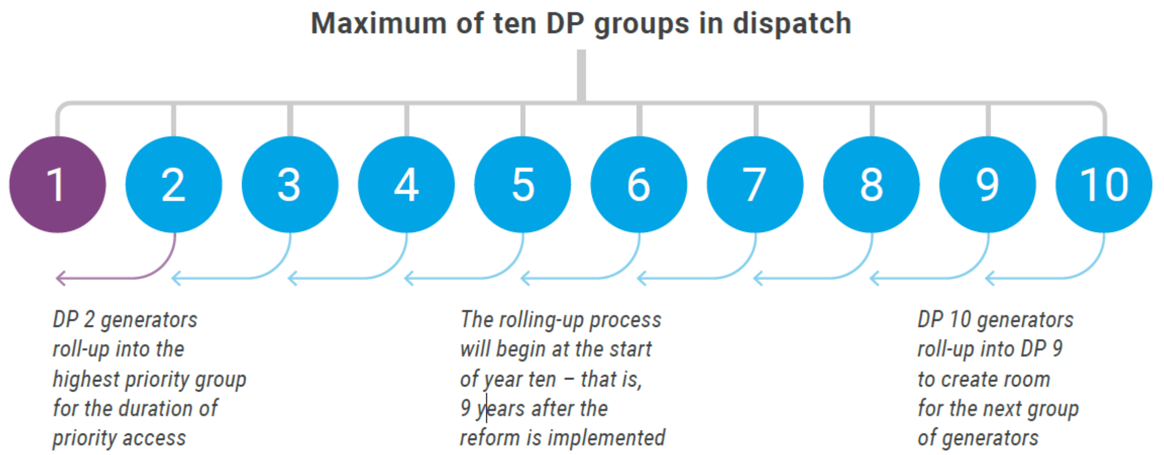
Figure 4.5: Model option 1 - grouping by time-window



As noted above, this model involves grouping generators and REZs by the year in which they meet a certain defined milestone or set of criteria (discussed in section 7.1.3 and section 7.1.4). Following year 9, the maximum priority levels practically available would all be utilised. At this time, participants in DP 2 would 'roll-up' into DP 1, with all other participants also rolling up one level. This would then make DP 10 available to new entrant generators connecting in year 10. This process is illustrated in Figure 4.6 below.

37 This means that, for 10 BPFs ranging from -$1000/MWh to -$200/MWh, the BPF ratio between adjacent DPs would be roughly 0.836. I.e, the high priority DP 1 has a BPF of -$1000/MWh, DP 2 has a BPF of -$836/MWh, DP 3 has a BPF of -$699/MWh, and so on until DP 10 which has a BPF of -$200/MWh.

Figure 4.6: Grouping by time-window roll-up process



The annual rolling up process ensures that at the time of making a final investment decision, investors have a good degree of certainty regarding their effective level of priority relative to incumbent generators and other generators who may seek to access the same area of the network. Investors could model the network congestion they can expect to face in a location, as well as the effect of prioritisation in that location, while having a degree of confidence on the level of protection from cannibalisation from later entrants.

This certainty for the first decade of operation covers most of the net present value of a project, after which a generator reaches the highest priority level until the end of the duration of prioritisation.

Assessment of model option 1 - grouping by time-window

Assuming 10 priority levels, model option 1 should be effective in reducing the cannibalisation of higher priority generators by lower priority generators located electrically close. Priority access would be more effective when the difference in dispatch priority groups is larger. For generators that are electrically far away (i.e. constraint coefficients are significantly different) and in different dispatch priority groups, priority access would be less effective.

The overall pattern of dispatch outcomes across the nine year period as generators move from the lowest to highest dispatch priority level, is largely predictable. This is generally confirmed by AEMO's test case work, which showed that generators in higher priority levels who are competing with generators located electrically close in the lower dispatch levels would generally receive improved dispatch outcomes. This predictability is supported by priority being allocated on the basis of a relatively simple and transparent mechanism – that is, time.

This model provides a good disincentive to non-REZ generators to connect in locations that are electrically close to REZ generators, particularly where a REZ has been allocated a dispatch priority level several levels higher than the non-REZ generator expects to receive.

In this model, two neighbouring REZs could have different priority levels. However, it is important to note that the effective level of access for generators in each REZ would be as good as the REZ coordinator's planning for the associated transmission upgrades. We would expect a REZ planning body to consider the location, scale and timing of neighbouring REZs and other transmission and interconnector upgrades when developing a REZ and defining the efficient generation hosting capacity within that REZ.

As this model groups generators by time-window and uses a mechanical queue system to determine generator BPFs, this model option is simple, clear and transparent for all participants.

In parallel to this process, the national planning regime – that is, the development of the ISP - would continue to operate. It would be revised every two years, incorporating existing and committed investment. Retirement of existing generating assets, investment in transmission capacity, and investment in storage would continue. Collectively, the transmission frameworks would work to benefit all participants and to deliver an efficient overall power system for the overall benefit of consumers.

4.3.2 Model option 2: Grouping by time-window REZ model

A second option for allocating priority access is a variation of model option 1. The grouping by time-window 'REZ' model would provide jurisdictions with the ability to grant REZs the highest level of priority, irrespective of the timing of REZ planning, declaration, specification and operation.

At a high level, the REZ model would operate as follows:

- Non-REZ generators would still enter the queue as set out in model option 1 - that is, based on the year in which they meet a certain defined milestone or set of criteria.
- REZ generators would automatically move to the front of the queue (DP 1) when they connect in a REZ and commence operation.

Since this model option is a variation of model option 1, our initial view for the BPFs used in this option is the same as for model option 1.

Variations within this approach would be possible to recognise that the concept of a 'REZ' is used by different parties to describe different ideas and concepts, depending on what a particular party wants to achieve.[38]

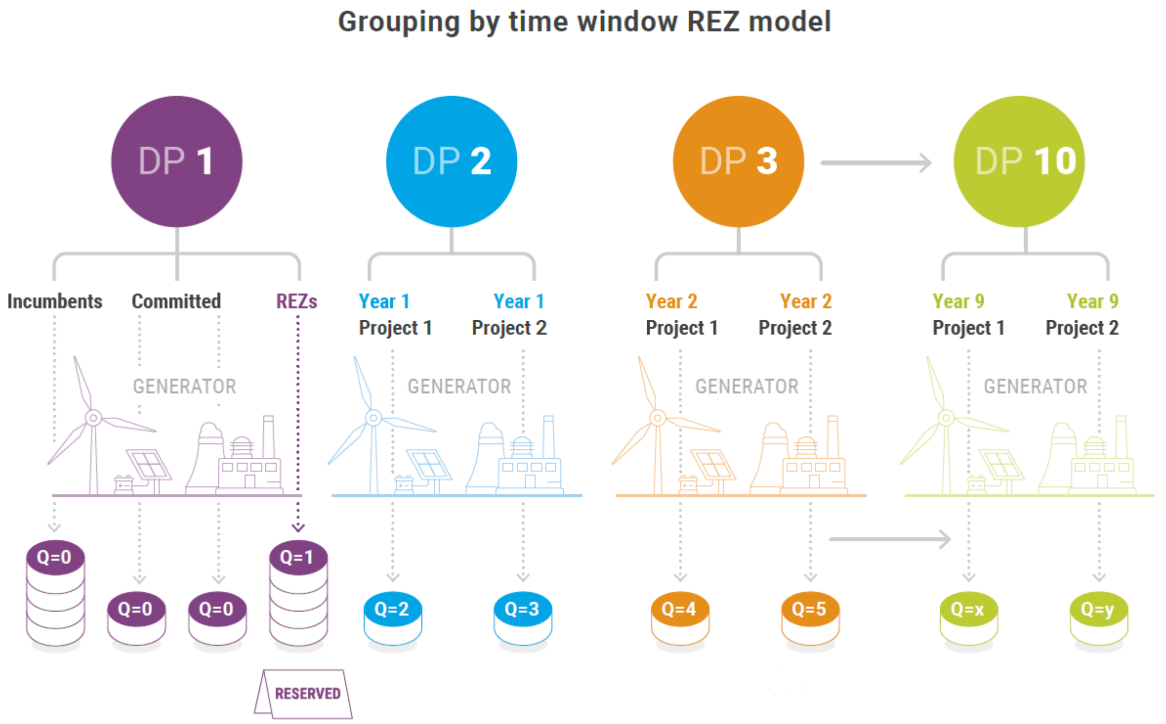
For example, limits around what constitutes a REZ for the purposes of priority access could be defined, such that generators would only be eligible to automatically receive the highest priority where:

- Transmission infrastructure is being built for the REZ in which the generator will participate so as to avoid a material rise in overall congestion.
- REZ generators are funding the transmission through access rights payments; many jurisdictions wish generators to fund transmission in their REZs, which this would give them an opportunity for.

An example of the grouping by time-window REZ model is provided in Figure 4.7 below.

38 'Renewable energy zone' is defined in chapter 5 of the NER as meaning "a geographic area in one or more participating jurisdictions that is the proposed location for the efficient development of renewable energy sources and associated electricity infrastructure."

Figure 4.7: Model option 2 - grouping by time-window REZ model



Assessment of model option 2 - grouping by time-window REZ model

Similar to option 1, option 2 should help to reduce the risk of cannibalisation of existing non-REZ generators by new entrant non-REZ generators connecting to the same constrained piece of transmission network.

By automatically allocating REZ generators the highest priority level, this model should also ensure that generators participating in a REZ now and in the future would receive prioritised dispatch over both:

- a new entrant non-REZ generator entering the market later,
- an existing non-REZ generator that entered the market earlier, but after the date the reform was implemented.

In this sense, this option provides a strong incentive for generators to opt to participate in a REZ. However, the downside of this approach is that it may disincentivise otherwise efficiently located and timely investment outside of REZs, for fear of being cannibalised by a yet-to-be announced REZ. That said, potential cannibalisation of a non-REZ generator by a REZ would be dependent on how electrically close they are and would reduce with time.

In addition, because two neighbouring REZs in different jurisdictions would have the same priority level, this model would not address the risk of generators in one REZs cannibalising the access of generators in other REZ (however, as noted previously, we would not expect this risk to be significant where a REZ planning body has defined the efficient generation hosting capacity within a REZ effectively).

4.3.3 Model option 3: Two tiers approach

The third option we have identified is a more significant variation of option 2. Under this model, legacy generators, committed generators (at the time the reform is implemented) and generation participating in REZs would all be grouped into a priority tier. Other new entrant generators who have chosen not to participate in a jurisdictional REZ would be given a lower level of priority in dispatch.

Using two levels of priority means that only two BPFs would be needed. As a result, the BPFs can set far apart to harden priority access. In comparison to options 1 and 2, this could effectively keep only the highest and lowest priority levels (as an example, -$1000/MWh and -$200/MWh).

Unlike option 2 which would retain an annual grouping process for generators located outside of a REZ, option 3 would group non-REZ generators together into a 'non-prioritised tier', where they would remain.

In terms of dispatch, REZ generators would be mapped to DP 1 and non-REZ generators would be mapped to DP 2.

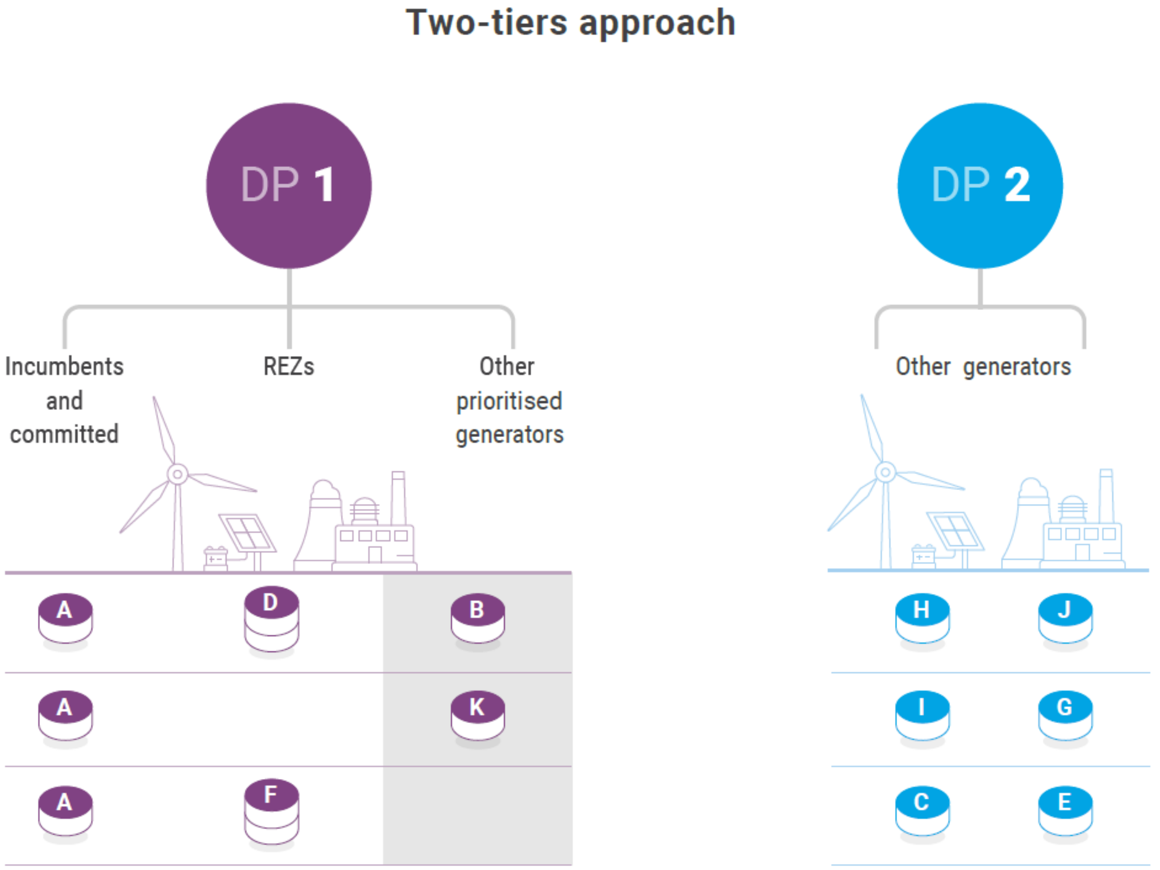
Importantly, generators would not be prevented from connecting outside of REZs, but doing so would mean that they would be accepting non-prioritised dispatch. This is unlikely to be a problem if they are locating in an area where they expect low network congestion. However, it could present a problem if they locate in an area with congestion or expected future congestion.

This model has the option to incorporate a mechanism that enables other generators locating efficiently to be allocated into the priority group. Importantly, this would provide an incentive for efficient investment outside of REZs. Identification of this subset of non-REZ generators could be undertaken by:

- a jurisdictional government identifying specific non-REZ projects or locations as 'priority',
- a central body (e.g. AEMO) based on modelling efficient hosting capacity in certain zones.

Participants would receive their priority level at the time they make their investment decision and retain that for the duration of prioritisation. An example of the two-tiers model is provided in the figure below.

Figure 4.8: Model option 3 - two tiers approach



Assessment of model option 3 - two tiers approach

Option 3 represents a departure from the market-based queue model agreed by Energy Ministers in 2023. However, it does have some attractions; it would only require two BPFs, one allocated to each group. This would allow for wider separation, and harder priority to be achieved between the two groups of generators.

Option 3 should be effective in reducing cannibalisation of prioritised generators by new entrant non-prioritised generators where the latter are located electrically close to prioritised generators – for example, in areas where a REZ network connects to the shared transmission network. This is because there can be a greater difference in BPFs if there are only two groups, resulting in 'harder' prioritisation.

The overall pattern of dispatch for prioritised and non-prioritised generators would largely be predictable.

This model would provide a strong disincentive to new entrant generators to connect outside a REZ or outside of areas with available hosting capacity. In addition, because this model would provide very effective protection to REZ generators against new entrant non-REZ generators considering connecting electrically close, this model may provide an alternative to jurisdictional access control schemes focused on limiting connections by non-REZ generators in and around a REZ network.

Additional REZs and enhanced hosting capacity will provide opportunities for future generators to efficiently connect and obtain priority access.

4.3.4 Model option 4: Dynamic grouping algorithm

The previous model options group generators into a few DP numbers and BPFs, as only a few meaningful BPFs can be used. These model options are "static" in that they are based on rules applied in planning timescales.

An alternative is a "dynamic grouping" algorithm which would be run close to, but before, real-time and include expected generation and transmission conditions. The exact timing – for example, whether 5-minutes ahead or day-ahead – would need to be decided.

This algorithm would run sequential dispatches to progressively prioritise or deprioritise generators based on when they connect and whether their dispatch would need to be constrained to avoid constraint violations. Effectively, the algorithm assumes higher priority generators get 'dispatched' ahead of lower priority generators and allocates prioritisation accordingly. The results from the dynamic grouping algorithm determines the corresponding BPFs for each generator in the access dispatch.

Note that the ESB previously considered a sequential dispatch approach, and decided it would be too slow and unreliable to be feasible, given the limited time available for running the dispatch algorithm (around 20 seconds) and the critical need to ensure a feasible and secure physical dispatch. These concerns can potentially be overcome under option model 4, as a hard priority grouping algorithm is run before dispatch to allocate prioritisation.

Whilst this dynamic grouping algorithm needs to be reliable, it is no longer time-critical. Its separation from the current dispatch interval means that, in the worst case, a failure of the algorithm would not have any adverse impacts on dispatch security. For example, the most recent successful grouping outcome could be used instead as input into priority access dispatch, although this would create an additional process for AEMO to administer.

The BPFs assigned to the two dispatch priorities in the priority access dispatch would need to be decided. With only two groups, the BPFs can be set far apart to harden priority access. A high BPF ratio would mean that the hard priority from the grouping algorithm would be largely preserved. A lower ratio would allow some softening of this prioritisation, which may have some policy benefits, so long as it is not so soft that cannibalisation again becomes problematic.

Dynamic grouping could be effective at preventing cannibalisation without the need for many DP numbers and BPFs (only two are needed). Compared to the time-window grouping methods, dynamic grouping would provide harder priority access for generators over new entrants, that would not decay with time nor be softer if the new entrant joins shortly after.

Assessment of model option 4 - dynamic grouping

Option 4 seeks to implement priority access through a 'hard' a priority access as is possible under bid price floors.

In addition, like model option 1, this model could prioritise certain REZs over others, to the extent that generators in different REZs are competing in the same constraints. However, as noted in the context of model option 1, the effective level of access for generators in each REZ would be as good as the REZ coordinator's planning for the associated transmission upgrades.

One potential concern with model option 4 is that the variable nature of dynamic grouping may make the outcomes of prioritisation harder to model, given that it is more dynamic in terms of what priority group a generator may end up in from dispatch interval to dispatch interval, which could have a negative impact on investment decisions. We welcome views from stakeholders, particular investors, on this point. We consider that this model does allow for investors to have confidence that, if a constraint binds, the generator would mostly be prioritised over later entrants- this should theoretically be clearer under this model compared to the first three.

Where an investor's modelling outcomes suggest there is uncertainty regarding impacts of prioritisation on dispatch, it could be argued that the area of the network in which the investor is looking to connect may not be a good network location. In this sense, priority access would be working as intended.

Dynamic grouping could provide an option for certain constraints to be excluded from prioritisation. Unlike model options 1-3, the dynamic grouping algorithm would be run before dispatch and only allocate prioritisation (and importantly, not dispatch targets). Therefore, the algorithm does not have to maintain physical feasibility and certain constraints could be excluded if desired. This could potentially address some stakeholder concerns that new entrants may face increased investment risk from priority access when wide-reaching constraints bind. For more information, see section 6.3.

A potential downside of dynamic grouping hardening priority access is that this model would likely lead to larger increases in the RRP relative to model options 1 and 2, if the RRP is set based on the access dispatch in the two-stage dispatch. Therefore, the benefits of model option 4 are likely to be greatest when implemented as part of a hybrid model that sets the RRP based on physical dispatch.

Another consideration is that dynamic grouping would need to be developed and tested, and could be more costly to implement compared to other model options.

4.3.5 Overall assessment of the priority access model options

Our initial overall assessment of the four model options is presented below in Table 4.1.

Table 4.1: Assessment of priority access model options

	Pros	Cons
Model option 1: Grouping by time-window	• Viable and gives improved certainty for investors. • Create a good incentive to invest in a REZ where the priority level received by a new entrant is significantly better (ie at least several levels higher) than it would otherwise receive from locating elsewhere. • Provides a simple, clear and transparent framework for participants, investors and jurisdictions to understand what priority different generators/REZs have against each other, both inside and across states.	• Modelling indicates that only a few meaningful priority levels can be implemented which give a reasonable assurance to participants of effective priority, while also minimising any inflation to the access RRP. • To accommodate 10 priority levels, BPFs would need to be relatively close together which creates soft priority between generators connecting in consecutive years. Prioritisation would only likely be meaningful for generators that connect several years apart or have similar constraint coefficients. • Could create REZ on REZ competition if earlier REZs have priority access over later REZs.
Model option 2: Grouping by time-window REZ model	• Viable and gives improved certainty for investors. • Would enable jurisdictions to create strong. incentives for prospective generators to locate in REZs for prospective generators, while providing some protections for non-REZ generators against other non-REZ new entrants. • Provides a simple, clear and transparent framework for participants, investors and jurisdictions to understand what priority different generators/REZs have against each other, both inside and across states.	• Modelling indicates that only a few meaningful priority levels can be implemented which give a reasonable assurance to participants of effective priority, while also minimising any inflation to the access RRP. • To accommodate 10 priority levels, BPFs would need to be relatively close together which creates soft priority between generators connecting in consecutive years. Prioritisation would only likely be meaningful for generators that connect several years apart or have similar constraint coefficients. • Would likely increase the risks faced by non-REZ generators, as non-REZ generators would no longer be able to get protection against new entrant REZs.
Model option 3: Two-tiers	• Modelling to date indicates that two priority levels with BPFs far apart allows for harder priority access. •	• Would likely increase the risks faced by non-REZ generators, as non-REZ generators would no longer be able to get protection against new entrant REZs.

	Pros	Cons
	• Could provide an appropriate mechanism to provide value to parties connecting in REZs (and potentially other generators and/or locations where there is capacity) and hence it supports efficient investment. • Provides a very strong disincentive to invest outside a REZ (or outside another 'priority' area depending on the design of this option).	• May cause concern for jurisdictions that rely on investments outside REZs, for example to meet state-specific emissions targets. • Stakeholder input to previous consultation has indicated considerable concern with heavy handed limitations and/or disincentive to connection and access to non-REZ areas
Model option 4: dynamic grouping	• Modelling to date indicates that two priority levels with BPFs far apart allows for harder priority access, which may improve investment certainty for investors. • Create a good incentive to invest in a REZ where the priority level received by a new entrant is significantly better than it would otherwise receive from locating elsewhere. • Provides a clear and transparent framework for participants, investors and jurisdictions to understand what priority different generators/REZs have against each other, both inside and across states.	• Harder prioritisation could result in larger increases in the access RRP in the two-stage dispatch compared to other model options. • Dynamic grouping algorithms need to be designed and tested. • Determining the corresponding BPF for a queue position is more complicated, due to the dynamic nature, than other options.

Summary of preferred option: model option 1 - grouping by time-window.

At this stage, model option 1 (grouping by time-window) is the AEMC's preferred priority access model, although the AEMC does see some theoretical merit in dynamic grouping. The downside with dynamic grouping is that this has not yet been tested or developed in any detail. The Commission is particularly interested in views as to whether stakeholders would see merit in option 4 relative to option 1.

Generators (and storage) would be assigned a queue number based on the chronological order in which they (or the REZ where they hold an access right) reach a defined event in the connection process (or REZ development process).

There would be 10 queue positions to represent 9 annual periods for which priority access for participants are grouped. Each year, participants would 'roll' to the next priority level, eventually pooling in the highest level of priority access.

The larger the difference in BPFs between dispatch priority numbers, the harder priority access would be. AEMO's work on implementation indicates that harder priority is unlikely to be achievable in NEMDE without creating unintended impacts on dispatch outcomes and the RRP, and priority access will have a degree of softness.

Question 4: Assessment of priority access allocation models

Each model option outlined in this section addresses the problem and reform objectives to different degrees.

Which model option do you prefer and why?

5 Congestion relief market

The CRM is a voluntary opt-in mechanism in which market participants can seek to revise their dispatch outcomes after access dispatch sets how much they can sell at the RRP. It can be more profitable for CRM participants to revise their position (increase or decrease dispatch) for a range of reasons - for example:

- a generator can decrease its output from access by paying another participant to physically generate instead, profiting on the difference between what it pays the other generator and what it would have cost to generate itself (fuel costs etc.),
- a generator gets dispatched and paid, when it otherwise would not,
- a battery can charge in a congested area at a lower price.

The revision determines the physical dispatch outcomes for participants i.e. leads to increases or decreases in actual output compared to the access dispatch. This revision in outcome from access dispatch to physical dispatch is paid at the CRM price, which is lower than the RRP for generators that are constrained-down (that is, dispatch for less than they are willing to produce at that price). This is different from current NEM arrangements for access where generators are only paid for the MW they physically dispatch into the grid.

Trading in the CRM can be seen as buying and selling ‘congestion relief’:

- Prospective buyers would generally be high cost and high emission generators behind a constraint that are dispatched under the status quo, and who are willing to reduce their output (or loads/storage behind a constraint that increase their consumption),
- Prospective sellers would generally be lower-cost, lower emission generators located behind the same constraint willing to increase output (or loads/storage behind a constraint that decrease their consumption).

Typically, buyers of congestion relief are generators who are dispatched to sell energy at the RRP, but choose instead to pay another generator through the CRM to meet their sale obligation, to avoid the cost of generating themselves. This decision effectively reduces the generation that is contributing to the congestion, i.e. it ‘relieves congestion’.

Participants in a CRM are incentivised to bid more cost-reflectively which will lead to physically efficient outcomes. For generators who do not opt-in to the CRM, their physical dispatch is determined and settled similar to the current arrangements.

Over the course of 2023, the ESB developed a specific design for the CRM component of the hybrid model, which involved a two-stage dispatch. First, a prioritised access dispatch would determine access quantities and RRPs. Immediately after, a physical dispatch would determine physical dispatch targets and CRMPs.

The CRM model, originally put forward by Edify Energy and the CEC, provides grandfathering of existing access to RRP, incentives for cost-reflective bidding and so efficient dispatch, and the ability to opt-in to exposure to local prices (congestion relief market prices or CRMPs) to manage existing trading or contractual arrangements.

The CRM model was more substantially progressed by the ESB than the priority access model, given it has been developed over a longer time period. The ESB have consulted on it twice, in November 2022 and May 2023, in both cases with stakeholder feedback informing detailed choices to advance the design.

The CRM model addresses some of the issues and stakeholder concerns compared to the status quo arrangements and previous access reform models put forward by the AEMC, ESB and others – most notably it allows market participants to opt-in to participating in the CRM.

This chapter:

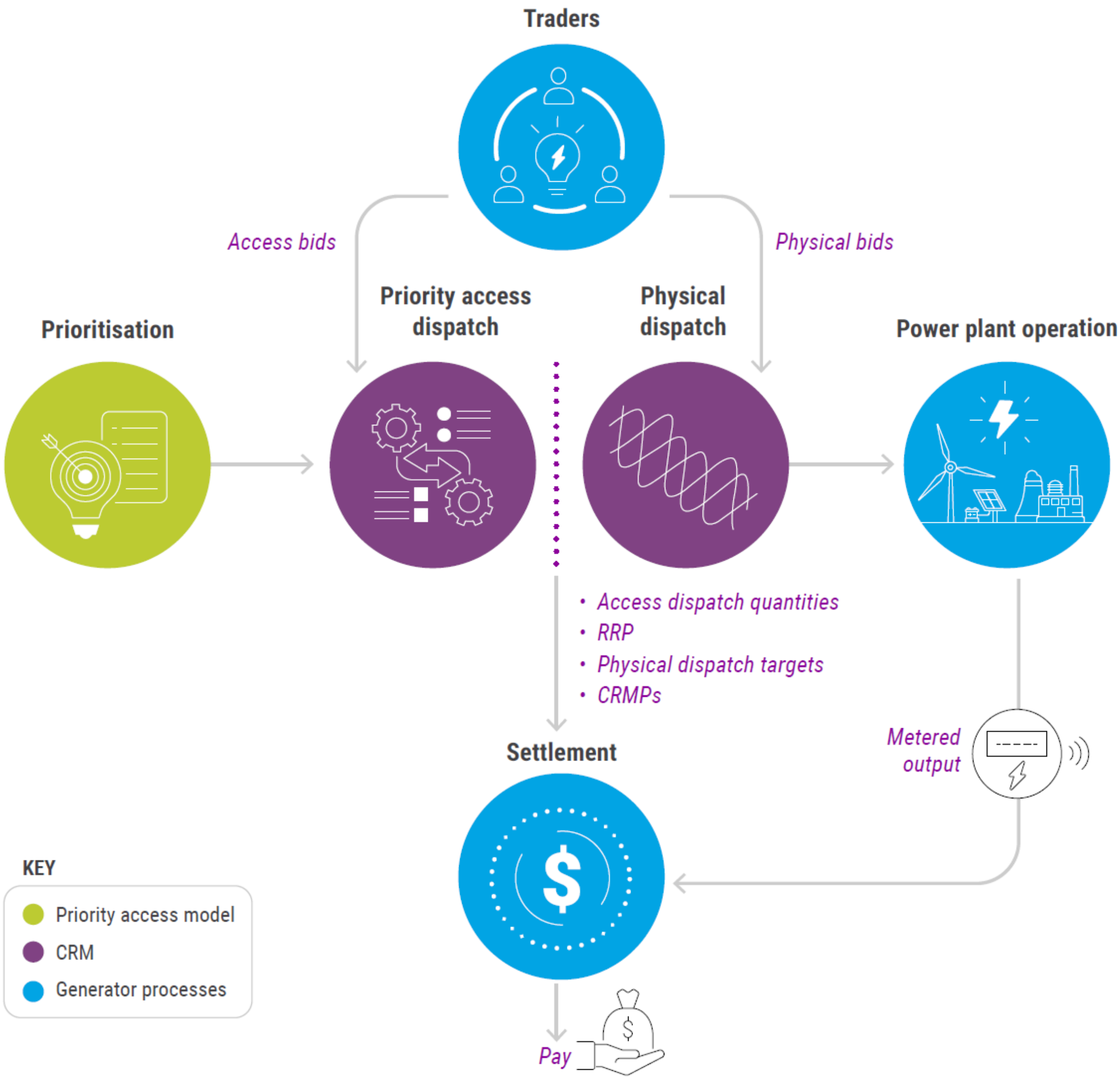
- provides an overview of the CRM, noting its key distinguishing features, and its benefits over the status quo and compared to previously considered access models
- provides a description of the two-stage dispatch and co-optimised dispatch models and assesses them. It explains the reason why the two-stage dispatch model, in combination with priority access, increases RRPs, and how the co-optimised model has been designed to address this problem. It explores potential issues with the co-optimised model. We invite feedback on this topic.
- explores and invites feedback on a number of other outstanding detailed design questions for the CRM model.

Appendix C outlines detailed design choices of the more developed two-stage dispatch model that have been informed by stakeholder feedback.

5.1 Design of the CRM

An overview of the CRM is provided in Figure 5.1 below, with priority access included as part of the access dispatch.

Figure 5.1: Overview of the CRM



At a high level, the CRM changes three components of the existing design: the way market participants bid/offer, the dispatch process, and settlement.

The following description is generic to both the two-stage and co-optimised designs; differences are explored in section 5.5.

5.1.1 Bids and offers

Non-scheduled market participants (i.e. most load, with some generators and storage) do not currently offer/bid into the wholesale energy market. This would continue under the CRM.

Scheduled and semi-scheduled market participants (generators, storage and load) already submit a set of bids/offers into the energy market. Under the CRM model, these existing bids would feed into the *access dispatch* (discussed below). Were the CRM to be combined with the priority access model, the floor price of these bids/offers may be different depending on the priority of the market participants, allowing higher priority market participants to be dispatched in the access dispatch in preference to lower priority generators, all else equal.

For those market participants that do not opt into the CRM, their processes would remain the same. They would continue to submit one set of bids/offers that would be used in the access dispatch, which mimics the status quo dispatch with the addition of priority access. Dispatch outcomes for these participants would be set in the access dispatch and 'locked' for the physical dispatch (i.e. no deviations would be allowed).

For those market participants that choose to opt into the CRM, they would additionally submit a second set of bids which would be an input into the *physical dispatch* (discussed below).

5.1.2 Dispatch

Under the model there are two dispatches:

- An access dispatch which determines access quantities for each scheduled and semi-scheduled market participant.
- A physical dispatch which determines physical dispatch targets for each scheduled and semi-scheduled market participant. For market participants which did not opt into the CRM, physical dispatch targets are set to access quantities. For opt-in market participants, the physical dispatch can differ from the access dispatch.

The physical dispatch targets are then sent to market participants as dispatch instructions, who have regulatory obligations to conform with them like today.[39]

5.1.3 Settlement

Non-scheduled market participants continue to be settlement at the RRP, as now:

- Energy revenue (Non-scheduled) = AGE x RRP

where:

- AGE is the adjusted gross energy (essentially metered energy[40]), and is positive for a generator and negative for a load
- RRP is the regional reference price[41]

All scheduled and semi-scheduled market participants are settled as follows:

- Energy Revenue (Semi/scheduled) = AGE × RRP + **(PQ - AQ) × (CRMP – RRP)**

where:

- CRMP is the local price of the market participant, as determined as the cost in the physical dispatch of meeting another unit of demand at the market participant's node.
- PQ is the dispatch quantity from the physical dispatch, and is positive for a generator and negative for a load.
- AQ is the access quantity from the access dispatch (again, positive for a generator, negative for a load).[42]

The **bold** term is new compared to the current market arrangements.

Because PQ is set to equal AQ for market participants that did not opt-in, the **bold** term equals zero for these market participants, meaning that they are settled as now at the RRP on their AGE.

39 For example, clause 3.8.23 of the NER.

40 See clause 3.15.4 of the NER.

41 How the RRP is determined depends on the choice between the sequential and co-optimised models

42 More accurately, dispatch targets are set for the end of the dispatch interval in units of power (MW). So, an arithmetic process will be required to covert PQ and AQ into energy (MWh) over the dispatch interval (e.g. the average of the respective quantities at the start and end of the dispatch intervals, divided by the number of dispatch intervals in an hour).

5.1.4 CRM trading

In this CRM model, unlike in the original Edify model, there is no explicit trading of congestion relief. However, trading is implied by any difference between the access and physical dispatch quantities. If a generator's physical dispatch is greater (less) than its access dispatch, it can be considered to be selling MW into (buying MW from) the CRM. Generators who do not opt in to the CRM have identical quantities in the two dispatches and so no CRM trading occurs.

5.2 Benefits of the CRM

The benefits of the CRM include:

- A more efficient physical dispatch
- An access dispatch similar to the status quo dispatch
- Participation in the CRM is voluntary.

5.2.1 The CRM would increase efficiency of dispatch and creates trading opportunities

The cost of dispatch will be lower under the CRM model than it is today, all else being equal. This is because the CRM incentivises all generators to bid in based on their operating costs, whereas in today's market, constrained-off generators have an incentive to bid at the market floor price, irrespective of their costs.

Box 4: CRM settlement

Recall that the settlement of scheduled and semi-scheduled generators (excluding losses) is as follows:

- Energy Revenue (Scheduled/semi-scheduled) = AGE × RRP + (PQ - AQ) × (CRMP – RRP).

For simplicity, if we assume that there are no variations between adjusted gross energy and physical dispatch targets, i.e. AGE = PQ, the settlement equation for a scheduled or semi-scheduled market participant simplifies as follows:

- Energy Revenue (Scheduled/semi-scheduled) = AQ × RRP + (PQ - AQ) × CRMP.

Thought of like this, access dispatch is settled at the RRP, while physical dispatch is an *adjustment* to the access dispatch settled at the CRMP. Opt-in generators transact on the difference between their physical and access quantities (PQ – AQ). For generators who do not opt-in, PQ – AQ equals zero.

In the presence of constraints, market participants would continue to have an incentive to 'disorderly bid' in the access dispatch to maximise receipt of the RRP. Indeed, access dispatch outcomes are likely to be less efficient that currently because of prioritisation, described in the previous chapter.

However, instead of disorderly bidding in the physical dispatch, a more profitable strategy is to express their willingness to buy and sell in the CRM with their physical dispatch offers. By offering at their short run marginal cost as opposed to at the market floor price:

- Any *decrease* in physical dispatch compared to the access dispatch will be paid for at a price less than the marginal cost of being physically dispatch – increasing profit.
- Any *increase* in physical dispatch compared to the access dispatch will result in a payment at a price more than the marginal cost of being physically dispatch – again, increasing profit.

Generators therefore have an opportunity to improve their profitability by participating in the CRM. For example:

- A relatively high-cost generator (e.g. coal or gas) that is dispatched in the access dispatch should be willing to reduce their output and instead *buy* congestion relief (i.e. have physical dispatch lower than access dispatch) providing their CRMP is sufficiently low – because it would be more profitable by avoiding costs associated with generating and instead paying a lower cost generator for its output instead.
- Conversely, a low-cost generator (e.g. variable renewables) that is not fully dispatched in the access dispatch would be willing to *sell* more energy (i.e. have physical dispatch higher than access dispatch) because it can still be profitable selling energy even if the CRMP is relatively low.

It would not be profit-maximising for generators to bid disorderly in the physical dispatch because it risks selling congestion relief while being settled at a very low CRMP. Because of the improved incentives to reveal their short run marginal costs, as opposed to bidding disorderly, the physical dispatch is more efficient. Note that, because these incentives are in the physical dispatch where only opt-in participants are bidding, the access dispatch outcomes from priority access are retained. Appendix D.2.2 presents a worked example of how the CRM can lead to a physically efficient dispatch while functioning effectively with priority access.

Of course, there are lots of complicating factors which affect generators' bidding behaviours. Like now when the system is unconstrained, generators will have an incentive to bid above their fuel costs to increase the price they receive. Contracts will also affect their bidding behaviour. Nevertheless, we expect that bidding efficiency will materially improve as a result of the CRM, particularly as contracts roll off and market participants have an incentive to form new contracts which allow them to receive the benefits of CRM trades.

Storage (such as batteries) and scheduled loads can increase their profit by participating in the CRM. In the CRM, load in congested areas would be able to effectively buy their energy at CRMPs below the RRP, reducing costs and increasing potential profits for storage. For a worked example of how storage or scheduled loads can benefit from the CRM, refer to appendix D.3.

The absence of disorderly bidding in physical dispatch can lead to changes to interconnector flows too, meaning that CRM trading can occur between generators in different regions who do not even participate in the constraint that is causing congestion. This is due to a "gearing" effect in dispatch, arising because the interconnector has a relatively low coefficient in a constraint compared to generators close to the constraint. This is commonly seen in actual dispatch outcomes, whereby generators constrained off in SW NSW bid at the MFP, causing NEMDE to reduce northerly flows on the Victoria-NSW interconnector (VNI) in order to allow those generators to be dispatched.

In the hybrid model, this outcome is likely to occur also in access dispatch (where disorderly bidding will continue), but will be unwound in physical dispatch, allowing for northerly flows on VNI to be restored. Refer to appendix A.1.1 for more information.

Box 5: Multilateral CRM trades

When considering the CRM, it's often easier to think of two market participants trading 'behind' a single constraint. For example, a relatively high-cost generator which has been provided access in the access dispatch physically generates less and instead purchases congestion relief from a relatively low-cost generator which is not provided access in the access dispatch – lowering overall dispatch costs compared to the status quo.

Under these trades the benefits to consumers are not obvious or immediate. Both generators increase their profit because of the reduced cost of dispatch, but consumers continue to pay the (unchanged) RRP, and so are no better off, at least in a snapshot dispatch interval.

However, modelling undertaken in 2023 suggested that this is not expected to be a typical trade. Most market participants 'utilise' constraints differently to one another, depending on their location. For example, imagine a situation where for each 0.5MW that a high-cost generator utilises of a constraint, a lower cost generator utilises 1MW. Under the access dispatch, if both generators bid at the market floor price (ignoring priority access), the higher cost generator will be dispatched because it uses less of the scarce transmission constraint. The CRM might lower the cost of the physical dispatch by:

- reducing the high-cost generator by 20MW (*buying* congestion relief instead),
- increasing the lower cost generator by 10MW (*selling* congestion relief),
- increasing the generation of another generator that does not participate in the constraint by 10MW to ensure that supply and demand are in balance.

Counter-intuitively, this third generator is also selling congestion relief despite not participating in the relevant constraint because its output has gone up compared to the access dispatch (PQ – AQ > 0).

Further complicating this picture is that:

- the participating generators can be in multiple regions,
- there can be more than one constraint binding simultaneously.

This isn't a problem however. The dispatch process is able to determine the most efficient change in physical dispatch versus the access dispatch given the bids, and it is trivial to determine the difference between the dispatches for settlement purposes.

Furthermore, while it may not be immediately obvious, in these more complicated cases there is typically more than enough money paid by buyers of congestion relief to pay sellers – leaving some settlement residue. This money can be returned to consumers. Modelling undertaken in 2023 suggested that consumers' share of the efficiency gains (compared to generators' share) may be significant.

5.2.2 Access dispatch is allocated to market participants through a process like the current dispatch

Under the CRM, access is allocated to market participants through a process like today's dispatch.

There are two motivations for basing generator access on dispatch. First, dispatch (and hence the amount of access) must comply with transmission constraints, which ensures that the market can settle: there is enough money paid into settlement by retailers (who pay RRP) to cover the cost of paying generators at RRP for their access.

Second, because dispatch (and hence the amount of access) must also reflect generator capabilities, it allows generators to physically follow their access dispatch if they wanted to. This accommodates those generators that choose not to opt-in to participating in the CRM.

If generators bid the same way into access dispatch as they do today then the level of access provided to each market participant will remain the same, minimising the impact of the existing generators arising from the reforms. This is not strictly achieved as bidding incentives will change somewhat, but it is a reasonable approximation that helps to reduce the impact on existing market participants of introducing the CRM.

5.2.3 The CRM is a voluntary, opt-in scheme

Market participants can choose not to opt into the CRM. If a generator does not participate in the CRM, their physical dispatch (the amount AEMO requires them to produce) would be identical to their access dispatch. This means that all of their output is settled entirely at RRP, with no exposure to their CRMP.

We consider that the scenarios where generators do not opt-in would typically be where they may have an existing power purchase agreement (PPA) which implicitly assumes a single settlement price. As discussed further in section 6.1, this PPA may need to be re-opened and potentially re-negotiated to make it suitable for dual settlement prices. Allowing the CRM to be voluntary, means such parties could continue to be exposed to the RRP until such a point in time when they enter into a new PPA or renegotiating their PPA becomes commercially viable. This reduces the transaction costs associated with implementation of the model. For more information on the CRM and PPAs, see section 6.1.

Of course, the ability of generators to not opt in is a double-edged sword. A lack of participation in the CRM could:

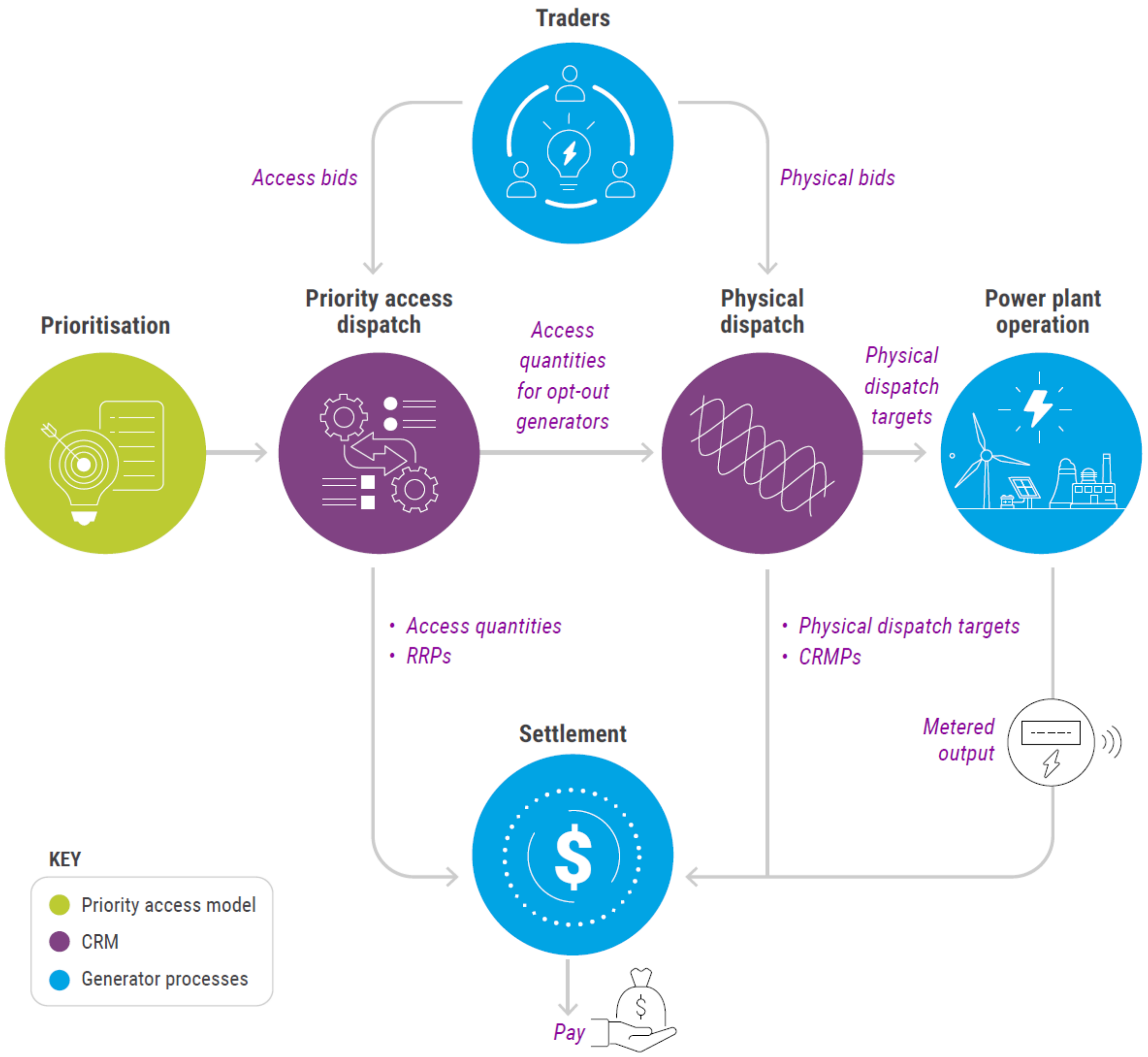
- at best, result in lower efficiency gains compared to those estimated in the cost benefit analysis,
- at worst, in combination with the priority access model, reduce efficiency over time as incumbent priority generators are – by not opting in – physically dispatched instead of incoming lower cost generators than would otherwise be dispatched in the existing arrangements.

We consider it likely that generators will participate in the CRM for the reasons explained above. That is, to the extent that the dispatch is inefficient under the status quo arrangements, it would generally be more profitable for individual market participants to opt into the CRM. If it is not profitable for an individual to opt into the CRM, this likely indicates that the efficiency benefits from their participation are rare and modest. In the short term, non-participation in the CRM may be indicative of high transitional costs associated with the need to renegotiate existing contracts. As these contracts roll off, the need to renegotiate ceases. When entering into new contracts, we consider it would be in the interests of the contracting parties to enter into arrangement that enable parties to take advantage of the opportunities for additional profit afforded by the CRM.

5.3 Two-stage dispatch

The version of the CRM developed by the ESB has two separate dispatch runs. An overview of this two-stage dispatch design is provided below in Figure 5.2.

Figure 5.2: Overview of the two-stage dispatch



5.3.1 Dispatch under the two-stage approach

The two dispatches are run one after the other. Access dispatch is run first. As now, it establishes the lowest cost combination of generation to meet demand given physical system constraints, but in this case taking account of *access bids/offers*.[43]

The access dispatch determines:

- access dispatch quantities for each scheduled and semi-scheduled market participant,
- the RRP for each region.

Physical dispatch runs immediately (e.g. a few seconds) after the access dispatch. For market participants which did not opt into the CRM, their access quantity is fed into and 'fixed' in the physical dispatch, so that their physical dispatch target equals their access quantity. The opt-in generators' offers in the physical dispatch are then taken into account, being dispatched to

43 Strictly, the combination of generation and load which maximises the value of trade – which equals the lowest cost combination of generation to meet demand if there is no scheduled load.

minimise the cost of dispatch to meet demand given the same physical constraints as the access dispatch. In a sense, the physical dispatch of generators that do not opt into the CRM are determined 'first' by the access dispatch, with the remaining, opt-in generators then dispatched 'around' them. The physical dispatch determines:

- Physical dispatch targets which are the same as access quantities for generators that do not opt in to the CRM, but may differ from the access quantities for opt-in market participants.
- Local congestion relief market prices (CRMPs) for each market participant that opts in.[44]These prices differ from one another in the presence of congestion.

The access dispatch must be complete and feasible. This is to cover the scenario (however unlikely) where *every* generator opts out, meaning that physical dispatch is forced to be identical to access dispatch. An infeasible access dispatch would then lead inexorably to an infeasible physical dispatch, which would obviously be unacceptable. This limitation means that access dispatch must include constraints that are not related to access, such as frequency control ancillary services (FCAS). However, this also helps ensure that the access dispatch is similar to the current dispatch, helping to ensure that the CRM is voluntary.

It is possible that the need for two complete and consecutive dispatches in the current design will create some operational challenges, particularly where dispatch re-runs are needed in the status quo, e.g, for intervention pricing. However, the development challenges are likely to be modest, given the similarity of the NEMDE functionality to the status quo. Indeed, the successful development of the NEMDE prototype gives some confidence in this respect.

5.3.2 Bidding under the two-stage approach

Access dispatch would be per today's dispatch and would be made by generators who opt-in and do not opt-in.

Generators who do not opt-in would not need to make separate bids into physical dispatch.

Physical bids for opt-in generators would be as they are today: 'gross' bids. That is, generators would express their willingness to be dispatched for a particular quantity for a particular price. All opt-in generators would therefore submit two complete sets of energy bids. This approach has the advantage of being the same as today, minimising cost and complexity for generators and AEMO.

Generators would also be able to specify quantity limits– the maximum difference between their access and physical dispatches.

5.3.3 Settlement and choice of RRP under the two-stage approach

The two, complete dispatches two-staged dispatch model means that two sets of RRPs are generated, presenting a choice of which to use for settlement:

- access RRP - calculated in priority access dispatch,
- physical RRP - calculated in physical dispatch.

The ESB considered that the access RRP was the preferred RRP choice, and this remains the AEMC's preference between the two options.

44 More accurately, local prices are calculated by the dispatch engine currently, and would be calculated by both the access dispatch and the physical dispatch under the CRM model. However, only the local prices from the physical dispatch for opt-in generators are used for settlement.

Table 5.1: Three choices of RRP under the two-stage dispatch

	Status quo	Access RRP	Physical RRP
How is RRP calculated	Based on a single dispatch which determines both access and physical dispatch.	Based on access dispatch, so arguably same as status quo.	Based on physical dispatch, so arguably same as status quo.
Bidding strategies in the RRP-setting dispatch	Constrained-off generators bid at MFP. Constrained-on gens bid unavailable. Others bid cost-reflectively.	Generators bid into access dispatch at BPF if expect CRMP<RRP (even if they are out-of-merit), or unavailable if expect CRMP>RRP (even if in-merit).	All generators bid cost-reflectively into physical dispatch, including those constrained on or off.
Prioritisation	RRP based on unprioritised dispatch.	RRP based on prioritised dispatch.	RRP based on unprioritised dispatch.

Box 6: A choice of RRP

Unfortunately, neither option for the RRP is perfect. If the RRP from the physical dispatch is used, we consider would have more downsides compared to the access RRP:

- **Generators who do not opt in are constrained on:** Generators that did not opt in may be physically dispatched but paid a price less than their offer price. For example, an unconstrained generator that does not opt in may bid at $90/MWh in the access dispatch. The RRP in the access dispatch is $100/MWh so, because the generator is unconstrained, it is dispatched in the access dispatch. As it does not opt into the CRM, its access dispatch automatically becomes its physical dispatch. But if the RRP from the physical dispatch is $80/MWh, the generator is being dispatched at a loss – effectively 'constrained on'.
- **Perverse access bidding incentives:** Unconstrained generators would have no exposure to the access RRP. While this had the advantage of simplifying their settlement, it also means that access quantity would be irrelevant for its settlement. This could introduce new incentives to bid disorderly in the access dispatch (perhaps to alter the access of its competitors or other generators in its portfolio).
- **Possible impacts on the voluntary nature and the contract market:** Contracts would be set on the physical RRP set in the physical dispatch, and generators with contract or retail positions may need to participate in the CRM.

However, using the RRP from the access dispatch can sometimes have its own downsides. As noted in section 3.2, the prototyping exercise showed that sometimes the implementation of priority access may impact the RRP.

Additionally, using the RRP from the access dispatch could be considered changes settlement. Generators that are not physically constrained and so have a CRMP equal to the RRP from the physical dispatch have the following settlement: Their access will be paid on the RRP from the access dispatch, while the difference between their physical and access dispatch will be paid on the RRP from the physical dispatch.

In addition to the issues raised above with the physical RRP, among other things, stakeholders also suggested that:

- It is inconsistent with the idea that generators who do not opt into the CRM are settled at the price taken from the dispatch which reflects CRM bids.
  - We note that there is some debate relating to this argument. By analogy, generators can decide to not opt into the FCAS markets, but bids by others in those markets nevertheless influence the RRP for energy that they are settled at. It seems implausible to suggest that the FCAS markets are not 'voluntary' as a result.
- Using the RRP from the physical dispatch would represent a change to the existing definition of the RRP, and so could prompt costly contract re-openings.
  - We note it is debateable which RRP is the 'true successor' of the status quo RRP, given that both access and physical dispatch are currently determined in the same dispatch and both RRP options separate that.

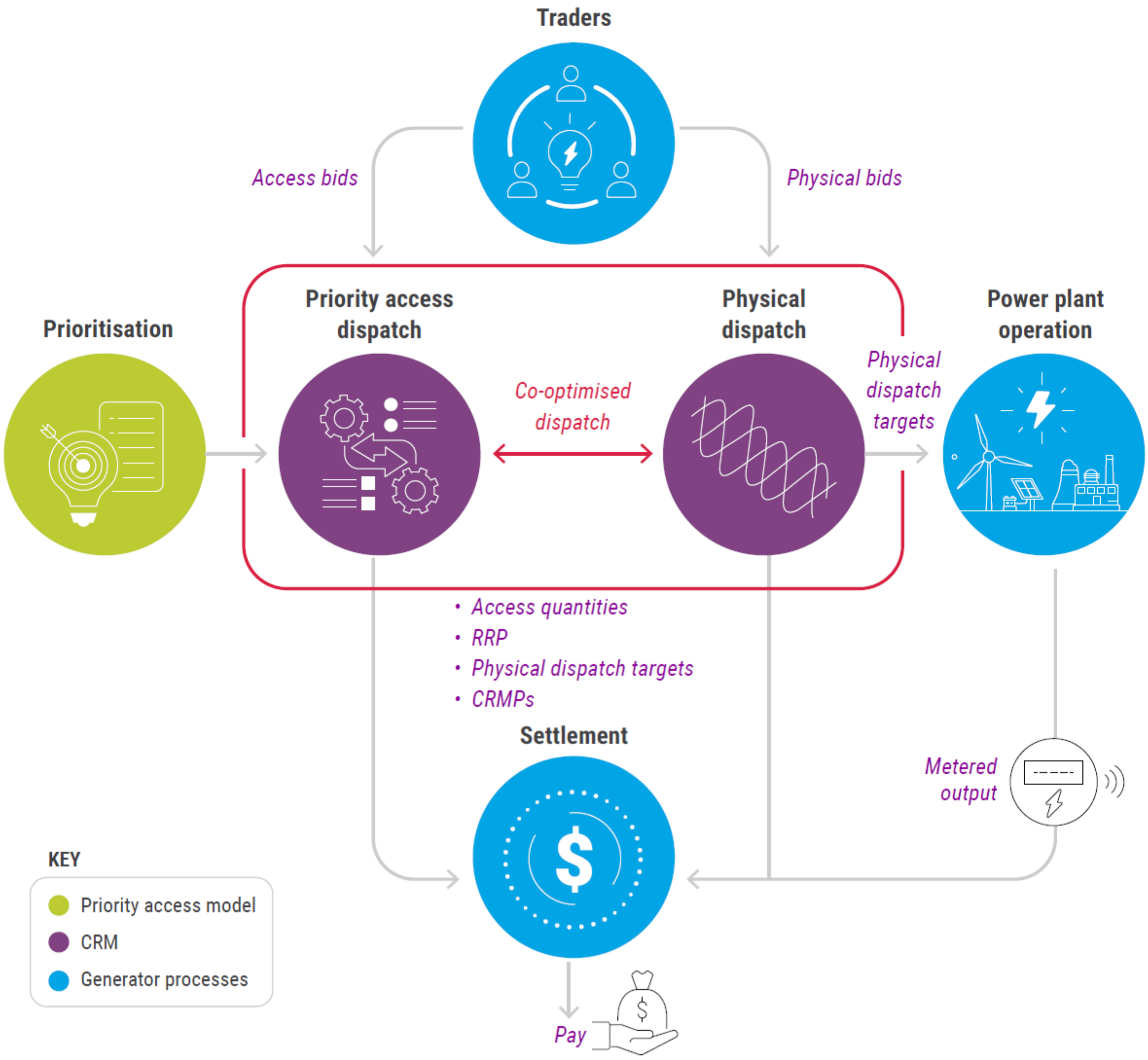
The prototyping analysis showed that in certain circumstances, the implementation of priority access may be difficult to predict and impact the RRP.

5.4 Co-optimised dispatch

As discussed in section 5.3.3, neither RRP option under the two-stage dispatch is ideal. Therefore, while the access RRP is preferred over the physical RRP, the ESB began considering in late 2023 whether an alternative implementation option could provide an RRP option that avoided issues with the two-stage dispatch RRPs. This consideration has led to the consideration of co-optimisation as an alternative implementation method for the CRM, which may provide an RRP that carries neither of the issues with the access RRP or physical RRP. We note that this co-optimised method has not been developed to the level of detail as the two-stage dispatch.

Co-optimisation refers to the two dispatches being carried out at the same time. This means that access dispatch can be set taking account of physical dispatch, and *vice versa*. In the two-stage architecture, this influence only goes one way: access dispatch can affect physical dispatch but *not* vice versa.

Figure 5.3: Overview of the co-optimised dispatch



Co-optimisation is used in today's dispatch, for energy and FCAS, for example. It is a conventional optimisation problem, with a single objective function which minimises the combined cost of the access dispatch targets and physical dispatch targets, and a set of constraints.

The objective function needs to reflect the combined cost of the two dispatches. This would be designed to avoid double counting. For example, if a generator is dispatched at 90MW in access dispatch and 100MW in physical dispatch, simply adding the cost of the two dispatches would reflect the cost of dispatching the generator at 190MW and so the objective function could then be minimised by just dispatching the generator in one or the other dispatch. To avoid this, the objective function would reflect the cost of dispatching the generator at 90MW in access dispatch and then an *additional* 10MW in physical dispatch, at the access and physical offer prices respectively.

With a co-optimised architecture, there is no need for access dispatch to be always feasible; in the unlikely scenario of zero CRM participation, the co-optimisation will automatically ensure this is the case anyway, and there is no over-riding reason for it to be feasible the rest of the time. This means that constraints that are not relevant to access can now be left out of access dispatch.

Importantly, the co-optimised design leaves FCAS and regional energy balance constraints out of the access dispatch; the rationale being they only affect the dispatch of FCAS and of unconstrained generators, neither of which is relevant to access. The constraints used in the two dispatches under the two designs are shown in Table 5.2 below.

Table 5.2: Constraints included in dispatch

Constraint category	Physical dispatch	Priority access dispatch	
		Two-stage	Co-optimised
Availability	Included	Included	Included
Ramping	Included	Included	Included
Transmission	Included	Included	Included
Regional Energy Balance	Included	Included	Not included
FCAS	Included	Included	Not included
CRM opt in/out constraints	Included	Not included	Included
Negative Residue Management	Not included (see note)	Included	Included

Note: Negative Residue Management is not needed in physical dispatch because settlement is nodal.

Because access dispatch does not need to be feasible and there are no regional energy balance constraints, it is also an option to permanently clamp the interconnectors in the access dispatch. This would relieve AEMO of the operational challenges of deciding when and when not to clamp. It is feasible under the co-optimised model (but not the two-stage dispatch) because interconnector flows in access dispatch affect neither RRP nor physical dispatch outcomes.

AEMO developed an Excel spreadsheet implementation of the co-optimisation logic using one of the test models that was used in calibrating the NEMDE prototype. AEMO has raised some concerns:

- The co-optimisation RRP is influenced by CRM bids and could indicate that the CRM is less voluntary with co-optimisation, similar to the physical RRP.
- The lack of a regional energy balance constraint means that access dispatch (and therefore payments at RRP) is no longer necessarily balanced with demand (and therefore receipts from market customers). This means that there could be the potential for settlement shortfalls which may be beyond the ability of TNSPs to absorb. The AEMC also considers that the further investigation is needed regarding inter-regional settlement residues.
- The test model redistributed inter-regional residues into intra-regional CRM residues which would require a new allocation process to distribute. The AEMC notes that the intra-regional CRM residues align with the same CRM residues that arise in the two-stage dispatch and would be allocated back to consumers (see appendix C.5).
- The combination of access and physical delta bids is more complicated than the existing bidding arrangements and may allow bid combinations that could potentially undermine priority access. The AEMC is considering a solution to address this in section 5.4.1.

Untested areas include the potential for gaming in access bidding given it does not represent a full physical dispatch (omits FCAS for instance) and may include distortions such as permanent clamping.

The co-optimised design will require substantial changes to NEMDE and associated systems (such as bidding and settlement), which have not been tested or costed like the two-stage dispatch option. This would be a more complicated NEMDE implementation compared to two-stage dispatch, in particular the creation of a new 'delta' bid structure for the CRM. However, we consider that some confidence can be drawn from the fact that co-optimisation of FCAS was successfully introduced into NEMDE when these became market ancillary services.

5.4.1 Bidding under the co-optimised approach

Because the dispatch function optimises the combined cost of the access dispatch and the *change* to the access dispatch caused by the physical dispatch generators would submit 'net' bids to the physical dispatch. That is, generators would specify the price they are willing to be paid/pay to increase/decrease their physical dispatch compared to the access dispatch (i.e, to sell or buy congestion relief). This is different to the 'gross' bids submitted under both the status quo and two-stage dispatch designs.

We expect that only constrained, opt-in generators - who are incentivised to bid disorderly in the access dispatch - would make these incremental/decremental bids compared to their access quantities. Unconstrained generators are not expected to bid disorderly in the access dispatch and so their willingness to sell is already reflected in their access bids.

Quantity limits which specify the maximum difference between the physical and access dispatches – an 'add-on' design feature in the two-stage design – are inherent in the co-optimised design with incremental/decremental bidding.

Dispatch co-optimisation means that physical bids can affect access dispatch outcomes. Specifically, between two otherwise equal generators, NEMDE will preference in access dispatch the generator who can, as a result of this dispatch, provide extra value in physical dispatch (e.g, by allowing its decremental bid to be dispatched). To correct for this effect, the bid price floor rules used to determine priorities in access dispatch must now capture the impact of both access and physical bids.

In the two-stage dispatch model, the bid price floor is simply applied using the formula 'access offer price ≥ BPF', where BPF is a fixed value based on the generator's priority.

The co-optimised dispatch requires a more involved formula, of the general form 'access offer price - extra value in physical dispatch ≥ BPF'.

For example, if BPF= -\$1000/MWh, and the value from physical dispatch is +\$100/MWh, the access offer price can be no lower than -\$900/MWh. With this correction, NEMDE is again indifferent between two equivalent generators both bidding at their respective bid price floors. Generators would not need to worry about this adjustment; they would bid into access dispatch at the normal BPF (e.g. -\$1000) and their bid would automatically be adjusted by AEMO to comply with the above formula.

The AEMC is currently developing the formula for calculating this extra value and considering any associated implications.

5.4.2 Settlement under the co-optimised approach

Under the co-optimised design, there is no choice of RRP; there is only one regional energy balance constraint from the physical dispatch and this is used to set the RRP for settlement. This addresses the problems with either choice of RRP from the two-stage dispatch:

- The RRP is *not* set by priority access dispatch and so is not directly impacted by prioritisation (noting that there could still be *indirect* impacts if there is a low level of opt in).
- The co-optimisation architecture ensures that unconstrained, generators who do not opt in are not 'constrained on'. Instead, they will only be physically dispatched if their offer price is below the RRP.
- Unconstrained generators will have far simpler settlement than under the two-stage dispatch approach using the RRP from the access dispatch – settled at their dispatch multiplied by the RRP (ignoring losses and variances between dispatch and adjusted gross energy).

5.4.3 Comparison of the co-optimised model versus sequential dispatch

The two-stage dispatch option has been more thoroughly designed by the ESB over the course of 2023. A number of detailed design decisions are outlined in appendix C.

It is not yet clear whether each of these decisions will apply in the co-optimised model. Some decisions may change or are moot. For example, as there are no FCAS constraints in the access dispatch in the co-optimised model, there is no need to consider the nature of FCAS bids in the access dispatch, nor opt-in status for FCAS. FCAS bids would not be required for the access dispatch; the access dispatch would not determine FCAS quantities or prices and so no possibility (or need) for market participation to opt in to settlement at different FCAS prices.

A summary outlining our initial assessment of the detailed design decisions is provided in Table 5.3 below.

Table 5.3: Comparison of design elements between the two-stage dispatch and co-optimised dispatch designs

Design Element	Proposed Design (two-stage design)	Same or different under co-optimised design
Who participates in CRM	Schedule and semi-scheduled gens, scheduled load, scheduled storage, MNSPs.	Same.
Rounding of constraint coefficients	No rounding.	Same.
Bidding regulations	No, at least initially. Post implementation review to assess whether bidding regulations required.	Same.
Settling variances (difference between dispatch and actual)	At RRP.	Same.
Allocate CRM residues	Allocated to customers via TUoS or NEM settlements.	Same.
Clamping and treatment of inter-regional residues	Largely replicates the status quo.	Either the same as status quo, or permanently clamp the

Design Element	Proposed Design (two-stage design)	Same or different under co-optimised design
		interconnectors, resulting in no inter-regional settlement residues.
Treatment of MNSPs	Generator-load pair.	Same.
Structure of CRM bids	Quantity limit on LMP exposure. No buy-sell spreads.	Design question moot under the co-optimised design. Quantity limits and buy-sell spreads are intrinsic under incremental/decremental bidding.
FCAS bidding	One set of bids.	Design question moot under the co-optimised design.
Opting in to CRM FCAS	Not permitted.	Design question moot under the co-optimised design.
Bid floor price in access dispatch	Moot – issue does not arise in the two-stage dispatch because access dispatch cannot be affected by physical dispatch and so there are no incentives to disorderly bid in physical dispatch.	As discussed above, access dispatch can be affected by physical dispatch, and so there may be incentives to disorderly bid in physical dispatch. Approach to address this issue TBC.

5.5 Overall assessment of the CRM implementation approaches

A summary of the features for the two-stage and the co-optimised implementation approaches for CRM is provided in Table 5.4 below.

Table 5.4: Features of CRM implementation approaches

	Two-stage	Co-optimised
Dispatch	Both dispatches are complete and feasible to ensure physical feasibility	Access dispatch is not complete and feasible - FCAS and regional energy balance constraints not included. Physical dispatch is complete. Physical feasibility is assured even if everyone opts out through co-optimisation.
Bidding	Access – gross Physical – gross (and voluntary)	Access – gross Physical – net (and voluntary)
Settlement	At the access RRP from the prioritised access dispatch	At the only RRP – from the physical dispatch outcomes

We consider that both approaches allow the benefits of the CRM to arise:

- increasing the efficiency of dispatch,
- allowing generators to not opt-in and only be settled at one price, the RRP,
- resulting in an allocation of access which is broadly consistent with the status quo, and minimising the impact of the CRM's introduction on incumbent generators.

Our view is that the theoretical benefits of co-optimisation do seem to have significant promise. It would mitigate the impacts on the access RRP (the preferable two-stage dispatch RRP) from priority access while also avoiding issues associated with the physical RRP, such as pricing inconsistencies for generators who do not opt in.

However, we also acknowledge that implementation costs would be higher than the current sequential dispatch method. AEMO have confirmed this with us, and so the benefits of the model would need to be higher to offset these costs.

We also recognise that there could be a perception that co-optimisation is less voluntary than the current lead model as CRM bids could affect or set the RRP that all participants face, including participants who do not opt into the CRM. We recognise that the voluntary nature of the lead model is a key benefit of the reform. We are interested in stakeholder views on this issue. Alongside this, there is the potential that bidding would be more involved. We are also interested in stakeholder views on this.

As previously mentioned in section 5.4, AEMO has raised concerns regarding the potential for unfunded settlements, and whether clamping would continue to be effective, under this model given that there is no regional energy demand balance. We consider the intra-regional settlement residue is almost always positive in the CRM, however the inter-regional residues warrants further investigation. We welcome stakeholder views on this point.

Question 5: Assessment of CRM implementation approaches

What are the relative advantages and disadvantages of each design?

Do stakeholders have a preferred design and if so, why?

6 We are considering a number of key concerns raised by stakeholders

Our project plan highlighted that there are five key stakeholder concerns that we need to consider whether we can satisfactorily mitigate and / or address stakeholder key concerns. These are:

1. Can participants meaningfully model the impact of priority access for new projects in a way that provides more efficient locational signals to investors? The work we are doing to answer this question is discussed in section 3.3.
2. To what extent do the inclusion of unpredictable constraints (e.g. outage/system strength) in priority access create unacceptable risks for participants and, if so, how could this be addressed? This is discussed further below.
3. What are the impacts of the hybrid model on PPAs? This is discussed further below.
4. How will the hybrid model impact the electricity market? This is discussed further below.
5. Risk of priority access being allocated late in a generator's investment and planning process, creating risks for investors. This is discussed in section 7.1.3 and section 7.1.4.

6.1 What is the impact of the hybrid model on PPAs?

Several stakeholders have expressed concern that introducing the hybrid model will result in participants having to reopen and renegotiate existing power purchase agreements (PPAs). Stakeholders have also expressed a concern that certain behavioural clauses found in some PPAs may mean that introduction of the CRM could have unintended outcomes for some generators.[45]

In response, in order to evaluate the materiality of concerns raised by industry bodies, the ESB/AEMC considered:

1. the possible triggers that could result in the reopening of long-term PPAs, both from the introduction of access reform in general and from a change to the RRP in particular,
2. whether maximum generation (and other behavioural) obligations found in some PPAs could result in unintended consequences.

In general, the AEMC considers that the impact of the reforms on a particular PPA will depend heavily on:

- the specifics of how access reform is implemented (including whether there are any grandfathering protections included in the TAR reforms),
- the specific terms of that PPA and the views of the parties about how their PPA and the associated generator is affected.

These views are generalisations based on a range of long-term, generation following renewable PPAs seen in the market, and are not specific views on any particular PPA. The interpretation of a contract is always on a case-by-case basis, and there may be PPAs in the market with specific drafting that could more easily be construed as either triggering a reopening, or 'forcing' a generator to participate in the CRM.

45 In recent meetings with industry peak bodies (AEC, CEC, AFMA, CEIG), a recurring concern raised by participants regarding the reform is that these "maximum generation clauses" found in some PPAs will effectively force generators to participate in the CRM, and that the voluntary nature of the CRM is therefore unlikely to hold true in practice.

Question 6: Feedback on impact of the hybrid model on PPAs

What are stakeholder views on the observations and AEMC initial views regarding impacts of the hybrid model on PPAs?

6.1.1 Triggers for reopening PPAs

Observation 1: Many PPAs commonly seen in the market (basic ISDA and bespoke PPAs) contain provisions for 'change in law' and 'market disruption events'. The introduction of the reforms is more likely to trigger these provisions, and therefore a reopening, where:

- There is a material change to the existence, operation or calculation of the spot price/RRP in a way that prevents or fundamentally interferes with the PPA transaction.
- A party argues the reform is a fundamental change in the design of the NEM and seeks to reopen on the basis it materially changes the way a generator may participate in the NEM.
- A party argues, and seeks to reopen the PPA on the basis, that the reforms otherwise prevent or materially interfere with the PPA transaction.

The extent to which the CRM reforms interfere with the transaction will depend on the changes that are made to the RRP. In this regard:

- A change to RRP outcomes would likely not, in itself, trigger reopening. This reflects the fact that the purpose of the contracts is to hedge exposure to RRP. Therefore, a change in value alone of the RRP does not change how (or whether) the parties are hedged against that price. In other words, it does not interfere with the fundamental transaction.
- Some parties could argue that the loss of a single 'spot price' where retailers pay, and generators receive, a common price (i.e. the introduction of a second CRM price) may trigger a change in the calculation of the spot price. However, it could also be argued that for generators opting out of the CRM, the "single price" requirement is maintained, irrespective of RRP choice.
- Whether a change to the formulation or calculation of spot price/RRP triggers a reopening depends on which of the RRP options (if either) represents a continuation of the status quo and which (if either) represents a change from it. Depending on the extent of the change made to the formula for, or the method of calculating, the RRP, there may be differences of opinion in the market as to whether the reforms constitute a "material" change or not, or whether it interferes with the parties transaction or not.

Observation 2: Priority access may trigger a reopener where the manner in which priority access is implemented (e.g. varying bid price floors) amounts to a fundamental change in the NEM design. Depending on the manner in which priority access is implemented, there may be differences of opinion in the market as to whether the reforms constitute a "fundamental"change or not, or whether it interferes with the parties' transaction or not.

Observation 3: It may be material to the contractual implications for the parties under a particular PPA whether the impact of the TAR reforms on the RRP, or the impact of the TAR reforms on the relevant generator, are minor or major.[46]

46 NSW Generation LTESAs, as an example, contain a specific reopener for 'LMP Events' that will likely be triggered by any congestion relief / TAR reforms pursued by the ESB/AEMC, provided a 'Cost Change Threshold' that is specified in the relevant LTESA is exceeded.

Overall, the contractual implications of a reopening will depend on the impact of the changes on the relevant PPA transaction, the potential solutions to address it and whether the terms of the PPA place parameters/constraints on the outcome to guide what changes may/may not be made to the PPA.

AEMC initial view: Under the reform, the price being paid by retailers and received by generators would be the same unless a generator chooses to opt into the CRM, thereby reducing the risk that the PPA requires renegotiation (and, where a PPA is re-opened, provides PPA counterparties with an incentive to maintain existing contracts by negotiating appropriate changes). We note that the hybrid model differs in this respect from the COGATI FTR/LMP model, which was not voluntary and applied two different prices to retailers and generators. In addition, many PPAs will expire at the time, or shortly after, the reforms would be implemented, reducing these risks. The voluntary nature of the CRM also reduces these risks. We note that the sharing of a stylised network model of the reform may help stakeholders understand the impacts of the reform in a way that helps inform future negotiations.

6.1.2 Maximum generation obligations

Observation 1: Of the behavioural obligations identified, it is only the 'maximise generation' obligation that will ordinarily have a tangible enough relationship to participation in the CRM to theoretically present a risk that PPA counterparties argue it is a reason a generator should participate in the CRM. However:

- These 'maximise generation' obligations are typically "reasonable endeavours" obligations, meaning they are qualified by what a reasonable person would do in the generator's circumstances.
- These 'maximise generation' obligations should also be read in the context of the PPA as a whole, including other relevant behavioural obligations (e.g. a minimum generation obligation setting a floor for the volume of electricity to be traded under the PPA), as well as the factual circumstances of the generator (e.g. the extent to which it is affected by network constraints).

Accordingly, it is likely that an opportunistic buyer would have difficulty arguing that such an obligation requires a generator to participate in the CRM.

Observation 2: A large number of existing PPAs are due to expire in 2030, when the RET scheme is scheduled to end. If the CRM is introduced in 2028, the pool of potential affected PPAs will likely decline after two years (noting that there will still be existing PPAs that extend after 2030). The exposure risk will decrease as newer PPAs start incorporating drafting to accommodate the CRM and older PPAs fall away.

Observation 3: There are other mitigating factors that may further reduce the likelihood of maximise generation obligations in existing PPAs being construed as requiring participation in the CRM, including:

- Whether the PPA contains a change in law/contract re-opener regime that is triggered by the CRM reforms and the contractual options available for addressing the change in law/market disruption event,
- Whether the parties voluntarily elect to amend the PPA prior to commencement of the CRM reforms to address participation (or otherwise) in the CRM,
- Transitional provisions in the CRM reforms that grandfather/stipulate the effect the reforms are to have on existing agreements.

Overall, the types of behavioural obligations commonly seen in PPAs are unlikely to 'compel' a generator to participate in the CRM. In exceptional circumstances (e.g, a highly constrained generator with a PPA containing very specific/absolute drafting and an opportunistic buyer), the buyer may seek to argue for an interpretation of the contract that the generator should be required to participate in the CRM. However, from a practical perspective, it is unlikely to be a common occurrence and mere participation in the CRM would not necessarily guarantee an increase in sent out generation as there will be a range of factors impacting dispatch outcomes in each trading interval.

AEMC initial view: On maximum generation clauses, the risk of generators being 'forced' to participate in the CRM due to behavioural obligations in their existing PPAs is low, based on the majority of contracts and that these obligations typically require "reasonable endeavours" to fulfil the relevant obligation. We also consider the voluntary nature of the CRM substantially mitigates this risk.

6.2 What is the impact of the hybrid model on financial markets?

Throughout the course of the ESB's consultation on the hybrid model, several stakeholders including the Australian Financial Markets Association (AFMA), have raised questions around the impact of the proposed reforms on financial contracts and, more broadly, on financial markets. Section 6.1 above discussed stakeholder concerns in respect of the impacts of the reforms on PPAs commonly seen in the market. We note that this has not been a focus to date. This section considers the key concerns raised by AFMA and its members regarding the impacts on financial markets.

In its submission to the ESB's May consultation paper, AFMA noted the following:[47]

> AFMA's main focus in responding to this consultation is to ensure that the design of the physical market continues to support efficient risk management through the financial market. We wish to ensure that any reforms do not compromise the critical role of the Regional Reference Price (RRP) as the key pricing indicator in the NEM.

Since that time, we have also met with AFMA to better understand their concerns. These are set out in the following sections.

6.2.1 The role of the financial market

AFMA's focus is on ensuring that the design of the NEM remains suitable to support a robust financial market that participants can use to manage their electricity market price risk. In this context, a key concern relates to proposals that could reduce the importance of the RRP as a price signal or reduce liquidity in the market.

AFMA has previously expressed strong opposition to the AEMC's COGATI proposal and the ESB's CMM proposal on the basis that these reforms would introduce basis risk into the market.[48] This could reduce the effectiveness of the RRP as a pricing signal, reduce liquidity and reduce participants ability to manage their risks. In turn, this could lead to further complication of the market.

47 AFMA submission to ESB's Transmission Access Reform Consultation Paper, May 2023.

48 (i.e. the movement in the difference between the RRP and the local prices that would be faced by participants).

AFMA did note in their prior submission to the ESB that a CRM proposal that would allow voluntary transactions to optimise participants dispatch behind constraints without undermining the primacy of the RRP, as the key risk management signal may be better.

The concern is that exposure to CRMPs, rather than the RRP, introduces basis risk for market participants in the CRM, which could reduce the volume of contracts sold by generators. This additional risk would need to be considered in how business set risk limits and may not be fully addressed by the voluntary nature of the CRM, as it was seen that priority access could reduce dispatch certainty and drive new participants to choose between accepting price risk or volume risk. These risks need to be considered by businesses when setting their risk limits and this is likely to reduce the quantity of contracts participants are able to offer to the market.

Priority access means that for new projects, there was a view that either congestion risk could be baked in or investors forced to face price risk. This could lead to generators offering less contracts and facing increased investment risks, and consequentially potentially have impacts on the investment in renewables. If this occurs then this could impact liquidity of contracts, noting that there are already likely changes to liquidity given the ongoing transition to a decarbonised fleet (outside of the impacts of TAR).

Reduced availability of contracts for retailers could increase costs or leave them unable to hedge their risks, which would lead to reduced competition and increased retail prices. Ultimately, this would lead to increased costs for consumers.

Similarly, concerns have been raised that priority access could ‘bake in’ congestion risk that could reduce dispatch volumes for new entrants, which could be substituted for price risk by participating in the CRM. If this increases investment risks, this could disincentivise any new investment in congested areas.

6.2.2 Thoroughness of ESB’s cost benefit analysis

In its submission to the ESB, AFMA also referred to the ESB’s cost-benefit analysis, noting that the CBA identified “substantial costs” of implementation for both AEMO and participants.[49] AFMA noted the preference of its members to see the identified benefits tested prior to any decision being made to implement the changes. This would avoid unnecessary costs being passed onto consumers.

AFMA goes on to express concern that the ESB’s analysis did not given adequate weight to the impact of the reforms on the financial markets. AFMA noted that its members are concerned that substantial changes to NEM dispatch may have an adverse effect on their ability to hedge their electricity market price risks. AFMA noted its expectation that changes to hedging costs would have a substantial bearing on the costs and benefits of the reforms, possibly of a similar order to the changes in capital expenditure over the investment timeframe that the cost benefit analysis has identified.

6.2.3 AEMC observations

Chapter 2 of this paper describes the key features of an access model, and the unique new elements that sets the CRM apart from other access models previously considered. These elements include:

49 The cost benefit analysis identifies the direct costs for AEMO and market participants as ~$260m to 2050 and that between $77m and $156m will be incurred as upfront costs.

- That access is allocated to generators through a process similar to today's dispatch; this ensures that each generator could, in principle, operate at its access level and follow changes to its access level over the day.
- That generators can bid into this "access dispatch" and their bids are processed and used like in today's dispatch.
- That generators can decide not to opt into the CRM, which means that their physical dispatch (the amount AEMO requires them to produce) is identical to their access dispatch, and so all their output is settled at RRP and none at CRMP.

There are two motivations for basing access on dispatch. Firstly, dispatch must comply with transmission constraints, and this ensures that the market can settle: there is enough money paid into settlement by retailers (who pay RRP) to cover the cost of paying generators at RRP for their access. Secondly, because dispatch must also reflect generator capabilities, generators could physically follow their access dispatch if they wanted to. This allows them to not opt in to the CRM.

The reason for the "access bidding" is to make the access dispatch similar to today's dispatch, meaning that the quantity that RRP is paid on is similar under the CRM to what it is today. The voluntary nature allows those generators who prefer to have their output paid for at a single price (i.e. RRP, not a mix of RRP and CRMP) to continue to do so. For example, this may be when a participant has a PPA, which implicitly assumes a single settlement price and might be re-opened and potentially re-negotiated to make it suitable for dual settlement prices. Of course, this is subject to the specifics of the PPA in question.

It is this voluntary nature of the CRM, and the preferred inclusion of quantity limits (see appendix C.7), that we consider that participants would be able to manage their exposure to the CRMP, and their ability to sell contracts, to their preferred level. Furthermore, we consider that increased congestion or price risk due to priority access would primarily impact new entrants in congested areas, which would be aligned with the reform objectives to improve investment efficiency and manage access risk by protecting the existing generators in the congested areas from being cannibalised by the new entrants.

In designing the CRM, these attributes are considered key. In this context, given that the current access model has been specifically designed to limit changes to NEM dispatch, we are interested in stakeholder feedback.

Question 7: Feedback on impacts of the hybrid model on financial markets

What are stakeholder views on the impacts of the hybrid model on financial markets? Specifically:

- How the proposed access model, or particular aspect(s) of the model, may impact their ability to manage price risk in the market?
- The subsequent impact that a reduced ability to manage price risk may then have on participants' hedging costs.

6.3 How will priority access incorporate wide-reaching constraints?

In response to the ESB's previous consultation on priority access, several stakeholders recommended that certain constraints – for example, outage, system strength or suddenly emerging stability constraints – be excluded from prioritisation to avoid unmanageable risks for investors.

We understand that currently, for both outage and system strength constraints, affected generators are often assigned the same participation factors (that is, constraint coefficients) within these constraints, because they 'utilise' the constraints to the same degree. This has the effect of ensuring that the impact of reduced transmission capacity arising from these constraints is shared equally (that is, pro-rata based on availability) among generators bidding at the floor price.

In the event prioritisation is introduced, it would no longer be the case that affected generators would 'share the pain' of these constraints equally. Rather, those generators who enter the market later and are assigned a lower level of prioritisation would be impacted to a greater degree than generators assigned a higher level of priority. Because operating conditions can change very quickly and the instances and impacts of certain constraints are very difficult to quantify and incorporate at the time an investment decision is made, the concern is that priority access could significantly increase investment risk compared to the status quo. This is true even where an investor has made an informed decision to locate in an uncongested area of the network in response to the locational signal provided by the priority access arrangements.

AEMC initial view

In terms of the problem, we are interested in understanding the materiality of the issue further. We note the recent system strength reforms put in place by the AEMC, which should reduce the instances of system strength constraints.[50] Although these reforms do not guarantee that generators will be capable of operating free of system strength constraints, the reforms do aim to ensure that the network is capable of hosting the efficient level of generation.

Regarding the other types of constraints, we are also interested in hearing from stakeholders on the extent to which the issue is driven by the priority access reforms, or whether the issue relates more broadly to TNSP performance and the impact their performance can have on the market and market participants. We note that prioritisation is most important for prioritised generators when the system is not functioning well – that is, in the presence of outages etc. Excluding these types of constraints could undermine the benefits of prioritisation. Indeed, the allocation of access is a zero-sum game; any 'sharing of pain' is of benefit to a lower priority generator which would otherwise not be provided access, but of detriment to a priority generator.

In terms of the proposed solution, we note that from a technical perspective, the dynamic grouping model for priority access would be able to exclude certain constraints. This is because the algorithm does not need to be physically feasible, since it would be run before dispatch and would not determine dispatch outcomes (other than influencing the prioritisation and BPFs of participants). By excluding a constraint from dynamic grouping, this would lead to similar access outcomes as the status quo in relation to that constraint (ignoring other prioritisation and binding constraints). That is to say, access dispatch would be dependent on participant constraint coefficients and, if everyone has the same constraint coefficients, affected generators would 'share the pain'.

Other priority access models are static (from dispatch interval to dispatch interval) and integrated with dispatch, meaning that they are unable to remove certain constraints from the effects of prioritisation as dispatch needs to be physically feasible.

50 The AEMC project page for 'Improving security frameworks for the energy transition' can be found here.

To the extent the original issue raised by some stakeholders is material, we are interested in understanding potential solutions to mitigate the identified risks, noting that excluding these constraints from prioritisation is unlikely to be a credible solution except under the dynamic grouping model.

Question 8: Feedback on wide-reaching constraints

Do stakeholders consider that priority access could increase investment risk due to wide-reaching constraints?

Do stakeholders consider that there is value in implementing the dynamic grouping option for priority access to mitigate this concern?

7 Each of the variants raise detailed design questions

7.1 Priority access: detailed design questions include duration and timing of allocation, and treatment of incumbents

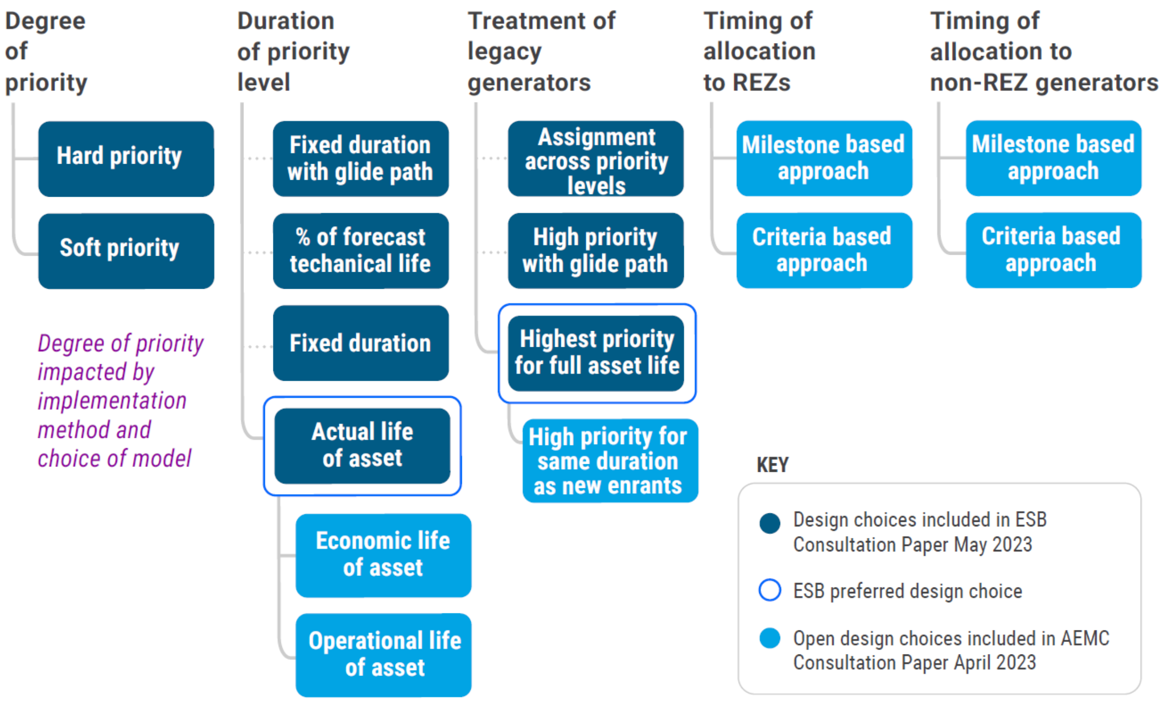
In the ESB's May 2023 consultation paper and informal stakeholder meetings thereafter, the ESB sought feedback from stakeholders on a range of design choices for priority access, including on:

- the duration of prioritisation,
- the treatment of legacy generators,
- the timing of allocation of priority to non-REZ generators,
- the timing of allocation of priority access to REZs.

In response to stakeholder feedback, the ESB narrowed the choices in each of the key areas listed above, with the intent of receiving further feedback from stakeholders, including jurisdictions.

Figure 7.1 below maps the ESB's considerations on the priority access design choices and highlights the design choices that remain open and are the focus of this consultation.

Figure 7.1: Priority access design choices



We have also included a discussion on the quantity of generator and REZ capacity (MW) allocated priority at the time of the initial allocation, and the process for allocating priority when there is a future REZ capacity expansion or a non-REZ generator project modification occurs.

These design choices - including our preferred options, are outlined in the sections below.

Question 9: Feedback on detailed priority access design choices

What are stakeholder views on the detailed priority access design questions and the AEMC's preferred positions?

7.1.1 Options for duration of prioritisation

The duration for which an investment in generation or storage assets maintains its priority level is an important design variable. Two key factors impact the appropriate duration of prioritisation:

- a longer duration would provide the greatest protection from cannibalisation, enabling proponents to better manage their access risk and deterring inefficient investment that may currently be profitable due to cannibalisation.
- however, if generators are receiving considerable value from priority access, this may delay otherwise efficient *dis*investment if it extends a project's profitability beyond a point where they would otherwise have chosen to leave the market.

Our preference is to implement an option for duration that supports long-lived access rights that are consistent with the objectives of the priority access reform, while also mitigating the concern that long-lived rights could delay economically efficient exit decisions. Accordingly, we have identified two options:

- Option 1: variable duration aligned to the asset's operating life (that is, until the resource exits the market). Actual operating life would provide the greatest protection from cannibalisation. On the other hand, it may provide disincentives for efficient retirement and raises questions in relation to how renovations of existing assets are treated.
- Option 2: fixed duration based on the asset's economic life as assessed by a central planner. Fixed duration could avoid the complications associated with the option above, but it would require a central planner to determine the duration. However, this may be a more tractable problem. Both AEMO and the AER have experience of making relevant determinations and it is reasonable to expect that either body could potentially undertake this task.

Under priority access model options 1-4 (described in section 4.3), long-lived access rights would be relevant in the context of generators in the highest dispatch priority level. Once a generator allocated to these priorities levels meets the end of its economic life, it would fall back into the lowest priority level:

- under model options 1 and 2, this would be to dispatch priority level 10,
- under model option 3 and 4, this would be the deprioritised group of generators.

It would then stay there until such time as it chooses to exit the market.

Preferred position: prioritise for the expected economic life of an asset

Our preferred position is option 2 above, that prioritisation is provided for the expected economic life of an asset.

In the context of the priority access lead model, this means that once a generator reaches the top priority level, it remains in this level for its expected economic life. After this point, they move permanently to position 10 in the queue.

This would require a central planner to set the duration of priority access.

7.1.2 Options for the treatment of legacy generators and/or storage

To encourage investment, it is a common principle in public policy that regulatory changes do not substantially impact the value of sunk investments. Doing so may discourage future investors who perceive future regulatory changes may impact the value of their investments. This concept is commonly known as "regulatory risk".[51]

This suggests that incumbents, including generators and storage committed by the time the reforms are implemented, should be "grandfathered".

The ESB considered the potential impacts of grandfathering legacy generators and examined historical outcomes to determine how often legacy generators are constrained by the network and bid to the market floor price. The analysis showed that thermal generators do, on occasion, face binding constraints and bid at the market floor price, although materiality varies considerably by region.

However, not all bidding at the MFP is as a response to network constraints. For some participants, bidding a negative price or even the MFP reflects their costs. An inflexible plant bidding into a 5-minute dispatch interval needs to consider the cost over the next hour or next day of not being dispatched and needing to then shut down. This could make them unavailable for a future period of time when prices may be higher and their generation required. In such cases, it could be logical to bid their minimum generation at, or close to, the MPF. Deprioritising legacy generators in these cases could have detrimental impacts on their operation and overall outcomes for customers.

Based on analysis undertaken by the ESB, our preference is that access arrangements for legacy generators be substantially grandfathered. That said, we note that the priority access design would be able to accommodate jurisdictional differences on grandfathering.

In addition, our preference is to align to the treatment of incumbents and new entrants once priority has been allocated, and not to distinguish by technology type. This would not prevent jurisdictions choosing to apply their own arrangements for certain technologies. This approach is also consistent with the emissions objective, which references the targets set by jurisdictions.

Preferred position: substantially grandfather legacy generators

Our preferred position is for the priority access model to substantially grandfather legacy generators. Under our priority access lead model, this means that legacy generators would be allocated the highest priority level.

We also propose that, once allocated priority, incumbent generators are treated the same as new generators. In the context of our lead model of priority access, this means that legacy generators would retain priority for the expected economic life of the asset, consistent with the approach to new generation. That said, jurisdictions could be provided with discretion in this area.

7.1.3 Options for the timing of allocation of priority to non-REZ generators

This design feature of the priority access model is only relevant to options 1, 2, and 4. Under option 3, non-REZ generators would not be prioritised.

A critical element of the design of options 1 and 2 is the timing of the allocation of priority access to generators – specifically, the timing of allocation of a dispatch priority level to a new entrant

51 This principle has been a feature of the decision to progress the CRM. The CRM allows participants to transition contract arrangements of their own accord in response to new financial incentives in the CRM. It has also featured prominently in informing many of the CRM design features such as the voluntary basis of the CRM.

generator that is not participating in a jurisdictional REZ scheme. Under the grouping approach, a generator would be allocated its dispatch priority level based on the year in which the project met the criteria.

In considering the options for allocating dispatch priority levels to non-REZ generators, we have been guided by the following principles:

- interface cleanly with the process for REZ queue number allocation,
- provide non-REZ generators with investment certainty,
- avoid unnecessary distortion in the connection process.

There are two options for identifying the point at which priority access could be allocated to a new entrant generator – that is, a milestone based approach and a criteria-based approach. There are then different options available under each broad approach, along a spectrum of very early to very late in the generator connection process.

In the ESB's informal discussions with generators and developers at the end of 2023, general support was provided for an approach which would allocate a priority level at the point a new entrant generator passes a set of criteria confirming the advanced nature of the project and commitment to construction.

Such an approach would allocate priority access to projects late in the connections process, but before the final investment decision. This would ensure that only genuine projects with a high probability of proceeding get allocated priority access while providing investment certainty. We do not consider priority access should be allocated early in the connections process, as this would create investment uncertainty for genuine projects.

Any criteria would likely be non-sequential and could be based on AEMO's commitment criteria and steps in the connections process, such as:

- certain major contracts signed,
- planning approvals received,
- certain amounts or types of finance secured
- stages in the connection process specified in the NER.

Preferred position: criteria based approach to allocating non-REZ generators

Our view is that a criteria-based approach to allocating generators a priority level is preferred because it will be:

- more reflective of different regulations/approaches in different NEM jurisdictions
- reduce opportunities for gaming the allocation of queue numbers.

In the context of the priority access lead model, a generator would, for a certain capacity (MW) of generation, be allocated the dispatch priority level corresponding to the year in which the generator met the relevant set of criteria.

7.1.4 Options for the timing of allocation of priority to REZs

This design feature of the priority access model is relevant to options 1 and 4. Under options 2 and 3, generators who choose to participate in a REZ would be granted the highest level of priority once they commence operation.

One of the objectives of transmission access reform is that it supports and strengthens jurisdictional REZ schemes. Under a queue model of priority access, this can be achieved by reserving priority access for generators participating within a REZ at a point in time that ensures:

- new entrant generators are incentivised to locate and participate in REZs, particularly where transmission network investment has been undertaken to support a REZ
- REZ generators can have confidence that their investment case will not be undermined by subsequent inefficient investments that locate outside the REZ in the broader shared network
- opportunities are minimised for subsequent connecting generators to 'free-ride' on REZ transmission network investments without contributing to them
- certainty is improved for all investors as to the level of congestion that can be expected in a particular location.

To achieve these objectives, priority access would need to be reserved for a REZ early enough that:

- incoming generators are dissuaded from connecting outside the REZ in anticipation of the upcoming REZ build,
- intending REZ generators have sufficient information about the level of priority they would receive by locating in a REZ, enabling them to make efficient and timely investment decisions regarding REZ participation.

However, it would also be important not to reserve priority access for REZs so early that:

- there is insufficient information available about the size, scale and location of a potential REZ to enable incoming generators to make efficient locational decisions
- REZ coordinators are able to reserve queue numbers for REZs that have not been fully scoped, and hence are still uncertain.

Like the approach to allocating priority access to non-REZ generators, there are two options for identifying the point at which priority access could be reserved by a REZ coordinator (or equivalent body) for a REZ – that is, a milestone-based approach and a criteria-based approach. There are then different options available under each broad approach, along a spectrum of very early to very late in the REZ development process.

Our early preference is to target the allocation of priority levels at a point that is around the early-mid stage of the REZ development process. There are two options:

1. milestone approach at an early-mid point in the REZ development process, e.g. REZ declaration
2. multi-criteria approach at an early-mid point in the REZ development process, e.g. when a REZ is committed and its capacity (MW) specified.[52]

Our early view is that the criteria-based approach may be preferable over the milestone approach because it allows the tests to be drafted in a more flexible way to cover potential differences, uncertainties or future changes in jurisdictional approaches and allows an additional limb to be added to potentially cover jurisdictions without formal REZ frameworks (e.g. South Australia).

The preferred approach would ensure that generators who choose to participate in a REZ are allocated a level of priority that is higher than they would otherwise receive by connecting outside a REZ, maximising the benefits of and incentives to connecting in a REZ. The timing would also be late enough in the REZ development process that the commitment for it to proceed and the parameters of the committed REZ are clear. That then would allow other potential investors to

52 Allocating priority earlier in the REZ development process risks allocating priority access too early when some REZs are still speculative and the capacity is likely to change. That will make it challenging to rely on the allocated quantity of priority access when making investment decisions and will require frequent updates to the quantity of priority access allocated to the REZ. Late allocation options are also undesirable as they could reduce the benefits of locating in a REZ and may create uncertainty that may make it harder for potential REZ participants to make informed decisions.

take into account the likely impact of the REZ on their project prior to making a final investment decision.

The criteria for assigning priority to a REZ would require further work in consultation with jurisdictions, given arrangements are different in each state as is the development of the REZ framework. Whilst there is some flexibility in the detailed arrangements, national consistency will be important given the prioritisation will feed into the NEM-wide dispatch process. National consistency through the planning processes will also be important as REZs in one region will affect access by REZs in others.

Preferred position: criteria-based approach to allocating access for REZs

Our view is that a criteria-based approach to allocating a priority level to REZs is preferred because it will be:

- more easily adapted to variations in REZ frameworks between states
- reduce opportunities for gaming the allocation of queue numbers.

In the context of the priority access lead model, a REZ coordinator would, for a certain capacity (MW) of generation, reserve the dispatch priority level corresponding to the year in which the REZ met the relevant set of criteria.

7.1.5 Quantity of generation capacity linked to a priority level

Queue numbers would be linked to aDP number and a specified MW of capacity. Existing generators or REZs wishing to expand their capacity at a later date would have to join the back of the queue for their capacity expansions.

Initial allocation of capacity linked to a priority level

It is likely that AEMO would be responsible for allocating generators and REZs a priority level linked to a specified MW of generation capacity:

- For REZs, the initial allocation would be based on the expected generation capacity of the REZ as set out in a specified document. The appropriate document to use would depend on the trigger for allocating priority access. For example, if formal declaration of a REZ is (or is part of) the criteria for reserving priority access, then the amount allocated would be based on the capacity set out in the declaration.
- For non-REZ generators, the initial allocation would likely be based on capacity of generation specified in a connection agreement.

In the case of REZs, it is likely that the expected capacity of a REZ may change following the initial allocation of priority, but prior to operation of the REZ. We note that updates to expected REZ capacity can occur in a range of circumstances. Examples include changes to capacity that occur at later steps in the process (e.g. in Queensland, capacity will be refined at each step from REZ Roadmap to declaration to REZ Management Plan), amendments to the REZ declaration that don't relate to an expansion (expressly permitted in Queensland and NSW), or changes to the generation capacity under the REZ declaration or access rights declaration that don't relate to an expansion (expressly permitted in NSW). In this context, it will be important to include a process for amending the initial quantity of priority access reserved for a REZ, to take recognise updates resulting from the receipt of more accurate information as the REZ progresses through the REZ planning and development process.

Our initial view is that an update process for REZs would apply where the relevant jurisdictional government or REZ coordinator publishes a change to the expected generation capacity of the

REZ prior to commencement of operation. Any increase to capacity resulting from an update would be given the same priority level as the initial amount of priority access allocated for that REZ.

In the case of non-REZ generators, it is also possible that the expected capacity of new plant could vary between the time of the initial allocation of priority access and energisation. It would likely be prudent to allow this to occur, potentially with some limits placed around the degree to which the final allocation of MW capacity could vary from the initial allocation. For example, a limit of 110% (or other suitable upper bound) of the initial quantity could be applied to the final quantity, with any additional installed MW over this final allocation allocated a lower priority level. Importantly, the suitability of imposing such a limit would need to be considered in the context of the specific priority access model option. That said, we expect that generators are likely to have a much higher degree of certainty regarding expected capacity compared to REZ coordinators.

Capacity expansions or modifications to REZs and non-REZ assets

In addition to changes in expected capacity prior to operation of a REZ or energisation of a non-REZ generator, the priority access arrangements will also need to include a process to recognise the potential for REZ capacity expansions, and non-REZ generator project modifications.

In the context of REZs, a REZ's generation capacity may increase in response to an expansion, augmentation or extension. ISP and jurisdictional planning documents show that most REZs will be developed in stages, so this process is likely to apply to most REZs. Our initial view is that expansions should be treated like a new REZ for priority access allocation purposes. This means new REZ capacity arising from an expansion would be given a lower priority than the initial stage of the REZ. The priority level would be based on the applicable queue number at the time the relevant test is met for the allocation of priority access for the expansion. The same trigger for the timing of priority access allocation should apply to expansions as applies to new REZs, eg next available queue number at the time of the declaration (or amendment to the existing declaration) for the expansion.[53]

In the context of non-REZ generators, project modifications include capacity expansions (increase MW capacity), repurposing (install new technology at existing site), and renovations (prolong asset life without changing MW capacity or technology). We understand that stakeholders have previously sought clarity on whether the priority access level (MW) or duration (time) would be increased if a generator's capacity or operating life increases after a modification.

To promote efficient locational signals and improve participants' ability to manage congestion risk, our initial view is that project modifications should not increase the level (MW) or duration (time) of priority access beyond that anticipated at the time of the original investment. The addition of new capacity or repurposing of existing capacity after the duration of prioritisation has ended, would need to be allocated a new priority level as if it were a new entrant.

This approach is not intended to deter use of existing sites, where this is more efficient than developing new greenfield sites. Any efficiencies available from expanding, repurposing or renovating an existing site / asset can still be captured by the developer, who will balance these against incentives to use network hosting capacity efficiently, just like new entrants.

53 It is also possible that REZ capacity could be changed (including decreased) a long time after priority access was allocated. For example, EnergyCo proposes that the CWO REZ's generation capacity may be different for the initial 20 year term of the access rights vs the 10 year extension to the term. Those types of changes a long time in the future should not flow through to changes to the amount of priority access that is allocated. There should be a time limit on when updates /changes to the capacity of the REZ lead to changes to the amount of priority access that is allocated.

Further, while this approach may result in a capacity expansion having a higher queue number (lower priority) than the original capacity, this does not necessarily imply that the actual level of access will be poor. Rather, the level of access will depend on the available hosting capacity of the network and the relativity of the queue number (and hence priority level) to other generators participating in the same constraints.

Preferred position: allocation initially based on expected capacity of projects with adjustments allowed until energisation

Our view is that the initial allocation and linking of capacity to a priority level would be based on:

- the expected capacity of a REZ specified in a document that corresponds to when the REZ is allocated a priority level
- the expected capacity of a non-REZ generator specified in their connection agreement.

We consider that there should be appropriate mechanisms to enable this initial quantity to be adjusted and reflect the capacity upon energisation. This will allow for changes in the expected capacity of REZs and non-REZ generators, which may occur for a variety of reasons between when priority access is allocated and when the REZ or non-REZ generator connects to the grid.

However, we consider that project expansions or modifications post-energisation should be treated as new entrants. For example, this would include renovations or repurposing of non-REZ generators, and capacity expansions to REZs from transmission augmentations or extensions.

7.2 Congestion relief market: detailed design questions include tethering and other matters previously consulted on

The ESB had preferences for a number of design details for the CRM, many of which have been consulted on previously. We currently retain the same views as the ESB in relation to the preferred design choices, at they apply to the two-stage dispatch option:

- **CRM participation:** scheduled and semi-scheduled participants only and corresponding registered dispatch unit identifier (DUIDs).
- **Rounding coefficients:** no rounding.
- **Bidding regulations:** no new bidding regulations, with the AER to monitor behaviour post-implementation.
- **Settlement on differences between physical dispatch targets and actual output:** settled at the RRP.
- **Settlement residue allocation:** same as today for inter-regional settlement residues, CRM residues to be determined and allocated to consumers either via TNSPs or retailers.
- **Treatment of MNSPs:** equivalent to a generator-load paid.
- **CRM bidding features:** quantity limits on CRMP exposure allowed, buy-sell spreads not allowed.
- **FCAS:** single set of FCAS bids used in both access and physical dispatch, only opt in for CRM FCAS.

Appendix C contains more details and reasoning for each CRM design choice. We are seeking any further feedback on these design choices particularly where views on detailed design choices relate to stakeholder preferences for a two-step or co-optimised implementation approach discussed in chapter 5

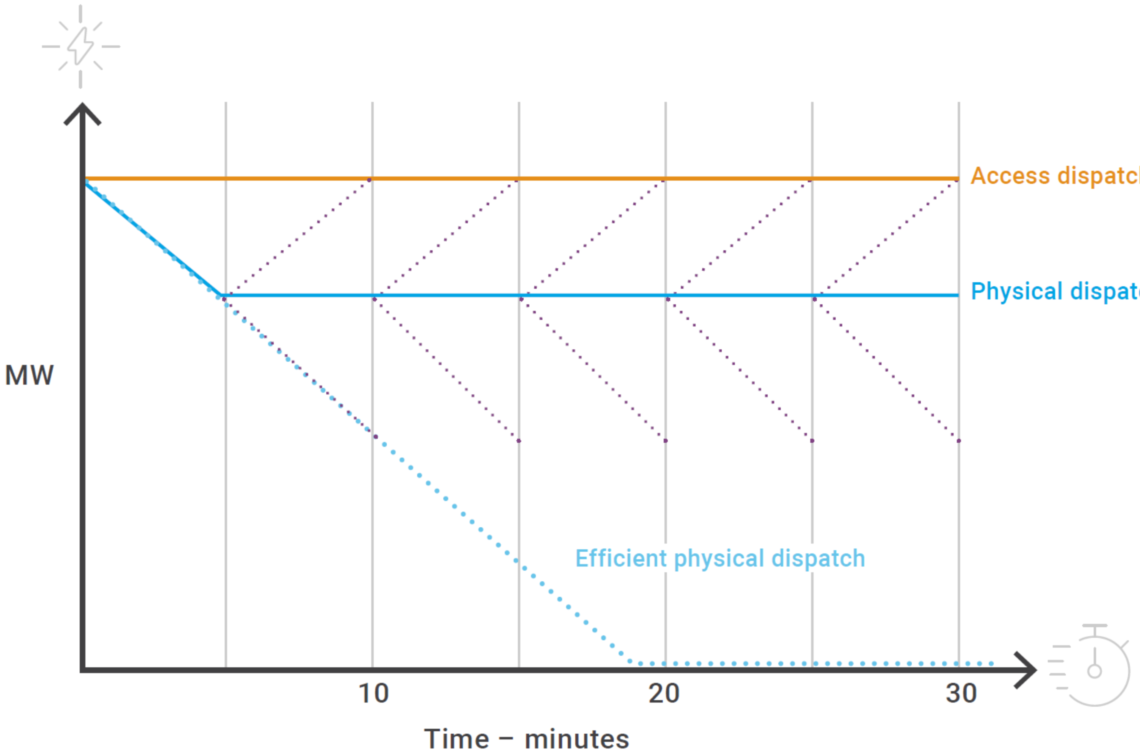
We are also after feedback in relation to tethering - whether the access and physical dispatch outcomes should be kept within 5-minute ramp constraints. This is discussed next in section 7.2.1.

7.2.1 Tethering

Currently, a generator's dispatch can be constrained by its ramp rates – that is, the ability of the generator to ramp up or down its output over time. The dispatch target at the end of the next dispatch interval must be between its physical generation at the end of the current dispatch interval plus/minus its maximum ramp up/down rates.

Given that under the CRM there are two dispatches, this creates the choice about how these ramp rate constraints should be treated. The physical dispatch should be constrained by the ramp rates of the generators, to ensure that physical dispatch is feasible (that is to say, the existing rules should apply). However, there is a question about the arrangements that should apply for the access dispatch for opt-in generators whose access and physical dispatches can differ. There are two choices illustrated in Figure 7.2 below.

Figure 7.2: Hypothetical incentives under tethered and untethered design



Note: solid blue line represents the hypothetical physical dispatch under the tethered option, the dotted blue line represents the hypothetical physical dispatch under the untethered option.

Tethered dispatch specifies that the access dispatch (orange) for a generator for the end of the dispatch interval must be within the purple dotted "cones" which represent the ramp limit of the generator. Because the point of the cone originates at the physical dispatch[54] at the end of the

54 Strictly, the ramp-rate limit applies the metered output, not physical dispatch. But these are the same if generators follow their dispatch instructions.

preceding dispatch interval, to maximise access to the RRP the generator must maintain a physical dispatch no lower than the thick blue line – by bidding disorderly if necessary.

The possible need to tether the dispatches had not been identified at the time of the cost-benefit analysis, which implicitly assumed an "untethered" approach. However, the resulting physical dispatch from tethering may differ from the hypothetically efficient physical dispatch (indicated for a single generator above with the dotted blue line), which could limit benefits from the CRM. We have not quantified the extent to which the operational benefits would be diminished by this effect. That said, the circumstances when the problems from tethering would arise may be quite rare, particularly given ramp constrained generators are exiting the NEM and the reforms are not estimated to be introduced for at least several years.

This indicates that the benefits of the hybrid model may be only slightly lower than those estimated in the cost-benefit analysis as a result of tethering dispatches.

Under an **untethered approach** the access dispatch for the next dispatch interval must be between its **access dispatch target** at the end of the current dispatch interval plus/minus its ramp up/down rates. This has similarities to AEMO's intervention pricing algorithm which is used to determine 'what-if' prices when a specified form of AEMO intervention takes place (e.g. RERT utilisation). Because the access and physical dispatches are not tethered, a ramp constrained generator will have a reduced incentive to maintain a high physical dispatch where physical dispatch is inefficient and the full benefits of the CRM can be realised through more efficient dispatch outcome.

Under the untethered approach the access dispatch will not be 'grounded' in physical reality, and will likely diverge over time from the physical dispatch. AEMO has raised several potential concerns as a result of this:

- Potential for 'what-if' dispatch to significantly drift away from reality e.g. if a unit trips and this is not reflected in the what-if run.
- Generators who are dispatched in the untethered access run can use ramping constraints to maintain a level of dispatch that influences their RRP payments without bearing the cost of physically generating. For example, once a coal plant gets dispatched at its maximum in the access run it can then use ramping constraints to permanently lock in that level of dispatch.
- If generators were to be able to suddenly change their opt-in status to opt-out, then the physical dispatch may not be feasible. A possible solution to this may as simple as not allowing a generator that opts in to subsequently quickly opt out.
- Quantity limits, which define the maximum difference between the physical dispatch and access dispatch, may also result in infeasible physical dispatch. A possible solution to this may be that generators are not allowed to have large quantity limits and then rapidly decrease them such that a generator cannot physically ramp up in time for the quantity limits to be honoured.
- It may be un-auditable and therefore mistakes in implementation or persistent gaming may be missed. The two dispatches may only re-converge infrequently – if at all – depending on whether constraints are binding and participation rates in the CRM. It may be difficult to determine if the access dispatch is 'right'.

Tethering in the context of the co-optimisation has not been fully investigated, but it is anticipated that it would have less impact on dispatch efficiency than tethering of the two-stage dispatch would. This would need to be further investigated, including any impact on priority access.

Preferred position: tethered approach

Based on AEMO's concerns with the untethered approach, the AEMC's preferred position is the tethered approach.

Question 10: Feedback on detailed CRM design choices

Do stakeholders have further views on the detailed design choices for the CRM that were explored by the ESB? Are these views related to a preference for a two-step or co-optimised implementation approach discussed in chapter 5?

What are stakeholder views on tethering, including the relative advantages and disadvantages of each design and any preference?

8 Making our recommendations

At the November 2023 Energy and Climate Change Ministerial Council meeting, Energy Ministers agreed to progress the agreed transmission access reform and congestion management through further design work, having considered advice from the EAP and stakeholder engagement.

The AEMC initiated a review to underpin this further design work by publishing Terms of Reference and project plan.[55]

The purpose of this review is to provide final recommendations to Energy Ministers on a design of the hybrid model that best meets the reform objectives. The intent is for the AEMC to report back to Ministers with final recommendations in 2024.

Following consideration of the AEMC's recommendations, Energy Ministers will make a decision as to whether to implement the hybrid model. If a decision is made to proceed, a detailed implementation phase including development of draft rules and consultation on these would commence.

When considering the issues within this review, the Commission will consider the range of factors outlined in the Terms of Reference and project plan, and is also guided by the National Energy Objectives

This chapter outlines:

- the National Electricity Objective (NEO) that guides all our work,
- the proposed assessment framework based on the objectives decided by the ESB in consultation with stakeholders and agreed by Ministers.

We would like your feedback on the proposed assessment framework noting that the objectives were informed by stakeholder feedback as part of the ESB's process in 2023.

8.1 The Commission must act in the long-term interests of consumers

In conducting reviews, the Commission must have regard to the relevant energy objectives.[56] For this review, the relevant energy objective is the NEO.

The NEO is:[57]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

55 The TAR project page can be found here.

56 Section 32 of the NEL.

57 Section 7 of the NEL.

The target statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[58]

8.2 We propose to assess this review using these four criteria previously agreed to by Energy Ministers

8.2.1 Our regulatory impact analysis methodology

Considering the NEO and the issues we have identified, the Commission proposes to use the set of criteria that underpinned previous work by the ESB on on transmission access reform. These criteria - which we have referred to throughout the consultation paper and from here on in, as "objectives" - will be used to assess our recommendations to Ministers. These objectives reflect the key potential impacts – costs and benefits – of potential review recommendations. We consider these impacts within the framework of the NEO.

The Commission's regulatory impact analysis will draw from previous analysis conducted by the ESB as well as additional qualitative and/or quantitative methodologies. Some of the previous and intended analysis is outlined in chapter 3. The depth of analysis will be commensurate with the potential impacts of any recommendations. We may refine the regulatory impact analysis methodology as this review progresses, including in response to stakeholder submissions.

8.2.2 Assessment criteria

The purpose of this reform is to address four transmission access reform objectives, which have been agreed by Energy Ministers and which were developed by the ESB in consultation with stakeholders:

- **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.
- **Manage access risk:** Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to efficient competition in the long-term interest of consumers.
- **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.
- **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.

58 Section 32A(5) of the NEL.

A Case for reform

In an electricity system “access arrangements” refer to the arrangements that govern how generators “access” or dispatch electricity into the grid and what they get paid for. The NEM’s current “open access” arrangements permit any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to, or causes congestion on - the broader power system. Under the current arrangements “access” (i.e. the megawatts you can sell at the RRP) is equal to your physical dispatch every five minutes. If a generator is not dispatched, it gets no access and is not paid.

The linkage between access and physical dispatch contributes to various operational and investment inefficiencies in the NEM increasing costs for consumers. These include:

- Increasing congestion risk: current NEM arrangements mean the costs of congestion are often borne (at least in part) by pre-existing generators rather than fully by a new entrant that causes the congestion. This can increase congestion and create a risk of “cannibalisation” (when a new generator locates in a congested area and displaces (or cannibalises) the dispatch of an existing generator).
- Investment inefficiencies: the regional pricing arrangements of the NEM mean that locational signals are not as clear as they could be for participants on where to build assets and best utilise the network. There are minimal commercial drivers for investors to choose locations to minimise congestion.
- Inefficient dispatch: when there is congestion, the current wholesale pricing arrangements can create inefficient and complicated dispatch outcomes. Flexible resources such as storage and demand response are also not encouraged to operate in a manner that recognises how they can add value to the system.

Transmission access reforms seek to address these inefficiencies.

There are several key elements of the NEM’s design that could be changed in order to create benefits by having the best use of the transmission infrastructure, lowering costs to consumers of the transition.

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

The current mechanism for deciding who gets dispatched in the presence of congestion does not provide clear signals to generators and storage about where it would be efficient to build and how to utilise the network. This results in outcomes that will not be coordinated and lead to higher overall costs. Outcomes can be opaque, volatile and hard to predict.

Dispatch outcomes can have ‘winner takes all’ characteristics and projects are exposed to the risk of cannibalisation (where a new entrant does not add usable new variable renewable electricity (VRE) generation to the power system and instead displaces pre-existing generators). This unpredictability adds to the cost of capital faced by investors, with the result that investing in the NEM is more expensive than in other comparable markets.

A.1 To deliver a least cost energy transition, we need to invest in the right places

In the absence of arrangements that provide clear signals to generators and storage about where it would be efficient to build and how to utilise the network, outcomes will continue to be uncoordinated and lead to higher overall costs.

New generation and storage will continue to locate and operate in ways that are inconsistent with minimising total system costs. One likely consequence is elevated congestion, which means electricity cannot be dispatched to meet demand at the lowest possible cost. In turn, this will drive the requirement for more transmission investment to alleviate the congestion, which would not have been needed if the investment and operation of generation and storage had been efficient. The cost of this additional transmission investment is borne by consumers.

These market-driven distortions are not contemplated in the ISP, which is an engineering assessment designed to minimise total system costs. The ISP model identifies the optimal development path for the transmission system based on the optimal siting and design of new generation and storage developments from a whole of system perspective. However, under the NEM's regional pricing model, there is no commercial driver for investors to choose the efficient locations identified in the ISP. If the market design encourages patterns of generation investment that do not align with the ISP, the ISP modelling will perpetually adjust in response to developments on the ground – and the adjustments are likely to be more costly than if investment had occurred in line with the original plan and network investment.

Due to the way electricity flows across the grid, constraints outside REZs will be felt inside each REZ and vice versa. This can only be addressed through transmission access solutions that apply across the whole system, of which REZs are a part.

Under the current access regime, even an investment that causes heavy congestion may still be profitable for an investor, because the costs of congestion may be borne in part by pre-existing generators rather than fully by the new party that caused the congestion. This is because the NEM's current access regime permits any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to the broader power system – and then the new generator may gain free access to the network at the expense of existing generators.

The hybrid model seeks to change this aspect of the access regime so that a generator whose investment decision causes inefficient congestion faces the associated costs, and a generator who locates where capacity is available, such as a REZ, is protected from subsequent connection risk.

The right NEM-wide arrangements will also ease pressure on other aspects of the market framework that currently bear the brunt of uncoordinated developments. As generators connect to parts of the system that are already full due to the NEM's malfunctioning access regime, problems manifest in the form of low and volatile marginal loss factors and an unpredictable, lengthy connections process.

A.1.1 Operational benefits

When there is congestion, the current wholesale pricing arrangements can create inefficient and complicated dispatch outcomes.

Even in a power system dominated by VRE generation, there will still be costs to congestion:

- synchronous generation which provides system strength, inertia and frequency and other services is likely to operate during periods of high inverter-based generation
- this would include a modest amount of thermal generation, which could be fuelled by gas or hydrogen and would not have zero marginal costs, to provide a range of services
- storage and hydro generation have opportunity costs and hence will not necessarily bid at zero price

- flexible loads will suffer opportunity costs when they are curtailed.

The NEM has a high market price cap, or maximum price that generators and storage may bid at the regional reference node. The level of the cap provides some incentive for investment in flexible dispatchable plant, especially plant that is required to maintain reliability but rarely used. It is expected that there will be occasional high prices up to the market price cap.

Stakeholders are correct to point out that there will be higher levels of curtailment at a low price point in the future. However, the volume of curtailment increases significantly over this time so there is actually a total higher value of curtailment. In the longer term, the distribution of RRPs may be dominated by zero prices (or negative prices reflecting the opportunity cost of not generating a large scale generation certificate) but there will also be periods of high prices.

In operational timeframes, the volume that a generator may dispatch into the market is determined via the NEM's dispatch engine (NEMDE). NEMDE is a co-optimised dispatch algorithm that determines the output of each generator that leads to the overall lowest cost dispatch of generators (as reflected via generators' bids) to meet demand.

NEMDE's objective is to meet demand whilst maintaining system security and avoiding violations of constraint equations. These constraint equations represent the physical limits of the system. Within these requirements, NEMDE finds the least cost way of dispatching generation out of the options available and based on generators' bids.

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. 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. This is determined in advance by AEMO for each constraint equation.

Each generator or interconnector on the LHS of a constraint has a constraint coefficient (also known as a contribution factor, shift factor or participation factor), which reflects the impact it has on the constrained transmission line. The coefficient measures the impact to the constrained line from a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector). The coefficient reflects the proportion of a generator's output or interconnector's flow which "uses" the equipment to which the constraint relates – it measures each generator's contribution to each constraint. Typically, the further away a generator or interconnector is located from the constrained line the less it uses of that line, and so the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.

Coefficients are highly granular and generators in a constraint can have unique coefficients. This reflects the physics of the way electricity flows across a meshed network. If there are several generators that could be 'constrained off', NEMDE will choose the lowest cost combination taking into account the prices offered and the coefficients. In circumstances where competing generators all offer the same price (for instance, because generators have bid the market floor price), coefficients become determinative. NEMDE minimises the cost of congestion by dispatching generators with the lowest coefficients first (if there is only one binding constraint).

This feature of dispatching generators with tied bids based on coefficients gives rise to "winner takes all" outcomes when a single network constraint is affecting the dispatch of generators with different coefficients. The winners and losers associated with coefficients in particular constraints may vary over time as generators enter and exit the market, their availabilities change and demand patterns change, or AEMO's constraint equations change to reflect these events. This approach gives rise to efficient dispatch outcomes, providing that generators are incentivised to bid in a manner reflecting their costs - but given the link between access and physical dispatch, there are many situations where generators in the NEM are not incentivised to bid in a manner reflecting their costs.

The constraint formulation that determines coefficients is designed to reflect the physical realities of the power system. As such, this approach gives rise to efficient dispatch outcomes, providing that generators are incentivised to bid in a manner reflecting their costs. Alternative approaches would have the result that NEMDE dispatches (and customers pay for) more energy than is necessary, with the additional MW unable to reach load due to congestion. This is known as 'race to the floor bidding', where in the presence of congestion and a high RRP, constrained generators know that the offers they make will be unlikely to affect their RRP, and so they bid to the floor price.

NEMDE selects market participants to be dispatched by minimising total as-bid costs while ensuring that the pattern of dispatch is consistent with the physical capacity of the system. It uses as an input the bids made by market participants; it does not distinguish between the underlying actual costs of generators or the value of their contract positions.

As a result, in the presence of congestion and disorderly bidding, dispatch is shared based on administered rules between generation with high and lower underlying costs, all of whom are bidding at the same price. This results in productive inefficiencies and ultimately results in higher prices for consumers. It would be more efficient for the lower cost generation to be dispatched ahead of the higher cost generator, and would also likely result in lower emissions as low cost generators typically tend have low emissions.

However, given these winner takes all outcomes, change is required to the way that these technical parameters flow through to the revenue received by market participants. Incumbents cannot change their location to optimise their constraint coefficient, but prospective projects can. But once prospective projects have decided where to locate, newer prospective projects can come along and result in a different outcome. This extreme version of open access makes investing in the NEM riskier than other comparable markets.

Similarly, operational inefficiencies can arise across regional boundaries. If congested generators bidding at MFP are located near an interconnector, they can be dispatched inter-regionally across the interconnector if their bids at MFP are more valuable than intra-regional generators not bidding at MFP. Depending on conditions in both regions on either side of the interconnector, counter-price flows can occur where energy flows from a high-priced region to a low-priced region. Counter-price flows create negative settlement residue (i.e. a settlement deficit) which is ultimately funded by, and increasing costs to, consumers.

This could become more complicated with the introduction of a new interconnector directly linking South Australia and NSW: known as Project EnergyConnect (PEC). Together with existing interconnectors, a loop is formed between SA, NSW and Victoria. This will be the first time that the NEM has had looped interconnectors, and the impacts are uncertain. It is likely that patterns of congestion will change, although unclear whether this will worsen the dispatch inefficiencies caused by bidding at MFP. One known effect is a likely increase in the problem of counter-price flows and the associated settlement deficits. AEMO has recently submitted a rule change proposal to address this issue.[59]

The problem of inefficient interconnector dispatch and counter-price flows can be exacerbated where the relative coefficients of the generators and interconnectors affected by the congestion

59 The rule change proposal can be found on the AEMC's project page here.

create a “gearing” effect. For example, congestion is commonly seen in SW NSW, where the combination of local generation and flows north on the Victoria-NSW interconnector (VNI) can potentially overload lines, leading to one or both being constrained in dispatch. Because this is not the main physical path for VNI, it has a much smaller impact on the congestion – typically by around a factor of ten – than the local generators. If the interconnector and generators were to bid at the same price, interconnector dispatch would be preferred, because 10MW of interconnector flow can be dispatched for each 1MW of local generator dispatch.[60]

However, bids will not be equal: the local generators will bid at the MFP, whereas the interconnector cannot, so the dispatch of the former is typically preferred by NEMDE. This leads to an inefficient and counterintuitive dispatch outcome where an extra 100MW (for example) of renewables in SW NSW is dispatched at the expense of 1000MW less dispatch of VNI. This commonly leads to a situation where 1000MW of renewables in SA and Victoria is prevented from generating, just so that an additional 100MW of renewables in NSW can do so. The resulting 900MW shortfall in total output would typically be met by an increase in generation from black coal in NSW and Queensland.

Further, the right NEM-wide transmission access regime will help us to stay ahead of, and facilitate the efficient investment in, the expected dramatic increase in large-scale battery deployment and emerging technologies such as hydrogen. A large flexible load, such as grid connected batteries or hydrogen, could be a source of demand response on the horizon which can help make the system stable. These technologies need incentives so that they charge (use energy) and discharge (not use energy) at the times that are most valuable. That way they align with, and not against, a high variable renewable energy power system. Investors should have the opportunity to be rewarded for leveraging the flexibility of these technologies.

A.1.2 Investors need to not be exposed to unnecessary risk

As the NEM transitions from a few large thermal generators to numerous smaller variable renewable energy (VRE) generators, market signals are needed to direct new investment to locations that would minimise the total cost of the transition. This will include efficiently investing in both new generation and transmission capabilities.

Locational signals are needed to direct and coordinate new investment to locate efficiently and minimise total system costs. Under the current open access, regional pricing arrangements of the NEM, locational signals are not clear as they could be for participants on where to build assets and best utilise the network.

The NEM’s existing open access arrangements can make it profitable for an investor to site new generation in areas of the network that are experiencing (or will soon experience) inefficient levels of congestion. For example, if an investor chooses to site new generation in a location where it is assigned a lower constraint coefficient than other existing generators, then the new generator will displace the existing generators whenever a constraint (or set of constraints) bind.[61]

Similarly, if the constraint coefficients of the new generator are similar to those of other existing generators, the new generator will largely offset the output of existing generators. We refer to the displacement or offsetting of the output of an existing generator by a new entrant generator as “cannibalisation”.

60 Strictly speaking, interconnectors don’t bid, but NEMDE takes the RRP in the exporting region as the effective bid price.

61 Each generator that participates in a constraint has a constraint coefficient (also known as a contribution factor or participation factor). 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.

While the new generator gets paid the regional reference price (RRP) on its output which makes the investment privately profitable, this occurs at the expense of the existing generator, whose output and profitability are correspondingly reduced. This can lead to a situation where the net increase in low-cost and low-emission generation is modest due to the reduction in output of the existing generators, compared to the new generator locating in an uncongested area.[62]

Box 7: Example of cannibalisation in the NEM

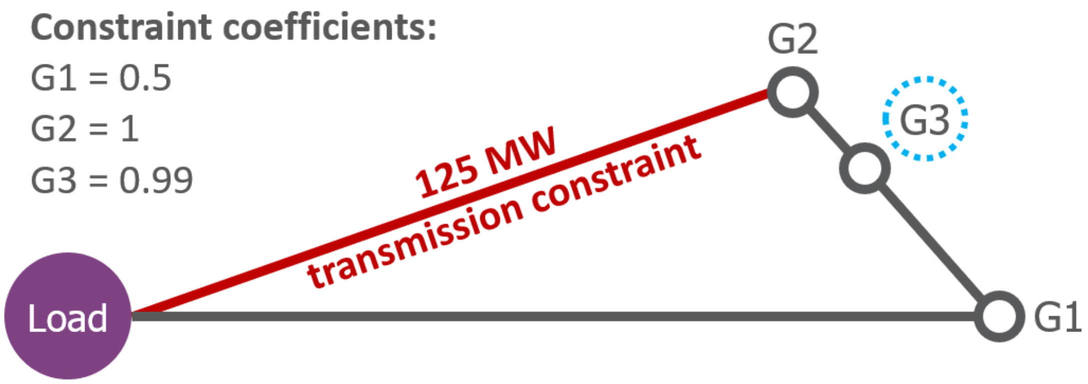
NEMDE's objective is to find the least-cost dispatch of generation without violating constraints, which represent the physical limits of the power system (such as the amount of electricity flow through a transmission line). Market participants (e.g. generators, scheduled load, interconnectors) that can have their dispatch varied to avoid violating a constraint are given a constraint coefficient. For example, the constraint coefficient of a generator for a transmission constraint reflects the impact to the transmission line from a 1 MW change in output from that generator.

A constraint is binding when the generators that can impact it cannot be dispatched anymore without breaching the limit. These generators are constrained. When NEMDE encounters constrained generators with the same bid price, they will be dispatched in order of constraint coefficients (from lowest to highest) when there is one constraint binding. This is to maximise the flow of low as-bid cost generation.

Because of this, new entrants can choose where to locate in a congested area such that they have lower constraint coefficient than existing generators. This allows the new entrant to get dispatched ahead of existing generators, 'cannibalising' their output.

For example: consider 3 zero cost generators (G1, G2, G3) each with 100 MW capacity, located near a 125 MW transmission constraint.

Figure A.1: Cannibalisation example



Assume G3 has not connected yet, so the dispatch would be:

- G1 (coefficient 0.5) dispatched first to capacity at 100 MW
- G2 (coefficient 1) dispatched to 75 MW to avoid violating the constraint
- Constraint equation: (0.5 x 100) + (1 x 75) = 125

62 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.

Now G3 connects as a new entrant and locates to have a coefficient of 0.99, which is lower than G2's coefficient. Therefore, G3 cannibalises the dispatch of G2:

- G1 is still dispatched first to capacity 100 MW
- G3 is then dispatched to 75.76 MW to avoid violating the constraint
- G1 is not dispatched at all as it has been cannibalised by G3
- Constraint equation : (0.5 x 100) + (1 x 0) + (0.99 x 75.76) = 125

In this example, the overall quantity of energy dispatched has only gone up slightly, by just 0.76MW. G3's output has instead, in a very large part, *offset* the output of G1. The overall cost of dispatch (and emissions) is therefore barely affected, despite the investment in a 100MW generator. This is an inefficient use of capital.

In turn, this will drive the requirement for more transmission investment to alleviate the congestion, which would not have been needed if the investment and operation of generation and storage had located in uncongested areas. This additional transmission investment increases the total system cost borne by consumers.

A.1.3 Investment risk due to cannibalisation

The NEM's current access regime permits any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to, or causes congestion on - the broader power system. An investment that causes heavy congestion on the shared network may still be profitable for an investor as the costs of that congestion may be borne (at least in part) by pre-existing generators rather than fully by the new party that caused the congestion. Given the new generator may gain free access to the network at the expense of existing generators, there is no commercial driver for investors to choose locations to minimise congestion.

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 risk of cannibalisation creates difficulty for investors to secure funding needed for their initial financing of capital to establish a generator site and connect it to the grid. Not only does this increase the cost of project financing, but it also reduces the incentive for further investment. Subsequently, energy prices can increase as generators seek to get a return on investment from their initial cost of capital. This behaviour can also prompt transmission investment to alleviate the costly constraint, paid for by consumers. If the generator had instead located in an uncongested area, the transmission investment may not have been needed.

The ability of generators to cannibalise one another creates additional congestion risks for investors who entered the market first and provides inefficient investment signals for incoming generators.

A.1.4 Ensuring REZ schemes deliver expected benefits

REZs are a regulatory tool to deliver more efficient and effective connection of renewables to the grid. Several jurisdictions are developing REZ schemes in their regions. The ISP takes into account the location and scale of these REZs and the optimal development path includes transmission development to support them.

We expect the transmission infrastructure relating to REZs to be designed to host a defined level of generation and storage capacity that will be met through a jurisdictional process, such as the process being undertaken in accordance with the NSW Electricity Infrastructure Roadmap.

While access with each REZ can be managed through a jurisdictional REZ arrangement, the overall value of a REZ, both to prospective investors and to the NEM, is subject to the broader access to the national grid. Under the current open access regime, participants could choose to connect to the grid at any point outside the REZ. Subsequent connections could reduce the access available to parties in the REZ and degrade the value of connecting within the REZ. It is also possible that a well-placed connection outside of the REZ could gain preferential access in dispatch.

In the medium to long term, the NEM's version of open access is incompatible with REZs because it is an unstable foundation for co-ordinated system development. At present, generators can connect where they want, including in parts of the system where there is no spare capacity available. They do not have to contribute to the cost of the shared transmission system. As a result that new projects can take advantage of network investments that were intended to provide access for REZ generators. Prospective investors may find it simpler and cheaper to connect just outside the REZ than to participate in a REZ tender process.

Connections outside of REZs could be prohibited to address this problem, although this solution runs against the grain of encouraging more VRE generation to connect to reduce costs, improve reliability and reduce emissions. Alternatively, transmission access reform can support and strengthen REZ schemes by:

- strengthening incentives for new entrants to locate and participate in REZ investments,
- giving REZ participants confidence that their investment case will not be undermined by subsequent inefficient investments that locate outside the REZ in the broader shared network,
- allowing market participants to connect outside of REZs without disrupting the coordinating efforts of the REZ,
- removing opportunities for subsequent connecting generators to "free-ride" on REZ transmission investments without contributing to them
- promoting the efficient use of REZ transmission infrastructure by creating a market design that rewards storage providers for alleviating transmission congestion and providing firming services for renewable generators.

B Testing priority access using a prototype

B.1 Using different bid price floors to change the inherent dispatch order to test priority access

Scheduling of generation in the NEM is orchestrated by the NEMDE. AEMO runs NEMDE every 5 minutes to produce the least cost set of dispatch instructions that satisfies demand and maintains system security. Generators are dispatched based on the combination of their bids and their impact on various constraints as represented by their constraint coefficients. Generators with low coefficients in a binding constraint are preferred when the constraint binds and all bidding is at the MFP. .[63]

The priority access reform aims to change the way that NEMDE schedules generators who are affected by a binding constraint. The objective is to provide better investment signals by improving the likelihood of dispatch for high priority generators and reducing the likelihood for low priority generators.[64]

To implement priority access in NEMDE requires changing the dispatch order that arises from bids and constraints in the status quo.

One way this can be achieved is by allocating a bid price floor (BPF) that aligns with a generator's priority level. For example, a high priority generator may be allowed to bid down to -$1000/MWh (per the status quo) whereas a low priority generator may only be able to bid down to -$500/MWh. The difference in BPFs in this example could allow the high priority generator to be protected from displacement by a low priority generator if the higher priority generator's dispatch is more valuable than the lower priority generator's dispatch.

To understand this, the ESB used AEMO's CRM prototype to test the implementation of priority access. The CRM prototype is a full version of NEMDE that can be used to study how actual dispatch outcomes would change under the CRM. It can also be used to assess how dispatch outcomes would have changed in the access dispatch run in the presence of different BPFs.

B.2 Methodology and approach to test cases

B.2.1 Experimental design

To test the implementation of priority access, AEMO ran numerous case studies that compared the outcomes of two dispatch runs, the base case and the test case.

- The base case is where the priority access reform has not been implemented. This was the actual dispatch outcome for a selected dispatch interval.
- The test case is where priority access has been implemented using separated BPFs. This was achieved by using the NEMDE prototype to rerun the historical dispatch outcome in which MFP bids for designated lower priority generators were changed to a new higher BPF.

Given the only difference between the test case and the base case is that the BPF are varied, this experimental design allows the impact of the reform to be analysed on a historical basis. However, the results do not purport to show how the reform would work in the future given that the future is highly uncertain and there would be multiple changes to bidding strategies, the generation mix and system constraints.

63 It is common for generators in the NEM that contribute to binding constraints to bid at -$1000/MWh when that constraint is binding. See here.

64 It should be noted that this only applies for the access dispatch run. The physical dispatch run is not prioritised and NEMDE will find the most efficient physical solution subject to CRM bids that are more likely to be cost-reflective than under current market arrangements. The benefit of improved dispatch outcomes in the access run are realised through financial settlement at the RRP.

Selection of case studies

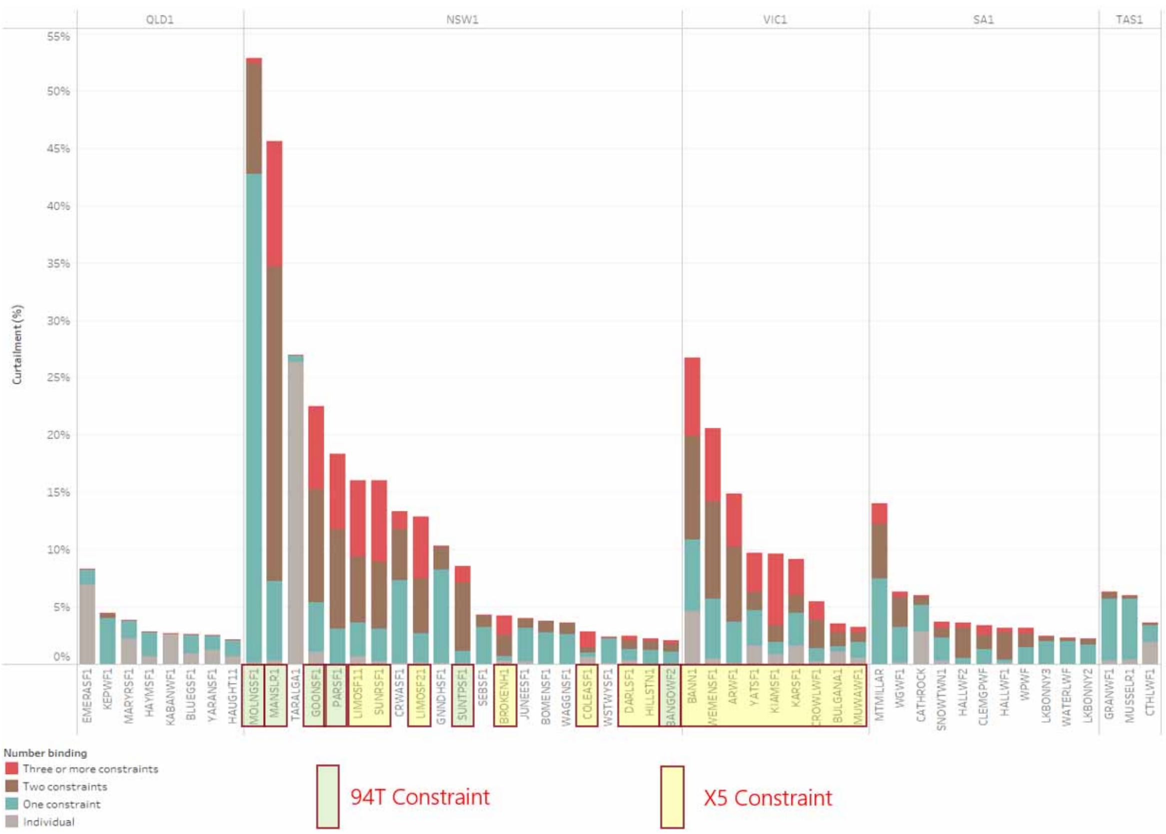
As discussed above, an analytical approach can be taken to understand the effect of priority access in simple, single-constraint cases. However, most congestion in the NEM occurs where there are multiple binding constraints with generators having different coefficients in different constraints.

Figure B.1 shows the generator DUIDs in each region that were most affected by curtailment in financial year 2023. The bars indicate the amount of curtailment for a DUID by number of constraints that were binding. Clearly, the highest level of curtailment in the NEM is associated with multiple binding constraints and given this is where priority access needs to be able to make a difference this was the focus of the case studies.

Two groups of DUIDs are highlighted in yellow and green. These are:

- the 94T set (green) in NSW that contains 13 DUIDs (6 are shown) including Manildra and Molong,
- the X5 set (yellow) that contains 27 DUIDs (16 are shown) spanning Victoria and NSW that are impacted by the X5 and related transmission line constraints.

Figure B.1: DUIDs curtailment breakdown by number of simultaneous constraints in FY2023



B.2.2 Dispatch intervals were selected to study a range of binding constraints.

Fifteen dispatch intervals were selected spanning FY 2023. This was done by analysing locational prices from actual dispatch runs for DUIDs in each of the 94T and X5 sets. Within a set there were 3 groups of DUIDs:

- *Robust DUIDs* – these had low locational prices due to generally low coefficients in binding constraints.
- *Marginal DUIDs* – these had locational prices at or below -$1000/MWh due to generally high coefficients. They were often constrained.
- *Mid-range DUIDs* – these had a range of locational prices and tended to have a mixture of coefficients in different constraints. They were sometimes constrained.

The aim in selecting dispatch intervals was to ensure that a variety of binding constraint conditions was sampled. This was achieved by examining the mid-range DUID locational prices and selecting fifteen DIs that exhibited low, medium and high locational prices.

The following table shows the selected dispatch intervals, which DUIDs were constrained and the key constraints in force for the 94T and X5 sets.

Figure B.2: Overview of selected dispatch intervals

Set	Date	Time	Main constrained DUIDs	Key 94T constraints			Key X5 constraints		
				94K2_94T	94K	94T	NIL_3	NIL_18	KGTS
94T	2023 02 23	15:40	Manildra, Molong, Suntop	Binding	Binding	Binding			Binding
94T	2023 03 04	13:00	Manildra, Molong, Suntop, Goodnumbla	Binding	Binding	Binding	Binding		Binding
94T	2023 03 07	16:05	Manildra, Suntop, Goodnumbla, Jemalong	Binding	Binding		Binding		Binding
94T	2023 03 08	13:35	Manildra, Suntop, Goodnumbla, Parkes, Jemalong	Binding	Binding				Binding
94T	2023 03 09	8:35	Manildra, Molong, Suntop, Goodnumbla	Binding	Binding	Binding	Binding		Binding
94T	2022 11 04	11:55	Manildra, Molong			Binding			
X5	2022 07 08	11:35	Ararat, Crowlands					Binding	
X5	2022 07 13	13:10	Ararat					Binding	
X5	2022 08 19	9:25	Limondale, Sunraysia, Wemen				Binding		Binding
X5	2022 08 19	10:35	Limondale, Sunraysia				Binding		
X5	2022 10 14	7:10	Ararat, Kiamal, Limondale, Sunraysia				Binding	Binding	
X5	2022 11 16	8:40	Ararat, Bannerton, Wemen					Binding	Binding
X5	2022 11 30	17:35	Ararat, Bulgana, Crowlands, Kiamal, Wemen				Binding	Binding	Binding
X5	2022 12 25	15:25	Limondale, Sunraysia, Wemen		Binding	Binding	Binding		
X5	2022 12 27	14:55	Ararat, Bannerton, Kiamal, Wemen		Binding	Binding		Binding	Binding

B.2.3 Designation of new entrants

Cannibalisation of access is most likely to occur when a large mid-range DUID connects in a congested area of the NEM and results in an existing marginal DUID being curtailed. Because of this, the case studies focused on identifying mid-range DUIDs that were being fully dispatched in the same constraint set as marginal DUIDs that were being curtailed.

These mid-range generators were designated as 'new entrants' for the purpose of studying how priority access would have changed their dispatch outcomes if the reform had been in place. The other generators in the constraint set were designated as 'incumbents'.

Each case study involved raising the BPFs of the designated new entrants and observing the change in dispatch of all DUIDs in the constraint set. As the BPF is raised for a new entrant there will often be an inflection point where the dispatch solution changes and the new entrant is dispatched less. This allows the incumbents, and particularly the marginal generators, to increase their dispatch up to their available headroom (the difference between their potential output and their actual dispatch).

The designated new entrants for the two queue case studies were:

- 94T Set – Jemalong and Suntop (these also happened to be the newest DUIDs)
- X5 Set – Karadoc, Silverton and Murra Warra 2.

B.2.4 Queue Positions and Bid Price Floors

The initial case studies focused on scenarios with two queue positions – incumbents and new entrants. The incumbents were allowed to bid at the MFP of -$1000/MWh, whilst the new entrants could only bid at a higher BPF. As noted above, under the status quo arrangements, it is common for generators that are affected by a binding constraint who want to maximise dispatch to bid at the MFP. Therefore, only new entrant bids at MFP in the base case were adjusted for the purposes of de-prioritisation. This assumes that these bids were the ones the generator wanted dispatch, regardless of the RRP.

New entrants had their MFP bids in the base case adjusted to various higher BPF levels in the test case. Typical BPFs used in the case studies were -$800/MWh, -$650/MWh and -$400/MWh but some scenarios tested higher values above -$250/MWh to see when dispatch outcomes changed. The approach of raising BPFs for low priority queue positions rather than lowering BPFs for high priority queue positions was preferred given it was administratively simpler to implement.[65]

Around half the total cases run were cases where there were two queue positions and the balance were with three or four queue positions. There were also a number of cases run where REZ location determined the priority order. This involved allocating the X5 set of DUIDs to the defined Victorian and New South Wales REZs and then designing a mix of two, three and four queue position scenarios.

The number of queue positions was limited by the number of mid-range DUIDs in each constraint set.[66] For example, the 94T set had 13 DUIDs with only four DUIDs falling into the mid-range category.

B.3 Testing results

The work program tested 326 cases studies for 15 dispatch intervals as shown in Figure B.3. The results from each of the case studies were collated and analysed and then assessed against the three test criteria.

65 If a lower MFP and BPF was chosen, all MFP bids would have to be lowered to this level, which would involve a larger amount of processing per test case.

66 Increasing the sample by designating robust DUIDs as new entrants would have been unlikely to lead to changes in dispatch outcomes given their low coefficients would override BPF differences.

Figure B.3: Overview of test cases run

Set	Date	Time	2 queue positions	3 or 4 queue positions	REZ	Total cases
94T	2023 02 23	15:40	10	14		24
94T	2023 03 04	13:00	10	14		24
94T	2023 03 07	16:05	10	14		24
94T	2023 03 08	13:35	10	6		16
94T	2023 03 09	8:35	10	6		16
94T	2022 11 04	11:55		8		8
X5	2022 07 08	11:35	12	14		26
X5	2022 07 13	13:10	12	4		16
X5	2022 08 19	9:25	12	14		26
X5	2022 08 19	10:35	12	4		16
X5	2022 10 14	7:10	12	14	11	37
X5	2022 11 16	8:40	12	14	4	30
X5	2022 11 30	17:35	12	10	7	29
X5	2022 12 25	15:25	12			12
X5	2022 12 27	14:55	12	10		22
Total 94T			**50**	**62**	**0**	**112**
Total X5			**108**	**84**	**22**	**214**
Total			**158**	**146**	**22**	**326**

B.3.1 Criterion 1 – Direction of change in access

The aim of this criterion was to assess how implementing priority access using the selected BPF improved dispatch outcomes for high priority queue positions and lowered them for low priority queue positions. This criterion was assessed for all incumbent and new entrant positions in all 326 cases by reviewing whether each case resulted in 'expected' or 'unexpected' outcomes.

An 'expected' outcome was the result if either:

- an incumbent (high priority) DUID that was not being fully dispatched in the base case (i.e. had headroom available) *improved* its dispatch outcome (i.e. used up some or all of the headroom), or
- a new entrant (low priority) DUID was dispatched *less* in the test case than the base case.

An '*unexpected*' outcome occurred if either:

- an incumbent was dispatched *less* in the test case than the base case, or
- a new entrant was dispatched *more* in the test case than the base case.

It was possible for a test case to include both an expected and an unexpected outcome simultaneously. For example, one incumbent generator might be dispatched more in the test case (expected) while another incumbent could be dispatched less in the test case relative to the base case (unexpected). Another possible outcome from the testing was no change in dispatch outcomes particularly if the BPF for new entrants was not high enough (i.e. priority was too soft) to lead to a change in dispatch.

For this criterion only the first (incumbent) and last (new entrant) queue positions could be categorised as expected or unexpected. It was not possible to assess how the middle queue positions would be expected to move given they are simultaneously deprioritised versus the top queue position and prioritised versus the bottom queue position.

The results for Criterion 1 are shown in Figure B.4.

Overall, 86% of cases shows the expected dispatch change for at least one DUID. The remaining 14% of cases exhibited no change in dispatch and many of these were associated with BPFs that were not sufficiently high e.g. -$800/MWh (i.e. where prioritisation was quite soft).

30% of all cases and 62% of cases using the 94T set of DUIDs showed an unexpected dispatch change. Most of these were associated with interactions between Molong and Manildra in the 94T set. These are both marginal DUIDs that were designated as incumbents and so should have both increased their dispatch. However, due to the close relativities of their coefficients in each of the multiple binding constraints it was often the case that Manildra increased its dispatch at the expense of Molong reducing its dispatch.

Another similar interaction occurred between the new entrants Suntop and Jemalong. In some cases when Jemalong was dispatched less Suntop increased its dispatch.

Even discounting these 94T interactions as outliers there were still 14% of X5 cases that presented unexpected outcomes. This illustrates that although priority access encourages changes in dispatch between queue positions it can also lead to changes in dispatch *within* queue positions for generators with the same BPFs.

Figure B.4: Results from criterion 1 - direction of change in access

Set	Date	Time	Cases	Expected dispatch change	Unexpected dispatch change
94T	2023 02 23	15:40	24	83%	63%
94T	2023 03 04	13:00	24	100%	96%
94T	2023 03 07	16:05	24	100%	88%
94T	2023 03 08	13:35	16	81%	0%
94T	2023 03 09	8:35	16	75%	63%
94T	2022 11 04	11:55	8	38%	0%
X5	2022 07 08	11:35	26	77%	0%
X5	2022 07 13	13:10	16	50%	0%
X5	2022 08 19	9:25	26	88%	0%
X5	2022 08 19	10:35	16	31%	0%
X5	2022 10 14	7:10	37	100%	22%
X5	2022 11 16	8:40	30	100%	20%
X5	2022 11 30	17:35	29	100%	34%
X5	2022 12 25	15:25	12	83%	0%
X5	2022 12 27	14:55	22	100%	27%
Total 94T			**112**	**86%**	**62%**
Total X5			**214**	**86%**	**14%**
Total			**326**	**86%**	**30%**

B.3.2 Criterion 2 – Predictability of change in access

For priority access to be successful in delivering the reform objectives an investor will need to be able to quantify the benefit of a high or low queue position in terms of improvement or reduction in expected dispatch outcomes and build this into their business case.

To assess this criterion two metrics were derived for all two queue case studies (it was not possible to calculate a meaningful metric for middle queue positions):

- Incumbent metric = change in MW dispatch / MW headroom available.
- New entrant metric = change in MW dispatch / MW dispatch in Base Case.

Note that the incumbent metric is only calculated where there is headroom available. The metrics were calculated for each case study and then averaged across all the cases and are shown below.

94T Results

Of the 94T generators designated as incumbents, those with available headroom in the case studies were four solar farms Goonumbla (GOONSF1), Manildra (MANSLR1), Molong (MOLNGSF1) and Parkes (PARSF1).

Across all case studies these generators showed an average of 17% of available headroom used (i.e. dispatch increased) when the BPF for the new entrants (Jemalong and/or Suntop) is -$800/MWh. This increases to an average 41% of available headroom used when the BPF for the new entrants is -$400/MWh. This is consistent with the expected result i.e. as the separation between queue positions increases (priority access becomes harder), the new entrants are dispatched less and the incumbents are dispatched more.

While the findings are consistent with expectations on average, there is a wide range of results at the DUID level as shown below. Note that Molong reduces its dispatch due to its interaction with Manildra. The reduction is greater than 100% because it is measured against available headroom. Its results have been excluded from the overall average, but are shown for completeness.

Figure B.5: 94T results from criterion 2 - predictability of change in access

94T incumbent	Region	BPF ($/MWh)		
		-800	-650	-400
BANGOWF1	NSW1			
BANGOWF2	NSW1			
BERYLSF1	NSW1			
BODWF1	NSW1			
GOONSF1	NSW1	38%	46%	46%
JEMALNG1	NSW1			
MANSLR1	NSW1	2%	33%	51%
MOLNGSF1	NSW1	-45%	-333%	-333%
NEVERSF1	NSW1			
NYNGAN1	NSW1			
PARSF1	NSW1	12%	26%	26%
SUNTPSF1	NSW1			
WELLSF1	NSW1			
Average		**17%**	**35%**	**41%**

Although there are only two new entrant generators, the new entrant results that show the average reduction of dispatch for new entrants reducing by 24% at a BPF of -$800/MWh. This increases to a 49% average reduction of dispatch at a BPF of -$400/MWh.

At a DUID level, Jemalong shows the expected trend in its dispatch, moving to being fully undispatched when the BPF reaches -$400/MWh. However, Suntop is much more resistant to changes in BPF reflecting its quite low coefficients in some of the binding constraints. In fact, Suntop barely moves as the BPF is increased and then actually increases its dispatch when Jemalong is fully undispatched.

Figure B.6: 94T new entrants - all cases

94T new entrant	Region	BPF ($/MWh)		
		-800	-650	-400
SUNTPSF1	NSW1	-47%	-82%	-100%
WELLSF1	NSW1	-1%	-4%	1%
Average		**-24%**	**-43%**	**-49%**

X5 Results

Of the X5 generators designated as incumbents, those with available headroom in the case studies were the wind farms at Ararat (ARWF1), Bulgana (BULGANA1), Crowlands (CROWLWF1) and the solar farms at Bannerton (BANN1), Kiamal (KIAM1), Limondale (LIMOSF1/2), Sunraysia (SUNRSF1) and Wemen (WEMENSF1).

The X5 cases show similar trends to the 94T cases but if anything, are more responsive to changes in the BPF. The overall average of headroom used by incumbents increases from 38% at a BPF of -$800/MWh to 53% at -$400/MWh. The results for new entrants shows a similarly greater reduction in dispatch as the BPF is increased. It is also worth noting that there is no equivalent to the Molong and Suntop results and the individual DUID outcomes are generally more comprehensible.

Figure B.7: X5 incumbent results from criterion 2 - predictability of change in access

X5 incumbent	Region	BPF ($/MWh)		
		-800	-650	-400
ARWF1	VIC1	23%	37%	40%
BANN1	VIC1	69%	74%	74%
BROKENH1	NSW1			
BULBESG1	VIC1			
BULBSEL1	VIC1			
BULGANA1	VIC1	38%	39%	48%
COHUNSF1	VIC1			
COLEASF1	NSW1			
CROWLWF1	VIC1	25%	50%	69%
DARLSF1	NSW1			
GANNBG1	VIC1			
GANNBL1	VIC1			
GANNSF1	VIC1			
HILLSTN1	NSW1			
KARSF1	VIC1			
KIAMSF1	VIC1	87%	87%	87%
KIATAWF1	VIC1			
LIMOSF11	NSW1	13%	13%	30%
LIMOSF21	NSW1	8%	9%	27%
MURRAY	VIC1			
MUWAWF1	VIC1			
MUWAWF2	VIC1			
NUMURSF1	VIC1			
STWF1	NSW1			
SUNRSF1	NSW1	16%	16%	34%
WEMENSF1	VIC1	64%	65%	70%
YATSF1	VIC1			
Average		**38**	**43%**	**53%**
Standard deviation		**28**	**28%**	**22%**

Figure B.8: X5 new entrant results from criterion 2 - predictability of change in access

X5 new entrant	Region	BPF ($/MWh)		
		-800	-650	-400
KARSF1	VIC1	-32%	-34%	-72%
MUWAWF1	VIC1	-35%	-52%	-52%
STWF1	NSW1	-49%	-51%	-82%
Average		**-39%**	**-46%**	**-69%**

Similar to the 94T set of DUIDs, there is a wide range of dispatch changes for the incumbents. At a BPF of -$800/MWh, Limondale 2 uses on average 8% of its available headroom, whereas Kiamal uses 87%. This variability is evident in the very high standard deviation of 28% falling to 22% at -$400/MWh.

The challenge for this criterion is that if the reform creates a wide range of potential dispatch changes, it may be difficult for an individual investor to factor this into their dispatch modelling. Understanding this issue is therefore important and work on the priority access reform will include additional formal consultation with industry to understand its impact in detail.

B.3.3 Criterion 3 – Change in RRP

The final criterion to assess was the impact of priority access on the RRP. The current design of the hybrid model to support the introduction of priority access can lead to less efficient dispatch outcomes. This is because priority access allows generators with higher coefficients to be selected over generators with lower coefficients reducing the amount of generation that can be dispatched behind a constraint and increasing the amount of generation required from unconstrained areas. Depending on the bidding strategies of unconstrained generators, this may or may not lead to an increase in the RRP.

This criterion was assessed by studying the change in RRP for each case. If the RRP increased by more than 5% in any of the NEM regions, this was recorded against that case. For those cases, a second data point was also recorded if the RRP in any NEM region increased by more than 25%.

The results are tabulated in the figure below.

Figure B.9: Results from criterion 3 - change in RRP

Set	Date	Time	Cases	RRP move >5%	RRP move >25%
94T	2023 02 23	15:40	24	13%	8%
94T	2023 03 04	13:00	24	13%	0%
94T	2023 03 07	16:05	24	13%	0%
94T	2023 03 08	13:35	16	0%	0%
94T	2023 03 09	8:35	16	19%	19%
94T	2022 11 04	11:55	8	0%	0%
X5	2022 07 08	11:35	26	4%	4%
X5	2022 07 13	13:10	16	0%	0%
X5	2022 08 19	9:25	26	88%	23%
X5	2022 08 19	10:35	16	31%	25%
X5	2022 10 14	7:10	37	76%	16%
X5	2022 11 16	8:40	30	0%	0%
X5	2022 11 30	17:35	29	100%	76%
X5	2022 12 25	15:25	12	33%	0%
X5	2022 12 27	14:55	22	0%	0%
Total 94T			**112**	**11%**	**4%**
Total X5			**214**	**42%**	**18%**
Total			**326**	**31%**	**13%**

Overall, the results show that:

- in 31% of cases, there was a RRP move of >5% in at least one NEM region,
- in 13% of cases, there was a RRP move of >25% in at least one region.

The X5 cases showed a greater RRP sensitivity to BPF moves relative to the 94T cases (42% having >5% change compared to 11% of 94T cases). This may be related to the fact that the X5 set of constraints contained two interconnector terms (Murraylink and VNI) whereas the

94T set of constraints did not, meaning the RRP change in the latter was entirely dependent on the NSW unconstrained generator bids.

It is also noteworthy that the average change in dispatch for the 27 DUIDs in the X5 set when there was a material RRP move was only 21 MW out of ~1500 MW total. This illustrates that relatively small levels of inefficient dispatch can lead to RRP changes.

These results do not attempt to predict how the RRP will change if priority access is introduced but to highlight that the expected impact of less efficient dispatch leading to higher RRPs is borne out in the testing results.

Future RRPs will be influenced by a range of factors which could lead to higher or lower impacts on RRP including generator costs and bidding strategies, the generation mix, and the locations of new connecting generators, and the augmentation of the transmission network and the evolution of system constraints.

C Detailed CRM design decisions in the two-stage CRM model

In November 2022 the ESB published a directions paper seeking feedback from stakeholders.

In May 2023 it published a consultation paper which confirmed the design of some elements of the CRM and raised new design questions for stakeholder comment. Taking account of this feedback, we present below various detailed design elements of the CRM which are 'locked in' were the two-stage dispatch design to be chosen over the co-optimised dispatch.

C.1 Who participates in CRM

The key determinant of who is allowed to participate in the CRM is whether they are scheduled/semi-scheduled versus non-scheduled, regardless of whether they are:

- load, generation or storage,
- connected to the transmission or distribution network.

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.

This choice was in large part pragmatic. The current dispatch engine does not calculate CRMPs for non-scheduled market participants (noting it already *calculates* CRMPs for all scheduled and semi-scheduled participants – they are just not used for settlement purposes). As a result, it is not possible without considerable cost to change the dispatch engine so that the CRM settlement equations could apply to non-scheduled market participants.

C.2 Rounding coefficients

Like today's dispatch, the access dispatch without prioritisation will have a 'winners take all' characteristic because even very small differences in constraint coefficients between generators can be determinative of dispatch outcomes.

An idea raised in the November 2022 directions paper was to 'round' the constraint coefficients to fewer decimal places in the access dispatch to diminish this 'winners take all' effect. Generators sharing the same (rounded) coefficients in the same binding constraints would have their access dispatch pro-rated.

The decision to pursue priority access alternatively addresses this issue. Unlike today, where access between market participants bidding at the floor price is determined by coefficients, the priority access model will also introduce prioritisation via differentiated bid price floors. Small differences in coefficients will become less important to the access allocation, and so the idea of rounding coefficients is redundant.

C.3 Bidding Regulations

Market participants will continue to have an incentive to 'disorderly bid' in the access dispatch. Indeed, a key benefit of the model is that if market participants bid in the access dispatch in the same way as today, their access to the RRP will be collectively unchanged upon introducing the CRM – meaning that market participants can only be better off from trading in the CRM.

However, the introduction of the CRM means that generators will not have identical incentives to bid as today. For example, currently, generators only have an incentive to disorderly bid if the RRP is greater than their short run cost. In contrast, under the CRM generators will have an incentive to bid disorderly when the RRP is greater than their CRMP, regardless of their cost.[67]

This means that some higher cost generators may gain access to the RRP at the expense of lower cost generators compared to the status quo. This has colloquially become known as the 'out of merit order problem' because generators that have costs above the RRP are not in the 'merit order'.

Generators granted access in this way would then be able to 'unwind' this position through the CRM. While the physical dispatch is expected to be efficient, the effect of these changed bidding incentives in the access dispatch means that not all market participants will be no worse off as a result of the reforms.

In turn, this prompted the idea that bidding in the access dispatch should be regulated in an attempt to preserve the *outcomes* of the current dispatch in the access dispatch (and so better ensure that all market participants were no worse off).

Many stakeholders felt that regulated bidding in access dispatch was inconsistent with the general philosophy of the NEM to allow generators to broadly bid how they want. In light of this feedback, and informed by the AER's views in particular, we prefer to not implement new bidding regulations upon the introduction of the CRM. Instead, and consistent with the AER's views, the AER should monitor behaviour to make an informed decision as to whether such regulations may be required post-implementation.

Similarly, we consider that this approach to not implement new bidding regulations likely remains appropriate to manage possible opportunities for generators to exercise market power over CRMPs. This could occur when participant(s) that alleviate constraints can control how much the constraint is alleviated, and by extension exert a degree of control over the marginal cost of the constraint and their CRMP (which would be higher than the RRP because they alleviate the constraint). We consider this would not directly impact consumers (who are not exposed to CRMPs) and would only temporarily directly impact market participants as new entrants locate nearby (incentivised by high CRMPs) and provide competition. Therefore, we do not currently consider that introducing bidding regulations would be justified, however the AER should monitor participant behaviour and can advise if regulations are needed.

Concerns that priority access may enable market participants to exercise their market power over the RRP determined in the access dispatch in the two staged model prompted the AEMC to explore the alternative co-optimised approach.

C.4 Settling variances (difference between physical dispatch targets and actual)

In today's energy market, participants' adjusted gross energy (essentially metered energy)[68] is settled at the RRP (ignoring marginal loss factors). 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.

In the May 2023 consultation paper we concluded – consistent with the majority of stakeholder feedback - that it is preferable for the variation between physical dispatch targets and AGE to be settled at the RRP, not the CRMP. This is reflected in the settlement equations in section 5.1.3. This

67 This is because generators could get revenue equal to '(RRP - CRMP) x AQ' and have no physical dispatch (through the CRM) or costs.

68 See clause 3.15.4 of the NER.

means that participants that do not opt into the CRM continue to have no exposure to CRMP, even if they do not meet their dispatch target. The alternative, settling the variations at the CRMP, would mean that even market participants who do not opt in would face the CRMP on these variations.

As with the current market, this creates incentives to not follow dispatch instructions when the RRP is high. This risk is currently mitigated by AEMO's non-conformance monitoring and will continue to be so under the CRM.

C.5 Settlement residues

C.5.1 Status quo arrangements

Settlement residue is the difference between payments made to AEMO by retailers and load 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.

Ignoring the effect of losses, settlement residue currently only arises 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 x (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 the RRP in the importing region being lower than the RRP in the exporting region. 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.[69] 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.

Settlements residue in the CRM

Recall that the revenue for scheduled or semi-scheduled generators in the CRM is as follows:

- Energy Revenue (semi/scheduled) = AGE × RRP + (PQ - AQ) × (CRMP – RRP)

This equation can be rearranged:

Energy Revenue (semi/scheduled) = AQ x RRP + (AGE – PQ) x RRP + (PQ – AQ) x CRMP

Thought of like this, a generator's revenue is comprised of:

- Access, at the RRP (first term)

69 Refer to AEMO's Guide to Settlements Residue Auction, version 4.0 final as at 1 Oct 2019, found here.

- Deviations between the actual metered outcomes and physical dispatch targets, also at the RRP (second term)
- CRM trades, at the CRMP (third term)

Also recall that for a non-scheduled market participant, energy revenue is:

Energy Revenue (semi/scheduled) = AGE x RRP

The total settlement residue (ignoring losses) is simply the sum of the energy revenue from all market participants (noting that for load, quantities are negative), which we can group into those settled at the RRP and those settled at the CRMP:

Total settlement residue excluding losses = ∑ [AQ + (AGE – PQ)] x RRP + ∑ (PQ – AQ) x CRMP

C.5.2 Inter-regional settlement residue arising from differences in RRPs

Access (AQ x RRP) and deviation payments ((AGE – PQ) x RRP) are at the RRP which is similar to today's market. This gives rise to settlement residue that is similar to today's inter-regional 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 access payments are made on access quantities and the deviation payments are based on dispatch deviations between metered energy and physical dispatch.

Correspondingly, the inter-regional settlement residue – being the sum of these two quantities – is based on the interconnector access dispatch targets and deviations. That is:

$IRSR = (AQ_{IC} + AGE_{IC} – PQ_{IC}) \times (RRP_M – RRP_X)$

where:

- AQ_{IC} is the dispatched interconnector flow in access dispatch
- AGE_{IC} is the metered interconnector flow
- PQ_{IC} is the physical dispatched quantity for the interconnector flow
- RRP_M is the RRP in the importing region
- RRP_X is the RRP in the exporting region.

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

There remains the possibility of counter-price flows leading to negative IRSRs. In this case the relevant "flow" relates to the access 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 access dispatch from time to time, similar to what it does today.

C.5.3 Congestion relief market settlement residue

Consider the component of the settlement residue (excluding losses) settled at CRMPs: Σ (PQ – AQ) x CRMP.

Unlike the access residue, this CRM residue is new because there is no CRMP settlement today. This settlement residue should be allocated to consumers, and is of direct benefit to them.

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 access dispatch is infeasible (over-constrained). Notably, however, counter-price flows in physical dispatch do not lead to negative residues and therefore do not need to be clamped.

The question then arises as to how to allocate this positive settlement residue to consumers. The consultation paper identified 3 options:

1. Add some or all of the residue to the IRSRs from the access 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.

The Commission does not support option 1. Unlike with the access residue, there is no direct relationship between the CRM residue and interconnector flows – or changes in interconnector flows – in the physical 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 access IRSRs could be detrimental by adding an extraneous factor that worsens the hedging value of the IRSR.

However, there is no obviously correct answer between options 2 and 3. 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. Under option 2, there is no obvious allocation of the residue between regions. CRM trading can happen within regions or between regions. To meet this objective, the allocation method should be fair and transparent. A possible 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.

This is a relatively minor detail that we will decide on in due course. We welcome feedback.

C.6 Treatment of MNSPs

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 connects 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.

Currently, the trading, dispatch and settlement of an MNSP is analogous to an equivalent scheduled 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:

Energy revenue (MNSP) = generator payout – load payment = 500MW x RRPVIC – 500MW x RRPTAS

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

Under the CRM design, MNSPs will be settled similar to an analogous scheduled generator-load pair, equivalent to their treatment currently. 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[70] – similar to scheduled generators and loads. Ignoring losses:

Energy revenue (MNSP) = generator payout – load payment

Energy revenue (MNSP) = $[AGE_{IC} \times RRP_M + (PQ_{IC} - AQ_{IC}) \times (CRMP_M - RRP_M)] - [AGE_{IC} \times RRP_X + (PQ_{IC} - AQ_{IC}) \times (CRMP_X - RRP_X)]$

where:

- AGE_{IC} is the metered flow over the interconnector, which is positive in the importing region
- PQ_{IC} is the physical dispatch target of the interconnector, which is positive in the importing region
- AQ_{IC} is the access quantity of the interconnector, which is positive in the importing region
- RRP_M is the RRP in the importing region
- RRP_X is the RRP in the exporting region
- $CRMP_M$ is the congestion relief market price at the point at which the interconnector connects to the shared network in the importing region
- $CRMP_M$ is the congestion relief market price at the point at which the interconnector connects to the shared network in the exporting region.

This equation can be rearranged as follows:

Energy revenue (MNSP) = $(AQ_{IC} + AGE_{IC} - PQ_{IC})$ x $(RRP_M - RRP_X) + (PQ_{IC} - AQ_{IC})$ x $(CRMP_M - CRMP_X)$

In the first term, we see that the MNSP receives revenue directly analogous to the IRSR that arises on regulated interconnectors. In the second term, we see that the MNSP additionally receives revenue relating to CRM trading.

C.7 Quantity limits

Quantity limits are a possible 'add-on' feature to the CRM design.

Under this feature, an opted in market participant could specify:

- The maximum quantity they would buy from the CRM (i.e. the largest negative number that (PQ – AQ) could be); and, separately
- The maximum quantity they would sell into the CRM (i.e. the largest positive number that (PQ – AQ) could be).

Without this feature, generators can effectively set minimum and maximum values for their physical dispatch through their bid. However, because they do not know their access dispatch in advance (i.e. when bids and rebids occur), this does not allow them to set these trading limits with any certainty.

The 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, increasing their exposure to the CRMP. It would also allow traders to manage contract positions which may allow for a proportion of output not to be sold via the PPA.

A related issue in the consultation paper was whether participants opting-in to the CRM are able subsequently to 'opt-out'. The ESB proposal (which may be revisited) that this would not be

70 In the detailed design we will need to be consideration of how to determine the relevant CRMPs given these are not currently produced by NEMDE.

permitted raised stakeholder concerns. The ability for to effectively not opt in by offering zero CRM quantity limits might allay these concerns, and is another factor in favour of including these quantity limits.

AEMO has already included quantity limits in its CRM prototype and is confident that these will be relatively low cost to implement operationally.

Based on strong stakeholder support and low implementation costs, we propose to include CRM quantity limits.

C.8 Buy-sell spreads

Another optional-extra feature of the CRM could be buy-sell spreads.

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 offer price in to the physical dispatch.
- Any sales to the CRM will be at a price no lower than the relevant offer price in the physical dispatch.

Any payments from trade in the CRM will need to be offset against the SRMC of generating more or less than indicated by the access dispatch. 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 not opt in to 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 physical offer prices above the access dispatch target. Similarly the bid spread parameter would in effect automatically lower the physical offer prices below the access dispatch target. The offer and bid spreads would be managed by putting a price on deviations in the physical dispatch from the access 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 not opt in.

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

Unlike with the CRM quantity limits, AEMO has *not* incorporated CRM spreads into its CRM prototype and has concerns that doing this operationally could be difficult and expensive.

Furthermore, with CRM quantity limits, a "soft" CRM opt in is already available, meaning that CRM spreads are not needed to provide this. CRM quantity limits can be used by bidders to rule out one side of CRM trade and so incorporate a margin on the other side. For example, the CRM buy limit could be set to zero and the CRM bid could then include a margin above cost, to potentially sell at a profit without any risk of buying at a loss.

With experience, CRM bidders may find ways to incorporate spreads directly into their CRM bids (e.g. by accurately predicting their access dispatch), without the need for a special spread facility.

Support for CRM spreads was the same as that for CRM quantity limits, i.e. from the same stakeholders for the same reasons and subject to the same implementation cost concerns.

Taking these factors into account, we have decided not to include the spread feature in the CRM design.

C.9 FCAS bids and settlement

Notwithstanding its name, the access dispatch in the two-stage dispatch design is actually a complete dispatch which also sets dispatch targets for FCAS. This is necessary to ensure that, in the unlikely event that no market participants opt in, the resulting dispatch is physically feasible. This is not the case in the co-optimised design.

Similarly, the physical dispatch also covers both energy and FCAS. Whilst the CRM design is focused on incentivising more efficient energy dispatch it will invariably lead to changes in FCAS dispatch. Hence, the two-stage dispatch runs will lead to two different dispatch quantities and two different prices for each FCAS service.

The design question under the two-stage dispatch design is whether generators should be able to submit a second set of FCAS bids to the physical dispatch, or whether there should be only one set of FCAS bids which apply to both dispatches. The question is moot under the co-optimised model.

The regional nature of FCAS dispatch means there are less incentives for disorderly bidding of FCAS in the access dispatch than there are for energy. However, the 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 physical dispatch. In this case, allowing two separate sets of bids – and so allowing cost-reflective FCAS bidding into CRM dispatch – might improve the efficiency of physical dispatch.

That said, while there are theoretically some potential benefits from allowing two sets of bids, the magnitude of these benefits is, relative to energy, likely to be relatively low (given the lower value of the FCAS market), whilst the implementation and operation costs will be relatively high (given there 10 FCAS products but just a single energy product). The fact that there is no stakeholder support for two sets of bids suggests that FCAS providers don't see much potential value either.

We therefore decided to use a single set of FCAS bids in the CRM model, which are inputs to both the access dispatch and physical dispatch.

C.10 Opting in to CRM FCAS

Under the two-stage dispatch design, to avoid being settled at two different sets of prices for FCAS (one from access dispatch, one from physical dispatch), a generator might wish to not opt-in for CRM FCAS. Analogous to energy, this would mean that the FCAS CRM dispatch targets are automatically set equal to the FCAS access dispatch targets.

Since the generators who do not opt-in to CRM FCAS would typically also be not opting-in to 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, for example a generator would be allowed to not opt-in to the CRM for energy but opt-in for FCAS. This question is moot under the co-optimised design, as there would only be one set of FCAS dispatch quantities.

The current NEMDE prototype allows for participants to opt-in or not for energy, but only opt-in for FCAS. To allow participants to not opt-in to CRM FCAS could add challenges – especially considering the number of FCAS products. It also might impact on CRM liquidity. The prototype results commonly show changes in FCAS targets between the access and physical dispatches, even for those generators not opting-in to the CRM for the energy market. The fact that NEMDE makes these changes suggests that not opting-in to CRM FCAS could limit the range of physical dispatch options available to NEMDE and thus limit potential dispatch efficiency gains.

Not opting-in to the CRM energy trading was introduced to address concerns about the impact of CRMP exposure on existing contracts, and the likely need to re-open and re-negotiate them. It is unclear whether exposure to FCAS CRM prices would create similar concerns, and no stakeholders have raised them. This might be because those generators with a desire to not opt-in to the CRM for energy don't generally offer FCAS anyway.

Two submissions to the ESB May 2023 consultation paper support an 'opt-out' for FCAS, i.e. a decision to not opt in to the CRM applies to both the energy market and FCAS (AFMA and ENGIE). One of the submissions (ENGIE) stated that "It seems likely that participants will choose both or neither, but better that they have the choice".

Nevertheless, given the lthe absence of issues with opt-in FCAS and the potential for adverse impacts on dispatch efficiency, the AEMC has decided only allow opt-in for FCAS.

C.11 Other detailed design decisions that have not been considered in detail

We are aware of numerous other matters that will have to be considered in the fullness of time, relating to:

- Treatment of various other non-price/quantity components of a generator's offer (e.g. daily energy constraints, available capacity, ramp rates and dispatch inflexibility profiles for fast start generators). Should these components of an offer be allowed to differ between the two dispatches, as price/quantities are?
- Pre-dispatch and Projected Assessment of System Adequacy (PASA) - how CRM would impact these functions.

- How the CRM interacts with the wholesale demand response mechanism.
- Losses and the treatment of settlement residue relating to losses.
- Requirements on AEMO and the AER to report on outcomes and/or monitor behaviour.
- Modifications to FCAS settlement.
- Prudential requirements.
- The treatment of parties who feature on RHS of a constraint – should they be able to participate in the CRM?
- Various 'interventions', by which we mean in this context any action taken by AEMO to change the dispatch outcomes (prices or quantities) that would otherwise have arisen through dispatch, e.g.:
  - the Reliability Emergency Reserve Trader (RERT),
  - non-market ancillary services (NMAS),
  - directions and instructions,
  - market settings (market price cap, market floor price, administered price cap and floor),
  - market suspension,
  - compensation payments in light of any of the above,
  - price adjustments (what-if pricing) in light of any of the above.
- Transitional or implementation rules.

D Worked examples of the hybrid model

This section sets out several worked examples of dispatch outcomes in the existing market arrangements and under the hybrid model.

These are simplified examples to illustrate the broader impacts on dispatch outcomes. Therefore, we assume:

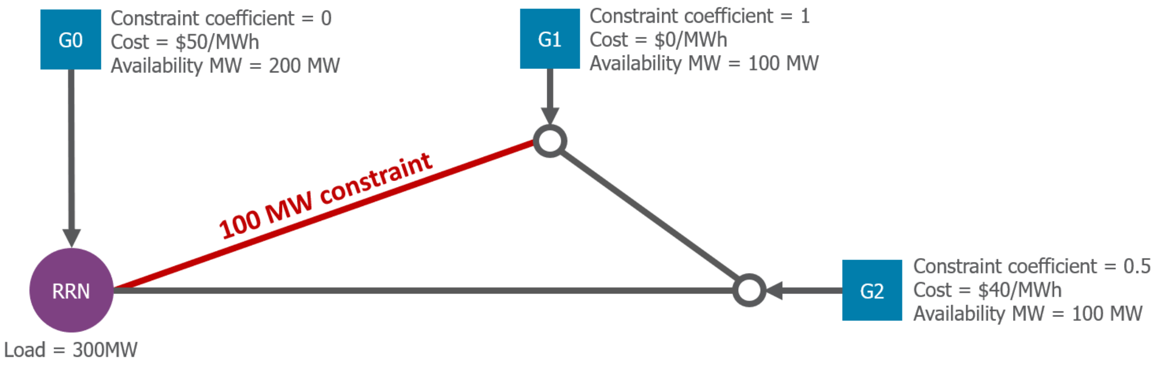
- two-stage dispatch for the hybrid model,
- no losses and no FCAS,
- one region and no interconnectors,
- generators follow dispatch targets exactly,
- generators in a binding constraint bid at their MFP (or BPF) in access/current dispatch,
- generators bid at cost in the physical dispatch for the CRM,
- generators not in a binding constraint bid at cost,
- generator revenue only comes from the spot market,
- generator costs come from a fixed cost per MWh physically dispatched.

D.1 Existing market arrangements

Consider the network shown in Figure D.1. G1 and G2 are constrained behind a 100 MW transmission constraint (indicated in red) and have constraint coefficients of 1 and 0.5 respectively. As they are constrained, both G1 and G2 bid at the MFP (-$1000/MWh), to try maximise their dispatch.

G0 is an unconstrained generator that bids at cost and sets the RRP at $50/MWh in all examples.

Figure D.1: Example network - two constrained generators



The dispatch outcomes are presented in Table D.1. Due to the constraint coefficients, G2 gets dispatch to capacity before G1 is dispatched until the constraint is binding.

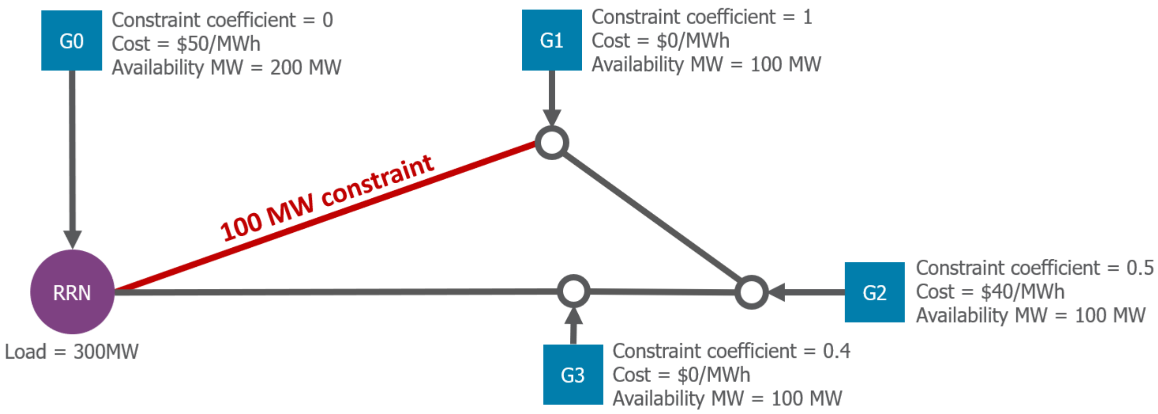
Table D.1: Status quo dispatch outcomes - two constrained generators

Generator	Bid ($/MWh)	Dispatch (MW)	Revenue ($/h)	Cost ($/h)	Profit ($/h)
G0	50	150	7,500	7,500	0
G1	-1,000	50	2,500	0	2,500

Generator	Bid ($/MWh)	Dispatch (MW)	Revenue ($/h)	Cost ($/h)	Profit ($/h)
G2	-1,000	100	5,000	4,000	1,000
Total		**300**	**15,000**	**11,500**	**3,500**

In a continuation of this example, assume that a new entrant G3 locates behind the constraint and has a constraint coefficient of 0.4. The changes to the network can be seen in Figure D.2. Identical to G1 and G2, G3 bids at the MFP to maximise dispatch.

Figure D.2: Example network - three constrained generators



These new dispatch outcomes are presented in Table D.2. Due to its lower coefficient, G3 is dispatched before G2 and G1. This results in G3 being fully dispatched to capacity, cannibalising output from G1 who is now only dispatched to 10 MW. Consequentially, the profit of G1 is reduced by $2,000. G0 is also dispatched less, as the total dispatch from the lower-cost generators behind the constraint increases.

Table D.2: Status quo dispatch outcomes - three constrained generators

Generator	Bid ($/MWh)	Dispatch (MW)	Revenue ($/h)	Cost ($/h)	Profit ($/h)
G0	50	90	4,500	4,500	0
G1	-1,000	10	500	0	500
G2	-1,000	100	5,000	4,000	1,000
G3	-1,000	100	5,000	0	5,000
Total		**300**	**15,000**	**9,500**	**6,500**

These examples demonstrate how existing generators are at risk of cannibalisation from new entrants. G1 is vulnerable to cannibalisation if any generator connects with a lower coefficient, and could be susceptible to not getting dispatched at all.

D.2 Priority access and the CRM

In these examples, we demonstrate how the hybrid model would work and how it can provide protections from cannibalisation, as well as allowing for an efficient physical dispatch.

D.2.1 Protection from cannibalisation with priority access

Consider the previous example in Figure D.2, but introduce priority access (the CRM will be included in the next example). As a new entrant, let G3 have a BPF of -$300/MWh. G1 and G2 are both incumbents and can bid at the MFP.

The dispatch outcomes from this priority access dispatch are presented in Table D.3, which replicates dispatch prior to G3 connecting. Therefore, priority access has protected G1 from being cannibalised by G3.[71] This reduction in dispatch and revenue could signal to G3 (specifically, G3 *before* it connects) that this location may not be preferable to build and its investment may instead be used to build a generator elsewhere. However, note that G3 is not dispatched at all despite contributing the least to congestion (excluding G0) and having the equal lowest underlying cost.

Table D.3: Priority access dispatch outcome - three constrained generators

Generator	Bid ($/MWh)	Dispatch (MW)	Revenue ($/h)	Cost ($/h)	Profit ($/h)
G0	50	150	7,500	7,500	0
G1	-1,000	50	2,500	0	2,500
G2	-1,000	100	5,000	4,000	1,000
G3	-300	0	0	0	0
Total		**300**	**15,000**	**11,500**	**3,500**

D.2.2 The CRM retains the protection of priority access and produces a physically efficient dispatch

When the CRM is introduced, this will allow the generators to trade dispatch outcomes between the access dispatch and physical dispatch. The generators bid in the same as the previous example in the access dispatch under the same incentives. However, the generators bid at cost in physical dispatch to maximise profit, as deviations between access and physical dispatches are paid their CRMP.

This results in the dispatch outcomes presented in Table D.4. The CRMP of G0 is the RRP, whereas the CRMPs of G1, G2 and G3 are determined based on the marginal generator behind the constraint, G1. The revenue amounts are calculated as such:

- Access revenue = access dispatch x RRP ($50/MWh).
- CRM revenue = (physical dispatch – access dispatch) x CRMP.

71 Note that whether a high-priority participant would get dispatched ahead of a low-priority participant is not guaranteed and dependent on their respective BPFs and their constraint coefficients.

Table D.4: Hybrid model dispatch outcome - three constrained generators

Generator	Access bid ($/MWh)	Physical bid ($/MWh)	Access dispatch (MW)	Physical dispatch (MW)	CRMP ($/MWh)	Access revenue ($/h)	CRM revenue ($/h)	Cost ($/h)	Profit ($/h)
G0	50	50	150	140	50	7,500	-500	7,000	0
G1	-1,000	0	50	60	0	2,500	0	0	2,500
G2	-1,000	40	100	0	25	5,000	-2,500	0	2,500
G3	-300	0	0	100	30	0	3,000	0	3,000
Total			**300**	**300**		**15,000**	**0**	**7,000**	**8,000**

As expected, the access dispatch outcomes are the same as the priority access outcomes in appendix D.2.1. Therefore, the financial effects of priority access are retained, however physical outcomes vary due to the CRM.

Notably, the lower-cost G3 is physically dispatched instead of the higher-cost G2. G3's profit ($3000/h) is less than under the status quo arrangements ($5000/h) but more than the priority-access-only dispatch ($0/h). This indicates how the locational signals for investment efficiency from priority access are retained with the CRM, but also reflect the capability for G3 to reduce system costs.

Despite not being physically dispatched and having negative CRM revenue, G2 is still profitable due to the access revenue granted to it through the access dispatch, where it was dispatched ahead of G3 due to having a higher priority.

Overall, the cost-reflective bidding in physical dispatch leads to a physically efficient dispatch, as shown by the total system costs. This is mirrored in the system profits, which are greater than the system profits in all previous examples without the CRM. Furthermore, compared to the priority access example, no one is worse off by participating in the CRM.

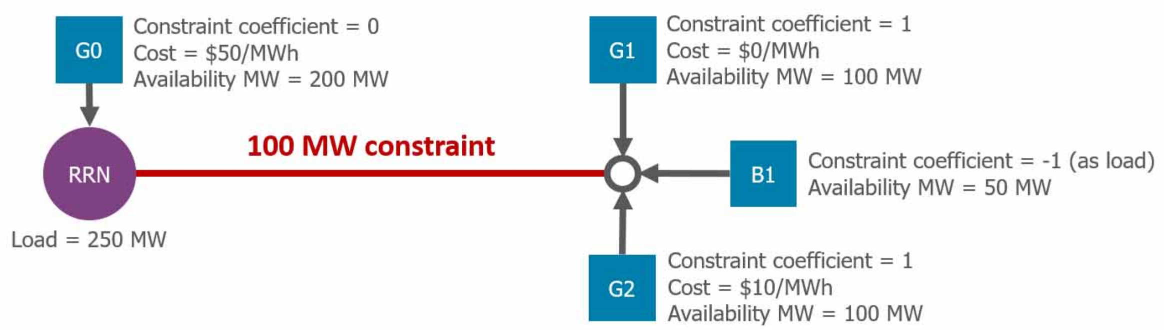
Therefore, these examples demonstrate how the hybrid model can protect existing generators via priority access, while also delivering a physically efficient dispatch through the CRM.

D.3 Storage can benefit from cheaper energy in congested areas

Through the CRM, storage and scheduled loads located in congested areas will be able to buy energy for prices below the RRP. This can provide incentives for storage to locate in congested areas, as this can provide increase their intra-day price spread and arbitrage profit. If storage locates in congested areas, this has system-wide benefits as otherwise spilled low-cost energy can be stored and used at a later time when it is needed, instead of not being generated.

For example, consider the network in Figure D.3 with a simple radial constraint. The battery B1 recognises that its local network will be constrained and its CRMP will be less than the RRP. As such, B1 chooses to bid only into the physical dispatch to charge with full exposure to their CRMP.

Figure D.3: Example network - battery in a constrained area



In the access dispatch, the higher priority G1 is fully dispatched while G2 and B1 are not dispatched at all. However, G2 is able to increase its physical dispatch through the CRM by 50 MW to supply the battery – this bilateral CRM trade is priced at the CRMP of $10/MWh. The settlement outcomes are presented in Table D.5.

Table D.5: Hybrid model dispatch outcome - battery in a constrained area

Generator	Access bid ($/MWh)	Physical bid ($/MWh)	Access dispatch (MW)	Physical dispatch (MW)	CRMP ($/MWh)	Access revenue ($/h)	CRM revenue ($/h)	Cost ($/h)	Profit ($/h)
G0	50	50	150	150	50	7,500	0	7,500	0
G1	-1,000	0	100	100	10	5,000	0	0	5,000
G2	-800	10	0	50	10	0	500	500	0
B1	-	15	-	-50	10	0	-500	-	-500
Total			**250**	**250**		**12,500**	**0**	**8,000**	**4,500**

For the battery, it is charging now and seeking to discharged later when the price is higher and congestion is lower. For example, this could be in the evening when solar farms are no longer generating (if G1 and G2 were solar farms). Note that in the existing arrangements, the battery would either be charging at the RRP of $50/MWh or not charging at all if it were too expensive. Therefore, the net profit of the battery is higher in the CRM by being able to charge at a CRMP lower than the RRP. This demonstrates the incentives for storage and scheduled loads to locate in congested areas and maximise profit.

Furthermore, without a locational incentive in the existing arrangements for the battery to locate behind the constraint, it may choose to build elsewhere in the grid (for example at the RRN). If it were to do so, its energy would come from another, and likely higher cost, generator (in this example, G0). This would be a more physical inefficient outcome for the system with potentially higher emissions, as higher emission generators tend to be higher cost.

Altogether, this example demonstrates how storage and scheduled load would be able to access lower prices for energy through the CRM. This incentivises such assets to locate and alleviate congestion by absorbing excessive low-cost energy, providing system-wide benefits in addition to privately beneficial outcomes.

E Glossary and abbreviations

E.1 Glossary and notes on language

E.1.1 Names of dispatch runs

In previous ESB documents, the dispatches in the two-stage dispatch were called the EN dispatch (short for energy) and the CRM dispatch. The EN dispatch was the initial dispatch run that determined access quantities and included priority access, with the CRM dispatch determining the physical dispatch quantities for CRM participants and carrying over the EN dispatch outcomes for participants who do not opt in to the CRM.

We have deviated from this language in this consultation paper. The access dispatch referred to in this paper corresponds to the EN dispatch, and the physical dispatch corresponds to the CRM dispatch.

We considered that the previous language can be confusing as it can imply that the 'EN' dispatch is *the* physical dispatch. This is only the case for generators who do not opt in, as the EN dispatch run only determines financial access to the RRP for CRM participants. Hence, we consider that a more appropriate name for the initial dispatch run is the access dispatch.

The second dispatch run determines the physical dispatches for CRM participants, but also carries over the physical dispatch quantities from the access dispatch for market participants that do not opt in. Therefore, all outcomes from the second dispatch run will correspond to the physical dispatch instructions. This is why we consider it is more appropriately called the physical dispatch.

In the context of using co-optimisation to implement the CRM, there is only a single dispatch run of NEMDE that determines both the access and physical dispatch quantities. Therefore, there are still separate access and physical *dispatches*, but they are determined simultaneously as part of a single co-optimised *dispatch run*.

E.1.2 Three different RRPs

Across the two-stage dispatch and co-optimised dispatch approaches for the CRM, there are three different possible RRPs:

- **Access RRP:** previously known as the EN RRP, it is set by the marginal cost of generation at the regional reference node (RRN) in the access dispatch (not necessarily corresponding to the physical marginal costs) in the two-stage dispatch method.
- **Physical RRP:** previously known as the CRM RRP, it is set by the marginal cost of generation at the RRN in the physical dispatch (i.e. not including access dispatch outcomes, such as generators who do not opt into the CRM) in the two-stage dispatch method.
- **Co-optimised RRP:** determined by the co-optimised dispatch run and is set by the marginal cost of physical generation (including generation from physical dispatch and generation from access dispatch that eventuates into physical generation) at the RRN.

Consideration of each RRP is discussed in chapter 5.

In the context of the two-stage dispatch, references to an unspecified RRP correspond to the access RRP, as this is the preferred RRP choice. For example, the prototyping of the hybrid model (see appendix B) found that priority access could lead to RRP increases within the assumptions of the modelling. These RRP increases were specifically for the access RRP and not necessarily representative of any potential impacts to the physical RRP.

E.1.3 Generators, loads and storage

Recall that a market participant can participate in the CRM depending on whether they are scheduled/semi-scheduled or unscheduled. This means that scheduled load, generation (also semi-scheduled), storage and market network service providers (MNSP) can participate in the CRM. To be strictly accurate when discussing CRM participants can either lead to clumsy sentences that are difficult to follow, or the frequent need reiterate that the market symmetrically applies to generators offering to sell as well as load bidding to buy.

For example, consider the strictly accurate sentence: “A scheduled or semi-scheduled generator, storage unit acting as a generator or MNSP (or load or storage unit acting as a load) which offers (bids) in the physical dispatch at a price less than (greater than) its CRMP will always be physically dispatched.”

Instead, we use often the term ‘generator’ as a shorthand for ‘scheduled or semi-scheduled generator, load, storage or MNSP’, unless the context requires differently. As such, the sentence above simplifies to: “A generator which offers in the physical dispatch at a price less than its CRMP will always be physically dispatched.”

As a consequence, topics and ideas are discussed in a simpler and straightforward manner, however readers should be aware that discussions often incorporate all relevant assets.

E.1.4 Hardness of priority access

The ‘hardness’, or equivalently ‘strength’, of priority access refers to effectiveness of dispatching (in access dispatch) a high priority generator over a low priority generator.

Completely hard priority access would ensure that a high priority generator is always dispatched ahead of a lower priority generator, if NEMDE can dispatch only one of them. Therefore, participants in a binding constraint and bidding disorderly (i.e. as low as possible) would get dispatched entirely in order of priority with no influence from constraint coefficients. This would be opposite to the status quo, where there is no priority access and dispatch of such generators is based on constraint coefficients.

However, implementing priority access through adjusting BPFs will mean there is inherently a degree of softness as completely hard priority access would require astronomically large (negative) BPFs. Dispatch of generators bidding at their BPF will depend on both their priority levels (through their BPF) as well as their constraint coefficients. This means that a lower priority generator with a sufficiently small enough coefficient and/or a low BPF could get dispatched ahead of a higher priority generator. The BPF method also has a dependence on the RRP – priority access will be softer as the RRP increases.

Mathematically, for a single binding constraint, generator A (in a binding constraint with a coefficient a_A) will be dispatched ahead of generator B (in the same binding constraint with a coefficient a_B) if:

$a_A/(RRP - BPF_A) < a_B/(RRP - BPF_B)$.

E.1.5 Buying and selling

A *seller* in the CRM has (PQ > AQ). This is where a generator is physically dispatched for more than its access quantity – they are *selling* (i.e. getting dispatched for) additional energy that they can physically generate in the CRM.

A *buyer* in the CRM is the opposite and has (PQ < AQ). This is where a generator physically dispatched less than its access quantity – they are *buying* (i.e. avoiding dispatch for) additional energy that they do not physically generate in the CRM.

E.2 Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BPF	Bid price floor
CIS	Capacity Investment Scheme
COGATI	Coordination of Generation and Transmission Investment
Commission	See AEMC
CMM	Congestion management model
CRM	Congestion relief market
CRMP	CRM price
DP	Dispatch priority
FCAS	Frequency control ancillary services
IRSR	Inter-regional settlement residue
MFP	Market floor price
MNSP	Market network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
PPA	Power purchase agreement
REZ	Renewable energy zone
RRP	Regional reference price
SRA	Settlement residue auction
TNSP	Transmission network service provider