Response to the AEMC Transmission Access Reform review paper

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baringa.com

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1 Executive summary

Enel Green Power has engaged Baringa Partners to provide an independent view on the needs case for the proposed transmission access reform and on the assumptions underpinning the cost benefit analysis previously undertaken to justify pursuit of the proposed approach.

In terms of the priority access model, we consider that there are existing measures in place which incentivise new projects to connect into network locations which have capacity to accommodate their dispatch. In particular, we consider the following measures play an important role in providing locational signals and – in some cases – protecting the access of other connected projects:

- Integrated System Plan;
- REZ Access Schemes;
- Capacity Investment Scheme;
- REZ Access Control measures;
- Enhanced Locational Information report;
- Exposure to Marginal Loss Factors;
- Exposure to technical curtailment; and
- Connection requirements.

Given this suite of existing measures, **there does not appear to be a strong need for priority access in the 2020s**. As the need for new arrangements potentially comes back into play in the late 2020s and into the 2030s, the policy design should:

- reflect the role many of these existing measures will continue to play in informing investment decisions;
- be fit-for-purpose in the context of the post-2030 market with a very high penetration of renewables; and
- align with any other post-2030 market design reforms pursued.

Further, in the interests of supporting investment in generation as the sector continues to decarbonise, and given the challenges to building new REZ network infrastructure quickly, **it will be important that the policy design does not seek to penalise connection to non-REZ network where the network has capacity to accommodate it**.

In terms of the congestion relief market, we consider that **the policy does have the potential to incentivise storage connecting into congested parts of the network** by monetising the value it can provide through alleviating congestion. This can deliver benefits for the market by reducing curtailment of clean, low cost, renewable energy and making more efficient use of the installed generation capacity.

However, the cohort of generators we would expect to participate in this market is limited, largely consisting of wind generators and standalone storage located behind congested lines.

In terms of disorderly bidding, we do not expect that the congestion relief market will impact the bidding strategies of coal-fired generators, hydro (run of river) generators and other inflexible technologies. It could reduce the volume of bids at market floor price for renewable energy generators but we expect that this impact would be limited to only the subset of generators expected to participate in the market, and only where constraints bind. It is also not clear that there is a benefit to consumers of dissuading wind or solar projects from bidding below their short run marginal cost.

There is merit in revising the cost benefit analysis with some updated assumptions to provide the AEMC and the wider market a closer approximation of the anticipated costs and benefits of the TAR as proposed than has been available to date.

Baringa has not undertaken independent cost benefit analysis as part of this work. However, we have identified a number of key assumptions we consider merit reconsideration. These are the assumptions around:

- Existing locational signals;
- Race to the floor incentives
- Congestion relief market participation;
- Simplification of market design; and
- Simplification of market dynamics.

The state of the market has also changed considerably since the analysis was originally undertaken. While this is inevitable and unavoidable with analysis undertaken at a particular point in time, if the analysis is being reconsidered to account for the issues with key assumptions, this would also present an opportunity to incorporate market changes which may impact on costs and benefits:

- Faster coal closure and renewables build; and
- Risk of delays to new transmission infrastructure.

Without revisiting the cost benefit analysis and ensuring that the assumptions and underlying market conditions reflect the policies as designed and the needs of the future market, it is difficult to ascertain what the anticipated net outcome of priority access and a congestion relief market is actually likely to be.

2 Introduction

The need for significant volumes of new generation and storage in the NEM, to enable the transition away from coal generation, is now well understood and widely accepted. Likewise, the transition will require significant new network infrastructure for the generation to connect into.

For many years now there has been a live policy conversation around how best to coordinate the new generation entering the market with the available network infrastructure, to reduce risks for connecting parties (and investors), efficiently use the network, and achieve least-cost outcomes for consumers.

At the crux of these conversations is the open access regime. Open access essentially entitles generators to connect to the network but does not entitle them to certainty of dispatch over the network, and leaves open the possibility (and in some cases the reality) of overcrowding of transmission lines with impacts on connected parties, irrespective of when they connected.

The current system is viewed by many as a source of uncertainty and risk for prospective new and operational generators alike, to the detriment of low-cost investment – investment which is desperately needed for the near-term energy transition. Similarly, however, many of the proposed policy solutions have also been criticised as likely to create uncertainty and risk, at least for some connecting generators, again to the detriment of investment. The AEMC, ESB and stakeholders have been working to resolve concerns around coordination of generation and network infrastructure for many years, and both state and federal governments have layered on their own approaches to support this outcome.

Transmission access reform (TAR) is the current face of this work to arrive at a solution for coordinating new generation and network capacity in the NEM. The AEMC has done a nice job of summarising the history, context and mandate of this work program in its latest consultation paper. In short:

- The Energy Security Board (ESB) was considering transmission access reform within its wider Post-2025 Market Design program;
- Following stakeholder pushback on earlier proposals, the ESB sought stakeholder proposals for alternative policy options and sought to pursue a 'hybrid' approach with two of the proposed options: a congestion relief market and a priority access model. In early 2023, Energy Ministers agreed that the ESB should develop the hybrid model further;
- The AEMC has now been tasked with undertaking a transmission access reform review, to make final recommendations to Energy Ministers in late 2024. Feedback on the recent consultation paper will inform the AEMC's review.

Transmission access reform is being endorsed by Energy Ministers as a potential means to address a range of untoward outcomes which they expect to arise under current policy settings, increasing costs to consumers. These can be paraphrased as[1]:

- Solar and wind projects may be curtailed due to network congestion, meaning the market does not see the full benefits of the low cost and zero emissions electricity;
- The certainty and value of REZs may be undermined by projects connecting outside of REZs and causing congestion and curtailment;
- Storage and flexible load resources which can create value by alleviating congestion will not see a revenue stream reflecting this (unmonetized value); and
- The value of investment in interconnectors and transmission may not be fully realised and transmission overbuild may transpire.

The hybrid model that is proposed to mitigate these issues consists of two components: priority access and a voluntary congestion relief market.

- Priority access:

  In simple terms, the proposed policy would see connected generators attributed a priority level essentially reflecting the availability of network headroom to accommodate dispatch of their capacity at the time of their connection. In the case that a line is congested, priority levels would play into the dispatch priority of generators behind the congestion, such that those with more favourable priority would be prioritised for dispatch over those with less favourable priority.

- Congestion relief market:

  The proposed policy would introduce a voluntary market in which congestion relief could be bought and sold between participants impacted by congestion, to allow for greater utilisation of available generation. In practice, the policy would be expected to introduce a new revenue opportunity for storage located behind constraints, in some circumstances, and may incentivise some generators to bid into the market at their SRMC rather than a lower value.

Cost benefit analysis has been undertaken to provide an initial view on the anticipated outcomes of implementing the two components of the hybrid model. The ESB published a cost benefit analysis paper in 2023 which drew on earlier modelling undertaken by NERA as well as more recent work by CEPA. Based on the assumptions and methodology implemented, the analysis found that the policies would together deliver net benefits for consumers.

The AEMC notes that "as a standalone solution, priority access may introduce new dispatch inefficiencies to the energy market"[2]. It is of the view that, while the two elements could be implemented individually, implementing the two together as a hybrid approach "leads to more efficient outcomes and prices for customers"[3].

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[1] AEMC, Transmission access reform consultation paper – April 2024, page iii, paragraph 21.

[2] AEMC, Transmission access reform consultation paper – April 2024, page iv, paragraph 25.

[3] AEMC, Transmission access reform consultation paper – April 2024, page iv, paragraph 26.

2.1 Scope of this report

Baringa Partners (Baringa) has been engaged by Enel Green Power Australia (Enel) to provide an independent view on the needs case for the proposed transmission access reform and on assumptions underpinning the cost benefit analysis previously undertaken to justify pursuit of the proposed approach.

We have not sought to respond to the specific consultation questions posed by the AEMC in this report, nor comment on the details of the proposed design. The advice presented in this report is qualitative only and has not been informed by bespoke market modelling.

3 Revisiting the needs case

The need for greater coordination of generation and network infrastructure has changed over time as changes to the policy and planning landscape have come to fruition – particularly the Integrated System Plan (ISP) being introduced – and as government support for generation and transmission has been announced. At its core, however, the needs case has remained tied to the concern that open access along with a lack of coordination leads to risks and costs for developers and potential inefficient outcomes for the system.

The current needs case put forward by the AEMC for the proposed transmission access reform extends beyond the longstanding concerns around locational signals and curtailment to now also include issues in operational timeframes, such as incentivising and monetising behaviours that alleviate congestion. The concerns are captured in the issues identified by Energy Ministers, provided in the previous section of this report.

In its consultation paper the AEMC lays out four objectives for the transmission access reform which respond to the issues identified by Energy Ministers[4]:

1. Investment efficiency: Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, taking into account the impact on overall congestion.
2. Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.
3. Operational efficiency: Remove incentives for non cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.
4. Incentivise congestion relief: Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.

Broadly, the priority access model is intended to address objectives one and two, with the congestion relief market intended to address objectives three and four.

In this section, we take a fresh look at whether there is still a relevant needs case for the transmission access reform as currently proposed, noting that a lot has changed in the market even in the few years since the initial elements of the hybrid model were first put forward by stakeholders, and also noting that the designs themselves have transformed since then. For simplicity, we have separated our assessment into the two components of the hybrid model: the priority access proposal and the congestion relief market.

[4] AEMC, Transmission access reform terms of reference, page 1

3.1 Priority Access proposal

Priority access has been proposed and is being considered in the AEMC's review as a mechanism to address a number of identified issues expected to arise under the current market design. Reflecting these issues, the policy is intended to deliver on two of the AEMC's objectives for this review:

- It is intended to provide better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers; and
- It is intended to manage access risk by establishing a level playing field that balances investor risk with the continued promotion of new entry.

In sum, we consider that a range of measures currently in place can be expected to sufficiently deliver on these objectives through much of the 2020s, such that a new and additional policy solution is not likely to be needed during this time. To be clear, the existing measures are not likely to entirely mitigate the risks and fully address the objectives above. However, they could reasonably be expected to do so to such an extent that the net benefits of introducing an additional policy in the near-term are debateable.

The need for revised access policy may become more material in the late 2020s and into the 2030s, however it should be noted that a range of other policies supporting the objectives above will still be in place. **It will be important that priority access or an alternative policy, if introduced, is designed in such a way that REZ connections as well as non-REZ connections *in areas with sufficient capacity* are not deterred from connecting, given the need for new clean generation capacity as the sector transitions**.

The measures we have identified and considered in this section, and their potential to contribute to the AEMC's objectives, are summarised in the table below.

Table 1: summary of existing measures that serve the AEMC's objectives for priority access.

Measure	Locational signals	Access risk
ISP	x	
REZ Access Schemes	x	
REZ Access Control measures	x	x
CIS	x	x
Enhanced Locational Information report	x	
Exposure to MLF	x	
Exposure to technical curtailment	x	
Connection requirements	x	x

A new approach, be it the priority access model or an alternative, could be required in the 2030s as some of the near-term measures may fall away (particularly the CIS). The approach adopted for the 2030s onwards should be integrated with the broader post-2030 market reforms currently under consideration at the Commonwealth level.

Given the prominent role that Renewable Energy Zones (REZs) are expected to play in enabling the energy transition, providing network capacity for significant new volumes of generation to connect into, we consider that they should be central to discussion of access arrangements. As such, we have structured our assessment of existing measures around in-REZ and out-of-REZ connections. The two categories are nonetheless highly interlinked, as the proposition and value of a REZ is partly dependent on the situation around connections outside of REZs.

3.1.1 Locational signals and management of access in REZs

Integrated System Plan

The Integrated System Plan (ISP) developed and published by AEMO biennially provides a critical coordination function between transmission infrastructure and projected generation across the National Electricity Market (NEM). This central planning and coordination work did not exist in its current form when transmission and generation coordination first entered the policy limelight and it constitutes a significant reform to coordination of future generation and transmission network needs.

The ISP has been integrated into the national regulatory framework such that the identified Optimal Development Pathway directly informs transmission investment decisions. It also provides a common and public understanding of the future state of the NEM and where stakeholders can expect that investments in new infrastructure will be made.

In its consultation paper, the AEMC proposes that "in practice the levels of congestion in the ISP can be considered to be the best case scenario"[5]. This view is based on the AEMC's view that the ISP does not take into account challenges with the existing open access regime and that the ISP also assumes projects bid at their costs.

Arguably, however, the ISP actually overstates the level of curtailment in the NEM. This is because the ISP modelling is based on a least cost co-optimisation of transmission and generation, but which does not apply an investment test to new generation projects entering the liberalised and competitive wholesale market. This would be expected to result in an overbuild of renewables relative to what we would expect to see if each project were required to be commercially viable in itself, with the overbuild then resulting in curtailment above that which would otherwise occur.

Irrespective of the validity of projected curtailment in the ISP, it now plays a very real role in the coordination of generation and transmission, given the real-world implications of the transmission network plans and particularly the nearer-term actionable projects. Baringa's experience working with wind and solar developers in the NEM reveals that the ISP is critically important in guiding long-

[5] AEMC, Transmission access reform consultation paper – April 2024, page iii, paragraph 19.

term locational decisions. The network build out is also largely reflected in market and network models used to develop revenue projections and advise investment cases for new projects, further cementing the material role it plays in the locational investment decisions of new connections.

Bespoke REZ access schemes

Renewable Energy Zones (REZs) are now fundamental to the future NEM. They provide a mechanism to efficiently and centrally connect regions of high wind and solar potential to the existing network backbone, and to load centres. REZs are not only a core feature of the ISP, around which the rest of the network is being designed, but are also a feature of state level network and energy transition plans.

REZs are intended to enable coordination of transmission and generation investment by design, with the network being planned and built out to reach areas in which new generation is expected to connect based on energy potential and a range of other metrics.

Beyond this inherent coordination purpose, it is important to note that Queensland, New South Wales and Victoria have all proposed to introduce bespoke access schemes in their REZs already, to provide certainty to the projects connecting within them. In all three states, physical access schemes are proposed to be applied. In a nutshell, this will allow the governments in all three states to place a cap on the total amount of new generation able to connect into identified REZs, therefore limiting the risk of oversubscription, network congestion and curtailment to levels they (and investors) deem efficient or reasonable. Physical access schemes introduce very clear locational signals for new investment into these regions until the available volume of access rights is subscribed, and then a very clear signal not to connect there. This is a very prescriptive way to coordinate generation and network infrastructure in these regions.

While physical access schemes are not currently proposed for South Australia and Tasmania, the three states in which they are proposed account for 89% of all installed capacity in the NEM for 2050, based on AEMO projections[6]. In the interests of providing certainty to investors, all are likely to (albeit not confirmed to) provide this coordination through the bespoke access schemes for at least 10 years from when the network is commissioned, meaning that most new projects connecting into REZs in the NEM can be expected to benefit from this coordination approach through at least the 2030s.

3.1.2 Locational signals and management of access outside of REZs

Capacity Investment Scheme

The Commonwealth Government's Capacity Investment Scheme (CIS) is anticipated to be the single biggest driver of new investment in the NEM between now and 2030. The policy was introduced in 2023 as a mechanism to deliver the government target of 82% renewable energy by 2030. Under the CIS, the government will support the development of up to 23 GW of new renewable energy generation and 36 GWh of clean dispatchable capacity by 2030, which is expected to be additional to

[6] AEMO ISP Draft 2024

the capacity already committed under other state policies. The support is being delivered in the form of government contracts which provide risk-sharing and revenue-sharing arrangements framed around a cap and floor, aimed at partially de-risking new investments.

This policy ambition is huge. Whether it achieves the full intended capacity or not, the CIS will drive a substantial volume of new generation and storage into the NEM over the coming years, and while some of this will locate in REZs, certainly a portion of the capacity will not.

CIS Agreements will be awarded through competitive tenders, which are currently structured around an initial non-financial bid stage and a subsequent financial bid stage. The non-financial bid stage requires proponents to respond to a range of merit criteria including a criterion concerned with project impact on the grid and market. Specifically, under this criterion[7] AEMO Services Limited (ASL) specifies that it will be assessing a project's potential to impact on network congestion, including its effect on other projects connected or expecting to connect to the network prior to the project. Further, it specifies that it wants to support projects that are intending to locate in a strong area of the network or that the connection of the project is not likely to lead to material curtailment and/or congestion of the generation of nearby renewable projects.

Through its assessment of projects against this criterion, it can be expected that projects applying for CIS Agreements – both those proposing to connect inside REZs and those proposing to connect elsewhere – will be subject to scrutiny of their potential network impacts. While it isn't entirely clear how ASL will assess the various responses it receives to this criterion, a project connecting outside of a REZ with the potential to materially increase curtailment in the REZ is unlikely to be looked on favourably.

Not all new capacity connecting into the NEM between now and 2030 will do so with a CIS Agreement (or an LTESA, which has similar merit criteria). However, those projects with CIS Agreements can be expected to have lower costs than those without, given their lower risk profile, which may then make them more competitive for other contracts such as Power Purchase Agreements (PPAs). This would then lend weight to the assumption that the majority of new projects will enter the market with a CIS Agreement, and therefore will be subject to this assessment by AEMO with their grid and market impacts scrutinised.

The CIS is designed around delivering a 2030 target, and regular competitive tenders are expected between now and the late 2020s. It is possible that auction-based procurement mechanisms may still be deployed in some form following the CIS as a means of coordinating incoming generation, even if this takes a different form and with limited or no subsidy attached. If the CIS support mechanism and/or an equivalent auction-based procurement mechanism is not in place post-2030, this level of scrutiny of new projects will also not be in place, and so the case for priority access may be stronger at that point in time.

REZ access control measures

[7] For Generation, in the forthcoming generation tender round, Merit Criterion 1 is Contribution to System Reliability and System Benefits.

As part of its access scheme policy, the NSW Government has the option to introduce an 'access control mechanism' alongside its access rights regime. This would provide a means to control connection of new projects to network infrastructure within the defined REZ geographic area but not on the specific network elements to which the access rights apply.

The intention of this policy lever is to enable the government to safeguard the objectives of its access rights regime – which is to say, it gives the government an option to reduce the risk of projects connecting near the REZ network and undermining the value of the REZ for connecting parties and the government. The de-risking benefit of a REZ could be undermined by creating congestion and leading to curtailment and greater losses in the REZ, or from the perspective of social licence or other broader outcomes. The exact method of access control and the scope and limitations of the mechanism have not been defined to date, granting NSW Government the opportunity to define the mechanism to suit the specific context of an individual REZ to which it seeks to apply the policy.

It is not yet clear whether NSW will choose to implement this policy lever, but it may choose to do so if it deems this is required to enable enhanced coordination of generation and its new REZ network infrastructure in any of its REZs as they progress.

Similar options are being explored and proposed in other regions.

The Victorian Government has proposed to apply a 'grid impact assessment' to projects connecting outside of REZs, as a means of ensuring that these projects do not result in 'excessive network curtailment' of REZ-connected projects[8]. A draft version of the grid impact assessment is expected to be published later in 2024, however it is proposed at a high level that it will require project proponents to demonstrate that their proposed projects:

- result in 'efficient investment', in accordance with the Victorian transmission planning objective, once this is embedded in updated legislation;
- do not impose undue incremental network curtailment on existing and planned REZ generators; and
- meet any other specified requirements.

In the context of Queensland, Powerlink's May 2024 consultation paper on the design of the bespoke access scheme for the Queensland network sought feedback on the circumstances in which 'REZ controlled assets' would be appropriate[9]. While further detail is not provided, the inclusion of this concept in the consultation paper illustrates that the option to control connection to assets outside of REZs is being explored.

Enhanced Locational Information report

[8] VicGrid, Victorian Access Regime under the VTIF, June 2024

[9] Powerlink, Queensland REZ design and development considerations, May 2024

AEMO published its inaugural Enhanced Locational Information (ELI) report in June 2024, with the intention to publish annual updates. The ELI report consolidates existing information about energy policy, capacity build out, network investment, system security and reliability, as well as economic signals, to provide a holistic overview of locational signals for investment in the NEM. The report was specifically designed to provide this locational information in a format that's clear and accessible, to inform decisions about where to locate projects in the NEM. The report was developed in response to the ESB's recommendations as part of its Transmission Access Reform work program.

Marginal Loss Factors

Transmission loss factors are arguably the original nodal locational signal in the NEM. They're not a new policy, but they undoubtedly they still play a key role in decisions about where to site new generation projects.

The current methodology for accounting for transmission losses, Marginal loss factors (MLFs), provides nodal-specific signals in the NEM. MLFs are lower in locations with high levels of congestion, which directly impacts market revenues, and thus developers are very careful to seek a reliable and credible long-term projection of MLFs ahead of their investment decisions.

Baringa works closely with debt and equity investors across the NEM. Through this experience we have seen that lenders and investors in generation projects are acutely aware of the impact MLFs have on revenues and profits. Baringa has also worked with several developers who have delayed or cancelled their final investment decision due to concerns about existing and projected future losses for their project.

There have been concerns raised that MLFs do not provide a suitable locational signal for investors given they're set annually and can demonstrate significant year-on-year variation. While this remans true in principle, they do nonetheless continue to provide a useful signal in many areas of the grid and provide a means to compare different areas of the grid.

Exposure to technical curtailment

Similarly to MLFs, technical curtailment in the NEM has a direct impact on project revenues and profits and therefore provides a strong rationale for connecting into uncongested network locations.

Technical curtailment occurs when AEMO limits the dispatch of generators to less than they would otherwise dispatch in order to manage network or system technical parameters. This is achieved by applying network constraints via the NEM dispatch engine (NEMDE). In some other markets, generators are financially compensated for technical curtailment, however this is not the case in the NEM where generators bear this cost.

The immediate impact on generator dispatch means that developers are incentivised to connect into areas of the grid in which they would not expect to be significantly impacted by constraints. As for MLF, a long-term technical curtailment study is now essentially a pre-requisite for a developer seeking to take an asset to financial close.

Connection requirements

To connect to the shared transmission network in the NEM, prospective connecting generators must undertake a range of technical studies and meet stringent standards, including generator performance standards (GPS). Within this cohort of requirements, prospective connecting parties need to demonstrate that they essentially 'do no harm' to other existing committed projects in the region in respect to certain technical parameters[10].

These connection requirements do not currently involve a broad assessment of the impacts of a new connection on existing and committed generators across the system. However, they do so for some technical parameters, and require the connecting party to undertake detailed analysis of a range of factors relating to their proposed connection site in the network, the network conditions at the location, and the impact of their own project on network conditions. To the extent that projects in a REZ are committed or existing, these requirements mean that the impact of new connections on these in-REZ projects, in the context of particular technical parameters, is considered and potentially remediated in the process of a connection being assessed.

Conclusion

The suite of existing mechanisms in the NEM summarised above, are effective at providing locational signals to guide new investment decisions to network locations in which their impact on the network, their own dispatch, and that of other projects will be minimal. In some cases, these mechanisms are also able to manage access risk, limiting the risk of subsequent connections to the network undermining network conditions for a given project. In the context of these mechanisms, the needs case for priority access in the 2020s does not appear to be material. There may be a need for revised access policy subsequent to this, however it should be noted that a range of other policies supporting the objectives above will still be in place.

3.2 Congestion Relief Market proposal

A congestion relief market has been proposed and is being considered in the AEMC's review alongside priority access, as a complementary mechanism to address perceived challenges on an operational (rather than investment) timeframe.

The policy is intended to address some of the issues raised by Energy Ministers through delivering on two of the AEMC's objectives:

- It is intended to remove incentives for non-cost reflective bidding to result in more efficient dispatch outcomes and more efficient use of the network; and
- It is intended to create incentives for storage and demand-side technologies to locate and behave in a way that benefits the broader system.

In sum, we consider that the proposed congestion relief market does have the potential to create incentives for storage to connect into congested areas of the network by monetising the value

[10] System strength and reactive current provision, for example.

these assets can provide through congestion alleviation. This can deliver benefits by reducing curtailment of low emissions, low cost, renewable generation. However, the cohort of generators we would expect to participate in this market is limited, largely consisting of wind generators and standalone storage located behind congested lines.

In terms of non-cost reflective bidding, the CRM is not expected to impact the bidding strategies of coal, hydro and other inflexible technologies. It could reduce the volume of bids at market floor price for renewable energy generators, but this impact would again be limited to only those expected to participate in the market.

In this section, we provide a brief overview of the policy's genesis and original intent, and then consider the current proposal and some of the assumptions which merit reconsideration.

3.2.1 Context of the congestion relief market

In June 2021, Edify Energy proposed a new Congestion Relief Market (CRM) design as an alternative to the Modified Congestion Management Market (CMM) and Interim Renewable Energy Zone (REZ) mechanisms outlined by the ESB in the Post 2025 Market Design Options consultation paper. The idea was then developed further by the CEC as "The Modified Congestion Relief Market", which kept broadly the same characteristics.

These proposals intended to introduce a new market which would identify and enact the most efficient in-market options to relieve congestion faced by generators in the NEM. Key characteristics of the designs put forward by Edify Energy and then the CEC include:

- The CRM would be incorporated directly into NEMDE constraints and co-optimised with the energy market. This was intended to allow for normal operation of the power system with relatively minor impacts on the status-quo operations of market participants.
- The CRM would operate as a spot market, only activating when a constraint is binding, due to line congestion. This would allow participants to directly value congestion on an individual case by case basis. Through this design, the market would also incentivise investment and competition in congestion relief (particularly in stand-alone storage assets) where it is most valued and directly address the relief of technical curtailment of specific renewable generators that need it.

While these proposals presented a potential positive impact on market efficiency, there were relatively few examples of when congestion relief could be incentivised, with storage assets highlighted as the most likely provider when located in a region impacted by congestion.

In November 2022, the ESB published the Transmission access reform directions paper with a new proposed design for a CRM. While this design had largely the same overarching objectives as the initial proposals, it proposed to implement the CRM through a secondary market which would be run sequentially and separately to the energy market, rather than via NEMDE and co-optimised with the energy market.

The most developed CRM design proposed in the current AEMC consultation maintains this approach and appears to be more focused on addressing perceived 'disorderly bidding' rather than, or alongside, relieving congestion problems in the NEM. At a high level the new design focuses on resolving inefficient outcomes from 'race to the floor' bidding by generators behind a congested line when aiming to be dispatched ahead of others. To remedy this the current design proposes a voluntary, opt-in secondary market, settled at the local node, in which generators can adjust their physical dispatch position away from the initial "priority access" position. The logic provided for this suggests that a secondary CRM would incentivise bidding at SRMC, instead of at the market floor price. This proposal of a voluntary model, rather than mandatory, reflects its understanding of stakeholder concerns and is a positive development.

The AEMC has also outlined in this latest consultation the option for a co-optimised dispatch approach rather than two stages. The co-optimisation approach would result in all market participants – irrespective of whether they've opted into the mechanism – receiving a single RRP which reflects the outcomes of the optimisation of energy and congestion relief bids in the region. The use case for this option still appears to focus on the re-ordering of dispatch rather than on congestion relief incentives.

The next section will discuss the needs case for these latest proposals in the current and future market contexts.

3.2.2 Consideration of the needs case

The congestion relief market was originally positioned as a market-based approach to efficiently resolve network congestion and thereby reduce technical curtailment in the NEM. It was anticipated to largely create an opportunity for stand-alone storage to be remunerated for providing direct congestion relief. As the policy has been developed further by the ESB and AEMC, the needs case has retained a need to remunerate storage for congestion relief, but has also come to include a need to address 'disorderly' bidding behind network congestion. Disorderly bidding was not contemplated in the initial design proposal - the original intent of the model was purely about congestion relief.

Remunerating storage for congestion relief

The need to create revenue opportunities for storage and flexible demand and to monetise the value they provide remains important in the market, but arguably less so than it was a number of years ago. Shorter duration batteries are now entering the market with little or no government subsidy, and longer durations up to 4 hrs are becoming more competitive. Further, the CIS will provide revenue underwriting for new clean dispatchable generation in the near-term, and state governments are pursuing their own targets with regard to storage of different durations. So, while valuing services from storage and flexible demand certainly remains important, the financing of many storage projects is currently less dependent on new revenue streams than was the case in the recent past.

If the CRM is implemented as designed, it would be expected to provide a new revenue opportunity and locational signal for storage behind congested network lines. Indeed, storage would be expected to be the main 'seller' of congestion relief and the majority of the benefit from the CRM would come from investment in storage enabling increased generation from renewables when located behind the same constraint. Given that storage is already incentivised to charge during the middle of the day when prices are lowest, it can be assumed that the revenue opportunities for storage are most likely to arise when storage is located in a wind-dominant area and behind a congested line, rather than in a solar-dominated area where generators will have less of an incentive to participate in the CRM. This notion is explored further in the next section of this report.

This benefit would be expected to be delivered under both the initial CRM design and the new CRM design. However, the initial proposal (from Edify or the CEC) for a co-optimised CRM would likely be the most efficient way of specifically incentivising congestion relief services rather than through sequential markets.

Addressing 'disorderly' bidding

The AEMC considers 'disorderly' bidding to be bidding from generation which is not representative of its short run marginal costs (SRMC) and as such leads to inefficient dispatch outcomes in the NEM. The TAR consultation argues that disorderly bidding comes as a result of race to floor bidding when generators are behind a constraint and therefore are incentivised to bid as low as possible if there is sufficient certainty they will earn (but not set) the RRN price on any dispatched energy.

Worked examples have been included in the initial ESB directions paper, the ESB cost benefit analysis and the two consultation papers (May 2023 and April 2024) of a scenario where generators behind a constraint will bid the market floor price of -$1000/MWh in order to ensure they are dispatched ahead of others. While there is a lot of value in including practical worked examples, we believe potential benefits of the new CRM have been misrepresented, particularly in the case of inflexible assets.

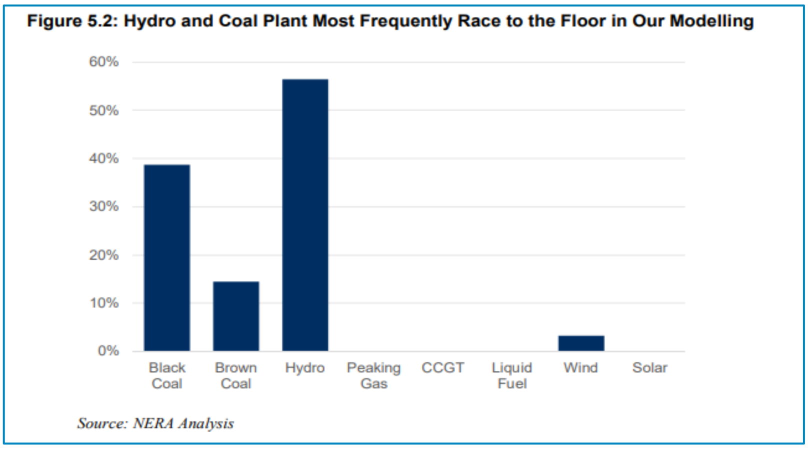
<u>Inflexible Assets - Coal and Hydro Generation</u>

Coal-fired and Hydro (run of river) generators can be observed bidding at the market floor price in the NEM, and this bidding strategy has been described in the consultation as race to the floor bidding. However, these generators are typically located on strong sections of the grid with good transmission capacity, relatively close to loads, rather than behind congested lines. The rationale for low bids in this case is not due to incentives to outbid competitors and avoid technical curtailment. Rather, it reflects the technical limitations of the plant: e.g. coal generators are inflexible below Minimum Stable Load (MSL) and face high startup costs if they are fully shut down.

We see this behaviour in the context of increasing rooftop and utility solar generation in the NEM. Minimum demand is becoming more prevalent along with very low prices in the middle of the day, followed by sharp increases in demand across the evening peak times when dispatchable generation is needed to ramp up. Inflexible generation with high startup costs must navigate this period by generating at their MSL across the middle of the day in order to offer generation in the evening peak. Additionally, the nature of the NEM being an energy-only market requires plant to recover not only SRMC but also fixed costs directly through their bidding. Any additional start-up costs added onto coal generation is likely to flow through to higher bidding during tighter periods.

NERA's Cost Benefit Analysis of Access Reform: Modelling Report commissioned by the AEMC in 2020 included analysis that found that race to floor pricing is almost exclusively carried out by Coal and Hydro plants[11]. This finding is illustrated in the figure below, from NERA's report.

Figure 1: Figure from NERA analysis of disorderly bidding[12]



We would expect that this bidding behaviour is mostly in line with system needs and does not represent a major additional cost in the long run if managed correctly through other policies. In the near-term while we're still dependent on coal for dispatchable generation in most NEM regions, preventing this behaviour will likely cause system stress across the evening peak. In addition, it is highly likely that these large coal generators will be needed to maintain a reliable and stable grid until bringing on new alternative technologies. As a result, any re-dispatch from the proposed new CRM will likely just be overridden by direct dispatch orders from AEMO which require the plants to stay online to provide this grid stability.

Variable renewable energy

Wind and solar generation do bid at the market floor price in some circumstances, including to outcompete other projects behind a congested line, and in doing so adhere the 'disorderly bidding' concept.

It is logical that renewable energy generation is incentivised to bid to the market floor price if it sits behind a constraint with numerous other generators (which in practice will likely mean that the contribution factors in the constraint equation will determine the ordering of curtailment). However, in the highly likely scenario that the generation facing congestion is all renewable, it is unclear how this bidding is negatively impacting market outcomes or consumers, as the generator dispatched will

[11] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p52

[12] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p52, Figure 5.2

always be a renewable asset using the same network with near \$0/MWh marginal cost (or negative opportunity cost).

CRM in a high renewables NEM

The congestion relief market is being designed in the context of a rapidly transitioning electricity sector in which wind and solar generation are making up an increasingly large portion of the total installed capacity and dispatched generation in the NEM. These new wind and solar generators are largely connecting into areas away from the strong network and, in some areas, face a risk of congestion when wind and/or solar energy resources are strong. In contrast, thermal generators tend to be located along the strong network backbone and closer to load.

In this context, the generators impacted by congestion are and will continue to be largely wind and solar generators, and not the thermal generators sited in favourable network locations. As such, we would question the assumptions that, under the CRM, relatively high cost generators will be willing to reduce their output to avoid the cost of generation:

- "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…
- Prospective **sellers** would generally be lower-cost, lower emission generators located behind the same constraint willing to increase output…"

In practice, it is not clear who the high cost and high emissions generators located in a congested area of the network would be, now or in the future market. The more likely situation is that standalone storage would be the buyer – given this technology is neither high cost or high emissions, this more realistic scenario may require a reconsideration of the policy intent and outcomes.

Conclusions

Overall, the current design of the CRM does have the potential to introduce incentives for storage to connect into congested areas of the network and operate to alleviate congestion, with this service being monetised. This has the potential to deliver benefits for the market and consumers by reducing the curtailment of low emissions and low-cost renewable generation that would otherwise have resulted from the congestion. However, as explored further in the next section of this report, participation in the CRM is expected to be limited to only a subset of generators.

We are not convinced that there is evidence of generators engaging in 'disorderly' bidding resulting in inefficient outcomes for consumers. In our view, there are technical and operational reasons for inflexible generators to bid in this manner, and renewable generators bidding at the market floor price does not appear to result in inefficient outcomes.

4 Revisiting the analysis

In February 2023, the ESB published a cost benefit analysis for the proposed transmission access reform. The AEMC has since focused work on further design of the priority access model and congestion relief market, dropping the previous alternative approaches which were also part of the CBA. Baringa has undertaken a qualitative assessment of the assumptions and approach underpinning the cost benefit analysis which is referenced in the current consultation as justification for choosing the current proposed approach. We have not been asked to undertake fresh quantitative analysis.

While the inclusion of this style of analysis in the early assessment of policy options was useful, **we believe that the analysis would need to be updated with a number of assumptions revised before it could be used to make a decision on the net outcome of either the priority access model or the congestion relief market as currently designed**.

Further, given that some form of priority access is not likely to be needed in the market until the 2030s, **any quantitative analysis used to consider its impacts should be framed around the projected state of the market in the 2030s**, rather than the technology mix and network topology of today.

We have summarised our key views on the cost benefit analysis used to support the TAR work program to date under two key areas:

- Key assumptions requiring revision; and
- State of the market.

4.1 Key assumptions requiring revision

Existing locational signals

The AEMC's analysis of the impacts of the priority access model on investment decisions, based on the locational signal it would provide, assumes there are few existing locational signals already informing these investment decisions. As identified in the previous section of this report, there are currently a range of measures in the NEM providing strong locational signals and incentivising developers and investors to locate new projects in areas of the grid with sufficient network capacity to accommodate them. The cost benefit analysis should be based on the incremental benefit of the priority access model being implemented in the context of these other measures, thereby capturing the additional impact of this policy which would not have been realised in its absence. The modelling carried out over investment timeframes in NERA's 2020 report in our opinion did not adequately model these as a counterfactual, as we will discuss later in this section.

Race to floor incentive

As discussed in the previous section of this Report, we believe that some of the underlying assumptions made by the AEMC about generator behaviour do not align with evidence or the technical reality of plant operation in the NEM.

Coal-fired and run-of-river hydro generators do bid at the floor price in the NEM, however analysis of the costs and benefits of the TAR needs to reflect that:

- These generators typically bid at market floor price in line with their technical limits, which are often quite important to ensuring the projects are able to contribute to security and reliability when needed. As such, introducing a price incentive to dissuade this bidding behaviour through the congestion relief market is unlikely to result in a change to the bid strategy. These generators should not be assumed to change their bidding from the market floor price to their SRMC with the introduction of the policy.
- These generators are not typically located behind congested lines in the network. Generators located in areas of the grid impacted by congestion are largely variable renewable generators with an SRMC of $0/MWh (and storage assets in future), rather than higher SRMC thermal assets. This is expected to be the case into the future as wind and solar increasingly dominate the installed technology mix. Assumptions in modelling of priority access and the congestion relief market should be consistent with this state of the market rather than assuming higher cost projects are located behind congestion.

Wind and solar projects likewise do sometimes bid at the floor price in the NEM (particularly when local constraints bind) – though this is much more common for wind than of solar. In terms of how this is reflected in the cost benefit analysis, the assumption that all generators behind a congested line bid at the market floor price should be tested against market data and stakeholder feedback. Further, the benefit case for the congestion relief market should be cognisant of the participation rate assumptions below.

Congestion relief market participation rate

The 2023 NERA analysis used to estimate the benefits of the congestion relief market assumed a 100% participation amongst market generators post 2030. Although a sensitivity was undertaken with lower participation rates, which was reported on, this was not picked up fully in the final cost benefit values.

As identified elsewhere in this report, there are a range of reasons that we would expect participation to be less than 100%. Key factors include:

- Thermal generators and many hydro and pumped storage generators are located in strong areas of the network and are very rarely, if ever, curtailed on account of network congestion. Other than limited cases in which these generators may be located in less strong network locations (particularly hydro and pumped storage generators), we do not expect that these technologies would have an incentive to participate in the congestion relief market.
- Generators in solar-dominated areas of the network are unlikely to have a strong incentive to participate. This is because, in these regions, the network is expected to be congested and requiring congestion relief in the middle of the day during peak solar hours. Any locally located storage assets will already be incentivised to charge during this period of time due to price signals in the market, meaning the congestion relief market will not change behaviour or offer any additional opportunity to reduce congestion.
- Renewable generators located in congested areas of the network which do not have storage assets located behind the congestion will not have access to a counterparty for congestion

relief. In the context of a congestion relief market being operational, we agree this may incentivise some additional storage to connect behind the constraint to leverage the potential value of providing congestion relief, however this locational incentive is expected to be marginal compared to the fundamental business case drivers for storage from wholesale and FCAS provision.

- As a greater portion of generation connects into the market in REZs over the coming decade, and many of these REZs apply bespoke access arrangements which reduce the risk of congestion, the percentage of total installed generators incentivised to opt in to a system designed to manage congestion is expected to decline.
- Hybrid storage systems are less likely to participate given they are already intended to provide congestion relief to their co-located generation asset. As such, participation is likely to be limited to standalone storage only.

Baringa has not undertaken independent analysis to arrive at the more preferable participation rate for cost benefit analysis. However, we are confident that the answer is well south of 100%. As such, revised cost benefit analysis should reconsider this assumption and determine whether the policy has the potential to deliver a net benefit for the system in the context of a far more limited participation rate.

Simplifications of policy design

The benefit case presented in the CBA for the priority access model is derived from the results of NERA's 2020 modelling exercise. This modelling was undertaken based on a different policy design to that currently proposed in the TAR, using the price outcomes of locational marginal pricing as a proxy for the locational investment signals under the priority access model. The NERA 2020 report highlights this by saying "*our results are a representation of the theoretical improvement in efficiency that settlement at LMP offers".*

While LMP does provide a strong locational signal, the outcome of implementing a policy that would result in generators earning the locational marginal price at 1,060 nodes across the NEM seems removed from the currently proposed access reform. In particular, the current policy design proposes to provide locational signals through a stratification of floor prices, giving projects progressively higher floor prices in line with timing of their connection to the grid. Importantly, this policy would only impact dispatch when numerous generators are behind a congested line **and** engage in a race to floor bidding. By assuming all differences between LMP and the RRP are realised by all generators at each node is not representative of how the priority access policy is expected to impact generators in the NEM.

Simplification of market dynamics

The NERA 2020 model does not explicitly look at economic build out of capacity across investment timeframes, using the proxy difference between LMPs and RRPs as "subsidies" on the cost of assets. For example:

"PLEXOS minimises total system costs rather than simulating the market-orientated logic that underpins new investment decisions."[13]**.**

Importantly, the model also simplifies intraday dynamics by solving for this least-cost solution over 24 blocks per month. By considering the outcomes in the market at 30-hour granularity, the model will not have taken into account the substantial variation in demand, prices and generation availability across the course of a day. This brings into question the validity of the assumed generation investment decisions in the market, particularly decisions around what is built and when, given some of the real-world market dynamics are not reflected. Most importantly in the context of transmission access reform, this does not consider:

- The correlation of renewable assets across the day
- The effect of storage charging and discharging times on dispatch

Any further analysis to consider the costs and benefits of the priority access model in the NEM will ideally model the market with a granularity that allows for intra-day dynamics, in order to more fully reflect the anticipated generation and storage investment under the policy.

4.2 State of the market

The market is changing rapidly and cost benefit analysis, like any other analysis, will necessarily reflect the current state and best available projections of the market at the point in time at which the analysis occurs.

However, if the cost benefit analysis is to be revisited in light of a number of assumptions requiring revision (identified above), this would also provide an opportunity to reconsider the costs and benefits of the policy in the context of recent and anticipated market changes. In particular, an updated cost benefit analysis could reflect:

- Faster coal closure and renewables build; and
- Risk of delays to new transmission infrastructure.

These are considered, in brief, below.

Faster coal closure and renewables build

The AEMC's priority access benefit estimation relies directly on results of the NERA 2020 study, which aimed to calculate the costs and benefits of transmission access reform in the NEM. The long-term capacity build out in the NERA model relies on demand projections, capex and opex assumptions and government policy to reach climate targets as of December 2019 (consistent with ISP inputs 2019). While this was the best available information at the time, these underlying assumptions have changed dramatically over the past five years. The magnitude of this change is illustrated in the figure below, which demonstrates the capacity mix forecast for FY35 in the 2019 ISP relative to the recently published Draft 2024 ISP, along with an additional scenario considered in the NERA analysis.

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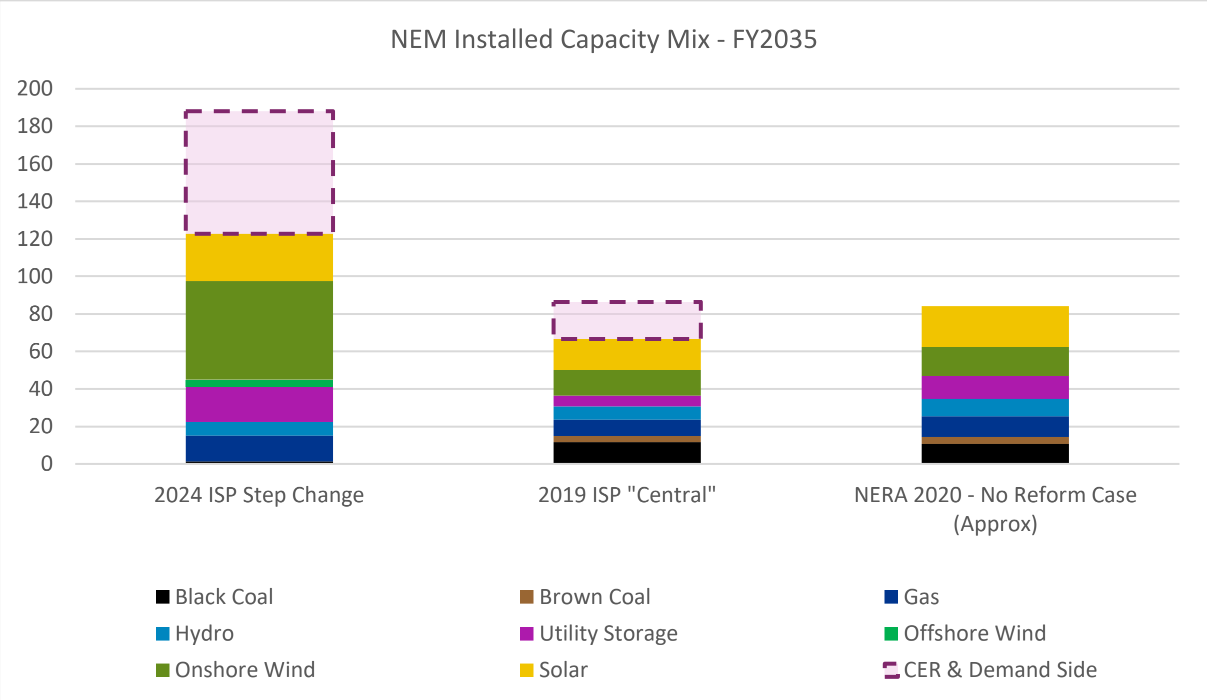
[13] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, page 22

Figure 2: Comparison of installed capacity between projections used in previous analysis and those in the current Draft ISP[14]

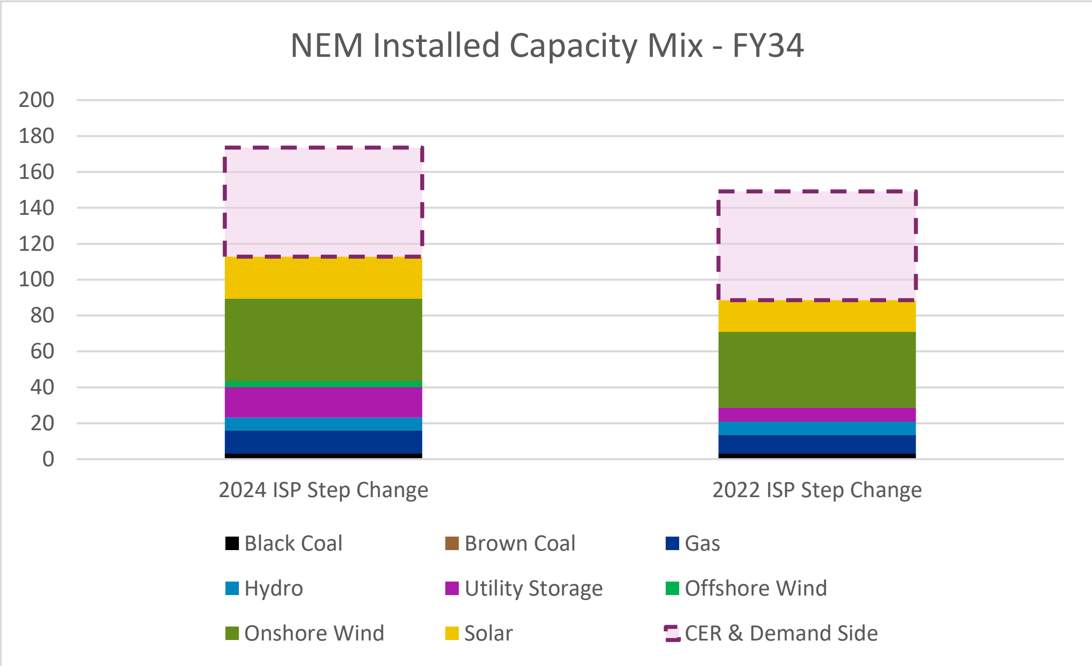


In particular, we note that the CBA was carried out before government commitments to the closure of coal plants. Nearer-term coal closures have had a huge impact on the expected capacity mix in the NEM. The magnitude of costs and benefits assessed based on the projected capacity mix from 2019 would be expected to look markedly different to those assessed based on current projected capacity mix.

The more recent 2023 NERA report, used to support the benefits of the CRM, used only two spot years to assess the impact, which were based on ISP 2022 figures. The second spot year which is used to represent the evolution of the market benefits is 2033/34. Even between ISP 2022 and ISP 2024 figures there is a large differential in this year, especially when considering utility storage build out which has grown 112% and is a central part of the benefits suggested with a new CRM. This delta is illustrated in the figure below.

[14] AEMO ISP Draft 2024; AEMO ISP Final 2022; NERA, Cost Benefit Analysis of Access Reform: Modelling Report, Figure 3.7

Figure 3: Comparison between installed capacity between spot year projections used in the 2023 CBA report and those in the current Draft ISP[15]:



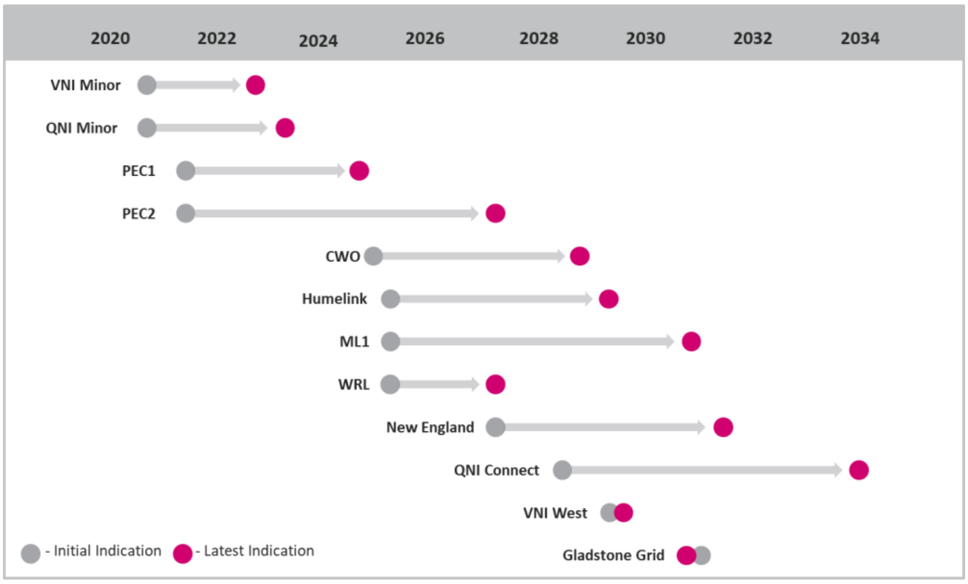
Risk of delays to new transmission infrastructure

The energy transition depends on a significant expansion of the transmission network to strengthen existing corridors, establish Renewable Energy Zones, and bolster interconnection. This work is fundamental to enabling new generation to connect into the NEM, particularly in regions not located near the existing network backbone.

For a range of reasons, key network projects set to be delivered in the 2020s have faced delays in recent years, likewise major generation projects (notably, Snowy 2.0). This is illustrated in Figure 4, which shows how the commercial operating dates (COD) of a number of major network projects have been delayed.

[15] AEMO ISP Draft 2024; AEMO ISP Final 2022

Figure 4: Illustration of the changes in anticipated COD for major transmission projects[16]



Getting these and future projects built is a priority and work is being done to mitigate the risk of further delays. However, it does suggest there is value in new clean generations projects which are able to progress without dependence on new network infrastructure, to ensure more new generation is available as the other network solutions are progressed.

In this light, any further analysis of the costs and benefits of the TAR should take into account the potential benefit of a policy landscape that enables investment in projects not dependent on new transmission network infrastructure where the network capacity is available outside of REZs, rather than deterring these connections.

[16] AEMO ISP Draft 2024; AEMO ISP Final 2022; AEMO ISP Final 2020; AEMO ISP Final 2018; AEMO 2016 NTNDP

5 Conclusions

To meet state and Commonwealth government commitments, and to enable the near-term transition away from coal-fired generation, it is critical that the NEM market conditions incentivise investment in new clean capacity and that the network infrastructure is there to support it.

Coordination of generation and network infrastructure is an important element in delivering both the incentives for investment, including through certainty and risk mitigation, and the network capacity for connections. However, it's also a challenging and complex policy area to work through.

Priority access

As presented in this report, our view is that the suite of other policies currently in place suggests the need for priority access is less strong in the 2020s. As the need for access arrangements comes back into play in the late 2020s and into the 2030s, any solution should be considered in the context of the system as it looks at that point in time, and in alignment with any other post-2030 market design reforms pursued. Further, in the interests of supporting new investment in generation across the grid as the sector continues to decarbonise, it will be important that the policy design does not seek to penalise connection to non-REZ network where the network has capacity to accommodate it.

In terms of the analysing the costs and benefits of priority access, an update to previous analysis would be worthwhile to provide a view on the market impacts under current market projections, and using a modelling methodology which more closely represents investment decision drivers than those used in the past. Any approach to analysis should be cognisant of the locational signals already provided in the market through existing mechanisms when trying to capture the incremental impacts of the proposed policy design.

Congestion relief market

In terms of the CRM, our view is that the policy does have the potential to incentivise storage connecting into congested parts of the network by monetising the value they can provide through alleviating congestion. This can deliver benefits for the market by reducing curtailment of clean, low cost, renewable energy and making more efficient use of the installed generation capacity. However, the cohort of generators we would expect to participate in this market is limited, largely consisting of wind generators and standalone storage located behind congested lines.

In terms of disorderly bidding, the CRM is not expected to impact the bidding strategies of coal, hydro and other inflexible technologies. It could reduce the volume of bids at market floor price for renewable energy generators, but this impact would again be limited to only those expected to participate in the market, and only where constraints bind.

Analysis of the costs and benefits of the CRM should reflect this limited pool of participants and the scale of benefits that this contingent of participants, alone, would provide.