Level 12
171 Collins Street
Melbourne VIC 3000

Postal address
GPO Box 2008
Melbourne VIC 3001

T 1300 858 724
F 03 9609 8010
E info@aemo.com.au

5 June 2024

Ms Anna Collyer
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

Ref: EPR0098

Dear Ms Collyer,

Submission on Transmission Access Reform

AEMO appreciates the opportunity to respond to the AEMC's consultation paper on Transmission Access Reform (TAR). Through its position on the Energy Security Board (ESB) AEMO has been actively involved in the development of TAR dating back to the ESB's Post 2025 Market Design advice to Ministers in 2021. During this time the model being explored has evolved from the Congestion Management Model (CMM) to the current hybrid model and AEMO has contributed by providing detailed advice on the impacts of different options on dispatch and settlements, assessing the implementation costs of TAR and developing a NEMDE prototype that has allowed the proposed reform to be rigorously tested.

AEMO's Integrated System Plan (ISP) highlights the scale of the energy transition and that it requires an unprecedented level of investment to deliver the generation and transmission required to meet emissions goals and deliver secure, reliable and affordable energy. AEMO continues to support the TAR objective of promoting investment in areas of the grid where renewable output can be maximised and inefficient congestion reduced. However, it is vital that the proposed market reforms are effective and do not make it harder to invest at a time when, as the ISP calls out, there is an urgent need for investment in generation, firming and transmission.

AEMO's extensive testing of priority access is described in the consultation paper (Appendix B). Based on this analysis, AEMO considers that TAR is unlikely to achieve the reform objectives. This is not a criticism of the policy intent or extensive work that has been put into developing this reform over several years. Instead, it is a function of the complexity of NEM dispatch which means that there is a risk that introducing priority access could, if anything, make dispatch outcomes harder to predict rather than easier.

Following the above-mentioned analysis, the AEMC is considering a co-optimisation model as a way of addressing the impact of priority access on increasing the RRP. AEMO has reviewed the co-optimisation model in detail and built an Excel model to assess its impacts. The outcome of this work is summarised in the consultation paper (at section 5.4).

A key concern is that the co-optimisation model introduces a new RRP that would be related to CRM bids i.e. it's a form of "CRM RRP". Given that retail load would pay the CRM RRP, wholesale contracts are likely to need to change to reference this new price and so generators who wished to hedge their output by selling contracts would need to participate in the CRM. Hence, the co-optimisation model would undermine the objective that the TAR model should be opt-out and would certainly have consequences for existing wholesale contracts e.g. it would constitute an “LMP Event” under NSW’s Generation LTESAs and potentially the Commonwealth’s generation Capacity Investment Scheme Agreements (CISAs) creating uncertainty for investors in these tenders.

The co-optimisation model would also make bidding significantly more complicated than it is today and would require new and yet to be developed rules to manage undesirable bid combinations. The model is also likely to be significantly more expensive to implement than the two-step hybrid model given it will require more extensive changes to NEMDE and its bidding interface to handle CRM delta bids and bid validation rules.

Finally, the lack of an energy constraint in access dispatch means there is a real risk of a settlements shortfall that would impose a funding burden on TNSPs or require AEMO to scale back generator payments. For these reasons and because the model is unproven and untested AEMO does not support the co-optimisation model.

The AEMC has also put forward a dynamic grouping variant on priority access which would introduce a new and unproven algorithm running in predispatch to allocate a quantity of MW for each generator unit to each of two priority positions. Apart from the system impacts and implications on bidding timeframes AEMO questions how this will create greater investment certainty given that a generator will not know which queue position it is in from one dispatch interval to another.

Given the above AEMO maintains its position that priority access is unlikely to achieve the reform objectives and if anything will make investment harder than it is today. This view is consistent with the overwhelming majority of submissions on priority access to the ESB’s consultation paper in mid 2023.

If priority access is ruled out it is still possible to implement the CRM on a standalone basis. AEMO agrees that the CRM has some benefits in allowing trading of congestion relief and facilitating a more efficient dispatch outcome. However, AEMO believes these benefits are marginal at best and highly dependent on the level of uptake of the CRM. The ESB’s CBA assumed 86% uptake from day one rising to 100% after two years which seems very optimistic and highly unlikely to be achieved. The net present cost of implementing the reform, estimated at $76m, however is significant and unaffected by the level of participation and the project would take three and half years to implement. AEMO questions the merits of implementing such a major reform with marginal benefits compared to other higher priority reforms such as CER integration, timely delivery of transmission, and frameworks for wholesale and essential system services.

Since COGATI was first proposed by the AEMC in 2019 the policy and reform landscape has shifted dramatically and governments are now heavily involved in supporting investment in generation and transmission to deliver the energy transition. These initiatives include the NSW Roadmap which aims to coordinate the development of transmission infrastructure in REZs with the underwriting of new renewable generation and storage. The Commonwealth is playing a lead role through Rewiring the Nation and the CIS which has been expanded to include renewables and bilateral RETAs. States are also directly investing in pumped hydro and REZ infrastructure and promoting their own schemes for battery storage and offshore wind.

In light of these activities, it is clear that market mechanisms are no longer the sole driver of a generator’s investment and location decisions. NERA’s modelling of the investment benefits of TAR were driven by the market reform leading to better locational decisions and avoiding 20 GW of solar built outside REZs. If governments are facilitating the augmentation of the transmission system and helping attract investment through their REZ schemes than the investment benefits assumed by NERA are already being realised and are independent of the market reform going ahead. In fact, if REZ location is a requirement to achieve the investment benefits then this could be more simply achieved through planning rules (or at the very least the right for a REZ coordinator to appeal an undesirable connection that might undermine a REZ). For instance, in Queensland this is already the case with a regulatory instrument in the Energy (Renewable Transformation and Jobs) Bill that defines REZ controlled assets that (a) materially affect, or will materially affect, the capacity or functioning of the REZ transmission network for the REZ; and (b) are outside the REZ or inside the REZ but not part of the REZ transmission network. AEMO understands that there has not been any impact assessment done to-date, but Powerlink would determine how it treats these assets in its REZ Management Plans.

In summary, based on analysis undertaken to date, and noting the AEMC is still undertaking modelling analysis, AEMO questions whether priority access will deliver the reform benefits and wants to ensure that it does not unintentionally undermine investment at a time when the NEM needs to attract as much investment as possible. The CRM has marginal benefits which are highly dependent on participation rates. AEMO is mindful of this given the cost to implement this reform is in the order of $33m upfront investment and an ongoing cost of $3.6m/year both +/- 50%.

Should you wish to discuss any aspects of this submission please feel to reach out to myself or to Paul Austin.

Yours sincerely,

Violette Mouchaileh
Executive General Manager – Reform Delivery

Attachment 1: Detailed submission

Attachment 1 – Detailed submission

Note: In the ESB's two-step model the first run was named the EN run and the second was the CRM run, The AEMC has changed these terms to "access" and "physical" which adds confusion particularly given the first run is a physically secure dispatch. In the co-optimisation model the physical run is the combination of the scheduled EN and CRM delta quantities. Hence, AEMO will continue to refer to EN and CRM runs for this submission.

Q1 CBA

AEMO has reviewed the ESB's CBA in some detail and recognises that the benefits case was compiled from a number of different sources undertaken at different times. The investment case relies on NERA's 2020 COGATI modelling in which the benefits are principally derived from the reform driving improved locational decisions that avoid the building of 20 GW of solar in poor locations. The operational and emissions benefits are sourced from a combination of the 2023 NERA CMM/CRM study for the low case and an extract from a 2020 paper that related to ERCOT for the high case operational benefits. The implementation cost estimates were provided by AEMO.

Whilst AEMO agrees with the decision not to update the CBA, AEMO believes that it is important to *qualitatively* provide context to the benefits case – particularly in light of recent developments.

AEMO questions the investment benefits in light of the significant change in the role of governments since the COGATI CBA was compiled. In particular, governments are now actively involved in underwriting generation investments through the NSW Roadmap, CIS and their own direct investments. They are also actively engaged in developing REZ frameworks that will augment transmission and encourage investment in superior grid locations.

Since the investment benefits that NERA identified depend on the reforms facilitating better locational decisions it is arguable that these are already being realised through government actions and so the reform benefits are significantly reduced. It is also worth noting that if REZ location is the principal driver of the investment benefits this can be achieved more simply through a planning framework. Such a framework does not have to be overly burdensome and can be applied on an exception basis – for instance through allowing a REZ coordinator to appeal an undesirable connection that would undermine a REZ or adopting the approach used in Queensland.

The 2023 NERA study that was used for the operational benefits was based on very high levels of CRM participation with 86% from day one and 100% within two years. AEMO believes that these are extremely optimistic and so a lower level of operational benefits is more likely. The high ERCOT case seems to be irrelevant to the NEM and it is not clear why it was included.

The emissions benefits are premised on the CRM incentivising SRMC bidding which leads thermal generation to trade congestion relief with renewable generation. However, AEMO notes that most binding constraints only include renewable generation, batteries and hydro. AEMO ran several NEMDE prototype cases which tried to replicate NERA's findings on emissions but these could not be reproduced. In fact, the SRMC bidding assumption places brown coal below black coal in the CRM merit order and AEMO was able to produce test cases where black coal was reduced and brown coal increased with mixed impacts on emissions.

Q2 Feedback on prototyping

AEMO's NEMDE prototype was originally developed to test the technical feasibility of the two-step CRM model and to understand its policy implications. AEMO conducted extensive testing of the CRM using the prototype and the ESB created a visualisation tool to share the results from a number of these test cases.

In undertaking this work the EN run was the original NEM dispatch run for a selected trading interval and the CRM run was based on different levels of CRM participation and different bidding strategies. For simplicity these assumptions were generally implemented at the level of a technology-type with all solar, for instance, assumed to be participating in the CRM and bidding at the negative LGC price. Clearly, there is the scope for more granular bidding assumptions for the CRM and involving industry in formulating test cases and reviewing the results.

In particular, a key driver of CRM benefits is that participants will bid at their SRMC. However, it is not clear how this assumption applies to energy constrained plant like batteries who are generally limited to around one cycle per day on average. If a battery can only charge once per day then a participant might bid the SRMC during the middle of the day but then have to bid themselves out of the market to preserve their state of charge for the evening peak. The interaction with FCAS bidding has also not been tested (the testing just used the original FCAS bids in the CRM) and this is an area that warrants further investigation given its impact on batteries.

The consultation paper describes the extensive testing of priority access that AEMO carried out using the NEMDE prototype and AEMO believes the results are sufficient to inform the policy decisions. The testing approach focused on the areas of the NEM where congestion is most prevalent and where the priority access reform needs to be able to make a difference. There are simpler areas of the NEM where only one constraint is typically binding but the impact of priority access in these areas can be assessed analytically. Even for the complex areas that AEMO reviewed there were around 20% of the cases where only a single constraint was binding. Hence, AEMO does not believe that further testing of priority access using the NEMDE prototype is warranted.

Q3 ACIL Allen modelling

Unfortunately, the ACIL Allen work has not yet been published and AEMO awaits their report. AEMO's prototyping work showed that the magnitude of the change in dispatch with priority access is hard to predict. This is because a generator's dispatch outcome is dependent on which constraints are binding, its constraint coefficient relative to other generators in each binding constraint and the bid price floors for different priority groups. The prototyping work showed that dispatch outcomes were subject to a series of step changes whereby increasing the bid price floor to a certain point would cause the dispatch outcome to suddenly tip in favour of one generator over another. These types of non-linear outcomes are very difficult to model and so investors will find it hard to quantify the impact of priority access in their investment cases.

Q4 Priority access allocation models

Whilst the consultation paper discusses the concepts of hard and soft priority the only practical implementation of this reform is a version of soft priority that uses separated bid price floors (BPFs). The ESB ruled out a theoretical sequential solve algorithm and AEMO supports that decision for the reasons outlined in the paper (section 4.2).

The degree of hardness or softness of dispatch depends on the separation of BPFs. AEMO did run experiments using the NEMDE prototype with very widely separated BPFs but these sometimes led to significant increases in the RRP and increased counter-price flows. Therefore, the testing plan for priority access was restricted to BPFs mostly between -$1000/MWh and -$250/MWh.

Whilst it is technically possible to implement a very large number of queue positions using BPFs (e.g. separated by $1/MWh) AEMO agrees with the AEMC that these would not be meaningful i.e. generators would not be able to meaningfully distinguish the benefit of one queue position over another. Hence, a smaller number of queue positions is warranted and the AEMC proposes 10 positions in both Option 1 and Option 2 and just 2 positions in Options 3 and 4.

AEMO's prototyping work was only able to test 4 queue positions but even with this small number it became very clear that the benefit of being in the middle queue positions was hard to identify. Depending on its constraint coefficient a generator in the first queue position should see an improvement in dispatch from priority access and a generator in the last position should see a reduction in dispatch but it is not obvious whether a middle position generator should see an improvement, a reduction or stay the same.

Hence, AEMO's preferred option for implementing priority access is to restrict the number of queue positions to a small number with BPFs that are separated by at least a few hundred $/MWh to provide a meaningful difference between positions. However, these should not be so far apart as to impact the RRP.

The other key design decision is whether there should be REZ-on-REZ competition. The AEMC's preferred model Option 1 would have REZs allocated different queue positions depending on when they meet the relevant criteria. Once the REZ is allocated a queue position subsequent connections within the REZ would be able to benefit from that locked-in queue position. This design will have some unintended and undesirable consequences, namely:

- REZs within a state will compete with each other.
- REZs in neighbouring states will compete with each other.
- Late connections can jump the queue by connecting in an early REZ with a locked-in queue position. This will undermine later REZ schemes given that generators will be able to effectively jump the queue by connecting into the early REZ.

Clearly, the incentive will be for REZs to aim to get the best queue positions and it is likely that the only acceptable situation will be if all REZs have the top queue position (along with incumbents) no matter when they connect.

If REZs and incumbents have the top queue position the choice is between Option 2 with 9 additional positions and Option 3 with 1 additional position. Given that AEMO has shown that the middle queue positions are hard to value AEMO's preference is for Option 3 which has just 2 queue positions with widely spaced BPFs and can be thought of as a "deprioritisation" model. AEMO believes this will be very effective (perhaps too effective) at incentivising investment in REZs given that projects in the bottom queue position will likely struggle to even get financing. If the objective is to encourage investment in REZs AEMO believes there are more effective mechanisms such as a planning approach to achieve this which would not overly disincentivise good projects outside of REZs.

AEMO has strong concerns with Option 4 the most important being that the methodology is premised on an unproven algorithm which aims to implement sequential solve (which the ESB rejected) in the predispatch timeframe. Whilst this creates more time for the algorithm to solve it does not address AEMO's concern that the NEM is too complicated for a sequential solve process and that the algorithm would require manual intervention when it inevitably "paints itself into a corner" and cannot find a feasible solution.

The algorithm will also have impacts for existing predispatch and dispatch processes and will require running predispatch every 5 minutes (instead of 30 minutes at present due to technical limitations) and to bring forward the dispatch bid cutoff time so that the dispatch bids can be manipulated. This is required because the result of the predispatch grouping is to allocate a certain amount of MW for each DUID to the top and bottom queue positions. These quantities will then have to be applied against the actual dispatch bid. For example, a 100 MW generator that is allocated 25 MW of top priority and 75 MW of bottom priority will need its actual dispatch bid changed to reflect this allocation. It will not necessarily be simple to overwrite dispatch bids particularly when they may be coupled with FCAS bids.

The other major problem with Option 4 is that it is not clear how it provides any investment certainty given a generator will have different MW in the top and bottom queue positions in each dispatch interval and it will have no understanding of why it ended up in one or the other position. Even REZ generators will have no assurance as to which queue position they will be assigned to and this will undermine the benefits of being in a REZ.

Q5 CRM implementation approaches

The CEC's original design for the CRM was to preserve the existing NEM dispatch and to allow optional, incremental congestion trading. This has been tested and costed through the implementation of the two-step model in the NEMDE prototype and AEMO is reasonably confident that it can work. The main uncertainty relates to the length of time to complete the end-to-end dispatch process from bid compilation through to NEMDE dispatch, through to issuing dispatch instructions which AEMO has not been able to test.

In the two-step model the RRP used for settlement can be determined as either the EN RRP or CRM RRP. The ESB chose to select the EN RRP maintaining alignment with existing NEM dispatch to minimise impacts on wholesale markets and AEMO supports that position.

The AEMC has proposed an alternative CRM implementation using a single pass co-optimisation approach. This is not the same as the NEM's current approach of co-optimising of energy and FCAS where each of the individual services are discrete. The co-optimisation proposed by the AEMC would co-optimise two energy services which are ultimately the same service - namely energy provision. This creates complex interactions between the EN bids and the CRM bids. For example, the effect of scheduling +2 MW of -$1000/MWh EN bids and -1 MW of $80/MWh CRM bids is to decrease NEMDE's objective function by -$2080/MWh for just +1 MW of dispatch. This bid combination will beat a +1 MW bid at -$1000/MWh from a generator that is not participating in the CRM thus undermining opt-out.

The AEMC has acknowledged that there will be a need for new bidding rules to manage unacceptable bid combinations but these have not been developed and are limited at present to preventing equal volume bids breaching the -$1000/MWh MFP (i.e. a -1 MW $80/MWh CRM bid would limit the EN +1 MW bid to -$920/MWh). However, this approach does not address all the possible bid combinations that can arise.

The interaction with priority access also needs to be considered. If combinations of EN and CRM bids can effectively replicate a wide range of BPFs then this would undermine the implementation of priority access which aims to award priority based on BPFs.

Another important issue is the impact on settlements which is caused by the lack of a regional energy balance constraint in the EN portion of the formulation. This means that the EN dispatch of generation can be greater than or less than total demand in the NEM. This has the potential to magnify inter-regional flows and it creates a more complicated settlements residue which is a combination on inter- and intra-regional residues. However, the most significant problem is when there is more generation scheduled than load in the EN run.

When this occurs there are fewer payers of RRP than receivers of RRP and so there is the potential for ongoing settlements shortfalls which may be beyond the ability of a TNSP to fund. If the TNSP were unable to fund the shortfall then AEMO would need to scale down the payments to generators which would have significant consequences for the NEM.

The main reason for considering the co-optimisation model is that it is purported to solve the problem of priority access impacting the RRP. However, it has not been proven that this is the case particularly as the change of RRP would also change wholesale contracts and therefore would change bidding strategies (i.e. as occurs in the NEM today participants would not bid SRMC in the CRM if they are defending a contract position or trying to influence contract prices).

Given that the co-optimisation model is a new and unproven model with some serious flaws AEMO believes that it should not be pursued.

Q6 Feedback on PPAs

AEMO believes participants are best placed to comment on their PPAs.

AEMO does note however that the NSW Generator LTESAs include a specific “LMP Event” clause that would be triggered by the introduction of TAR and the CISA contracts may have the same clause. The “LMP Event Amendment Principles” require that the LTES Operator be put in the same commercial and risk position as if the LMP Event had not occurred but it is not clear how this will be resolved. Given that priority access may reduce dispatch quantities (compared to incumbents) and the CRM can impact the total revenue the invocation of this clause is likely to lead to a greater cost of subsidising new generation.

Q7 Impacts on financial markets

AEMO’s analysis of the co-optimisation model shows that the RRP can be set by the CRM bids and so this will have a similar impact on financial markets as choosing the CRM RRP from the two-step model. Given the CRM aims to incentivise SRMC bidding this could produce very different RRPs to today. Therefore, this will likely lead to contract re-openers for wholesale contracts and PPAs that are still in operation.

Going forward, the choice of CRM RRP would mean that all retail load would be settled on this basis and so the wholesale contract would need to evolve to manage a retailer’s exposure to the CRM RRP. However, there will be fewer sellers of wholesale contracts than at present because a generator will have less certainty as to whether it will receive the CRM RRP. Generators in constrained areas, in particular, will be exposed to the CRMP and so they will be less willing to sell CRM RRP referenced contracts. This risks a reduction in contract market liquidity with a consequent increase in wholesale prices that would ultimately be passed onto consumers.

Q8 Wide-reaching constraints

NEM dispatch is determined by the combination of bid prices and a generator’s coefficient in a binding constraint. Priority access aims to change the inherent dispatch order by tipping the balance in favour of generators with high priority and reducing the dispatch likelihood for low priority generators. Therefore, any new constraint that binds is likely to lead to different dispatch outcomes compared to the status quo. However, as the prototyping work shows the impact of priority access is hard to predict and a lot will depend on the other constraints that are in operation and the relative coefficients between constraints.

The two-step implementation of the hybrid model is designed to ensure that the EN run is physically feasible and so must contain the full set of constraints to ensure a secure dispatch outcome. The reason for this is that the CRM is optional and so the CRM run may at times have no participation. Hence, it is not possible to omit constraints from the EN run. Whilst it is possible to omit constraints from the access part of the co-optimisation model AEMO does not believe that model should be pursued for the reasons stated previously.

It has been suggested that dynamic grouping may solve the problems arising from the combination of priority access and wide-reaching constraints leading to all or nothing dispatch outcomes. Whilst the dynamic grouping algorithm could exclude wide-reaching constraints the end result is that each generator has MW allocated to one of two queue positions and the actual dispatch run will include the wide-reaching constraint and potentially result in the same all or nothing outcome.

Q9 Detailed priority access design decisions

AEMO notes that the introduction of a queueing regime, dispatch priority positions and associated BPFs will create an administrative overhead and require new systems and processes. AEMO's view is that the priority access design decisions should be made with a view to minimising complexity and reducing the cost of implementing new systems. From AEMO's perspective the main system impacts of priority access are:

- Administering the assignment of a queue position and bid price floor to a generator.
- Ensuring that a generator's bids do not breach its BPF.

AEMO's bidding and dispatch systems operate at dispatchable unit (DUID) level so priority access should preferably be applied at the same level. To understand why this is important consider how AEMO currently ensures that generator bids do not breach the market floor price (MFP). Participants lodge bids on a sent-out basis (at the TNI) so a participant with an MLF of 0.95 wishing to bid at -$1000/MWh would lodge a bid at -$950/MWh and AEMO's systems would adjust it in NEMDE to the equivalent bid at the node of -$1000/MWh. If the MLF adjusted bid is below -$1000/MWh AEMO floors the bid at the MFP and notifies the participant so they can correct at their end. Hence, the main monitoring task for AEMO currently is once a year when the MLFs change.

The introduction of priority access would progressively create up to 10 queue positions which would roll forward after 10 years. If a DUID is only associated with one queue position then AEMO just needs to look up the current BPF for the DUID and then compare it to the MLF adjusted bid.

If, as the consultation paper proposes, the BPF is associated with a quantity of generation at a DUID the bid verification process becomes more complicated as AEMO now has to check both bid price and bid quantity. Consider a single DUID that has 70 MW that can bid at the MFP and 30 MW that can bid at -$800/MWh. If after adjusting for MLFs the generator bids 50 MW at -$1010/MWh, 30 MW at -$930/MWh and 20 MW at -$801/MWh it is not clear how AEMO should verify these bids. This process becomes even more complicated if dynamic grouping is introduced given AEMO will need to overwrite bids in every dispatch interval.

Q10 Detailed CRM design choices

AEMO supports the detailed CRM design choices in 7.2 of the consultation paper.

However, AEMO does not support the untethered design in 7.2.1 for the reasons outlined by AEMO in the consultation paper. In particular, the design of the two-step CRM model has to ensure that the first run produces a physically feasible solution. This requires that it is anchored to the SCADA values that are inputs into NEMDE. As AEMO's work on intervention pricing has shown there is a risk that a what-if run can deviate materially from reality over time and this can create problems with dispatch and pricing outcomes and auditability. The proposed untethered design would deviate in perpetuity and would have no means of ensuring that storage, for instance, does not charge or discharge indefinitely.