6th June 2024

Ms Anna Collyer
Chair
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2001

Dear Ms Collyer,

Transmission Access Reform Consultation Paper (May 2024)

Hydro Tasmania welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) *Transmission Access Reform Consultation Paper* (EPR0098).

Access reforms have been discussed for many years and through various iterations. Recognising the materiality of congestion risk facing our power system under future scenarios, Hydro Tasmania has been an active participant in access reform discussions. Our participation has included numerous submissions to consultation processes, direct engagement with leading market bodies, and participation in Technical Working Groups (TWGs).

In the previous phase of consultation (conducted by the Energy Security Board (ESB)), we encouraged the ESB's ongoing development of the hybrid model but did not consider the model sufficiently progressed to proceed to rules drafting. Since this period, significant work has been undertaken (particularly via the TWG) to further refine the Hybrid Model and resolve outstanding design issues.

While some design choices remain outstanding, we remain cautiously supportive of the reforms as currently proposed. Hydro Tasmania encourages the AEMC to continue refining the design of options presented via a rule drafting phase. However, a commitment to proceed with implementation should only occur if a workable final design can be established.

It has consistently been Hydro Tasmania's view that the Priority Access and Congestion Relief Market (CRM) must:

1. Limit disruption to market participants and operate cohesively with existing market structures.
2. Strengthen incentives for new generation, storage and loads to connect in a location that enhances efficiency.
3. Provide enduring constraint risk management tools for generators.

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4. Improve the inter-regional trade of energy via interconnectors.
5. Avoid unnecessarily impeding contract market liquidity.
6. Recognise the dynamic nature of transmission capacity.

We are increasingly comfortable that these design principles can be met, however the treatment of interconnectors under the Hybrid Model remains a critical element that is yet to be fully considered. Hydro Tasmania's specific comments on the final design of the Hybrid Model are discussed in **Attachment A**. These comments relate to:

i. Treatment of legacy generators.
ii. Preferred method for allocating access.
iii. Workability of Hybrid Model with Renewable Energy Zones (REZs).
iv. Setting the Regional Reference Price under the Hybrid Model.
v. Financial market impacts (inc. contract market liquidity).
vi. The inclusion or exclusion of constraints.
vii. Cost-benefit analysis.

Hydro Tasmania looks forward to proactive and constructive engagement with the AEMC on these proposed reforms. If you wish to discuss any aspect of this submission, please contact Jonathan Myrtle (Jonathan.Myrtle@hydro.com.au).

Yours sincerely,

JN Cooper

John Cooper
Manager Market Regulation

Hydro Tasmania

Attachment A – Hydro Tasmania's comments on the Hybrid Model

i. Treatment of legacy generators

Question 9: Feedback on detailed priority access design choices

The treatment of legacy generators has been a critical and contentious design element throughout the access reform discussion. Any arrangement for allocating access to legacy generators needs to find an appropriate balance between providing stronger locational signals for new investments (to help avoid uneconomic levels of congestion), while continuing to facilitate investment in new generation necessary to meet our renewable and decarbonisation objectives.

Hydro Tasmania supports the AEMC's preference to assign legacy generators the highest possible priority for the economic life of the asset, while simultaneously allowing newer generators to 'roll up' into higher priority levels as years progress. We believe the dynamic between these two design features represents an improved and reasonable balance in allocating congestion risk between new and existing assets.

An important consideration regarding the treatment of legacy generators is how the refurbishment, redevelopment or upgrade of existing renewable assets might be treated under the scheme. It is Hydro Tasmania's view that, where a plant can be extended beyond its economic life or redeveloped on a like-for-like basis, and its continued operation remains consistent with the National Electricity Objectives (NEO), including the newly included emissions objective, this generator should retain its priority level.

The refurbishment, redevelopment or upgrade of existing assets can present substantial efficiency savings by leveraging the assets and infrastructure of prior investments, while minimising disruption to the evolving power system.

ii. Preferred method for allocating access.

Question 4: Assessment of priority access allocation models.

The AEMC have presented four high-level options for the allocation of priority access under the proposed Hybrid Model.

1. **Grouping by time-window:** Generators would be grouped by year for the duration of prioritisation, before rolling them up into a higher priority group as the number of available priority levels was met. Each priority level would have a corresponding bid price floor (BPF).
2. **Grouping by time-window REZ model**: Same as option 1, however jurisdictions would also be provided with the ability to grant REZs the highest level of priority, irrespective of the timing of REZ planning, declaration, specification, and operation.
3. **Two tiers approach**: Under this model, legacy generators, committed generators (at the time the reform is implemented) and generation participating in REZs, would all be grouped into a priority tier. Other new entrant generators who have chosen not to participate in a jurisdictional REZ, would be given a lower level of priority in dispatch.
4. **Dynamic grouping algorithm**: An algorithm would be run close to, but before real-time, and would run sequential dispatches to progressively prioritise or deprioritise generators, based on when they connect and whether their dispatch would need to be constrained to avoid constraint violations. Effectively, the algorithm assumes higher priority generators get 'dispatched' ahead of lower priority generators and allocates prioritisation accordingly.

Hydro Tasmania has assessed the relative merits and pitfalls of the four options as follows:

Option	Merits	Pitfalls
Option 1: Grouping by time-window	- Predictable which can enhance certainty for generators. - For newly connecting generators locating in uncongested areas of the network, provides better protection from future congestion than other options. - Time windows can be tailored to achieve appropriate level of hardness/softness in priority.	- Too many levels will reduce the "strength" of BPFs in the locational decision making of new entrants. - May create a somewhat disorderly race between jurisdictions to establish REZs first to receive higher priority.
Option 2: Grouping by time-window REZ model	- As per option 1. - Supports REZ development	- May allow for REZ generators to cannibalise access of pre-existing generation. - Weaker incentives for REZs to be sized appropriately and for optimal REZ build out.
Option 3: Two tiers approach	- Will strengthen protection for legacy generators from cannibalisation.	- Will result in a more pronounced 'winners and losers' outcome. - New connecting generators outside of REZs do not receive priority access over generators that come in after them. - May require central body to determine appropriate access level.
Option 4: Dynamic grouping algorithm	- May more accurately reflect the dynamic nature of grid capacity and distinct characteristics of individual constraints. - May provide better options to strengthen the protection of investments in interconnectors.	- Computationally complex. - Likely more costly to implement. - Will result in greater uncertainty for generators.

Hydro Tasmania's current view is to support some form of amalgamation between options 1 and 2. We recognise the importance of incentivising the connection of new generating assets in REZs. Notwithstanding, we consider there may be merit in providing REZ generators a high (but not highest) priority level. If REZ infrastructure is designed appropriately, this is likely to be inconsequential to REZ generators, while continuing to provide a high degree of confidence for legacy generators.

Hydro Tasmania considers it may be more appropriate to have fewer priority levels with larger gaps between bid price floors, and a 2-3 year 'roll up' of priority levels. This provides a somewhat 'harder' level of access and provide a stronger incentive for new generators outside of REZs to connect in more efficient areas of the network and avoid creating inefficient levels of congestion.

The AEMC rightly note that without reforms to the NEM's access regime *'the value of investment in interconnectors may not be fully realised.'* Our current understanding of options 1 and 2 (operationalised via different BPFs) is that they would provide better access to legacy and earlier connecting generators on an *intra-regional basis*. However, further work is required to determine whether this model provides better access to legacy generators on an *inter-regional* basis.

Some constraint equations implicate generators from multiple regions as well as interconnector(s). Under these scenarios, our understanding is that generators will be capable of bidding at their market floor price, while an interconnector's "bid" will effectively be locked at the regional reference price of the exporting region. In this sense, NEMDE will typically constrain interconnectors first. This aspect of NEMDE may limit the effectiveness of priority access in addressing constraints across jurisdictional boundaries.

On this basis, Hydro Tasmania also agrees with the AEMC's position that there may be some merit in further examining option 4. We believe this option could present a more workable solution to address the issue of wide-reaching constraints (addressed below). In addition, we believe this approach may provide better protection for the free flow of energy across interconnectors. We consider this an important policy design question for ongoing consideration. We encourage the AEMC to allow further time for option 4 to be assessed, with particular focus on how this option may be capable of maximising the utility of interconnectors under future energy scenarios.

iii. Workability of Hybrid model with Renewable Energy Zones (REZ).

Federal and state governments are making substantial investments in the NEM's transmission infrastructure. This includes supporting the development of interconnection between regions and expanded (or strengthened) intra-regional transmission networks to give rise to Renewable Energy Zones (REZ).

Hydro Tasmania encourages the treatment of REZs (and the allocation of access within REZ) to be consistent across jurisdictions. If applied inconsistently, we consider there will be a risk of inefficient competition between regions, where regions vie for renewables investment through more favourable access arrangements. We consider this may undermine the indicated benefits of the Hybrid Model.

We note that under some design options in the paper, new REZs would receive similar (or the same) access as existing generators. While we appreciate the importance of incentivising connection in new REZ, it will be critical that any targeted grid investments to facilitate new REZ developments are sized appropriately to avoid (as far as possible) the creation of inefficient congestion on the network more broadly. This will be particularly important for new REZ being developed in close proximity to current or future interconnector assets.

iv. Setting the Regional Reference Price (RRP) under the Hybrid Model.

Questions 5: Assessment of CRM implementation approaches

In the consultation paper, the AEMC presents 3 options for RRP formulation and notes drawbacks associated with each of these. We agree with the AEMC that, under a two-stage model, using the RRP from physical dispatch would have more downsides than using the access RRP. The main drawback of using the RRP from access dispatch is, when paired with priority access, an increased RRP in some scenarios. This was demonstrated by AEMO's prototyping. However, both the consultation paper and AEMO's prototyping does not:

- Present a forward-looking view of how priority access could affect investment incentives.
- Provide an indicator of the likely materiality of this potential drawback and how often it will apply under a broad set of market conditions.

To attempt to address some of the identified limitations of the two-step dispatch, the AEMC has proposed a co-optimised RRP. Based on the information available in the consultation paper and TWG meetings, we believe a co-optimised RRP would introduce more problems than it fixes and that the AEMC should direct its attention to other aspects of the reform's design. Limitations of the co-optimised approach include:

- A weakened incentive for generators to bid at cost in the CRM, which has the potential to undermine the effectiveness and benefits of the CRM.
- A stronger departure from current market arrangements, with much more far-reaching and difficult to predict impacts on contract market liquidity and existing contracts (PPAs).
- Is less developed than the two-stage model and so will take longer to test and implement, adding further delays to an already long consultation process.
- Has been identified by AEMO as much more costly to implement.

Based on the above, Hydro Tasmania's view is that RRP should be calculated based on access dispatch, rather than any amendment to the RRP after CRM adjustments. This approach appears most consistent with current market arrangements and is less likely to create uncertainty for market participants or negatively impact contracting and market liquidity. We also consider this would be a least cost approach from an implementation cost perspective.

v. Financial Market impacts (inc. contract market liquidity).

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

Cap contracts are a critical risk mitigation tool that enhance competition in retail markets, driving lower costs for consumers. Therefore, we consider that any access reform proposal must carefully consider the impact on cap contract liquidity, and the implications this may have for the market at large. Importantly, the final design must avoid unnecessarily reducing contract market liquidity, due to market participants losing confidence in their ability to back cap contracts across interconnectors.

If designed appropriately with a two-stage dispatch using the access dispatch price as the determinant of the RRP, our view is that this should minimise disruption to current market arrangements and importantly, should not have a significant impact on contract market liquidity. In some instances, we believe the proposed reforms may have the potential to improve contract market liquidity for longer-dated contracts, on the basis that generators would have a greater degree of certainty over the future levels of access. Where generators decide to not opt-in to the CRM, we do not believe this should create any material change to status quo arrangements.

vi. The inclusion or exclusion of constraints / far-reaching constraints

Question 8: Feedback on wide-reaching constraints

In response to prior consultation processes, several stakeholders recommended that certain constraints – for example, outage, system strength or suddenly emerging stability constraints – be excluded from prioritisation to avoid unmanageable risks for investors.

Currently, for both outage and system strength constraints, affected generators are often assigned the same constraint coefficients, meaning these generators share the pain of the constraint. This would no longer be the case under a regime with prioritisation (enacted through different price floors). Delineation of constraints only seems plausible via the proposed Dynamic Grouping Algorithm (option 4). Barring the adoption of option 4, we consider it is too complex to address the issue of wide-reaching effects with the Hybrid Model proposed in the paper.

We also note that the proposed reforms do not increase the overall risk associated with major transmission outages and far-reaching constraints. Rather, it increases the risk that the impact of such events will be borne by individual participants. To this end, we encourage further assessment of option 4 to consider how this approach can maintain a degree of 'pain sharing' in the event of wide-reaching constraints. Should option 4 be deemed implausible, we consider individual market participants should still be capable of managing risks associated with different constraint types under the reform. This could include via developing a broad portfolio of assets, taking out insurance against low probability and high impact events, co-location with storage, or in specific contracting terms.

vii. Cost-benefit analysis.

Question 1: What are stakeholder views on the cost benefit analysis?

In the consultation paper, the AEMC notes that the cost benefit analysis (CBA) of the hybrid model published in February 2023 estimated a net consumer benefit (excluding emissions) of $2.1-5.9 billion, and that despite updates to design details since then, the overall benefits are unlikely to be significantly changed.

While Hydro Tasmania agrees there is sufficient evidence that the hybrid model (as designed) could deliver material benefits to consumers, we caution against ascribing significant value to the CBA estimates because:

- Economic modelling of this nature is highly complex and accurately modelling participant behaviour (in both operational and investment timeframes) in response to the reforms is impossible.
- The NERA market modelling (used for the CBA) only presents single year efficiency estimates for years 2023-24 and 2033-34. Comparing only two years can limit the usefulness of the modelling and potentially undermine confidence in the robustness in comparison to a study that presents results for every year.
- No modelling was conducted on benefit of the different options on investment timeframes. While some historical and international studies were drawn on by the ESB in the CBA, it remains unclear whether the actual benefits of the reform would fall within the range presented in the CBA ($2.13bn-$5.47 bn).

Despite the above, Hydro Tasmania agrees that re-doing the CBA is unlikely to provide additional useful information and may act to further delay progress of the reform. Instead, there needs to be a focus on keeping implementation costs as low as possible for consumers to realise the full benefit of the reform.