21 December 2022

Anna Collyer
Chair
Energy Security Board

Submitted by email to: info@esb.org.au

Dear Ms Collyer

AEC Submission to ESB Transmission Access Reform – Directions Paper

The Australian Energy Council (the "**AEC**") welcomes the opportunity to make a submission in response to the Directions Paper (the paper).

The Australian Energy Council is the peak industry body for electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. AEC members generate and sell energy to over 10 million homes and businesses and are major investors in renewable energy generation. The AEC supports reaching net-zero by 2050 as well as a 55 per cent emissions reduction target by 2035 and is committed to delivering the energy transition for the benefit of consumers.

Introductory Comments

Congestion management reform has been a challenging matter for many years which is inevitably complex and controversial. For its June submission, the AEC agreed on four general principles that any reform should attempt to advance:

1. Market participants should have confidence in their network access levels for the life of the plant in which they have invested.
2. Participants should have reasonable predictability of the impacts of congestion to maximise their trading confidence, and to minimize negative impacts on contracting.
3. Investors should remain free to self-determine their location, but should be incentivized to locate efficiently.
4. Access regimes should attempt to maximise dispatch efficiency.

At that time the ESB had presented a quadrant of options, and the AEC leant towards the Congestion Relief Market (CRM) over the Congestion Management Mechanism (CMM) in the dispatch timeframe, and congestion fees over dispatch priorities in the investment timeframe.

The AEC notes the Paper has made considerable theoretical progress in the CRM and dispatch priorities design since June. In particular, the "tie-breaking" suggestions for the dispatch priorities implementation, combined with the CRM, presents a theoretically holistic approach to investment, access confidence and dispatch efficiency. The priorities approach has advantages over congestion fees in that it does not require a controversial calculation of the fee, and that investors will not be displaced by a "deep pocketed" entrant.

Despite the theoretical progress, a frequently voiced concern from AEC membership is that participants have not been able to gain a confident understanding of the complexity of the reforms through the Paper. We acknowledge the ESB's efforts to provide explanatory forums for our membership which has been helpful, but these reforms need to be socialised deeply into businesses before they can gain acceptance. This will require more material and time than is currently available.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

Firstly the ESB has not yet published the quantitative material from NERA Consulting. This seems essential for industry understanding. That is not just to understand the cost-benefit of the reform, but more pertinently to observe how the theory would operate in real world constraint conditions.

Secondly Ministers have asked for recommendations to be brought to their first 2023 meeting, expected in February. Whilst this timeframe was not set by the ESB, it is now evidently unreasonable. This is because only in November 2022 has the ESB published a theoretical design and seems unlikely to be able to publish quantitative analysis until 2023.

The AEC suggests the ESB alert ministers to this additional time requirement and that recommendations should now be expected in the second half of 2023. Whilst the AEC accepts this will provoke some frustration, it should be explained that the proposals are internationally novel and it has taken time to develop implementable designs from the high-level models put forward by industry. Furthermore, the proposed reforms represent a significant change to the NEM and while they initially appear beneficial, more analysis and consultation is required to ensure the reforms are rigorously tested before any implementation.

As stated on page 14, at the October 2022 ministers' meeting, ministers tasked Senior Officials to consult on "the full range of options" including additional options that are not set out in this paper, with recommendations to ministers for March 2023. This concerns the AEC, as what is meant by "the full range of options" is unclear.

A strong view of industry is that the options presented in the Paper are considerably more acceptable than their predecessors. The ESB already had considerable engagement on those predecessors, and has appropriately responded to the clear message they received about them. The ESB should not have to keep revisiting rejected options.

The AEC is engaging in the proposed reform on the basis that the dispatch mechanism, the CRM, is voluntary and that existing assets that prefer to be dispatched and settled in the current arrangements can continue to do so. This provides contracting confidence and has been critical to it gaining industry acceptance. However, the Paper's references to the CMM as a fallback option continues to raise industry concerns. The AEC suggests the ESB focus its work entirely on CRM, which will in turn focus the resources of both Ministers and stakeholders.

The AEC is concerned that a perception of complexity and international uniqueness in the current recommendations has arisen in government that may attract interest in options that appear less complex or unique. In response the AEC would note:

- The network itself is complex and so is its representation in the existing dispatch engine. Attempting to grasp at what may at first seem a "simple" solution will more likely just hide the complexity through an inaccurate representation.
- The NEM already has an internationally unique approach in its representation of the network via "hub and spoke" constraint equations, which seems unlikely to change. As the underlying representation is unique, then any congestion management scheme that sits upon it will necessarily be also unique.
- Uniqueness necessarily arises because the design is not being placed on a blank sheet of paper. The ESB correctly recognises that participants and AEMO are heavily invested in the current design, and the design must attempt to achieve its objectives whilst causing the least possible disruption. Minimising disruption is a far more important benefit than international consistency.
- Whilst Locational Marginal Pricing (LMP) is often cited as a widely used approach internationally, in reality each LMP electricity market applies and settles it in quite different ways. Were the NEM to adopt LMP, its actual systems and settlements would still be entirely bespoke.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

In any case, if Ministers insist on bringing options beyond this paper back into discussion, it is clear this line of work will need to extend at least into late 2023.

Outline of hybrid model

Implementation considerations

Q1. Should the core elements of the hybrid model be implemented on a staged basis and if so, what factors should inform the decision with respect to staging?

This will depend upon the implementation project which is yet to be researched.

Detailed design choices -operational timeframes
Q2. Do you agree with the proposed scope of market participants included in this access reform?
Q3. Should different treatments apply to any particular categories of market participant?

The AEC agrees the mechanisms only seem workable for scheduled and semi-scheduled assets and is consistent with the way these assets are treated in scheduling processes. Other assets effectively get fully-firm access.

However, there is a risk that the reform creates an additional distortionary advantage in configuring assets to fall beneath these thresholds. In 2018 the AEC unsuccessfully proposed lowering scheduling thresholds from 30 to 5MW for new connections. The ESB is invited to consider this matter and comment on whether it is worthwhile reconsidering this rule change coincidentally with this reform.

The AEC agrees that the connection voltage, i.e. transmission or distribution connected, is irrelevant to participation.

Alternative distributions of congestion risk in the energy market
The ESB has proposed a decision option to round constraint coefficients in the energy market.
Q4. Do you agree with the assessment of risks and opportunities for these design options?
Q5. What is your preferred option and why?

Further information is required as to whether this rounding would result in insecurity (for example if coefficients were collectively rounded to below what is recommended by engineering limits). Clearly this would not be acceptable. If in response to this, materially greater safety margins in limits were required, this would imply failing to exploit full network capacity.

If however it could be shown that rounding did not increase network security risk nor result in new safety margins, then rounding to the nearest decimal point may resolve the most egregious “winner take all” examples without greatly changing dispatch efficiency. The AEC recognises that it would however only lead to congestion sharing in some cases, and there will naturally remain boundary cases, for example between 0.748 and 0.752 where the issue would not be resolved.

Arbitrage opportunities between the energy market and the CRM for out of market generators
The ESB has proposed options in response to the new arbitrage opportunities between the energy market and the CRM.
Q6. Do you agree with the analysis of key risks and opportunities for each design option?
Q7. Are the design choices more applicable to certain categories of market participant?
Q8. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

ABN 92 608 495 307

The AEC recognises the issue and the potential for a new form of "disorderly bidding" to arise when a constrained generator's cost is above the RRP. It is possible that it may self-resolve, as the incentive only arises if other participants in the constraint choose to use the CRM. Those others, upon observing the behaviour, could retaliate by withdrawing from the CRM, which would result in energy market losses for the first participant where it is running below cost. The first participant would then presumably cease the behaviour.

All of the three options proposed to tackle the issue create significant concerns.

The AEC has most concerns about option 2's proposal to impose constraints on bidding freedoms and with any suggestion of different treatment of generators based on technology type. Option 3 does not appear practical, particularly given that the Short-Run-Marginal-Cost (SRMC) of storage and other energy limited resources varies from hour to hour.

Given these issues, Option 1 may be the least unpreferable option depending on the materiality of the issue and its ability to self-resolve. This materiality could be studied through modelling, including the retaliation described above. If the materiality is forecast to be low, option 1 could initially be used, with a subsequent review identified to observe whether the modelling proved accurate.

4.2.4 Treatment of storage acting as a generator and as a load

The ESB has proposed options for the treatment of storage as a generator and as load.

Q9. Do you agree with the underlying assumptions for the respective incentives of storage acting as a generator and as load?

Q10. Do you agree with the analysis of key risks and opportunities for each design option?

Q11. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?

The ESB's concerns about circumstances of a new inefficient incentive arising for storage appear to be identical to those discussed in the previous section about generators. The AEC's preference is for option 1, i.e. that the storage should be treated the same for acting as a load and generation and that it should not be subject to specific controls.

A key benefit of the CRM as presented by its designers is that storage is able to transact "off market" with constrained generators with realised dispatch efficiencies benefiting both. This transaction would occur at the price the paper has described as a "LMP". However this should not be thought of as a nodal, cost-base price, but rather the intersection of the generator's "off market" CRM supply offer and the storage's CRM load bid.

The AEC agrees that the circumstances of a storage when acting as a load being exposed to a LMP in excess of RRP would appear to be remote and seem unlikely to require a control.

Calculation of RRP

The ESB has outlined two options for the calculation of RRP which has consequential impacts for the treatment of FCAS in the CRM.

Q12. Do you have a preferred calculation for RRP and why?

Q13. Which approach do you prefer for the treatment of FCAS and why?

Q14. If the technical implementation plan requires that we adopt your non-preferred calculation of RRP and FCAS prices, what are the risks?

This is an area that could be greatly assisted by presentation of modelled results to better explain and quantify how the RRP would likely vary between the two approaches. The paper suggests the difference is

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

ABN 92 608 495 307

minor, but forum discussions have implied there are significant differences when constrained interconnectors are involved.

The AEC approaches the CRM on the basis that it is "optional", i.e. that a participant who has decided that it does not want to participate, ends up in an identical dispatch and settlement to status quo, which includes the RRP against which they are settled. Philosophically, this means that the RRP should be determined exclusive of CRM. Although it is unclear what the effect of a change in RRP basis would have on existing hedge contracts, keeping RRP exclusive of CRM avoids opening this difficult question.

Settlement of metered output
The ESB has outlined two options for the formula of settlements.
Q15. Do you agree with the risks and benefits of the two options and their materiality?
Q16. Do you have a preferred settlement formula and why?
The original proponents of CRM always recognised that a process that led to participants receiving one price for a primary dispatch, and then another for an optional dispatch, could not be metered at both steps. Only one can be physically measured, and the other must be deemed from dispatch targets. The means that inevitable variations between target and actual output will be allocated to the physically measured settlement.

The choice between two options, as to whether the settlement of energy market dispatch or CRM is to be based on measurements may not have great financial materiality. This is because non-conformance rules force participants to closely follow dispatch targets and variations from them tend to balance out over time.

Regardless of materiality, Option 1 seems philosophically consistent with the presentation of the CRM as an "optional" mechanism, i.e. it maintains status quo in that variations from target are priced at the energy market price. Alternatively, pricing these variations at the price of a mechanism that a participant has chosen not use would seem to violate the mechanism's "optional" status.

Market Participants that alleviate constraints
The location of the Regional Reference Nodes (RRN) in the NEM results in the incidences of constrained-on situations being much rarer than constrained-off and so congestion management models are not designed with these situations principally in mind. The AEC agrees that the CRM may have the potential to add value in constrained-on situations, so it would be disappointing to truncate LMP at RRP, but if it were, the majority of the CRM's rationale would remain.

The AEC is not overly concerned by market power. A LMP that reflects a locational scarcity is beneficial by attracting well placed new entry and deferring network investment. The greater concern is a settlement shortfall caused by loads being settled only at RRP whilst some supply is settled higher. In that regard the suggestion of treating the mismatch as a network ancillary service has merit.

Forecasting information
The paper has not covered issues of forecasting market outcomes in the presence of a CRM. Predispatch forecasts of both the energy market and CRM adjustments would appear to be essential. Whilst likely to be feasible, it is necessary that this matter be soon scoped in order to identify any challenges that would arise and the broad structure of new database tables that participants will need to engage with.

5 Detailed design choices – investment timeframes – locational signals
Form of queue right
Q17. Should the ESB work towards providing as many unique queue numbers as is feasible (given implementation challenges) or is a tiered approach preferable?

If there were no practical barriers, the AEC would be attracted to full granularity, for example defining priorities even by the calendar date of connection. However, it is understood that high granularity poses serious dispatch convergence difficulties. For these reasons, the AEC considers reducing the number of unique process by using a tiered approach the only practicable approach.

Allocation mechanism
Q18. What mechanism should be used to allocate queue positions to generators? E.g. first come first served, auctions, a combination or another approach?

As suggested on page 74, there are advantages in each depending on the circumstances. The AEC suggests that FCFS could be the default approach and used in individual incremental new entrant connections. However TNSPs can be encouraged to operate auctioning processes over these priorities where it is known that more than one new entrant is interested in connecting to a shared area with interacting impacts at broadly the same time.

The paper has not discussed how interconnectors would be treated in the prioritisation process. As section 2.1.6 has discussed, the current arrangements give interconnectors effectively the lowest priority. Whilst acknowledging this, the AEC suggests investigating whether further access degradation can be avoided. For example, it might be possible to treat interconnector priority as if they were entrants at the time of introduction of the new arrangements. Thus new-entrants would receive an efficient signal to not further crowd them out.

Duration of rights
Q19. Would stakeholders prefer that the priority access rights (i.e. queue positions) be set for: the life of the participant's asset, a fixed duration, or a fixed duration with a glide path?
Q20. If set for a fixed duration, what period of time do stakeholders consider would be most appropriate? Should this period be adjusted if combined with a glide path?

As noted in our introductory principles, the AEC prefers that investors should have confidence in network access for the life of their assets. The AEC also understands designers' reluctance in allocating a perpetual commitment in a network that is rapidly and dramatically changing. If the ESB is not prepared to do this, then at least a minimum of two thirds of the asset's expected economic life is but in the case of 10-year lived batteries it should be 100 per cent of economic life.

If priorities are to be given a shelf-life, then upon expiry it would not be appropriate for incumbents to suddenly "go to the back of the queue". Instead what should happen is that early entrants should be progressively brought to the front alongside the original incumbents. E.g. if the scheme is introduced in in year X and the priority is designed last Y years, then in year X+Y+1 those connectors who joined in year X+1 would be promoted to priority zero, and so forth for every subsequent year. Original incumbents would remain at priority zero.

Method used to calculate fees
Q21. Which of the proposed metrics do stakeholders consider should be used as the basis for calculating congestion fees? Are there alternative metrics the ESB should consider?

As noted in the introduction, an attraction of the CEIG priorities approach when combined with CRM is that congestion fees calculations are not required.

If congestion fees are to be enacted we are unable to comment yet on what we believe to be the best approach for their calculation. As noted in the Discussion Paper the methods for calculating these fees is complex and model dependent, which has not yet been evaluated by the ESB.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

ABN 92 608 495 307

The metrics proposed in the Discussion Paper are all based on estimated costs whereas estimated benefits appear to be ignored. Another potential approach to establishing a metric to arrive at appropriate fees could be based on output where the generator pays a very small fee for every MWh it exports. The fee would be based on the cost of the transmission assets.

While this approach violates the principle that generators do not pay TUOS it may be a workable solution for an evolving market requiring enormous investments in VRE , storage and firming that could be potentially easier for potential investors to model. It may be worth exploring this further.

Fee calculation process
Q22. Noting the trade-off between investor clarity and accuracy, do stakeholders have feedback on how bespoke the modelling should be?

The AEC is of the view that what is being proposed in the Directions Paper represents a significant improvement on the current access arrangements. In light of this, keeping the changes as simple as possible may be the best approach as the majority of benefits should accrue with basic changes whereas returns from adding additional accuracy are likely to be diminishing if not detracting.

Timing
Q23. At what time within the connection process should the queue position or congestion fee be locked in?

The AEC agrees with the proposed timing in the Directions Paper whereby applicants receive an indicative queue position or congestion fee at the time of their application and this is the finalised when the connection agreement is completed.

Maintaining multiple simultaneous connection applications
Q24. Should there be a process for batching connection applications and jointly establishing connection requirements and fees?
Q25. Could an expression of interest process, combined with auctions, be used to manage multiple simultaneous connections?

A batching process supported by expressions of interest and auctions appear to be efficient ways of dealing with multiple simultaneous connections. As discussed earlier, it would not be the default approach, but instead exercised by the TNSP where information suggests there is multiple party interest.

Qualifying criteria
Q26. Should there be conditions precedent which must be met before a queue position or congestion fee is finalised and accepted? If so, what sort of measures would be appropriate?

Some form of qualifying criteria is important so as to avoid entities that are not genuine or would be very unlikely to able to proceed with their proposal could effectively bank a queue position congestion fee.

Use it or lose it
Q27. Once set, parties would be expected to progress to implementation. Should there be time limits or expiry dates for projects which do not progress in a timely manner? If so, what time limit would be appropriate?

Yes the AEC considers this to be an important principle to prevent the banking as noted in our response to Q26. Two years may be appropriate.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

ABN 92 608 495 307

Treatment of incumbents

Q28. Do stakeholders have a preference for any of the options listed above regarding the treatment of incumbents in transitioning to the priority access variant? Are there alternative options for the treatment of incumbents under this model that the ESB should consider?

The AEC's preference is for option 1, in that it remains highest priority until it expires at retirement or at a specified date. In this option, if it were to expire in year 10, then in year 11 the incumbent would not go suddenly to lowest priority, but would be treated as equal to those who connected in year 1, and in year 12 with those who connected in year 2 and so forth.

Options 2 and 3 do not recognise incumbency and in doing so do not encourage new-entrants to locate optimally. These options therefore contradict the entire rationale for the reform.

In that vein the third paragraph of section 5.7.2 which suggests that for fairness the current regime of gradually declining access could be maintained, seems to contradict chapter 2's characterisation of access cannibalisation as a serious market design failure. Declining access is the key characteristic of the ESB's concerns about the NEM's existing access regime which has triggered this reform initiative in the first place.

Q29. Do stakeholders support the calculation of congestion fees reflecting the protection of incumbents under the model? If so, do stakeholders have feedback on feedback on how to determine the appropriate degree of protection?

Consistent with the intent of the reform to beneficially incentivise parties who can still make a locational decision, congestion fees would only be applicable at time of connection. There is no case for recovering costs from historical connections.

The paper has not engaged with the question of the beneficiary of the congestion fees, which presumably go to customers through the defrayment of transmission charges. However, if the model does not recognise priority access, then the appropriate beneficiary should in fact be the incumbent participants whose access has been degraded by the connection. If the calculations behind a congestion fee are broadly accurate, then the fee would also represent a broadly fair compensation for their loss of access.

Options to reduce congestion impact

Q30. Should the ESB develop proposals to give generators options to reduce their congestion impact (in return for a lower fee or worse queue position) as part of its congestion management reform package? If so, what options should be included?

Such optionality is attractive but will be complex and requires additional work and may be better introduced as a second phase of reform. It would seem to be most workable in a hybrid that applies both congestion fees (which would be discounted) combined with dispatch prioritisation (which would de-rank).

In regard to the NEOEN suggestion, it could potentially be implemented via multiple Dispatch Unit Identifiers (DUIDs) to the one plant, i.e. the opposite of aggregated units.

Governance

Q31. Do stakeholders support the proposed governance arrangements?

Whilst the AEC's natural preference is for nationally consistent governance, it recognises that jurisdictions have substantially deviated in recent years and developed their own bespoke REZs. In that regard the suggestions in the paper seem the only workable approach.

6 Detailed design choices – investment timeframes – enhanced investor information

Hosting capacity assessment

Q32. Would investors find indicative network hosting capacity values useful for their siting decisions, noting the fundamental limitations of static modelling of the network?
Q33. If so, do stakeholders support defining "zones" of the network based on the sub-regions developed by AEMO for its capacity outlook modelling for the ISP? Are there alternative approaches the ESB should consider? Do stakeholders have feedback on how granular congestion zones need to be to provide useful information to investors?
Q34. Should the ESB focus its efforts on an alternative approach, including making underlying data accessible for investors to conduct their own modelling, more granular ISP modelling by the joint system planners or calculating curtailment forecasts? Are there further alternative approaches that the ESB should consider?

These hosting capacity assessments are welcomed by the AEC. It is difficult to answer the detailed questions presented in the paper without knowing more about the fulsome design of the access regime. In that regard the intent of chapter 6 is very welcome, but the specific questions seem premature.

In any case, the enhanced investor information should not be approached of as a specific recipe of deliverables to be locked in at the starting date of access reform, but rather a process of continuous improvement that evolves as the industry evolves.

Treatment of diversity

Q35. Do stakeholders support hosting capacity assessments that provide investors with a single figure of static capacity under a single set of pre-determined operating circumstances? If so, do stakeholders have feedback on what the assumed operating circumstances for the assessment should capture?

In the first instance, a simple approach is preferable. However if it can be demonstrated that there would be net benefits associated with a more complex approach that defines MW capacity for technology types then this should be considered. An example of this would be a reduction in curtailment if an 'ideal' technology mix results in this outcome.

Q36. If stakeholders prefer multiple hosting capacity values that reflect a range of scenarios, should seasonal conditions be relied on? Alternatively, Should the information be presented in terms of technology-specific values?

Please see answer to Question 35.

Q37. Do stakeholders have any feedback on how load and storage is best captured in the assessment of hosting capacity? Do stakeholders support assuming peak demand for the assessment?
Q38. Should the hosting capacity assessment be based on all types of constraints, and not just thermal, even though this may result in more conservative figures?

Hosting capacity should be based on all types of constraints (eg voltage) and even though the figures are more conservative they are likely to be more accurate.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

Phone +61 3 9205 3100
Email info@energycouncil.com.au
Website www.energycouncil.com.au

Capacity included in the forecasts

Q40. If indicative hosting capacity values are calculated, do stakeholders support capturing only committed network augmentations, generation and load or should anticipated projects also be included?

Only committed network augmentation capital expenditure, generation and load. If anticipated projects do proceed and increase hosting capacity then this can be utilised under the processes for hosting capacity increases.

Governance

Q43. Do stakeholders support the proposed governance arrangements?

The AEC prefers that AEMO has responsibility.

Any questions about this submission should be addressed to the writer, by e-mail to Ben.Skinner@energycouncil.com.au or by telephone on (03) 9205 3116.

Yours sincerely,

Ben Skinner
GM Policy
Australian Energy Council