10 June 2022

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Chair
Energy Security Board
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ESB Consultation paper: Transmission Access Reform

Dear Anna,

Energy Networks Australia (ENA) appreciates the opportunity to respond to the Energy Security Board's (ESB) Consultation paper on Transmission Access Reform.

ENA is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

ENA notes the actionable ISP rules have been in place less than 2 years. These rules enable transmission projects to be considered based on both committed and anticipated generation development. With the move to net zero the need to step up the development of new renewables, transmission and critical essential system services has taken a step change. Transmission network is a critical enabler of the move to a low emissions economy whilst maintaining an efficient level of congestion.

To achieve Australia's decarbonisation goals for the electricity sector, ENA recognises that power system development needs to be better co-ordinated and not left entirely to decisions of individual investors. ENA agrees that the current open access model is incompatible with co-ordinated system development such as Renewable Energy Zone (REZ).

The ESB is considering four shortlisted options in the consultation paper:

Investment timeframes

- Congestion zones with connection fees
- Transmission queue

Operational timeframes

- Congestion management model (CMM) with universal rebates
- Congestion relief market (CRM)

In summary, ENA:

- Recommends that these models must have an appropriate independent cost benefit analysis before recommending to Ministers. Some options, such as the Congestion Relief Market, carry significant

implementation costs and risks, and ENA notes that delays in implementation will result in foregone benefits. It should also be made clear who will pay for implementation costs;

- Notes that if market participants do not support making congestion costs explicit in the market, through LMP, then central planning solutions will be required to manage this aspect on behalf of market participants and to make alternative locational incentives visible (e.g. connection fees based on forecast levels of congestion);
- Recommends that any preferred models should not introduce a bias for new generation between transmission or distribution connection. Distribution connection within a congested area will have largely the same impact as transmission connection within that area;
- Suggests that the ESB should be mindful of the impact of the large volume of non-scheduled, dx connected, resources of any congestion management model
- Notes that the congestion zones + connection fees model appears to be able to be universally applied across the National Electricity Market (NEM), both within and outside REZs, and can operate largely independently of any changes to the NEM Dispatch Engine (NEMDE). It also leverages the local planning knowledge of Transmission Network Service Providers (TNSPs);
- Suggests that the transmission queue model appears to still require significant further design. It also appears that it is intended that there is a single transmission queue across the entire NEM with Australian Energy Market Operator (AEMO) administering the expressions of interest (EOI) and connection process. Anything other than this would require each network constraint to be allocated to a specific sub-region of the NEM for that queue. We do not support this model as a single national queue bypasses the local planning and investment knowledge of TNSPs, while a more granular implementation will be cumbersome and fails to recognise the meshed nature of the network;
- Understands the operational models rely largely on a series of financial transfers between market participants, based on the level of access rights they hold resulting from the earlier investment models. While we do not see a direct role for TNSPs in the working of these operational models we wish to better understand the nature and depth of the information requirements from TNSPs that will be required to support these models;
- Welcomes further clarity on the role and responsibilities of the TNSPs in each of these models as the TNSPs are generally the transmission planner in each state;
- Notes that there seems to be almost continuous adjustment to the transmission planning, connection and investment framework, which creates additional uncertainty during a time of rapid transition.

More detail on these points is provided below.

Independent Cost Benefits Test

National Cabinet has instructed the ESB to progress detailed design work on transmission access reform and to propose a rule change to Ministers in December 2022. The ESB currently considers that the models are able to be mixed and matched and complement state energy policy developments. It is important before more costs are added to consumers that a cost benefit analysis of the options is undertaken and an assessment of the time to implement to ensure that there are sufficient incremental benefits above the actionable ISP rules and state policies to ensure that these additional costs actually deliver net benefits to consumers.

The ESB has likened the cost of the CRM to the earlier Coordination of Generation and Transmission Investment cost estimates of $300m +/- 30% and AEMO provided a cost estimate into the post 2025 consultation papers for CMM of only $10-$20m. It is recommended that AEMO fine tune its expected costs for the models and industry costs be added to ensure that there are net benefits for consumers.

ENA also notes the concerns raised in the AEMC's Operational Security Mechanism work that the ability to co-optimise multiple markets was difficult and the markets may not solve in the timeframes needed. In firming up the costs, the practicality of co-optimising an energy market with congestion relief and FCAS should be tested further.

For all these reasons, the models must have an appropriate independent cost benefit analysis before recommending to Ministers. It is also important that any cost benefit analysis does not only consider each model in isolation but which combination of investment and operation solution works best together. Some options (i.e. the Congestion Relief Model) carry significant implementation costs and risks, and ENA notes that delays in implementation will result in foregone benefits. It should also be made clear who will pay for implementation costs.

Investment timeframe solutions

Congestion zone and connection fees

The congestion zones + connection fees model appears to be able to be universally applied across the NEM, both within and outside REZs, and can operate largely independently of any changes to the NEMDE. It also leverages the local planning knowledge of TNSPs.

The congestion zone and fee model is likely to require increased visibility of transmission congestion information on a forward looking basis. The ability to accurately forecast the entry, exit and location of both load and generation and the impact on congestion at network sub elements is difficult. The definitions of committed and anticipated generation projects could also be considered to assist in generator contributions.

The congestion zones and fees may need to be reset on a regular basis. The Consultation paper suggests that connection fee would provide a locational signal for generation investment. The Consultation Paper goes on to suggest that the connection fee would be set at a point in time for a generation asset and the fees could be used to net off the transmission charges ultimately paid for by consumers. The investment timeframe solutions are the only models which offer some generator contribution to the costs of new transmission investment. ENA suggest more information is needed regarding TNSP's role in calculating, collecting and investing in infrastructure.

The ESB should be mindful of the impact of the large volume of non-scheduled, distribution connected, resources in any congestion management model. This model would do nothing to curb new generation at distribution. By 2050 the level of Distributed Energy Resources (DER) in the NEM will contribute about 30% of the NEM capacity and will have increased five fold in the Integrated System Plan Step change scenario. The utilisation of this growing generation capacity to reduce costs across the NEM will be important.

Any ESB preferred models should not introduce a bias for new generation between transmission or distribution connection. Distribution connected generation within a congested area will have largely the same impact as transmission connection within that area.

ENA welcome further clarity on the role and responsibilities of the TNSPs who are generally the transmission planner in each state.

Transmission queue

ESB acknowledge the model is not viable in its current form, it doesn't appear to work well for meshed networks and the increased level of centralisation is unlikely to be least cost. While incumbent generators may be low in the queue, they are not necessarily protected as new generators can improve their position through transmission charges or storage. It is unclear how this option de-risks investment as it augments price and dispatch outcomes in the operational timeframe.

It is also not clear that the most cost-effective energy dispatch occurs. The transmission queue model appears to still require significant further design. It also appears that it is intended that there is a single transmission queue across the entire NEM with AEMO administering the expression of interest and connection processes. Anything other than this would require each network constraint to be allocated to a specific sub-region of the NEM for that queue. ENA does not support this model, as a single national queue bypasses the local planning and investment knowledge of TNSPs, while a more granular implementation will be cumbersome and fails to recognise the meshed nature of the network.

Outside the REZs, new connections would still occur on an open access basis, however their queue position would be managed so that it did not undermine the REZ generators' limited physical access arrangements. There is potential that this may be an additional hurdle or that expression of interest processes or auctions and queues may slow down the connection process, beyond the REZ arrangements.

ENA notes there seems to be almost continuous adjustment to the transmission planning, connection and investment framework, which creates additional uncertainty during a time of rapid transition.

Operational timeframe solutions

Congestion management model with universal rebates and Congestion relief market

The congestion management model with rebates offers a locational marginal price signal behind constraints during congestion. Rebates would be made available to existing and new entrants regardless of their location (whether in a REZ or not). This option may also readily apply to scheduled DER, demand side participation on the distribution network that is scheduled.

Shadow locational marginal prices (LMPs) already exist in the NEM and as noted earlier this is a potentially cheaper solution than the alternative CRM model.

ENA understands the operational models rely largely on a series of financial transfers between market participants, based on the level of access rights they hold resulting from the earlier investment models. While we do not see a direct role for TNSPs in the working of these operational models we wish to better understand the nature and depth of the information requirements from TNSPs that will be required to support these models.

Any solutions adopted should encourage dynamic loads with respect to constraints, support the provision of essential system services and provide a long-term benefit to consumers. ENA considers that there would be benefit in worked examples or use cases that reflect different size and connection types.

ENA welcomes the continued opportunity to work with the ESB on the role of the TNSP in these models and the information requirements as the detailed models evolve. It is also important that any solution not

be at the expense of system strength. System security, including future requirements, need to be considered when progressing any further development of option combinations. In some instances, when system security is also taken into account, a network solution may be the least cost option for relieving congestion. As noted above, the models will have more significant impact on network capacity and informational requirements which will require clear governance arrangements, including into constraint equations.

Any questions on this response should be directed to Verity Watson, vwatson@energynetworks.com.au.

Yours sincerely,

Andrew Dillon
Chief Executive Officer