Energy Security Board
Email: info@esb.org.au

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Delta Electricity's Response to the transmission access reform consultation paper May 2022

Delta Electricity (Delta) welcomes the opportunity to respond to the Energy Security Board's (ESB) transmission access reform consultation paper and acknowledges the extensive engagement the ESB has carried out and consideration it has given to industry feedback.

Key considerations

Delta supports reforms that promote the prudent use of existing energy infrastructure and efficient delivery of new infrastructure to ensure customer receive reliable and secure power at the lowest cost. To achieve this, Delta considers the following points are fundamental to any transmission access reform:

- Existing transmission network capacity should be utilised, and an efficient amount of congestion allowed to occur before expensive augmentation or new transmission is considered (i.e. transmission build should follow congestion so that customers are not paying for spare capacity that may underutilised).
- New transmission build should be rigorously tested through the RIT-T process to ensure customers only pay for lowest cost solutions to support a reliable and secure power system.
- New generators seeking network connection access, beyond what is efficient from a whole of system perspective, should pay for the network reinforcement capital cost to send their generation to market, with any costs passed through to customers meeting the AER's cost pass through efficiency assessments.
- Reforms should improve transparency and predictability of congestion to ensure any changes to dispatch improve market certainty and trading and minimise impacts on contracting.

Delta understands from the consultation paper, and strongly supports, that incumbent generators would not be subject to any new congestion connection fees or other investment signals. Incumbent generators do not contribute to the cost of the shared transmission network and receive no access rights.

Rationale for transmission access reform

The status quo approach to transmission and generation investment has been described as:

- being uncoordinated,
- lacking transparency and certainty for investors,
- resulting in inefficient generation investment, and
- likely increasing customer electricity bills more than is necessary.

This sub-optimal investment environment and downstream impact on customer bills is likely to continue to concern governments and may result in out-of-market interventions, which would only erode underlying investor certainty further.

Therefore Delta supports changes to transmission access that would provide:

- clearer signals and greater certainty for intending generation and storage investments;
- stronger operational signals for storage and dispatchable loads in the form of energy or congestion relief prices that reflect the benefit these technologies provide to the power system; and
- assurance that existing generators would be no worse off (compared to the status quo) in terms of curtailment risk due to congestion.

Assessment criteria

Delta supports the ESB's assessment criteria, which is comprehensive and acknowledges the complex task of balancing the trade-offs between addressing each one of the criteria. Given the rising complexity and cost of the energy reform environment, Delta suggests that where possible:

- practical, simpler, and lower cost solutions are chosen over more complex options that deliver, more or less, the same benefit and value to the market, and
- risk is allocated to those parties who are best able to manage it.

Delta's preferred options

<u>Investment-timeframe options</u>

Delta prefers the congestion connection fee option as it is likely to:

- Provide a clear and transparent financial signal to investors, which is known upfront prior to any financial commitment being made.
- Allow investors/new generators to see deeper connection costs which shifts some of the risk from consumers to investors who are better able to manage it.

Delta agrees with stakeholder suggestions, such as a traffic light system or Transmission Statement of Opportunities (TSOO), that would improve the transparency and clarity for investors. Delta suggests greater clarity is needed on where the revenue from the congestion connection fee would be spent. Delta anticipates the revenue would be used to support more transmission capacity, when efficient to build, to offset congestion impacts on incumbent generators where that congestion has surpassed the efficient level.

Delta does not support the queue option because:

- It seems unlikely to send a strong location signal as clarity on their queue position may not be known until late in the development and connection process, after they have already invested in the project.
- It may lead to inefficient dispatch outcomes as less-efficient generators may be dispatched ahead of more efficient generators because they have a higher queue position.

Operational-timeframe options

Delta supports the congestion relief market (CRM) option over the congestion management model (CMM) option.

The CRM is more clearly defined and provides greater transparency and certainty for market participants. It allows participants:

- greater revenue certainty as they would continue to receive the regional reference price for energy but be incentivised to bid closer to their short run marginal cost (SRMC);
- certainty on what price they will be dispatched for congestion relief; and
- greater ability to manage market risks which should minimise impacts on the contracting market.

While Delta's understanding is that both the CMM and CRM may potentially achieve similar operational and incentive outcomes, it considers at this stage:

- there is limited detail on how the CMM's charges and rebates would be calculated and shared among participants; and
- it introduces greater complexity and administrative burden through increased steps to calculate and distribute charges and rebates.

The ESB has indicated implementation costs are potentially significantly more for the CRM option. Delta encourages the ESB to conduct and include a thorough cost assessment of each option in the draft detailed design for the next stage of consultation.

Further information and responses to stakeholder questions can be found in Attachment 1. To discuss any of the issues raised in this submission please contact Joel Aulbury, Regulation and Strategy Manager, at joel.aulbury@de.com.au.

Yours sincerely

Anthony Callan
Executive Manager Marketing

ATTACHMENT 1 – Delta's response to consultation paper questions

Questions for congestion zones with connection fees option

Questions - congestion zones with connection fees	Delta's response
What form of incentive should be used to influence generator location decisions?	A fee that reflects the level of congestion in each defined zone would provide a strong financial locational signal. The fee could be as low as zero where there is sufficient hosting capacity and above zero in areas with greater congestion. The fee could also vary, depending on how the plant intends to operate, between high and low/no renewable resource periods to ensure appropriate locational signals are sent to intending storage or other dispatchable loads for zones where these types of participants may provide congestion relief.
What methodology should be used to calculate the efficient hosting capacity of the network for each zone? • How does this methodology reflect differences in the output profiles of different generator types?	For each zone, the methodology should identify whether more generation or more transmission will deliver the next MW of energy at the lowest cost to customers. The efficient hosting capacity of the network is the point where the next MW of generation is more expensive than building more transmission. In practise, this would mean an amount of congestion would need to occur before more transmission would deliver the next MW at a lower cost. As noted throughout this submission, Delta considers efficient transmission build should relieve congestion, not create headroom network capacity that may not be utilised. This methodology would also need to accommodate for storage and other dispatchable loads as these technologies would effectively increase the efficient hosting capacity of the zone.
How should the model treat multiple generators seeking access to the same part of the network?	The model could adopt some aspects of the approach used by AEMO Services to award access agreements in Renewable Energy Zones. For example, the model could initially cull worst performing projects in terms of impacts on other local generators and the level of community consultation and support for the projects. Once the most beneficial projects are shortlisted, they could be further differentiated through their impacts to power system security and whether they plan to provide energy during peak demand periods. If required, a connection fee auction could occur allowing the highest bidder to be prioritised (starting at the minimum connection fee set by the AER).

Questions - congestion zones with connection fees	Delta's response
Who should be responsible for administering various aspects of the framework?	The AER and AEMO should bear the responsibilities of administering a new framework of congestion fees. The framework should utilise and complement the existing RIT-T and ISP processes, which have been more aligned from 2000 with the publication of the AER's 'Guidelines to make the ISP actionable'.[1] More specifically, and in conjunction with broader consultation, AEMO would be best placed to identify and define congestion zones and the AER would calculate the fees associated with each zone.
How should connection fees be calculated? • What is the correct balance between accuracy and simplicity/transparency? • What should happen to revenue paid by generators?	Connection fees should be set to send clear and transparent signals to investors where there is (and is not) hosting capacity in the Transmission network. The revenue collected by TNSPs should be regulated by the AER and go towards funding additional transmission capacity when congestion reaches a point that it is efficient to do so. To be clear, it is Delta's strong view that the most efficient approach (and lowest cost for consumers) is for augmentation of networks to follow after an efficient amount of congestion has been allowed to occur. In areas where the connection fee is high, because of existing high levels of congestion, Delta expects that all revenues from these connection fees will fund new transmission to remove the inefficient congestion created by the newly connected generators. Otherwise, incumbent generators are likely to face greater congestion and be constrained down/off which would undermine the greater investor certainty the reform is trying to achieve.

[1] These guidelines were part of a broader reform led by the Energy Security Board (ESB) which resulted in changes to the NER to make the ISP more actionable. The new rules became effective from 1 July 2020, with the new guidelines coming into effect through the 2022 ISP.

Questions for transmission queue option

Questions – transmission queue	Delta's response
How should a generator's queue position manifest in operational timeframes?	Delta does not support the queue option but makes the below comments to some questions in the event the ESB decide to progress this option.
What methodology should be used to calculate the efficient hosting capacity of the network (for the purposes of establishing whether initial queue positions are available)? • How does this methodology reflect differences in the output profiles of different generator types?	No response.
Who should be responsible for administering various aspects of the framework?	No response.
Can queue positions can be traded?	In the event where a queue is established and generators can fund additional transmission to improve their queue position (see response to the last question in this table) it would seem reasonable that a generator could trade its queue position.
Should energy storage be subject to the same queuing terms as generators?	Yes, storage should be treated like any connecting generator for the purpose of joining the queue. Storage should be sent the appropriate signals and incentives through the operational-timeframe option chosen.
Should the framework encourage efficient retirement decisions for end-of-life generators and if so, how?	The existing framework already provides generators and the market efficient retirement signals in the form of electricity and fuel prices through the futures markets and generators' own end of life asset assessments. As a result, generators currently provide a three-and-a-half-year notice of closure to AEMO and the market. Any reform that attempts to fast-track retirements increases the already present risk of future capacity shortfalls and system security concerns.
Should the ESB explore options for new connecting generators to be able to elect to fund additional transmission investment, and receive greater access certainty in return?	Yes. If a transmission queue is established new entrants should be able to elect to fund additional transmission capacity and then benefit from this. This approach would allow those generators that can and want to manage their own risk to do so, and it may even decrease (or at least not increase) costs past onto customers.

Key questions for Congestion Management Market with universal rebates option

Questions – Congestion management model (CMM) with universal rebates	Delta's response
What objective should we seek to achieve when selecting a metric to allocate rebates between generators? • Should we remove the "winner takes all" characteristics implicit in the current specification?	Rebates should be allocated to those who are genuinely fully or partly constrained. Generators that have no intention of generating at a particular price should not be eligible to receive rebates by simply being available during those intervals. If the framework incentivises generators to bid their SRMC, then this bid can be used to distinguish between those genuinely constrained and those that are not. Otherwise, higher cost generation could make windfall gains at the expense of lower cost generation. The status quo approach of "winner takes all" is designed to achieve the most efficient dispatch outcome. Any move away from this approach would need to demonstrate clear benefits greater than the cost to do so and loss of efficiency.
What are the consequences of the CMM in terms of bidding incentives?	The consequence is that generators should be incentivised to bid closer to their SRMC as strategic bidding below SRMC may result in congestion charges that outweigh revenue gained through the energy spot market. While the congestion rebate may offset some of the congestion charge, it is unlikely to offset the full amount if other participants are bidding closer to their SRMC. That is, the net effect of congestion charges and rebates should benefit those generators who bid closer to their SRMC compared with those who do not. Delta suggests the ESB provide detailed work examples to demonstrate this.
Should we adapt the model to preclude peaking generators from receiving rebates when the RRP is low?	Exclusions of generators from receiving rebates should be based on their bids, not their technology type. That is, a gas peaker would likely not receive a rebate when the price is low because its lowest priced volume bid is likely to be higher than the dispatch price. However, if a gas peaker was bidding below the dispatch price it should be eligible to receive a rebate.

Key questions for Congestion Relief Market option

Questions – Congestion relief market (CRM)	Delta's response
What key attributes should the ESB seek to preserve as it works out how the dispatch algorithm should solve in the congestion relief market?	The ESB could retain a single bid approach that is used to solve both the energy and congestion relief markets. Under this approach, participating in the congestion relief market would not be optional and would encourage participants to bid closer to their SRMC.
What implementation costs are involved – both for AEMO and market participants?	Delta notes it would incur some implementation costs but does not consider this to be material. AEMO is best placed to comment on its implementation costs.
Should we adapt the model to remove the "winner takes all" characteristics implicit in the current specification?	See response above to the same question under 'Questions for CMM option'.
Should we adapt the model to reflect queue position in deciding which parties may sell congestion relief?	Delta does not support the queue position option.
What are the consequences of the congestion relief market in terms of bidding incentives?	Under a congestion relief market generators would still be settled at the RRP for energy, but they would be settled for congestion relief at the local marginal price. The consequence is that generators would be incentivised to bid at their SRMC as they may be dispatched for energy as well as congestion relief. For example, if a generator were to bid to the floor (-$1,000 MW) and was dispatched for congestion relief it would: • Reduce its own output and pay another generator to produce energy at a rate of $1000 per MWh, or • pay a storage/dispatchable load to consume energy at a price of $1,000 MWh.
Should we adapt the model to preclude peaking generators from selling congestion relief when the RRP is low?	See response above to the same question under 'Questions for CMM option'.