23 June 2022

Congestion management Technical Working Group

Working paper – Overview of submission for the Transmission access reform consultation paper

The consultation paper sought feedback on four model options (two in investment timeframes, two in operational timeframes). The ESB anticipates that the next stage of detailed design will be a hybrid model that incorporates one of the investment models and one of the operational models.

Thirty parties have responded to the ESB's consultation paper on transmission access reform:

EnergyAustralia	Energy Queensland	Stanwell
Flow Power	CEIG	Finncorn (on behalf of ECA)
EUAA	ENA	Australian Financial Markets Association (AFMA)
Delta Electricity	ACEN	Fluence
Acciona Energia	CS Energy	Australian Energy Council (AEC)
Tilt Renewables	Snowy Hydro	Neoen
Shell	Origin	ENGIE
Tesla	Hydro Tasmania	Energy Consumers Australia
AGL	Alinta	Iberdrola
Edify	CEC	
Australian Aluminium Council		

This document consolidates key themes of feedback shared in the submissions including general comments, and feedback on each of the four model options.

1. General comments

Theme	Feedback
Withholding judgement on model preferences	• A number of respondents felt unprepared to provide clear model preferences. They are awaiting: o Cost benefit analysis (see below) o Worked examples to show the impact of model choices on different participant types o Outcomes of the rebate allocation method
Cost-benefit analysis	• 53% of respondents requested a CBA to support decision-making. • Queries were raised on the cost estimates provided for operational models: o \$300M +/- 30% CRM cost estimate based on COGATI (compared to quotes for (i) fast frequency response ancillary market (ii) ST PASA network model) o \$10M - \$20M CMM cost estimate based on July 2021 Final Advice to Ministers (compared to \$28M - \$34M AEMC consultant paper for implementation of LMPs).
Delays in investment	• Participants raised concerns about delays to investment across all model options except for the CRM eg: o Queue – introduction of EOI and auction processes could delay connection processes, delays in confirming queue position would

	affect the timeliness of an investment decision, bottlenecks created if a project with a favourable queue fails to proceed. o Connection fees – potential delays to connection process o CMM – investment complexity and risk, difficulties in securing project finance due to challenges of forecasting LMPs and rebates.
Reforms for batteries	• Acciona separately listed a number of reforms to incentivise investment in storage by addressing barriers to its operational and economic potential: o Exempt batteries from paying TUOS o Improve registration flexibility for batteries to allow co-location with variable renewable generators (i.e. register as semi-scheduled) o Enable batteries to monetise value of grid services o Address rules which require generators to ramp linearly to their dispatch target and which limits a battery's ability to provide cap type services and ramp up quickly to capture high prices. • Fluence also encouraged the ESB to consider the interactions with connecting to the grid in areas of higher renewable penetrations. Storage may best placed to help alleviate congestion, but the grid may be weaker. Additional revenue to alleviate congestion may not be enough to outweigh the risk of a delayed and burdensome grid connection.
Out of merit generators	• For both operational models (CMM and CRM), there was concern around out of merit generators benefiting from a flow of congestion payments. However, the potential solutions are themselves problematic. o Pre-determining who is out of merit via the rules of the model is hard to do without violating the important principle of technology neutrality or introducing an element of cost-based dispatch to a bid-based dispatch market. (*ENGIE*) o Opposed to the concept of a centrally-inferred estimate of SRMC given challenges of estimating for BESS, pumped/standard hydro and volatile fuel costs for gas / coal. Definition of peaking generator and calculation of costs will change based on market conditions. (*Shell, Hydro Tasmania, ENGIE*). o Question exclusion of high SRMC plant when RRP is low (good faith bidding requirements) and good reasons to bid below SRMC (unrelated to gaming e.g. anticipating higher price positions later to offset loss, avoiding ramp up/down degradation, managing hedge positions). Potential adverse system strength implications if parties are exposed to congestion costs. (*EnergyAustralia*)
Inter-regional settlement	• Need to do further work to determine the impact on holders of inter-regional settlement residue units, which are currently a valuable tool for managing price risk between regional RRPs (*ENGIE*) • Unclear of rebate options on generator outcomes and substitute for inter-regional settlement residues. IRSRs would need to be allocated a portion of congestion rebates based on the LMPs of the node at which they connect in each region or IRSR units would reflect only the price difference between the LMPs of their respective connection point in each region (less effective for inter-regional hedging) (*Shell*)

The table below summarises the full and partial support of model options by participant type.

Participant type	Supporter		Key themes
	Zones	Fees	
Consumer	3/4	3/4	• Support the use of connection fees to fund Tx augmentation or offset TUOS charges (if it doesn't meet a RIT-T)
Generator/developer	16/21	8/21	• ~38% of generators (full and partial supporters) were open to fees as being a clear locational signal, particularly if fees can fund incremental Tx upgrades to manage congestion risk (rather than offsetting TUOS). • Opponents of the fee considered the consumer benefits would be offset by the risks of connection delays/cost/inaccuracies and ultimately pass through of costs back to consumers. Enhanced information was deemed sufficient as the locational signal.
Retailer	1/1	1/1	
Storage	2/2	0/2	• Only 1 out of 2 storage providers expressed a view on fees (Tesla)
Network service provider	1/2	1/2	• 1 supporter of the fee acknowledged the challenges of its calculation but also its flexibility in applying across the NEM. • 1 opponent stated that increased connection costs faced by generators will likely complicate and deter investment.
Total	23/30 *77%*	13/30 *43%*	

2.1. Enhanced provision of congestion information

There was strong support to provide enhanced information to enable assessments of congestion; a 'no-regrets' reform. The only respondents that did not give support either did not accept any case for change and/or did not comment on this model option. Support for enhanced information included:

- Transmission Statement of Opportunities (highest level of support)
- Traffic light system
- Mandatory congestion studies (CEC)
- Ensure the AEMO connections database remains up to date (*Acciona*)
- AEMO to share a dynamic open access model to assess congestion impacts on projects (*Acciona*).

2.2. Value of the connection fee

Participants proposed similar concepts to the consultation paper and TWG.

Connection fee	=	NPV of the cost of congestion created by the connecting asset (*Finncorn/ECA*).
	=	Long run incremental cost of network investment (*AEC, posed as*).
	=	Expected value of CMM rebates that generators receive in dispatch (*AGL*).

      - Costs to deliver the maximum level of congestion a generator is prepared to accept (*Shell*).
      - TNSP commitment that output will not be constrained (physical access) (*Alinta*).

2.3. Use of funds from the connection fee

- Customer representatives supported the use of fees to fund Tx augmentation to reduce future congestion or offset TUOS charges.
- Generators supported using the funds to upgrade the network.
    - If connection fees were not used for this purpose, it could result in a new entrant prepared to pay high connection fee, not used to upgrade Tx and neighbouring generators are constrained. Connection fee should be linked to higher certainty of congestion risk. (*Shell*)

2.4. Potential modifications to the design of the connection fee

- Establish a minimum connection fee to ensure all generators are making some contribution to offset network costs. (*EUAA*)
- For dispatchable assets, offer a choice to face a lower (or zero) connection fee with obligations not to be dispatched in competition with renewables, or to face the identical connection fee (*Finncorn/ECA*)
- Calculate cost over a shorter 4-5 year period due to the inherent uncertainty in calculation and forecasting. (*AGL*)
- Create a dynamic, rather than static charge and/or allowing for periodic reviews to adjust the fee to reflect changes in congestion due to network augmentation or inaccurate forecasting. Dynamic repricing could better reflect lower connection costs facilitated by technological advancement. (*EA, Hydro Tasmania*)
- Leverage the system strength framework including the zonal congestion standard developed by AEMO and TNSP (*EA*)
- Commitment by the TNSP in return for connection fee. (*Alinta, Iberdrola*)
- Design access rights that fully reflect the true availability of transmission capacity in real-time. (H*ydro Tasmania*)
- New generation should be developed to replace coal ahead of closures. Investment that physically displaces coal will ensure that transmission lines are well used into the future. (Iberdrola)

2.5. Alternative design options

- Limit access (similar to REZ physical access arrangements in CWO) (*EA)*
- Some form of congestion self-remediation (*EA)*
- Mandatory participation in control schemes (*EA)*
- Transmission Statement of Opportunities should be established to demonstrate that modelling can be done centrally and accurately, before fee structures are considered (Iberdrola).

3. Transmission queue

The table below summarises the full and partial support of the transmission queue by participant type.

Participant type	Supporter	Key themes
Consumer	0/4	• Risk of inefficient outcomes on a 'first-come first-served' basis.
Generator/developer	4/21	• 4 supporters include CEIG, Tilt Renewables, Shell and ACEN (listed energy platform of the Ayala Group with renewable assets in SE Asia). • Supportive of improving queue position by funding network upgrades. • CEIG does not support ESB's proposed amendments to apply the queue position in operational timeframes. Instead, it proposes the queue should be considered before contribution factors in the dispatch algorithm when resolving tied bids behind a binding constraint.
Retailer	0/1	• Respondent did not provide comments on the queue model.
Storage	0/2	• Respondents did not provide comments on the queue model.
Network service provider	0/2	• May not lead to a lowest cost dispatch or reduce investor risk. • Requires continuous adjustment to the transmission planning connection and investment framework.
Total	4/30 *13%*	

3.1. Limited support for the transmission queue

There was limited support for the transmission queue, which may reflect the participants' difficulties in engaging with a model that was theoretical in nature rather than articulating tangible outcomes. Key concerns included:

- Inefficient dispatch outcomes and increases consumer and environmental costs (*EA, Delta*, *Acciona, AGL, ENA, Finncorn/ECA*)
  - Priority rebates in CMM undermines universal allocation principles (*EA)*
  - Queue orders for CRM undermines dynamic efficiency (*EA*)
- Overly complex process (EOI/auction) for unknown financial right in congestion (*Acciona, CS Energy, Origin, Finncorn/ECA*
- Integer queue position does not distinguish between variable renewables, dispatchable generation, storage (*FInncorn/ECA*)
- Impact on contract liquidity (*CS Energy*)
- 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 (*ENA*).

3.2. Design suggestions if the model is pursued

- Proposal to round the curtailment coefficients is worth further consideration (*CEIG*, *Tilt*)
- If the detrimental impact on new developments appears too severe, perhaps an adjustment can be made where existing investments are not 100% insulated from increased congestion, instead of doing 'no harm', new generation could be allowed to do a 'small amount of harm'. (*Tilt*)
- Queue could apply within REZs only, and inform the allocation of rebates (*ACEN*)
- A limited right to CMM rebates until all other assets with lower queue positions are placed in a net position (after LMP + rebate) that is no worse than if the higher queue position assets were not dispatched (*Finncorn/ECA*)
- Generators should be allowed to fund Tx upgrades to benefit from improved queue position (*Delta*, *Tilt*)
- Queue position should be allowed to be traded (*Delta, CS Energy, ENGIE*) but monitored to prevent gaming.
- Treat storage like any generator (*Delta*)
- Queue position could take the form of a small advantage to the participation factors of projects with better queue positions (Iberdrola).

The table below summarises the full and partial support of the CMM by participant type.

Participant type	Supporter	Key themes
Consumer	3/4	• 2 parties strongly stated their preference given benefits for generators, consumers and storage/flexible load. Remains supportive of LMP/FTR model. • 1 party is supportive, but awaits the worked examples of outcomes for energy users and rebate allocations. • 1 participant did not state a model preference.
Generator/developer	4/21	• 4 supporters included Hydro Tasmania, ACEN, Shell and ENGIE (awaiting worked examples) and AGL (advocate for LMP/FTR model but only if there was a demonstrated case for change). • Opponents highlighted the increased complexity, investment uncertainty and cost of capital as a result of: o Additional variability and forecast challenges for LMPs and rebates o Renegotiation of offtake agreements o Increased volume risk for contracted parties o Loss of contract liquidity. o Potential for new gaming behaviours (*Neoen*).
Retailer	0/1	• Rebates would only be an approximate hedge for basis risk and therefore an ineffective risk mitigation. • Costs associated with contract renegotiations and updates to billing systems. (Flow is particularly affected given its pass-through PPA arrangements).
Storage	0/2	• Lack of a strong and direct signal for storage as the CMM is currently conceptualized (*Tesla*)
Network service provider	1/2	• 1 party stated that if parties did not accept managing explicit congestion costs / LMPs were not accepted, it would require a centrally planned solution instead. (*ENA*) • 1 party was not prepared to make a judgement until worked examples were provided.
Total	8/30 *27%*	

4.1. Rebate allocation

There was no clear preference for the method of rebate allocation. There was preliminary feedback on:

- The need to manage basis risk (*Acciona*, *Snowy Hydro*, *Origin*, *Finncorn/ECA*, *AFMA*) which might lead to a preferred objective to align access and dispatch outcomes (*Finncorn/ECA*, *Hydro Tasmania*)
- Sharing of risks (*Hydro Tasmania*)
- Increased certainty for generators (*Hydro Tasmania, ACEN*)

Participants are awaiting worked examples to understand the impact of the rebate allocation methods for their individual circumstances. There were concerns raised that the allocation metric may influence generator bidding to be inefficient.

4.2. Impact on storage and flexible load

- One of the key decision-making factors is whether BESS can take advantage of high prices in energy and FCAS markets when they arise by dispatching. If the BESS has located in an area where there is congestion, then lower charging prices will make little difference if its dispatch is constrained during high price trading intervals. (*Shell*)
- Incentives for batteries should maintain flexibility; storage will seek to discharge when revenue opportunities are high, this is integral to its business case, and it may be contractually required to do so. (*Acciona*)
- Both storage providers supported the CRM in preference to the CMM as a stronger locational signal for batteries with a dispatch rather than post settlement mechanism.
- One stakeholder considered that storage was inefficient for managing congestion (*Neoen*).

The table below summarises the full and partial support of the CRM by participant type.

Participant type	Supporter	Key themes
Consumer	0/4	• Disorderly bidding could continue in energy market, with no certainty of net efficient outcomes from voluntary CRM. • Risk of shallow market; uncertainty of uptake of a voluntary mechanism may not provide enough surety for storage/flexible load. • No international precedent of a CRM.
Generator/developer	15/21	• Parties support the CRM as a voluntary market which allows for flexible management of financial exposure • Note that 1 party disputed the 'optional' nature of the CRM given the single bid approach which encourages participants to bid closer to SRMC. (*Delta*) • Parties that did not support the CRM were awaiting outcomes of a cost-benefit analysis (*AGL*) or expected implementation and operational costs to outweigh the benefits (*ACEN*) or did not accept the case for change. • Offers into the energy market and CRM should be linked, such that assets would be preferentially offered into the energy market if prices are acceptable (*Iberdrola*)
Retailer	1/1	• Support the optionality for participants • Reduced billing impacts for complex retail PPAs.
Storage	2/2	• Provides a clear revenue path for batteries. • More transparent locational signal via dispatch mechanism, rather than post settlement mechanism. • Support for the co-optimised , single pass approach allows for minimising the total cost of dispatch.
Network service provider	0/2	• Respondents did not provide feedback comments.
Total	18/30 *60%*	

5.1. Cost benefit analysis

10 respondents challenged the cost estimates for the implementation of the CRM.

Overall, 16 out of 30 respondents recommended that a formal cost-benefit analysis be undertaken which would include a review of the implementation costs and relative benefits.