Shell
ENERGY

10 June 2022

Anna Collyer
Chair
Energy Security Board

Dear Ms Collyer

RE: Transmission Access Reform Consultation Paper

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Energy Security Board's (ESB) transmission access reform consultation paper.

About Shell Energy in Australia

Shell Energy is Shell's renewables and energy solutions business in Australia, helping its customers to decarbonise and reduce their environmental footprint.

Shell Energy delivers business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers, while our residential energy retailing business Powershop, acquired in 2022, serves more than 185,000 households and small business customers in Australia.

As the second largest electricity provider to commercial and industrial businesses in Australia[1], Shell Energy offers integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. The company's generation assets include 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and the 120 megawatt Gangarri solar energy development in Queensland.

Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy, while Powershop Australia Pty Ltd trades as Powershop. Further information about Shell Energy and our operations can be found on our website here.

General comments

Shell Energy has been actively involved in the ESB's Transmission Access Reform (TAR) workstream over the past few years. We have consistently argued that any solution needs to deliver overall benefits to the market and consumers and in particular, avoid damaging the contracts market. Although we have not always agreed with the ESB on the pressing need for reform of the transmission access system, we have continued to engage constructively. We are therefore pleased that the ESB has shifted away from a congestion management model (CMM) only option to a two-solution system. The ESB's preference to use one model to address congestion in investment timeframes and another to address the challenge at an operational timescale represents a sensible

[1] By load, based on Shell Energy analysis of publicly available data.
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2021.

approach, and one that allows for increased flexibility in how current and future investors operate when faced with congestion.

As has been the case throughout the Transmission Access Reform work program, our main concern is the impact that these reforms will have on the contract market. Any solution which reduces contract market liquidity will fail to address the broader needs of the market as a whole. It is through this lens that we assess the ESB's options for access reform.

To date, there has been little analysis done on how these reforms will impact the contracts market. Without this it is incredibly challenging to determine whether one model offers a substantially improved set of costs and benefits over another model, or indeed, over the status quo. At the stakeholder webinar on 26 May, Shell Energy noted that the ESB has indicated that it has commissioned modelling to assess and compare the CRM and CMM. We urge the ESB to ensure that this modelling considers what the impact these models will have on contracts markets. Alternatively, a sensitivity analysis could explore the potential outcomes of reduced contract market liquidity under the CMM in particular.

The ESB has consistently argued through this process, that reform of the transmission access regime should ideally lead to battery energy storage systems (BESS), or other flexible load or storage, locating in areas of the grid where they could be used to alleviate the impact of congestion. Currently, the ESB argues that the CMM is attractive as it has the potential to provide low locational marginal prices (LMPs) in an area subject to congestion, which could incentivise a battery storage system to locate there and therefore benefit from lower charging costs. The BESS would then act to utilise low cost energy that would otherwise be spilled. However, charging costs form just one part of the overall decision behind choosing where to locate battery storage.

One of the most important factors in assessing the preferred location for BESS is that a 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. Other issues such as land access and its costs, and charging resource availability when needed also play significant roles in the decision of where to locate a BESS. Introducing LMPs at times of congestion is not a panacea for many of the issues that the proposed transmission access reform is seeking to address.

Shell Energy still does not consider there to be a strong need to reform the current access arrangements. By and large, the market has solved the issues themselves, with new participants taking better stock of locational drivers as marginal loss factors and the presence of other generators when choosing where to build new generation. That said, there is certainly scope for further improvement in the area of market information provision and to encourage generators to invest in network augmentations.

Congestion zones with connection fee

As a whole, Shell Energy does not strongly prefer either of the two investment timeframe options. Indeed, there could be elements of the two options – transmission queue or connection fees – that could be combined into a single solution. In particular, we are supportive of the concept that a generator that has paid for physical network augmentation should be granted preferred access, either through an improved queue position, or through firmer access to CMM rebates, should the CMM be implemented. Our comments therefore reflect where we see that improvements could be made to the design that the ESB has presented.

Shell Energy proposed a locational connection fee model when the ESB called for alternative models earlier in 2022. We are pleased that the ESB has taken this input on board and used our proposal as a basis for the congestion zones with connection fees model. We still see that there could be benefits in a connection fee model if it encourages both existing and new generators to invest in network augmentations or limits the ability of new generators to increase constraints on existing generators.

The ESB's indicative design does stray from the intent of our proposed connection fee model in parts. The consultation paper suggests that connection fees could be set at high or low levels to either encourage or discourage generation in particular locations. In our view, connection fees should reflect the costs necessary to deliver the maximum level of congestion a generator is prepared to accept. In practice, this is likely to mean that in certain areas connection fees will be higher than in other areas if larger network augmentation projects are required, but if a generator determines that the total costs of a project including connection fee are efficient even in a relatively constrained part of the network, then that should be an acceptable outcome. Provided of course that the connecting generator's decision does not materially harm existing generators.

A well-designed connection fee model should not represent a central planner's view of where new generation should be built. Instead, it should give the commercial entities the capability to determine where the optimum coordination of generation and transmission exists. This may not be where a central planner considers it is. The willingness of the connecting generator(s) to pay a connection fee to facilitate network augmentation provides a strong signal as to where efficient connection locations exist. It also transfers the risk of poor locational decisions from consumers to the connecting generator(s).

Further, the consultation paper appears to suggest that connection fees may not necessarily be used for the purposes of actually delivering network augmentations, but instead could be used to reduce transmission costs for end users. The consultation paper states:

> *"If a connection fee model were adopted, it would be necessary to consider what should happen to revenue recovered from generators via connection fees. For instance, the revenue could be used to offset transmission use of service charges paid by consumers by funding transmission expansions contemplated in the ISP and selected via the transmission planning process."*[3]

While reducing transmission costs for end users would be a worthy goal of broader reform, our design was based on the premise that generators paying a locational connection fee would be directly funding transmission augmentation where requested. We acknowledge that there may be instances where a generator seeking to connect into a REZ could pay a connection fee which offsets some of the construction costs, but this would be relevant to the specific generator and transmission project rather than by virtue of the system's design. We consider that there are real risks to investors in implementing a system where a generator pays a connection fee but no network augmentation occurs as congestion will still occur – and perhaps even be worse. This would represent a poor outcome and would seem to be entirely contrary to the aims of this reform.

If connection fees are not used for augmentation such that existing generators are not negatively impacted, then we may end up with a scenario where a new generator is willing to pay a high fee to connect but their project constrains down existing generators. One of the key aspects of the investment timeframes solution is to provide greater certainty about transmission access when making investment decisions. If a project has paid a connection fee then it should have a strong degree of certainty over what they are paying for, in this case congestion risk (or lack thereof). To move away from this concept would undermine the whole point of these proposed reforms. It would create a situation like now where economic projects can be harmed by congestion brought about by subsequently connecting generators.

The situation could be exacerbated under the CMM depending on the exact design. If generators that have paid connection fees receive firmer allocations of congestion rebates (which would be a reasonable design choice), then where augmentation has not occurred, other generators would likely face a fall in their allocated rebates as there is more generation to share the same amount of congestion charges paid. This presents an

[3] Energy Security Board, *Transmission Access Reform consultation paper*, May 2022, p28

inequitable outcome, and one that is worse than current outcomes, as well as one that increases risks for generators.

The ESB queries how multiple generators seeking to connect to the same part of the network should be treated. Ideally, Shell Energy considers that the TNSP, and perhaps even AEMO, would have a role to play in informing the various parties and coordinating a scale-efficient approach that would allow multiple generators to connect. The Rules should be clear in this regard to remove any uncertainty that TNSPs and AEMO have an obligation to provide information and facilitate efficient network augmentation outcomes.

We consider that a well-designed connection fee model would factor in the kinds of technologies seeking to connect and the expected times of congestion in each part of the grid. For instance, a congestion zone with largely solar plants may be able to host a wind farm or energy storage without necessarily requiring significant transmission augmentation. Alternatively, a generator seeking connection at that location may agree to be constrained off during daylight hours when solar output is high in return for a low connection fee.

Transmission queue

Shell Energy sees a number of positive elements in the proposed transmission queue design. In principle, the notion that the last generator to connect is the first to be curtailed is a reasonable concept. However, as the consultation paper notes, once generator coefficients are taken into account, it would be exceedingly rare for a queue position to be used as a tie-breaker.

We also consider the ESB should correct some of the claims it makes around the impact of marginal loss factor (MLF) and generator coefficients. Generator bids as submitted are based on prices at the regional reference node (RRN). While prices may vary at the connection point, it is the price corrected by the MLF, at the RRN that is used to determine dispatch outcomes. The consultation paper states that "generator coefficients tend to determine who gets dispatched in the presence of congestion"[4]. While generator coefficients certainly play a role, there are several other factors including minimum stable loads and ramp rates that also impact which generators are dispatched at times of congestion. It is not so simple as to suggest that generator coefficients lead to "winner take all" outcomes.

There are two elements of the transmission queue that we consider represent strong design options for any investment timeframe option, and that could be combined with the connection fee model. The first is the use of a queue position as a factor in determining who is allocated congestion rebates under the CMM, should the CMM be implemented. The second element we see as a good design choice is the concept that a generator could improve its queue position by investing in network augmentation. This latter mechanism complements the connection fee model as it effectively rewards generators that contribute to improve the transmission network. Where a generator contributes to improve the capability of the transmission network to deliver energy to consumers, we consider the generator should be allocated a firmer position in the queue for allocation of congestion rebates. Shell Energy is certainly more favourable to an overall design that incentivises both new and existing generators to invest in augmenting the transmission network.

As with our comments of the connection fee model, it is not enough for a generator to simply pay to improve their queue position. Any payment must be linked to a physical network augmentation.

One potential downside of this option that we observe is the potential for a slow process when going through an expression of interest (EOI) and then an auction to receive a queue position. From a developer's perspective they would have to be ready at the point of EOI, then go through an administrative process to get a spot in the queue. If an auction is required further delays would occur. Developers would effectively be slowed down by

[4] Energy Security Board, op cit. p 15.

the pace of the decision-making process to allocate queue positions. This could lead to delays in building new generation and potentially higher costs to deliver projects. In contrast, the connection fee model is unlikely to lead to such delays provided that any payment is linked to a physical network augmentation to mitigate congestion. The queueing model could be improved by linking direct generator funding of network augmentation with allocation of queue position.

Congestion Management Model

The ESB has outlined the basic architecture of the CMM for some time, since it originally proposed the model. As such, we have little more to add on how it would operate. What is still unclear, and essential to understanding the impact of the CMM, is how congestion rebates would be allocated to generators. We note that the ESB has set out five potential options for allocating rebates, but the actual impact on generators remains unclear. We consider that there needs to be a comprehensive assessment of how each would operate in practice and the impacts of each model on existing and new generators. We welcome the ESB's commitment to exploring "the pros and cons of the various design choices for allocation metrics ...[and] how different allocation metrics might support efficient hedging arrangements in the contract market both now and in the future..." Shell Energy is extremely interested in the outcomes of this work and would be eager to participate in any industry working groups on the matter.

With respect to the rebate allocation options discussed, Shell Energy is firmly opposed to the concept of a centrally-inferred estimate of short run marginal cost (SRMC). Given that fuel costs can vary sharply – recent trends in gas and electricity prices are a good example of this – any estimate will invariably be wrong. It is also unclear as to how the SRMC for BESS, pumped hydro storage or standard hydro would be calculated. Linking market outcomes through congestion rebates, to inaccurate estimates of SRMC is likely to increase risks to consumers and lead to a reduction in the volume of contracts generators are prepared to make available.

We also thank the ESB for clarifying how generation from non-scheduled and semi-scheduled generation would likely be treated under the CMM. At the public forum on 26 May, the ESB indicated that semi-scheduled generators' availability would be set at the lower of the actual dispatched volume or the uninterruptible intermittent generation forecast (UIGF) value.

Shell Energy has also identified a range of issues with the notion of excluding peaking generators from congestion rebates if the regional reference price (RRP) is below $300/MWh. Firstly, it would require a methodology to be developed to designate what constitutes a "peaking generator". Then it assumes that a designated "peaking generator" would only generate at prices above $300/MWh and, by extension, that it limits its contract market activity to selling caps. In practice, so called "peaking generators" may make some volumes of swap or option contracts available at prices lower than the $300/MWh strike price for caps. Similarly, "peaking generators" may operate at lower prices to support a hedging position for a retail book. Further, the $300/MWh strike price is largely a historical artifact and may not be reflective of the cost to generate based on gas or diesel prices. In reality, it may be economic to generate at prices below $300/MWh, or conversely, it may not be economic to generate until spot market prices are higher.

By restricting some generators to receiving congestion rebates when the RRP is more than $300/MWh, a generator's flexibility to operate under a range of market conditions is reduced. Overall, we see the proposal as not in the best interests of the market at a time when the market is in transition. Output from gas/liquid fuelled generators, BESS, pumped hydro storage and standard hydro generators will be required to ensure reliable supply to consumers as coal fired generators retire and greater volumes of intermittent renewable generation are in the market.

As indicated above, the concept of restricting congestion rebates to certain types of generator also poses issues for how a "peaking generator" is defined. While this role has traditionally been played by gas-fired or diesel-fuelled generators and in more recent times batteries, coal-fired generators and hydro-electric plants may make some volumes available only at prices above $300/MWh. The continued rollout of grid-scale batteries and the potential for increases in demand response changes the nature of what has typically been known to be peaking generators. In the case of batteries, being able to charge at negative prices may mean that it is economic to dispatch at prices below $300/MWh, particularly when interactions with frequency control ancillary services markets are considered.

Shell Energy considers that the ESB should revisit the mechanics of how any limit on providing congestion rebates to designated peaking generators may apply, including which generators are classified as such, how demand response would be treated, and the bid stack of the generators at the time. Indeed, if a peaking generator has a volume of energy above minimum stable load bid in at sub $300/MWh prices then we consider it would be reasonable to allow for congestion rebates to be paid to volumes bid below $300/MWh (or alternative value).

The consultation paper is also silent on the allocation of congestion rebates to inter-regional settlement residue units. The Paper does suggest that implementing the CMM would remove the need for AEMO to manage negative inter-regional settlement residues at dispatch. Such an outcome could only be achieved where inter-regional settlement residues are allocated a portion of congestion rebates based on the LMPs of the node at which they connect in each region. Absent this, transmission use of system charges would need to increase to fund the increase in negative inter-regional settlement residues. The only other potential alternative to this would be that inter-regional settlement residue units would no longer reflect the price difference between the respective RRPs but would be changed to reflect only the price difference between the LMPs of their respective connection point in each region. Such an outcome would result in the inter-regional settlement residue unit being less effective for hedging inter-regional basis risk. Either of the outcomes indicated would in Shell Energy's view have a negative impact on the contracts market. We ask that the ESB provide greater clarity with regards to the allocation of congestion rebates to inter-regional settlement residue units.

One clear advantage of the CMM is that it can work neatly with either of the investment timeframe options in that the allocation, or firmness of congestion rebates can be linked to queue position, or paying a connection fee. Access to congestion rebates could also represent a fair return for what generators would receive for paying a connection fee or investing in transmission network augmentation to improve their queue position. As we have made clear already, this is contingent on any connection fees being used to augment the network and not simply as a fee to reduce overall network costs.

An area that remains unclear to Shell Energy is with regards to claims made in the Paper that the CMM will reduce costs to consumers via improvements in dispatch outcomes. In isolation, neither the CMM nor CMM will necessarily improve network flows to consumer loads. As such, they are unlikely to influence the regional reference price (RRP) outcome and settlement pricing to market customers for non-scheduled loads which will continue to be based on the RRP. While scheduled loads could benefit if they were located in an area of network congestion, LMP outcomes could also be high at times where a supply side deficit was present at that location. Such an outcome could occur where intermittent generation is the only supply side resource. It is therefore unclear to Shell Energy that claims set out in the Paper with regards to consumer costs are justified.

Overall, Shell Energy wishes to reserve judgement on whether the CMM is a preferable approach until we see the results of the ESB's work on allocation metrics. We recommend that this work form part of a broader assessment of the costs and benefits of the whole transmission reform approach to ensure that it will deliver value for the market and energy users.

Congestion Relief Market

Shell Energy is attracted to a number of the design elements in the congestion relief market (CRM). The notion of a voluntary market to reveal the value of congestion both to those who wish to be dispatched and those who agree to be constrained off is an appealing prospect. However, we share the ESB's concern about the implementation costs. We consider there would be significant initial and ongoing costs for ourselves, and other market participants, to upgrade systems to allow for bidding into the CRM for all possible constraints. In addition, systems would likely have to be updated regularly to take into account new constraints when they eventually emerge. Finally, we are concerned that requiring NEMDE to co-optimise for another market would lead to a further delay in the issuing of dispatch instructions which is already delivered late leading to market inefficiencies.

Finally, it appears to be more difficult to determine what benefits a generator would receive from either of the investment timeframe options if they were implemented alongside the CRM. Although the consultation paper suggests that generators with a higher priority queue position could be eligible to sell into the CRM, this appears to be a relatively weak incentive.

Overall, Shell Energy is unconvinced that the costs and complexity involved in establishing a CRM will outweigh the benefits it may ultimately provide.

Conclusion

At this stage, Shell Energy is reserving judgement on the choice of any particular mechanisms to address congestion, particularly in operational timeframes. We believe that a cost-benefit analysis is essential to giving market participants more information on the potential impacts of these reforms. As of yet, there has yet to be a comprehensive assessment of the costs of implementation and the benefits that these designs may bring. The previous assessment from NERA had flaws that over-represented the notional benefits that reform would bring. It is also essential that the ESB consider the impact of this reform on contracts markets. Deep and liquid contract markets underpin reliability of supply to consumers, healthy retail competition and efficient retail pricing for end users.

We do note that the ESB's decision to shift from a single-mechanism solution to a two-part solution is a significant and appropriate change. Using different mechanisms to provide incentives to address congestion at the investment and operational timeframes respectively is a positive step.

The two proposed investment timeframe options – congestion zones with connection fee or transmission queue – have a number of positive aspects that could improve signals to better locate new generation projects. In particular, Shell Energy supports the concept that generators who have funded network augmentations should benefit in some way. One potential benefit could be firmer access to congestion rebates under the CMM.

There are several design elements for all options that we consider need further examination. For example, we consider that under both investment timeframe options, funds received from generators paying either a connection fee or to improve their queue position should be used to directly fund network augmentation in those areas. We consider the ESB's suggestion that this revenue could be used to directly reduce TUOS costs for consumers could place higher risks on generators as it would likely reduce the funds available to other generators in a congested node. Where generators are incentivised to invest in network augmentation customers are likely to benefit from lower transmission costs as generators have paid for something that would ordinarily be paid for by consumers. Network augmentations are also likely to improve network flows, therefore improving reliability of supply for consumers. Without direct network augmentation, neither the CMM nor CMM alone will improve network flows.

Finally, we look forward to examining the ESB's work on examining different allocation metrics for congestion rebates and how they could support efficient hedging arrangements in contract markets. Shell Energy is prepared to work with the ESB to discuss this in more detail.

For more information on this submission, please contact Ben Pryor, Regulatory Affairs Policy Adviser (ben.pryor@shellenergy.com.au or 0437 305 547).

Yours sincerely

[signed]

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