6 June 2024

Jessie Foran
Australian Energy Market Commission
Level 15, 60 Castlereagh St
Sydney NSW 2000

Dear Ms Foran

RE: Transmission Access Reform

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Transmission Access Reform (TAR) 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 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 an active participant in the various consultation processes on transmission access reform, starting with the coordination of generation and transmission investment implementation (COGATI) review in 2019. We have engaged extensively with the AEMC and Energy Security Board over the past few years.

Overall, Shell Energy agrees that creating a locational signal for investors to locate generation in less congested areas would be a beneficial reform. It would deliver benefits through reduced congestion and reducing the total investment, including both generation and transmission investment, required to deliver the level of resources needed for the NEM to remain reliable and secure and reduce greenhouse gas emissions.

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[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.

Without a strong and easily understood locational signal, the NEM may repeat current outcomes where some generation has been poorly located resulting in zero market benefits, negatively impacting the previous investment decisions of other participants. These poor locational decisions have then resulted in calls for additional and often costly network investment to relieve generator output congestion, the costs of which are borne solely by consumers. Such an outcome fails to consider the total costs of generation and transmission investment with each considered in isolation from an investment decision perspective. This is a poor outcome for consumers.

We remain unconvinced of the need for a signal to improve locational dispatch efficiency signals in operational timeframes noting that this may not impact the wholesale and retail market prices paid by market customers. Although well intentioned, we consider that the proposed Congestion Relief Market (CRM) adds significant risk and complexity to the market and is likely to create significant costs, both initial and ongoing, for a fraction of the total benefits compared to a locational investment signal.

Ultimately, Shell Energy sees that whatever policy approach is chosen for TAR, it should be simple, low cost to implement and avoid damaging the contracts market. At this stage, we argue that the full hybrid model, consisting of the priority access model and CRM does not meet these principles, largely due to the cost, complexity and risks the CRM introduces.

The priority access model on its own would appear likely to deliver an improved locational signal to investors, depending on how priority access levels are allocated. We are concerned that based on the analysis the AEMC has conducted, it may be somewhat complex to implement the CRM given the nature of the National Electricity Market Dispatch Engine (NEMDE).

The key advantage of the priority access approach is that it provides a strong signal that earlier investments in generation will be somewhat protected against the risk of future congestion as either new investments connect, or new constraints emerge. That said, we also understand that there is a risk that new constraints may emerge that have not previously been forecast by the Australian Energy market Operator (AEMO) or Transmission Network Service Providers (TNSPs). Under the priority access model, future investors would bear all the congestion risk despite making their investment decision on the best information available at the time.

Shell Energy recognises the purpose of the locational signal provided by the priority access model is to ensure that the congestion risk is applied to the most recent generators to connect. Yet, in instances where new constraints emerge due to inadequate planning for or analysis of the transmission network, it appears that new generators face the consequences of the TNSP or AEMO's actions.

Shell Energy considers that there could be value in considering a simpler approach. This could involve giving TNSPs responsibility for forecasting constraints and assessing the network needs if a new generator wishes to connect. This process is similar conceptually to the recently announced Victorian Access Regime.[3] Prospective generators would then be allowed to:

- connect at a location with no change compared to the current connection process if no increase in congestion is forecast;
- connect with restrictions on their operation or with a clear description of the network augmentations the generator must implement to reduce congestion to an acceptable level; or
- be prohibited from connecting at a specific location.

TNSPs should also be responsible for remediating newly emerged network constraints if this was a result of inadequate or incorrect analysis, forecasting and planning.

[3] VicGrid, Victorian Access Regime, June 2024.

This would represent a significant change from the NEM's current open access regime, to a more 'controlled' access regime. Yet, Shell Energy considers this could be implemented relatively quickly – with appropriate guardrails to avoid 'gold-plating' of the network – and with very limited costs to improve certainty of connection and congestion risk for both existing and new resources.

The submission that follows contains Shell Energy's responses to specific design option questions raised in the consultation paper. For more details, please contact Ben Pryor, Regulatory Strategy lead (ben.pryor@shellenergy.com.au or 0437 305 547).

Yours sincerely

[signed]

Libby Hawker
GM Regulatory Affairs & Compliance

Shell ENERGY

Priority access allocation models

Shell Energy favours Option 1, grouping new entrants by time window with incumbents at the highest priority level. We consider this provides the clearest and least risk signal to discourage investment in already congested areas.

While we acknowledge the desire for Renewable Energy Zones (REZ) to also have highest priority access as set out in option 2, we consider there is a risk that this could result in unintended consequences. Subject to the specific structures of REZs, it is possible that a new REZ both within and in different states could result in increased constraints both within and across states. A new REZ allocated a higher level of priority access compared to Option 1 could simply curtail the access of previously connected REZs and existing resources. This would then punish generators in a REZ that connected to the grid earlier. It could also result in state governments declaring REZ areas for the purpose of giving connecting generators in that new REZ higher priority in the dispatch queue. This would be an inefficient outcome that would simply increase costs to consumers.

Option 3, which would allow AEMO or jurisdictions to determine which generators should be prioritised exposes investors to too much sovereign risk. We consider there to be a genuine risk that such an arrangement could result in governments using priority levels to favour certain technologies and would be subject to change following elections. Although it could be considered that a model with two classes of either prioritised or de-prioritised generators is conceptually simple, the practicalities of allowing factors other than the date of connection to influence the order is concerning.

Finally, option 4, with its dynamic grouping model would in our view not provide increased benefits in terms of increased certainty to investors when compared to option 1. Also, the fact that it is likely to be more costly and complex to implement, will require multiple NEMDE solution runs to solve, potentially impacting the NEM dispatch process, as well as being untested as part of the previous TAR work indicates that it should not be pursued further.

CRM implementation approach

Shell Energy does not see the net benefits of a CRM as we consider it will add significant complexity, risks, and costs. If CRM is to be implemented, Shell Energy strongly supports the two-stage dispatch model (noting we are largely unconvinced of the need for the CRM). We consider that maintaining the Regional Reference Price (RRP) in its current format is critical to ensuring contract market liquidity is supported. Any change to the calculation of, or structure of the RRP risks creating a need to renegotiate existing contracts and creates risk in the market. If generators are uncertain of the impact this may have on price and dispatch, then it may make them less likely to offer contracts into the market at the same levels as currently.

We consider that transparency and understanding of outcomes will be key incentives in participants' decision to participate in the CRM market. In our view, the two-stage dispatch and pricing process will be less harmful than the alternative proposed singe stage co-optimisation process as it offers more transparency and will assist building confidence in participants with regards to the CRM being able to provide stable and certain dispatch and pricing outcomes.

We disagree with the AEMC's assessment that a co-optimised energy and CRM dispatch is similar to the co-optimised Frequency Control Ancillary Services (FCAS) markets. The optimisation feature of the co-optimised energy and FCAS markets dispatch is that it ensures that generators have sufficient headroom and footroom available to manage changes in frequency while still maintaining adequate energy market dispatch. This therefore helps to maintain both system security and reliable supply to consumers.

In contrast, the CRM does no such thing. The purpose of the CRM is to enable generators (or load) to trade congestion relief by either agreeing to generate less than they otherwise would (or a load to consume more) within a local congestion pocket to allow another party to generate more. Its primary purpose is therefore to utilise energy that would otherwise be spilt, at the efficient price.

The AEMC argues that the CRM will improve dispatch efficiency to near short run marginal cost (SRMC) theoretical levels. However, this fails to factor in a number of issues regarding bidding and dispatch which includes factors other than simply volume in price bands. Generators will need to consider ramp rates, offers for FCAS as well as offers for essential system security services (in the near future), and any instances of intervention pricing in the market at the time, all of which will move dispatch away from the theoretical SRMC levels. The CRM if implemented will add significant complexity and costs to the management of bids and rebids in the NEM for what we estimate will be at best only a marginal improvement in dispatch efficiency.

Further, we question how a price set in the CRM could be used to set either a regional energy or CRM price. The design of the CRM is such that, in order to create the efficient price, it must create a local price for energy in each sub-regional congestion pocket separate to the RRP. Given that multiple sub-regional congestion pockets can exist at dispatch, each of which can only have a distinct efficient price outcome, we are unable to determine how the proposed co-optimisation process could calculate the efficient RRP or regional CRM price. The only reason that price exists is because a generator is willing to generate less (or a load to consume more) when a local constraint exists. We therefore fail to see how a co-optimised approach could work in practice across an entire region.

If CRM is to be implemented, it can only claim to provide market benefits via a two-stage dispatch and pricing solution; the first to calculate the efficient dispatch and RRP based on the current dispatch and pricing framework and the second run to enable CRM trading and dispatch at the efficient sub-regional or locational (CRM) price.

Feedback on impact of hybrid model

Power Purchase Agreements (PPA)

Shell Energy considers that the AEMC's assessment of the risks of the hybrid model on PPAs is largely sound. That said, we believe the AEMC is somewhat optimistic in assuming that the impact is limited if the hybrid model is implemented in 2028. While many PPAs may end in 2030 with the end of the Renewable Energy Target (RET), the AEMC does not have visibility of the terms of PPAs and as such, it is uncertain the extent to which implementing the full hybrid model could affect them.

Some parties may be able to come to agreements with respect to how to treat the implementation of the TAR hybrid model. Yet others may wish to re-open contracts, particularly if there is a strong benefit to one party. In general, participants would prefer not to resort to renegotiating contracts as a principle. Shell Energy considers that adoption of only the Priority Access component based on the Option 1 framework, or our suggested controlled access model, where access would be determined based on pure chronological order of resource project entry would limit the impact on existing PPAs as existing and committed resources would all be allocated the same access as the current market.

We recommend that the AEMC continue to undertake analysis on the interaction between PPAs and CRM participation prior to any decision to proceed further with the proposed TAR framework.

Financial markets

Throughout our engagement on TAR, Shell Energy has strongly argued that financial markets need to be supported and that any reforms that may reduce contract market liquidity should be avoided.

Retaining the existing structure of the RRP appeared to be designed to maintain the signals for contract markets and reduce risks to contract market participants. We are concerned that the AEMC again seeks feedback on an alternative approach that would redesign the way the RRP is set. This would have a significant negative impact on contract markets, and could result in participants making lower levels of contracts available. Also, only the Priority Access Option 1 model in our view has the potential to retain incentives for the ongoing provision of firm contracts. Options 2 to 4 introduce uncertainty and unmanageable risks to participants which will flow through as lower levels of available contracts and/or increased contract prices.

Similarly, the impact of the CRM is unlikely to be positive for financial markets. Where there is added complexity, uncertainty or risk – which we believe would be the case in the early stages of the CRM, or if the co-optimisation dispatch and pricing model is implemented – participants are likely to take a risk averse approach and avoid selling contracts to the levels they do today. This would have significant impact to retail pricing and competition, particularly for non-vertically integrated retailers.

We encourage the AEMC to exercise caution when considering the potential impacts of the TAR hybrid model and its individual components and implementation options on financial markets.

Wide reaching constraints

The AEMC sets out that some stakeholders have proposed that certain constraints should be excluded from prioritisation because it places the congestion risk on new generations rather than sharing the risk.

Shell Energy takes the view that because the precise purpose of the priority access model is to introduce a form of locational signal via imposing congestion risks on new entrants, there is no reason to exclude certain constraints from prioritisation. Doing so would weaken the signals to locate new investments in less constrained parts of the grid.

We recognise that in some instances, new constraints may emerge due to incomplete analysis or insufficient planning on the part of the TNSP or AEMO. In these cases, we consider it reasonable to share the risk of such constraints. This is because a participant may have acted in good faith in locating in an area of the grid without existing or forecast constraints only to be faced with the full risk of constraints at a later time due to circumstances outside its control. Indeed, this is the very driver for transmission reform.

In our view, it is a reasonable policy principle that risks are best placed on those with the capability to manage them. As such, where an unforecast constraint exists due to insufficient analysis or inadequate planning, there is a strong case to exclude such constraints from prioritisation and/or alternatively to make the party responsible for the error take action in the form of remediation of the technical issue or compensation to the affected participant(s).

Other design elements

Shell Energy supports the ESB's previously reached positions that incumbent generators should have highest priority access for the technical life of their asset. Such an outcome would include where the life of an asset is extended due to an agreement negotiated with government such as the proposed Orderly Exit Mechanism. Similarly, we also agree with the design choice that once a generator reaches the highest priority level, it retains that level for the technical life of the asset. We support technical life being determined by the owner of the resource, such as aligned to a generator's notice of closure date, as opposed to this being assessed by an external body such as AEMO determining the technical or economic life of the plant.

We also continue to support a framework where a participant may choose to fund a network augmentation that delivers a real increase in transfer capability across the transmission network to consumer load in return for allocation of the highest priority access position. We consider that such a framework provides the highest probability of optimising generation and transmission investment as the total costs of a project is considered in the investment decision. It is unclear to us why such a clear efficiency choice has yet to be definitively considered by the AEMC to date in this review process.