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Dear Commissioners,

AEMC 2019, Co-ordination of Generation and Transmission Investment – Access Reform, Discussion Paper

EnergyAustralia is one of Australia's largest energy companies with around 2.6 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, solar and wind assets with control of over 4,500MW of generation capacity in the National Electricity Market (NEM), and we are committed to developing new assets required to continue supporting a reliable, affordable and sustainable electricity market.

We thank the Commission for developing, and provider greater detail, on the design of the proposed reforms.

We agree with the Commission's view that changes are needed to the regulatory framework to support investment in generation and transmission. It appears that most market participants and stakeholders also hold this view. However, we do not believe that the market supports the reforms as proposed by the AEMC, and in particular the pace with which industry are expected to understand and adopt the reforms. We think that the process the AEMC has outlined poses a great risk to market investment, to the detriment of customers. The priority for the AEMC during the market transition should be to support investment in the sector, while ensuring consumers are protected from unnecessarily high costs. In the context of other reforms being implemented (5 Minute Settlement[1]), or expected to be implemented within the timeframe (Demand Response[2], Consumer Data Right[3], ESB's 2025 Market Design[4]), we strongly encourage the AEMC to take an orderly, staged approach to this reform. This would involve taking incremental steps along the path to major reform, allowing market participants time to digest and adjust to the changes. An implementation date of mid-2022 for the reforms is not realistic. Instead the AEMC should consider less complex changes that can be initially made to address key concerns, meanwhile continue to assess and develop the proposed major reforms.

[1] https://www.aemc.gov.au/rule-changes/five-minute-settlement
[2] https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism
[3] https://www.accc.gov.au/focus-areas/consumer-data-right-cdr/energy-cdr
[4] http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-national-electricity-market-nem

Substantial investment in the market is required and large, complex changes to the regulatory framework are likely to be an impediment. While the AEMC has highlighted that other jurisdictions have similar access frameworks that operate well, this argument fails to acknowledge the transitional period will be challenging and may serve to hinder the transition to a new generation fleet, rather than assist.

Stepping stone alternatives towards ESB 2025 market reform

Over the course of the extended consultation on these reforms, the AEMC has identified numerous problems the current market design poses for market efficiency and investment appeal. These include:

- On-going generation investment in areas that are congested;
- Efficient, appropriately located and timely investment in transmission infrastructure;
- Disorderly bidding (bidding unavailable, race to the floor, increased directions);
- Inefficiency of MLF used in dispatch processes;
- Inefficient dispatch signals for storage;
- Inability for generators to invest in deep and shallow transmission and to co-invest in system strength remediation;
- Uncertainty in future MLF and congestion;
- Efficient incentives for network outage timing;
- Network concerns over changes to rate of return and ability to manage balance sheets due to SRAs.

As we have highlighted in previous submissions, the AEMC are seeking to address a range of issues, not all of which are significant or a priority to resolve. The intent of the reforms is to improve co-ordination in investment between generation and transmission, but it remains unclear how addressing disorderly bidding, or network return concerns are either a priority or related to co-ordination in investment.

It appears that the reforms are focussed on addressing operational inefficiencies in dispatch, with the objective of subsequently addressing long run inefficiencies in locational investment decisions in both generation and transmission. Instead it may be the case that generation is simply penalised for its location, with an inability to respond to the operational price signal it is receiving. Further, it is possible that fleeting congestion will be interpreted as a constraint that needs to be addressed with transmission investment that comes at a very high cost to customers. It is not clear that the reforms provide a stronger signal to transmission businesses to build and we welcome comment from both AEMO and network businesses on how they will utilise this information in planning. In particular we would like to understand whether there will be incentives to invest in low capital cost solutions to alleviate congestion, such as innovative run-back schemes and application of dynamic ratings, rather than expensive capacity increases.

We suggest the AEMC, in their final report, highlight the key issues affecting investment coordination and seek solutions to address these that are simple and fast to design and implement.

- For the most part, it appears that improvements to transmission investment will be made through the Actioning the ISP paper (although final details of this reform are not yet known so it remains unclear how creating locational price signals will contribute to improved signals for transmission investment).

- Efficiency in network outages could be addressed with reform to the existing incentive scheme.

- The AEMC consultation process on MLFs could be used to address deficiencies. Issues with MLFs can be addressed on their own merit and shouldn't be used to justify dynamic locational pricing.

Should the AEMC choose to focus on resolving operational dispatch inefficiencies, we suggest that this could be achieved in the short term with less complex reform described below.

Improving efficiency of Tie-breaking outcomes

A simpler approach to resolving this concern would be to introduce locational pricing without FTRs and with settlement residues allocated on an availability basis. This approach will not change locational investment incentives, but it will address disorderly bidding problems associated with winner takes all outcomes and disorderly bidding, driving more economically efficient bidding and dispatch outcomes.

Improving tie-breaking outcomes with locational element

An approach to providing locational signals within tie-breaking would be to determine dispatch based on connection time. In other words, the most recently connected generator would be dispatched last. This would serve as a locational signal not to invest in areas that are likely to be congested and face tie breaking outcomes. This approach presents a very clear barrier to entry for new assets, but these barriers only exist in areas that are congested, encouraging investment in other parts of the network. The changes would need to consider existing assets as equivalent in terms of connection date. This proposition needs further development and consideration.

The investment challenge

EnergyAustralia, using published AEMO data, estimates that at least $155 billion will be required to over the next 20 years to transition the infrastructure in the NEM. EnergyAustralia will be a significant contributor to this investment. With the third largest customer base in the NEM and over 1600 MW of retiring generation expected in the next 12 years, we are actively exploring investment in projects that will provide the firm and reliable energy that is needed to supply our customers.

We do not consider that these reforms will make investment decisions easier by providing greater confidence in likely outcomes, rather the proposals are increasing uncertainty and the complexity of assessing investments and creating an additional barrier to investment.

While the AEMC supposes that the reforms will provide market participants with greater revenue certainty, we are not yet able to ascertain if this is indeed the case. The reforms contain several significant conceptual changes to the status quo that will take some time to understand and a consultation period of four weeks is indicative of a desire to implement the changes rapidly rather than well. These major changes include changing the regional reference price to the VWAP (Volume Weighted Average Price), introducing local pricing for generation, and introducing FTRs (Financial Transmission Right) with uncertain costs and returns. The restricted time provided for analysis, the complexity of the reform, and lack of quantitative analysis to date mean that we are unable to digest the changes and form a strong view as to whether the reforms do indeed provide greater market certainty for investors in future.

It may take many years before participants are able to invest with confidence into the new reforms. Implementation will generate a great deal of uncertainty as participants wait for the reforms to be developed, work through the details, implement, experience the first few years of the reform and learn how the market will perform, behaviour of participants. It could be up to a decade before the market has true confidence in the changes.

Investing in the current market is challenging, and making rapid changes to the framework is likely to erode confidence in the market. While the reforms may be more economically efficient from a theoretical perspective, this has yet to be demonstrated and it is a leap of faith for participants to trust that it will improve market outcomes. We think the AEMC could better support the market by considering reforms it could implement in the short term to address key issues that serve to support investor certainty, rather than undermine confidence.

Changes in risk exposure and ability to predict the future

The AEMC has dismissed industry concerns that the reforms will increase risks as a 'misconception' about the design. We maintain our view that these reforms will increase risk.

Generators currently have a transmission capacity risk that they do not have guaranteed dispatch. The proposed reforms do not alleviate this risk through the provision of FTRs as these are either not firm or not sufficiently abundant to provide cover for all generation load.

Under the proposed reforms participants will face the uncertainty of their ability to procure sufficient FTRs in future to avoid being exposed to extreme price risks as this will depend on auction outcomes. While the design of the reform may deliver FTRs that can be considered more or less firm, it will not be possible for all market participants to secure firm rights as the volumes sold will be set conservatively in order to achieve that high degree of firmness. Further, arbitrage related purchasing, which drives liquidity, could further affect the ability of generators to secure firm rights for their entire capacity. This means that some generators may be exposed to basis risks for a portion of their capacity. Uncertainty regarding future exposure will attract either a risk premium in financial contracting or lead to reduced number of financial contract offers, both of which will drive an increase in wholesale prices.

As a consequence, the existing volume risk becomes volume and price risk which is inherently riskier when managing a hedged position.

To illustrate this issue, consider a situation where the probability of a constraint binding is 10%. For illustrative purposes, every time the constraint binds a generator's output is reduced by 10% and that the local price (P_L)becomes zero).

The below chart compares expected revenue in a given interval under the existing and proposed regulatory environments.

- Under the current framework, the expected reduction in revenue compared to a situation where dispatch is guaranteed to due to sufficient network capacity is 1%.

  Where reduction in expected revenue ($P * \Delta Q$) is calculated as:

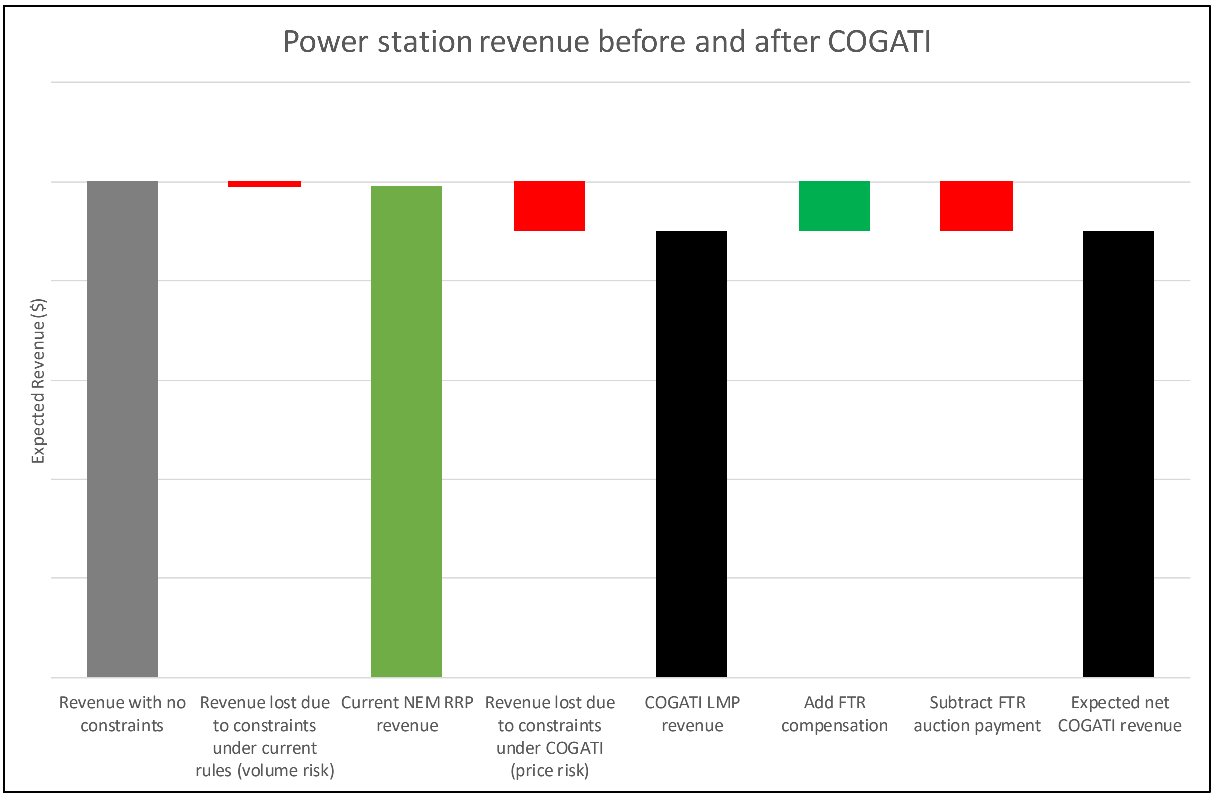
  $$P * \Delta Q = P * (10\%\ chance\ of\ constraint * 10\%\ reduction\ in\ load)Q = 1\% * PQ$$

- Under COGATI, the expected reduction in revenue compared to expected revenue with guaranteed dispatch (no constraints) is 10%:

  $$1 * (P * Q) - [(0.1 * P_L * Q) + (0.9 * P_R * Q) = 10\% * PQ$$

This ten-fold decrease in expected revenue translates to higher risk for generators.

With the addition of FTRs to manage this risk, there is no change to expected revenue as the FTR compensation and auction payments are equivalent. This is because participants would be expected to pay up to the expected payout from the FTRs i.e. their value.



A key selling point of the reform is improved certainty for investors. Currently, investors face the uncertainty, and challenge, of forecasting congestion and loss factors for transmission associated with their assets. The reforms will instead require AEMO to forecast whole of system capacity limits and constraints to set parameters for the auction.

Dealing with new modes of congestion that appear in operations that can't be effectively priced ex-ante is a critical concern as it appears the auctioned FTRs will only encompass constraints *currently* in AEMO's dispatch engine (at the time of the auction). This could exacerbate inefficiencies and risk premiums due to inefficient FTR allocations; if capacity sold in early auction rounds becomes an overallocation due to the emergence of new constraints, it appears that AEMO will be required to incorporate this inefficient allocation within subsequent auction rounds, essentially 'baking in' the inefficiency. This is particularly pertinent for non-locational based constraints which cannot be mitigated by efficient locational investment decisions.

Market participants will also need to forecast possible outcomes when seeking to optimise their risk profile and determine their value of hedge products. AEMO and TNSPs will need to share and release Operations and Planning Data Management System (OPDMS) snapshots and contingency analysis to help industry understand and analyse congestion risks, including complicated volatile and non-thermal constraints. It appears that all market participants will need to become power system specialists to participate successfully in the auction process.

Aside from the increased complexity, we query whether these forecasts are likely to be materially more reliable, and less volatile, than current forecasting requirements. Arguably the need to purchase an FTR is a larger risk than the risk of miscalculating an

MLF forecast. Due to the opacity of likely outcomes, particularly in the first few years of auctions, we anticipate there will be much higher risk associated with investment. Despite best endeavours to produce accurate forecasts, the occurrence of non-credible, unforeseen outcomes, or delays in new transmission build, will introduce new risks for generators, who face these risks now but will now face both price and volume risk, rather than just volume risk, as illustrated above, which they cannot control or manage.

Further, the reforms will not be economically efficient. AEMO's determination of the level of capacity to auction will lead to economic deadweight losses if it over or under forecasts capacity. An over forecast will result in excess hedges being available, that then become less firm. An under forecast will result in an inability of generation to access the efficient level of FTRs. While economic losses exist within the current market framework, the materiality of these losses compared to the materiality of losses under the proposed reforms have not been well demonstrated.

It is also not clear how AEMO or transmission networks will be incentivised to improve the quality of their forecasts. Generators and customers instead face the risks associated with systemically inaccurate forecasting.

Consultation and Implementation timeframe

Without a staged and orderly process, the current timeframes proposed by the AEMC are unrealistic and likely to lead to consumer detriment.

As we have highlighted in previous submissions, the interaction with the implementation of 5-minutes settlements and as-yet-unknown changes arising from the ESB's 2025 review have not been adequately addressed.

Overlapping implementation timeframes will introduce complexity in system design, build and testing. Market participants will need to manage successive system changes and multiple testing environments based on different sets of market rules and different points in time. For example, to start designing changes for COGATI in 2020, participants will need to have visibility of their expected system landscape when the rule commences in 2022. However, this might not be known until late 2021 when design work for Demand Response reform is completed. Further, the test environment for COGATI in 2021 will need to reflect the system changes made for 5 Minute settlement and Demand Response, but these will not have been completed. It is not clear that industry will have sufficient capacity to manage this incredibly complex timeline of successive and overlapping reform.

Industry resources are currently employed to develop the changes required for 5-Minute Settlement. These resources will be engaged until mid to late 2021 when the changes are completed. We anticipate that further resources will be concurrently required to implement Wholesale Demand Response[5], Consumer Data Right[6], Embedded Networks[7] and the ESB 2025 reforms[8] . Resources for technology system development, change management and market analytics will be needed to prepare for the changes.

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[5] https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

[6] https://www.accc.gov.au/focus-areas/consumer-data-right-cdr/energy-cdr

[7] https://www.aemc.gov.au/market-reviews-advice/updating-regulatory-frameworks-embedded-networks

[8] http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-national-electricity-market-nem

We suggest that the implementation timeframe for COGATI is better integrated with the changes proposed by the ESB. This will allow the ESB to consider the interaction between its recommendations and COGATI and propose an orderly, staged coherent roadmap to reforming the market. The required changes to NEMDE alone, to implement the VWAP, should not be underestimated.

The impact of a short transition period on existing contracts also needs further consideration and the AEMC should exercise caution in this space to avoid market disruption and chaos. Changes required to financial contracts and long-term purchase agreements that have already been executed using the regional reference price could cause larger changes and market chaos than anticipated.

Finally, The AEMC's haste to work towards implementation is also hampering industry's ability to understand and assess the reforms. The design of the proposal has shifted with each consultation paper and many details are as yet unknown. Notwithstanding consultation next year on the rule change, this is our last opportunity to provide feedback before a recommendation is made to COAG. It would therefore be remiss of the AEMC to make strong recommendations to COAG about a reform design that industry has not had adequate time to assess, and which does not yet have any quantitative information to support its intent. Industry staff with deep expertise in energy markets have struggled to interpret, understand and explain the principle design and whether it is workable, and the lack of industry understanding puts implementation at risk.

The consultation process has also revealed compromises in the design that must be made, which weaken the usefulness and consistency of the reforms and create additional complexity and coherence issues. For example, the VWAP has been adopted to incorporate locational attributes of non-scheduled load due to the decision to not implement full nodal pricing (which raised doubts around residue sufficiency), and the measures discussed for mitigating potential market power issues reveal an inherent weakness in the model that requires a discretionary intervention to manage.

Quantitative Analysis

We are very supportive of the AEMC's proposal to undertake quantitative analysis of the proposed reforms. This will be integral to giving industry confidence in the benefits of the reform.

In particular we strongly support the use of paper trials and quantitative analysis on the sufficiency of the settlement residue fund administered by AEMO, and the sufficiency provided by different levels of conservatism when setting the total volume of FTRs available. As we have previously stated, the AEMC needs to quantify the magnitude of the costly dispatch outcomes highlighted in the discussion papers such as the costs of directions to ensure reliable energy supply due to generator bidding behaviours.

The AEMC should also support AEMO and transmission providers to conduct backcasting exercise over the past 5 years at least, to assess whether forecasting accuracy is acceptable. The Commission should also consider conducting ex ante forecasts over the next year that are assessed against observed outcomes, prior to implementing the reforms.

In particular we think it is important for the AEMC to conduct analysis on the sufficiency of the settlement residue fund administered by AEMO, and the sufficiency provided by different levels of conservatism when setting the total volume of FTRs available.

Comments on detailed design elements

Given the timeframe for response, we have provided limited comments on the design presented by the AEMC.

- Further work is needed to assess the impact of real-time dynamic Marginal Loss Factors (MLF) on the practical process of bidding. As the MLF moves, entered bids could be rejected by AEMO for exceeding the bounds of the reliability settings (higher than market price cap or below market price floor). Will a change in MLF be allowed as a valid rebid reason? Rebids could be required every 5-minutes to manage continuous changes in MLFs.

- The AEMC has indicated that generators may have their quantity of FTRs purchased to their generation capacity. How will a retailer's quantity be set?

- The AEMC has suggested that the allocation of FTRs is made public. We consider this to be inconsistent with the contracting market and a release of commercially sensitive information. Should oversight be required, it may be appropriate for the AER to have access to this information, but it is unclear why information needs to be made accessible to the public.

- The reform could be simplified by identifying a subset of nodes that are likely to be congested and introducing trading around these nodes only, using a minimum materiality threshold on connection paths.

- Can the AEMC clarify if it will be possible to transfer FTRs to another entity bilaterally without needing to release them to the auction process?

- When considering options for making the FTRs firm, did the AEMC consider the approach of scaling up the VWAP?

- We disagree with the view that market power issues won't emerge. Aside from manipulating market prices in the short term, participants could manipulate the market over the long term; by generating at low levels for a period the value of FTRs may be reduced, the generator could purchase these hedges and subsequently bid to generate at capacity, substantially increasing the value of FTRs. This could be become cyclical by not purchasing the subsequently highly valued FTRs and then running at minimal levels, undermining their value.

- Further details on the changes to the transmission congestion financial incentive scheme are needed to assess whether transmission businesses face appropriate consequences for both forecasting adequacy and construction delays, both of which place uncontrollable risks on generation businesses.

- How will local price for a generator that appears in two or more constraint equations that bind simultaneously with different marginal values?

- The inclusion of Time of Use FTR unnecessarily complicates the auction process and will be expensive to assess and administer. These appear to be a solution to stakeholders who are concerned they will need to purchase hedges to cover 24 hours of congestion when they only need to manage the risk for a period of time. Unless there is systemic congestion occurring in different time periods on the same infrastructure, it is likely that the value of the TOU FTR will equate the value of the FTR over a 24-hour period.

Conclusion

We recognise that market reform is required to support ongoing investment in the NEM.

We do not yet have confidence that the reforms will support investment, or that potential cost increases due to increased complexity have been adequately considered. The AEMC has dismissed industry concerns regarding market uncertainty but has not yet provided sufficient evidence to support its position.

While the reforms proposed by the AEMC may have merit, the costs and risks of transition need to be given greater consideration. A short implementation period poses significant risk to the success of both system implementation and on-going investment.

It is important that change is orderly and supports, rather than undermines, investor confidence. We recognise that the AEMC will conduct quantitative analysis in 2020 and we welcome the contribution this information will make to the discussion of these reforms.

In the meantime, we think it is irresponsible for the AEMC to make any strong recommendations to COAG regarding the reforms before the benefits case has been demonstrated and while stakeholders have reservations about the efficacy and suitability of the reforms.

If you would like to discuss this submission, please contact Georgina Snelling on 03 9976 8482 or Georgina.Snelling@energyaustralia.com.au.

Regards

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