EnergyAustralia
LIGHT THE WAY

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

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Mr John Pierce
Mr Charles Popple
Ms Michelle Shepherd
Ms Allison Warburton
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Lodged electronically: www.aemc.gov.au (EPR0073)

Dear Commissioners,

AEMC 2019, Co-ordination of Generation and Transmission Investment – Access Reform, Directions 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.

EnergyAustralia welcomes the publication of the Directions Paper, and the Commission's consultation to date. There is no doubt this reform to the access framework has ambitious objectives and a complex implementation path, so we encourage the Commission to continue to discuss options with industry transparently and cooperatively, particularly during this period when significant transmission and generation investment is being considered.

We agree with the Commission's overall objective to drive better coordination between generators and network businesses when making investment decisions and support the AEMC's efforts to adopt a market-based approach to achieving this coordination.

The transition to a low-carbon future has introduced new risks to investment, due to the rapid volume, and rate, of development that is required. The Co-ordination of Generation and Transmission Investment (CoGaTI) review has implicitly raised discussion of which parties should bear the risk of this investment being inefficient; generators, network businesses or consumers.

A principle recognised by the Commission is that risks should be borne by those best able to mitigate them, as this should result in efficiently costed risk management. This implies that customers, generators and network businesses could bear some of the risks, to minimise inefficient investment in future transmission or generation.

In the current open access market, generators directly bear the risk that they could be constrained off at times of congestion and/or suffer unfavourable changes in their Marginal Loss Factors (MLFs), while customers indirectly experience the consequences through increased wholesale price outcomes. These are credible and genuine risks that sophisticated investors in the energy market expend resources to assess when making an investment decision. The information required to assess this risk is provided in MLF and detailed constraint and network data produced by AEMO and Transmission Network Service Providers (TNSPs), but also sought by investors through independent MLF and congestion modelling that utilises information known about other investment plans. For this analysis, AEMO's recent efforts at enhancing information provided to participants about market developments (including ISP assumptions and datasets and information about connection enquiries)[1], and the Commission's draft rules for increasing transparency of new projects[2] will provide greater support to generators making investment decisions.

It is not clear in the current, or proposed, regulatory arrangements whether networks bear risks of their investments being inefficient and the benefits not being realised.[3] Once a regulated investment is approved, the networks recover the costs, regardless of whether the benefits case ever materialises. This shifts all risk to consumers, with none borne by the network business who are ultimately making the investment decision. The CoGaTI reforms seek to shift some of this risk to generators, but it is not clear that generators will make different locational decisions, or if this will simply increase costs for investors, possibly reducing appetite for investment.

If the objectives of this reform are to encourage coordination, then we encourage the Commission to consider the broader implications of the risk allocations; how they currently fall in the electricity supply chain and whether they are economically efficient. Is the objective to make generators take on more risk, or to protect assets from future congestion?

The Commission consider that the volume risks, currently faced by generators, and the price risk, introduced by the proposed reforms, are comparable and that the provision of transmission hedges will improve a generator's ability to manage their risk. We disagree with this assumption. Further, it is not yet clear how the funds generators spend on purchasing hedges will translate to building appropriate infrastructure that reduces congestion. Consequently, the transmission hedges serve to impose additional costs and complexity on generators, without clear evidence of benefits arising from reduced risk. The reforms are likely to make investment decisions more costly and more complex, dampening investment signals rather than supporting them and potentially acting as a barrier to entry. The complexity will also create a risk that investment decisions are made by those that do not fully appreciate the nature of the risk they are undertaking. While the market is inherently complex, there is a limit to the level of complexity that can be managed before there are adverse impacts on investment.

Without knowing more details about the proposed pricing for hedges and how these relate to planning and deterministic physical transfer capacities across the network, it is extremely difficult to assess how purchasing transmission funds will lead to appropriate infrastructure investment that reduces costs. If the cost of hedges is large enough to underwrite transmission, these costs are likely to be significant relative to the costs of

[1] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps
[2] https://www.aemc.gov.au/rule-changes/transparency-new-projects
[3] As was the case prior 2008 when TNSP's individual investment decisions were subject to ex-post capex reviews based on benefits realisation, regardless of whether they overspent their regulatory allowance. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/statement-of-principles-for-the-regulation-of-transmission-revenues-december-2004

the generation build, tempering appetite for investment. If it is not sufficient to cover transmission costs, and reflects a token contribution toward build, this just becomes a penalty on generators that does not necessarily translate to firmness of a position or reduced risks.

We are not yet convinced that the extent of the reform proposed by the Commission will be a cost-effective means to addressing the true needs of the future market and have concerns that some elements of the proposed design may have perverse unintended consequences. The Commission must be clear on its objectives and must conduct rigorous analysis of the benefits and costs of each element of the reforms against these objectives. Further, it is challenging for industry to comment on the package of changes due to the significant differences between the Consultation Paper and the Directions Paper, and the short timeframe for response. This submission outlines our views on the key objectives for access reform and highlights our concerns with the currently proposed design, identifies areas requiring further policy design work.

We note that there are still many areas of design that are yet to be considered, which presents a challenge in assessing the merits of the reforms against the stated objectives. We are keen to continue to work with the Commission on these details through its ongoing rigorous consultation process. To do this properly takes time, and it needs to reflect the other significant changes in the market.

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

Regards

Sarah Ogilvie
Industry Regulation Leader

1. **Investment in dispatchable generation and risk management**

A key focus for the AEMC should be to ensure regulatory frameworks provide appropriate signals and support for investment that is needed in the future. EnergyAustralia sees that the fundamental features of the future system will be capacity that is dispatchable, and is able to also provide increasingly important system services such as inertia, frequency response and voltage control to help balance a NEM with much higher penetration of intermittent generation.

There has been significant investment in non-dispatchable plant, supported by government schemes such as the Renewable Energy Target (RET) and Clean Energy Finance Corporation (CEFC), however, this type of generation alone does not necessarily provide reliability or system support services. To address this gap, investors now need to focus on providing a mix of dispatchable and intermittent energy capacity. The proposed COGATI reforms could undermine this investment, for both existing and proposed assets. In our view, given current information on the design of the reforms, the conceptual transmission hedge products described will not provide a sufficient financial hedge to match the uncertainty created by the dynamic nodal price.

We are particularly concerned with the Commission's suggestion that transmission hedges will provide market participants with an adequate risk management tool to manage the price risk. As described in the Discussion Paper, the transmission hedges appear to be analogous to existing Inter-Regional Settlement Residues (often referred to as SRAs). These are used by participants to manage price risk, but they are not considered a firm hedge because the physical limitations of the system remain independent of the hedge product.

The firmness of SRAs can be affected in a number of ways, including but not limited to, counter price flows on interconnectors caused by physical operational requirements to manage system security, or by lines being de-rated due to a contingency. In these circumstances SRA payments are reduced and at times can be zero. The Commission has acknowledged that transmission hedges may not fully compensate a generator as payments may need to be scaled, so are inherently non-firm. However, they have not considered how this will impact on a generator's ability to then offer financial risk management products to retailers if they do not have revenue certainty.

A generator looking to sell a financial contract into another region may look to purchase SRA to manage the risk of price separation between the regions. When price separation occurs, the price they are paid for generation in their region may be lower than the price in the region into which they have sold a contract, leaving the generator exposed to paying out a financial contract that exceeds their received pool revenue. By purchasing an SRA, the generator can have some confidence that if price separation occurs, they will receive some payment via the SRA instrument. This payment may not necessarily fully compensate the difference in spot prices between regions (due to reasons highlighted in previous paragraph) so these payments are not considered firm. Generators do not consider SRAs as secure firm financial products that can adequately under-write inter-regional financial contracts such as swaps and caps.

EnergyAustralia has serious concerns that introducing the transmission hedge reform, that creates an intra-regional product analogous to the inter-regional SRA, could result in reduced liquidity in the contract market, which is a critical aspect to funding future generation investment.

The corollary of introducing an intra-regional SRA type mechanism will be an inability for generators to offer intra-regional financial products, due to a lack of confidence that they will receive sufficient pool revenue to defend them because the settlement and transmission hedge are not equal. This will be particularly poignant for dispatchable generators that are relied upon to provide energy security, and subsequently price security for retailers through the trade of financial products. If generators are not confident they can defend financial contracts, the volume of contracts offered may decrease, or the prices increase. This will create unmanageable price risks for retailers, but may also reduce investment if generators are unable to receive adequate risk premiums in their contracts that are needed to underpin future investment.

When considering co-ordination of investment, the Commission should consider how changes to the regulatory framework will affect investment in generation, particularly dispatchable generation, and generation that is able to provide system security services. EnergyAustralia is concerned that the proposed development of transmission hedges may in fact act as a barrier to additional investment and introduce further risks to the firm contract market, potentially impacting the availability of contract and associated liquidity in the market.

It then appears to EnergyAustralia that the COGATI reform is inconsistent with the Retailer Reliability Obligation (RRO), which aims to incentivise investment in new dispatchable generation, utilising the current, relatively liquid contract market.

We would encourage the AEMC to ensure that these reforms not only need to provide co-ordination to new intermittent generation, but they must also be designed to incentivise ongoing investment in dispatchable capacity as well.

2. **Broader impacts of the reform and the need for a regulatory impact assessment**

In progressing these reforms, we suggest the Commission commit to conducting a cost benefit analysis prior making a recommendation to COAG.

The Commission has outlined a number of issues with the current regulatory framework including:

- **Disorderly bidding in tie-break outcomes** whereby generators with higher short run marginal costs are dispatched ahead of lower cost plants. Generators face volume risk for congestion but no explicit price signal for congestion.

- **Winner takes all in tie-break outcomes** where investors aren’t required to consider the impact on incumbents when the new plant displaces existing assets from dispatch due to application of constraint factors on a congested line.

- **Changes to Marginal Loss Factors** (MLFs) where subsequent investment decisions can have detrimental impact on the MLF, and therefore revenue, of incumbents.

- **Lack of coordination for remediating system strength** where multiple generators are investing independently on 'do no harm' measures.

- Inadequate **compensation for network outages** where generators are not dispatched. The existing signals to networks to minimise outage length and optimise time of outage are blunt.

- **Consumers bearing risk** of over or under investment in transmission investment.

- **Increased volume of connection enquiries** creating increasing costs and complexity for AEMO and TNSPs.

As yet, none of these issues have been quantified by the Commission beyond illustrative examples and we are unable to assess whether they are material issues. The Commission have indicated that while these costs may be minimal at present, they expect these costs to increase in future and that it is hard to quantify these future costs. We suggest that a trend analysis of the last 8 years should give some indication of whether the anticipated problem has been materialising with the recent wave of investment. The Commission could also utilise AEMO's scenario modelling to assess the likely magnitude of these issues in future.

For reforms of this size, it is important that the Commission can demonstrate that there will be quantifiable benefits to customers. As part of its analysis in this review, the Commission should quantify some of the current and expected future costs of the current regulatory framework including:

- The extent of changes and volatility in MLFs and the material impact this has on dispatch efficiency and overall NEM pool prices, and the impact on cost of capital for new investment.

- Quantifying the cost of the measures taken by generators to meet the 'do no harm' provisions.

- Quantify the impact of network outages on spot prices and costs of constrained generator dispatch.

- A reassessment of the market impact and costs of disorderly bidding, noting that in future it is likely that more generators behind a constraint will be zero/low marginal cost units, meaning that the concern around disorderly bidding of out of merit order dispatch is no longer relevant, resolving this issue naturally.

- Summarise information AEMO currently produces on the impacts of congestion caused by constrained dispatch.

- The costs of delayed connections due to the volume of connection enquiries.

This information will be beneficial for the Commission, government and stakeholders in assessing the need for reform.

We believe there could be hidden costs in this reform that have not been identified by the AEMC that could undermine the stated intent of reducing costs to customers. While customers will face lower Transmission Use of Service (TUOS) charges, they may face higher energy costs (due to increased fixed costs of generators through the requirement to purchase transmission hedges) that outweigh the reduction in TUOS. What may appear to be a reduction in costs to customers, is in fact a transfer to wholesale costs plus an additional cost added to wholesale energy costs. These additional costs could include:

- Increased risk management costs for generators and retailers to manage price risks due to inadequacy of transmission hedges as a risk management tool. By transferring some of the coordination risk to generators, the total cost of investment may be increased;

- Higher costs of capital for transmission build due to higher Weighted Average Cost of Capital (WACC) faced by generators as opposed to regulated networks due to the fact that generators are now partially funding transmission build;

- Generators requiring higher prices, or greater volatility, to recover higher fixed costs of purchasing transmission hedges. This may be politically unpalatable but efforts to dampen this volatility will weaken necessary signals for generation investment. It is already difficult to commit to a multi-decade payback in the current volatile environment. Adding another layer of uncertainty and costs will only serve to increase this difficulty.

It is also important that the Commission sufficiently costs the transition requirements. We have observed with 5 Minute Settlement that industry costs were significantly understated. AEMO's initial cost estimates were $15 million (Final Determination, Page 145)[4] but these have now increased to at least $120 million. Without recourse to review a rule change in light of revised costs, it is important that the Commission is confident in AEMO's initial costings prior to making a rule change determination.

We note that there is likely to be significant system cost to existing participants as well to ensure they are sufficiently positioned to manage the new dispatch realities of dynamic nodal pricing and the associated transmission hedges. We would encourage the Commission to explore this further.

Finally, given the significant nature of the reforms, we strongly suggest the Commission conduct a 'paper trial' prior to making a recommendation. This will not only allow the Commission to identify and rectify design issues, but allow stakeholders an opportunity to familiarise themselves with the proposed changes and support the Commission's analysis. There may also be avenues to test these reforms via the new regulatory sandbox process that the Commission is in the process of establishing.[5]

In addition, the Commission should test the transmission hedge arrangements, including product type, purchase process, purchase price etc, against the following scenarios, with existing data, to analyse the impacts and ensure the reform delivers are a robust outcome:

[4] https://www.aemc.gov.au/rule-changes/five-minute-settlement
[5] https://www.aemc.gov.au/news-centre/media-releases/aemc-recommends-new-regulatory-sandbox-arrangements

- A greenfield TNSP augmentation to support a renewable zone;
- An existing transmission line that is not currently congested; and
- Local pricing nodes that are 3 or 4 nodes away from the regional reference node, where the transmission is meshed.

We recognise the Commission's desire to implement reform expediently to address the issues it has identified, however there is a risk the reforms are implemented hastily, resulting in policy that does not meet the intended objectives and may have perverse unintended consequences. Significantly more analysis is required to give industry confidence that these changes are fit for purpose and will deliver benefits to consumers. We question whether the complexity of these reforms will hinder the possible benefits identified in theory.

3. Key design questions remain outstanding

There are a number of key design questions that are unknown, impacting our ability to ascertain the consequences and value of the proposed reforms. These include:

- **Grandfathering**, in particular ensuring that existing dispatchable capacity is not disadvantaged, given its importance to ensuring both reliability and security. Current asset investment decisions should be protected from reforms to ensure they are not financially disadvantaged.

- **How transmission hedges will translate to transmission infrastructure build**. The obligations, incentive mechanisms, timeframes and penalties on TNSPs are not clear. For example, if a generator has multiple routes to the regional node and purchases a transmission hedge, is this investment used to address congestion on all possible routes, or does the TNSP have discretion in where it will invest to honour the hedge purchase?

- The Directions Paper suggests that **hedges will not be paid until the transmission is built**. This seems counter-intuitive as at that point there is likely to be minimal occurrence of congestion and the need for a hedge – generators are likely to most need hedges before the infrastructure is built.

- **Transmission hedge auction process.** It is not clear that this will be a liquid process. If an available product is for a hedge from a node to the regional node, the highly locational nature of the product will restrict the number of generators interested in purchasing the hedge, and limit the ability of generators that are unsuccessful in the auction to buy hedges in a secondary market. Further work also needs to be done to consider how the costs of the hedges will be cost-reflective, and whether the party purchasing the hedge needs to be a physical generator on the node.

- **The interaction with planning process.** It remains unclear how and when transmission hedges will be available for purchase, and how AEMO will consider the purchase of hedges in producing the Integrated System Plan (ISP). It also remains unclear how the money from purchasing the hedge will be used in a TNSP's 5 year Regulatory Review.

- **Mitigating disorderly bidding.** It is unclear how the reforms will prevent disorderly bidding. For example, if a party has purchased all the available hedges, they could seek to drive the local price to market floor to access the price differential between the local and the regional prices. Other generators, who may have lower marginal costs but not purchased hedges, will not be dispatched. The generators could also seek to generate less than their volume of purchased hedges, providing congestion still occurs they can contrive a net short position to the local price.

- How locational pricing signals will be **co-optimised with the FCAS market** to ensure that generators that have not purchased transmission hedges are adequately compensated for their generation.

The Commission should progress these items as a priority as they are integral to determining whether the reforms will have the intended outcomes. Stakeholders should be provided sufficient time to assess the details.

Further design issues that we require more detail on include:

- How MLFs will be considered;

- How System strength and other system services can be valued and sufficient market signals provided for these; and

- Treatment of existing contracts e.g. PPAs.

We also note the Discussion paper outlines that charging reform has become a second order priority but does not provide a proposed timeline for progressing this work. Can the Commission provide this to stakeholders?

4. What transmission hedge products should be provided

It is difficult to provide definitive guidance on the appropriate design of the hedges without understanding how the funds used to buy them will be converted into transmission that reduces congestion. The complexity in trying to provide locational signals is that they are not static, making it difficult to appropriately price a transmission hedge product to provide the best signal. Investment decisions are made based on the best information known at the time of investment. As the market evolves, the generator faces the consequences of changes in its environment. Under the proposed COGATI reforms, the generator that made efficient investment at a particular time, may be subject to a 'locational signal' transmission hedge cost in future, however, they have no capability to respond to this signal, it is simply an unforeseen future cost.

EnergyAustralia suggest that simple products should be offered through the transmission hedge purchasing process, allowing secondary trading and/or a derivatives market to evolve to craft products suitable for the market at a given point in time. For example, a 24-hour product can be purchased by a solar farm which can then sell contracts for compensation payments made overnight if it sees value in this option.

The length of the transmission hedges will be critical. Long term contracts will provide greater investment certainty, which is important in the current investment market environment. However, shorter term contracts will allow greater flexibility in reflecting the changes in market value over time. It will be difficult to accurately price the value of a transmission hedge for long periods of time.

5. Consultation timeframe

There remains only one more substantive consultation paper prior to the Commission producing their final report. We are concerned that the Commission has not allowed sufficient time to engage with participants on the numerous as-yet-unspecified design details before a final design package is submitted to COAG. It is important that the Commission and stakeholders have time to revisit discussion of key design elements once the package is complete to ensure consistency of outcomes.

This creates a risk that reforms are progressed before critical details have been consulted on and before a full regulatory impact assessment is completed. It is not clear that the Commission intends to conduct a regulatory impact assessment, which should be absolutely imperative for a reform of this size.

Further, the Commission's timeframe for implementation is ambitious. Based on the Commission's current work plan, the rule change process will be complete by mid-2020. This leaves only two years for AEMO and Participants to identify and implement required changes and concurrently assess and address any changes in risk exposure. We would encourage the AEMC to not repeat the mistakes of the Retailer Reliability Obligation implementation which has resulted in significant uncertainty to the industry and ongoing issues being identified with its design, rule drafting and implementation.

Significant work will be required to draft and consult on the rules and for AEMO and participants to identify and implement required system changes and processes. It is EnergyAustralia's view that AEMO has a significant work program to implement regulatory reform and running further reforms in parallel will only increases costs and introduce risks. Similar to 5-Minute Settlements, there is likely to be an impact on existing contracts that will need to be managed during a transition, particularly PPAs, financial contracts and other long-term arrangements with customers.

By hastily implementing these changes, the Commission is creating risk of significant financial disruption to customers and market participants, that could be avoided through a more orderly and considered transition process.

Further, as we have outlined previously, the ESB 2025 design work is scheduled to be completed immediately after the AEMC completes its rule making process for the COGATI reforms. It would be pragmatic to extend the consultation on COGATI design through 2020, providing the ESB a complete and fully assessed reform package to consider. A commitment decision should then be made in conjunction with the ESB market design decision process.

We suggest the Commission reconsider their implementation timeframe to minimise the disruptive impacts of the reform and confusion arising from concurrent reform implementation. Stakeholders will need sufficient time to analyse and assess the design details. The tight timeframe will lead to compressed consultation timeframes, at a cost of rigorous analysis by stakeholders.

6. Comparison with international markets

EnergyAustralia notes that the Commission have drawn comparisons to international markets that operate access frameworks similar to the proposed design. While this analysis can provide insight, we express caution in the conclusions that can be drawn from the operation of access arrangements in other jurisdictions. These markets have different objectives and structures.

For example, the Commission has compared the COGATI to reforms in New Zealand. New Zealand recently introduced a transmission hedge scheme, however this was predominantly to address an issue they identified in their energy market design. As a fully nodal model, they found that there was limited competition as generators were unwilling to offer contracts to retailers operating in other zones. The framework is not designed to support transmission infrastructure investment. In effect the FTR model in New Zealand mimics our existing regional pricing modal with Inter-regional settlement residues used to manage price separation utilising SRAs.

While international models provide a useful source of information, their successes, and failures, should not be projected onto the Australian market due to inherent differences in market design and market features.

Conclusion

We understand the Commission's call for greater coordination of transmission and generation investment. As a guiding principle, those who are best able to mitigate the risk should bear it. Consumers currently bear the risks of "roads to nowhere".[6] However, if this is the Commission's objective we greatly encourage the Commission to consider simpler options than the proposed nodal pricing and transmission hedge package. At the very least some simpler, but perhaps less elegant, options should be presented as alternatives to enable industry to compare and acknowledge that such complexity is in fact required.

In our view, significant further work is still required before a complete assessment of these reforms can be made by stakeholders. In particular, greater detail on grandfathering, conversion of transmission hedges to transmission build and provision of system security services is required. The Commission should be undertaking to produce more rigorous cost benefit analysis and assessing the impacts on dispatchable generation and contract availability. The transmission hedges described by the Commission are analogous to SRAs and it is our view that this will inadequately allow generators to manage risks in the market, with implications for viability of existing and future assets. We would welcome exploring simpler methods of addressing the issues identified by the Commission.

The consultation and implementation framework remains tight, and this presents a key risk to the successful implementation of these reforms. We encourage the Commission to expand it's consultation timeframes, not only to ensure it has the right reform response for its objectives, but also so that implementation issues can be identified and mitigated early during consultations and not after the Rules have been made.

[6] AEMC, Directions Paper: Coordination of Generation and Transmission Investment – Access Reform, 27 June 2019, page i.