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
Dr Brian Spalding
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, COGATI Implementation – access and charging, Consultation Paper & Supplementary Information 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 in the National Electricity Market (NEM).

EnergyAustralia welcomes the opportunity to comment on the Commission's ongoing review of access reform in the NEM. The proposed changes are complex and significant, and we value the AEMC's thorough consultation process and ongoing engagement with stakeholders. EnergyAustralia looks forward to continuing to work with the AEMC to develop the path to transition to a cleaner energy market.

The Energy Security Board's (ESB) 2025 Market Frameworks review seeks to assess the optimal energy market framework required to support the efficient delivery of energy services in future. While this scope is broader than the Co-ordination of Generation and Transmission Investment (COGATI) review, it has significant overlap. Considering this, it would be imprudent to commit to a significant reform before the ESB review is complete. We therefore strongly encourage the AEMC to continue their work with a view to assisting the ESB assess the merits and pitfalls of access reform by examining the technical design requirements, but to refrain from committing to any major changes prior the completion of the ESB's work.

The AEMC's consultation process should seek to scope and scale the problems that exist, or could exist, with access frameworks, to support the ESB with this element of their review. We encourage the AEMC to not limit their scope to examination of COGATI, but to consider the broader options available to address issues identified with access and assess their relative merits.

While the broader ESB and AEMC reviews are conducted, there are several reforms that could be introduced to address some of the key issues identified by the AEMC. These reforms could provide immediate improvement to the market and be easily incorporated within any future market reform, while allowing the ESB and AEMC to continue their reviews using the current market design as a base case. This includes greater provision of information to the market regarding Marginal Loss Factors (MLFs) and connection requests.

We encourage the AEMC to continue to an analyse and define the scope and scale of the issues created by the current access framework. Considering a broader market frameworks assessment by the ESB, we encourage the AEMC to use the COGATI consultation process to develop and assess this particular market design in detail, but not to commit the industry to a particular path before the ESB's work is complete. There are several low-cost options that could immediately address some of the issues identified by the AEMC, prior to the completion of the ESB work.

In recommending any changes, the AEMC should clearly articulate how a new framework would lower the costs to customers of transitioning the generation fleet and ensure that the change does not have significant perverse outcomes. Every market design has benefits and drawbacks and the AEMC needs to clearly define how this change would deliver benefits that exceed the cost of any drawbacks and the cost of transition.

The remainder of this submission presents EnergyAustralia's perspectives on the landscape of overlapping reforms, problem identification, understanding unintended consequences and some specific design questions to take forward.

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

Interaction with other reforms

There is likely to be significant overlap between the AEMC's COGATI consultation process and the ESB's 2025 market frameworks review. We therefore encourage the AEMC to develop advice for the ESB that is based on extensive stakeholder consultation and structured assessment with a clear focus on problem identification for the current and future NEM. This will enable the ESB to leverage the work in their comparison of possible future frameworks. In doing this, the AEMC should have scope to fully explore related issues and reforms to consider the broader impacts on industry and customers from the proposed changes. It is important that any major reform recommendations and implementations are co-ordinated.

It is also imperative that the rate of change within industry does not stretch participants beyond their ability to manage the impacts of the change. The below chart outlines the major reforms and rule changes related to access that are currently underway. It illustrates the challenges participants face in preparing their businesses for the inter-related changes. For example, a generator in the final stages of preparing to implement systems and process for Five Minute Settlements will concurrently need to prepare for dynamic pricing, and while in the final stages of implementing business strategy to engage with dynamic pricing, participants will need to start preparing for the market post 2025.

This timeframe for multiple reforms places significant pressures and risks on business systems and processes, but also creates high levels of complexity and uncertainty on any businesses considering investment in new assets. Significant regulated transmission investment is expected to be considered within the next five years. It is not clear how these will be reflected in the analysis of alternate market frameworks; is it assumed that they are already part of the NEM, or will they be considered as scenarios whereby their respective benefits cases could vary depending on the market framework under which they're assessed.

To maximise reform outcomes and minimise uncertainty and unnecessary disruption, the focus of the COGATI review should be in assessing the range of options available and exploring the implications arising from them following more detailed assessment of design options.

Reform schedule as currently proposed

	Project	2019	2020	2021	2022	2023	2024	2025	2025+
Major Market Reforms	5 Minute Settlement			Reform starts					
	Reliability Obligation (RRO)	Reform starts							
	Market Making	Final rule made	Speculated start						
	COGATI		Final rule made		Dynamic Pricing starts	Firm Access starts			
	ESB market review			Review complete				New market starts	
	Actionable ISP, RIT reform & current projects		ISP II	Actionable RIT starts	QNI & VNI Upgrades		SA-NSW 'Riverlink'		Basslink 2.0 Snowy 2.0
Related rule changes and reviews	Transparency of new projects (3 rule change requests)	Rule change consultation period							
	MLF reform (2 rule change requests, AEMO review)	Rule and Review consultation period							

Defining the scope and scale of the problem

The NEM is changing. We agree with the AEMC that there is currently, and will need to be in future, a significant volume of new and varied forms of generation capacity seeking to gain access to the network.

If the frameworks are not right, this could lead to inefficient overbuild and ultimately higher than necessary electricity bills for consumers. WE see problem identification as critical to this review.

In the *Supplementary information paper,* the AEMC have outlined the key reasons for reform to be:

- Long-term locational signals (congestion, transmission losses and inter-regional prices) are insufficient for efficient investment.

- Disorderly bidding to maximise dispatch leads to dispatch of higher cost resources and inefficient operation of grid storage.

- Generators not compensated for loss of revenue due to extended network outages.

- Significant annual fluctuations in marginal loss factors creating investment risk.

- Inefficient investment to address system strength requirements as assets are installed by individual generators to meet 'do no harm' provisions, rather than investing in shared assets.

- High volume of connection enquiries creating resourcing issues at networks and AEMO and changes in connection agreement requirements; creating costs, delays and uncertainty for developers.

- Existing cost sharing arrangements for Renewable Energy Zones (REZs) (such as the Scale Efficient Network Extension framework) insufficient to support co-ordinated investment due to 'free-rider' problem.

While the paper outlines these challenges for market participants in the current environment, it does not clearly articulate the broader problem with the existing framework and how the proposed changes will reduce the price that customers will pay for the transition of the generation fleet.

It would be beneficial for the AEMC to quantify the magnitude of these symptoms, both under current conditions and under future predicted market conditions. In particular, the AEMC should analyse the extent of disorderly bidding and uncompensated networks outages and assess the economic costs these impose on customers. This should include a consideration of a future market where the majority of generation has a zero, or very low, short run marginal cost. This analysis should then be supported by an assessment of the range of options to address the problems. We need to ensure we are finding innovative, cost-effective solutions for clearly defined problems, not finding problems to justify a proposed solution.

Based on the information the AEMC has provided to date, it is EnergyAustralia's view that the proposed solution does not necessarily solve all the perceived problems and may in fact introduce significant new uncertainties into the market.

Solutions to address stated issues

Several of the stated issues could be addressed with less substantial changes that target the specific issue without negatively impacting other areas of the market.

Providing efficient locational investment signals

The AEMC have suggested that existing market information is insufficient to support efficient investment in generation. However, AEMO have recently endeavoured to improve the availability of market and network information for stakeholders.

AEMO published its first Integrated System Plan (ISP) in July 2018. This document extended the existing National Transmission Development Plan (NTNDP) by identifying Renewable Energy Zones (REZ) which are areas within the NEM deemed to be the most efficient places for new generation investment.

Within the ISP AEMO identified eight zones that are immediately optimal places to develop new generation assets. In identifying and assessing the merits of different REZs AEMO considered the quality of the resource and diversity of resources, system strength, capacity of existing network infrastructure (including MLF's) and proximity to load centres.

The ISP was the first report produced by AEMO that provided such substantial information to the market about the optimal locations for new generation investment.

The purpose of the ISP, as suggested by the *Independent Review into the Future Security of the National Electricity Market* (the Finkel Report) was to enhance co-ordination of investment by improving the information available. The ISP was published less than a year ago and while there has been substantial support in progressing network investment specified in the report, there has not been sufficient time lapsed to assess whether the report has been successfully utilised to guide efficient investment.

AEMO has also made additional efforts to provide information to prospective investors. This includes a map showing the location of connection enquiries[1], and extensive stakeholder roadshows on MLF's and on the connection process and requirements for generators. Further, transmission network service providers (TNSPs) have published information about the availability of capacity at their connection points.

EnergyAustralia recommend that AEMO continue to develop its information resources for stakeholders. Given the anticipated high volume of connecting stakeholders, AEMO should consider enhancing the accessibility of the information by compiling a dedicated page on its website that outlines all resources available to prospective generators. This reference page could also provide guidance as to the risks and uncertainties underpinning the information AEMO publishes. This would not be specific financial advice on particular projects, rather general information to assist prospective investors in assessing the feasibility of their projects.

There are also several rule changes proposed that seek to improve the coordination of connections and reduce uncertainty for existing and future investors by providing information about current and possible future market conditions. This includes:

- NEM information for project developers (ERC0260)
- New project transparency (ERC0257)
- TNSP confidentiality exclusion (ERC0268)

Marginal Loss Factor fluctuations

MLFs are a strong locational signal and many participants, including EnergyAustralia, strongly consider current and predicted future MLFs when identifying potential projects. AEMO have been engaging with participants on possible changes to MLF calculations to make them more transparent and reduce volatility for investors. EnergyAustralia understand that AEMO is continuing to review their MLF information and calculations and is developing improvements to the quality and frequency of data that they use in calculating MLFs. Further, there are two rule change proposals[2] that the AEMC has indicated it will use to conduct a broader review of MLF regulations. These reviews by both market agencies have the potential to address the challenges facing investors that the AEMC has outlined.

Continuing to make more information available regarding MLFs will allow participants to model different MLF outcomes under different assumptions. This will equip prospective participants to be better informed when making investment decisions.

[1] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps
[2] Loss Factor Frameworks (ERC0262), Inter-regional settlement residue allocation (ERC0251)

Financial impact of network outages on generators

TNSPs currently face some penalties for taking outages that lead to high prices. [3] The cost of these outages is reflected in NEM dispatch using the marginal value of constraints. It is our understanding that TNSPs currently have a performance target for the number of dispatch intervals with a binding constraint caused by an outage. This is a very blunt, binary tool but there may be an opportunity to refine this mechanism to improve outcomes for generators. There may also ben an opportunity to stimulate performance improvements through the economics regulatory framework set out in Chapter 6A of the National Electricity Rules (NER).

We note that for the long-term reliability and security of the NEM that the ability for TNSPs to take outages is fundamental. We encourage the AEMC to do further work in understanding how TNSPs currently co-ordinate outages with impacted participants and whether there are specific reforms that could address co-ordination issues.

Realising the anticipated outcome and unintended consequences

It is not clear how all the stated issues would be resolved with the proposed reforms and there has been minimal analysis to date of the possible drawbacks of the proposed reform. No framework is perfect and there needs to be careful consideration to ensure that any change has benefits that far exceed the costs of a transition and any subsequent unintended consequences.

While the AEMC suggests that the framework outlined in the Consultation Paper would lead to better market signals for investment, we suggest that the AEMC needs to undertake more detailed modelling of more complex examples to understand whether these outcomes are realistic within the NEM. The current examples provided by the AEMC have focussed only on simplified radial system, but in reality, the NEM is a highly complex meshed network. It would be useful for the Commission to consider a number of more complex scenarios including:

- Pricing and settlement outcomes at a node that is subject to several constraints between its location and the regional reference node. For example, generation that is located far from the regional reference node (RRN) which has multiple paths to the RRN.

- Pricing and settlement outcomes at a node that is facing constraints on two different lines.

- Whether dynamic pricing and settlement outcomes apply for constraints that are not caused by thermal issues. For example, constraints for transient stability and/or voltage collapse.

- Interaction and co-optimisation with ancillary service markets.

- Pricing and settlement outcomes at generators near, or on, an interconnector.

[3] In AEMO's role as the system operator they cannot allow outages to go ahead if they consider there may be impacts to system security.

- Regional transfer pricing and associated Settlement Residue Auction (SRA) units for constrained interconnectors.

- Pricing and settlement outcomes for disaggregated generation, such as a demand response aggregator, that sits behind multiple nodes.

- A highly distributed environment where generators and loads within the same area. E.g. market generators in a constrained region may see low prices which will drive lower production, conversely price-responsive load in the same region will see a high price leading to reduced load. This could lead to a further congestion and a further reduction in generation, precipitating a feedback loop.

- Optimising dispatch where higher cost units alleviate low cost resources in other parts of the network i.e. where it is most efficient to dispatch a more expensive unit at a constrained node because it provides services that relieve constraints in other parts of the network that have low cost assets.

These scenarios should be explored in more detail to identify the practical implications of operating nodal pricing regime within the NEM. The AEMC, in their assessment, should carefully assess the likely impacts on the physical, financial and investment markets. For all the above, AEMC should consider how these outcomes would impact on the ability of generators to offer financial contracts to parties liable for customer consumption at the regional reference price. They should also be considered in the context of dynamic nodal pricing as a stand-alone reform, and in conjunction with firm access.

The AEMC have indicated that the two key phases of the proposed reforms could also be considered as stand-alone reforms. We have identified several issues if dynamic pricing were implemented as a single reform, either as part of a transition or as a stand-alone reform.

The most significant is the detrimental impact this could have on financial market liquidity as dynamic nodal pricing would create contract complexity and introduce basis risk. If a generator is constrained and faces a nodal price that is lower than the regional reference node (RRN) price, it may be financially exposed due to a difference in the payment it receives from AEMO (based on the nodal price) and the higher price that it may be contracted to pay to a counterparty (at the RRN price).

This price risk is significantly greater than the volume risk that generators currently face. Under current arrangements generators face the risk that they may be constrained and unable to generate to match the volume of contracts they have sold. This risk is generally predictable based on previous market outcomes and generators use knowledge of their constraint risk to contract for volumes they have reasonable confidence in dispatching. If the generator has underestimated its constraints, it may face high prices, but this will only be for the small portion of volume that is constrained.

Under dynamic nodal pricing the generator will instead face significant price risk for their entire volume of generation. Generators may be running at the required capacity but will be receiving a price that is substantially lower than the regional price, exposing the generator to high prices for their entire load, rather than a portion. While constraints may again be reasonably predictable over time, the inability of generators to defend a contracted position will reduce their ability to offer contracts at expected times of constraint. This is a much larger risk to take and will likely attract higher premiums, at cost to customers, or serve as a deterrent to offering contracts as generators may prefer to face a market price, rather than be exposed to a high price differential. This risk could lower liquidity, reducing investment in generation, or raising costs for customers.

This risk will be exacerbated under any market making obligations (as introduced within the Retailer Reliability Obligation (RRO)[4], and under consideration by the AEMC)[5] as generators will be forced to trade contracts for which they don't have price certainty, creating an unmanageable basis risk between the local price and the reference node. The AEMC consider the interaction of these changes on the Market Liquidity Obligation imposed under the Retailer Reliability Obligation (RRO).

It is unclear how implementing nodal pricing as a stand-alone reform would address the key issue of providing efficient pricing signals for investment and co-ordinating investment. Locational pricing doesn't mitigate the risks that prices could change, or solve the predictability problem. While it provides information about real-time congestion, it doesn't improve the ability to forecast future prices and congestion any more than existing MLF data. Under this reform there could still be multiple parties connecting concurrently in a similar location resulting in lower prices for all units at that the node. It is not clear how highly volatile dynamic pricing would provide clearer signals than MLFs to reduce this risk.

Potential barriers to entry

There is a risk that dividing generators into sub-nodal regions could result in isolated market power issues due to the small number of generators. This could create barriers to entry for new investment.

Another possible risk for is that these changes increase the complexity of participating in the NEM, creating a barrier to entry. The proposed reforms are likely to increase the complexity of bidding decisions as generators will need to consider prices at both the RRN and the sub-node. For each unit the generator will need to consider the price, the expected congestion payment, the possible constraints and the likelihood that they will bind. AEMO will need to make available volume, price and congestion payment information at a 5-minute level for every unit, in real time.

These are potential issues that should be explored in further detail.

Design questions for technical working group

As the AEMC develops the design for the proposed reforms there are several critical issues that need to be analysed in depth. This includes:

- Grandfathering of existing access;
- The interaction of dynamic pricing with other pricing mechanisms such as Reliability and Reserve Trader (RERT) and intervention pricing and direction/affected participant compensation;

[4] http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules
[5] https://www.aemc.gov.au/rule-changes/market-making-arrangements-nem (ERC0249)

- How non-firm generators (for example semi-scheduled generators) would receive capacity-based compensation when their effective capacity is constantly changing;

- How congestion payments are allocated to avoid perverse outcomes and minimise basis risk;

- Pricing of nodes that are constrained due to non-thermal issues. These constraints are complex and the outcome of the combination of combination of generators dispatched, rather than the total volume of energy as is the case with thermal constraints;

- Allocation of access rights and pricing for an interconnector in proximity to a constrained node;

- Pricing for deep and shallow access rights;

- Interaction with other proposed reforms. For example, the AEMC is currently considering the creation of a new participant category, a Demand Response Aggregator (DRA), that would bid and be dispatched by NEM Dispatch Engine (NEMDE) but would be highly disaggregated; it is unclear how constrained pricing would apply to these participants.

We anticipate that the AEMC will explore these, and other design questions, within their technical working group.