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Australian Energy Market Commission
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To whom it may concern

Coordination of Generation and Transmission Investment – Access Reform – Directions Paper

Meridian Energy Australia Pty Ltd and Powershop Australia Pty Ltd (MEA Group or Powershop) thank the Australian Energy Market Commission (the AEMC) for the opportunity to provide feedback on the Directions Paper on the Coordination of Generation and Transmission Investment – Access Reform (the Paper).

MEA Group is a vertically integrated generator and retailer focused entirely on renewable generation. We opened our portfolio of generation assets with the Mt Millar Wind Farm in South Australia, followed by the Mt Mercer Wind Farm in Victoria. In early 2018 we acquired the Hume, Burrinjuck and Keepit hydroelectric power stations, further expanding our modes of generation. We have supplemented our asset portfolio by entering into a number of power purchase agreements with other renewable generators, and through this investment in new generation we have continued to support Australia's transition to renewable energy.

Powershop is an innovative retailer committed to providing lower prices for customers and which recognises the benefits to customers in transitioning to a more distributed and renewable-based energy system. Over the last five years, Powershop has introduced a number of significant, innovative and customer-centric initiatives into the Victorian market, including the first mobile app that allows customers to monitor their usage, a peer-to-peer solar trading trial and a successful customer-led demand response program. Powershop has also been active in supporting community energy initiatives, including providing operational and market services for the community-owned Hepburn Wind Farm, supporting the Warburton hydro project, and funding a large range of community and social enterprise energy projects across Victoria through our Your Community Energy program.

MEA Group believes it is important to clearly articulate the problem the AEMC seeks to resolve through the proposed reform. As discussed in its biennial report published in December 2018 the AEMC correctly observed the following:

"*There is a significant amount of generation capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity for the generation to connect, which limits these generators accessing the wholesale market and so creates congestion resulting in costs for consumers. In addition, interconnectors are sometimes constrained, meaning that consumers cannot always access lower cost energy from generation in neighbouring states. This creates congestion, meaning that consumers bear the cost of more expensive generation being dispatched to supply their demand*".[1]

The December 2018 AEMC report appears to meet the requirements of Stage 1: *Scoping Analysis of the Terms of reference for reporting on drivers of change that impact transmission frameworks*', provided by the Council of Australian Governments (COAG) to the AEMC on 29 February 2016. Stage 2 of the same terms of reference

[1] Australian Energy Market Commission, Final Report, Coordination of Generation and Transmission Investment –, 21 December 2018, page i

required the AEMC to consider whether Optional Firm Access (OFA) remains fit for purpose and if it did whether it would meet the requirements of the National Electricity Objective (NEO).

The same terms of reference also required the AEMC to provide details of the proposed assessment methodology and analysis methodology to allow the determination as to whether any other improvements to the current regime could be undertaken. MEA Group notes the development of the Australian Energy Market Operator' s (AEMO) Integrated System Plan (ISP) since the release of the initial COAG Energy Council's terms of reference. It is MEA Group's opinion that the Paper as currently drafted does not address the above requirements.

Therefore we believe it is reasonable to expect the provision of a detailed cost benefit analysis that looks at a range of options (including but not limited to OFA) to enable stakeholders to undertake meaningful and robust debate of the merits of each proposed approach. MEA Group does not agree that the Paper outlines a clear case for reform nor has it provided detailed analysis of the various options to address the issue of congestion across the NEM.

By comparison the proposed reform appears to identify a solution before undertaking a rigorous analysis of the potential alternatives or with an indication of the costs associated with each alternative. This makes stakeholder analysis difficult to perform particularly in respect of the detailed nature of the questions the AEMC has posed in the Paper.

At its core the reform seeks to better align the risks associated with the long term investment decision in relation to transmission infrastructure with those who are best placed to bear them. MEA Group does not disagree with this underlying philosophy although we note this is a fundamental shift away from the open access model that has underpinned investment in generation and transmission across the NEM since its inception approximately 20 years ago.

Dynamic Regional Pricing:

With regard to the AEMC's first stage of its proposed reform – Dynamic Regional Pricing (DRP), MEA Group does not believe that the AEMC has demonstrated a clear case for this reform given the issue that the reform seeks to resolve – transmission congestion. Whilst MEA Group understands the AEMC's judgement in respect of the introduction of DRP – that being to create a price difference against the Regional Reference Price (RRP) in order to place a value on congestion – we also note the AEMC's views in respect of disorderly bidding by generators during periods of transmission constraints and the intent to resolve this issue through the introduction of DRP.

We note that as part of the transmission frameworks review in 2013 that, *"ROAM Consulting estimated that over the period June 2008 to June 2011, electricity dispatch costs were $21 million higher than they could have been due to race to the floor bidding behaviours."*[2] On that basis it would appear that disorderly bidding is a minor issue, given the small cost to the NEM as identified by the ROAM Consulting report, that does not warrant the investment in a complex reform process, even if the AEMC is correct in their estimate that the issue may become worse throughout the energy transition with the influx of storage projects.

The Paper goes on to note that "*ROAM Consulting's forward-looking modelling estimated that removing race to the floor bidding could save $8.8 million (in net present value terms) over the 18 years to 2030, with annual savings increasing to $3-6 million in the last five years of the period.*"[3] This further underpins our view that disorderly bidding practices are not an issue that would warrant significant and complex reform.

Transmission Hedges – Financial Transmission Rights (FTRs):

Stages Two and Three of the proposed reform address Transmission Hedges – which allow generators to purchase a transmission hedge and receive a financial pay out under that hedge (commonly referred to as Financial Transmission Rights (FTRs)). Whilst appearing to provide a mechanism for the costs associated with transmission investment to be borne largely by generators (as opposed to consumers via Transmission Use of System (TUOS) charges), MEA Group have concerns that the following underlying and fundamental assumptions for this stage of the reform are flawed:

1. That the FTRs purchased by the generators will be sufficient in magnitude to fund the significant investment required by Transmission Network Service Providers (TNSP) in transmission to unlock constraints and provide access for new generation; and
2. those generators are prepared to coordinate their connection proposals with each other in order to optimise the connection arrangement for a renewable energy zone or particular transmission node.

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[2] ROAM Consulting for Australian Energy Market Commission, Modelling Transmission Frameworks Review, 28 February 2013

[3] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 40

MEA Group remains unconvinced that in the first assumption the scale of transmission investment and augmentation can be sufficiently absorbed by a finite number of renewable projects seeking to connect through the introduction of financial transmission rights. We note the Public Interest Advocacy Group's (PIAC) proposal attempts to distribute costs more efficiently between generators and TNSP's so as to reduce the risk borne by consumers in respect of transmission investment.

Ultimately MEA Group believes it will be a combination of public/private and generator/TNSP funded investment that leads to an efficient and optimal outcome for the power system of the future and for that reason would continue to support the existing RIT-T arrangements in their simplest form.

MEA Group deems there are likely to be components of the RIT-T process that could be improved to ensure the true market benefits of a proposed investment are captured. Fundamentally this is a process that delivers against the NEO and is expected to continue to do so.

AEMO's most recent Insights paper following the 2018 ISP for the NEM '*Building power System resilience with pumped hydro energy storage'* demonstrates that with the appropriate transmission investment under the existing RIT-T process in projects such as KerangLink and HumeLink, a significant portion of transmission loss factor and constraint issues that many generators are subjected to will be addressed. MEA Group believes the existing regime works however, some processes need to be accelerated to ensure they are delivered in a timely and efficient manner.

MEA Group also believe it is important to note the likelihood that a TNSP is likely to have a lower cost of capital than generators and therefore it is more likely to result in a lower overall cost to consumers, if TNSPs continue to construct and operate the shared transmission network as opposed to it being funded largely by generators. We also do not share the AEMC or TNSPs' concerns that there is a significant risk that investment in new transmission lines will become *"roads to nowhere",*[4] provided we continue to follow the RIT-T process for investment in regulated transmission assets.

The Paper states that *"network businesses have voiced their concerns about changes to their rate of return, as well as uncertainty being created by the suggestion of asset write-downs"*[5] however, we do not believe this should cause transmission reform. Consequently we do not agree with the AEMC's views in the Paper, *"Under the final access regime, transmission investment costs would no longer be recovered solely from consumers through TUOS charges. A portion of these costs would instead be collected from generators through the purchase of hedging products. This means that the TUOS component of a customer's bill should decrease."*[6] There does not appear to be any modelling underpinning this statement and we believe it ignores the likely increase in generation costs that would offset any gains made in respect of TUOS savings.

Finally we note the AEMC's view that, *"This increased financial certainty should incentivise generators to bear a potentially large portion of the costs of transmission infrastructure that are currently shouldered (sic) borne by consumers."*[7] MEA Group has not seen any modelling to support the view that through the sale of FTRs, sufficient financial incentives will be created for TNSPs to invest in the shared transmission network and fund the required augmentation to connect these projects.

System Strength:

MEA Group notes that the Paper includes a proposal for the FTRs to incorporate solutions to system strength issues which are manifesting across the system as a result of rule changes that require new connections to connect on a 'do no harm' basis. *"For example, one possible way that access reform could assist is that access rights could include a product which meets the generator's obligation in relation to system strength."*[8] It is not clear how this would work at a practical level. For example when a generator identifies and develops a potential wind or solar project they will want to know how much the FTRs will cost and incorporate those costs into the overall project development and construction budget.

The TNSP won't be able to advise of system strength remediation requirements until a site has been fully developed and the system strength and fault current requirements are fully documented. Only at this stage will the TNSP be able to provide a firm offer and the corresponding FTRs can be priced. On face value this does not appear any

[4] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 10

[5] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page i Summary

[6] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 21

[7] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 21

[8] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 21

different to the current circumstances where a generator develops a project on the basis that the system strength remediation requirements are unknown until a full impact assessment is complete and the results of the 'do no harm' test become clear.

The Case for Market Reform:

The Paper states *"The Commission considered that this reform would provide an incentive for generators to underwrite the appropriate amount, location and timing of transmission investment. Generators would balance the costs of transmission investment against the costs of congestion, as well as other locational decision factors such as fuel resources. In addition, the reform would transfer the investment risks associated with new transmission infrastructure away from consumers and towards generators (who are better able to manage these risks)."* [9] This statement summarises the Commission's case for reform – that generators are best placed to manage transmission investment risk.

As discussed in this submission MEA Group is not convinced the generators are best placed to manage this risk. Expecting generators to coordinate their investment and timing decisions to underwrite a sufficient quantum of transmission investment given the numerous competing drivers for investment, is unlikely in our view. Furthermore if a significant quantum of investment is required in order to supplement a retiring synchronous generation fleet, then introducing additional complexity and uncertainty into the market is likely to have a stifling effect rather than stimulate the market at this point in time.

The Paper states *"The original NEM design choice reflected a compromise between reflecting the underlying realities of the system and the benefits of a simple unified price model."* [10] MEA Group contends that this has led to a functioning and liquid forward energy market with multiple, credible counterparties allowing participants to effectively and efficiently manage their price and volume risk. Until there is modelling that clearly demonstrates the benefits of introducing additional markets into an already complex market design and settlement system, MEA Group remain unconvinced on the proposed reform measures as outlined in the Paper.

MEA Group accept the AEMC is attempting to redefine the allocation of risks associated with transmission investment away from consumers and onto generators as evidenced by this statement in the Paper, *"Most importantly, it should ensure that consumers do not bear undue risks or unnecessary costs of transmission investment that is built to service new generation. Building transmission to benefit generators means that generators should contribute to the costs of transmission investment."*[11] However industry need to clearly articulate the risks and costs associated with the alternative (status quo) before we can be convinced of the merits of the proposed reform.

The ISP:

MEA Group believes that the ISP should remain the central planning repository for transmission investment across the NEM going forward. Given the significant transformation currently underway, with an unforeseen level of generators seeking to connect to the network (roughly equal to the current size of the NEM (50 GW)) it is sensible to maintain a centrally coordinated and planned transmission system that can best meet the needs of the transforming nature of the energy supply mix going forward. MEA Group notes that whilst there is a significant quantum of generation proposed for connection over the coming decades, it would caution that not all of that generation will ultimately proceed for a variety of reasons and therefore there is a significant risk of over-estimating the scale of this issue.

The AEMC notes in the Paper that, *"Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service"*[12] which is a sentiment the MEA Group agrees with. However MEA Group does not agree that "*Due to the current lack of locational price signals in the transmission framework"*[13] generators are not provided with sufficient locational investment signals under the current framework.

We do recognise that *"having made a locational decision, a generator is not readily able to manage the risks arising from transmission losses, congestion, and to a lesser extent, inter-regional price variation"*[14] which leads to the important issue of how existing generators would be treated under a reformed market environment.

[9] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 27

[10] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page ii Summary

[11] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 30

[12] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 43

[13] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 12

[14] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 14

Noting the AEMC's comments in the Paper *"it may be more efficient for one larger synchronous generator to be built and its fault current to be "shared" between generators. Better coordination of generation and transmission investment could help resolve these issues,"*[15] MEA Group believes this further strengthens the argument for the ISP to be the key driver for transmission investment going forward.

The Paper remains unclear as to how the introduction of DRP and FTRs would provide an environment where this type of coordination amongst generators and TNSPs would be achieved. MEA Group believes this style of reform is likely to increase the market power of the incumbents. They will be best placed to operate in an increasingly complex regulatory environment, with the capacity to absorb likely higher transmission costs across their vertically integrated generation and retail businesses.

Interaction with other proposed and confirmed reform:

MEA Group also has concerns with the reform's interaction with various other reform packages and rule change requests which include but are not limited to the Energy Security Board's (ESB) Post 2025 Market Design, Transmission Loss Factor Rule Change requests, the ESB's proposed transmission underwriting investment strategy, 5 Minute Pricing introduction and Wholesale Demand Response Mechanism proposed for introduction the same day that Dynamic Regional Pricing is proposed to be introduced.

MEA Group believes there is a real and genuine risk of introducing too much reform for participants and stakeholders to adequately respond to and prepare their business to effectively operate in an increasingly complex environment.

MEA Group appreciates the effort the AEMC has made in developing both the Final Report, 21 December 2018 and the Paper. However we do not believe sufficient quantitative analysis or data has been provided for MEA Group to develop an informed and considered position in respect of the options the AEMC has tabled. MEA Group also does not believe the process meets the requirements under Stage 2 of the terms of reference set by the COAG Energy council in February 2016 for the reasons set out previously.

This complex reform could have numerous unintended consequences if the industry and the AEMC rush this reform with poor analysis or ill-considered solutions. This could result in any perceived benefits evaporating. On that basis, we set out below some high level responses to the AEMC's questions. MEA Group would request that quantitative analysis and a clear set of options be tabled as part of this consultation process in order for stakeholders to provide meaningful and constructive feedback to the AEMC.

QUESTION 1: ALLOCATION OF SETTLEMENT RESIDUES

- Do stakeholders agree with the main advantages and disadvantages identified in relation to the different approaches for allocating settlement residues?
- Of the approaches identified under each implementation scenario, which do stakeholders think best meets the design principles (set out in Appendix A)?

MEA Group generally agrees with the advantages and disadvantages identified in relation to the different approaches for allocating settlement residues. We would likely support Option C – primary allocation on the basis of transmission hedges held where surplus residues would support a fund to increase the firmness of transmission hedges (i.e. to offset scaling back transmission hedge settlement payments when the hedge volume exceeds available transmission capacity).

This mechanism would potentially lead to sufficient settlement residue in order to underpin pay-outs against transmission hedges under all scenarios. It is important to note however, that we fundamentally disagree with the proposed approach in respect of DRP and would encourage the AEMC to consider all options including a full nodal pricing regime which would more accurately address the transmission loss factor.

- What other factors or information would stakeholders consider relevant to determining the preferred approach?

[15] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 16

MEA Group believes the status quo should be an option that is quantified in terms of costs and benefits with analysis on the extent of the disorderly bidding issue and its cost to the market in respect of the overall total cost of generation across the NEM annually. We also believe that the transitional arrangements for existing generators and market customers need to be clearly articulated and made available for consultation with the market in a timely manner. Consideration should also be given to the impact the reform changes could have on the liquidity of the forward contract market which has historically relied upon a regional reference price.

Requiring parties to forecast and then contract against a dynamic price that will change with time as generation and load enter and exit that region could potentially lead to a less liquid forward market with counterparties reluctant to offer a hedge against a dynamic regional price for some generators and market customers.

As noted previously in this submission we are concerned about the introduction of another financial derivative into an already complex system. We agree it is challenging to determine how to treat storage but we feel it should be incentivised to import at times where there is a constraint so as to provide the lowest cost overall dispatch outcome for the market.

QUESTION 3: CHOICE OF REGIONAL PRICE

- Under the proposed model, some categories of market participant would continue to face a common regional price. Do stakeholders agree that the issues outlined above are relevant for assessing whether this regional price should be the existing regional reference price or an alternative (for example, a LAP approach)?
- Are the other issues that should be considered?

MEA Group is concerned that load aggregation pricing may result in it being very difficult for new retailers to enter some geographies (zones) of the grid where there is a limited number of generators that would be prepared to enter into a hedge with them. The relevant generator may exercise considerable market power in a situation where a transmission constraint is binding and they are the only generator being dispatched well above the regional reference price.

QUESTION 4: LOSSES

- Noting that the Commission will be considering the merits of different approaches to calculating and applying loss factors in relation to the Adani Renewables rule change requests, what are stakeholders' views of the advantages and disadvantages of the different approaches outlined above, in the specific context of the dynamic regional pricing model outlined in this chapter?

There are a number of options the AEMC could consider as part of this reform including but not limited to a nodal pricing regime, where losses are measured in real time and the energy spot price reflects those losses. MEA Group notes one of the AEMC's proposed approaches "*Using real-time loss factors that are calculated every trading interval to better reflect system conditions*"[16] would be conducive with a nodal pricing regime.

In respect of the potential approaches considered by the AEMC in its Paper we believe it remains an important factor that whichever regime is ultimately selected it must reflect the actual two way flow of AC power and the physical loss of energy throughout the system. Although the current Marginal Loss Factor (MLF) regime results in an over recovery and leads to a surplus Intra Regional Settlement Residue, the MLF regime loosely reflects the actual physical characteristics of the power system at the date the MLF is calculated. This is a fair reflection of the losses associated with the system.

It is important that this reflection of the system be preserved so as to retain the locational signal to investors and participants of congestion in the grid. For that reason MEA Group would not support a collar and cap mechanism or a grandfathering approach to MLFs. MEA Group would support a proposal that calculates the MLF more frequently to correctly reflect seasonal flows across the power system along with peak and off-peak loss factors, noting these should more accurately reflect the actual losses in the system.

MEA Group does not agree with the AEMC's view that the introduction of DRP does not introduce a new net risk to generators. MEA Group expects that the complexity involved in managing a 'three part' risk (congestion, local marginal price, settlement residue) will reduce the willingness of supply-side participants to offer primary hedge products. A liquid forward market is critical to retailers being able to offer the lowest possible cost of goods sold

[16] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 62

to their customers and by introducing a pricing regime that could potentially result in a less liquid forward market, there is real risk wholesale electricity prices could rise.

MEA Group also believes that if this reform package were introduced then change of law clauses would likely be triggered under existing offtake and settlement contracts. The magnitude of these changes could potentially lead to the re-negotiation of some contracts but more significantly would result in a change to many retailers' forward contracting positions resulting in an immediate and unintended change to the risk profile faced by many of these retailers.

QUESTION 5: EXPECTED IMPACT OF THE REFORMS

- Do stakeholders agree that these issues are relevant in assessing the impact of dynamic regional pricing?
- Are there other issues that should be considered?

MEA Group agrees that the issues outlined by the AEMC are all relevant issues when assessing the impact of DRP. There are a number of other issues that we believe should be considered by the AEMC as part of the proposed reform package including:

- contract liquidity;
- grandfathering provisions when it comes to the allocation of FTRs to existing generators;
- market power in some segments of the grid;
- the capacity for some generators to game the system and create situations of congestion so as to drive the local price higher; and
- timing in relation to the ESBs Post 2025 market design and other proposed reform measures and rule change requests/implementation timeframes.

QUESTION 6: TRANSMISSION PLANNING

Do stakeholders agree that access reform and the Integrated System Plan should be integrated? If so, do stakeholders agree with the Commission's assessment about how this could be achieved?

MEA Group believes the ISP should be central to the planning and investment in transmission assets moving forward. We agree that should the reform package be introduced the ISP should incorporate information from generators in respect of the quantum of transmission hedges that have been sold.

However we would expect that through the ESB's work to action the ISP, including making those changes to the RIT-T process which allows the ISP to be incorporated into the RIT-T assessment framework, that this would be sufficient to drive the necessary investment in transmission assets going forward. We also feel that AEMO's continued engagement with generators throughout the development of each subsequent ISP means their transmission requirements are adequately addressed in the ISP.

We think this is the most appropriate mechanism to better coordinate generators and transmission network service providers. As previously discussed we do not expect this to result in stranded transmission assets as this approach is far simpler, requiring minimal rule changes or reform to existing markets and systems.

With regard to the proposed duration of transmission hedges, MEA Group would strongly favour longer term hedges that were commensurate in duration with the design life of the asset they were underpinning. It is our view that the transmission hedge product would be a variable megawatt (MW) capped at the generators maximum registered capacity for the duration of the asset life (25+ years).

QUESTION 8: PRODUCT PROCUREMENT

Do stakeholders agree that access products should be purchased via an auction?

MEA Group notes that the Paper states, *"This is because an auction process allows multiple parties to reveal their demand for firm access at the same time. It also allows for a limited amount of access rights to be allocated to those parties who would value it most highly".*[17]

MEA Group is not sure how this approach addresses the issue of congestion, particularly if the TNSP were only prepared to auction off a limited volume of access rights. The auctioning of the same amount of what is already a

[17] Australian Energy Market Commission, Directions Paper, COGATI – Access reform, 27 June 2019, page 77

scarce resource is unlikely to resolve the issue of congestion, nor is it likely to facilitate the transformation of the power system.

What it does is ensure that any transmission investment is underwritten by the generator and not the consumer, consequently reducing the risk of stranded investments for the TNSP. We feel this issue could be better addressed via the ESBs proposal to create a Government fund to underwrite investment in transmission assets particularly when it comes to renewable energy zones.

QUESTION 9: PRODUCT PRICING

Do stakeholders agree that a fair value approach to pricing may be beneficial?

If MEA Group were to support the proposed reform the fair value method should include all types of constraints including thermal, system security and stability constraints.

QUESTION 10: TNSP INCENTIVES AND REGULATIONS

Do stakeholders agree that an operating incentive scheme on TNSPs is required?

MEA Group agrees that an operating incentive scheme on TNSPs is required but the scheme should result in firm transmission rights that are sold under the hedge products by the TNSP. If generators are going to need to procure transmission hedges to hedge against pricing differentials at their connection point then we feel this should result in firm access for a generator to be dispatched up to the RRP.

MEA Group are concerned this model places a significant amount of market power in the hands of the TNSP who will in many cases be the sole counterparty for generators to acquire transmission hedges from. This could result in monopolistic behaviour and outcomes that do not meet generator's requirements or are contradictory to the NEO.

We thank the AEMC for the opportunity to provide feedback on the Paper and look forward to continued engagement in this process. Should the AEMC wish to discuss any of the above please don't hesitate to contact me.

Yours sincerely

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