MORRISON&CO

26 April 2019

Elizabeth Bowron
Senior Advisor
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235
Via email: elizabeth.bowron@aemc.gov.au.

Dear Ms Bowron,

Introduction to HRL Morrison & Co ("Morrison & Co")

Morrison & Co is an investment manager with a 25-year track record in the Australian energy and infrastructure sector. Our clients are overwhelmingly Australian and New Zealand superannuation funds and institutional investors.

Our investments are across the Australian energy sector, including generation, renewable energy development, retailing and transmission networks. The total value of the energy assets in which we have significant interests is over A$15 billion[1]. We consider ourselves active managers and our executives include a number of individuals with deep energy sector expertise. We therefore welcome the opportunity to participate in the AEMC's process and look forward to involvement throughout the various stages.

Views on the AEMC's Consultation Paper and Process

- **Strategic transmission planning:** The framework for transmission investment needs to be both strategic and subject to appropriate investment incentives, encourage prudent transmission development, whilst minimising gaming. Neither nodal pricing nor the firm transmission rights ('FTR') however are required to incentivise the strategic transmission development contemplated by the Integrated System Plan ('ISP'). Nodal pricing addresses short-run issues but does not create incentives for transmission network service providers ('TNSPs') to develop 25+ year assets. Similarly, the proposed FTR mechanism does not consider the dynamic investment incentives and behavioural economics that drive transmission investment. A TNSP will be unlikely to secure approval from its Board and funding from its shareholders for a transmission investment that does not appropriately consider long-term, risk-adjusted returns. Moreover, an FTR instrument that does not appropriately price counterparty and project risks incentivises inefficient investment outcomes, ultimately increasing system and consumer costs. The ISP could instead be efficiently delivered via existing frameworks and their evaluation processes provided there are appropriate incentives and a risk/return balance for network investors. It is not clear that the regulatory framework currently affords this support;
- **Consideration of alternatives:** The AEMC consultation document incorporates much of the 2015 Optional Firm Access ('OFA') proposal. However, we see some drawbacks to the OFA type approach. We anticipate distortions in the wholesale electricity market, and we find it hard to see how the approach of generator funded transmission would work in practice within

[1] Approximate full enterprise value of the unlisted businesses in which Morrison & Co has significant investments

the context of the implementation of the ISP. It appears that the AEMC has moved straight to OFA without considering a range of alternatives that might better meet the overriding objectives of reform;

- **Nodal pricing:** Morrison & Co is cautiously supportive of dynamic regional pricing in wholesale markets. However, if this approach is adopted, we consider it best to incorporate learnings from comparable geographies, notably within the standard market design in the US and in New Zealand (Morrison & Co is an active participant in both of these energy markets). Dynamic regional pricing as described by the AEMC is a move towards nodal pricing but with some distinctive characteristics that we believe are likely to distort operation of the market and change property rights, requiring consideration of transition measures. Importantly, as seen in New Zealand nodal pricing does not create long-run incentives for transmission development, nor should it be expected to, providing instead a solution to short-run price discovery;
- **Geographically differentiated terms of access to transmission:** Morrison & Co considers that evolution of the commercial arrangements for access to the transmission system by all users may be appropriate. Geographically differentiated pricing can allow users to internalise differential transmission costs in their decisions, to the overall benefit of all customers. However, while such differentiation may be envisaged by the AEMC, we invite the AEMC to consider the following issues. First, we suggest that both generation and load should be subject to an access pricing regime as decisions of both affect the cost of transmission. Second, pricing should be as simple as it can be. While in theory generators and load will respond appropriately to complex pricing mechanisms, in practice, we know that many in the market are more likely to make better decisions if simpler approaches are used;
- **Trading of rights:** Morrison & Co is not opposed to a framework that allows transmission rights to be traded but has concerns based on historical examples of gaming, whereby first-movers 'banked' tradeable rights in an attempt to secure windfall gains from subsequent parties, hindering network access and development of transmission infrastructure. Any mechanism would therefore need to address these types of issues in a transparent way, take into consideration the value of existing rights and be demonstrated to support a strategic approach to transmission investment aligned with evidenced commercial incentives and the decision-making processes undertaken by TNSPs, their Boards and shareholders;
- **Demand charges for transmission and constraints:** The proposals are focused on generation. However, it is remiss to develop a system of geographically differentiated charges for generation that do not address demand and demand management measures. The consultation should address and model distortions between load and generation prices. Storage should be considered and treated consistently with its operating model;
- **Transition mechanisms:** Changes to the framework will impact existing assets (under development or in operation) that have made investment decisions based on an expectation of a particular set of commercial and regulatory arrangements, with a reasonable assumption of no significant change. The AEMC's changes might therefore require transition and/or compensation mechanisms in order to be equitable;
- **Phasing**: The AEMC should consider the adverse consequences of insufficient clarity in the entire reform package before parts of it are implemented. Staggered, spaced-out implementation would likely create winners and losers with significant economic impacts that might not be consistent between stages. Co-ordination with the COAG 2025 market reform initiative is also critical given the reform of complementary wholesale market elements; and
- **Simplicity**: Market participants should face price signals that are clear, can be understood, and acted on. It is easy for this area of work to become too complex, and it is important not to let the best be the enemy of the good.

This consultation has been issued as part of a review of transmission and generation access. Morrison & Co however sees it as a much more fundamental review, with substantial changes to the default commercial arrangements on which the wholesale electricity market works. We encourage a deeper approach to consideration of these issues, and propose the following criteria to assess options:

- Does the option appropriately consider complex investment processes and incentivise efficient, strategic investment in transmission?
- Does the option create appropriate incentives on all market participants in the short term for dispatch of generation, load management and storage?
- Does the option create appropriate incentives on parties in the long term, in the overall interests of the system, and ensure that all system users face costs that incentivise the right decisions?
- Are appropriate transition arrangements in place so that past decisions based on reasonable expectations are respected?
- Is the system relatively straightforward to understand, participate in and comply with in a way that does not prejudice equitable access?
- Does the option support the continued progression of necessary investment in the near term?

We value open communication and seek to work collaboratively with the AEMC

We welcome the opportunity to engage with AEMC as partners with a common interest in delivering a sustainable and cost-efficient energy system for consumers, industry, regulators and investors. We would be pleased to meet in person to discuss the issues we have raised. Please contact Michael Faulkner via email (michael.faulkner@hrlmorrison.com) or by phone on 0431 041 074 with any questions.

Yours sincerely

Paul Newfield
Chief Investment Officer
HRL Morrison & Co

Steven Fitzgerald
Head of Asset Management
HRL Morrison & Co

Appendix 1: Morrison & Co's additional responses to the questions posed by the AEMC in its Consultation Paper

Phasing and timeframes for access reforms

- We encourage the AEMC to provide or undertake market modelling of the potential economic impacts of the proposed changes on stakeholders and an associated cost-benefit analysis, given the scale and impact of changes proposed. This would provide an agreed starting point for all participants and facilitate evidence-based engagement
- The AEMC is proposing a phased approach to implementing its proposed reforms. There is however a strong likelihood that there will be winners and losers at each stage, making progress to further reform progressively harder, and leads to the potential for incentives from evolution of the framework to conflict with earlier implementation. We therefore recommend that the AEMC consider implementation in one, integrated stage
- It is unclear how the AEMC's proposed reforms are expected to interact with other regulatory processes, particularly the AER's 2023 RORG, AEMO's upcoming ISP plans and the COAG 2025 market reform initiative to be undertaken by the ESB. AEMC's proposed reforms create significant interface issues and result in substantial risks which increase required returns for transmission and generation investments.

Dynamic Regional Pricing ('DRP')

- The extent of settlement risk for generators requires additional modelling. Current constraint risk can be difficult to predict, and any changes should not simply shift the uncertainty from one source (annually set MLFs) to another (variable market price). The existence of both DRP and MLFs would add to uncertainty, risk and ultimately consumer cost.
- There might also be a perception amongst some participants that a dynamic price region brings about local market power. More details and modelling around the potential circumstances of that occurring would be helpful in informing the consultation process.
- We do not believe that nameplate capacity is an appropriate metric on which to allocate settlement residue as it potentially provides inefficient or unintended incentives for developers. Instead, a measure based on dispatchable generation should be applied. This would reward efficient site selection and plant operation rather than overbuild. In addition, for existing plants owned by large market participants with assets across regions, the proposed settlement revenues could lead to gaming and higher system costs, with minimal price signal or information benefit.
- Development of a non-distorting pricing framework for the participation of battery storage within the network is critical. The proposal to apply different pricing for storage and generation is something we approach with caution as it could lead to distorted incentives in the location and bidding behaviour of storage systems. All generation and all loads should be treated consistently.
- It is unclear to us why changes from regional pricing to nodal would impact market contract liquidity nor how a difficult-to-price FTR would provide an improved ability for generators to hedge market price or transmission constraints.
- Finally, the AEMC should consider impacts of any changes on existing PPAs for generators and capital providers, given change in law provisions

Information from Dynamic Regional Pricing

- It is unclear what role dynamic regional pricing will have in transmission investment decision-making. As discussed above, the drivers of transmission investment are creditworthy counterparties willing to enter into firm, long-term contracts that underpin an appropriate return on investment.
- Whilst the information sourced from dynamic regional pricing may complement AEMO's ISP to some extent, AEMO already has a strong understanding of areas of system weakness, including existing price signals and it is not clear how DRP information is expected to significantly influence strategic transmission planning.
- It would be unhelpful to forcibly incorporate DRP information into TNSP investment processes via rule changes; if by itself the information from DRP does not provide economic signals, then it should not be the role of rule changes to distort efficient economic decisions rather than deliver least-cost solutions.

Generators Fund Transmission Investment

- At present the default generator right is to receive the Regional Reference Price ('RRP') if dispatched, but without dispatch rights. These default rights will be changed as a result of the proposals, but the new default right could be complex. It is important that the existing default generator rights are clearly identified in order to effectively estimate the cost impact of transmission charges of any generator, which also facilitates the development of a TUOS charging structure. Moreover, given existing obligations on TNSPs to provide connection, it is unclear why generators would be incentivised to buy firm access for something that they currently expect to be developed anyway.
- It is unclear how the AEMC's proposed FTR mechanism is consistent with a strategic approach to transmission development nor how at a localised level FTR instruments would be priced or commercially evaluated. The FTR proposal does not appear to incorporate the commercial mechanisms that lead to the development of transmission. The decision by a TNSP's Board and shareholders to fund transmission depends on the existence of either a creditworthy corporate counterparty able to credibly enter into long-term contracts, or a sovereign entity (the AER), to provide a return on investment. Replacement of the AER with entities of a lower creditworthiness would increase the risks to the capital investment, via stranding and counterparty risk. It would be difficult for Boards and shareholders to agree to fund projects with a fundamentally higher risk profile, or would necessitate a significantly higher required return, thereby potentially stymieing investment or increasing the up-front cost of an FTR instrument to a level such that renders a generation project uneconomic. Without appropriate satisfaction of these risk factors and credible commitments by parties to a long-term arrangement, the incentives to develop transmission assets would not exist.
- It is also unclear how free-riding implicit in the FTRs is proposed to be mitigated. In the event that one generator does buy firm access (at a potentially significant cost) and the TNSP expands the network to accommodate this, the TNSP would be rationally incentivised to build some excess capacity in anticipation of future connections, creating a 'free ride' to subsequent generators and logically leading to few participants wanting to be the 'first mover'.
- In the event that existing generators are granted FTRs, significant market disruption might occur. As a result, in the event that this instrument is implemented, it should only be on a forward-looking basis, with appropriate transition and/or compensation for existing assets adversely affected. Ultimately, incentives on generators need to be dynamically consistent and not susceptible to gaming.
- The challenge of FTRs speculation or 'site banking' in certain nodal areas may also arise. Intrinsically linked to pricing of FTRs, it may occur in situations where transmission rights are

worth close to or more than generation profits. The AEMC should consider mechanisms to address this issue.

- Price discovery for FTRs is difficult to assess and requires more detail on structural parameters. The AEMC should consider the differential counterparty risks associated with generation project proponents and the resulting impacts on pricing. The construction of large-scale transmission would require large, creditworthy counterparties or complex, risky 'clubs' of smaller developers, raising questions as to the efficient pricing of FTRs. An instrument that cannot be reliably priced cannot form the basis of large-scale transmission investment.
- The AEMC should consider the significant complexity, compliance and costs that would arise from an FTR mechanism, including requirements for specialist additional resourcing (pricing, valuation, accounting, tax and legal advice) as well as ongoing commercial negotiation, administration and trading. This cost and complexity would put all but the largest organisations at a substantial disadvantage, stunt market activity and lead to further concentration of the market amongst a small group of participants.

IR TUOS, Framework and Reforms

- The complexity of TUOS charges requires the AEMC to provide baseline market modelling to confirm energy flows, costs and charges. The analysis to demonstrate the current arrangement should explicitly state the rights of current generators and TNSPs as well as assess current and future demand, which drive load and pricing charges.
- The framework needs to be consistent with commercial arrangements and show a clear relationship between charges and load. In addition, any amendments to the TUOS framework will depend on and need to be consistent with changes to transmission rights, changes to access costs and implications for existing (as opposed to future) generators.