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Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

By online submission

Dear Mr Pierce

Coordination of Generation and Transmission Investment – Access Reform Directions Paper 2019

Thank you for the opportunity to submit to the COGATI – Access Reform Directions Paper (the Directions Paper). AEMO shares the broad objectives of the Directions Paper, including driving better investment decision making through congestion pricing and to providing an avenue for generators to effectively hedge risk. However, we suggest that more analysis is required before a direction for access reform can be set and used as a basis for rule change proposals. A mix of mutually compatible access reform elements is required to meet current and future requirements. This is why rule changes to enact the actionable ISP are important and why it is important to further consider REZ funding models. These are tangible measures to underpin long term investment in transmission assets.

A form of nodal pricing and financial transmission rights may be a key enabler of efficient short term operation and investment decisions. This is a key reform that intersects with nearly all elements of NEM operations: spot market dispatch, settlement and prudentials; and affects many participant groups in the NEM. Therefore, we should take the time to explore other purer forms of nodal pricing and FTRs and avoid the possible inflexibility that may come from Dynamic Regional Pricing (DRP). We have suggested areas of further work to achieve this.

DRP would be major reform to the NEM. DRP produces a pseudo nodal price for generation with respect to congestion but it does not price load and generation at each node. A full set of nodal price signals would allow for the development of hedging products which relate to both the loss and congestion components of price separation between two nodes (or a hub representing a group of nodes). If the AEMC were to pursue a holistic package of access reform, then serious consideration should be given to nodal markets with financial transmission rights.

AEMO continues to support the ESB's 2025 market design process. Ensuring that issues and options raised in the Directions Paper are well considered makes it more likely that proposals will be complementary to the ESB's work and deliver benefits for consumers.

The attached submission builds on these points.

We would welcome the opportunity to discuss the matters raised in this submission further. Should you have any questions, please contact Kevin Ly, Group Manager Regulation on (02) 9239 9160.

Yours sincerely

Peter Geers
Chief Strategy and Markets Officer

ATTACHMENT 1
AEMO SUBMISSION TO THE COGATI ACCESS REFORM DIRECTIONS PAPER 2019

KEY POINTS

- We agree with the overarching aims of the Directions Paper which are to drive better investment decision making through congestion pricing and to provide an avenue to effectively hedge risk.
- We support a form of nodal pricing and financial transmission rights but suggest that alternative models are more closely aligned with international and academic best practice.
- At this stage we are not convinced that the dynamic regional pricing model in the Directions Paper is flexible enough to provide a future proof solution for the changing nature of the NEM.
- We support the development of REZ funding models and the Actionable ISP. In particular, the ESB process of making the ISP actionable and reducing the implementation time for strategic network developments would improve the resilience of the NEM power system. These approaches are required alongside nodal pricing to deal with long term investment in transmission.
- Further analysis should be done to enhance the likelihood that access reforms will deliver benefits to consumers and be complementary to the 2025 market design proposals being considered by the ESB. An orderly transition is required from now to when NEM reforms are implemented post 2025.

1. Introduction

AEMO welcomes the opportunity to examine the transmission access regime of the NEM. AEMO sees locational marginal pricing and financial transmission rights as complementary to the ISP and a key reform to allow the NEM to accommodate the high turnover in generation assets in the forthcoming decades. Ultimately any direction set for rule change proposals has to deal with the imminent challenges facing the NEM such as maintaining system security, reliable supply and affordability in the context of increasing variable renewable energy. The access regime requires a number of measures working together to ensure these challenges are met. As such, this submission provides comments in relation to:

- The principles that should underpin an access regime
- The elements of the AEMC access reform proposal we support
- Areas of the AEMC proposal we have reservations about
- Areas for further analysis and development

2. Objectives and principles

To deal with current and future challenges, the purpose of access reform should be to achieve the following objectives, which were also outlined in our submission to the Consultation Paper[1]:

[1] AEMO. *2019 Submission to COGATI Consultation Paper*, April 2019. Available at: https://www.aemc.gov.au/sites/default/files/2019-05/AEMO.PDF

- Accuracy – The market design should create price signals that accurately reflect the costs of congestion at a given point on the network.
- Transparency – The market design should be transparent, eliminate as far as possible information asymmetries between market participants and respond predictably to changing market conditions.
- Liquidity– Transmission rights should be designed to support liquid markets and efficient network and market outcomes. Transmission rights should provide project proponents and operators with a way to manage risks associated with changes in access levels and price separation over time.
- Security & reliability – Transmission access reforms should not impede and where possible should complement AEMO & TNSP's ability to manage system security.

We consider that these objectives are consistent with the AEMC's objectives. However, we suggest there may be more direct ways of meeting these objectives while avoiding risks.

3. Areas of the AEMO and AEMC alignment

3.1 Accurate and transparent price signals

AEMO supports further work to assess the potential benefits and costs of revealing locational price signals through a form of nodal pricing. From a system and market operator perspective, making pricing more reflective of constraints is likely to increase alignment between generator bidding and system conditions. This has the potential to be a sound bedrock for appropriately identifying and solving a range of issues in order to maintain a secure, reliable and efficient power system.

3.2 Mechanisms to manage risk

Locational marginal pricing has the potential to support new forms of risk management such as financial transmission rights. Higher penetration of VRE heightens risk in terms of changing marginal loss factors and inadvertent pricing outcomes arising from the RRP pricing structure. Exposing locational marginal prices forms a basis upon which hedging products can be developed. For example, in New Zealand and PJM, the FTR product includes losses (see Appendix A).

3.3 Information to enhance transmission planning

Local price signals can create more accurate information regarding the value that generators place on network access at given points on the network. This information can help to inform transmission investment decisions.

3.4 REZ funding models

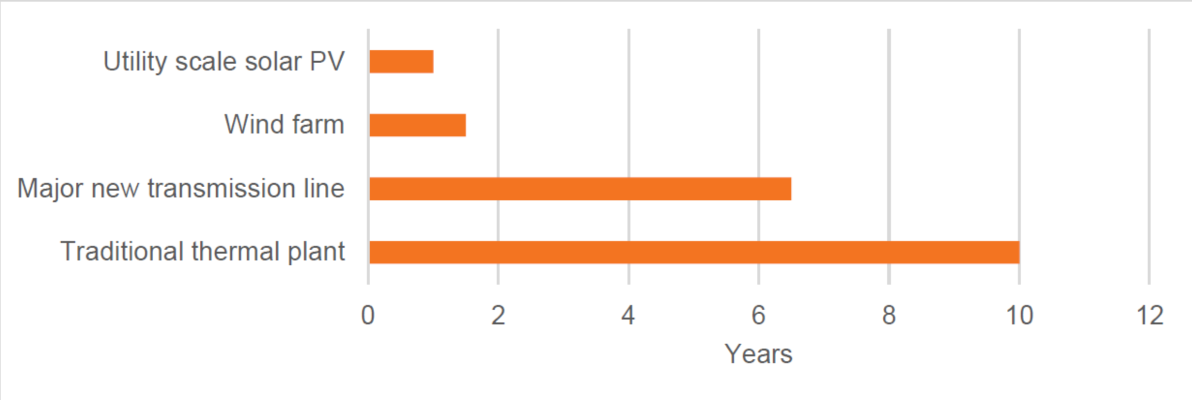
We welcome the AEMC's consideration of a shared cost recovery model for REZs. A workable REZ funding model may continue to provide benefits even after a nodal pricing and a transmission hedging regime is implemented, given that FTRs are better suited to shorter term risk management rather than underpinning long term investment.

AEMO agrees that renewable energy zones should act as a facilitator of coordination between generators and other generators. In its role as Victorian TNSP, AEMO already pursues synergies in new generator connections where the timing of connection applications presents an opportunity to do so. Alternative approaches to organising the connections process could allow for some coordination between generators. However, this approach is not a panacea given a persistent and natural level of competition between generators.

There is also a potential role for a REZ framework, and the broader transmission pricing arrangements, to promote coordination between generation and transmission. The ISP will identify a whole-of-system plan that supports the efficient development of the power system. We support further consideration of transmission cost allocation, including whether there are options to allocate costs in a way that more closely reflects the beneficiaries. These reforms should be designed to complement the ESB's work to convert the ISP into action.

We note that the International Energy Agency (IEA) and National Renewable Energy Laboratory (NREL) have both recognised that REZs can have a role in helping to address the misalignment in lead times between transmission and generation projects.[2] As noted in our previous submission, timing issues mean that an additional layer of coordination is likely to be required.

Figure 1. Indicative lead times associated with major electricity infrastructure



We welcome further consideration of the model proposed by PIAC, which highlights the potential benefits of cost sharing to promote the long term interests of customers through the efficient development of REZs. Among other things, it would be useful to define more clearly what types of assets would be subject to the proposed funding model. For instance, a REZ could potentially refer to connection assets or shared transmission infrastructure. Further work is likely to be required to clarify how underutilisation risk would be managed under the PIAC model, since historically TNSPs have been unwilling to take on this type of risk.

AEMO supports further consideration of a broader range of REZ development models currently used internationally, such as Germany's Grid Expansion Acceleration Act[3], Great Britain's Transmission Investment for Renewable Generation mechanism[4], the Texan Competitive Renewable Energy Zones (CREZ) model and MISO's Multi Value Projects model.[5] AEMO considers that this work has the potential to be a major project in its own right, and there could be merit in pursuing these issues independently of the COGATI process.

4. Areas where AEMO may have a different view

[2] NREL (2017) *Renewable Energy Zone (REZ) Transmission Planning Process: A Guidebook For Practitioners*, September 2017, https://www.nrel.gov/docs/fy17osti/69043.pdf and IEA (2017) Getting Wind and Sun onto the Grid – a Manual for Policy Makers https://www.iea.org/publications/insights/insightpublications/Getting_Wind_and_Sun.pdf

[3] Bundesnetzagentur, Grid Expansion in Germany: What you need to know, 2014.

[4] Ofgem, https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/transmission-investment-renewablegeneration

[5] US Department of Energy, https://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf and https://gwujeel.files.wordpress.com/2013/07/miso-ercot-cost-allocation-methods.pdf

4.1 Transmission hedges and long term investment.

The consultation process for Optional Firm Access highlighted intractable issues in determining the price for long term access rights and deciding how to grandfather existing rights. AEMO suggests that requiring transmission hedges to underwrite long term transmission capacity is both not necessary and results in uncertainty, costs and additional risk.

The short run price signals and the congestion and loss rentals FTRs create are unlikely to recover the capital and operating costs of new transmission lines. Further, relying on such price signals alone is likely to result in under-investment in transmission.

Transmission investment is a very long-term investment and is dominated by economies of scale.

- FTR pricing is linked to short run marginal cost and is based on assuming that all capacity is incremental expandable. Effectively the FTR reflects the impact on short run costs of the last one megawatt of transmission capacity.
- It follows that the value of an FTR does not equate to the value of transmission capacity and is generally much less. Further if there is congestion and new capacity is built to relieve that congestion then the value of congestion rents (and hence the value of FTRs) will fall with the investment.

Therefore, transmission investment cannot be solely funded based on the sale of FTRs. However, once an agreement is made to fund an investment, the parties funding it can be awarded the benefit of the FTRs. This provides them protection against future congestion but does not offset the cost of the initial investment.

FTR prices are more likely to have a role in indicating demand for access which then informs transmission investment undertaken through the actionable ISP framework or TNSP planning. However, AEMO notes that there are numerous other factors that need to be considered when planning a transmission network, including the needs of customers to have a secure and reliable power supply in the context of a changing generation mix. Investment lead times mean that relying on generators to signal future transmission investment needs leads to a chicken and egg problem.

AEMO recognises that there may be an incremental role for long term access rights to apply to generator funded augmentations. In this case, generators might wish to fund incremental investment in addition to the baseline investment identified in the ISP, and then have rights over their investment. While this approach might be a useful tool for generators in certain circumstances, we do not envision that it would be a major driver of transmission investment in the NEM.

4.2 DRP and nodal pricing

DRP is just one way of approaching nodal pricing in the NEM. However, there are limitations, primarily due to the fact that it maintains a focus on the RRP. This choice was made to limit costs and limit disruption to financial contracts. While these are worthwhile aims, not enough analysis has been done to assess whether this would actually hold true and whether the benefits of achieving these aims outweighs the benefits of alternative models.

DRP relies on the current dispatch pricing mechanism, NEMDE, to determine local prices. The local prices determined by NEMDE are a by-product of a dispatch system, whose primary aim is to formulate RRP using regional supply and demand and a set of constraints. The local prices produced in NEMDE do not dynamically price losses and do not dynamically price load at each node. In other words, DRP produces a pseudo nodal price for generation with respect to congestion but it does not price load and generation at each node. A full set of nodal price signals would allow for the development of hedging products which relate to both the loss and congestion components of price separation between two nodes (or a hub representing a group of nodes).

Other models which price load and generation at the same locational point may be better at accommodating different locational patterns of demand and supply over time; exposing a price for load (batteries and demand side response); and possibly including losses in the transmission hedging product. Pricing load and generation at the same locational point may better equip the NEM to transition through various chapters of demand and supply patterns in the coming decades. If this were to be done properly, a re-think of the current dispatch pricing approach may be required as this is currently set up to solve for the RRP and may not efficiently be able to orientate to solve for load and generation at the same location, concurrently.

It should be noted that an alternative nodal pricing approach could be used as a basis to achieve a similar model to that set out in the Directions Paper, as a starting point. For example, generation could be priced at each node and a new RRP could be formulated from a weighted average price of the load price determined at each node. However, a purer form of nodal pricing may be be more flexible so that pricing regions for generation and load could change with supply, demand and the transmission network in the NEM. Accomodating changing generation and supply patterns overtime, is after all, a key aim of the COGATI reforms.

5. Further areas for analysis and development

This is an area of reform that has the potential to unlock significant benefits in the NEM. However, more market design analysis and development is required before AEMO can support the development of rule changes. This analysis should take into account the full range of challenges facing the NEM as contemplated as part of the ESB's review of post 2025 market design. In order to achieve an orderly transition, it is necessary to consider the sequencing of reform prerogatives and how different elements of the framework interact.

In order to introduce a fit for purpose access regime, it would be necessary to consider:

- Ensuring that any model accounts for a high penetration of VRE - any form of nodal pricing and transmission hedges need to accommodate the transmission access needs of intermittent generation, which set $0/MWh prices and may not require a set level of access throughout the day.
- Future system requirements – also to accommodate VRE, a nodal pricing framework would also ideally work with the growing requirements for system services in the NEM such as system strength, inertia and flexible ramping products.
- Access pricing and access rights – only one model has been proposed by the AEMC and many others exist internationally and in academic literature. AEMO believes Nodal Pricing and Financial Transmission Rights is a more efficient approach to access reform. AEMO has identified the following areas for consideration and there are likely others:
    - the level of nodal pricing granularity appropriate for the NEM and the inclusion of load;
    - the dispatch pricing system and power system model most amenable to supporting nodal pricing and FTRs;
    - the design of the hedging products and the likely level of firmness;
    - the structure and timing of the auctions;

- how nodal pricing and FTRs would intersect with current NEM dispatch, settlement, prudentials and registration;
- prudential and risk concerns for an FTR market; and
- assessing market power concerns.

As per section 3.4, AEMO supports and would welcome further development of REZ models.

Appendix A

Here we provide an overview of different markets that have a nodal pricing and financial transmission rights - New Zealand Electricity Market (NZEM); ERCOT (in Texas); and PJM (in the north east of the US). This is included to highlight other approaches to nodal pricing and transmission hedging around the world.

Feature	NZEM	ECROT	PJM
Year commenced	1996	2001	1997
Year LMP commenced	1996	2010	1998
Current use of LMP	Real time market (No day ahead market)	Day ahead market Real time market	Day ahead market Real time market
Central unit commitment?	No	Yes	Yes
Form of scheduling	NEM like optimisation but with a DC power flow with losses varying with transmission flow.	Iterations between market optimisation, AC power flows, and contingency analysis	Iterations between market optimisation, AC power flows, and contingency analysis
Network nodes	≈ 600	≈ 780	≈ 12,000
Settlement nodes	≈ 200	≈ 500	≈ 3,150
Generator prices	LMP	LMP	LMP
Load prices	LMP	Weighted average LMP zones: 4 large, 4 small	LMP
FTRs first offered	2013	2010	1999
FTRs sold for	Month	Time blocks in month	Time blocks in month
FTR types	Obligations and options	Obligations and options	Obligations and options
FTRs settled against	Real time market	Day ahead market (some against real time market)	Day ahead market.
Nodes / hubs at which FTRs tradeable	8 nodes (corresponding to load centres and/or major generation centres)	Any node 7 hubs (4 hubs corresponding to 4 large pricing zones).	Any node 12 hubs.
LMP components	Losses and congestion	Congestion	Losses and congestion
FTR coverage	Losses and congestion	Congestion	Congestion
Capacity market?	No	No	Yes
Max bid/LMP.[6]	$NZ 20,000/MWh	$US 9,000/MWh	$US 2,850/MWh

[6] The specific limits vary with circumstance and may be different between day ahead and real time markets. The values presented are indicative of the highest energy price that could occur in one or both of the day or real time market.