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12 November 2019

Mr John Pierce AO
Chair - Australian Energy Market Commission
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SYDNEY SOUTH NSW 1235

Dear Mr Pierce

**Submission to Discussion Paper on the Proposed Access Model for the Coordination of Generation and Transmission Infrastructure**

Thank you for the opportunity to comment on the Australian Energy Market Commission's (AEMC) 'Coordination of Generation and Transmission Infrastructure Proposed Access Model' discussion paper. Please find attached the Australian Energy Regulator's (AER) submission to the discussion paper.

We maintain our support for the AEMC progressing its consideration of the proposed changes to the wholesale electricity pricing framework and the introduction of an accompanying financial risk management framework.

As we have stated in our previous submissions to the Coordination of Generation and Transmission Investment (CoGaTI) Implementation review, we agree that dynamic regional pricing (DRP) provides better price signals to market participants around network congestion. This is expected to guide generation to locate in areas that are cheaper to serve with transmission capacity and, in turn, promote more efficient generation and transmission investment. The improved price signals are also expected to promote more efficient dispatch, as well as more efficient operational decisions by generators and storage.

The introduction of FTRs should also provide generators with greater transparency and tools to manage congestion pricing risk (subject to the design of the FTRs). This should enhance their ability to contract for the sale of generation and therefore promote competition with benefits to consumers. It remains our view that the concurrent introduction of a financial risk management framework (i.e. financial transmission rights (FTRs)) is therefore necessary.

We agree that such change is needed urgently to better facilitate the National Electricity Market (NEM) transition that is currently occurring, as set out in the AEMC's discussion paper. In addition, the AEMC's proposed access model acts as the foundation for market designs being considered under the Energy Security Board's (ESB) NEM 2025 work program. Any major market reforms to arise from that project are likely to require better locational signals and (financially) firm access to the transmission network.

We thank the AEMC for providing a high-level design of the proposed access model to allow stakeholders to evaluate the reform in its entirety and to begin consideration of the many interrelated design aspects. Our attached submission identifies challenges with a number of the specific design decisions that are proposed in the discussion paper. We hope our comments inform a robust and sustainable design of the proposed access reform model, which, on the whole, we consider should be progressed.

Overall, we consider the results of the AEMC's proposed modelling will need to be available before a number of decisions on the design of the access model can be made. We identify and expand on these aspects of the design in our attached submission, including the need to understand the impact of FTR features on revenue adequacy and the extent to which local market power is expected to arise.

We support the AEMC's acknowledgement that the access model design will need to provide flexibility for the exploration of different future market designs under the ESB's NEM 2025 work program. It is important for this access model to be able to adapt to and facilitate a range of possible future market design scenarios. We consider more work could be done in drawing the links between this proposed access model and the future market designs being considered under the NEM 2025 work program. For example, it would be useful for the AEMC to set out how this proposed access model would work with the different market design options that are likely to be considered under the NEM 2025 work program, to ensure the access model is as flexible as possible.

More generally, a flexibly designed model will enable the framework to best adapt to the needs of the market and evolve as those needs change. To that end, we recommend the AEMC consider how prescriptively the design of the proposed access model would need to be set out in the National Electricity Rules.

Finally, we support the AEMC's decision to not pursue the direct link to transmission planning (the 'third pillar' of the proposed access model). We considered there were substantial challenges with the proposed direct link between the availability of FTRs and the transmission planning and investment framework. It is our view that the integrated system plan (ISP), supported by the regulatory investment test for transmission (RIT-T), should lead the transmission planning and investment decision making process. We agree that the price signals and information to arise from the introduction of DRP and accompanying FTR framework will inform this process.

We thank the AEMC for the opportunity to contribute to the proposed access model discussion paper and look forward to our continuing involvement in the CoGaTI access and charging reform work program. If you have any questions about our submission, please contact Arista Kontos (08 8213 3492).

Yours sincerely

Clare Savage
Chair
Australian Energy Regulator

# AER Submission

# Coordination of Generation and Transmission Infrastructure Proposed Access Model Discussion Paper

November 2019

# Contents

# 1 Introduction

The AER welcomes the opportunity to respond to the AEMC's Coordination of Generation and Transmission Infrastructure Proposed Access Model discussion paper. This submission sets out our views on the AEMC's proposed design of the access model. We have structured this submission as follows:

- section 2 discusses the potential market power issues associated with the proposed access model, and impacts on our market monitoring processes
- section 3 discusses design aspects of dynamic regional pricing (DRP)
- section 4 discusses design aspects of the financial transmission right (FTR) framework, including their procurement.

We continue to support the AEMC in progressing its consideration of the proposed access model – specifically, the introduction of DRP and concurrently implemented FTR framework. This submission identifies aspects of a number of the specific design decisions that warrant further consideration; our comments on these are aimed at informing the AEMC's consideration of the trade-offs in reaching an internally consistent and robust design.

We agree that there is an urgent need for this access reform in order to facilitate the NEM transition, as the AEMC has set out in the discussion paper. We therefore continue to support the planned implementation date of July 2022.

As we stated in our submission to the CoGaTI directions paper, the costs and benefits of different design options should be compared against the status quo, and design choices made that balance theoretical and practical considerations. Together, these should avoid letting 'the perfect become the enemy of the good' in developing a workable reform model.

## 1.1 Flexibility for future evolution

In our submission to the COGATI consultation paper, we set out overarching principles that we considered should guide the access (and charging) reforms under the COGATI review. This included the following:

- Any reforms should be developed having regard to their role and fit within the broader reform program, in particular:
  - the work program to make the ISP actionable;[1] and
  - the ESB work program relating to NEM 2025 design.[2]

Overall, the AEMC should seek to develop a model that can accommodate future market designs that are developed through the NEM 2025 project. We note that nodal pricing, which is common in electricity markets overseas, seems to be consistent with a range of market designs.

## 1.2 Modelling of the reform's impacts

In this submission, we raise the need for the AEMC to undertake modelling to understand the expected pricing outcomes under DRP. This is particularly necessary to properly

[1] AEMC, *Final Report: Coordination of Generation and Transmission Investment*, 21 December 2018, Recommendation 1, p. 10-11.

[2] ESB, *Post 2025 Market design for the National Electricity Market (NEM)*, March 2019, Available at: http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20-%20Post%202025%20Market%20Design%20-%20Scope%20and%20Forward%20Work%20Plan%20-%2020190322.docx.pdf

understand the potential for, and nature of, local market power issues to arise (see section 2), as well as to inform the AEMC's consideration of the appropriate regional price to be adopted (see section 3.2).

It will be important for this modelling to indicate the likely effect of the proposed access reform on wholesale electricity prices both in the short term and, to the extent possible, in the longer term when investment has responded to the revised incentives. This should inform the AEMC's broader consideration of the benefits of the reform relative to the costs.

## 1.3 Revenue adequacy

Revenue adequacy occurs when the residue that arises from the wholesale market settlement is at least equal to the total payout obligation under the FTRs that have been sold. Settlement residue is a function of the capacity of the transmission network that is available in a given dispatch interval. In determining the volume and combination of FTRs to be made available, consideration must be given to the level of settlement residue that is expected to arise in each dispatch interval relative to the FTR payout obligations.

We welcome the importance the AEMC is placing on promoting sufficient settlement residue to pay out the FTRs. The impact of FTRs on the liquidity of the contract market will depend on the design of the FTRs and the broader framework – specifically, how firm the FTRs will be.

We recommend the AEMC delay making final decisions around the design of FTRs until it completes its simultaneous feasibility study by mid-2020. Given that there are trade-offs to be made with respect to the types and features of FTR products as they impact simultaneous feasibility and revenue adequacy, we consider that these decisions are best left until the results of the simultaneous feasibility study are available.

Overall, we recommend the AEMC's design of the framework be guided by the following overarching principle: the proposed FTRs (when combined with DRP) should allow generators and loads to hedge their financial risk to a similar extent (or better) than under the status quo.

# 2 Market power and our monitoring functions

We look forward to the outcomes of the AEMC's zonal study of the network, to be carried out by December 2019. Without this modelling, we cannot discount the possibility of market participants exercising local market power under the DRP framework. In turn, without understanding the nature and extent of the harm that might arise from the exercise of any local market power, we cannot comment on appropriate mitigation mechanisms. We expand on these views in the following sections.

## 2.1 Characterisation of issues

As stated in our submission to the directions paper, we consider that more granular wholesale electricity pricing has the potential to make the exercise of market power more transparent.[3] We agree with the AEMC that concerns around market power under DRP pertain to circumstances where network constraints are binding and market participants can influence the *local* price in regions that lack competition (local market power). However, we are concerned that the AEMC has oversimplified its characterisation of how local market power issues may arise.

From the literature, it seems the circumstances under which local market power can be exercised, and the role of FTRs and hedging contracts in either enhancing or mitigating that market power, is complex and context specific.[4] Whilst we agree that conventional hedging contracts can reduce market participants' incentives to exercise local market power under a nodal pricing framework, FTRs can actually increase such incentives, depending on where the participant is located and the FTRs it holds. The AEMC's proposed zonal study needs to be carried out before we can assess with any confidence the potential for local market power to be exercised in different areas across the NEM under the proposed new framework. We note that we also monitor the forward contract market, on which we would also need to understand the potential for, and implications of, market power.

The exercise of local market power under a DRP framework can have detrimental effects on the market, even when retailers and other non-scheduled load continue to face a single regional price. For example, the exercise of market power can:

- Lead to inefficiencies in the market, such as generators being dispatched out of their merit order (meaning more expensive generation is dispatched when cheaper generation is available), or demand response service providers providing these services when they are not needed

- Lead to an increase in the regional price because the volume-weighted average price (VWAP) (see section 3.2.2 below) is the volume-weighted average of local prices. If there is sustained increases in certain local prices, this can pull the average up.
- Lead to inefficiencies in the allocation of FTRs. For example, a monopsony buyer of FTRs at a location may be able to secure FTRs at zero or close to zero prices.

As part of its zonal study, the AEMC has stated it will determine how many participants are in each location, to understand the share held by any one generator in each zone. In doing so, we recommend the AEMC consider portfolio effects,[5] as well as the impact of settling

[3] We note that this is dependent on the design of DRP.

[4] Harvey and Hogan, *Nodal and Zonal Congestion Management and the Exercise of Market Power*, January 10, 2000, p. 1; see also Joskow and Tirole, *Transmission rights and market power on electric power networks*, RAND Journal of Economics Vol. 31, No. 3, Autumn 2000, pp. 450-487 and Gilbert et al, *Allocating transmission to mitigate market power in electricity networks*, RAND Journal of Economics Vol. 35, No. 4, Winter 2004, pp. 691-709.

[5] Where one company owns a portfolio of generation, they can change the output of one generating plant to benefit another generating plant in the portfolio.

scheduled and non-scheduled participants at different prices. For example, there may be an area in the network where two generators are located, both under common ownership, but one is scheduled and the other non-scheduled. These two generators may be able to behave in a way that advantages the price at which the other is settled. We have also seen instances in the past where a generator at each end of a thermal constraint has caused the constraint to bind. Under the proposed new framework, scheduled participants might be incentivised to cause a constraint to bind, where it is in their capacity to do so, in order to increase their FTR payouts.[6]

## 2.2 Proposed mitigation measure

The AEMC has proposed addressing potential local market power issues with an ex ante offer cap on generators that are deemed to be pivotal. A pivotal supplier test could be, for example, if the generator is required to meet demand at one or more transmission nodes.

We note that varying forms of ex ante offer caps are employed in other jurisdictions as regulatory mechanisms to mitigate local market power. It is our view, however, that we first need to understand the nature of any market power issues that are expected to arise both in the NEM and the contract market under the proposed access model, including the extent of the resultant harm, in order to identify an appropriate solution.

Nevertheless, we have identified the following considerations for the AEMC with respect to its proposed ex ante offer cap:

- The AEMC suggests that the offer cap could be set, for example, at the price of the second highest bid in the wholesale market, 'with this made by another generator who was cleared'.[7] Again, consideration should be given to the potential for generators under common ownership to adjust their bidding in a way that increases the offer cap of the other.[8]

- Certain generators in the NEM are required to run at all or certain times to meet demand, including times when there is no second highest offer. For example, under the proposed mechanism, Hydro Tasmania would be deemed pivotal all of the time; likewise for AGL's Torrens Power Station in South Australia during certain periods in summer. The proposed pivotal test and offer cap calculation may have broader implications on the market. On this note, consideration would also need to be given to the impact of such a policy decision on the Office of the Tasmanian Economic Regulator's wholesale contracting regulatory framework and the responsibilities on Hydro Tasmania in relation to regulated wholesale market contracting.[9]

- If any cap is a mechanical calculation, we agree it is most practical for it to be determined by AEMO. However, if calculating the offer cap requires some economic judgement, we consider that, as the economic regulator, we would be better placed to determine each offer cap instead. We note that this may be a substantial task, with a potentially material impact on our resources.

- The mechanism would need to be accompanied by a significant reporting regime to monitor compliance. The costs of this should be factored into AEMC's consideration of the magnitude of the solution relative to the extent of the harm arising from any local market power.

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6 Alsac et al, *The right to fight price volatility*, IEEE Power and Energy Magazine, July/August 2004, p. 57.
7 AEMC, *CoGaTI Proposed Access Model Discussion Paper* (14 October 2019) p. 45.
8 An alternative approach to determining an ex ante offer cap could be limiting the generator to offering 80 per cent (for example) of its output at a price less than twice its input fuel cost, or double the average at which it offered the bulk of its output over the previous month.
9 See Office of the Tasmanian Economic Regulator, *Electricity Wholesale Contract Guideline*, Version 2.0, December 2016.

## 2.3 Wholesale market monitoring and reporting

As part of the implementation of the proposed changes, we would need to review our wholesale market monitoring processes to ensure these are appropriate for identifying instances of market power and market manipulation in the spot and contract markets under a revised access model.

In addition, we reiterate the need for the AEMC to consider, as part of the implementation work, whether changes to our existing reporting requirements under the NER would be warranted under a new DRP framework. As noted in our submission to the directions paper, the introduction of local marginal prices (LMPs) would significantly increase the number of reports we would need to produce under clause 3.13.7. We therefore recommend the AEMC consider whether the current requirements would remain appropriate and fit-for-purpose under the proposed new framework. As noted in our previous submission, we consider it would be more efficient and informative for the AER to group events and report on them periodically (e.g. quarterly), as opposed to reporting on all of them individually.

We would be happy to work with the AEMC on identifying the potential market power and market manipulation issues that may arise under the proposed new framework and considering the appropriate monitoring and reporting that may be needed. As part of this, we would be keen to understand the information AEMO can provide to understand the pricing outcomes that are likely to arise under DRP. From this analysis, the AEMC may find it necessary to review and update our monitoring and reporting functions as provided for in the NER.

The need to be able to model expected pricing outcomes under the proposed access model supports the case for the introduction by AEMO of a network 'digital twin' – a real-time replica of the NEM which would be informed by actual grid performance. In our view, current modelling techniques are insufficient to accurately understand the impact of this reform on the settlement process, including the interplay with other reforms, such as 5 minute settlement and the proposed Wholesale Demand Response Mechanism (WDRM).

# 3 Wholesale electricity prices: Dynamic regional pricing

We maintain our support for the AEMC progressing its consideration of DRP. While we consider full nodal pricing is the most economically efficient option, DRP is a pragmatic alternative that provides improved price signals to market participants around network congestion. This is expected to guide generation to locate in areas that are cheaper to serve with transmission capacity and, in turn, promote more efficient generation and transmission investment. We also agree that DRP removes incentives for disorderly bidding, promoting dispatch efficiency.

## 3.1 Scope of DRP

From an economic perspective, the optimal model for promoting dispatch efficiency and efficient generation / load investment decisions is for all market participants to be exposed to their locational marginal price (LMP) (i.e. full nodal pricing). However, as we stated in our submission to the directions paper, we recognise that there are practical challenges with this, namely settling all load at different LMPs within different market regions. Further, as the AEMC notes, if all load were to also face the LMP instead of a common regional price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially need to be struck against different LMPs.

As such, we maintain our support for scheduled and semi-scheduled market participants to face their relevant LMP and for non-scheduled load to face a common regional price for the region they are located in. Importantly, the locational price signals will be made available to those participants that can most easily respond to them, namely generators and grid-scale storage such as batteries and pump hydro storage facilities.

However, as we set out below, the decision to settle non-scheduled generation at a regional price raises challenges with calculating the volume-weighted average price (VWAP). As such, we consider there could be benefits to settling non-scheduled generation at the LMP.

The AEMC also proposes a 12-month 'waiting period' for market participants who have changed categories to reverse their decision. We consider this to be a sensible solution to participants strategically switching scheduling categories at the expense of other non-scheduled market participants. Under the current provisions of the NER,[10] there is greater discretion around market loads (compared to generators) becoming either scheduled or non-scheduled, around which the proposed waiting period will set necessary parameters. Setting the waiting period at 12 months seems appropriate, as a lesser period may detract from its effectiveness in curtailing "price shopping". In considering the appropriate timeframe, the AEMC should seek to understand how often Market Customers,[11] in particular, seek to switch scheduling registration categories under the current clause 2.3.4(d) of the NER.

In addition, we consider it would be useful for the AEMC to catalogue the range of other distortions that are reasonably likely to arise, such as the potential for generators at low LMPs seeking to integrate with loads (such as towns or factories) in order to bypass the transmission network.

[10] Under NER, clause 2.3.4(d), a *Market Customer* may request *AEMO* to classify any of its *market loads* as a *scheduled load.*

[11] 'Market Customers' are retailers and end users who buy electricity in the spot market: AEMO, 'Participant categories in the National Electricity Market' information sheet, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Participant-Categories-in-the-NEM.pdf

## 3.2 The regional price

The AEMC proposes to adopt a VWAP as the common regional price that non-scheduled participants will face. We agree with the AEMC that adopting a VWAP will promote revenue adequacy, and we consider it is more consistent with a full nodal pricing framework than the regional reference price (RRP). If the Regional Reference Price (RRP)[12] were chosen as the regional price, then the LMP would need to be capped at the RRP to allow for revenue adequacy. This is because, in those trading intervals where the LMPs exceed the RRP, there may not be enough money coming in from load to payout generators' FTR obligations under wholesale settlement.

In the following sections, we set out considerations for the AEMC in determining the appropriate regional pricing method. In summary, we have identified what we see as being material issues with calculating the VWAP (which, as noted in the section above, may persuade the AEMC to also settle non-scheduled generation at LMPs). These issues, combined with the costs and complexities of redeveloping NEMDE, should be considered against the benefits from allowing LMPs to exceed the regional price. Again, we consider modelling is needed of the expected pricing outcomes under DRP to inform the AEMC's consideration on this issue.

### 3.2.1 Costs versus benefits

**Adopting the VWAP as the regional price**

We consider the benefits of adopting a VWAP should be weighed against the associated costs and complexities. These can be considered against maintaining the status quo, under which the RRP is the common regional price, or other alternative regional pricing approaches.

In terms of costs, in addition to the economic considerations discussed in the following section (sub-section 3.2.2), NEMDE will need to be redeveloped in order to capture and map the local prices at existing non-scheduled load connection points. This is necessary in order to determine the weighting of non-scheduled participants at different connection points in calculating the VWAP (see **Appendix A**). The AEMC notes the indicative costs in redeveloping NEMDE are not yet known.

In terms of benefits, the VWAP promotes revenue adequacy and is more consistent with a full nodal pricing framework. This is because the sum total of prices paid or received by the relevant market participants is the same as under nodal pricing, even though the relevant market participants continue to face only one price.

**Adopting the RRP as the regional price**

If the RRP were alternatively chosen as the regional price, then the LMP would need to be capped at the RRP to allow for revenue adequacy. The AEMC states that this would dilute the benefits of the locational signals that are expected to arise from the introduction of LMPs to the market.

While we agree with this, it is possible that LMPs will rarely exceed the RRP in practice. Currently, it is very rare that load at a remote intra-regional node is greater than network capability at that point, as network capability is driven by reliability standards. It is even rarer to have generation also located at the same node, which is the only case where the LMP should exceed the RRP.

[12] Which is the locational marginal price at the Regional Reference Node.

As part of its zonal study, we recommend the AEMC consider congestion patterns and the LMPs that are expected to arise under DRP, in order to also properly understand:

(a) how often LMPs would be expected to exceed the RRP, and

(b) the extent to which they would be expected to exceed the RRP.

This will inform a view of whether capping LMPs at the RRP would, in practice, significantly dilute the price signalling function of LMPs under DRP. The AEMC's study should adopt a forward view, to consider the impact of increasingly decentralised generation on the ability of generators to deliver power to loads in the future, and the resultant impact on expected pricing outcomes.

As an additional consideration, to the extent that allowing the LMP to exceed the regional price gives rise to issues of local market power,[13] this may be avoided under a framework where the LMP is capped at the RRP. This could also reduce or remove the need for a specific mitigation mechanism.

### 3.2.2 Issues with calculating the volume weighted average price

The following discussion sets out economic challenges we have identified with calculating the VWAP, for the AEMC's consideration.

**Unexpected outcomes with calculating the VWAP**

Our analysis (contained in **Appendix A** of this submission) suggests that, depending on the volume of non-scheduled generation relative to non-scheduled load, the AEMC's proposed VWAP has the potential to yield the following unexpected outcomes:

- Instances where the VWAP lies outside the range of the lowest and highest nodal prices in a region, which raises questions around whether the VWAP is providing the correct signals to non-scheduled generators and loads
- Instances where the VWAP does not exist
- Instances where the system operator collects settlement residues that are substantially larger than the FTR payout obligations that are required to meet the needs of the scheduled generators and loads.

These unusual outcomes are, in part, a consequence of the proposal to price non-scheduled generation at the region-wide price. We are not of the view that the volume of non-scheduled generation will be relatively large in the foreseeable future – a virtual power plant, which aggregates distributed energy resources, will be required to be a scheduled generator; similarly, under the proposed WDRM, demand response service providers will also be treated as scheduled generation. Therefore, the unusual outcomes that we have identified from calculating the VWAP may only occur infrequently in practice.

Examples 2-4 in **Appendix A** demonstrate how adjusting the level of non-scheduled generation (offset by non-scheduled load) can result in a VWAP that lies outside the range of the lowest and highest nodal prices in the region. This seems counter-intuitive and raises the question of whether the VWAP would provide the correct price signals to non-scheduled generators and loads. This is relevant as non-scheduled generators and loads are still expected to respond to price signals, such as signals for when to charge and discharge electric vehicles.

13 Noting our discussion above about the need for modelling to understand the potential for, and extent of, local market power under the proposed new framework

The geographic averaging of the VWAP immediately removes some price signals. However, we do not want the signals in the VWAP to be perverse. Allowing for situations where the price that non-scheduled participants face lies outside the range of LMPs of scheduled participants could provide a signal for potentially inefficient behaviour by non-scheduled generators and loads.

We consider it would be useful for the AEMC to consider the issues demonstrated by the examples in **Appendix A**, namely the impact they may have on the operation of the DRP framework and how these issues might be resolved.

# 4 Financial risk management: Financial transmission rights

The introduction of FTRs should also provide generators with greater transparency and tools to manage congestion pricing risk (subject to the design of the FTRs). This should enhance their ability to contract for the sale of generation and therefore promote competition with benefits to consumers. It remains our view that the concurrent introduction of a financial risk management framework (i.e. financial transmission rights (FTRs)) is therefore necessary..

The AEMC is proposing that market participants be able to buy FTRs that pay out on the price difference between:

- a LMP and any regional price (and vice versa); and
- a regional price and any other regional price.

We support the AEMC's rationale for this decision. We further support the FTRs between two regional prices replacing the current inter-regional settlement residue auction distribution units that are periodically auctioned off.

In the following sub-sections, we set out considerations for the AEMC around the expected competition for FTRs between LMPs and regional prices under the proposed framework design, including the impact this could have on purchase prices and secondary trading.

## 4.1 FTR demand and liquidity

We expect that the demand for each FTR between an LMP and a regional price will be limited for the following reasons:

- The AEMC has stated that only "physical participants" should be able to purchase these FTRs. This will exclude non-physical participants from taking part in the FTR auctions as speculators.
- The limited number of purchasers with the same injection and withdrawal nodes may limit demand, with FTRs between each specific LMP and the regional price expected to only be of value to a limited number of physical participants who are located near the relevant LMP.[14] We expect this to be an issue even in meshed areas of the network. This is because it is not the underpinning flows on the network that is relevant to whether participants will find value in the same FTR – the FTRs are between *prices*, and so participants will need to share an LMP in order to find the same FTR of use to them.
- Given many physical market participants currently behave in the spot market also as speculators, we would expect some additional demand for each FTR from a local price to a regional price (and vice versa). However, the AEMC has proposed that the ability of physical participants to use their purchased FTRs should be capped at some measure of their physical capacity in the market.

We consider the AEMC should examine whether there may be instances where a generator is a monopsony purchaser of FTRs at a particular location. Under this scenario, the single buyer of the FTRs may, in the absence of a reserve price, be able to purchase the FTRs at close to a zero price. As such the purchase price of the FTRs may not reflect the value of the expected future payout to the holder, potentially generating windfall gains. Such an undesirable outcome is less likely to occur in practice if the auction is vigorously competitive.

[14] Kristiansen, 'Markets for Financial Transmission Rights,' *Energy Studies Review* 13(1) 2005, p. 46 and Deng et al, 'The Inherent Inefficiency of Point-to-Point Congestion Revenue Right Auction', p. 2.

Related to this, our views on the benefits that speculators can provide in an FTR market are contained below (see sub-section 4.1.1).

### 4.1.1 The role of speculators

We expect that the participation of speculators in the FTR market would increase the level of demand and provide liquidity and competition, not just in the FTR market but also the broader energy market.[15] As noted above, many physical participants would also be expected to behave as speculators in an FTR market.

We are not convinced that allowing non-physical participants to take part in FTR auctions, or allowing speculator behaviour by physical participants, will reduce the ability of those physical participants who are located near the relevant LMPs to manage their congestion risk. To the contrary, speculators that build portfolios of FTRs would be better positioned to provide physical participants with a greater variety of tailored FTR products that more precisely target a market participant's exposure to congestion risk, promoting contract market liquidity.[16] In the discussion paper, the AEMC further acknowledges that the emergence of a secondary market would reduce the need for bespoke products to be sold in the primary market. We agree and elaborate on the benefits of this in promoting revenue adequacy below (see section 4.3.1).

The increase in demand for FTRs as the result of allowing speculator behaviour could also go towards mitigating any market power issues that manifest around the purchase of FTRs.

We note that there are likely to be challenges in defining a group of 'physical participants' who can purchase FTRs and the parameters around how those participants can use them. For example, it will be important to define 'physical participants' in a way that allows intending participants (such as new connecting generators or developers) to participate in the FTR auctions. If physical participants are given any scope to behave as speculators in the FTR auctions, we suggest the AEMC consider allowing non-physical participants to do the same.

## 4.2 FTR payouts

### 4.2.1 Source of revenue to back FTRs

The AEMC's intent is for the number of FTRs sold to be set so there will likely be excess settlement residue – i.e. settlement residues in excess of that required to meet the payout obligations of the total volume of FTRs sold in any given dispatch interval. We support this, as it promotes the revenue adequacy principle. For clarity, we note that even when the revenue adequacy principle is met in expectation, there will be instances where shortfalls unexpectedly occur (e.g. unplanned outages).

The AEMC is proposing that excess settlement residues accumulate in a fund to be drawn down to mitigate instances of FTR payment shortfalls. In our submission to the directions paper, we advocated using excess settlement residues to offset TUOS charges. However, we acknowledge that the AEMC's current proposal will improve the firmness of FTRs. This should be in the interests of consumers as it could reduce market participants' cost of capital, and increase the revenue generated through the sale of the FTRs.

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15 Energy Trading Institute, *The Benefits of Financial Transmission Rights and the Need for Enhanced Credit and Risk Management Protocols in PJM* (Position Paper), 2019, p.6.

16 Ibid, p. 7.

Where the fund is exhausted, we support scaling back FTR payments to the level of settlement residues that arise within the relevant dispatch period. We are of the strong view that consumers should not fund payment shortfalls through TUOS increases.

We remain supportive of using FTR sale proceeds to reduce TUOS for consumers. Consumers currently bear the full costs and risks of transmission investment and we agree with the AEMC that they should be reimbursed by market participants that wish to access the settlement revenue arising as a consequence of that transmission network.

## 4.3 FTR types and features

### 4.3.1 Impact on simultaneous feasibility and revenue adequacy

The AEMC notes that it plans to conduct a simultaneous feasibility study by mid-2020 to assess the adequacy of revenue used to back FTRs. It states that this will help determine the volume of FTRs to be sold at each location of the network, as well as the different financial resources that could be utilised to back FTRs and which of these resources are most suitable.

We recommend the AEMC delay making decisions around the design of FTRs until the results of this study are available. This will support informed consideration of the trade-offs to be made with respect to the types, and features, of FTR products

For example, we consider there are a number of design decisions that can affect the simultaneous feasibility of FTRs and, in turn, revenue adequacy. These include designing FTRs as option instruments,[17] and allowing for 'time of use' FTRs, which would only pay out differences between the LMP and regional price at predetermined times of the day. We recognise the benefits of these design choices in providing market participants with some variety of FTR products that correlate with their risk management needs (such as a generator's intermittent output). However, we also consider speculators can create more sophisticated and tailored products for market participants in a secondary market (see sub-section 4.1.1).

## 4.4 Procurement of FTRs

We support the proposal to use simultaneous feasibility auctions to determine the quantity and combination of FTRs to be sold. As the AEMC has noted, it is important to employ this approach as the purchase of one particular FTR will impact the quantity of available FTRs for other areas of the network. Simultaneous feasibility auctions are commonly applied in other jurisdictions with FTR markets. We further agree that AEMO should be responsible for this auction.

We recognise the potential for incumbent participants to purchase all the available FTRs, thereby taking up capacity for years into the future, which would impact new entry into the market. We support the AEMC's proposed method of selling FTRs in tranches to mitigate the ability of incumbent generators to do this. However, we acknowledge the trade-off with needing to ensure sufficient lead time in order to enable participants to properly manage their financial risk.

### 4.4.1 Transitional arrangements

Under the transitional arrangements for implementing the proposed access model, the AEMC states that there will be a need to grant incumbent generators FTRs for free. In determining the appropriate approach for grandfathering FTRs, we recommend the AEMC

[17] See Hogan, *Financial Transmission Right Formulations*, Harvard University, March 31 2002, p. 33.

closely consider the potential impacts on competition in the wholesale electricity market. More specifically, we recommend AEMC balance the following:

- allocating FTRs such that windfall gains or losses are minimised for incumbent generators in moving to the new access model
- ensuring any barriers to entry for new generators are not increased.

We further agree that, in approximating the implicit access that generators currently enjoy under the status quo, it is a relevant consideration that generators' current implicit access is at risk of being degraded over time under the current open access regime (namely due to the potential for co-location by new generators). We agree this should mean that any gifted FTRs to incumbent generators should taper off over time

## 4.5 Losses

We support the concept that local prices should reflect marginal costs (including dynamic losses). We agree that there will naturally be some dispatch inefficiency arising from difference between actual marginal loss factors (MLFs) and the assumed MLF. However, we consider adopting a dynamic MLF will improve the accuracy of the MLF relative to the actual losses arising in each dispatch interval.

We consider there should be instruments (namely, FTRs) that allow effective hedging of inter-nodal price differences. We are open to understanding the arguments for introducing a specific FTR for participants to hedge against the risk of price differences arising from losses under the new access framework. We look forward to the outcomes of the AEMC's continued consideration on this matter, and providing our feedback once the AEMC has developed robust proposals for addressing the associated issues.

## 4.6 Enhancing the Service Target Performance Incentive Scheme

Finally, as the AEMC notes, we currently administer the Service Target Performance Incentive Scheme (STPIS)[18] to incentivise TNSPs to reduce the impact of planned and unplanned outages on wholesale market outcomes.

We support the use of improved granular information under DRP to enhance the market impact component of the STPIS, to better encourage TNSPs to maximise network availability (and, in turn, the availability of FTRs). We are open to considering how the STPIS can be enhanced under the new access framework to further promote incentives on TNSPs to reduce the risks of inefficient unplanned outages and maximise network availability in response to demand under the new access model framework. We do agree, however, that it would be inefficient for a TNSP to operate and plan its network to provide capacity for settlement residue to be sufficient to cover the cost of FTR payouts at all times.

We note that the STPIS should remain in the form of a scheme (i.e. it should not be prescribed in the rules) to allow it to evolve with the changing market.

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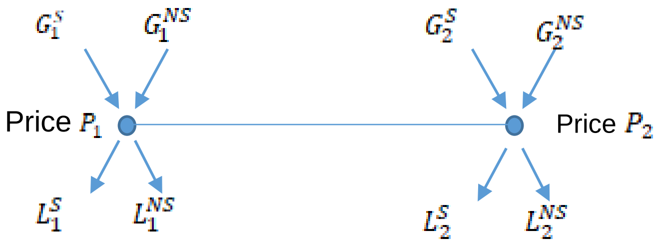
[18] AER, *Final Electricity Transmission Network Service Provider Service Target Performance Incentive Scheme*, Version 5 (corrected), October 2015, available at: https://www.aer.gov.au/system/files/AER%20-%20STPIS%20version%205%20%28corrected%29%20-%2030%20September%202015.pdf

# Appendix A – Economic challenges with the VWAP

To illustrate the points made in our submission (section 3.2.2) let us consider a hypothetical example using the simplest possible network with two pricing nodes and both scheduled (S) and non-scheduled (NS) generation and load:




We will denote the region-wide price (paid to non-scheduled generation and paid by non-scheduled load) as $P^R$.

### Setting the VWAP

The AEMC's objective is to set the region-wide price at a level so that the system operator receives the same total residues as would arise if all generators and loads were correctly priced (i.e. if all market participants were to face an LMP). In order to do this, the region-wide price must be set in the following way (see below for expanded equation):

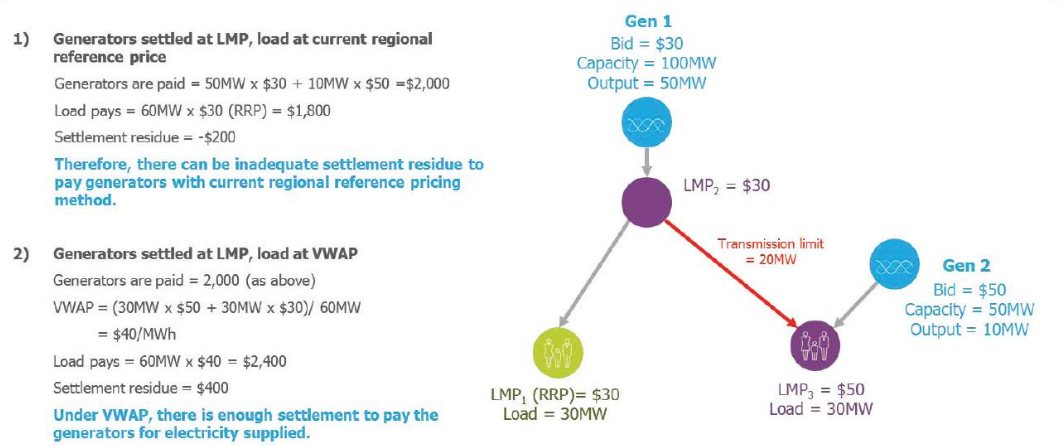
$$P^R = \frac{\sum_i P_i Z_i^{NS}}{\sum_i Z_i^{NS}}$$

This is a volume-weighted average price (VWAP), with the prices weighted by the net injection of non-scheduled generation at each node: $Z_i^{NS} = G_i^{NS} - L_i^{NS}$.

### *Example 1*

Let us start by considering the illustrative example used by the AEMC in its discussion paper to illustrate the VWAP:[19]

**Figure 4.1: Wholesale settlement under the current regional pricing method and VWAP**




[19] Coordination of Generation and Transmission Infrastructure Proposed Access Model discussion paper, page 37, Figure 4.1.

The key inputs are summarised in the following table:

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 50 MW | 0 | 0 | 30 MW | 10 MW | 0 | 0 | 30 MW |
| **Settlement price** | $30/MWh | | $P^R$ | | $50/MWh | | $P^R$ | |

Using this example, the total residue received by the dispatch engine is:

$$60 \times P^R - 30 \times 50 - 50 \times 10 = 60 \times P^R - 2000$$

The VWAP in this case is:

$$P^R = \frac{\$30 \times 30 + \$50 \times 30}{30 + 30} = \$40$$

As the AEMC points out, if the regional price is set to the VWAP, the residues are $400 and there is enough settlement to pay the generators for the electricity supplied.

**Instances where the VWAP lies outside the range of the lowest and highest nodal prices**

We can vary this example slightly to illustrate the impact of non-scheduled generation. Let us suppose there is an additional 30MW of non-scheduled generation at node 1, offset by an additional 30MW of non-scheduled load at node 2:

***Example 2***

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 50 MW | 0 | 30 MW | 30 MW | 10 MW | 0 | 0 | 60 MW |
| **Settlement price** | $30/MWh | | $P^R$ | | $50/MWh | | $P^R$ | |

The VWAP is now $50/MWh:

$$P^R = \frac{\$30 \times (30 - 30) + \$50 \times 60}{(30 - 30) + 60} = \$50$$

We could consider a slightly different example with more non-scheduled generation at node 1 (matched by an increased in non-scheduled load at node 2):

***Example 3***

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 50 MW | 0 | 60 MW | 30 MW | 10 MW | 0 | 0 | 90 MW |
| **Settlement price** | $30/MWh | | $P^R$ | | $50/MWh | | $P^R$ | |

The VWAP is now above both the nodal prices:

$$P^R = \frac{\$30 \times (30-60) + \$50 \times 90}{(30-60)+90} = \$60$$

***Example 4***

We can also find simple hypothetical variations in which the VWAP is below the range of nodal prices. Specifically, we add a non-scheduled generator at node 2, offset by increased non-scheduled load at node 1:

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 50 MW | 0 | 0 | 80 MW | 10 MW | 0 | 50 MW | 30 MW |
| **Settlement price** | $30/MWh | | $P^R$ | | $50/MWh | | $P^R$ | |

The VWAP is now *below* both the nodal prices:

$$P^R = \frac{\$30 \times (80) + \$50 \times (30-50)}{(80)+(30-50)} = \$23.33$$

**Instances where the VWAP does not exist**

It is also possible to find examples where the VWAP does not exist. This occurs whenever the net injection of unscheduled power across the nodes sums to zero. To illustrate this, we consider a hypothetical case in which the scheduled generation is balanced by scheduled load, so the unscheduled generation and load must also be balanced:

***Example 5***

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 300 MW | 0 | 10 MW | 70 MW | 0 | 300 MW | 70 MW | 10 MW |
| **Settlement price** | $30/MWh | | $P^R$ | | $50/MWh | | $P^R$ | |

$$P^R = \frac{\$30 \times (70-10) + \$50 \times (10-70)}{(70-10)+(10-70)} = undefined$$

**Collecting residues that are too large for the payouts of FTRs**

We can also consider whether the use of the VWAP could result in the system operator collecting residues which are substantially higher than the needs of the FTRs. Only the scheduled generators and loads need to purchase FTRs (non-scheduled generators and loads are all transacted at the same price), so the total volume of residues required is related to the volume of scheduled generators and loads.

We consider the following example:

***Example 6***

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 10 MW | 0 | 300 MW | 200 MW | 1 MW | 10 MW | 200 MW | 301 MW |
| **Settlement price** | $10/MWh | | $p^R$ | | $110/MWh | | $p^R$ | |

In this example, there is a large flow of power from node 1 to node 2 (110 MW), but nearly all of this power is unscheduled and therefore does not incur any inter-nodal price difference risk. Only 10 MW of the flow is scheduled generation from node 1 which is matched by a 10 MW scheduled load at node 2. This flow incurs the risk of inter-nodal price differences. Therefore, there is a need for around ($110-$10) x 10 MW = $1,000 to hedge the inter-nodal price differences.

But the merchandising surplus (assuming generation and load is correctly priced) in this case is $11,000 (price difference multiplied by the flow).

The VWAP is:

$$p^R = \frac{\$10 \times (200 - 300) + \$110 \times (301 - 200)}{(200 - 300) + (301 - 200)} = \$10110$$

With this regional price, the total residues collected are $11,000, which is substantially higher than the hedging requirement of only around $1,000.

**Unexpected outcomes**

Finally, to illustrate the point that the VWAP can be very sensitive to conditions, we modify the example above slightly so that rather than a scheduled generator at node 2 selling 1 MW to a non-scheduled load at node 2, let's suppose that the non-scheduled generator at node 2 sells 1 MW to the scheduled load at node 2. The injections are now as follows:

***Example 7***

| | $G_1^S$ | $L_1^S$ | $G_1^{NS}$ | $L_1^{NS}$ | $G_2^S$ | $L_2^S$ | $G_2^{NS}$ | $L_2^{NS}$ |
|---|---|---|---|---|---|---|---|---|
| **Output / Load** | 10 MW | 0 | 300 MW | 200 MW | 0 MW | 11 MW | 201 MW | 300 MW |
| **Settlement price** | $10/MWh | | $p^R$ | | $110/MWh | | $p^R$ | |

The VWAP is now very large and negative:

$$p^R = \frac{\$10 \times (200 - 300) + \$110 \times (300 - 201)}{(200 - 300) + (300 - 201)} = \$ - 9890$$

**For reference: Expanded equation for setting the VWAP**

Assuming that scheduled generators and loads are correctly priced, and non-scheduled generators and loads receive a region-wide price, the total residues collected by the system operator are as follows:

$$R = \sum_i P_i (L_i^S - G_i^S) + \sum_i P^R (L_i^{NS} - G_i^{NS}) = MS + \sum_i (P^R - P_i) Z_i^{NS}$$

From this it follows that, for total residues to be equal to the merchandising surplus that would arise if all generators and loads were correctly priced, then we need:

$$\sum_i (P^R - P_i) Z_i^{NS} = 0$$

Which implies:

$$P^R = \frac{\sum_i P_i Z_i^{NS}}{\sum_i Z_i^{NS}}$$