2019 COGATI Review: Proposed Access Model

Response to AEMC Discussion Paper

8 November 2019

Energy Networks Australia

Contents

Energy Networks Australia www.energynetworks.com.au
Unit 5, Level 12, 385 Bourke Street Melbourne VIC 3000
P: +61 3 9103 0400 E: info@energynetworks.com.au
Energy Networks Association T/A Energy Networks Australia
ABN: 75 106 735 406

Key messages

- Energy Networks Australia supports in principle the Australian Energy Market Commission's (AEMC) revised proposed access model, which has the potential to result in benefits to consumers from more efficient market outcomes and provides a new tool for generators to manage congestion risk, which has been cited as a substantive barrier to new generation investment.
- Notwithstanding, it remains important to ensure that stakeholder concerns are understood (particularly from the generation sector), and that the implementation of the reforms is undertaken on the basis of a realistic timeframe that allows the new framework to be introduced in a manner that is pragmatic, workable and appropriately manages transition risk whilst providing a solid foundation for further future development.
  - Energy Networks Australia recognises the AEMC's intent to take account of the interaction with other major reforms currently being progressed (including Energy Security Board (ESB) post-2025 review and the introduction of 5-minute settlement).
  - The AEMC should also satisfy itself through its proposed quantitative analysis that the costs of transitioning to the new arrangements are not disproportionate to the future benefits.
- Energy Networks Australia supports the AEMC's decision to drop the 'third pillar' of its reforms as set out in the earlier Directions Paper,[1] where transmission hedges would have been used to drive network investment. Energy Networks Australia had expressed concerns with this pillar related to its conceptual and untested basis, and likelihood of proving unworkable in practice. Energy Networks Australia considers that information from the introduction of Locational Marginal Prices (LMP) and Financial Transmission Rights (FTRs) will, by themselves, be a useful additional source of information for Integrated System Plan (ISP) and local Transmission Network Service Provider (TNSP) planning purposes.
- Energy Networks Australia supports the AEMC's proposal that AEMO is the party that deals with both auction and FTR-related revenues. Transferring the role TNSPs currently play in managing wholesale market settlement residues (both inter-regional and intra-regional) will reduce the costs TNSPs currently incur to manage the substantive cashflow issues caused by the volatility of those settlements residues, as well as reducing the associated volatility on customers' Transmission Use of System (TUOS) charges.
- Energy Networks Australia supports the AEMC's intention to introduce dynamic marginal loss factors and the integration of these within the new pricing framework, on the basis that it more closely reflects the realities of the network.
  - Energy Networks Australia notes that the AEMC is separately considering whether the FTRs offered would cover both congestion and differences in

[1] AEMC, *Coordination of Generation and Transmission Infrastructure Proposed - Access Reform*, Directions Paper, 27 June 2019.

loss factors between nodes. While noting the likely benefit to generators from the ability to hedge MLFs, Energy Networks Australia also notes that the incorporation of loss factors within FTRs is not a common feature of markets internationally. As the AEMC works through this issue, Energy Networks Australia advises caution in ensuring that any arrangement that also incorporates loss differentials does not result in a substantive lowering of the FTR auction revenues that would otherwise be used to benefit consumers through offsetting TUOS charges.

» Energy Networks Australia encourages the AEMC to design the arrangements on a pragmatic basis initially reflecting a conservative allocation approach. The FTRs offered to generators should be as financially firm as possible, with the proceeds from the auction of FTRs quarantined to the extent possible and used to benefit consumers through offsetting TUOS charges;
» Energy Networks Australia supports the AEMC's proposal that the Market Impact Component of the Service Target Performance Incentive Scheme (STPIS) scheme be updated to reflect the introduction of LMPs, on the basis that the overall revenue at risk is intended to remain unchanged (at 1 per cent of Maximum Allowable Revenue (MAR)).
» Finally, Energy Networks Australia urges the AEMC to consider how the proposed arrangements would apply to generators connected at the distribution network level, in a manner that ensures competitive neutrality.

Overview

Energy Networks Australia is pleased to make this submission to the AEMC on behalf of its transmission members in response to the Discussion Paper for the coordination of generation and transmission infrastructure (COGATI) review, as well as for continuing participation on the technical working groups established to progress these reforms.

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

While the intended reforms should lead to improved efficiency in the NEM, there remains a number of issues to be worked through

Energy Networks Australia is supportive in principle of the reforms as set out in the Discussion Paper as they will lead to improved efficiency in the National Electricity Market (NEM). Addressing these reforms is particularly important given the need for a renewal of the generation fleet, the ongoing transition to greener technologies being employed in that renewal and given the issues generators have identified with the current lack of sufficiently firm access in inhibiting the new investment that will be required.

Energy Networks Australia considers that the AEMC should however be mindful of the issues raised by stakeholders (in particular, generators) and work through these issues in determining the detailed implementation design.

The AEMC should also satisfy itself through its proposed quantitative analysis that the costs of transitioning to the new arrangements are not disproportionate to the future benefits. While the benefits of adopting LMP and FTRs are generally accepted from international experience, the fact remains that substantial effort will be required to transition from the current NEM design. However, Energy Networks Australia also cautions against getting 'bogged down' in the cost benefit analysis at the expense of ensuring that there is adequate attention given to how the reforms should be implemented.

The required reforms are necessarily complex and interact with other changes being made concurrently to the market arrangements. It is important that they are done well, and introduced in a manner that is pragmatic, workable and appropriately manages transition risk whilst providing a solid foundation for further development. The implementation timetable therefore needs to be realistic in order to ensure that the benefits are realised.

Energy Networks Australia supports the AEMC's decision to drop the 'third pillar' of the reforms that would have linked transmission investment to the sale of hedges

Energy Networks Australia supports the AEMC's decision to drop the 'third pillar' of its reforms as set out in the earlier directions paper,[2] where transmission hedges would have been used to drive network investment.

Energy Networks Australia previously set out its concerns with this pillar related to its conceptual and untested basis, and likelihood of proving unworkable in practice.

Energy Networks Australia considers that AEMO's ISP process and local TNSP planning processes should remain at the heart of shared network planning in order to ensure a focus on investment that represents the most efficient outcomes for consumers. Energy Networks Australia notes that information from the introduction of LMP and FTRs will provide useful information for ISP and TNSP planning purposes.

Energy Networks Australia notes that the AEMC's separate paper on models for the development of Renewable Energy Zones (REZs) includes a model (the AEMC's 'preferred model') that appears to reintroduce a role for hedging contracts in driving transmission investment. Energy Networks Australia would have concerns if the REZ models were used to re-prosecute the case for this link.

[2] AEMC, *Coordination of Generation and Transmission Infrastructure Proposed - Access Reform*, Directions Paper, 27 June 2019.

Elements of the proposed wholesale pricing reform can be enhanced

Energy Networks Australia is supportive of the AEMC's proposal for Dynamic Regional Pricing, including that Locational Marginal Pricing (LMP) applies to scheduled and semi-scheduled market participants, and that non-scheduled load continues to receive a reference price, on the grounds of the efficiency gains that these reforms can deliver. Energy Networks Australia also supports the following positions put forward in the Discussion Paper:

- that the volume-weighted average price (VWAP) should be used as the basis for regional pricing; and
- the development of dynamic marginal loss factors and the integration of these within the new pricing framework.

Energy Networks Australia has suggestions on some elements of the detailed design of the LMP method of pricing energy. Specifically, Energy Networks Australia considers that:

- ideally all wholesale market generators (including non-scheduled generators) should face the LMP, which would be consistent with international best practice; and
- the proposed 12-month waiting period for reversing a change to a participant's categorisation has the potential to give rise to gaming opportunities and may result in issues with ensuring FTR revenue adequacy.

The development of FTR product specificity should be left to the market

Energy Networks Australia supports the AEMC's proposal to develop the specification of financial transmission rights (FTRs) over time in a series of pragmatic steps. This includes limiting the FTRs offered initially to options instruments.

However, Energy Networks Australia cautions the AEMC to not 'over-engineer' other key design elements as part of this review and, instead, to incorporate flexibility that will let market participants decide what is optimal. This includes the:

- FTR tenure and lead times;
- prices that can be hedged using FTRs (and whether the hedges address congestion, losses or both); and
- when FTRs are active.

Energy Networks Australia considers that the choice of FTR configurations offered should be pragmatic, and subject to what can be achieved computationally and what market participants want.

Energy Networks Australia considers that including losses in the design of FTRs is likely to present some significant challenges related to ensuring the revenue adequacy of FTRs. Energy Networks Australia notes that in other markets (including PJM), FTRs hedge congestion risk, but do not also hedge loss differences between nodes. Energy Networks Australia advises caution in ensuring that any arrangement that also incorporates loss differentials does not result in a substantive lowering of the FTR auction revenues that would otherwise be used to benefit consumers through offsetting TUOS charges.

A principles-based approach to linking FTRs to congestion revenues should be adopted

Energy Networks Australia broadly supports the AEMC's proposed treatment of congestion revenues and agrees that the quantity of FTRs made available should be determined such that they are commonly dealing with excess revenue, and only rarely dealing with a settlement shortfall.

However, we also consider that:

» this principle would result, over time, in the Excess Settlement Residue Fund (ESRF) almost monotonically growing; and
» FTRs should be as financially 'firm' as possible.

To this end, this submission sets out a number of principles that Energy Networks Australia considers should apply in developing the proposed arrangements for FTRs further.

Energy Networks Australia supports the allocation of FTRs via auction

Energy Networks Australia agrees with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of FTRs sold. This would apply in the first instance and Energy Networks Australia envisages that secondary trading of FTRs could subsequently occur on a bilateral basis.

Energy Networks Australia considers the auction should be aligned with international best practice and that it would be appropriate for AEMO to be responsible for this auction.

Energy Networks Australia understands the rationale for restricting participation in the FTR market to physical NEM market participants on pragmatic grounds, as the FTR market takes time to develop and establish credibility. It may be possible later to consider extending participation to other participants.

Energy Networks Australia also considers that a distinction on who can participate between within-region and region-to-region auctions would be artificial and inconsistent with the nature of the auction, which would simultaneously award FTRs across the whole system.

Energy Networks Australia supports the recommendation that AEMO is the party that deals with both auction and FTR-related revenues

Energy Networks Australia supports the AEMC's proposal for AEMO to be the party that deals with both auction and FTR related revenues.

Transferring the role TNSPs currently play in managing wholesale market settlement residues will reduce the costs TNSPs currently incur to manage the substantive cashflow issues caused by the volatility of those settlements residues. It will also reduce the associated volatility on customers' TUOS charges.

The risk profile for TNSPs should remain the same as the status quo

The AEMC is proposing that the TNSP revenue at risk under STPIS would remain the same, but that the measurement of network performance against which the STPIS amounts are calculated (specifically the Market Impact Component) would draw on information revealed by the LMP.

Energy Networks Australia agrees with the Discussion Paper in that whatever mechanisms are put in place, the risk profile to TNSPs should indeed be no different to what they are currently exposed to (ie, 1 per cent of MAR).

Energy Networks Australia would expect any such modification to go through the normal AER consultation process in order to allow fuller consideration of how such a change could be implemented.

A trial and thorough testing of any new model is strongly encouraged

Energy Networks Australia supports the conduct of a discrete paper trial of the proposed model and comprehensive modelling, as well as for the introduction of dynamic regional pricing to be subject to thorough systems tests and trials, ahead of 'going live'.

It will be important to ensure that the implementation activities and timeframes are realistic to ensure full stakeholder buy-in and understanding, in order for the benefits of the proposed reforms to be realised. This includes the interaction with other major reforms that are also currently being progressed.

Consideration should be given to how the arrangements may apply to distribution networks, to ensure competitive neutrality

Energy Networks Australia seeks to clarify whether the reforms at the transmission level are intended to be extended to the distribution network. If so, we note that the operation of the distribution system differs from the transmission system and therefore there would be a number of issues to work through.

Energy Networks Australia urges the AEMC to consider how the proposed arrangements would apply to generators connected at the distribution network level, in a manner that ensures competitive neutrality.

1 Introduction

Energy Networks Australia is pleased to make this submission to the AEMC on behalf of its transmission members in response to the Discussion Paper for the COGATI review, as well as for continuing participation on the technical working groups established to progress these reforms.

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

In general, Energy Networks Australia is supportive of the reforms as set out in the Discussion Paper as they can be expected to lead to improved efficiency in the National Electricity Market (NEM). Implementing these reforms is particularly important given the need for a renewal of the generation fleet, the ongoing transition to greener technologies being employed in that renewal and given the issues generators have identified with the current lack of sufficiently firm access in inhibiting the new investment that will be required.

Energy Networks Australia supports the AEMC's decision to drop the 'third pillar' of its reforms as set out in the earlier directions paper,[3] where the sale of transmission hedges would have been used to drive network investment. Energy Networks Australia previously set out its concerns with this pillar related to its conceptual and untested basis, and likelihood of proving unworkable in practice. Energy Networks Australia considers that AEMO's ISP process and local TNSP planning processes should remain at the heart of shared network planning in order to ensure a focus on investment that represents the most efficient outcomes for consumers. Energy Networks Australia notes that information from the introduction of LMP and FTRs will provide useful information for ISP and TNSP planning purposes.

Energy Networks Australia recognises and supports the AEMC's intent to take account of the interaction with the other major market reforms currently being progressed (including Energy Security Board's (ESB) post-2025 review and the introduction of 5-minute settlement).

It will be important to ensure that the implementation activities and timeframes are realistic to ensure full stakeholder buy-in and understanding, for the benefits of the proposed reforms to be realised. It is also important that there is adequate preparation and trialling prior to the introduction to the reforms.

1.1 Structure of this submission

The structure of this submission is as follows:

---

[3] AEMC, *Coordination of Generation and Transmission Infrastructure Proposed - Access Reform*, Directions Paper, 27 June 2019.

- Section 2 comments on aspects of the AEMC's proposed wholesale pricing reform;
- Section 3 provides responses to some of the questions posed on the AEMC's proposed introduction of Financial Transmission Rights; and
- Section 4 provides some observations on the proposed transitional arrangements the AEMC sets out in the Discussion Paper.

Energy Networks Australia has not responded to the questions put forward in the Discussion Paper relating to the AEMC's proposed quantitative analysis. Energy Networks Australia broadly supports the proposed cost benefit analysis and considers that that the AEMC should satisfy itself that the costs of transitioning to the new arrangements are not disproportionate to the expected future benefits. However, to the extent that the proposals now reflect arrangements that have been implemented successfully in other markets, Energy Networks Australia cautions against getting 'bogged down' in the cost benefit analysis at the expense of ensuring that there is adequate attention given to how the reforms are implemented.

Energy Networks Australia seeks to clarify whether the reforms at the transmission level are intended to be extended to the distribution network. If so, we note that the operation of the distribution system differs from the transmission system and therefore there would be a number of issues to work through. Energy Networks Australia considers that a guiding principle in extending the reforms into the distribution network would be to ensure competitive neutrality.

2 Wholesale pricing reform

Energy Networks Australia supports in principle the AEMC's revised proposed access model, as set out in the Discussion Paper, to reform wholesale electricity pricing so as to use the Locational Marginal Prices (LMP) approach.

The Discussion Paper sets out a number of questions that relate to the scope of LMP. Energy Networks Australia sets out its responses to those questions in the following sections.

2.1 Scope of locational marginal pricing

Energy Networks Australia supports the AEMC's proposal to introduce LMP, including that it applies to scheduled and semi-scheduled market participants, on the grounds of the efficiency gains that the use of LMP is expected to deliver. Energy Networks Australia is also supportive of the proposal that retail load would continue to face a common regional price.

Nevertheless, we recognise that the introduction of LMP presents significant implementation issues. There is a clear need for stakeholder buy-in, particularly from the generation sector, to ensure that the implementation is a success and that the potential efficiency gains are actually delivered. Careful management of stakeholder buy-in is particularly important in the context of the significant other market reforms that are being implemented concurrently.

One question raised in the Discussion Paper relates to which market participants will face LMP. The AEMC is proposing that:

- Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the LMP at their transmission connection point.
- Non-scheduled market participants (including retail load) would continue to face a common regional price for the region they are located in.
- Some participants would have the option of becoming scheduled should they wish to face their LMP. Market participants would, however, not otherwise be able to opt in or out of facing an LMP.
- Where the option of selecting their participation category is available to a market participant and exercised by that market participant, it would have to wait 12 months before it could reverse that decision.

While Energy Networks Australia recognises that non-scheduled generators are a small class of generators, we consider that non-scheduled generators should, ideally, also be settled at their LMP, rather than at a common regional price. The rationale for this is two-fold:

1. **Investment signals.** Investment signals for non-scheduled generation would be distorted if they do not face their LMP (since they would face a different, and less-efficient locational price signal than other generators); and

2. **Gaming**. Generators that have the potential capability to switch between scheduled and non-scheduled status would tend to pick whichever status received the higher price at their particular location. In this situation the outcome that is best for the individual might not be best for the system as a whole, and this misalignment would tend to reduce market efficiency.

Expanding on the second point above, allowing some participants optionality (ie, points 3 & 4 of preceding bullet point list) allows for the possibility of gaming and this possibility could be eliminated if the optionality is simply not created. Further, the existence of this optionality would have consequences for the revenue adequacy of FTRs. With this optionality, the congestion rent collected under the LMP method of settlement could be different depending on which group of participants exercised their options. In the case where option exercise decisions endure for 12 months, the implication is that FTR allocation decisions would need to align, and therefore would be limited to 12 months.

Energy Networks Australia notes, however, that if the group of non-scheduled generators can be guaranteed to be small enough then it is possible this would not be a material issue.

Question 1 in the Discussion Paper asks:

- **Do stakeholders consider that the scheduled / non-scheduled distinction offers a sensible basis for determining which parties should face local or regional pricing?**
- **Is the proposed waiting period of 12 months to reverse a change to a participant's categorisation workable and appropriate?**

Regarding the first part of this question, Energy Networks Australia agrees in the case of non-scheduled load but not, ideally, in the case of non-scheduled generation for the reasons set out above.

While load locational investment decisions are rarely influenced by locational pricing (since in most industries the cost of electricity forms a relatively small proportion of total cost), there are exceptions to this. For example, a problem currently exists in parts of Europe where new data centres locate inefficiently close to city centres because of a lack of locational signals (a similar situation exists for some new heavy industries). A case could therefore be made that very large new loads could potentially be subject to locational signals, although the details would need to be worked out.

Generation locational investment signals are much more likely to be influenced by locational pricing since revenues from the sale of electricity are essentially 100 per cent of total revenues for most generators and are a high percentage even for most non-scheduled generators.

A distinction between generators and loads in the case of non-scheduled participation is therefore reasonable. It is also the case that the international norm and best practice is generally to apply nodal prices to all generators, and weighted average nodal prices to non-scheduled load.

Regarding the 12-month provision, Energy Networks Australia suggests that the 12-month provision is not appropriate for the gaming and FTR revenue adequacy reasons set out above and that, ideally, non-scheduled generation would not have the optionality that leads to such a provision.

In Section 4.2.3 of the Discussion Paper the AEMC states:[4]

> *"It may be the case that larger loads in certain areas of the network might wish to face a locational marginal price, if this is expected to result in a more favourable price. Under our proposal, non-scheduled load can opt in to the locational marginal price if they are willing and able to become a scheduled market participant"*

We would agree that flexibility should support market efficiency, but we would be cautious regarding allowing participants the option to 'cherry-pick' between LMP and averaged prices. Allowing large loads the option to pick which is best for them will not necessarily deliver the best outcome, again because the outcome that is best for the individual might not be that which is best for the system as a whole. An alternative for the AEMC's consideration is to apply LMP to all loads over a predetermined amount of MW.

2.2 Constraints in pricing

The Discussion Paper raises the issue of what network constraints will influence locational marginal prices. The AEMC proposes that:

- under the proposed approach to dynamic regional pricing, LMPs would differ across the network when certain thermal and non-thermal transmission constraints arise.
- these constraints must relate to the shared network and be included in the NEM dispatch engine (NEMDE).

Question 2 in the Discussion Paper asks:

- **Do stakeholders agree with characterisation of the constraints that would be reflected in locational marginal prices?**

Energy Networks Australia's view is that, to the extent practicable, all power flow constraints should be incorporated in the NEM dispatch engine and accordingly in the calculation of associated LMPs.

LMP has a specific theoretical basis and is applied as such in the international markets that use it. Energy Networks Australia considers there is a relatively standard mathematical formulation and method of transmission system representation, which

[4] AEMC, *Coordination of Generation and Transmission Infrastructure Proposed Access Model*, Discussion Paper, 14 October 2019, p. 31.

underlies each of these markets in the context of necessarily containing somewhat of an approximation of the full list of system constraints that apply in the 'real world'.

For example, the natural form for assessing a voltage stability limit might be to maintain a minimum level of reactive reserves at critical busbars. This type of limit is analysed across a wide range of power system conditions in off-line studies and an equation is developed that limits power flows and dispatch outcomes so as to achieve the required reactive power reserves. The result is a form of power flow constraint that is an approximation of the underlying physical limit (reactive power reserves) and which will give rise to locational price differences when the constraint binds. Conceptually this is the same as the current NEM dispatch engine where a variety of types of limits to power system operation are transformed into power flow constraints.

2.3 Regional pricing method

The Discussion Paper raises the issue of how the regional reference price should be calculated. The Discussion Paper states that, ideally, the regional price would be the volume weighted average price (VWAP) for unscheduled demand and supply within the region.

Energy Networks Australia agrees with the VWAP approach in principle. We also agree with the AEMC that it is reasonable for non-scheduled load to pay a Regional Reference Price (RRP).

For the reasons set out earlier we consider that all generators (including non-scheduled) should ideally face LMP, and assuming that non-scheduled loads are the only category of participant facing the RRP, the logical basis for calculating the RRP is then the consumption-weighted average LMP of those non-scheduled loads. This approach results in the same level of revenue as if full nodal pricing was employed, and therefore:

- » the energy market is guaranteed to be revenue adequate;
- » the FTR settlement is guaranteed to be revenue adequate; and
- » RRP represents an efficient average price signal for the consumers concerned.

We note that volume weighting achieves the three outcomes listed above in the example set out in Figure 4.1 of the Discussion Paper only because all generators and all loads are assumed to be scheduled. If non-scheduled generators were excluded from the volume in the weighted average calculation, then these three outcomes just listed could not be guaranteed to hold. The 'volume' in the weighted average volume calculation should therefore be the consumption at the non-scheduled loads.

The basis for calculating the RRP might need to be monitored and revised in the future if a very large proportion of load moves to being flexible (i.e. a 'two sided' market) – for example, following the introduction of demand-side participation. In this case the RRP would still meet the three requirements above, but it might be less suitable as a contract reference price because it would be based on increasingly thin volumes. If this set of circumstances were to arise, and if a new index was required for contract reference purposes (rather than the use of a regional hub location), then it could be appropriate to create, in addition, a new index that is the overall load-weighted LMP in the region concerned.

Question 3 in the Discussion Paper asks:

- Do stakeholders agree with characterisation of the benefits and costs of moving to a volume-weighted average price?
- What other costs and benefits do stakeholders think should be taken into account?

Energy Networks Australia agrees with the characterisation of the benefits and costs of moving to a VWAP, subject to the factors set out above. Energy Networks Australia sees the key benefits of the approach outlined to be the three points listed above.

2.4 Inclusion of loss factors in wholesale electricity prices

The Discussion Paper discusses the subject of inclusion of loss factors in wholesale electricity prices. The AEMC's proposal is that LMPs as well as the regional price will include dynamic loss factors.

Energy Networks Australia supports the AEMC's proposal for the development of dynamic marginal loss factors and the integration of these within the new pricing framework.

Question 4 in the Discussion Paper asks:

- Do stakeholders agree with the Commission's qualitative analysis of the potential dispatch efficiency benefits that could result from adopting dynamic loss factors?
- What other costs and benefits do stakeholders think should be taken into account?
- Do stakeholders agree that the alternative ex ante approach to incorporating dynamic loss factors should not be pursued further at this stage?

Energy Networks Australia agrees with the AEMC's qualitative analysis of the potential dispatch efficiency benefits that could result from adopting dynamic loss factors.

Energy Networks Australia notes that the issue of dynamic loss factors is a separable issue from the introduction of FTRs and is supported in its own right as having a net benefit and being consistent with international practice.

Regarding *ex-ante* approaches, we are not sufficiently informed as to whether a calculation of dynamic losses very close to (and just before) real time would be significantly different to a determination of actual losses *ex-post*. Clearly there could be differences in implementation cost and complexity between the two approaches. If the loss values resultant from each approach are consistently very similar then there might not be a strong argument either way; nevertheless, clearly the *ex-post* data has the benefit of reflecting the actual use of the transmission system, which is in principle an advantage. We suggest this be an implementation issue, to be decided based on an analysis of the relative costs and benefits, rather than a matter of policy decided at this time based on partial information.

2.5 Market power

The Discussion Paper questions how market power issues should best be dealt with. In summary:

- The AEMC does not envisage that market power will be increased as a result of these reforms, but will undertake specific impact analysis to determine the significance of market power considerations under dynamic regional pricing.
- If a market power mitigation mechanism is needed, then an *ex ante* offer cap would be introduced in the event that a generator was deemed to be pivotal (i.e. deemed to have market power at that specific time and location). The offer cap would be set at a value related to the conditions in the wholesale market at the time the cap is applied.
- In addition, the AEMC recommends that the AER should review its existing wholesale market monitoring functions and processes, with the potential to introduce more stringent provisions in the event of a material problem.

Energy Networks Australia broadly agrees with these sentiments.

Question 5 in the Discussion Paper asks:

- Do stakeholders agree with our characterisation of how market power issues may arise under dynamic regional pricing?
- Do you agree with our proposed response to market power issues?
- What other costs and benefits may result from this response to market power issues?

Energy Networks Australia is broadly of the view that a move to LMP pricing ought not increase the extent of market power in the NEM and that, rather, market power is a function of the underlying level of market concentration in each relevant sub-market. Market power and market power mitigation can therefore be viewed in a broader context and not necessarily linked to the implementation of dynamic regional pricing.

Nevertheless, Energy Networks Australia does not disagree with the AEMC's proposed market power actions.

3 Introduction of Financial Transmission Rights

Energy Networks Australia supports the AEMC's proposal to strengthen the available tools for financial risk management in the wholesale electricity market by introducing FTRs.

The Discussion Paper sets out a number of questions that relate to the scope of FTRs. Energy Networks Australia responds to these in the following sections.

3.1 Type of FTRs

An important question raised in the Discussion Paper relates to what type of FTRs should be offered. The AEMC proposed that:

» the type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment.

» this means that the financial transmission right would never result in a payment liability for the right holder.

Question 6 in the Discussion Paper asks: » **Should financial transmission rights be limited to options instruments?**

Energy Networks Australia supports the AEMC's proposal to develop FTRs over time in a series of pragmatic steps.

Energy Networks Australia accepts that there may be pragmatic reasons to limit FTRs to options instruments initially. In particular, it notes that the use of 'swaps' would likely lead to the need to comply with a number of financial market obligations, including prudential requirements.

Energy Networks Australia notes however that in the longer term an FTR swap may prove to be a better hedge than an FTR option (and therefore may have more demand from market participants) because it provides full certainty of the price difference between two locations, rather than simply a price floor. The value of FTR obligations has been demonstrated in the US markets that have FTRs.

3.2 Prices that can be hedged

The Discussion Paper raises the issue of the prices that can be hedged by FTRs. The AEMC is proposing that market participants would be able to buy FTRs that pay out on the price difference between:

» a local price and any regional price

» a regional price and any other regional price.

Question 8 in the Discussion Paper asks:

- Have we appropriately identified the pairs of prices that can be hedged through the instruments?
- Would more or less flexibility than that recommended be preferred?

Energy Networks Australia considers that the choice of FTR configurations offered should be pragmatic, and subject to what can be achieved computationally and what market participants want.

Section 5.3.3 of the Discussion Paper sets out two additional configuration types which the AEMC considered but does not propose to offer. It might be that these two additional configurations are not pragmatic, or not computationally feasible. However, it is not clear that this is the case and Energy Networks Australia suggests that neither be ruled out until this determination has been made.

The two additional configuration types are as follows:

- An FTR that relates from a local price to another local price:
  - The AEMC acknowledges that ‘node-to-node’ FTRs could be valuable to some participants but argues that allowing them would dramatically increase the number of possible FTRs that would be offered in an auction and so therefore they will not be allowed.
  - Energy Networks Australia notes that while the demand for node-to-node FTRs at this time is unknown, and may well be low, we consider that auction complexity would not necessarily be increased by allowing the possibility of including them. The auction should be capable of accepting node-to-node FTRs with no greater computational complexity than node-to-region FTRs. While the number of potential combinations of FTR configurations could increase exponentially, the number of FTRs actually bid should not. Node-to-node FTRs will be awarded in the auction if the transmission capability exists and/or if they are valued more highly than node-to region FTR alternatives.
  - We are of the view it is too early to conclude this configuration type should be excluded from consideration, and that further analysis is warranted on this point.
- Financial transmission rights that relate to a few pre-defined ‘hubs’:
  - The AEMC rules out a methodology that allows only a small set of nodes to apply in node-to-region FTRs.
  - In this case we caution, in contrast to the point above, that allowing too many nodes could give rise to an unmanageable auction model size for little added value. We accept that 8 nodes is likely too few for the NEM but, on the other hand, producing an auction model that allows every single pricing point to potentially be bid might make the auction model too large to be practical, with most nodes never actually bid on. In practice under LMP there will tend to be groupings of similarly-priced nodes emerge.
  - Our comments on this configuration type are consistent with our first point above, ie, again, we are of the view it is too early and not necessary to make a

final conclusion – in this case that all nodes can be FTR nodes. We think that further analysis is warranted on this point.

3.3 When FTRs are active

The Discussion Paper raises the issue of when the transmission rights should pay out. The AEMC is proposing that market participants would be able to acquire rights which pay out either at all times of the day ('continuous rights'), or at specific pre-defined times of the day ('time of use' rights).

Question 9 in the Discussion Paper asks:

- Are continuous and time of use rights appropriate, given the trade-offs identified above?
- Are more bespoke products desirable through the auction, and how might they be accommodated?
- What are your expectations of a secondary market emerging to provide bespoke products, if desired by the market?

Energy Networks Australia's view is that it is not necessary to make decisions on these topics at this time. Any such decision would effectively represent a constraint on the market, and there is not sufficient basis at this time to conclude that such specific constraints are necessary and beneficial.

Rather, we consider that the model should provide for the market to dictate through forces of supply and demand the products that are most desirable. The FTR auction can be designed, for example, to simultaneously accommodate bids and offers for continuous and time-of-use FTRs. The auction clearing mechanism can determine which set of transactions delivers the greatest value to market participants, within the confines of the transmission system's actual transfer capability.

In relation to secondary markets, Energy Networks Australia envisages that secondary trading of FTRs could occur on a bilateral basis, so long as credit and other contract requirements are met. Energy Networks Australia can also envisage that existing FTRs could potentially be resubmitted into subsequent FTR auctions for resale, under defined conditions.

3.4 Revenue adequacy

The Discussion Paper raises the issue of the revenue adequacy of FTRs. The key elements of the AEMC proposal are that:

- the source of revenue to back financial transmission rights would arise from the difference between what generators are being paid and what load is paying under dynamic regional pricing.
- excess settlement residues in a given time period would accumulate in a fund administered by AEMO. This would be drawn down from when there is insufficient settlement residue in a different time period.

- when the fund is exhausted, FTR payouts would be scaled to the extent necessary.

Question 10 in the Discussion Paper asks:
» How the number of FTRs sold should be determined? How, specifically, might this be achieved/targeted?   » How should excess settlement revenue not required to fund financial transmission rights be treated?   » Who should pay for any shortfall in settlement revenue?   » Should the revenue from the sale of the financial transmission rights be used to back the FTRs?

Energy Networks Australia broadly supports the AEMC's proposed treatment of congestion revenues as set out in Section 5.5 of the Discussion Paper. Energy Networks Australia agrees that 'the quantity of FTRs made available should be determined such that we are commonly dealing with excess revenue, and only rarely dealing with a settlement shortfall.'[5] However, Energy Networks Australia also considers that:

- this principle would result, over time, in the Excess Settlement Residue Fund (ESRF) almost monotonically growing. While this fund will in certain instances be needed to support FTR payments due to transient transmission system conditions not resulting in sufficient congestion rent, on average the contributions to this fund will be positive and not negative. It should not be allowed to grow unchecked, and the benefit of this fund should ultimately accrue to consumers.
- FTRs should be as financially firm as possible and the existence of the ESRF would facilitate this, so long as the principle of not systematically over-allocating FTRs is adhered to. Having FTRs that are as financially firm as possible is expected to increase their value to market participants.

For these reasons we consider the following principles should apply:

- A conservative approach should be adopted (this is particularly important when the reforms are first introduced and reflects a pragmatic approach that can be revisited once the arrangements have become more established).
- The quantity of FTRs made available should be determined such that we are commonly dealing with excess revenue, and only rarely dealing with a settlement shortfall (as per the Discussion Paper).
- Revenue generated through the sale of FTRs should be used to offset TUOS (as per the Discussion Paper), although it could also be used in part to make participants whole with regards to any relevant grandfathering arrangements (Refer to Section 8 of the Discussion Paper and question 31).

[5] AEMC, *Coordination of Generation and Transmission Infrastructure Proposed Access Model*, Discussion Paper, 14 October 2019, p. 62.

- FTRs should be as financially firm as possible (in contrast to the Discussion Paper).
- The ESRF should be used to guarantee an appropriate level of firmness of FTRs and in the unlikely event the ESRF would otherwise go negative, the FTRs should be scaled, with the auction revenues kept quarantined and returned to consumers via TUOS (in contrast to the Discussion Paper); and
- Since the ESRF is expected to grow almost monotonically over time, it should be periodically reset with excess accumulated funds above a reserve credited to TUOS (suggested to be in March each year).[6]

3.5 Non-thermal constraints

The Discussion Paper raises the issue of the treatment of non-thermal constraints.

Question 11 in the Discussion Paper asks:

- Has the Commission identified the challenges relating to non-thermal constraints?
- How might these challenges be accommodated in the design of the FTRs?

Please refer to Energy Networks Australia's response to Question 2, and in particular to the characterisation set out in section 4.3 of the Discussion Paper.

FTR quantity limits in the FTR auction should be based on an assessment of the transfer capabilities between the nodes of the transmission network and the determination of those transfer capabilities should be consistent with that applicable to the LMP calculation.

3.6 Losses and FTRs

The Discussion Paper raises the issue of how transmission losses might be able to be hedged with FTRs. The AEMC proposal is that FTRs should hedge the risk of price differences arising from losses. Specific details of how this would be achieved, however, are yet to be determined.

Question 12 in the Discussion Paper asks:

- Has the Commission identified the challenges relating to losses?
- How might these challenges be accommodated in the design of the FTRs?

Energy Networks Australia understands that the AEMC is intending to include losses as part of FTRs. Energy Networks Australia considers the AEMC has not identified all the challenges relating to including losses in the design of FTRs in the Discussion

[6] This will allow the values to be included and off set in the TUOS calculations for the tariffs applying from July.

Paper, and that including losses in the design of FTRs would present some significant challenges related to ensuring the revenue adequacy of FTRs.

We note that there is a theoretical basis for FTRs inclusive of losses[7] but that it is not standard practice in markets with FTRs. FTRs that cover the congestion element of LMP differentials only would still have value in the NEM (and this is how the FTRs commonly operate). Therefore, if the AEMC is not able to find a practical way of incorporating losses, Energy Networks Australia suggests that the AEMC should still implement FTRs to manage congestion.

Energy Networks Australia also notes that the proposed adoption of dynamic loss factors is a separable issue to the introduction of FTRs and should be introduced irrespective of whether a way can be found to enable losses to be hedged as part of the FTRs.

3.7 Method of sale of FTRs

The AEMC is proposing that:

» Financial transmission rights would be sold through a series of simultaneous feasibility auctions of the network run by AEMO, with input from TNSPs being used to set the parameters of how many financial transmission rights could be sold.

» The auction would determine the quantity and combination of financial transmission rights sold, given market participants willingness to pay for them and the expected physical characteristics of the network. The simultaneous feasibility auction is designed to provide financial transmission rights with an appropriate level of firmness.

Question 13 in the Discussion Paper asks:

» **Do you agree with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of financial transmission rights to be sold?**

» **Should AEMO be responsible for this auction?**

» **Should the reserve price be zero?**

» **What other insights do you have on the design of the auction?**

Energy Networks Australia agrees with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of financial transmission rights to be sold. This would apply in the first instance and, as discussed under Question 9, Energy Networks Australia envisages that secondary trading of FTRs could subsequently occur on a bilateral basis.

[7] Refer, for example to https://sites.hks.harvard.edu/fs/whogan/Harvey_Hogan_Loss_Hedging%20_FTRs_011502_.pdf

Energy Networks Australia agrees that it would be appropriate for AEMO to be responsible for this auction. Energy Networks Australia supports the AEMC's proposal for AEMO to be the party that deals with both auction and FTR related revenues. Transferring the role TNSPs currently play in managing wholesale market settlement residues will reduce the costs TNSPs currently incur to manage the substantive cashflow issues caused by the volatility of those settlements residues, as well as reducing the associated volatility on customers' TUOS charges.

As discussed under Question 6, Energy Networks Australia accepts there may be pragmatic reasons to limit hedging products to options initially. We can think of no reason why an option would have a value of less than zero.

Energy Networks Australia considers the auction should be aligned with international best practice. The principle should be to impose as few constraints on market participants as possible, other than those constraints which reflect the underlying physical capability of the transmission network.

3.8 Tenure and lead time of FTRs

The Discussion Paper investigates the subject of the appropriate tenure and lead time of FTRs. A key feature of the proposed approach is that quarterly products would be available up to three to four years in advance.

Question 14 in the Discussion Paper asks:

» **What is the appropriate tenure for the financial transmission rights?**

» **How far in advance should the financial transmission rights be made available? What factors should the Commission take into consideration when determining the lead time?**

Energy Networks Australia recommends that the AEMC take into account learnings from international markets in this respect, including from the PJM multi-round FTR auctions.

We note, with reference to Question 1, if non-scheduled generators are able to select whether they are scheduled or non-scheduled every 12 months then the revenue adequacy of FTRs might not be assured unless their tenure was 12 months or less.

Energy Networks Australia also notes that although generators have raised length of tenure as an issue, the experience of other markets with FTRs is that the duration of FTRs is not in general be expected to align with the duration of generation projects. This appears to be an issue for the AEMC to work through with generators.

3.9 Participants in the FTR auctions

The Discussion Paper raises the issue of who should be eligible to compete in FTR auctions, and proposes that:

» Only physical market participants should be able to purchase financial transmission rights in the auction run by AEMO with the payout on the difference between local prices and regional prices.

  - In addition, their ability to purchase these financial transmission should be capped at some measure of their physical capacity in the market.
- In contrast, all market participants (including non-physical participants) would only be able to purchase financial transmission rights that payout on the difference between two regional prices.
- Anybody would be able to participate in any secondary market for FTRs which emerges.

Question 15 in the Discussion Paper asks:

- **Should participants to the auction be limited to physical market participants in the case of financial transmission rights between local and regional prices?**
- **Should non-physical participants be allowed to buy financial transmission rights between regional prices?**

Energy Networks Australia considers that initially there may be good pragmatic grounds for restricting participation in the FTR market to physical NEM market participants, on the basis the FTR market will need time to develop and establish credibility. Inclusion of market participants who only have financial positions (and no physical positions) might not be beneficial at the outset of the reform process.

In the longer term however, Energy Networks Australia does not see a compelling reason why only physical market participants should be able to purchase FTRs between a local price and a regional price through the auction process. A restriction of this sort would appear to place an unnecessary constraint on the potential competitiveness of the auction. If physical players do not value certain FTRs as highly as non-physical players, yet the non-physical players are denied access, then final customers will suffer as a result because they will have been denied the benefit of those higher revenues.

Energy Networks Australia considers that a distinction between within-region and region-to-region participation would be artificial and inconsistent with the nature of the auction, which would simultaneously award FTRs across the whole system.

4 Transition

The Discussion Paper sets out a number of questions that relate to transitioning to the AEMC's proposed reform model. Energy Networks Australia responds to these in the following sections.

4.1 Grandfathering generators with FTRs

The Discussion Paper raises issues associated with grandfathering some level of financial transmission rights for generators.

> Question 31 in the Discussion paper asks:
>
> » Do stakeholders agree with the proposed approach?

Energy Networks Australia does not have sufficient information with which to form a basis to agree or disagree with the proposed principles and approach.

We note that the introduction of FTRs will affect existing generators where it exposes them to LMP price differentials that they do not currently face. However, Energy Networks Australia also notes that the reforms will provide generators with a new ability to hedge to obtain more financially firm access. Generators do not currently have any access rights under the open access regime.

We also note that the LMP method of pricing has price impacts for loads as well as generators, relative to the status quo, and it is not clear why the proposed grandfathering arrangements could not apply to loads on an equivalent basis as generators. It could be envisaged for example that VWAP might be higher for loads than the existing RRP. Grandfathered FTRs to such loads could offset that price rise on a transitional basis. A mechanism that was more truly a smooth transition from the status quo to the new arrangements for the overall market might be one that appropriately splits the grandfathered FTRs between both generators and loads.

If the objective of the grandfathering proposals is to smooth the transition, and do so in the most equitable way possible, it would be helpful to make that objective explicit so that alternative proposals can be evaluated against defined criteria.

Further, it is important to recognise that the duration of grandfathering to manage the transition will come at a cost to generating funds from FTR auctions that can be used to benefit consumers by reducing TUOS.

4.2 Transition for TNSPs

The Discussion Paper raises transition issues for TNSPs. The AEMC is proposing that the TNSP revenue at risk under service target performance incentive scheme (STPIS) would remain the same, but that the measurement of network performance against which the STPIS amounts are calculated would draw on information revealed by the LMP. The following is a more detailed summary of the key elements of the AEMC proposal in this regard:

- The proposed model includes enhancing the existing STPIS for TNSPs to manage the network in line with when and where capacity is most valued by the market. The incentive would reflect more granular information being revealed from the dynamic regional pricing.
- The AEMC suggests that the enhanced incentive scheme should better align the risks that TNSPs face with those faced by market participants. For example, since settlement shortfalls would be based on the spot market price, the risks that TNSPs face would reflect better approximation of the market value of the congestion that is created (compared to the current tariffed market impact component penalty). However, the risk that TNSPs would be exposed to under the enhanced STPIS should be no different to what they are currently exposed to.
- The AEMC considers that the enhanced operational incentive scheme for TNSPs could be put in place to apply to each TNSP as part of their next revenue determination in accordance with relevant guidelines and regulatory arrangements.

Question 32 in the Discussion Paper asks:

- **Do stakeholders agree with our considerations for transmission network service providers in relation to transition?**

Energy Networks Australia agrees that whatever mechanisms are put in place, the risk profile to TNSPs should indeed be no different to what they are currently exposed to. Energy Networks Australia understands that the revenue at risk would remain 1 per cent of MAR. Energy Networks Australia suggests that the current arrangements under which performance in relation to the incentive scheme results in an increment or decrement to the MAR would remain appropriate (rather than the incentive being funded out of settlement residues).

Energy Networks Australia considers that there is insufficient information currently to understand or evaluate what is proposed and would expect any such modification to go through the normal AER consultation process in order to allow fuller consideration of how such a change could be implemented. However, Energy Networks Australia is broadly supportive of a more refined MIC element of the STPIS.

4.3 Implementation

The Discussion Paper raises issues associated with alternative approaches to implementation.

Question 33 in the Discussion Paper asks:

- **In light of the proposed access model specification put forward in this paper, do stakeholders have views on an appropriate implementation date?**

It will be important to ensure that the implementation activities and timeframes are realistic to ensure full stakeholder buy-in and understanding, in order for the benefits of the proposed reforms to be realised.

The interaction with other major reforms currently being progressed (including the ESB post-2025 review and the introduction of 5-minute settlement) also needs to be taken into account.

Energy Networks Australia is supportive of a paper trial, and further it will be important for the introduction of the arrangements to be subject to thorough systems tests and trials, ahead of ‘go live’.