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2 August 2019

Mr John Pierce
Chair - Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

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

Thank you for the opportunity to comment on the Australian Energy Market Commission's (AEMC) 'Coordination of Generation and Transmission Investment – Access Reform' (CoGaTI) directions paper. Please find attached the Australian Energy Regulator's (AER) submission to the CoGaTI directions paper.

In our submission to the AEMC's earlier consultation paper, we expressed support for the evolution of the National Electricity Market (NEM) to promote better price signals to market participants around network congestion, to better guide generation to locate in areas that are cheaper to serve with transmission capacity than others. This, in turn, is expected to promote more efficient transmission investment and result in lower overall costs to consumers in the long-term.

We support continuing to explore the proposed changes to the wholesale electricity pricing framework, namely through the introduction of Dynamic Regional Pricing (DRP). We agree that if DRP is implemented, a financial risk management framework should be concurrently implemented to allow market participants to hedge against the risk of the relevant locational marginal price diverging from the regional reference price (or alternative regional price). Together these reforms should provide generators and loads with tools to manage congestion whilst continuing to ensure the liquidity of the electricity contracts market.

The priority should be to understand the impact of DRP and transmission hedges on the market under different design options. We are particularly interested in ensuring that mechanisms for identifying and addressing the potential for market power and other unintended consequences are considered as part of this reform. It is important that the expected benefits of the proposed reform outweigh the overall costs and complexity.

We are mindful that it is consumers who currently bear the risk of inefficient transmission network investment, as this is funded through transmission charges that consumers pay. We restate the importance of having a robust transmission planning process, and expect that the work program to action the Integrated System Plan (ISP) will enhance centralised coordination of transmission planning and promote the long-term interests of consumers. However, the current environment is highly uncertain, and the Finkel review recommended the ISP process to 'facilitate the efficient development and connection of renewable energy zones across the [NEM]'.[1] Given this, we are concerned that consumers may be shouldered with unnecessary costs if transmission lines become 'roads to nowhere'. While costs cannot be shifted away from consumers (as generators would ultimately reflect any additional costs from purchasing Financial Transmission Rights in their pricing), a shift in risk allocation may improve accountability in transmission investment planning and decision making.

At this stage, the link between the sale of transmission hedges and the transmission planning and operating framework remains unclear to us. As such, there are substantial design details that need to be worked through before the viability of such a model can be properly assessed.

It is our view that if the link between transmission hedges and transmission planning and operation cannot ultimately be achieved due to design challenges, there is still likely benefit in implementing only stages one and two of the AEMC's proposed model (namely, DRP and a transmission hedging model). The AEMC should continue to consider these stages for implementation.

Our attached submission elaborates on these issues, and comments on some of the open design questions contained in the directions paper.

We also note the related work and reforms currently being considered by the AEMC and other market bodies. We agree with the AEMC that there are a number of interconnections and interdependencies that need to be considered. For example:

- For more incremental work, such as the transmission loss factors and transparency of new projects rule change requests, we expect the CoGaTI reforms to provide holistic solutions that cover these individual issues.
- For more holistic reforms, such as actioning the ISP and the NEM 2025 work program, we expect the CoGaTI reforms to feed into and complement these. In particular, it is critical that all stakeholders continue to engage in the CoGaTI consultation process as it will help shape and inform the NEM 2025 program. It is important that the AEMC continue to highlight the importance of engagement in these processes to market participants and investors.

We thank the AEMC for the opportunity to contribute to the 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 Angela Bourke (03 9290 1910).

Yours sincerely

Paula Conboy

Chair
Australian Energy Regulator

[1] Finkel. A et al, *Independent Review into the Future Security of the National Electricity Market – Blueprint for the future: Recommendations*, June 2017, p. 4.

AER Submission

Coordination of Generation and Transmission Investment – Access Reform Directions Paper

August 2019

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1 Introduction

The AER welcomes the opportunity to respond to the AEMC's Coordination of Generation and Transmission Investment – Access Reform directions paper. This submission sets out our views on the proposed access reform model, including potential impacts on our ability to implement the National Electricity Rules (NER). We have structured this submission to largely follow the AEMC's directions paper:

- section 2 considers potential market impacts of the AEMC's proposed reform model
- section 3 considers design aspects of Dynamic Regional Pricing (DRP)
- section 4 considers transmission hedging
- section 5 considers the link to transmission planning and operation
- section 6 considers implementation and transitional arrangements.

At the outset, we consider it important to build an understanding of the costs and benefits of the proposed model, as for any significant reform. However, we recognise the challenges with modelling quantitative costs and benefits, particularly for forward-looking benefits in an uncertain future. This would rely on robust assumptions being made. We therefore support the AEMC using qualitative analysis to understand the cost and benefits of different design options, supported by quantitative analysis to the extent possible.

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. For example, we agree with the AEMC that the reform model should not be so complex as to hinder participation in the market.

1.1 Principles for Reform

Our submission to the AEMC's earlier consultation paper set out overarching principles that we consider should guide the access and charging reforms. Our comments in this submission continue to reflect these overarching principles:

- Risk should be allocated to the parties in the best position to manage those risks;
- It is important to facilitate the development of access reforms that deliver better signals to transmission network service providers (TNSPs) of where generators seek to invest and signals to generators of the cost of the TNSP investment;
- Any charging and access framework should be non-discriminatory, technologically neutral and adaptable to different physical configurations of the grid;
- Additional sophistication in charging models should be developed with regard to the transparency and comprehensibility of the approach so participants are able to respond efficiently to those price signals; and
- 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;[2] and
  - the Energy Security Board's work program relating to Post-2025 design of the National Electricity Market (NEM).[3]

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

2 Potential market impacts

We support the AEMC's intent to carefully examine the impacts of this reform on the market. It is extremely important to understand the unintended consequences that may arise from the introduction of this reform framework, particularly the potential for market power, the expected impact on forward contract market liquidity and the net impact on consumers.

2.1 Market Power

We consider that, under the AEMC's proposed access reform model, there may be potential for market participants to exercise market power (that is, the ability to increase wholesale electricity prices above their long run marginal cost, and sustain those prices).[4] For example, a generator can increase prices by reducing the volume it offers below a given price, increasing the price it offers for a certain volume or reducing the capacity it offers to the market. In doing this, the generator faces a price-volume trade-off where it loses some volume at the competitive price but earns a higher price on the remaining volume.

One of our functions is to monitor and report on the performance of the NEM. This includes analysing and identifying whether there is effective competition in the market. We would need to understand how the introduction of DRP and transmission hedges may change the behaviour of market participants. We suggest the AEMC consider its proposed reform model in parallel with other regulatory mechanisms that may be needed to mitigate the exercise of market power. In the following sub-sections, we consider how market power might be exercised by market participants and the regulation that may be required.

2.1.1 Wholesale market participants

We consider that more granular wholesale electricity pricing has the potential to make the exercise of market power more transparent, but this is dependent on the detailed design of DRP. It will be important to understand how all the potential pricing nodes are mapped out and where an individual generator, or a group of generators under common ownership, may have market power.

Hedging contracts can reduce market participants' incentives to exercise market power, as the price-volume trade-off becomes smaller. However, there is a potential for market participants to exercise market power in how they purchase and trade transmission hedges that payout based on price differences between nodes (e.g. the regional reference node and another node, as in the AEMC's proposed model). For example, there may be scenarios where holders can increase their hedge payouts by deliberately increasing or reducing congestion.[5]

As such, we recommend the AEMC analyse simple two- or three-node scenarios where generators with market power can manipulate price or volume to make congestion appear worse or 'better' than it actually is.

The identification of network locations where generators may have market power should inform any additional bidding regulations that may be required under a DRP and transmission hedge framework. This is the case in other jurisdictions that have implemented nodal pricing. For example, PJM incorporates a number of specific 'market power mitigation'

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3 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

4 AEMC, *Final rule determination: Potential generator market power in the NEM*, April 2013, p. iii.

5 Alsac et al, *The right to fight price volatility*, IEEE Power and Energy Magazine, July/August 2004, p. 57.

rules to prevent the exercise of market power in specific network locations, which involve direct capping certain generators' offers based on the lesser of their cost-based or price-based schedules.[6] The New York ISO adopts a similar *ex ante* approach under its zonal pricing regime by mitigating certain participants' bid parameters where the bid exceeds certain thresholds and would have a significant effect on the energy price.[7] We recommend that, in parallel to the design of this reform model, the AEMC carefully consider the associated regulations that may be needed.

The main regulation around bidding under the current NER (with respect to our role) is the requirement for participants to not make offers, bids and rebids that are false, misleading or likely to mislead.[8] As stated in the NER, the making of an offer, bid or rebid represents that they will not be changed unless due to a change in material conditions or circumstances. Under a DRP framework, any binding transmission constraints that arise, but which have not been forecasted, would, in our view, constitute a change of 'the material conditions and circumstances'.[9] The generators at the impacted node would therefore be able to rebid. We recommend the AEMC consider the application of this regulation under a DRP framework to ensure it continues to operate as intended. The AEMC should do so in the context of the potential for market manipulation under a DRP framework, such as any potential for generators to manipulate transmission constraints to increase hedge pay outs.

2.1.2 Transmission network service providers

If the sale of transmission hedges is linked to transmission planning and operation (see section 5 below), it may create incentives for TNSPs to exercise market power, or for their owners to purchase generation assets and share information. For example:

- If the proceeds from selling transmission hedges flow to TNSPs to fund transmission investment and they have a role in setting the price parameters of transmission hedges, they will likely face incentives to maximise this revenue stream and there may be opportunities to exercise market power.
- We will need to consider the treatment of costs in regulatory determinations, as TNSPs should be restricted from recovering costs from consumers that have already been recovered from generators through the sale of transmission hedges. We anticipate the revenue from transmission hedges would be treated like a capital contribution, but it is too early to confirm this.
- Increasing interrelation between transmission and generation activities may create opportunities for coordination through complex ownership structures. There are already some NSPs whose owners are investing in generation and/or storage assets, and the proposed link to transmission planning may create incentives for information sharing and other types of coordination to maximise revenue. This may warrant stronger structural separation, or stronger ring-fencing requirements and monitoring.

As such, the design of the AEMC's proposed link to transmission planning and operation needs to be carefully considered along with corresponding adjustments to the regulatory regime. We look forward to providing more input on these issues once we receive more information about this element of the AEMC's proposed model.

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6 PJM, *Manual 11: Energy & Ancillary Services Market Operations, Section 2: Overview of the PJM Energy Markets,* Revision: 106, Effective Date: May 30, 2019, section 2.3.6.1, p 40.

7 NYISO, *Manual 12: Transmission and Dispatch Operations Manual*, Version: 4.1, Effective Date: 12/04/2018, p 81.

8 National Electricity Rules, clause 3.8.22A.

9 If the constraints are forecast, this would not constitute a change in conditions.

2.2 Pass through of costs to consumers

Under the AEMC's proposed reform model, some generators will be faced with additional costs from purchasing transmission hedges to hedge against the price risk they face under DRP. However, they will also benefit from greater financial certainty and improved risk management tools relative to the status quo. Depending on any changes to their risk profile from purchasing transmission hedges, this might be reflected in higher wholesale market prices. However, we acknowledge that the proceeds from selling the hedging products may be provided to TNSPs, which may result in lower transmission use of system (TUOS) charges.

Overall, it is important for the proposed reform model to provide a net benefit to consumers, relative to the status quo. While we recognise the difficulties in accurately estimating this, we consider more information could be provided on:

- the financial impact of the reform model on different market participants
- which impacts are transfers and which are net costs and benefits
- how the costs and benefits on different market participants get passed on to consumers.

2.3 Interactions with the distribution network

We agree with the AEMC that there may be interactions with distribution networks in this review. The following interactions should be further analysed:

- Incentives for parties to locate on either the transmission or distribution network. This decision should be based on economic efficiency, and the proposed reform model should not create incentives to locate on one over the other.
- Interactions with the use of distributed energy resources. DER penetration can lessen the need for transmission investment and large scale generation, and the AEMC's model should be responsive to those signals.

3 Wholesale electricity prices: Dynamic Regional Pricing

We support the direction of the AEMC's consideration of the DRP framework as set out in the directions paper. Overall, it remains our view that DRP is a workable model and we support the AEMC in continuing to explore it.

When transmission constraints bind as the result of congestion, locational marginal prices (LMPs) dynamically arise at the affected node(s). Under the proposed DRP framework, certain market participants will receive/pay the LMP at their corresponding node where it diverges from the regional reference price (RRP).[10] The RRP is the wholesale market price that is calculated at the Regional Reference Node for a region.[11] The increase in granularity of pricing relative to a common regional price can provide locational signals for more efficient generation investment. Specifically, the information from DRP can encourage more efficient decisions regarding the type (baseload versus peaking, etc.), size (in MW) and timing of investment. In addition, DRP should also help drive more efficient operational decisions on the part of generators.

In the sections below we set out our views on certain design aspects of DRP and the potential impact of this model on our responsibilities.

3.1 Regulatory Implications

3.1.1 Reporting on wholesale markets

As noted in our submission to the review's consultation paper, we recommend consideration of what sort of data would or should be available in our role of reporting on wholesale markets in order to address risks of impact to the market, such as the potential for exercise of market power.

With respect to our existing reporting requirements under the NER, consideration will be needed on how locational marginal prices (LMPs) will be treated. For example, under clause 3.13.7 of the NER, we are required to determine whether there is a significant variation between the spot price forecast and actual spot price in each trading interval, and review the reasons for the variation. A starting point for considering how we may carry out this existing requirement under a DRP framework, would be for the AER to report on significant variations that occur between the forecast and actual LMPs at each node in a trading interval (where it diverges from the regional reference price (RRP)). This would be in addition to continuing to report on significant variations between the forecast and actual RRP. However, this may significantly increase the number of reports we would be required to prepare.

Clause 3.13.7 also requires us to report on trading intervals where the spot price exceeds $5,000/MWh. Again, in considering how we may apply these existing NER requirements under a DRP framework, a starting point would be to report on trading intervals where any LMP exceeds $5,000/MWh. As above, this may also significantly increase the number of reports we would need to produce.

Careful consideration will need to be given to these reporting requirements, so we can ensure our reporting under a new DRP framework remains appropriate and fit-for-purpose, providing useful information to the market. It may be more informative for the AER to group events and report on them periodically (e.g. quarterly), as opposed to reporting on all of them individually.

[10] It is noted that the AEMC is considering whether the common regional price should remain as the RRP or change to an alternative.

[11] The Regional Reference Node is generally a substation that represents, electrically, the centre of the network in an identified region.

These NER requirements are in addition to our own thresholds that we currently have for market reporting. We will need to review our reporting arrangements under a DRP model to ensure they continue to provide market participants and stakeholders with sufficient and useful information about activity in the NEM.

3.2 Allocation of settlement residues

As the AEMC notes, intra-regional settlements residues will arise due to differences between the LMPs that some participants will receive/pay across locations and the RRP that other participants will receive/pay. The quantity of the intra-regional settlement residue is equal to the physical flow on the line multiplied by the difference between the LMP and the RRP (or an alternative regional price).

We agree that, under DRP, intra-regional settlements residues should be allocated to participants that have purchased Financial Transmission Rights (FTRs) to fund the payout obligation under these hedges. We also agree that DRP should ideally be implemented concurrently with the transmission hedging model to allow relevant market participants to hedge against the price risk that will arise (see section 6).

However, the open design options for DRP, such as the scope (see section 3.3), can affect the level of settlements residues that arise for each settlement period – in particular, whether there will be a surplus or a deficit overall relative to the payout obligation under the total hedges sold. We consider this should be carefully explored in the AEMC's analysis, including the circumstances in which it is expected that surplus, or a deficit in, settlements residues will occur, the extent of the surplus/deficit and the frequency.

It is our view that surplus settlement residues should not be returned to market participants because to do so has the potential to distort market behaviour.[12] They should instead be used to offset TUOS charges.

A key question is whether this framework can be designed in a way such that settlement residues will be at least equal to the total payout obligation on the transmission hedges held by participants. This is often referred to as 'revenue adequacy', and is discussed further in section 4.1. At this stage, we consider the DRP and transmission hedging model should be designed to meet the revenue adequacy principle if possible.

3.3 Scope of Dynamic Regional Pricing

From an economic perspective, the optimal situation for promoting dispatch efficiency and efficient generation / load investment decisions is for all market participants to be exposed to the LMP. However, we recognise there are practical challenges with this, namely settling all load at different LMPs across different market regions.

We therefore support the AEMC's proposal for all scheduled (including semi-scheduled) participants to be exposed to the LMP and all non-scheduled participants to be settled at the regional price. The inclusion of scheduled load would allow the framework to capture grid-scale storage and pumped hydro facilities, which are the proportion of load that make locational investment decisions. These types of load also have the ability to respond to changing LMPs.

The distinction between scheduled and non-scheduled participants achieves a balance in relation to the cost and complexity of the framework's design. We agree that linking the regulations for determining scheduling status to pricing status is sensible because the rules

12 Surplus settlement residues refers to the situation in which the intra-regional settlement residues exceed the payout obligation on the transmission hedges.

for defining scheduled and semi-scheduled generation are already well-understood by market participants.

We note that under the proposed Wholesale Demand Response Mechanism (WDRM), Demand Response Service Providers (DRSPs) will be treated equivalent to scheduled generation, to be registered as scheduled participants. Therefore, under the AEMC's proposed DRP framework, we understand the LMP will be the relevant price for the purposes of settlement under the WDRM. We consider this a sensible outcome given DRSPs will be behaving equivalent to scheduled generators, by bidding in the market and responding to AEMO's dispatch instructions.

4 Financial risk management: Transmission hedges

We support further consideration of transmission hedges as a tool for participants to manage the risk under DRP of wholesale market prices diverging when transmission constraints bind (price risk). Financial transmission rights are one option for this.

In the abstract, an FTR is an instrument for hedging the price risk that arises from variation in prices across different locations.[13] An abstract FTR from node *i* to the reference node has a payout equal to the price difference across the two nodes multiplied by a 'volume' as shown below. The 'volume' in the FTR contract might be fixed, or otherwise dependent on actual line flow, the line limit which is dependent on weather conditions (e.g. wind speed and direction, ambient temperature, etc.), or other factors.

FTR payout = (Price at reference node – Price at node i) x Volume

In theory, with the right combination of FTRs, generators and loads would find that they can enter into exactly the same hedges as they would if all generators and loads were located at the same pricing node. In other words, with a fully effective set of FTRs, generators and loads can choose to be in the same hedge position as they would like to be if all generation and consumption occurred at the same price. In reality, however, this may not occur as the hedge may not be fully firm.

The design of an effective set of FTRs remains a complex issue which has not yet been fully resolved in the theoretical literature. As such, we recommend the AEMC give careful consideration to learnings from other jurisdictions and the theoretical literature to date. We discuss some of the issues in the sections below.

4.1 Revenue adequacy

The concept of revenue adequacy is linked to section 3.2 above, which considers the allocation of intra-regional settlement residues. We agree with the AEMC that the settlement residues should be used (in the first instance) to fund the provision of FTRs. However, a key question associated with this is whether we can expect the total settlement residues to be (greater than or) equal to the total payout obligation on the set of FTRs. This is the question of revenue adequacy, and we consider this is important for the AEMC to consider.

If the AEMC cannot meet the revenue adequacy principle, the hedges will not be fully firm (all else equal), which may reduce their value to market participants.[14] However, we consider there may still be a net benefit relative to the status quo. Pragmatically, even if the hedges are not fully firm, a generator that purchases these hedges could be in a better financial position than they are in under the current framework, as they will have increased risk management tools and greater financial certainty relative to the status quo. We recommend further information be provided on this issue, and the trade-offs assessed.

A hedge that is not fully firm may also still support a DRP framework that results in better locational and operational decisions for impacted generation and load (relative to the status quo), and the sale proceeds could still reduce TUOS charges and inform transmission planning.

[13] By way of comparison, conventional hedge instruments (swaps and caps and so on) are instruments for hedging the variation in prices over time.

[14] We acknowledge that the theoretical literature sets out certain results which apply to fixed-volume FTRs. Specifically, it is well established that, provided the set of fixed-volume FTRs which are held in the market are "simultaneously feasible" on the underlying physical transmission network, the total settlement residues is less than or equal to the total payout obligation on the FTRs. Nevertheless, we caution the AEMC against focusing exclusively on fixed-volume FTRs (see section 4.3). We consider other mechanisms could be explored and developed to meet revenue adequacy with more general FTRs. However, this remains an open research question.

In addition, the total volume of FTRs that can be supported will depend on the future network capability. It will remain necessary to forecast network capacity into the future to be able to understand what volume of FTRs is consistent with revenue adequacy. We understand TNSPs do this now to an extent.

4.2 FTR procurement and sale proceeds

We support exploring the procurement of FTRs via auction if there is sufficient demand (AEMC Question 8). This appears to be the most common process in other jurisdictions.[15]

If FTRs are only used as a financial risk management tool (that is, not linked to transmission planning), there are options for the allocation of sale proceeds. For clarity, we note that these sale proceeds differ from the intra-regional settlement residues – one arises from the sale of FTR instruments; the other arises when transmission constraints bind and LMPs diverge within a region (and is proposed to be used to fund FTR payout obligations). Possible options for the allocation of FTR sale proceeds include:[16]

- provided to TNSPs and used to reduce TUOS for customers (applied in New York, Texas)
- applied to a fund to use in periods of revenue inadequacy (California), used to fund FTR payouts (New Zealand), distributed to holders of auction revenue rights (applied in PJM, New England, MISO).

We are interested in further exploring ways in which FTR sale proceeds could be used to reduce TUOS for consumers, given they currently bear the full costs and risks of transmission investment. However, we recognise that ultimately all options would flow through to some reduction in electricity costs for consumers.

4.3 FTR design and pricing

We consider market participants are best placed to comment on the FTR products they would find useful. However, we note there are some design challenges in developing a set of effective FTRs:

- There are challenges with fixed-volume FTRs on their own. Fixed-volume FTRs may not be a sufficiently useful risk management instrument for market participants that produce or consume varying volumes of electricity. As such, it is our view that the AEMC should not restrict its consideration to fixed-volume FTRs and explore allowing a broader range, such as relating the FTR volume to the flow on the relevant line. The AEMC may also consider exploring the ability for market participants to trade FTRs and adjust their FTR positions to align with forecast generation levels as these become more certain.
- There is a trade-off in setting FTR locations, as more location options increase flexibility and suitability to different generators, but also adds complexity to the framework. Further, when there are many location options, there may be fewer buyers of each product, which affects liquidity and potentially market power.
- Overall, there is a trade-off between designing FTRs that are suitable for a diverse set of generators, and the associated complexity and transaction costs.

15 NERA, *Review of financial transmission rights and comparison with the proposed OFA model*, March 2013, p. 6.
16 NERA, *Review of financial transmission rights and comparison with the proposed OFA model*, March 2013, pp. 4-5.

5 Transmission planning and operation

We support mechanisms that encourage efficient generation and transmission investment decisions, including mechanisms that promote better co-optimisation. With significant uncertainty as to the future configuration of generation and, therefore, the future configuration of the network, we support considering shifts in risk allocation to parties in the best place to manage those risks.

The current environment is highly uncertain, and the Finkel review recommended the ISP process to 'facilitate the efficient development and connection of renewable energy zones across the [NEM]'.[17] Given this, we share the AEMC's concern that consumers may be shouldered with unnecessary costs if transmission lines become 'roads to nowhere'. While costs cannot be shifted away from consumers (as generators would ultimately reflect any additional costs from purchasing FTRs in their pricing), a shift in risk allocation may improve accountability in transmission investment planning and decision making.

This part of the AEMC's model is untested, and on the detail available we are unclear how the AEMC's proposed link between FTRs and transmission planning and operation would work in practice and contribute to efficient transmission investment. For example:

- How can the volume of FTRs map to transmission capacity in practice? How does this interact with and promote efficient non-network options?
- How are the different investment lead times managed?
- How are over and under-funding situations managed?

We consider that the price signals and information from DRP and transmission hedging would contribute to the transmission planning process anyway. An explicit link between FTRs and transmission planning may not have a high marginal benefit given its costs and complexity.

5.1 Regulatory implications

We consider that the link to transmission planning, depending on its design, could impact our functions under the NER. In particular, it may impact our application of the cost benefit analysis under the regulatory investment test for transmission (RIT-T), and our network revenue determination processes.

We would need to think about how any contribution from generators would be treated in the assessment of credible options within both the ISP and RIT-Ts. In doing so, we may need to review the RIT-T guidelines to take into account the impact of the FTR framework. There may also be transitional implications where proposed investments may be part way through the planning process.

For revenue determinations, consideration needs to be given to whether the model would impact TNSPs rate of return on capital, and how any changes could be incorporated given the rate of return instrument in the National Electricity Law (NEL).

[17] Finkel. A et al, *Independent Review into the Future Security of the National Electricity Market – Blueprint for the future: Recommendations*, June 2017, p. 4.

5.2 Link to ISP

We agree that these access reforms and AEMO's ISP and the RIT-T should be properly integrated. It is important that these mechanisms work together to promote efficient transmission investment and deliver benefits to consumers.

The interaction between the AEMC's link to transmission planning and the ISP process will need to be clearly articulated as the design evolves. This should consider the impact of TNSP-led transmission investment to meet asset management and jurisdictional reliability standards on generators' decisions to purchase long-term hedging instruments that are linked to transmission investment (and the value of these hedges).

5.3 Operating incentive scheme

An operating incentive scheme on TNSPs would affect our functions because it would alter or replace the market impact component of the STPIS. This is because the market impact component of the STPIS is designed to encourage TNSPs to minimise the impact of network outages on the dispatch of generation. This overlaps with the AEMC's proposed operating incentive scheme.

Once we have seen more details of how any operating incentive scheme on TNSPs would operate, we will be able to consider, and comment on, the impact of this change, including whether it justifies the market impact component of the STPIS being replaced.

6 Implementation

6.1 Implementation timing

We agree that DRP and transmission hedge products (as a risk management tool) should be implemented concurrently to market participants to hedge against price risk. We consider concurrent implementation should also make the transition of the reform simpler for stakeholders to navigate.

However, if there are challenges that delay the implementation of the transmission hedge framework, then we consider DRP should be introduced on its own in the interim, alongside a simple allocation of intra-regional settlements residues to go some way in mitigating the price risk. Alternatively, the interim alternative to DRP set out in the directions paper, could potentially be relied upon.[18] This would allow for some movement towards promoting better price signals to market participants around network congestion.

It remains our view that any granular constraint information that can be made available to market participants prior to implementation of DRP will promote a better transition into a more sophisticated and dynamic settlement model. We strongly support the AEMC's proposal to publish historic and forward-looking LMPs and information about binding constraints ahead of implementation.

6.2 Transitional arrangements

We agree with the AEMC's proposed transitional principles,[19] but propose an amendment that explicitly captures the need to ensure that grandfathered arrangements do not distort market behaviour or wholesale pricing.

[18] AEMC, *Coordination of Generation and Transmission Investment – Access Reform* Directions Paper, p 45, Box 6.