Response to OFA Draft Report

A REPORT PREPARED FOR AGL, ORIGIN, SNOWY HYDRO AND HYDRO TASMANIA

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Executive summary

We have prepared this report for AGL, Origin, Snowy Hydro and Hydro Tasmania in response to the AEMC's Draft Reports on Optional Firm Access, Design and Testing.

The Commission's Draft Reports found that under current market conditions, the implementation of OFA would not contribute to the National Electricity Objective. The AEMC reiterated its view that the existing arrangements had performed reasonably well. We agree with those observations. However, the Draft Reports went on to suggest that if drivers emerge of a major transformation of the generation and transmission capital stock, where the outcomes are highly uncertain, the balance of expected benefits and costs of OFA would shift in favour of implementation. The Commission recommended that it should be tasked with monitoring market conditions for the emergence of these drivers as part of its last resort planning power responsibilities.

This report argues that OFA does not offer an appropriate way forward for the NEM, irrespective of potential changes in market conditions and uncertainty regarding generation technologies and costs. This is largely because, we submit, the AEMC has failed to establish the existence of significant problems in the current market design that OFA would be likely to effectively address. Rather, it appears that the AEMC's emphasis on different assessment criteria has changed in such a way that supports the presentation of its preferred option rather than the magnitude of the problem(s) to be addressed. As such, the recommended way forward in the OFA Draft Reports appears to be 'a solution looking for a problem' rather than the natural consequence of the evidence tabled during the past and current reviews. We suggest it would have been better if the AEMC had originally commenced the Transmission Frameworks Review by seeking to identify significant problems arising under the existing arrangements and formulating options directed at resolving those problems. It is only if problems identified with the current arrangements were so profound and far-reaching such that a tailored response would become unwieldy that radical option such as OFA should have even been conceived.

Even taking as given the AEMC's most recent assessment criteria, we consider that OFA is unlikely to yield the benefits claimed in the Commission's Draft Reports. In particular, OFA is unlikely to lead to a meaningful or desirable transfer of risks from customers to generators. If anything, OFA could lead to customers facing more volatility in delivered electricity prices than they do at present. Further, OFA is unlikely to improve the coordination of transmission and generation investment decision-making. This is because it is difficult to see how OFA would improve the quantity and quality of revealed information upon which such investment decisions are based. Rather, the reverse seems more likely.

We are likewise sceptical that developments in the future would make OFA a more worthwhile reform than at present. This is because despite what could fairly be described as an eventful 16 years since the NEM commenced, neither we nor the AEMC could identify any significant generation locational decisions that were demonstrably inefficient when they were made and that would have been significantly more efficient had OFA been in place at the time.

One concern raised by the Commission about the current arrangements is the risk of greater than one-for-one interconnector 'degradation' due to poorly-located new generator connections. The Lake Bonney wind farm in South Australia has been cited as an example of this phenomenon. However, it is far from clear that this locational investment decision was inefficient when it was made or whether OFA would have made any difference had it been in place.

Under these circumstances, we see no value in 'warehousing' OFA for potential future application and we see no role for market monitoring of the type envisaged by the Commission. Such monitoring cannot – by definition – be capable of gauging the degree of uncertainty surrounding unforeseen developments (the so-called 'unknown unknowns'). Yet these are the issues or factors that presumably would, according to the Commission's framework, motivate the adoption of OFA.

Finally, we have specific concerns with the proposed allocation of roles and responsibilities in relation to the setting of LRIC-based access prices. In our view, the proposed arrangements will widely disperse responsibility – and hence, accountability – for setting appropriate price signals across all the NEM institutions. Poor investment outcomes made in response to inappropriate prices are likely to result in a 'blame game' between the relevant institutions

It is clear to us that OFA will add significant costs and complexity to the market for little, if any, benefit just at the time when major shifts are occurring. If, despite this, the Commission feels compelled to pursue the case for changes, we submit it should investigate the nature of perceived practical shortcomings in the current market design to establish if there is an underlying problem and then formulate appropriately tailored solutions. We have set out a proposed framework for the form of monitoring/review that could be undertaken and the approach the AEMC should take to responding to significant issues if any are identified.

1 Background

We have prepared this report for the Group in response to the Australian Energy Market Commission's (AEMC's or Commission's) Draft Reports on Optional Firm Access, Design and Testing, dated 12 March 2015.[1] The OFA Draft Reports build upon the discussion of optional firm access in the OFA First Interim Report of July 2014[2] and the AEMC's Final Report for its Transmission Frameworks Review from April 2013.[3]

Volume 1 of the OFA Draft Report found that "in the current environment, absent some major shift in market conditions and government policy settings, the implementation of OFA would not contribute to the National Electricity Objective." The AEMC reiterated its previous view that "...the existing arrangements had, from an overall perspective, performed reasonably well." We agree with these observations.

However, Volume 1 of the OFA Draft Report went on to say:[4]

> In a future where patterns of generation and transmission investment were much more uncertain, however, a mechanism whereby more transmission investment was driven by commercial negotiations between generation and transmission investment decision makers may be warranted.

Specifically:[5]

> If drivers emerge of a major transformation of the generation and transmission capital stock, where the outcomes are highly uncertain, the existing mechanisms for co-ordinating generation and transmission operations and investment may prove inadequate. In these conditions, the balance of expected benefits and costs of optional firm access would shift in favour of implementation.
>
> In the absence of these conditions there is no doubt that, from time to time, bidding behaviour or system operation issues will arise in particular locations due to transmission constraints. Where the materiality of these issues on market outcomes is small and duration likely to be temporary, regulatory interventions are unlikely to be warranted. Where the impact is material, specific and targeted measures can be considered through the rule change process, rather than by changing the foundations of the NEM through optional firm access or market based congestion management systems.

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1 AEMC, *Optional Firm Access, Design and Testing*, Draft Report – Volume 1, 12 March 2015 (OFA Draft Report – Volume 1); AEMC, *Optional Firm Access, Design and Testing*, Draft Report – Volume 2, 12 March 2015 (OFA Draft Report – Volume 2); Together, 'OFA Draft Reports'.

2 AEMC, *Optional Firm Access, Design and Testing*, First Interim Report, 24 July 2014 (OFA First Interim Report).

3 AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013 (TFR Final Report).

4 OFA Draft Report – Volume 1, p.i.

5 OFA Draft Report – Volume 1, p.i.

Therefore, rather than recommending an immediate shift to OFA, the OFA Draft Report provisionally recommends for the AEMC to monitor market conditions for the emergence of these transformative drivers. The AEMC is to undertake this monitoring as an adjunct to its last resort planning power (LRPP) responsibilities.[6]

This report argues that OFA does not offer an appropriate way forward for the NEM, irrespective of potential changes in market conditions and uncertainty regarding generation technologies and costs. This is largely because, we submit, the AEMC has failed to establish the existence of significant problems in the current market design that OFA would be likely to effectively address. Under these circumstances, we see no value in 'warehousing' OFA for potential future application and we see no role for market monitoring of the type envisaged by the Commission. If, despite this, the Commission feels compelled to pursue the case for changes, we submit it should investigate the nature of perceived practical shortcomings of the current market design and formulate appropriately tailored solutions.

This report is structured as follows:

- Section 2 describes the AEMC's changing rationales for OFA
- Section 3 explains our response to the key aspects of the AEMC's OFA Draft Report assessment
- Section 4 sets out our recommended way forward
- Appendix A discusses the Lake Bonney interconnector 'degradation' case study in more detail.

6 OFA Draft Report – Volume 1, p.83.

2 AEMC's changing rationales for OFA

As noted above, while the AEMC has not recommended immediate implementation of OFA in its recent Draft Reports, the AEMC does suggest that OFA may be an appropriate reform in the future.

In this context, we consider it is worthwhile to briefly recount how the AEMC's justifications for OFA have changed over time. In particular, this section highlights what appears to be the AEMC's:

- *Diminishing* emphasis on:
  - avoiding non-cost-reflective – or 'disorderly' – bidding by generators facing congestion and
  - promoting 'market-led' and decentralised transmission investment decision-making and
- *Increasing* emphasis on:
  - re-allocation of risk for transmission investment from consumers to generators
  - negative externalities of new generation connections on potential interconnector flows
  - effectiveness of inter-regional hedging in terms of the firmness of SRAs and the perceived inefficiency of counter price flows.

We note that in some cases, the shifts in the AEMC's emphasis are subtle and may reflect changes in phraseology. Nevertheless, the changes are real and serve to support the Commission's recommendations despite a lack of evidence of significant problems with the current arrangements and despite the shortcomings of OFA that have been raised over time by stakeholders.

2.1 Transmission Frameworks Review

2.1.1 Second Interim Report

The OFA model was first described in the AEMC's Second Interim Report for the Transmission Frameworks Review (TFR).[7] In that report, the AEMC highlighted the key issues with the current arrangements that OFA was intended to address.

7 AEMC, *Transmission Frameworks Review*, Second Interim Report, 15 August 2012 (TFR Second Interim Report).

These issues were:[8]

- Generators' lack of certainty in dispatch when there is congestion – resulting in incentives for generators to offer their power at non-cost-reflective prices
- Lack of clear and cost-reflective location investment signals for generators – resulting in a lack of efficient co-optimisation of generation and transmission investment

The Second Interim Report emphasised that OFA would promote more market-led development of the transmission network.[9]

While the report did refer to a more appropriate allocation of risk for transmission investment under OFA, this point received relatively short mention.[10] Similarly, the ability of new connecting generators to degrade interconnector capacity was mentioned briefly.[11] Again, there was relatively little discussion of the issue of inter-regional hedging as an example of market failure and OFA was not assessed in terms of its impact on effective inter-regional hedging.[12] The report placed considerably more emphasis on the problem of 'disorderly bidding' and the way that OFA would 'largely address' this problem.[13]

The TFR Second Interim Report was accompanied by a technical report on OFA.[14] This report did not include any discussion of investment risk allocation implications of OFA, but devoted many pages to overcoming disorderly bidding.[15]

2.1.2 Final Report

The TFR Final Report began to rebalance the nature of the AEMC's arguments for OFA. However, it still devoted as much attention to the potential for OFA to resolve disorderly bidding[16] as it did to the role of OFA in re-allocating risk for

8 TFR Second Interim Report, p. 20.

9 TFR Second Interim Report, pp. 45, 50-51.

10 TFR Second Interim Report, pp. ii, 50-51.

11 TFR Second Interim Report, pp. 51-52, 75.

12 TFR Second Interim Report, pp. 39-43, 47-49.

13 TFR Second Interim Report, pp. iv, 19, 22, 45, 52-53.

14 AEMC, *Transmission Frameworks Review*, Technical Report: Optional Firm Access, AEMC Staff Paper, 15 August 2012 (TFR OFA Technical Report).

15 TFR OFA Technical Report, pp. 7, 12, 27, 83, 113.

16 TFR Final Report, pp. 5-6, 8, 96, 109-114.

transmission investment.[17] It also maintained a focus on OFA promoting 'market-led' decentralised transmission development.[18]

2.2 Optional Firm Access, Design and Testing

2.2.1 First Interim Report

The balance of the AEMC's arguments for OFA shifted further by the time of its First Interim Report on optional firm access, design and testing. The expression 'disorderly bidding' was not mentioned in this report and the objective of removing incentives for non-cost-reflective generating bidding was cited only once. The report discussed issues with non-cost-reflective bidding under the current arrangements but noted that modelling by ROAM Consulting found that the resource costs of such behaviour were relatively small – in the range of $3-15 million per annum.[19] These figures are broadly consistent with previous estimates of the cost of disorderly bidding, such as Frontier's modelling for the AEMC as part of the Congestion Management Review.[20] The First Interim Report also took a more circumspect view of the merits of OFA in discouraging non-cost-reflective bidding, noting that:[21]

> Where local pricing influence is strong under optional firm access, a generator will tend to operate closer to its access level. This may lead to a firm generator displacing a lower-cost non-firm generator in dispatch. This would be a loss in productive efficiency.

And:

> A new form of pricing power may be introduced around local prices.

The First Interim Report also made far less reference to OFA promoting 'market-led' transmission investment.[22] In contrast to the TFR Final Report, there was no mention at all of more decentralised decision-making.

Unlike the AEMC's previous reports, the First Interim Report included a discrete section on the "Efficient allocation of risk" under OFA.[23] This section more fully articulated the AEMC's contention that OFA would better align the party responsible for initiating a transmission investment with the risk of that

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17 TFR Final Report, pp. i-ii, iv, 7, 19, 97, 105-108.

18 TFR Final Report, pp.7-8, 67-68, 96-97, 106-108.

19 OFA First Interim Report, p.29.

20 See AEMC, *Congestion Management Review*, Final Report, June 2008, pp.15, 90-99.

21 OFA First Interim Report, p.30.

22 OFA First Interim Report, p.33.

23 OFA First Interim Report, section 3.5.8, pp.36-37.

investment subsequently being uneconomic. The AEMC stated that it was better for generators to carry more of the risk of transmission investment given their better knowledge of the risks of inefficient transmission investments than customers. It appears that this argument replaced or substituted for the AEMC's previous point about OFA promoting market-led or decentralised investment decision-making.

2.2.2 Draft Reports

By the time the AEMC published its OFA Draft Reports, the apparent weights placed on different justifications for OFA had changed considerably from when OFA was first raised. In particular, we note that:

- Improved risk allocation had become the first-mentioned criterion favouring the implementation of OFA, occupying an entire chapter of the report. Volume 1 commented as follows:[24]

  > One of the main elements in choosing a market design or form of regulation is deciding who takes responsibility for the various risks that are present. In the context of optional firm access, the Commission is concerned with how the risks relating to transmission and generation investment are shared between generators, TNSPs and consumers.

  As noted above, far less emphasis was placed on this issue in the TFR Second Interim Report. At the same time, the OFA Draft Reports barely referred to the benefit of 'market-led' or decentralised transmission investment. This supports our view that risk allocation had replaced market-led transmission development from the TFR.

- More efficient co-optimisation of generation and transmission investment was the second-mentioned criterion, and a reference was made to modelling undertaken by Ernst & Young indicating present value benefits from OFA ranging from $51 million to $670 million.[25]

- Improving the effectiveness of inter-regional hedging was the third-mentioned criterion with the Commission concluding that:

  - *ex ante* SRA auction prices being regularly less than outturn price differentials indicates that IRSRs are not being bought to hedge price risk[26], and

  - interregional products need to be improved and that this may lead to increased competition across the NEM.

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24 OFA Draft Report – Volume 1, p.19.

25 OFA Draft Report – Volume 1, p.38.

26 OFA Draft Report – Volume 1, p.60.

- Efficient dispatch of generation had become the last-mentioned criterion and the value of such inefficiencies was accepted as being small. Moreover, the Volume 1 Draft Report accepted that OFA would remove 'some' (rather than all or most) of these inefficiencies.[27]
- Other criteria discussed were:
  - Financial certainty for generators
  - Incentives on TNSPs to operate the network efficiently.

There is nothing inherently wrong, in a policy evaluation process, with changing the relative emphasis on different assessment criteria in line with clear evidence of the nature of the problem(s) to be addressed. However, in the present case, it appears that the AEMC's emphasis on different assessment criteria has changed in such a way that supports the presentation of its preferred option rather than the magnitude of the problem(s) to be addressed. As such, the recommended way forward in the OFA Draft Reports appears to be 'a solution looking for a problem' rather than the natural consequence of the evidence tabled during the review(s).

We suggest it would have been better if the AEMC had originally commenced the TFR by seeking to identify significant problems arising under the existing arrangements and formulating options directed at resolving those problems. It is only if problems identified with the current arrangements were so profound and far-reaching that a tailored response would be unwieldy that a radical option such as OFA should have even been conceived.

The next section closely examines the justifications provided by the AEMC for its conditional recommendation in favour of OFA.

[27] OFA Draft Report – Volume 1, p.75.

3 Response to OFA Draft Report assessment

This section examines and responds to the AEMC's assessment of OFA in its Draft Reports, focusing on two broad areas:

- The AEMC's application of its updated assessment framework and
- Other concerns with the AEMC's recommended way forward.

3.1 Response to the AEMC's assessment of OFA

This sub-section responds to a number of aspects of the AEMC's assessment of OFA. The aspects of the AEMC's assessment considered are:

- Efficient generation dispatch and disorderly bidding (section 3.1.1)
- Risk allocation (section 3.1.2)
- Efficient coordination of generation and transmission investment (section 3.1.3)
- Effective inter-regional hedging (section 3.1.4).

3.1.1 Efficient generation dispatch and disorderly bidding

OFA Draft Report explanation

The efficacy of OFA in mitigating the costs of non-cost-reflective bidding under the current arrangements can be dealt with fairly briefly. As noted in section 2, the emphasis placed by the AEMC on the role of OFA in mitigating incentives for non-cost-reflective generator bidding has declined over time. Addressing 'disorderly bidding' was originally one of the primary drivers for OFA. However, by the time the OFA Draft Reports were prepared, the AEMC appeared to have accepted that:[28]

- The resource costs of the 'race-to-the-floor' form of disorderly bidding (bidding down to -$1,000/MWh to secure dispatch) were relatively low and had declined in recent years. The AEMC commissioned modelling from ROAM Consulting, who found in 2013 that the productive efficiency losses caused by disorderly bidding were in the range of $3-15 million per annum over the period 2010 to 2012. ROAM also found that removing race-to-the-floor bidding would save just $8.8 million in net present value terms over the period 2013 to 2030.

28 OFA Draft Report – Volume 1, pp.74-75.

- OFA would not address (and and was not intended to address) other forms of non-cost-reflective bidding, such as 'late strategic rebidding' or '5/30' bidding.

Frontier response to OFA Draft Report

It appears to us that the reason why disorderly bidding initially assumed such high importance in the AEMC's assessment is that episodes of disorderly bidding have very visible wholesale settlement effects and some stakeholders may have confused the wealth transfers resulting from such outcomes with losses of overall economic welfare. Our report to the National Generators Forum of April 2012 prepared in response to the AEMC's First Interim Report for the TFR pointed out many such events – such as the incident described in AEMO's submission of an outage between Wallerawang and Mt Piper in December 2009 – would have had relatively little impact on the resource costs of dispatch.[29]

The AEMC appeared to adopt a similar framework as we did when it commissioned the modelling from ROAM referred to above. Our own modelling for the National Generators Forum in 2013, using a more sophisticated methodology than our 2008 modelling for the Congestion Management Review, found that the costs of disorderly bidding over the years 2012/13 to 2014/15 were likely to have been approximately $1-5 million per annum.[30]

Although not mentioned in the body of their Draft Reports, the AEMC also appears to have accepted that OFA can give rise to new incentives for generators to bid in a non-cost-reflective manner.[31] In our view, the interplay of incentives faced by generators under OFA means that the nature of any incremental dispatch efficiency improvements due to OFA have to be determined empirically rather than analytically. Such an analysis is necessarily extremely complicated, reflecting the complexity of OFA.

3.1.2 Risk allocation

OFA Draft Report explanation

As discussed in section 2, the AEMC has placed increasing weight on improved risk allocation arrangements as justification for its provisional support for the implementation of OFA.

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29 Frontier Economics, *Transmission Frameworks Review – 1st Interim Report, A report prepared for the National Generators Forum*, April 2012, pp.6-8.

30 Based on the more realistic 'reversion' case; the costs in the 'no reversion' case were in the range of $12-14 million per annum. See Frontier Economics, *Economic costs of disorderly bidding, A report prepared for the NGF and the CEC*, May 2013, pp. iii, 28, 32-33.

31 OFA Draft Report – Volume 1, Appendix E, Table E.1 – Summary of submissions, p.129.

In Volume 1 of the OFA Draft Report, the AEMC contended that OFA offered the following benefits compared to the status quo:

- Risk associated with demand projections:[32]
  - Under the current arrangements, if TNSPs make investment decisions that build the network to the wrong size or in the wrong location due to errors in demand projections, consumers will largely bear the cost of there being too much or too little transmission network capacity. According to modelling by ROAM Consulting, such over-investment in transmission had occurred in south-east Queensland.
  - Under OFA, generators would face LRIC-based prices for access. Generators could then choose to invest or not, based on their own analysis. To the extent generators funded some transmission investment, they would bear the risk that the transmission they funded turned out to be unnecessary or otherwise inefficient. According to the AEMC, assigning some responsibility for transmission investment decision-making to generators could be expected to lead to improved management of the associated risks. However, the Draft Report noted that where firm access was insufficient to provide reliability, the TNSP would still need to undertake a reliability RIT-T and the costs of any investment deemed necessary would continue to be funded by load-side customers.
- Risk associated with supply-side changes:[33]
  - Under the current arrangements, if TNSPs plan and invest based on assumptions about relative generation costs that turn out to be flawed, consumers will bear the higher system costs that result. Consumers have little ability to directly influence transmission investment decisions. TNSPs rely primarily on a transparent and public RIT-T process to ensure their decisions are efficient.
  - Under OFA, to the extent generators choose to be firm, they accept the risk of both their plant investment as well as part of the transmission investment they benefit from as a result of their purchase of access rights. This provides generators with strong incentives to make the right technological and locational investment decision. The AEMC suggested that generators would have better information about their own costs than the TNSP, but would still have to rely on estimates of rival technologies' costs. Further, generators would face stronger incentives to improve their

32 OFA Draft Report – Volume 1, pp.20-23.

33 OFA Draft Report – Volume 1, pp.23-25.

future decisions regarding locational decisions and their influence on transmission investment than the TNSP.

Frontier response to OFA Draft Report

The AEMC's contentions regarding the allocation of transmission investment under OFA raise two issues:

- First, whether OFA will lead to any meaningful transfer of risk from electricity customers to generators. Our view is that consumers could actually face greater risk from volatility in prices for delivered energy under OFA than under the current arrangements.
- Second, whether any transfer of transmission investment risk will be to the ultimate benefit of electricity customers. Our view is that any such transfer may have questionable impacts on customers.

The implications of OFA for the efficient co-ordination of generation and transmission investment is discussed separately, in section 3.1.3 below.

Would OFA lead to a meaningful transfer of risk?

The vast majority of transmission investment since the start of the NEM has been undertaken to meet demand-side reliability standards (DSRSs) at least cost, given forecast demand and expected generation costs. This means that unless under OFA generators agree to pay for access rights, there will be no re-allocation of transmission investment risk. However, even if generators do agree to pay for access, it is far from clear that customers will face less price risk in the consumption of delivered energy.

To the extent that generators pay for transmission access, their fixed (ie non-volume-dependent) costs and total costs[34] would be higher than otherwise. This must mean – in a workably competitive market equilibrium – that generators will need to expect to earn higher average wholesale prices under OFA to remain as profitable as they would if they did not need to pay for access. Assuming ongoing load growth, this would imply that under OFA, generation investment would occur somewhat *later* than under the current arrangements, when demand and expected wholesale prices were somewhat higher, to allow generators to earn *ex ante* normal profits on their investments[35].

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[34] What is commonly known as generators' individual long-run marginal costs (LRMCs).

[35] Alternatively, in an environment of flat or declining demand, generators may choose to reduce fixed costs by spending less on maintenance at the expense of availability, by mothballing or by retiring plant. These outcomes all lead to tighter supply demand conditions and higher wholesale prices.

For example, it may be that:

- Under the current arrangements, a generator needs to expect to earn average wholesale prices of $80/MWh to make normal profits, so generation investment would occur in, say, year 2.
- Under OFA, a generator procuring access needs to expect to earn average wholesale prices of $90/MWh, in order to pay for access and still make normal profits, so generation investment would occur in, say, year 3.

The present value of the higher wholesale price path under OFA should be, in equilibrium, *ex ante* equal to the cost of paying for transmission access plus a risk premium to reflect the uncertain ability of generators procuring access to recover the higher fixed costs they need to incur.

This means that, other things being equal, payments for access would result in end-use customers paying lower transmission charges and higher wholesale electricity prices than in the absence of OFA. If demand turned out to be just as anticipated, customers would pay a higher delivered electricity price under OFA as a result of risk-averse generators needing to be compensated for accepting greater risk. That is, generators would need to recover a risk premium over and above the cost of firm access such that customers would see an increase in wholesale electricity costs that more than offset any reduction in per-unit transmission charges.

In the presence of uncertainty, given the increased level of fixed costs for generators under OFA, OFA would tend to increase the volatility of wholesale electricity prices.

Consider what would happen if outturn demand were higher or lower than anticipated, with equal probability:

- If demand were lower than anticipated:
  - Customers would pay higher per-unit transmission charges than if demand were as expected. However, under OFA, the share of transmission costs payable by customers would be lower than under the current arrangements because generators would have paid some of the costs. Therefore, the absolute level of per-unit transmission charges would not rise by as much under OFA as under the current arrangements. Some of the loss due to the effective stranding of transmission assets would be borne by generators.
  - Customers would pay lower wholesale electricity prices than if demand were as expected. For example, customers may effectively pay only the *avoidable* costs of marginal generation (say, $40/MWh) rather than the *total* costs (or LRMC). Due to the higher fixed costs of generators under OFA, the equilibrium average price of wholesale electricity payable by customers would fall by more under OFA than under the current

arrangements. For example, under the current arrangements, low demand may cause average wholesale prices to fall from $80/MWh to $40/MWh, whereas under OFA, average prices may fall from $90/MWh (the new LRMC, inclusive of access costs) to $40/MWh. This reflects the fact that under low demand conditions, generators will not be able to recover their fixed costs, which include their transmission access costs.

As a result, customers are unambiguously better off overall under OFA in the short term.

- If demand were higher than anticipated:
  - Customers would pay lower per-unit transmission charges than if demand were as expected. As the share of transmission costs payable by consumers would be smaller under OFA, the absolute level of per-unit transmission charges would not fall by as much as under the current arrangements. Some of the benefit of more valuable transmission assets would be enjoyed by generators.
  - Customers would pay higher wholesale energy costs than if demand were as anticipated. Due to the higher fixed costs of generators under OFA, the price of wholesale energy payable by customers would need to rise by more under OFA than under the current arrangements to compensate generators for the increased downside risk they face when demand is lower than anticipated – even assuming risk neutrality. For example, while under the current arrangements, average wholesale prices could rise from $80/MWh to $120/MWh in unexpectedly high demand conditions, under OFA, average wholesale prices may need to rise from $90/MWh to $140/MWh.

    Assuming equal probability of high and low demand conditions, and given that it could expect to earn only its avoidable cost (ie $40/MWh) under low demand conditions, a generator paying for access (ie implying an LRMC of $90/MWh) would need to expect a commensurately high price under high demand conditions to yield *ex ante* normal profits.

    As a result, customers would be unambiguously worse off overall under OFA until investment responds.

Therefore, to the extent generators choose to purchase access under OFA, customers will see a delivered energy bill that reflects less risk from volatility in transmission charges and more risk from volatility in wholesale energy costs. Further, if, as is likely, generators are risk averse to some degree, average wholesale prices under high demand conditions would need to be expected to rise by more under OFA than they would fall under low demand conditions. This raises the question of whether OFA would lead to a meaningful transfer of risks from customers to generators or whether it might actually subject customers to greater volatility in delivered electricity prices than they would experience under the current arrangements.

Given the proportion of the typical customer's bill comprised of energy costs is (at about 30%) much greater than the component attributable to transmission costs (about 10%), customers may prefer to effectively pay an insurance premium by underwriting transmission costs in exchange for reducing the risk of facing more volatile wholesale energy costs.

A further issue arises in the event that a generator defaults on the payment of its annual access prices to a TNSP. It is easy to envisage a case where:

- A generator enters into a long term access arrangement in good faith.
- The TNSP invests to meet the incremental firm access requirement of the generator.
- The generator subsequently makes persistent losses and its owners/administrators/receivers default on annual access price payments to the TNSP.
- The transmission investment is no longer funded by the generator, leaving consumers bearing this risk.

In fact, the access prices themselves make this outcome, other things equal, more likely as they unambiguously increase generators' fixed costs without commensurate rises in revenue.[36]

Would any transfer of risk be to the ultimate benefit of consumers?

As jurisdictional network planners and owners, TNSPs (outside Victoria) used to carry the risk of 'stranded' network investments through the scope for periodic optimised deprival valuation (ODV) processes under the former National Electricity Code. This risk was removed first by the ACCC as transmission regulator in 2004[37] and that removal was subsequently reaffirmed by the AEMC in 2006 when it made the revised chapter 6A of the National Electricity Rules.[38]

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36 The analysis in our March 2015 report (see section 5.3.4, pp. 47-49) showed that the average regional access prices from the AEMC's initial report (AEMC, *Supplementary Report: Pricing*, 31 October 2014) could lead approximately 5,000 MW of generation capacity to move to a loss making position on an EBITDA basis. The level of access prices in the AEMC draft report has increased substantially, in the majority of cases to multiples of the initial prices, implying that any updated analysis would show significantly more than 5,000 MW of generation would becoming loss making under OFA.

37 See ACCC, *Statement of principles for the regulation of electricity transmission revenues – background paper, Decision*, 8 December 2004 (available at: http://www.aer.gov.au/node/12754), pp.39-42.

38 See AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule* 2006 No.18, 16 November 2006, available at: http://www.aemc.gov.au/getattachment/14c81a96-dd77-4530-9d6b-2c55ebe889c3/Rule-Determination.aspx), pp. Xviii, xx, 97-98.

Both the ACCC and the AEMC justified the reallocation of transmission investment risks from TNSPs to consumers as necessary to increase investment certainty for TNSPs and thereby promote greater transmission investment. The AEMC now appears to believe that reallocating (some of) the risk of transmission investment from customers to generators is appropriate. But the AEMC has not sought to reconcile the view that this would be desirable with its previous view, which is reflected in the prevailing transmission regulatory arrangements. These arrangements isolate TNSPs from most of the risk of transmission investment that subsequently turns out to be unnecessary or inefficient. If anything, prospective generators are more likely to be deterred from investing from higher risks than TNSPs.

3.1.3 Investment coordination

OFA Draft Report explanation

Volume 1 of the OFA Draft Report made the point that efficient coordination of transmission and generation investment requires:

- information being exchanged between the generation and transmission sectors
- that information being accurate and meaningful to the recipients and
- investment decisions by each generator and TNSP incorporating this information and being efficient in light of that information.

The Draft Report stated that under the existing arrangements, generation and transmission investment decisions occur separately. The AEMC considered that the differences in these processes have the potential to result in inefficient coordination of investment.[39] In particular, under the current arrangements, the RIT-T used to assess transmission investment depends on assumptions used by and modelling undertaken by the TNSP. While TNSPs consult on the assumptions and modelling publicly, there are often differing views amongst participants – as shown in the Heywood upgrade assessment. In the future, the AEMC considered that such assessments may become more difficult due to greater uncertainty about relative generation technology costs at different locations. This would increase the potential for the TNSP to invest in a development path that does not enable the least-cost combination of generation and transmission.

The Draft Report also referred to a report prepared for the Commission by consultants, Houston Kemp (HK). The report by HK found that there had been some generation investments in the south-east of South Australia that had a

39 OFA Draft Report – Volume 1, p.33.

'multiplicative' impact on potential Heywood interconnector imports. This was suggestive of a sub-optimal outcome. However, the AEMC concluded that:[40]

> To demonstrate whether this is actually the case [that such investments were inefficient], it would be necessary to consider what the counterfactual outcome would be, that is, what would occur if these generators had been charged costs associated with transmission infrastructure.

The AEMC commented that under OFA, generators would receive more signals about where to locate. This would result in more efficient locational decisions being made. The Draft Report referred to a report prepared for the Commission by consultants Ernst & Young (EY), which found that a move to OFA could result in net present value (NPV) benefits of $86.6 million over the period 2014 to 2040.[41] The NPV of benefits could be:

- As low as $51 million in a scenario with a reduced RET and no carbon price
- As high as $670 million in an emissions reduction scenario.

In general, the benefits would be larger under scenarios incorporating higher demand growth, higher transmission degradation and greater emissions abatement.

The Commission concluded that the information and signals for investment that would be provided under OFA become more important in a future that is characterised by changing and uncertain transmission and generation development where:[42]

- relative costs are harder to estimate (because of the entry of new technologies with uncertainty trajectories) and
- where demand (and so the value of transmission/generation development) is less certain and/or harder to predict.

Frontier response to OFA Draft Report

Our previous report contentions

Our recent report[43] for the Group – which was submitted to the AEMC in response to the OFA First Interim Report and which itself reiterated many of the points made in our October 2012 report[44] for the NGF – addressed a number of

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40 OFA Draft Report – Volume 1, p.35.

41 OFA Draft Report – Volume 1, p.38.

42 OFA Draft Report – Volume 1, p.41.

43 Frontier Economics, *OFA design and testing – response to AEMC First Interim Report, A report prepared for AGL, Origin, Snowy Hydro, Hydro Tasmania and Stanwell*, March 2015 (Frontier March 2015 report).

44 Frontier Economics, *Optional Firm Access, A report prepared for the National Generators Group*, October 2012 (Frontier October 2012 report).

the points that were repeated by the Commission in the OFA Draft Report. We briefly restate and expand on our previous responses as follows.

First, we note that the locational signals under the current transmission planning arrangements are more powerful than is commonly assumed. These signals arise through the operation of the RIT-T and participants' expectations of how the RIT-T will be applied in future.[45] Specifically:[46]

- A TNSP's decision <u>to undertake</u> a transmission investment helps make a remote generation investment more profitable and a local generation investment less profitable
- Conversely, a TNSP's decision <u>not to undertake</u> a transmission investment does the opposite – it helps make a local generation investment more profitable and a remote generation investment less profitable.

Second, generators face a range of additional locational signals when investing. These include:[47]

- AEMO estimates of static loss factors (SLF) reflecting year ahead expected losses at a specific node and directly scale revenue received for output and
- Risks of being 'constrained-off' based on published intra- and inter-regional transmission constraints (which allow for the inclusion new entrants at different points in the network) on a forward-looking basis.

In both cases, potential new entrants receive clear signals that specific locations in the network are more or less favourable than others in terms of expected dispatch revenue (via SLFs) and/or dispatch risk (via forecast consequences of transmission constraints) that influence location decisions.

Consistent with these signals, our March 2015 report observed that the AEMC had not produced any concrete evidence that the existing arrangements have resulted in materially sub-optimal coordination of transmission and generation investment on an *ex ante* basis.[48] Indeed, the AEMC's TFR Final Report conceded:[49]

> There is limited firm evidence that the current arrangements have caused significant coordination issues to date.

Our March 2015 report went on to discuss a number of substantial generator investments since the NEM commencement (Millmerran, Uranquinty and

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45 See Frontier October 2012 report, pp.7-9.

46 See Frontier March 2015 report, pp.55-56.

47 See also Frontier October 2012 report, pp.5-6.

48 Frontier March 2015 report, pp.56-63.

49 AEMC TFR Final Report, p.iii.

Mortlake) and discussed the available contemporaneous evidence surrounding the rationale for these decisions.[50] We found that in none of these cases did the evidence support a view that the locational decisions made were inefficient at the time they were made. In the case of Uranquinty, we referred to a report for the developers prepared in part by ROAM Consulting,[51] which specifically examined the scope for existing and future transmission constraints to limit Uranquinty's output. We have been involved in a number of similar studies for potential new entrant power stations ourselves. Our experience has been that, in many instances, underlying network congestion can be less of an issue than the formulation of specific transmission constraints used in dispatch by AEMO. This seems to the case with regard to Lake Bonney's impact on the Heywood interconnector since early 2013, as discussed further below and in the Appendix.

Further, our March 2015 report highlighted the shortcomings of the EY modelling emphasised by the Commission. In particular, we pointed out that the way EY characterised the existing arrangements – as a world where 'transmission follows generation' – was inaccurate.

We noted that:[52]

- EY's methodology sets a highly inefficient baseline against which to measure the worth of OFA relative to a reference case where generators are assumed to invest in a completely unconstrained transmission system for 25 years, with transmission investment then following.
- The vast majority of EY's reported benefits accrue in the post-2030 period of the modelling.
- If the EY/ROAM representation were even broadly accurate, the history of the NEM would be littered with examples of clearly inefficient generation and transmission investment decisions (given the information known at the time). However, neither EY/ROAM nor the AEMC have been able to cite such examples.
- ROAM itself had previously undertaken at least one study[53] that involved performing the type of analysis its modelling assumed is not being undertaken by generation investors under the current arrangements. This

50 Frontier March 2015 report, pp.56-63.

51 See HMA Consulting, *Export Capability of Proposed Uranquinty Power Station*, 25 July 2006 (available at: http://www.aemc.gov.au/getattachment/745f6b38-1d36-40c3-80a1-39f90c1b51fd/Babcock-and-Brown-12-March-2008-Uranquinty-Export.aspx, accessed 12 May 2015).

52 Frontier March 2015 report, Box 4, pp.63-64.

53 See HMA Consulting, *Export Capability of Proposed Uranquinty Power Station*, 25 July 2006 (available at: http://www.aemc.gov.au/getattachment/745f6b38-1d36-40c3-80a1-39f90c1b51fd/Babcock-and-Brown-12-March-2008-Uranquinty-Export.aspx, accessed 12 May 2015).

directly undermines the integrity of the approach EY used to estimate the investment coordination benefits of OFA.

Our previous reports have also explained at length that the LRIC-based pricing signals under OFA are heavily reliant on the planner's explicit or implicit views and assumptions regarding the location of future demand and the nature and location of future transmission and generation investment required to serve that demand.[54] LRIC-based transmission charges are not prices as ordinarily understood, determined through market forces. The implication is that if the planner's views about the future course of market development are not based on the best available information, LRIC-based prices will could inefficiently distort generation investment decision-making relative to the signals provided under the current arrangements.

Centralisation of decision-making and better information revelation

As we noted at a recent meeting with Commissioners, evaluating the relative merits of the current transmission planning arrangements and OFA fundamentally involves understanding which regime promotes *better information revelation* of the least-cost means of meeting DSRSs. There is no real question about whether the existing arrangements fail to produce investment outcomes in accordance with the analysis of the RIT-T. The so-called decentralised nature of investment decision-making under OFA is a chimera because if investors are rational and profit-maximising, they will invest in accordance with the signals (both price and non-price) they are provided. Assuming the same information is revealed through both processes, the investment outcomes should be close to identical.

Hence, the relevant criterion for choosing between the current and OFA arrangements is the quantity and quality of information revealed and acted upon under both approaches.

In this context, we reiterate the points we have made in our previous reports that:

- The RIT-T utilises published information about assumed demand and transmission and generation costs and technologies, which are scrutinised and reviewed via an open, multi-round consultation process undertaken immediately prior to the time when a specific, identified reliability-driven transmission investment needs to be committed to meet DSRSs. Stakeholder input can help influence modelling assumptions in various ways, such as by informing the development of particular scenarios, which are then weighted to produce the ultimate outcome. Critically, the analysis is tailored to and focused on the issue of the day, creating the best opportunity for relevant information to be disseminated and included in the assessment.

54 See Frontier October 2012 report, pp. 9-17; Frontier March 2015 report, pp. 64-68.

- The OFA LRIC pricing model utilises assumptions that do not appear to be open to stakeholder input and the most pertinent assumptions are not necessarily re-examined immediately prior to or following an existing or prospective generator's access request. This highlights two major drawbacks with use of the LRIC pricing model:
  - First, the LRIC process is far less open than the RIT-T process. In a RIT-T process, assumptions and forecasts are made public. Under OFA, the TNSP privately offers an access price to a generator, who either accepts or rejects the offer. In cases where a project proceeds, the volume of firm access and price paid is likely to be commercial-in-confidence, and so will be difficult for other generators to scrutinise or learn from. Where a high LRIC-based price causes a project to not proceed, other potential investors' (including new entrants') ability to scrutinise access price offers would be even more difficult and opaque.
  - Second, even if the pricing body – whether the AER, AEMO or the TNSP – sought stakeholder input on the assumptions used in the model, stakeholders are unlikely to be as focused or engaged in any such abstract-seeming or remote consultation exercise as they would be in a RIT-T consultation, where an identified real-life investment with practical financial implications for stakeholders' viability was being assessed.

  Box 1 discusses some of the issues with the current version of the LRIC pricing model in more detail.

Box 1: LRIC pricing model

In contrast to an issue-specific analytical approach (such as a RIT-T assessment), the OFA LRIC model utilises a single stylised network model and a single set of transmission cost data to produce synthetic 'prices' for financial network access at different locations throughout a network. The AEMC has always described this LRIC model as "stylised".[55] We agree with this description and would point out that significant simplifying assumptions are required in the model. For example, stability constraints are no longer proposed to be modelled *at all*, rather "rules of thumb"[56] are proposed instead. Such simplifying assumptions degrade the ability for the model to produce accurate – as in, reflective of all current available information – access prices at each and every node in the network.

The AEMC states with regard to access prices calculated using an LRIC approach:

> While individually calculated prices might be more reflective of estimates of costs made at the time of access procurement, a stylised model should be capable of producing reasonably cost-reflective prices to provide good locational signals. That is, prices would reflect the right relativities in costs between locations... Further, achieving fully cost-reflective prices is something that may never be possible to achieve.[57]

55 OFA Draft Report – Volumes 1 & 2, for example Volume 2, pp. 43-62.

56 OFA Draft Report – Volume 2, p. 53.

57 OFA Draft Report – Volume 2, p. 49.

We strenuously disagree with this view. Access prices represent a significant cost to generators and the absolute level is of critical importance and should be a focus of the modelled outcomes. This is important if access prices are to send accurate signals for investment in new generation plant and even more relevant to existing generators. Access prices could have the correct "relativities" and still lead to potential new entrants not investing in the NEM. Incumbents will face a Hobson's choice between accepting a potentially excessive access prices at their current node to remain firm (in transitional assistance auctions and once such assistance rolls off) and trying to compete as a non-firm generator against firm competitors who can offer more wholesale contracts at the regional reference node. Correct "relativities" will not stop a currently low cost generator from making losses if access prices are too high and/or the detriments of being non-firm are severe.

We also disagree with the notion that inaccurate access prices are not a significant issue because access rights are tradable. With regard to inter-generator trade, regardless of whether significant trade occurs, by definition consumers cannot captures any benefits (or suffer any detriments) of such trade. With regard to generator-TNSP trading, generators have a right to 'sell back' firm access rights, essentially at the access prices at the time of the sell back. The AEMC states that:

> There should be no overall impact on TNSPs and TUOS customers; so long as the LRDC calculation reasonably estimates the avoided costs associated with the sell-back, consumers would be no worse off.[58]

Whilst there are some possible examples where a sell-back may occur without a significant detriment accruing to consumers, such as the local load exit example raised by the AEMC, there are also cases where the sell-back right increases costs faced by the TNSP and ultimately consumers. For example, if a generator initially pays a low access price for a 10 year access term, and access prices subsequently rise in year 3 due to unexpected changes in load and power flows across the NEM, it would be possible for the generator to exercise its sell-back right and lock in a certain profit equal to the difference between the NPV cost of the remaining 7 years' access at the low access price and the NPV payment of an offsetting 7 years of access at the current high price. Ultimately, it seems likely that generators may be able to use their-sell back right to inter-temporally arbitrage errors in the access prices that arise over time to the detriment of consumers.

In any case, the fundamental problem with the LRIC model is that it may produce access price relativities that do not reflect the best currently-available information about generation and transmission costs at different locations – information that will typically be revealed through a RIT-T consultation and assessment process. If the access prices produced by the LRIC model do not reflect the best available information, they will be 'wrong' in that they could encourage investors to make inefficient decisions.

The reason why the LRIC model will generally not produce efficient prices stems from its highly assumptions-driven design. The LRIC model currently assumes:

- a peak demand forecast by connection point, over 10 forward looking years, which is then escalated at assumed growth rates for a further 40 years
- a baseline network expansion plan over 50 forward years
- incremental fixed and variable network costs over 50 forward years
- levels of incumbent firm access over 50 forward years
- reliability requirements over 50 forward years

Access prices depend on all of these assumptions, which raises a number of issues.

58 OFA Draft Report – Volume 2, p. 77.

In particular, the baseline expansion plan is critical to how access prices are set, as it is impossible to generate access prices without taking an explicit or implicit view on:

- where and by how much will load increase in the future,
- where and by how much will transmission and generation need to be developed in the future

Whilst the AEMC appears confident in making planning assumptions over a 50 year forward period to produce access prices, they have decided that determining the initial transitional assistance allocation solely via a modelled approach is likely to involve "arbitrary assumptions"[59] and unacceptable inaccuracies.[60] This conclusion, that modelling a snap shot of access volumes at a point in time under known conditions involves risk whereas modelling forward looking nodal access prices which depend on long term assumptions is workable appears inconsistent. This issue is exacerbated by the use of the model by a centralised agent (ie the AER or otherwise) who faces little consequence for inaccurate access price forecasts.

While forecast assumptions are needed under the current approach, these assumptions are subject to much greater scrutiny than the assumptions in the LRIC model (see above).

Finally, under OFA, generators are subject to a stylised access price with potentially severe commercial implications while this access price is forecast by a central party (the AER) who bears no risk of forecasting error and is highly dependent on long term inputs from third parties with a conflict of interest in the level of access prices offered to generators (AEMO and the TNSPs) – see also below.

Source: Frontier Economics

The above considerations mean that OFA is unlikely to yield investment outcomes that reflect as current and accurate information about transmission and generation costs as under the RIT-T. For OFA to be more effective at promoting efficient investment coordination than the existing arrangements, OFA would need to be considerably better than the RIT-T process at utilising individual generators' (assumed private) information regarding their individual costs.

Therefore, OFA will only produce a more efficient generation-transmission investment outcome than the current arrangements <u>if:</u>

- the investment coordination inefficiency resulting from the crudeness and inaccuracy of the OFA pricing model outcomes

  ...is <u>more than offset</u> by...

- the greater investment coordination efficiency stemming from:
  - the more accurate *relative* generator technology and locational cost information available to <u>individual</u> generators

    compared to

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59 OFA Draft Report – Volume 2, p. 95

60 OFA Draft Report – Volume 2, pp. 90-95.

- the *relative* generator technology and locational costs used in a RIT-T assessment incorporating all relevant stakeholder consultation input.

While individual generation investors could have superior private information about particular generation technology costs and/or generation costs at particular locations, they are unlikely to have superior information about all plant technologies and investment costs at all different locations than would emerge through a RIT-T consultation process. Indeed, Volume 1 of the OFA Draft Report itself concedes that under OFA, generators will need to rely on outside estimates of rival generation technologies.[61]

While individual participants' lack of full information is seldom a problem in normal markets where prices automatically and impersonally adjust to reflect the forces of demand and supply,[62] prices generated by the LRIC model are not determined in a market – they are synthetic charges, centrally-determined by a 'black box' model in a 'back room'. Therefore, unless most individual investors generally have better information than would emerge from a RIT-T, it is far from clear than investment outcomes under OFA would be superior to those resulting from a RIT-T process.

Finally, we note that inefficient transmission investments resulting from errors in forecasting customer demand are largely irrelevant to the investment coordination merits of OFA because to the extent TNSPs over-forecast demand under OFA, TNSPs will still be empowered to undertake transmission investments they perceive necessary to meet DSRSs even if generators do not agree with their demand forecasts. Moreover, if generators are generally privately of the view that a TNSP has over-forecast demand – and hence is likely to over-build the transmission network – generators are unlikely to be willing to pay for access rights, leaving the risk and cost of such investments with end-use customers (as it is now).

What about in the future?

A key argument made in favour of OFA in the Draft Report is that although the existing arrangements have not resulted in clearly inefficient generation locational decisions to date, this may change in the future due to greater uncertainty about generation technologies and costs at different locations.

We are deeply sceptical of this claim for a number of reasons.

61 OFA Draft Report – Volume 1, p.25.

62 See, for example, Hayek, F.A, "The Use of Knowledge in Society", *American Economic Review*, Volume XXXV, September 1945, No.4, pp.519-530, especially at p.527.

First, the NEM has been operating for over 16 years through a range of demand and supply conditions, as well as major policy and technology changes. These include:

- a substantial oversupply of baseload generation in the late 1990s in Victoria and New South Wales
- a shortage of peaking generation and interconnection for meeting summer heatwave-driven demand in the early 2000s in the southern states
- quiescent peak demand and spot prices over the middle years of the 2000s
- strong peak demand and supply shortages over the period 2007-2010 due to drought and record heatwaves in south-eastern Australia
- increases in targets for renewable energy from 9,500 GWh in 2001 to approximately 45,000 GWh (excluding existing hydro) by 2009 and the splitting of the former target in 2011 into the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET)
- energy efficiency measures such as the phasing out of incandescent lights and Mandatory Energy Performance Standards (MEPS)
- since 2010, a domestic solar PV installation boom
- a substantial fall-off in wind generation investment in recent years due to uncertainty regarding the future of the LRET
- the imposition of a high (by world standards) carbon price and the removal of that price two years later.

In spite of what could fairly be described as an eventful period in the Australian electricity supply industry, neither we nor the AEMC can identify any significant generation locational decisions that were demonstrably inefficient and would have been significantly more efficient had OFA been in place.

Second, leaving aside the risk allocation argument discussed in section 3.1.2 above, it is unclear how greater uncertainty about generation technologies and costs will boost the merits of OFA relative to the existing arrangements:

- Under the RIT-T, greater uncertainty regarding future costs can be incorporated through the use of more 'reasonable scenarios' in the assessment. The TNSP is then required to transparently weight the outcomes from these scenarios according to their expected probability of occurring.[63] This means that the investment decision that is ultimately made – whether that is for investment in transmission, demand-side response or local generation – should reflect all the information on a (albeit subjective) probability-weighted basis.

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63 AER, *Regulatory Investment Test for Transmission*, Final, June 2010, clauses (3) and (4)(a)(ii).

- Under OFA, it is unclear how generator cost uncertainty will be reflected in LRIC prices – if at all. It is likely that greater uncertainty will simply mean that LRIC-based prices are more likely to be 'wrong' than they were previously, further distorting generator locational decisions. In this context, we note that although the Heywood upgrade RIT-T analysis was a matter of dispute, participants generally agreed on generation cost inputs. The issue in contention in that case was the assumed network capabilities that underpinned the forecast net benefits. This is not an issue that would necessarily have been resolved under OFA.

It could be that the AEMC believes that benefits from OFA could arise from the ability of generation investors under OFA to 'wait and see' how the uncertainty is resolved before investing. This contrasts with the investment process under the existing arrangements where TNSPs invest despite uncertainty. However, we note that under the existing arrangements, most transmission investment is undertaken to meet DSRSs. Under the RIT-T any investments need to be undertaken at a time that maximises net market benefits (or minimises net market costs if the project is needed for reliability corrective action). This means that the timing of a project undertaken pursuant to a RIT-T cannot, *ex ante*, be delayed without foregoing expected net benefits. The merits of the existing arrangements and OFA should be compared by holding the timing of the investment decision constant. If this is done, the attention returns to which regime provides the better information revelation – which we consider is clearly the current RIT-T arrangements.

Interconnector degradation

As noted above, perhaps the Commission's key indicator of problems under the current arrangements is the impact of a handful of wind farm investments in south-east South Australia. The HK report found that there had been some investments that had a 'multiplicative' impact on potential Heywood interconnector imports. However, the Commission observed that this was only suggestive rather than conclusive of inefficiency.

We agree with the OFA Draft Report that to determine whether such investments were reflective of inefficiency, it would be necessary to consider the counterfactual under OFA. After all, it may be that a particular new generator reduces transmission flows on a more than one-for-one (MW) basis, but is still consistent with the efficient development of the industry due to the low costs of the offending plant.

For example, take the Lake Bonney wind farm, which the HK report identified as having a multiplicative negative effect on Heywood interconnector imports into South Australia. While this plant may be having negative effects now, ElectraNet's Annual Planning Reports from 2010 and 2011 specifically noted that the risks of such effects had been foreseen and were to be countered through a run-back control scheme in order to limit the impact to 1-for-1.[64] Further, it appears that the impending Heywood upgrade – to be commissioned by July 2016[65] – will substantially expand the scope for South Australian electricity imports from Victoria, overcoming the problems imposed by Lake Bonney. We note that the Heywood upgrade was found by the proponents to have a very high benefit-cost ratio.[66]

Overall, the evidence suggests that the location of Lake Bonney may well have been efficient at the time despite the negative multiplicative effect it has had and will have on Heywood import capability over the period 2012 to 2016. This is because the favourable wind location of Lake Bonney on the 'Limestone Coast' of South Australia[67] may potentially result in enough additional zero-marginal cost energy output to outweigh the effect of short-term transient degradations of Heywood import capacity.

In other words, the better wind capacity factors at Lake Bonney compared to where it would have needed to locate to connect to the 275 kV network may more than offset the cost of substituting some relatively high-cost South Australian generation for low-cost Victorian generation due to the degradation. However, this would need to be tested empirically.

In any case, it is far from clear that had OFA been in place in 2009 (or earlier) when Lake Bonney 3 was seeking connection, OFA would have altered Infigen's location decision.

Appendix A provides further detailed discussion of the Lake Bonney example.

3.1.4 Effective inter-regional hedging

As discussed in section 2.2.2, the AEMC has recently identified concerns with the effectiveness of inter-regional hedging. These concerns appear to relate primarily to:

- Inter-Regional Settlement Residue (IRSR) units being a non-firm product

64 See ElectraNet, *Annual Planning Report 2010 -2030*, June 2010, p.101; ElectraNet, *Annual Planning Report 2011*, June 2011, p.109.

65 See AEMO, *The Heywood Interconnector: Overview of the Upgrade and Current Status, South Australia Advisory Functions*, July 2014 (available at: http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/Heywood-Interconnector-Update, accessed 13 May 2015), pp.5-6.

66 A benefit-cost ratio of 3.375:1 – see ElectraNet and AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Conclusions Report*, January 2013, pp. v, 106.

67 See Infigen, *Powering the Future with Renewable Energy*, Infigen Energy Wind Farms (available at: http://www.infigenenergy.com/Media/docs/IFN-Wind-Farms-Brochure-ca7d8535-8c0a-4b66-9306-1b899253e510-0.pdf, accessed 13 May 2015).

- 'Race-to-the-floor' bidding by generators leading to reductions in flow and/or counter price flows that degrade the firmness of IRSRs
- IRSRs trading *ex ante* at less than actual outturn price differentials, with this being evidence that generators are not using these products to hedge inter-regional price differentials.

We disagree with the AEMC that the issues it has identified reflect real problems for the market. We are further concerned that the issues identified will become the next primary motivation for OFA, or some related policy proposal, in the future.

In brief, we would make the following points:

- IRSRs being auctioned at prices that are less than expected contract price differentials between regions[68] does not represent a market failure. IRSR payouts are correlated to difference payments on swap contract at each node. To suggest that the difference in strike prices on firm swaps should equate to payouts of IRSRs represents a fundamental misunderstanding of the differences between the products.
- IRSRs are not valued by generators and retailers in and of themselves. They are one input, along with physical generation and/or vanilla swap and cap products, that can allow generation in one region to competitively serve load in another region. Again, the returns on IRSRs can have positive or negative correlations to the other physical and financial products that comprise an interregional trade. If IRSR payouts are negatively correlated to say, cap payouts, then the value of the IRSR to a potential buyer will be reduced below the face value of the IRSR.
- Participants can and do engage in interregional trade using a combination of products. We support Snowy Hydro's submission to the OFA Interim Report and the discussion of evidence presented as part of the ACT consideration of AGL's 2014 acquisition of Macquarie Generation.[69] There is clear evidence that generators can sell electricity in other regions and that retailers can purchase electricity from other regions using combinations of current market products. Given this scope, there seems little need for regulatory invention.
- Given that inter-regional trade can and does occur in practice, it is difficult to see how material increases in competitiveness could arise from firmer IRSRs. Current levels of competition already reflect inter-regional trading that is occurring. Any dispatch inefficiencies arisen from 'race-to-the-floor' bidding are a separate issue and, as discussed in section 3.1.1, have consistently been shown to have little economic significance.

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68 OFA Draft Report – Volume 1, Table 7.1, p.60.

69 OFA Draft Report – Volume 1, pp. 61-62.

3.2 Other concerns with recommended approach

3.2.1 Questionable role of 'monitoring' to trigger OFA

As noted above, the AEMC's Draft Report suggested that OFA could become a net beneficial reform if:[70]

> ...drivers emerge of a major transformation of the generation and transmission capital stock, where the outcomes are highly uncertain, the existing mechanisms for co-ordinating generation and transmission operations and investment may prove inadequate. In these conditions, the balance of expected benefits and costs of optional firm access would shift in favour of implementation.

And:[71]

> The Commission considers that optional firm access could help the market adapt in an environment of major changes in the capital stock requiring significant investment and characterised by high levels of uncertainty with respect to relative costs, technologies and hence location decisions...

To this end, the Draft Report proposed that the Commission undertake monitoring as an adjunct to its LRPP responsibilities.[72] At this stage, the intent is that monitoring would be aimed at identifying signs that conditions are beginning to change in a way that the benefits from optional firm access could be greater.[73] The Commission suggested that:[74]

> Most signs or indicators that would increase investment can be linked with either changes to emissions costs; or changes to the costs of generation. There would also need to be indicators about the level of demand.

The Draft Report signalled that the Final Report (due by mid-2015) would set out more detailed consideration of how monitoring of NEM conditions should take place if OFA was not to be implemented immediately, taking account of submissions responding to the Draft Reports.[75] While we welcome further consultation on the potential indicators that could be monitored, we remain unsure about what monitoring will mean in practice. It appears that the AEMC will effectively be preparing an annual commentary on historical and expected market developments; the AEMC will be reporting on known developments and uncertainties surrounding those developments. To this extent, the work undertaken by the AEMC may actually *reduce* the investment community's

70 OFA Draft Report – Volume 1, p. i.

71 OFA Draft Report – Volume 1, p. v.

72 OFA Draft Report – Volume 1, p. 83.

73 OFA Draft Report – Volume 1, p. 83.

74 OFA Draft Report – Volume 1, p. 84.

75 OFA Draft Report – Volume 1, pp. v, 4 and 84.

uncertainty regarding some of these drivers and developments. But we also note that such an analysis cannot – by definition – gauge the degree of uncertainty surrounding unforeseen developments (the so-called 'unknown unknowns'). Yet these are the issues or factors that presumably would, according to the Commission's framework, motivate the adoption of OFA.

We also disagree with the AEMC that the future market landscape will necessarily be more uncertain than it has been in the past. As noted above, the NEM has experienced major unexpected changes over its history. Few investors or commentators in 1998 would have predicted that power would regularly flow from Queensland to New South Wales, or from South Australia to Victoria. Few would have predicted the scale of the renewable energy targets that were introduced several years ago, or the enormous boom in domestic solar PV experienced over the last half-decade. Few would have predicted the large increases in gas, oil and black coal prices or the rise of vertically-integrated 'gentailers'. Yet leaving aside the large boost to network investment over recent years attributable to over-forecast demand and tight mandated planning standards – neither of which would have been avoided by OFA – investment outcomes have largely been efficient.

All of this suggests that the substance of the proposed AEMC monitoring role remains unclear in content and purpose.

3.2.2 Governance issues/conflicts re access price-setting and pricing model inputs

We have specific concerns with the proposed allocation of roles and responsibilities in the OFA Draft Reports, particularly concerning the setting of LRIC-based access prices.

Under OFA:[76]

- TNSPs would be responsible for specifying the network conditions that would be used in the firm access planning standard. These specified conditions would be approved by the AER. These conditions are intended to represent an extreme set of conditions, such that system operation would typically be inside the limits.
- The price paid by generators for firm access would be produced through a regulated, stylised pricing model, developed and maintained by the AER with data inputs from TNSPs and AEMO as the National Transmission Planner (amongst others).

76 See OFA Draft Report – Volume 2, Table 3.1, pp. 16-18; also, pp. 10-13.

- The stylised expansion plans on which access prices would be predicated would not be the actual plans that the TNSP would follow to develop the network (ie, access prices are different to project costs). There would not be a one-to-one mapping between an access request and a transmission expansion project.
- The TNSP would 'turn the handle' of the model.

The AEMC's OFA Draft Report – Volume 2 indicated that the Rules would be relatively non-prescriptive in these areas.

In our view, the proposed arrangements will widely disperse responsibility – and hence, accountability – for setting appropriate price signals. By appropriate prices, we mean prices that would induce the sort of investment outcomes likely to follow from well-run RIT-T processes. To the extent LRIC prices are inaccurate, the responsibility will be split between TNSPs, the AER, the AEMC and AEMO. At least under the current arrangements, the TNSP conducting the RIT-T is responsible for the integrity of the test's application; and that application can be independently reviewed by the AER upon request or the lodgement of a dispute. Under the AEMC's proposed structure, all the NEM institutions will be involved in the price-setting process to some degree;[77] none will be in a position to objectively determine whether and how the model or the model inputs are flawed and need to be changed, nor which institution has failed to perform its functions adequately. Poor investment outcomes made in response to inappropriate prices are likely to result in a 'blame game' between the relevant institutions, requiring intervention by the COAG Energy Council to resolve. This would be a far from desirable dynamic to institute.

[77] Although in practice, we consider that AEMO will dominate the LRIC modelling process due to its large informational and expertise advantage over the other institutions. However, even if this occurs, it would not avoid the dispersion of accountability noted above.

4 Proposed way forward

This section makes suggestions regarding a proposed way forward for the AEMC and the COAG Energy Council.

4.1 'No regrets' reforms

In the first instance, we propose two changes to existing transmission and market arrangements that could be assessed and pursued irrespective of what else follows. These 'no regrets' changes largely involve strengthening existing information revelation processes.

As discussed in section 3.1.3, the current NEM arrangements are already highly effective at revealing relevant information about the efficiency of generation investment at different locations. This information facilitates the coordination of generation and transmission investment. However, these processes could be improved to reveal more information, more accurately and in a more timely fashion, thereby sending stronger and more accurate signals to participants.

4.1.1 RIT-T

We suggest that the RIT-T process could be improved by ensuring that the assumptions and methodology relating to any power flow modelling are documented as clearly as are assumed generation costs and the approach used to forecast generation investment and dispatch. This would ensure that stakeholders are clear on the material assumptions being made in this area. Greater transparency of such data would assist stakeholders to make more meaningful submissions to the appropriateness of inputs, approach and modelled outcomes. Such information would have been very useful in the recent Heywood upgrade evaluation.

4.1.2 SLFs

AEMO currently provides forward-looking, multi-year static loss factor estimates upon request on an 'all care, no responsibility' basis. We do not currently see any ways in which this process could be improved.

4.1.3 Constraint data

AEMO currently provides significant documentation on constraints, including:

- Complete information on the current constraint set to market participants via the participant infoserver.[78]
- Constraint documentation, such as weekly constraint update reports[79] and constraint formulation guides.[80]
- Monthly and annual constraint reports,[81] which document constraints that have bound in practice and other relevant information.
- Publishing of a subset of system normal constraints on an annual basis. Currently, this occurs as part of AEMO's NTNDP process.[82] The basis on which the subset is chosen is not entirely clear and we believe it to be based on an assessment by AEMO of the materiality of a given constraint, i.e. constraints that are expected to bind are published and constraints that are not expected to bind are not.

These initiatives are to be commended. There are two key areas where current processes could be strengthened to provide improved ability for potential new entrants to more accurately assess transmission issues when making locational decisions.

First, AEMO could publish the complete set of system normal constraints. This would not seem to impose considerable extra effort on AEMO and would substantially improve potential new entrants' ability to assess congestion issues. AEMO's assessment of materiality is unlikely to account for potential new entrants' possible generation investments. Specifically, constraints that would not be expected to bind with current and committed generation (and which are therefore not published) may in fact be likely to bind if a large new generation

78 For an overview of systems see http://www.aemo.com.au/About-the-Industry/Information-Systems/Using-Energy-Market-Information-Systems .

79 See http://www.aemo.com.au/Electricity/Market-Operations/Congestion-Information-Resource/NEM-Weekly-Constraint-Library-Changes-Report .

80 See http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Guides-and-Descriptions/Constraint-Formulation-Guidelines .

81 See http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Monthly-Constraint-Report and http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report respectively.

82 AEMO's 2014 thermal and stability constraints book can be found http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/esoo/2014/ESOO%20Update/2014_ESOO_Stability_Constraints.ashx and http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/esoo/2014/ESOO%20Update/2014_ESOO_Thermal_Constraints.ashx .

facility is being considered. At the moment, such constraints are 'unknown unknowns' to new entrants.

Second, AEMO could tighten validation processes to ensure the accuracy of these data and make public notifications and corrections if errors are found. Frontier Economics and Macquarie Generation identified material errors in the published constraint books[83] released in 2012. Despite notifying AEMO in April 2013, these books were not corrected. More worryingly, the books were not removed from AEMO's website and no disclaimer was published, making it possible for other stakeholders to continue to use incorrect constraints. Ensuring that these books are error-free is critical to the value they provide to participants. AEMO itself may not fully appreciate the value of this information to potential new entrants.

4.2 Broad options for more fundamental change

In order to avoid the perception of developing options that appear to be 'solutions looking for a problem', we propose the following framework for how more fundamental change should be considered.

We suggest that the AEMC should either:

- Accept that nearly a decade (since the commencement of the Congestion Management Review) of more-or-less sustained focus on the NEM congestion management and transmission planning arrangements has yielded little in the way of demonstrable and significant inefficiencies; or
- Return to conducting a detailed review and analysis of market outcomes to determine whether observed inefficiencies were increasing in scope and severity by a sufficient degree to warrant some form of response. If, having decided to undertake further review and analysis, the AEMC observes clear evidence of significant inefficiencies or identifies strong indications of significant impending inefficiencies, it should focus in the first instance on developing proportionate solution options. It is only if problems are identified with the current arrangements that are so profound and far-reaching that tailored responses are likely to become unwieldy that a radical option such as OFA should even be conceived. The next sub-section highlights areas that the AEMC may wish to examine more closely.

83 See constraint "S>>V_NIL_NIL_TX1_114WA" in http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2012-National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_ConstraintWorkbook.ashx . The error set flow from Victoria to South Australia on Heywood to a line rating of 274 MW for 2013/14 in error, corrected value is 621 MW. This has a material impact on any modelling. The error still stands without comment on AEMO's website as of 18 May 2015.

In either case, there is no reason for the AEMC to 'warehouse' OFA as a change to be triggered under particular conditions that may or may not indicate likely significant inefficiencies going forward.

4.3 Potential forms of monitoring and responses

If, in spite of the lack of substantive evidence of any material inefficiency in the NEM to date, the AEMC chooses to pursue further analysis, there are several areas that it may choose to undertake further monitoring. These and the potential responses that may follow from such monitoring are outlined below.

To be clear, our starting position is that, after a decade of intensive focus on these issues which has produced no evidence of material inefficiency, formal monitoring over and above current arrangements[84] is not required.

We consider that the areas where the AEMC may contemplate further analysis are:

- Congestion and dispatch inefficiencies
- Multiplicative displacement of interconnectors and
- Inter-regional trading.

4.3.1 Congestion and dispatch inefficiencies

Dispatch inefficiencies arising from congestion have been the subject of extensive analysis by the AEMC and other stakeholders. Given that multiple studies have consistently found that the resource costs of historical and likely future congestion are relatively immaterial, we believe that monitoring should be focused on identifying levels of congestion at least as severe as those which have occurred in the past. Second, the long history of congestion reviews in the NEM, and in some cases of specific policy responses, provides a blueprint for the process by which these issues can be managed via proportionate responses, if in fact a response is required at all. We submit that the process that ultimately led to the change of the Snowy regional boundary provides the best such example.

Monitoring

Monitoring should focus on identifying whether non-cost-reflective bidding is increasing in frequency and severity to the point where it exceeds stipulated benchmarks as least as severe as instances observed to date, such as:

84 Such as the AER's annual State of the Energy Market report, AEMO's annual ESOO and NTNDP processes and the many processes conducted by jurisdictional and federal regulators, departments, special purpose inquiries and community advocacy groups.

- Frequency – a generator is constrained-off or -on as a result of non-cost-reflective bidding for more than 50 hours per annum during system normal times for at least three consecutive years; and
- Severity – non-cost-reflective bidding observed during the ten most prominent six-hour incidents in a year results in at least $1 million of resource cost inefficiencies per incident on average (ie $10 million welfare loss for the ten incidents) for at least three consecutive years. The choice of a six-hour period was based on the five-hour duration of the Wallerawang-Mt Piper constraint of 7 December 2009 that led to the disorderly bidding episode highlighted by AEMO in its submission to the AEMC's TFR Issues Paper.[85]

Any further criteria should be set with reference to the most severe historical instances, consistent with the principle that it would require more severe outcomes than observed to date for a regulatory response to be justified.

Potential proportionate responses

The Snowy regional boundary Rule change was initiated by concerns about the dispatch outcomes resulting from the perverse bidding incentives faced by Snowy Hydro. These perverse incentives often led to flows on the former Snowy to Victoria and Snowy to NSW interconnectors being reduced despite high demand conditions in the importing regions.

In brief, the Rule change process involved:[86]

- The trial of a modification to NEM pricing and settlements for the Tumut power station proposed by Snowy Hydro, which utilised Constraint Support Payments and Constraint Support Contracts (CSPs/CSCs).
- Assessing a number of competing proposals by various parties including:
  - Snowy Hydro's proposal to abolish the Snowy region, with the former parts of the region to be allocated to the New South Wales and Victorian regions, approximately along jurisdictional boundaries
  - Macquarie Generation's proposal to split the Snowy region into two parts
  - The Southern Generators' congestion pricing proposal – which effectively sought to make the Tumut CSP/CSC trial permanent and utilise positive settlement residues on the Snowy-NSW interconnector to offset negative settlement residues on the Victorian-Snowy interconnector.

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85 See AEMO, *Transmission Frameworks Review – Submission to AEMC's Issues Paper*, 7 October 2010, Appendix B.

86 See AEMC website at: http://www.aemc.gov.au/Rule-Changes/Abolition-of-Snowy-Region (accessed 15 May 2015).

- These alternatives were subject to considerable scrutiny and stakeholder consultation. Each response was measured against both the prevailing arrangements and relative to the other responses.
- Both analytical and empirical analysis identified the Snowy abolition option as being most likely to change Snowy Hydro's incentives around bidding and result in the largest resource cost savings relative to the prevailing arrangements and the other response options.
- Ultimately the AEMC decided to proceed with the abolition option, which came into effect on 1 July 2008.

What can be learnt from this process? We would submit three key lessons.

First, congestion issues are highly specific and require highly specific solutions which can only be developed once the problem is properly identified. In this case the issue related to bidding incentives, a unique position in the network and was demonstrated to be persistent.

Second, the process itself generated a range of innovative solutions to a specific and well defined problem. The process began with policy-makers proposing solutions, but led to further proposed options and high levels of engagement from a number of participants. We believe this was to the benefit of the process, the outcome and ultimately consumers and would be worth emulating in the event that congestion issues are demonstrated to be material in the future.

Third, the possible responses comprised a wide range of general tools – financial contracting arrangements, changes to operational constraints and reconfiguration of the NEM regions. These general tools were focused on the specific problem that had been identified and in some cases combined in novel ways. We submit that a readymade solution to an as yet unidentified problem, such as OFA, is unlikely to be a best outcome when compared to a set of tailored potential solutions.

To the extent that a material congestion issue is identified in the future, we would recommended seeking to develop a number of tailored and proportionate responses that utilise a broad range of approaches and draw on the innovation of the wider participants in the NEM.

4.3.2 Multiplicative displacement of interconnectors

The issue of multiplicative displacement of interconnectors is a special case of (perceived) inefficient generation locational investment decision-making. As noted above, the AEMC's consultants have identified Lake Bonney as an investment that *may* have located inefficiently.

In our view, it is far from obvious that, say, Lake Bonney 3 represented a materially inefficient investment as of the time it was made (or even subsequently) notwithstanding its current transitory multiplicative displacement effect on Heywood imports. The HK report did not identify other comparable instances of this issue. As such, there seems little justification for expending too many resources to monitor multiplicative displacement effects going forward.

To the extent that monitoring of displacement effects occurs and successfully identifies material and persistent effects, we propose two possible proportionate responses.

The first seeks to deal with the issue conditional on being able to accurately forecast the displacement *ex ante*, which has implications for monitoring. The second approach is conditional on these issues being unforeseeable in practice and relies instead on TNSP incentives.

Neither of these approaches is ideal. We would note that the shortcomings of the forecasting approach to resolve this issue apply equally to OFA.

Monitoring

The AEMC should establish bi-directional transfer capabilities for each interconnector prior to monitoring commencing. For the purpose of the forecasting response, the AEMC should also develop a forecasting approach that can predict multiplicative displacement of an interconnector due to a new generation connection and be obligated to produce public forecasts of the impact of any new entrant generation facility (>100 MW).

The AEMC should then seek to identify instances, *ex post*, where the output of a new generator in a specific set of binding constraints containing that new generator displaced imports by 1.5MW or more for each MW of new generator output, for at least 500 hours per annum, for three consecutive years and that the displacement was equal to at least 100 MW of interconnector flow in each event.

In the event that public displacement forecasting had occurred, the monitoring would also seek to determine if the forecast had accurately predicted the issue.

Proportionate responses

To the extent that the AEMC had accurately forecasted a multiplicative displacement event, a forecasting response could be pursued. Alternatively, an incentives-based response would be considered. Ideally either or both approaches would be compared to other possible responses and the prevailing arrangements.

Forecasting based

The ability to accurately forecast multiplicative displacement *ex ante* would enable:

- Denying the connection. This would require a Rule change to strengthen the current conditions of connection to exclude connections that were forecast to lead to multiplicative displacement effects as defined above. Responsibility for enforcing these enhanced conditions of connection would rest with the TNSP.

- Facilitating bilateral negotiation between the TNSP and the connecting generator to fund a solution to the issue.

In our view, it is unlikely that such issue could be reliably forecast given the number of long term forward looking assumptions required. This view is reinforced by our analysis of the connection of Lake Bonney 3. We see this as consistent with our concerns about the ability of the LRIC model to produce sufficiently accurate access prices under OFA.

Incentives based

If multiplicative displacement cannot be reliably forecast then an alternative would be to create incentives for the TNSP to conservatively restrict connections that prove problematic in the future (based on their own analysis and judgement). This incentive would be created by making the TNSP liable to 'make good' (outside of regulated revenue) for any multiplicative displacement that occurs in practice.

Again, this is not ideal and may simply lead to unacceptable barriers to connection.

4.3.3 Effective inter-regional hedging

Although difficulties around inter-regional trading have been raised by the AEMC, our starting point is that:

- Despite the NEM being a regional market, significant inter-regional trade can and does occur in the NEM via a number of channels. These are discussed in section 3.1.4.
- To some extent, there is an inherent conflict between designing the market arrangements to support inter- and intra-regional derivatives trading. 'Firming up' interconnectors will tend to reduce the firmness of intra-regional generators and may result in a net dis-benefit if a smaller volume of derivatives is traded overall.

Furthermore, we note that where negative settlement residues have in the past arisen (reducing the value of IRSR units as an inter-regional hedge), this was often a result of major network outages. Analysis by the NGF in 2012 showed that of 20 episodes of disorderly bidding, 17 had been associated with such outages – only three had occurred under system normal conditions.[87]

This suggests that if any monitoring is contemplated, it should focus on identifying a material reduction in the ability of participants to inter-regionally

87 See Letter from Mt Tim Reardon (Executive Director of the NGF) to Mr John Pierce (AEMC Chair), dated 21 December 2012, entitled "NGF Response to AER Special Report – The impact of congestion on bidding and inter-regional trade in the NEM, December 2012"..

trade, and should not focus on the outturn 'firmness' of IRSR units in and of themselves.

Monitoring

If monitoring of inter-regional trade is to be undertaken, it should focus on identifying if inter-regional trade is materially impaired relative to current levels and/or whether participants consider there to be a material increase in barriers to inter-regional trade. Unfortunately, this is hard to monitor. Approaches include:

- Undertaking data driven analysis of actual inter-regional trading. Unfortunately, whilst an empirical approach is our preferred option, this seems unworkable in practice. IRSR information would be available to the AEMC; however, the use of IRSR units represents only one channel by which inter-regional trade can occur. We do not recommend that the AEMC or anyone else should be able to access participants' financial hedge information given that these data are highly commercially sensitive.
- Seeking stakeholder input and feedback. The AEMC could develop surveys to seek generators' and retailers' views on inter-regional hedging. Example questions could relate to:
  - Whether participants currently trade inter-regionally
  - Whether participants perceive any barriers to such trade

  The main drawback of this approach is the ability for participants with a vested interest to provide spurious anecdotal information. Wherever hard data can be used to corroborate anecdote, it should be pursued.

Proportionate responses

If monitoring identifies clear problems with prevailing levels of inter-regional trade, any response should focus on the clearly-identified source of any material problem.

For example, if numerous participants reported that barriers to inter-regional trade were increasing due to insufficient firmness of IRSRs units, we would recommend identifying the underlying cause of reduced inter-connector flows (which could arise due to congestion, bidding or other factors) and to then look at a range of responses that focus on the identified problem. Such responses may include financial arrangements that increase the firmness of IRSRs but should be considered in conjunction with:

- Reformulation of relevant constraints. It may be that the physical network can actually support increased interconnector flows but that constraints are too conservative or providing poor signals to some generators.
- Options for net beneficial investment in either generation or transmission under the RIT-T to relieve underlying congestion. We would note that the

inclusion of competition benefits under the RIT-T allows for the competitive benefits of increased inter-regional trade to be explicitly included.

- Potentially, regional boundary changes depending on the nature of the problem.

It could also be the case that the underlying issue is structural. Our view would be that none of the above options would completely remedy a problem arising due to market power.

Alternatively, the underlying issue could be one of reduced market liquidity for standard financial products. In this case, the level of firmness of IRSRs would be moot and responses would be focused elsewhere.

Appendix A – Lake Bonney case study

In the OFA Draft Report, the AEMC put forth the commissioning of Lake Bonney stages 2 and 3 as examples of potentially inefficiently-located investment. This is consistent with a number of submissions to the Commission's Review and other public statements by various South Australian government bodies.

As noted above, the AEMC commissioned Houston Kemp (HK) to examine the issue of historical coordination of transmission and generation investment.[88] HK ultimately concluded:

> The Lake Bonney 2 and 3 wind farms have had a multiplicative effect on the limit of the Heywood interconnector (ie, 1MW from these wind farms has reduced interconnector flows by more than 1MW):
>
> > This is evidence of a sub-optimal outcome, eg, in circumstances where demand is high in South Australia and there is not a lot of wind generation in South Australia generally but there is in the SESA region, the interconnector can only provide a fraction of the support it could if the SESA wind farms were not connected;
>
> The Eyre Peninsula provides a good example of a locational decision made by generators that has ultimately resulted in additional transmission costs borne through generation as a result of ElectraNet having to pay more for network support at Port Lincoln.[89]

This conclusion appears to be based on stakeholder statements and evidence of what appears to be a constraint that reduces imports on Heywood by more than 1 MW for every additional 1 MW of dispatch from Lake Bonney 2, Lake Bonney 3 or Canunda wind farm. HK's key empirical result is reproduced in Figure 1. This shows that in calendar years 2013 and 2014, there appears to be a constraint that limits Heywood imports by more than 1 MW for every 1 MW produced at the Lake Bonney and Canunda wind farms (long edge of the red triangle in the 2014 figure).

Despite their conclusions, HK did not:

- Identify the actual constraints involved
- Explain why there was no evidence of multiplicative displacement of Heywood imports in 2011 and 2012
- Establish whether the Lake Bonney investment were in fact inefficient (although they discuss a framework for this assessment)
- Analyse what would have happened if OFA had been in place around the time Lake Bonney 3 was being planned (circa 2009)

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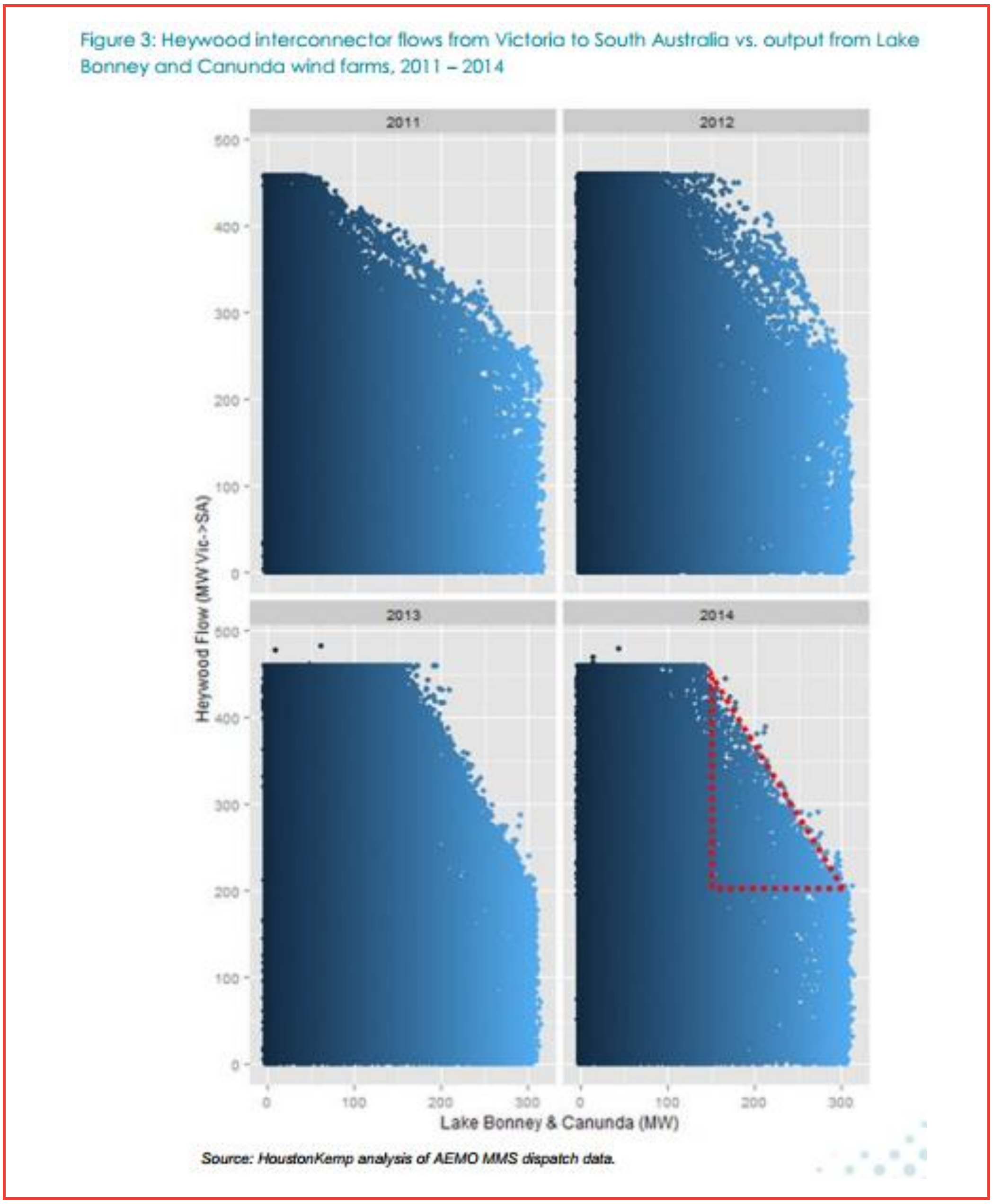
88 Houston Kemp, *Historical analysis of coordination between transmission and generation investment in the NEM*, 2 February 2015 (HK report).

89 HK report, p.18.

- Comment on the impending decommissioning of the entire Keith to Snuggery 132 kV line (which Lake Bonney and Canunda are connected to) as part of the Heywood interconnector upgrade.

Figure 1: Houston Kemp analysis of wind farm dispatch versus Heywood imports



Source: Houston Kemp Report, p17

Our analysis shows that in 2014, there is indeed a thermal constraint that leads to more than 1 MW for 1 MW displacement of Heywood imports if Lake Bonney 2 or 3 bid negatively. This constraint is the thermal limit on the Keith to Snuggery 132 kV line (V>>S_NIL_SETB_SGKH), to which Lake Bonney and Canunda are connected. The points on the long edge of the Houston Kemp triangle in

Figure 1 almost exclusively correspond to 5 minute dispatch intervals where this constraint is setting a binding limit on Heywood imports. This limit occurs because Lake Bonney 2 and 3 bid negatively, but not at the floor price. The Lake Bonney 2 and 3 units currently have coefficients of 1 whereas Heywood has a coefficient of 0.5376. This means that if the constraint is binding, then other things being equal, an increase in output from the wind farms requires a reduction of Heywood imports of 1.86 MW (the reciprocal of the Heywood coefficient) to avoid violating the constraint. AEMO's NEMDE can and does find this outcome to be optimal if:

- the sum of:
  - the bid price of Lake Bonney 2 and/or 3 and
  - the dispatch cost of increased output from other South Australian generators required to meet demand (the 0.86 MW needed over and above the wind farm dispatch to meet SA demand)

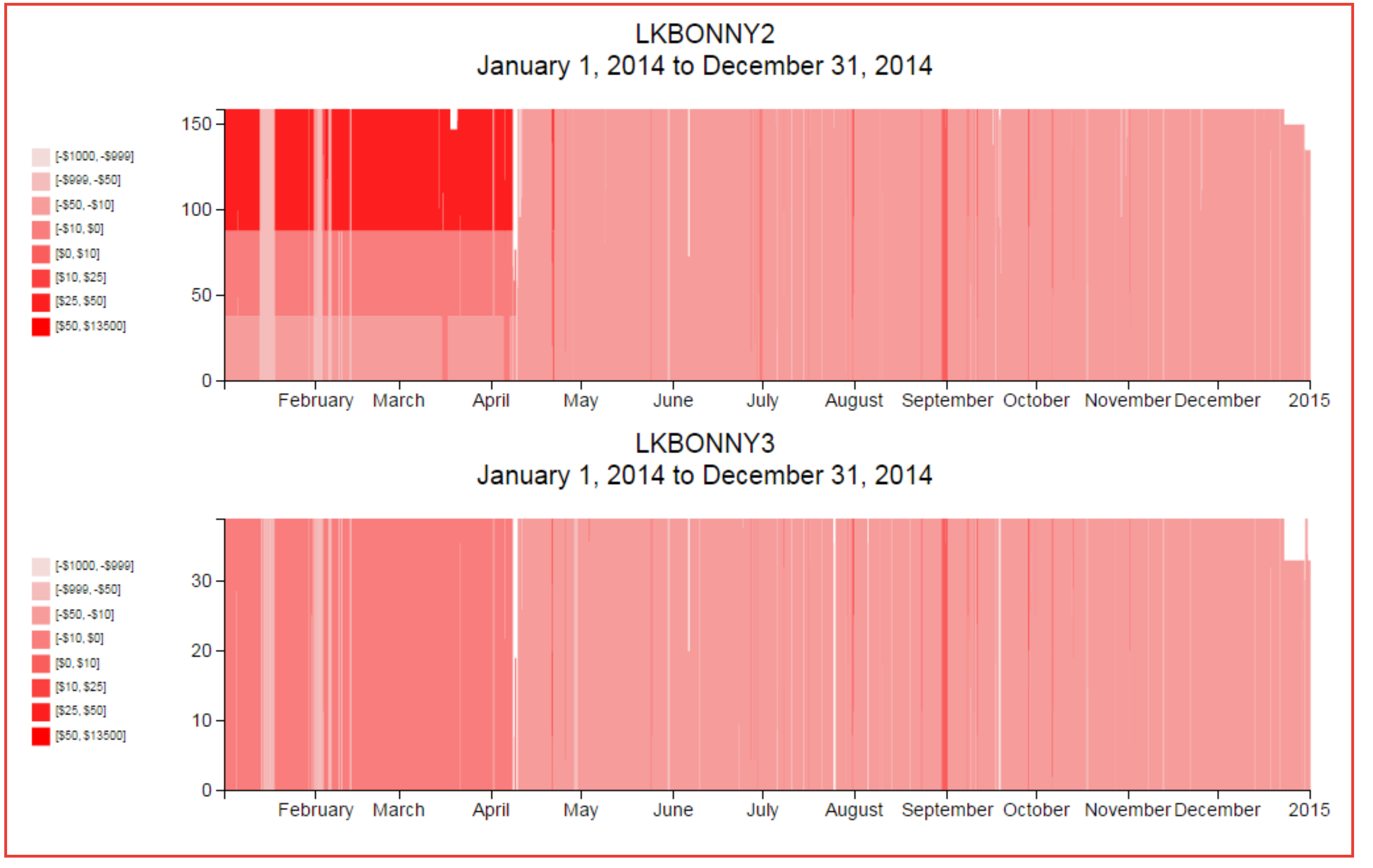
is less than

- the dispatch cost of displaced Heywood imports (the 1.86 MW from Victoria, loss adjusted)

This is an empirical question and depends on the demand, constraint, bidding and other inputs into NEMDE for any given 5 minute dispatch interval.

What can be seen is that over 2014, both Lake Bonney plant typically bid negatively with the majority of capacity offered in the -$50/MWh to -$10/MWh range, as shown in Figure 2. The likely reason Lake Bonney bid in this manner is that this closely corresponds to the opportunity cost of an LGC certificate, which traded around $35/certificate over 2014. Put simply, one could expect Lake Bonney would be willing to pay $34 to be dispatched (bid -$34/MWh) in order to generate an additional LGC that can be sold for $35, resulting in a $1 profit to the owners of Lake Bonney.

Figure 2: Lake Bonney bids, 2014



Source: Frontier Economics analysis of AEMO bidding data

Accordingly, when Lake Bonney bids negatively (in the -$50/MWh to -$10/MWh range), this can lead to Heywood imports being displaced by the wind farm's output. This occurred numerous times in 2014.

We note that:

- Such bidding behaviour by Lake Bonney does not imply irrationality, nor does it appear to be bidding with the explicit intent of displacing Heywood flows. Lake Bonney seems to be bidding to reflect market prices for LGCs rather than 'bidding to the floor'.
- NEMDE appears to be correctly identifying that meeting both short term demand, transmission constraints *and the LRET* is best achieved by dispatching Lake Bonney 2 and 3 in preference to imports on Heywood, noting that NEMDE explicitly accounts for the greater than 1 MW for 1 MW displacement. It is difficult to see this as evidence of a material inefficiency.

One question is why Figure 1 does not reveal similar phenomenon in 2011 and 2012. Prior to the start of 2013 there is no evidence of a constraint leading to multiplicative displacement of Heywood. It is not clear to us how the transmission system operated to avoid this displacement issue prior to 2013 when Lake Bonney 2 had been operational from 2008 and Lake Bonney 3 from 2011.

Our analysis has not fully resolved this issue, but we have discovered that:

- AEMO changed all the SA-VIC inter-regional constraint equations to add Lake Bonney 3 as of 2 January 2013;[90] this included the V>>S_NIL_SETB_SGKH constraint and correlates exactly to the timing of changes in dispatch observed by HK.
- AEMO changed the complete set of SA-VIC constraints, including V>>S_NIL_SETB_SGKH, again as of 22 March 2013 due to "revised PF [power flow] based on latest network model & added new operating margins".[91] This *may* have reflected changes in expected load and embedded generation in South East SA reported by HK which are claimed to have exacerbated the issue.
- ElectraNet was clearly aware of the possibility of a multiplicative displacement effect as far back 2009, prior to Lake Bonney 3 being commissioned, and operated a run back control scheme at Lake Bonney 3 to manage the issue. In 2010, ElectraNet stated that:

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90 AEMO, *NEM Constraint Library Changes Report for the week 31 December 2012 to 6 January 2013*, December 2012.

91 AEMO, *NEM Constraint Library Changes Report for the week 18 March 2013 to 24 March 2013*, December 2012.

> The Lake Bonney Wind Farm Stage 3 is currently undergoing commissioning and is connected to the existing Mayurra substation. An automatic run back control scheme will be installed at the wind farm to limit local wind farm generation such that any displacement on Heywood interconnection flows is not more than on a one for one basis.[92]

Similarly, in 2011, ElectraNet said:

> The Lake Bonney Wind Farm Stage 3 has an automatic run back control scheme to limit its generation such that any displacement on Heywood interconnection import is not more than on a one MW per MW of generation basis.[93]

- ElectraNet and AEMO jointly proposed an upgrade to the Heywood interconnector, which was assessed through a RIT-T process over 2012-13.[94] The proposed (and now approved) upgrade includes decommissioning of the Keith to Snuggery 132 kV line.[95]

Given that ElectraNet managed to avoid any greater than 1 MW for 1 MW Heywood displacement issue over 2008 to 2012, it is not clear what the motivation was for the change in constraints in AEMO's dispatch process from 2013 that subsequently led to a greater than 1-for-1 displacement of Heywood imports.

We consider it likely that the observed issue around Lake Bonney and its impact on Heywood imports has more to do with unforeseeable and transitory changes to AEMO's constraint set than reflecting a material and persistent inefficiency. Further, the Heywood upgrade has been found to yield substantial net benefits based in part on the export of South Australian wind generation to the rest of the NEM. We also note that the magnitude of these benefits is so great that it is unlikely that the investment at Lake Bonney would itself have influenced the choice of the upgrade option. Taken altogether, this suggests that the investment at Lake Bonney, if assessed prior to its commissioning, would likely have been considered consistent with the long-term efficient development of the industry.

Critically, it seems highly unlikely that OFA, had it been present in 2009, would have materially changed outcomes in a way that improved inefficiency or investment co-ordination. ElectraNet clearly sought to manage the issue both prior to the commissioning of Lake Bonney 3 and in practice over 2011 and 2012. It was only in light of a change in constraint equations years later – potentially reflecting changed market conditions – that an issue presented itself.

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92 ElectraNet, *Annual Planning Report 2010 - 2030*, June 2010, p.101.

93 ElectraNet, *Annual Planning Report 2011*, June 2011, p.109.

94 ElectraNet and AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Conclusions Report*, January 2013 (Heywood PACR).

95 The approved upgrade option (1b) – see Heywood PACR, p.29.

The Heywood upgrade is occurring in any case as a result of a large estimate of net benefits.

Therefore, it appears to us that under OFA, one of two outcomes would likely have occurred:

- Lake Bonney would have faced a high access price (although this seems unlikely) and would have not entered the market. In this case, customers may have ultimately faced higher costs of meeting the LRET.
- Lake Bonney would have faced a low access price (which seems more likely given that ElectraNet took steps to manage any issues) and subsequently been developed, in which case the issues that arose when constraint equations were changed in 2013 would have still been possible and would not have been borne by Lake Bonney, but by ElectraNet and ultimately by end-users.

The alternative scenario – in which a hypothetical access price modelled in 2009 reflecting ElectraNet's then-stated views would have accurately signalled changes to constraint equations made by AEMO four years later, which would then lead to strictly more efficient or coordinated outcomes than are ultimately occurring under the RIT-T – seems highly improbable.

The Lake Bonney example serves as a useful case study of both the flaws in the policy development approach (where problems have been sought after the solution of OFA was developed) and as a case where the efficacy of access pricing to actually lead to more efficient outcomes under OFA seems misplaced.

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