Transmission Frameworks Review – 1st Interim Report

A REPORT PREPARED FOR THE NATIONAL GENERATORS FORUM

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1 Introduction

This report has been prepared by Frontier Economics (Frontier) for the National Generators' Forum (NGF) in response to the Australian Energy Market Commission's (Commission's or AEMC's) Transmission Frameworks Review – 1st Interim Report (the 1st Interim Report or Report).

The comments in this report are confined to the five policy packages contained in sections 6 to 10 (inclusive) of the 1st Interim Report. We have attempted to formulate our comments in accordance with the assessment framework outlined in section 3 of the Report, with the minor qualification that we consider the importance of good regulatory practice (that is, minimising implementation and transitional costs as well as complexity) as integral to the National Electricity Objective rather than as a standalone requirement.

In general, while the 1st Interim Report points out a number of advantages and disadvantages of Packages 2 to 5, we believe that the purported benefits of these Packages are overstated and that the implementation and governance difficulties as well as the wealth transfer effects associated with them are understated to the point where they compromise good regulatory practice. As a result, we believe that refinement of the existing market design and access arrangements is the most appropriate way forward. Incidentally, we note that the Commission itself commented that it has yet to be persuaded that existing arrangements are not providing reasonably effective outcomes compared to the characteristics of an efficient regime.

This report is structured as follows:

- Section 2 comments on Package 2 – Open access with congestion pricing
- Section 3 comments on Package 3 – Generator reliability standards
- Section 4 comments on Package 4 – Regional firm access model
- Section 5 comments on Package 5 – National locational marginal pricing
- Section 6 compares these Packages to Package 1

2 Package 2 – Open access with congestion pricing

This section discusses the effects of Package 2 on:

- The economic efficiency of dispatch and
- Derivative trading and investment

2.1 Effects on the economic efficiency of dispatch

We note the Commission's view in the 1st Interim Report that Package 2 should improve the economic efficiency of dispatch by sharpening congestion price signals.[1] In our view, whether Package 2 is likely to improve dispatch efficiency is very much an empirical question and cannot be known *a priori*. This is because Package 2:

- May not eliminate, and may even increase, the incentives for generators to engage in 'disorderly' bidding as defined in the Report and
- May encourage the exercise of transient market power by generators

Finally, the value of any dispatch efficiency improvements that could potentially arise under Package 2 is likely to be very small.

2.1.1 Incentives for disorderly bidding

The 1st Interim Report stated that under Package 2, "a generator behind a constraint has no incentive to offer its energy below its short-run marginal cost" (SRMC).[2] This was the foundation for the Commission's view that the Shared Access Congestion Pricing (SACP) model should improve the economic efficiency of dispatch.

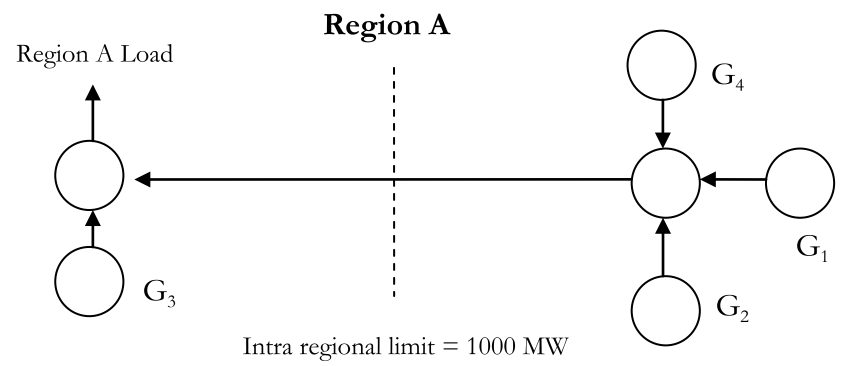
The effect of Package 2 can be seen by slightly altering some of the parameters in the Package 2 example in Appendix A of the 1st Interim Report.[3] The basic structure of that example is reproduced below.

1 1st Interim Report, p.73.

2 1st Interim Report, p.73.

3 See pp.212-216.

Box 1: Appendix A example



Source: AEMC 1st Interim Report, Appendix A

Assume that:

- G1 and G2 each had capacities of 400 MW instead of 500 MW and
- G4's SRMC was $60/MWh instead of $30/MWh

Under the current arrangements, G4 would not have incentives to bid disorderly and would not be dispatched because the regional reference price (RRP) of $50/MWh is less than G4's SRMC of $60/MWh. Rather, G1 and G2 would be fully dispatched and G3 would dispatched to 700 MW and the transmission constraint would not bind. G4's profits would be zero and dispatch resource costs would be minimised at $59,000 (being 400 x 20 + 400 x 40 + 700 x 50).

However, under Package 2, G4 would get a significant share (over 65%) of the settlements residues on the constrained line irrespective of its level of dispatch. This means G4 would have incentives to bid just over 200 MW disorderly (ie below $40/MWh, which is below G2's SRMC) in order to force the constraint to bind. This would push the locational marginal price (LMP) applying to G1, G2 and G4 down to $40/MWh while the RRP would remain at $50/MWh.

This would allow G4 to earn:

200 x (40-60) = -$4,000 *plus*

650 x (50-40) = $6,500

= $2,500 profit

Dispatch resource costs would rise to $61,000 (being 400 x 20 + 400 x 40 + 200 x 60 + 500 x 50).

This simple change to the example illustrates the incentives for disorderly bidding under Package 2 where there are none under the current arrangements. Many similar examples could be constructed. This means that even ignoring the heightened incentives under Package 2 for the exercise of transient market power (see below), the net effects of Package 2 on both the extent and frequency of disorderly bidding and on dispatch efficiency are analytically ambiguous.

2.1.2 Transient market power

As the Commission noted in both the Snowy Region Rule change process and the Congestion Management Review (CMR), addressing 'mis-pricing' through more refined locational pricing in the energy market can create incentives for generators to:

- Withhold a proportion of their capacity from the market and/or
- Offer capacity at a price well in excess of their marginal cost of generation

These behaviours are often described as generators exercising 'transient market power'. The exercise of transient market power by generators can cause higher-cost plant to run in place of available lower-cost plant. This results in higher resource costs of dispatch than would otherwise be the case and can detract from, or outweigh, any positive bidding incentives created by locational pricing.

To quote from the AEMC in the CMR:

> However, where generators have some degree of market power, it is not possible to conclude on the basis of analytical reasoning alone whether more localised pricing arrangements would enhance economic efficiency. This is because generators with some influence over their local nodal price may seek either to withhold a proportion of their output or to offer it at a very high (non-cost-reflective) price in order to maximise their profits based on a price-volume trade-off. One manifestation of this behaviour might be a tendency for generators to leave some spare capacity or "headroom" on the transmission network between their location and higher-priced nodes. The absence of locational pricing may provide incentives to such generators to bid at or below their resource costs in order to be dispatched. They would not benefit from exercising any transient market power they have.
>
> This issue was highlighted in our analysis on the various Rule change proposals concerning the Snowy region. While one of the options (the Southern Generators' congestion pricing proposal) would have ensured both Murray and Tumut generation received their theoretically correct local nodal prices, we found that this could provide incentives for Snowy Hydro to generate less at peak times than in the Snowy region abolition proposal…
>
> **The presence of a degree of market power means that correcting mis-pricing does not necessarily improve the economic efficiency of dispatch.** In such an environment, as was the case in the Snowy region situation, the extent to which outcomes are likely to be efficient is an empirical matter.[4] (emphasis added)

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4 AEMC, *Congestion Management Review, Final Report*, June 2008, p.191.

Indeed, in its Snowy Region decision, the AEMC approved the Rule change abolishing the Snowy region rather than the other proposals in part to avoid the withholding incentives arising from the Split Snowy Region option and the Southern Generators' option. It is again worth quoting the AEMC at length, this time from the Commission's Final Rule Determination:

> The Split Snowy Region and Southern Generators' Congestion Pricing proposals both reduce Snowy Hydro's incentives to engage in disorderly bidding of Murray and Tumut generation by removing much of the risk of those plants being mispriced. However, both these proposals introduce strong incentives for Snowy Hydro to maintain headroom, or prevent congestion, on all lines between its plant and the Victorian or NSW RRN, depending on the direction of flows. At times of northward flows if there are no constraints between Tumut and the NSW RRN, the price at the Tumut RRN will be similar to the NSW RRP, while if there is a constraint between Tumut and the NSW RRN, the price at the Tumut RRN will fall below the NSW RRP. Withholding output at Tumut at these times may reduce the risk of constraints binding between the Tumut RRN and NSW RRN during northward flows, increasing the likelihood of a relatively higher Tumut RRP.
>
> Similar incentives for Snowy Hydro to bid in a way to prevent lines between its generation and the neighbouring RRN from constraining exist at times of southward flows, enabling Snowy Hydro to "import" the higher price from the neighbouring region. The incentives for Snowy Hydro to maintain headroom are driven by both the potential to maximise revenue across its generation output by accessing a relatively higher price, and the potential to manage basis risk by minimising interregional price separation (as discussed in Section 4.1 and 4.4). Once again, it is unclear from a conceptual analysis if these alternatives would lead to more efficient dispatch outcomes compared to the Abolition proposal. The Commission has undertaken quantitative modelling to inform its analysis.
>
> ….
>
> By pricing Murray and Tumut generation at the Victorian and NSW RRNs, respectively, the Abolition proposal promotes incentives for Snowy Hydro to maximise its production by bidding competitively. In contrast, Snowy Hydro faces incentives to withdraw capacity in order to maintain headroom at times under the Southern Generators' Congestion pricing and Split Snowy Region proposals, resulting in less efficient dispatch outcomes when compared to the outcomes under the Abolition proposal.[5]

The Commission concluded that the Snowy abolition option would improve dispatch efficiency by more than the other options.

Similar considerations could arise in relation to Package 2. Generators may be settled on the basis of more locationally-refined prices, but this may encourage

5 AEMC, *National Electricity Amendment (Abolition of Snowy Region) Rule 2007, Rule Determination*, 30 August 2007, pp.20-21.

them to withhold or price-up a proportion of their capacity to profitably increase those prices during certain periods.

The key relevant conclusion from the Commission's previous analysis is that the short term economic welfare implications of Package 2 are *a priori* ambiguous.

2.1.3 Materiality of mis-pricing effects

The extent to which Package 2 would reduce the harm caused by disorderly bidding partly depends on the prevalence of this behaviour. Anecdotally, we note that disorderly bidding, while not uncommon, is not pervasive in the NEM.

As part of the CMR, the AEMC commissioned modelling from Frontier Economics to estimate the dispatch efficiency impacts of mis-pricing.[6] This was done to give the Commission some idea of the potential materiality of net benefits that could flow from a move to full generator nodal pricing.

Importantly, Frontier's modelling only attempted to measure the benefits of avoiding disorderly bidding; as it was based on price-taking bidding behaviour, it did not allow for generators to exercise transient market power. Consequently, the negative dispatch efficiency implications of encouraging the greater exercise of transient market power were, quite deliberately, not taken into account. The modelling was undertaken using data for the 2007/08 financial year. Two states of the world were modelled:

- A base case where all plant were dispatched at their opportunity cost (eg all generators bid full capacity at their SRMC). This is what would occur in a price-taking environment with no mis-pricing.
- A mis-pricing case where plant had the freedom to bid or offer at the market price cap or floor, depending on whether they were constrained-on or -off respectively. This was to capture the incentives for plant to engage in disorderly (but still price-taking) bidding in a market with mis-pricing. This case assumed that generators could predict whether they were likely to be constrained-on or -off prior to submitting their final offer.

Frontier compared these two states of the world to derive the additional resource costs of dispatching the market in the presence of mis-pricing. Eliminating mis-pricing by introducing full generator nodal pricing and ignoring the incentives for generators to exercise transient market power, Frontier found total dispatch efficiency benefits of just $8.01 million for the entire year.

In this context, we observe that the discussion of the materiality of congestion in section 5.3.3 of the 1st Interim Report conflated several issues.[7] First, the

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6 AEMC, *Congestion Management Review, Final Report*, section B.4.1.2, pp.90-101.

7 p.51.

stakeholder examples of the 'inefficient outcomes' of congestion focussed on the *financial* rather than the *economic welfare* effects of mis-pricing. For example, the Report noted an incident on 7 December 2009 highlighted by AEMO when a planned transmission outage between Wallerawang and Mt Piper led to rebidding that caused pool settlement to be $300 million higher than it otherwise would have been.[8] It is clear from AEMO's submission that the higher cost of pool settlement was largely not reflective of higher resource costs of dispatch. Rather, the main result of the incident was a higher NSW RRP. It is true that the incident likely did lead to some real inefficiency. In particular:

- the dispatch of peaking plant Tumut, Guthega, Uranquinty, Colongra and Shoalhaven was higher and
- the volume of lower-cost imports was lower

than in AEMO's 're-run' case, to the extent this can be considered the appropriate counterfactual (see below).

However, even accepting the re-run case presents the appropriate counterfactual, the total economic welfare effect of the incident was likely several hundreds of thousands of dollars rather than hundreds of millions of dollars. For example, assuming that the approximately 1500 MW of peaking plant dispatched in place of imports had a weighted-average SRMC of $55/MWh instead of $15/MWh for imports, the total welfare effect over five hours would have only been:

1500 x (55-15) x 5 = $300,000

This is one thousand times smaller than the impact put forward by AEMO. The remainder of AEMO's calculated $300 million effect was a wealth transfer and not a loss of economic efficiency. As noted in chapter 3 of the 1st Interim Report, the National Electricity Objective emphasises economic efficiency for the long term interest of consumers, not the achievement of short term wealth transfers.

Second, even the above calculation exaggerates the economic efficiency effect (as well as the wealth transfer effect) of mis-pricing because AEMO's modelling assumed that all plant would have retained their pre-constraint offers in the re-run case. AEMO explained that the unexpected constraint encouraged Mt Piper and other New South Wales generators to bid in a disorderly fashion to the market floor price while enabling Wallerawang to exercise transient market power by repricing some of its offers to higher levels. Even under full generator nodal pricing, Wallerawang would have had incentives to rebid some capacity into higher price bands in order to push up its local price as well as the NSW RRP. This would have likely necessitated some degree of increased dispatch of the peaking plant mentioned by AEMO. Therefore, a more realistic calculation of the

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

economic efficiency impact of the 7 December incident requires a much more sophisticated game-theoretic modelling exercise than undertaken by AEMO. Nevertheless, we consider it quite possible that the real welfare loss on that day due to mis-pricing was under $200,000.

Therefore, it is incorrect for AEMO to contend that the alleged $300 million of increased pool settlement on 7 December 2009:

- Could have been avoided entirely by eliminating mis-pricing and/or
- Accurately represented the value of the efficiency loss arising from the constraint

We submit that the value of any productive efficiency gains from moving to a form of generator nodal pricing is likely to be relatively small. We suggest that if the AEMC decides to progress its consideration of Package 2 to the next stage of the Review, it should commission or have regard to quantitative modelling of the dispatch resource cost effects of the changes.

2.2 Effects on derivative trading and investment

There are a number of ways in which Package 2 could affect generation investment and new retailer entry in the NEM. The first is through its effect on derivatives trading and the second is by directly changing settlement outcomes in the spot market.

2.2.1 Derivative trading path

Generators in the NEM – particularly those that are not part of vertically-integrated portfolios – typically hedge a large proportion of their output through exchange-traded or over-the-counter derivative contracts. These contracts are settled at the RRP in a given region. Most generators trade contracts settled at the RRP of their local region, because those are the prices against which their output is settled. This avoids the basis risk that arises when generators enter electricity derivatives that are settled against 'foreign' RRPs. Generators do sometimes enter contracts settled at other regions' RRPs and use inter-regional settlement residue (IRSR) units to hedge inter-regional basis risk. However, intra-regional contracting is far more prevalent.

Retailers also seek to enter wholesale derivatives to hedge most if not all of the expected consumption of their customers in order to avoid being exposed to spot price volatility.

Therefore, the maintenance of a liquid market for derivatives is important to the risk management activities of both generators and retailers. The absence of a liquid derivatives market may deter or delay entry or investment in the wholesale and retail markets.

As noted in the 1st Interim Report:

> These hedging mechanisms underpin investment by providing greater certainty over a future stream of predictable and stable revenues. Without such mechanisms, generation investment becomes more difficult as financing may not be forthcoming or the cost of financing may become prohibitively expensive as the risk premium must reflect the higher risks associated with less predictable revenues.[9]

One effect of Package 2 may be to increase the firmness of IRSR units by reducing incentives for generators to engage in disorderly bidding, although whether this occurs is ambiguous as noted above. However, to the extent it did occur, it could also lead to generators within a region becoming <u>less</u> willing to enter contracts settled at their local RRP. Given that intra-regional contracting is by far a more common hedging activity for most generators than inter-regional contracting, Package 2 is likely to result in a net reduction in derivative contracts being offered in a region. This could inefficiently deter or delay new generation investment and, as a consequence, deter new retailer entry.

More generally, as acknowledged by the AEMC,[10] it is clear that Package 2 would not resolve financial trading risks for generators in the NEM. This is because the MW volume of firm hedging cover it would provide would be extremely uncertain. It would depend on the volume of each generator's available generation relative to the entire volume of available generation affected by a transmission constraint in each trading interval. This means, for example, that generator A could receive a firm hedge of 100 MW if constraint 1 binds, but only 20 MW if constraint 2 binds and so on. Further, these volumes may change from trading interval to trading interval as different generators' availabilities change or year to year as new plant enters or exits the market. These effects and uncertainties mean that the liquidity of derivatives trading and the support derivatives trading provides to new investment may not improve under Package 2 and may worsen.

2.2.2 Spot market settlement path

In the 1st Interim Report, the Commission commented that Package 2 would be unlikely to strengthen locational incentives for generation investment compared to the current arrangements.

> This is primarily because new generators automatically receive a CSC for a significant proportion of their capacity (reducing the CSCs that would be received by existing generators), providing them a level of protection against

9 1st Interim Report, p.21.

10 1st Interim Report, p.70.

> congestion regardless of when and where they locate. As a consequence, the SACP model provides few incentives for minimising long term congestion.[11]

We submit that Package 2 could actually worsen locational incentives for new generators compared to the status quo. This is because the final rights are allocated based on capacity. In particular, large high-cost generators could find it more profitable to locate behind constraints than at present.

This can be seen by again considering the Package 2 example in Appendix A of the 1st Interim Report and making two small changes to the parameters. Assume that G4's SRMC was $40/MWh instead of $30/MWh and G2's SRMC was $30/MWh instead of $40/MWh.

Under the current arrangements, all generators behind the constraint would bid disorderly and G4 would be dispatched on a pro rata basis to 600 MW (being 1500/[1500 + 500 + 500]). The RRP would be $50/MWh and G4 would earn profits of $6,000 (being 600 x (50 – 40)).

However, under Package 2, while G4 would not be dispatched, it would receive settlement residues worth $12,000 (being 600 x (50 – 30)). Thus, G4's profit would have doubled without it going to the trouble of generating.

Therefore, Package 2 seems to provide stronger incentives for large high-cost plant to locate behind transmission constraints than at present. Such plant simply have to declare themselves available in order to claim their capacity-based share of residues.

For both these reasons, Package 2 could worsen investment incentives for new generators, which could reduce the strength of wholesale and retail market competition in the NEM.

11 p.73.

3 Package 3 – Generator reliability standards

This section discusses the effects of Package 3 on:

- The economic efficiency of dispatch
- Derivative trading and investment and
- Transmission governance and investment efficiency

3.1 Effects on the economic efficiency of dispatch

As noted by the Commission in the 1st Interim Report, Package 3 would be unlikely – in itself – to change the way in which generators make their operational decisions.[12] Generators would still have an incentive to bid in a disorderly manner when congestion arose. However, as noted by the AEMC, depending on the level at which the standard is set, the instances of binding constraints may fall. One way in which dispatch efficiency could be harmed is through the proposed generator transmission use of system (TUoS) charge. If this charge was not designed carefully, it could inefficiently deter use of the existing network and increase generator offer prices, all else being equal. This could lead to higher resource costs of dispatch than at present.

3.2 Effects on derivative trading and investment

There are a number of ways in which Package 3 could affect generation investment and new retailer entry in the NEM. The first path is through its effect on derivatives trading and the second is through the proposed generator TUoS charge.

3.2.1 Derivative trading path

By obliging TNSPs to augment their networks to a certain standard, Package 3 could reduce prevailing levels of congestion. If this occurred, it could encourage generators to offer a greater volume of derivative contracts. This could potentially promote generation investment and new retailer entry.

However, generators would receive nothing resembling a 'right' that is enforceable or tradeable. They may still be constrained-off without compensation if circumstances require. Moreover, congestion would still arise under this Package and may approximate existing levels at times due to the 'lumpiness' of transmission infrastructure and lags in planning and developing that

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12 p.88.

infrastructure. This means that generators may receive little additional encouragement in practice to offer hedge contracts to counterparties.

Generators' incentives to invest would be further attenuated to the extent that generators bore the costs of additional transmission investment under the standard through TUoS.

3.2.2 Generator TUoS path

The 1st Interim Report proposed that all generators would be required to pay ongoing TUoS charges to fund the cost of additional transmission investment under the standard. Charges would be fixed by 'zone' and the AEMC suggested that a useful starting point could be NTNDP zones. These would be refined based on the criteria established.

Given that a precise methodology for generator TUoS charging was not developed in the 1st Interim Report, it is difficult to comment on the specific implications of such a regime. However, we note that developing a generator TUoS charging regime is likely to be a major challenge in itself. Unless carefully developed, a generator TUoS charging regime could penalise use of the existing network. This could harm the economic efficiency of dispatch.

Appendix C of the 1st Interim Report raises some of the many issues that would need to be resolved in setting a long-run marginal cost (LRMC)-type of TUoS charge. As noted by Ernst & Young during the NECA Transmission and Distribution Pricing Review in 1999:

> Any determination of prices based on future costs is subjective, and generally require a large number of assumptions to be made. In particular an assessment of long run prices is inherently dependent on the assumptions which are made about the future development of the transmission system, including new load and generation sources. Potentially quite different pricing outcomes may result if different assumptions are made, or even a different view is taken regarding the order in which developments may occur.[13]

We consider these issues to be amplified in the context of the Australian NEM. This is because unlike the highly-meshed British transmission system and many others, the Australian system is long and 'stringy'. Due to the lumpy nature of transmission infrastructure, an individual investment in a stringy network will tend to have much more pronounced effects on the LRMC of network use at various points on the network than in a more heavily-meshed network. Further, unlike Britain and the stringy New Zealand transmission system, there is no long-term prevailing direction of flow. All of this means that developing meaningful and stable LRMC-based transmission pricing signals is likely to be more difficult

13 Ernst & Young, *Allocation of new investment costs in the regulated network*, p.56, in Volume II of NECA, *Transmission and Distribution Pricing Review, Final Report*, July 1999.

in Australia than elsewhere. Volatility in generator TUoS charges will not promote efficient generator locational decisions and will simply increase the risks and costs of new investment. Therefore, the risks and costs of errors in implementing a generator TUoS regime are unlikely to be matched by any potential benefits.

At this stage, we note that despite multiple review of transmission pricing methodology since the start of the NEM, TUoS charges for load are still not based on an LRMC methodology. As such, we suggest that if LRMC-type charges were to be developed in the NEM, they should first be applied to load charging where reliability standards are well established and the charges can be easily compared and contrasted to the current CRNP-based charges. This is not to say that CRNP-based transmission charges are ideal and we agree with many of the shortcomings of the CRNP methodology discussed in the 1st Interim Report. However, seeking to define appropriate generation-based reliability standards as well as develop a generator TUoS charging methodology in a single process is likely to extremely difficult. We suggest that any TUoS experimentation should be conducted on load charges first.

Finally, any generator TUoS arrangement would penalise existing generator participants who have made investments that are now sunk. No efficiency objective is served by taxing sunk investments.

3.3 Transmission governance and investment efficiency

This Package gives rise to a host of governance and efficiency issues that the 1st Interim Report does not fully acknowledge. The most significant of these are discussed below.

3.3.1 Unclear accountability and jurisdictional acceptability

Under Package 3, a 'hybrid' generator reliability standard would apply. An unnamed independent body would need to derive economically-based deterministic reliability standards for various zones in the NEM utilising a measure known as a generator 'certainty premium'. The geographic boundaries of these zones would be based on quantitative analysis to determine groups of connection points that reflected similar costs to maintain a common standard.

Developing appropriate standards and establishing the zones to which different standards apply would not be a clear-cut exercise and would involve a high degree of subjectivity. This makes it all the more important that the body in question has a robust governance structure and accountability framework.

The key governance questions are:

- Which body should set generator-based reliability standards and draw zone boundaries and
- If a new institution is required, to whom should it be accountable

If the objective of incremental transmission investment in pursuit of generation reliability standards was to promote economic efficiency, then arguably the AEMC should be the standard-setting body.

However, for the AEMC to set reliability standards could create a conflict of interests. The AEMC would be in the position of implementing the very Rules it chose to make. This could encourage the AEMC to make Rules that were simpler to apply or harder to monitor compliance with than would otherwise be appropriate. In any case, for the reasons given below, we are not convinced that investments made under this Package would boost economic efficiency.

If the main purpose of incremental transmission investment made under this Package was to benefit generators, then it may be more appropriate for the standard-setting body to be accountable to NEM generators. No such body exists at present and any body created would need to be acceptable to the NEM jurisdictions.

We also note that TNSPs would not be financially at risk if outages reduced power transfers within the network, raising the risk that TNSPs would not be sufficiently accountable for poor performance.

3.3.2 Certainty premium and transmission investment efficiency

Our key concern with Package 3 is the concept of a generator 'certainty premium' and the risk that its use would lead to inefficient over-investment in transmission. The 1st Interim Report commented that the reliability standards for generators should be derived from economic analysis that relates transmission costs to the value generators place on access reliability. However, the value that generators place on 'access certainty' may have little to do with the achievement of economic efficiency. In this respect, there is a major difference between the Value of Customer Reliability (VCR) concept mentioned in the Report and the generator certainty premium concept. The VCR attempts to reflect the value that end-use consumers would put on electricity if they were able to signal their willingness to pay for electricity in real-time.

The VCR concept is used to overcome what electricity economist Steven Stoft calls the two 'demand-side flaws' in electricity markets:[14]

- The first flaw is the lack of real-time pricing for virtually all customers
- The second flaw is the ability of a load to take power from the grid without a prior contract with a generator

By contrast, generators have a mechanism for signalling the strength of their interest in being dispatched at any given time, namely, their offer prices.

If there is any economic foundation to the certainty premium concept, it must emanate from a link between:

- greater dispatch certainty
- leading to an increased willingness of generators to offer derivative contracts
- leading to increased liquidity in the trading of derivative contracts
- leading to lower barriers to generation investment and to increased retail competition

To the extent this link holds, there may be some benefit in slightly 'over-building' the transmission network compared to what can be justified under the current RIT-T. However, the discussion in the 1st Interim Report did not articulate this framework and seems to be based on a fairly inchoate idea that the willingness of individual generators to pay to avoid the costs of congestion should somehow be incorporated into the RIT-T analysis.

The lack of a robust economic foundation to the certainty premium concept means that the outcome is likely to be inefficient over-investment in transmission, with both generators and loads bearing the cost. History has shown that the AER faces significant difficulties in restraining TNSP investment that is justified by meeting deterministic reliability standards.

14 Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press (2002), p.15.

4 Package 4 – Regional firm access model

The Regional Optional Firm Access (OFA) model incorporated in Package 4 is effectively a market design taking the form of generator nodal pricing with financial transmission rights (FTRs). Under Package 4, rather than being allocated at no cost or auctioned, 'firm' access rights would be allocated based on an administered pricing regime, being an agreement to pay generator TUoS charges.

This section discusses:

- The economic efficiency of dispatch implications of Package 4
- The governance and implementation issues created by Package 4
- The derivative trading and investment and implications of Package 4

4.1 Effects on the economic efficiency of dispatch

We note the Commission's view in the 1st Interim Report that Package 4 should improve the economic efficiency of dispatch by addressing the existing incentives for disorderly bidding.[15] The Report noted:

> Under the regional OFA model, a firm generator would be compensated for being constrained off and so would have no reason to disorderly bid to ensure dispatch.[16]

However, the Report does concede the risk that the regional OFA model might create new incentives for the 'gaming' of offers:

> - by firm generators, in order to become eligible for compensation. Firm generators that were out of merit might lower their offers such that they were still not dispatched but became eligible to receive compensation. However, they would risk being dispatched and settled at less than cost; and
> - by non-firm generators, in order to minimise their contributions. Non-firm generators might increase their offers with the aim of increasing the LMP and therefore reducing compensation contributions payable. Again, there would be risk involved - in this case, of not being dispatched.[17]

The second of these behaviours is a form of generators exercising transient market power and was discussed in relation to Package 2 in section 2.1.2 above.

15 1st Interim Report, p.103.

16 1st Interim Report, p.103.

17 1st Interim Report, p.103.

The first of these behaviours is effectively a new incentive to engage in disorderly bidding for similar reasons as we consider disorderly bidding would arise under Package 2 (see section 2.1.1 above).

As with our discussion of Package 2, the incentives to engage in disorderly bidding under Package 4 can be seen by making a few simple modifications to the Package 4 example in Appendix A. Assume that:

- G1 and G2 each had capacities of 450 MW instead of 500 MW
- G4's SRMC was $60/MWh instead of $30/MWh
- G4 had firm access rights for 600 MW, G1 for 400 MW and G2 was non-firm

Under the current arrangements, G4 would not have incentives to bid disorderly. G1 and G2 would be fully dispatched (to 450 MW each) and G3 would dispatched to 1700 MW. Dispatch resource costs would be minimised at $112,000 (being 450 x 20 + 450 x 40 + 1700 x 50).

However, under Package 4, G4 would have incentives to bid just above $40/MWh. Of this, 100 MW would be dispatched. This would cause the line to constrain at 1000 MW flow. The RRP would still be $50 and the LMP at X would be a fraction over $40/MWh (round down to $40). G4 would earn $4000 on its dispatched output (100 x 40). It would also earn $6000 (600 x (50-40)) on its transmission rights. This is $10000 in total. G4 would also incur operating costs of $6000 (100 x 60), so G4's profit would be $4000. Dispatch resource costs would be increased to $113,000 (being 450 x 20 + 450 x 40 + 100 x 60 + 1600 x 50).

This simple change to the example illustrates the incentives for disorderly bidding (and higher resource costs of dispatch) under Package 4 where there are none under the current arrangements. Many similar examples could be constructed. This means that, even ignoring the heightened incentives under Package 4 for the exercise of transient market power, the net effects of Package 4 on both the extent and frequency of disorderly bidding and on dispatch efficiency are analytically ambiguous.

Finally, as noted in the discussion of Package 2, the magnitude of economic welfare gains from more efficient dispatch may be very small in practice.

4.2 Implementation and governance issues

The key issues with this Package concern implementation and governance. The way these issues are resolved will drive the effects on derivative trading and investment.

4.2.1 Defining firm transmission rights

This Package effectively involves offering every generator in the NEM the option to obtain a Constraint Support Contract (CSC) up to its requested volume. Each CSC is actually a 'bundle' of rights – one for each constraint in the NEM that may bind and cause the generator to be constrained-off from its RRN. These bundles would need to be created individually for each firm generator depending on its location in the network and its coefficient in all relevant AEMO constraint equations. As with regular FTRs, the process of defining firm access rights could require tests to be undertaken to determine the feasibility under system normal conditions of simultaneously satisfying all the rights that were ultimately distributed. This means that AEMO, as market and system operator, would either have to define the set of available firm access rights or be centrally involved in their specification.

The 1st Interim Report identified some but not all of the issues associated with the process of defining firm access rights. Although the proposed firm access rights are intended to be firm only under system normal conditions, there is unlikely to be clarity regarding which constraint equations were applicable under system normal conditions despite the AEMC's best intentions that this definition is "practical, unambiguous and economic".[18] AEMO uses several thousands of constraint equation and alters or replaces them on a regular basis with little notice to participants. This means that despite participants having 'firm access rights', these rights may not actually be firm in many circumstances. In fact, they are likely to be least firm at times when they are most in demand, because most significant congestion usually occurs during prior outage conditions, which would clearly fall outside any definition of 'system normal'. This will have implications for the effect of this Package on the liquidity of derivatives trading.

We presume that AEMO, as market and system operator, would have the role of defining firm access rights in consultation with TNSPs. If so, this would create potentially serious governance and accountability issues. In particular, if AEMO had the role of defining rights while TNSPs were legally and financially accountable for planning and operating their networks to satisfy those rights, it would not be clear whether non-firm outcomes were due to over-specification of rights by AEMO or poor planning and operational performance by TNSPs or some combination. The option of TNSPs defining the firm access rights is difficult to see working, because TNSPs do not manage the constraint equations in the NEM dispatch engine (NEMDE) and therefore lack the information necessary to determine what rights could be made available to whom.

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18 1st Interim Report, p.104.

4.2.2 Pricing firm access rights

Whereas standard FTRs are typically auctioned in most North American electricity markets, the AEMC's proposed approach to allocating firm access rights is based on the payment of generator TUoS charges. The generator TUoS charge would be developed by TNSPs in accordance with Rules made by the AEMC.

Even under ordinary circumstances, developing an appropriate methodology for generator TUoS charges would be a challenging exercise, as discussed above in relation to Package 3. However, where payment of transmission charges is used as the basis for allocating firm access rights, this would create an additional tension between:

- Generators' willingness to pay for firm access rights, which would be based on the expected settlement residue from the rights (ie the SRMC of congestion) and, as such, would tend to vary considerably by trading interval/day/week/season/year and
- Administratively-set generator TUoS charges which would be based on a LRMC- or CRNP-type methodology

Most of the time, LRMC-based charges would exceed generators' willingness to pay for firm access rights. This is because until the flow on a line is near its limit, congestion costs are minimal. This would tend to mean that most generators would opt to remain non-firm. However, as congestion to a particular zone increased, we would expect that generators' expectations of congestion costs and hence their willingness to pay for firm rights would quickly exceed TUoS charges. This would mean that most generators would seek rights and there would be a sudden excess demand for firm rights at a particular location. In this case, some form of pro rating of the allocation of firm access rights would have to apply.

More generally, it is not clear how the need for investment would influence generator TUoS charges. A key point raised in the Report was that generators may need to 'book' firm access rights for certain minimum periods where new transmission investment was required to underwrite the provision of those rights. If minimum booking periods did not apply, generators could opportunistically opt to be non-firm as soon as a transmission investment was committed and the expected costs of congestion fell. However, the Report did not acknowledge that minimum booking periods for firm access can effectively become like a deep connection charge. This is because booking periods would need to be long enough (and/or TUoS charges high enough) to ensure that generators did not have an incentive to seek rights for only as long as required to trigger the development of new transmission capacity under the proposed generator access standard.

If minimum booking periods were used in combination with generator TUoS charges to underwrite new transmission investments, this would influence the appropriateness of different charging methodologies. In particular, LRMC-based charges are designed to be high when the need for new transmission investment is imminent and to drop after investment has occurred creating spare capacity. However, if generators sought firm access at a location where transmission investment was required, and this meant they needed to book rights for a minimum period, the annual TUoS charges they would pay would have to be very low – given that the LRMC of the network would be very low post-investment. This would, in turn, necessitate very long booking periods to prevent opportunistic firm access applications. For example, assume that pre-investment, the LRMC-based TUoS charge at a particular location was $5/MWh. Then assume that a new generator applied for firm access rights, but accommodating these rights required a major and costly augmentation. Following that augmentation and the connection of the generator, assume that the LRMC-based TUoS charge would fall to $1/MWh. This would mean that the generator would need to book the rights for five times as long to recover the cost of the augmentation compared to if the charge remained constant. This example shows how minimum booking periods effectively make annual TUoS charges into deep connection charges. A shorter booking period could be achieved by employing a CRNP-based methodology, because CRNP tends to produce higher charges at locations that are served by large and costly assets. CRNP-based charges therefore tend to <u>rise</u> after investment rather than fall. However, this would provide perverse signals more generally because it would discourage use of the network in areas where excess capacity was greatest.

To the extent that a generator TUoS regime mimicked a deep connection charging regime, this would raise the same types of free-riding issues as those discussed in the 1st Interim Report in relation to deep connection charges. For example, it is not clear whether and what size of new transmission investment would go ahead if only a single 200 MW generator sought firm access when the most economic size for a transmission augmentation was 400 MW. If the larger-sized investment proceeded, it is not clear whether other generators would be able to free-ride or whether TNSPs would develop the system in sub-optimal increments to accommodate individual private benefits.

A simpler alternative to generator TUoS charges that would avoid many of these problems may be to simply auction firm access rights.

4.2.3 Governance of transmission standards

As discussed above in relation to Package 3, this Package would give rise to significant governance and accountability issues for transmission.

The key governance questions are:

- Which body should set generator-based reliability standards and TUoS charges and

- If a new institution is required, to whom should it be accountable

For the reasons given above, we think there are risks in the AEMC taking on this role and any new body would require jurisdictional approval.

4.3 Effects on derivative trading and investment

4.3.1 Derivative trading

As noted above, the development of firm access rights based on system normal operating conditions would mean that the rights would be non-firm in many circumstances. Typically, the rights would be least firm when firmness was most highly valued. Uncertainty over what conditions reflect system normal would accentuate the uncertainty over the firmness and hence diminish the value of the rights to generators.

4.3.2 Sunk versus new entrants

The 1st Interim Report emphasised that unlike a deep connection regime, a generator TUoS regime does not 'discriminate' between incumbent and new entrant generators. The discrimination arises, according to the Report, because:

> …incumbents' ongoing use of the network, as well as new generator entry and demand growth, contributes to constraints that may trigger transmission investment. Incumbents' use of the network will also create costs in terms of the maintenance and replacement of assets required to ensure that network standards continue to be met.[19]

The Report went on to say that charging new entrants deep connection charges would raise their costs relative to incumbents' costs, "affecting allocative efficiency". The Report went as far as to say that the discrimination inherent in a deep connection approach could lead to inefficient network usage.[20]

We disagree with these contentions for the reasons explained below.

To the extent congestion arose under Package 4 and raised the SRMC of using the grid, all generators – both incumbent and new entrants – would face the same incentive to exercise or not exercise transient market power. The conferral of firm access rights to certain generators would not distort how they bid relative to others subject to the concerns above disorderly bidding noted above.

As for whether the operation of an incumbent generator contributes to the need for augmentation, we consider that this is the wrong question to ask because the term 'causation' is capable of different interpretations. We submit that the better

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19 1st Interim Report, p.259.

20 See p.99.

question is to ask which participant(s) are in a position to make decisions that can change the likelihood or timing of new investment being undertaken. In this context, incumbent generators have made sunk investments and are generally not in a position to influence whether and when new transmission investment is undertaken. The only caveat is if payment of TUoS could encourage existing generators to exit materially earlier than otherwise. This is an empirical question, but even if this were to occur, it would be a very distant and possibly immaterial effect. The main effect would be a wealth transfer from existing generators to new generators and loads.

By contrast, new entrants have (by definition) not made an irreversible investment decision and so can be influenced in the immediate future by a transmission charging regime. For example, new entrants could choose to locate in a different area or develop a different technology of plant based on a range of factors including transmission charges.

This means that making new connecting generators pay for the costs of an augmentation – an augmentation that would not be required if they did not enter at a particular time in a particular location – would not produce allocative inefficiency. Rather, smearing the costs of accommodating new generators' output onto existing generators is likely to lead to allocative inefficiency because it would mean that average wholesale prices would not reflect the full cost of meeting an additional increment of demand.

Therefore, what the Report refers to as 'discrimination' between incumbent and new entrant plant is consistent with efficiency whereas the application of generator TUoS charges to incumbents would largely succeed in effecting a wealth transfer from existing generators to other parties. Such a transfer would not contribute to meeting the National Electricity Objective.

5 Package 5 – National locational marginal pricing

As Package 5 is the least developed and most radical of the Packages, the comments in this chapter should be treated as provisional, based on our best interpretation of the discussion of this Package in the 1st Interim Report.

This section discusses:

- The economic efficiency of dispatch implications of Package 5
- The implementation and governance issues created by Package 5
- The derivative trading and investment and implications of Package 5

5.1 Effects on the economic efficiency of dispatch

5.1.1 Transient market power and disorderly bidding

As with Packages 2 and 4, we note the Commission's view in the 1st Interim Report that Package 5 should improve the efficiency of dispatch by sharpening congestion price signals and removing the incentives for disorderly bidding.

We disagree with this view. As with Packages 2 and 4, it is not clear whether Package 5 would necessarily result in generators bidding closer to their SRMCs nor whether it would improve dispatch efficiency. This is because Package 5:

- Would not eliminate the incentives for generators to engage in disorderly bidding and
- Would encourage the exercise of transient market power by generators

The effect of locational pricing and settlement on generators' incentives to exercise transient market power was discussed in relation to Packages 2 and 4 above. There is no need to reiterate the risks here other than to note that all forms of increased locational refinement in generator pricing and settlement will tend to encourage some generators to either withhold a proportion of their capacity from the market or to offer that capacity in excess of its SRMC in order to maximise spot market profits. To the extent Package 5 led to lower levels of generator hedging (see section 5.3.1 below), it would tend to accentuate generators' incentives to exercise transient market power.

The remainder of this section will demonstrate how Package 5 would not eliminate incentives for disorderly bidding.

Incentives for disorderly bidding under Package 5 would be particularly pronounced where transmission outages occurred. This is because, unlike for Packages 2 and 4, access rights under Package 5 would be fully financially firm.[21] This can be seen by taking the Package 5 example in Appendix A and modifying it slightly to:

- Make G4 rather than G2 the firm generator to the extent of 500 MW
- Reduce the capacity of the transmission limit to 200 MW due to an outage and
- Raise the capacity of G3 to 3000 MW

Under these conditions, the SMP would still be $50/MWh because even in an unconstrained network, meeting 2,600 MW of demand would require the dispatch of the more expensive G3. G1 would be settled for its dispatched output on its LMP, which would be $20/MWh if it bid in line with its SRMC.

G1 would be dispatched to 200 MW and would earn profits of:

200 x (20-20) = $0 *plus*

500 x (50-20) = $15,000

= $15,000

Despite not being dispatched, G4 would earn profits of:

500 x (50-20) = $15,000

However, both G1 and G4 would have incentives to bid disorderly in order to maximise the value of their firm access rights and their overall profit. If both G1 and G4 bid at -$1,000/MWh for 200 MW each, the LMP at their location would likewise be -$1,000/MWh and they would be dispatched to 100 MW each based on the tie-breaking rules. What they would lose on their dispatch they would recover many times over from the value of compensation on their access rights.

G1 would earn profits of:

100 x (-1000-20) = -$102,000 *plus*

500 x (50+1000) = $525,000

= $423,000

[21] 1st Interim Report, p.110 and p.121.

G4 would earn profits of:

100 x (-1000-30) = -$103,000 *plus*

500 x (50+1000) = $525,000

= $422,000

This is much higher than if they each bid at their SRMCs.

To take a more practical example, consider the events of 7 December 2009 mentioned in the AEMO submission and discussed above when a planned transmission outage between Wallerawang and Mt Piper led to disorderly bidding by Mt Piper. In that case, even if Mt Piper had been settled on the basis of its -$1,000/MWh offer price, so long as it held firm access rights in excess of its dispatched volume, it would still likely have had incentives to bid disorderly.

Finally, as with Packages 2 and 4, we emphasise that the value of any dispatch efficiency improvements arising under Package 5 would likely be very small.

5.1.2 Lack of real-time signals for demand-side response

By settling all NEM load at the SMP, Package 5 would eliminate all congestion-based signals and incentives for real-time demand response from loads. Currently, both generators and loads are able to benefit – at least in principle – from responding to tight demand-supply conditions at any given RRN. This is because binding constraints can be relieved equally by additional generation or reduced load. This is recognised in the design of the British Balancing Mechanism arrangements. However, under Package 5, there would be no such signals and loads willing to curb demand to relieve congestion would only be rewarded through the avoidance CRNP-based of TUoS charges. This effect of the elimination of RRPs is further discussed below in relation to load locational decisions in section 5.3.2 below.

5.2 Implementation and governance issues

Due to its complexity and degree of departure from the current arrangements, this Package raises the most significant implementation and governance concerns of all the Packages.

5.2.1 Required institutional changes

The 1st Interim Report acknowledged that this Package would require the establishment of a single NEM-wide TNSP, which may not be feasible. The Report also noted that in light of the incentive scheme to apply to the single TNSP, it may not be appropriate for AEMO to continue its role as network planner and procurer in Victoria.

Further, according to the Report, AEMO's role would become focused on market operation. Certainly, in our view, AEMO would need to relinquish its role in system operation[22] and hand this to the single TNSP, who would be accountable for network availability, flows and performance more generally. As the Report noted, these would be substantial changes and the benefits of any change would need to be similarly substantial to justify the direct and indirect costs of change.

5.2.2 Governance of system and network operation

As noted above, Package 5 involves giving a new single TNSP full control over network and system operation. At the same time, the single TNSP would be subject to a comprehensive incentive scheme that exposed the TNSP to at least a share of the uplift costs incurred to provide firm access rights.

At one level, it makes sense to integrate the roles of network and system operation if the objective is to identify a single point of accountability for all network performance and access issues. However, even an entity that combined the roles of all of the existing NEM TNSPs and AEMO could not be certain of the magnitude of power flows and the value of settlement residues in the network because much would depend on the pattern of generation bidding and dispatch. For example, many of the issues raised by AEMO in relation to 7 December 2009 resulted from the disorderly bidding of Mt Piper and other generators. This would not be within the control of the single TNSP under Package 5.

The uncontrollability of generator bidding and other factors would mean that the single TNSP would have strong incentives to minimise the amount of 'baseline' network capacity and any releases of short and long term 'incremental' capacity in order to limit its exposure under the proposed incentive scheme. This would, in turn, limit the scope for generators to obtain firm access to the NEM hub (see below), with negative consequences for the willingness of generators to offer derivative contracts. Although the Report noted that the baseline could not be determined by the TNSP without independent oversight for this precise reason,[23] the fact remains that it would be exceedingly difficult for a body such as the AER to determine whether and to what extent the TNSP defined baseline capacity conservatively in order to minimise its own risks.

More generally, due to the profound informational asymmetries that would arise under this Package, the AER would find it extremely difficult to establish an incentive scheme that appropriately rewarded and penalised the TNSP's performance.

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22 Meaning scheduling and dispatch.

23 1st Interim Report, p.11, footnote 207.

The AER would be at constant risk of:

- Systematically over-rewarding the TNSP for its performance
- Rewarding or penalising the TNSP for network outcomes outside the TNSP's control

5.2.3 Governance of transmission planning and investment

The Report noted that under this Package, there would be a single national set of integrated planning standards for generation and load. The generation element of these standards would drive the network investments required to provide additional firm capacity. This raises similar issues as raised in relation to Packages 3 and 4 regarding the setting of the appropriate generation reliability standard.

In particular:

- Which body should set generator-based reliability standards and TUoS charges and
- If a new institution is required, to whom should it be accountable

Further, it is not clear what would be the economic basis for setting higher generation-side planning standards than currently apply under the operation of the cost-benefit assessment in the RIT-T. It appears that the sole test for developing a generator-side augmentation would be whether a generator(s) was willing to underwrite the augmentation by 'booking' firm access rights for a sufficiently long period. Such investment may not maximise economic welfare if it was primarily motivated by securing dispatch at the expense of other, slightly more expensive generators elsewhere in the NEM.

Presumably, firm access rights to transmission capacity made available through augmentations to meet load reliability standards would not be made available in this way and would be available through auctions. However, this is not clear in the Report.

5.3 Effects on derivative trading and investment

5.3.1 Derivative trading

Package 5 could be expected to have a number of implications for the extent of trading in wholesale derivative instruments.

First, if the single TNSP were able to limit its offerings of firm access rights in line with its incentives (see section 5.2.2 above), this would reduce generators' ability to manage basis risk between their own LMPs and the hub SMP. This would reduce the liquidity of derivatives trading, raising barriers to efficient new investment in generation and retailing.

Another major deterrent to derivatives trading under this Package would be the need for an uplift charge in addition to a balancing charge. The Package does not appear to provide any means by which these charges can be hedged by market participants even though the uplift charge in particular may be substantial and unpredictable.

Our understanding is that the balancing charge was designed to recover differences between the expected and actual proceeds from the sale (whether bilateral or through auctions) of firm access rights. In principle, if generators are rational, well-informed and risk-neutral, the balancing charge should on average be zero. If generators are willing to pay a premium for the certainty provided by firm access rights, the balancing charge may be negative on average (ie a rebate).

Our greater concern is the proposed uplift charge. This charge would recover the difference between the compensation payments required to make access rights fully firm and the residues available from NEM settlement. Therefore, this charge would need to recover the shortfall in rights compensation that would arise if, for example, transmission outages or generator bidding behaviour reduced flows (and hence settlements residues) below the level needed to pay full compensation.

In addition, we presume that the uplift charge would need to recover the amounts paid to 'constrained-on'[24] generators under Package 5. By definition, the SMP would be less than some LMPs in the presence of binding constraints and the difference would need to be funded in some manner. The 1st Interim Report did not explicitly acknowledge this point. However, we presume that if the payment of LMPs in excess of SMP were funded out of general settlement, the cost of these payments would ultimately have to be recovered through the uplift charge. This could lead to extremely high uplift charges arising under tight demand-supply conditions occurring simultaneously with transmission outages, such as on 7 December 2009.

The key problem created by these arrangements is that while generators would be able to obtain firm access to the SMP through the purchase of firm access rights, retailers and load customers could not hedge balancing and particularly uplift charges. Yet both retailers and load customers would be exposed to these costs.

This problem can be illustrated by taking the Package 5 example in Appendix A and modifying it slightly to make the load 1600 MW instead of 2600 MW and assuming no disorderly bidding.

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24 Generators whose offer prices and LMPs were higher than the SMP would not be constrained-on under Package 5 in the same way as under the existing arrangements because such generators under Package 5 would be paid their LMPs rather than the RRP.

This means that:

G3 is dispatched to 600 MW at an LMP of $50/MWh, earning $30,000

SMP is $30/MWh (based on unconstrained dispatch of G1 and G4 meeting load)

Customers pay 1600 x $30 = $48,000

G1 and G4 are both dispatched to 500 MW at an LMP of $30/MWh and receive 500 x $30 = $15,000 each ($30,000 in total)

G1 and G2 do not receive any settlements residue from their firm access rights

Total settlements shortfall = $30,000 + $30,000 - $48,000

= $12,000

Unsurprisingly, this is the difference between G3's LMP and the SMP multiplied by G3's dispatch: ($50-$30) x 600 = $12,000

This shortfall would need to be recovered via the uplift charge.

The amount to be recovered through uplift could be much higher if G3 were to exercise transient market power. There is nothing in this example stopping G3 offering its entire capacity at the market price cap of $12,500. This would not affect the SMP (which would remain at $30/MWh in line with unconstrained dispatch), but would increase the shortfall to be recovered via uplift to: ($12,500-$30) x 600 = $7,482,000. Clearly this would not be an acceptable outcome for retailers' and loads' risk management purposes.

The result of the unhedgability of uplift charges under Package 5 could be that although generators may be willing to offer more derivatives contracts than at present, retailers may be much less willing to compete for customers and large loads may need to exit the market. This would severely undermine the market objective.

5.3.2 Load investment

Package 5 would abolish the existing NEM regions and RRPs. This would mean the end of regional variations in the spot price payable by load. Although average spot price outcomes are only one of many influences on load locational decisions, the implementation of Package 5 would remove these signals entirely. The 1st Interim Report noted that loads would still see a long term signal through TUoS charging "similar to the current approach". However, the current approach to TUoS charging in most jurisdictions is based on CRNP. As discussed in the 1st Interim Report[25] and elsewhere[26], CRNP tends to be a poor

25 pp.247-248.

26 Ernst & Young, *Allocation of new investment costs in the regulated network*, p.56, in Volume II of NECA, *Transmission and Distribution Pricing Review, Final Report*, July 1999.

proxy for the LRMC of transmission. The likely result is less efficient load locational decisions than at present, ultimately resulting in higher average costs of delivered energy to consumers.

6 Comparison with Package 1

As noted in the 1st Interim Report, the existing frameworks for congestion management and transmission investment and pricing in the NEM are not without a number of shortcomings. In particular:[27]

- Sub-optimal locational investment incentives for generators
- Uncertainty surrounding dispatch leading to illiquid contract markets and barriers to generation investment
- Unpriced congestion leading to disorderly bidding behaviour

We agree with the AEMC that the magnitude of the welfare loss accruing from these technical inefficiencies is unclear. In particular, as discussed above, we are not convinced that the welfare losses caused by disorderly bidding are material enough to warrant substantial change to the existing NEM arrangements.

This is especially so in light of the shortcomings of the proposed Packages 2 to 5 in the 1st Interim Report. These can be summarised as follows:

- None of the Packages that implement some form of more localised pricing (Packages 2, 4 and 5) could be expected to overcome generators' incentives for disorderly bidding. Packages 2 and 4 could reduce disorderly bidding in some circumstances under which it occurs now, but may induce disorderly bidding in circumstances where it presently does not arise. Package 5 could strengthen incentives for disorderly bidding in outage conditions compared to the present because of the payoffs from the proposed firm access rights.
- All of the Packages that implement some form of more localised pricing (Packages 2, 4 and 5) could be expected to accentuate generators' incentives to exercise transient market power in order to avoid constraints binding and thereby maintain relatively high prices at the generator's location. As noted in the AEMC's Snowy Region Rule decision, the dispatch inefficiencies arising from transient market power under more localised pricing arrangements can more than offset any improvement in efficiency due to reductions in disorderly bidding.
- In any case, the magnitude of any welfare improvements arising from more efficient dispatch under the more localised pricing Packages is likely to be minimal, as suggested by the work undertaken by Frontier Economics for the AEMC in the Congestion Management Review.
- So-called firm access rights provided or available under Packages 2, 4 and 5 would be unlikely to provide firmness to participants when it was most highly valued. In particular, the firmness of rights under Package 2 would vary

[27] p.63.

depending on a range of unpredictable factors. Firm access rights under Package 4 would only be firm under very benign 'system normal' network conditions, whereas the value of firmness would be highest under prior outage conditions. Meanwhile, Package 5 would be likely to leave retailers and large loads unable to hedge large uplift costs arising from needing to pay constrained-on generators their bid prices.

- To the extent access rights do provide some degree of a locational hedge, they may distort locational investment decisions. In particular, Package 2 could encourage large high-cost generators to locate behind constraints.
- Those Packages incorporating new transmission planning arrangements based on proposed new generator reliability standards (Packages 3, 4 and 5) would be likely to raise serious governance and accountability issues and lead to inefficient over-investment in transmission. It is not clear how the governance and accountability issues could be addressed without the creation of a new body – accountable to NEM generators – to set these standards. This may not be acceptable to the participating NEM jurisdictions.
- Those Packages incorporating generator TUoS charging (Packages 3 and 4) raise issues concerning the efficiency implications of these charges. Unless generator TUoS charges were set carefully, they could inefficiently deter use of the existing network and/or distort long term locational investment decisions.
- The creation of a single NEM-wide TNSP with responsibility for the entire network's operation under Package 5 would likely be fraught with difficulties. Such an institution would have strong incentives to minimise its exposure to any incentive scheme for maximising network availability and firm access. The AER would face tremendous obstacles in designing an incentive scheme that appropriately rewarded and penalised such an institution.
- Package 5 would also eliminate locational pricing signals for load. This would apply to both operational decisions (demand-side response incentives would be much diminished) and load investment decisions.

These drawbacks suggest that radical change to the NEM arrangements is unlikely to prove worthwhile. In this context, the existing arrangements represent a reasonable starting point from which to make incremental improvements.

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