NATIONAL GENERATORS FORUM

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

Reference: EPR0019

Dear Mr Pierce

The National Generators Forum welcomes the opportunity to comment on the AEMC's *Transmission Frameworks Review, First Interim Report*, as released on 17 November 2011.

The NGF is the national industry association representing private and government owned electricity generators. NGF members operate all generation technologies, including coal-fired plant, gas-fired plant, hydroelectric plant and wind farms. Members have interests in all States.

The NGF appreciates the excellent work that the AEMC has undertaken to date in the Transmission Frameworks Review. The options listed in the First Interim Report incorporate some innovative thinking and proposals on possible ways of managing and minimising "the coordination problem" between competitive generation markets and monopoly network providers. Setting an appropriate framework for managing this interface through market and regulatory measures is complex and contentious. In a regulatory area such as this, there will always be difficult trade-offs with different design and implementation features. We are grateful for the methodical approach that the Commission has followed in the review so far.

The AEMC has indicated that it is likely to narrow its focus to one or two packages of measures in its next report. To assist the Commission, the NGF has provided an assessment of the five options in the First Interim Report drawing on: the experience of NGF members; practical examples of market outcomes under current arrangements; and an analysis of possible limits and weaknesses of various concepts proposed by the AEMC.

The NGF is supportive of the NEM's existing regional competitive market model and believes it provides a more productive electricity sector than a central planned and owned entity. We consider the competitive market model requires some regional approximations to encourage trade due to the difficulties in pricing ex ante costs of a shared transmission system, which is subject to significant externalities. These regional approximations should be where supply, demand and transmission conditions allow for a homogenous pool of participants to deliver the efficiency benefits of the competitive market model.

There should be an acceptance of some productive inefficiency to facilitate the regional competitive market model and, where possible, these may be overcome but only to some extent, by incentives on market participants and planners. Regional dispatch risk is a key factor that incentivises market participants to avoid inefficient transmission costs, whilst not unduly inhibiting the regional competitive market model. No evidence in the Review to date has proven there to be undue dispatch (productive) inefficiencies in the NEM due to network congestion.

Should the regional competitive market model need supporting with firmer trading arrangements, it is sensible for consumers to underwrite the risk. However the quid pro quo of consumers doing so is to place an administered incentive on market participants. This administered incentive should reflect the costs of transmission that, with firm trading, will no longer be present in the market incentives. That being said, the NGF considers there to be no evidence the NEM's competitive market model requires firmer trading arrangements.

With the above framework in mind, the NGF has deliberated over the packages in the Interim Report and has found Shared Access Congestion Pricing, Generator Reliability Standards and Optional Firm Access packages to be unsatisfactory. We believe these options are inferior to the status quo, which is consistent with the above framework.

This leaves the final package, Locational Marginal Pricing with Firm Transmission Rights (LMP-FTR). This was found to be an interesting package as it is consistent with the above framework. Members generally had some concerns over using a competitive market model to provide Planners with incentives. In addition members had concerns with the implementation of this design and the regulatory risk this would entail. We concluded that this model would not work because incentives on market participants to game uplift payments would mean that only a self-funding model could be considered acceptable by the AEMC. Yet by being self-funding we concluded the LMP-FTR model would inhibit the competitive market model of the NEM. In addition the LMP-FTR model was not considered fit-for-purpose for the relatively small power market of the NEM, which in any case shows no evidence of material inefficiency in its market and planning arrangements.

The NGF engaged Frontier Economics to prepare an independent economic report of the AEMC's policy measures. Frontier evaluates options 2 to 5 drawing on previous modelling work, analysis and finding of previous transmission reviews, analysis of the various incentive properties of each option, and a discussion of the implementation issues involved with any substantial change to pricing and access arrangements. Frontier applies three assessment criteria:

- effects on the economic efficiency of dispatch
- effects on derivative trading and investment
- transmission governance and investment efficiency

Frontier is of the view 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. Frontier believes that the AEMC should focus on refining and improving existing arrangements if the Commission or industry can provide evidence that there is scope for more efficient outcomes.

The NGF hopes that the attached submission assists the AEMC with its analysis and looks forward to participating in the next stages of the Review. Please contact David Scott (07 3854 7440, david.scott@csenergy.com.au) if you have any questions regarding this submission.

Yours sincerely

D. Bowker.

David Bowker
<u>On behalf of the Executive Director</u>

07 February 2011

NGF response to Australian Energy Market Commission's First Interim Transmission Framework Review Report

The NEM's existing incentive structure

To improve productivity of the electricity sector in Australia reforms were introduced for a "directly regulated" network to provide access to participants in an "indirectly regulated" competitive market. This was to overcome the problem of capital being inefficiently employed by a "central planner" not subject to the "invisible hand" of competition.

The difference in regulation between the generation market and network monopolies is justified on the basis that economies of scale can be achieved with a single site generator, but not for individual transmission circuits. For transmission, it is assumed economies of scale benefits necessitate a regulated monopoly.

In Australia this led to the separation of the networks and generators and then further separation of generators into competing companies. This separation between networks and generators presents a complication, referred to as the "coordination problem" in achieving the most efficient electricity system, because there is no longer the central planner coordinating transmission and generation investments and operation. This is heightened because generation and transmission are, to some extent, substitutes in providing reliable electricity supplies.

When a single company owned all the generating and transmission assets, it could assess all the capital and operating costs of both options, such as transmission losses, differences in fuel (congestion) costs and infrastructure financing costs.

Upon separating generation and transmission, the regulatory framework had to place incentives on generators and retailers ("market participants") and regulated monopolies ("planners") to replicate the perceived benefits of the 'central planner' model. This response to the Commission's First Interim Report ("Report") focuses on the type and extent of these incentives, looking at ways they can work to encourage market participants and planners to minimise system costs of the electricity sector.

The wholesale costs of the electricity sector to which we refer are delivered through market participants ensuring returns on "sunk" investments in a highly volatile commodity market. This is done by market participants voluntarily trading in financial derivatives to hedge volatile pool sales (or expenses) which are required by law to be made via the market operator's physical exchange. The competitive market model should ensure supply is delivered at the lowest cost, with a price producers are willing to sell and consumers are willing to pay, at a given level of risk, in real time and investment timescales. The NGF considers wholesale energy costs to include the net of physical and financial market trade.

The transportation costs in this wholesale market are: transmission assets that ensure a reliable and secure supply to consumers; energy losses incurred in using them; and increased wholesale costs through instances where a more expensive participant must supply due to a lack of transmission.

In this response to the Report, the NGF considers system costs to be the aggregate of costs from the wholesale market and the transportation costs from the transmission network.

Incentives on market participants and planners

The AEMC should consider incentives as an attempt to avoid inefficiencies presented by the coordination problem, knowing that such inefficiencies are eclipsed by the proven benefits of introducing the competitive market model.

For planners, in the absence of market signals, incentives take the form of economic assessments, planning reports (all of which are premised on the consumers' willingness to pay) and market indicators such as connection agreements. There are opportunities for performance target schemes which may mimic the competitive pressures of the market, although we will explain later that such incentives can potentially change operational practices in ways not originally intended.

When we consider planners, the obvious problem is these network monopoly providers only have information on network costs, rather than costs of market participants, be they incumbents or entrants. The economic tests that planners run will therefore only be as good as the assumptions used in running the economic tests for deciding when and where to augment the transmission system. These assumptions should be made sufficiently transparent by planners to allow rigorous analysis by regulators and participants.

For market participants, which includes potential investors in retail and generation, incentives must reflect the fundamental dynamics of the market in which they are competing so consumers can be served at the lowest cost. Transmission costs can be included as a relevant cost in the consideration of the fundamental dynamics of the market. An incentive may therefore be an allocation of shared transmission system costs to change market participants' behaviour to avoid such costs.

There arise difficulties in designing incentives on market participants because the shared network is subject to externalities, where one market participant can impose a cost on another. In other words, the shared network is dynamic, rather than static, so transmission costs are impossible to allocate on an ex-ante basis, especially for a significant period.

This is a particular problem when incentives are supposed to change behaviour of market participants because the incentive would have to act before the decision by the participant. However the only way to accurately capture and allocate costs of a shared transmission system is on an *ex-post* basis. The NGF contends that it is impossible to perfectly incentivise market participants' behaviour as the error in the ex-ante allocation of transmission costs itself, may well lead to inefficient behaviour. This means there will always be inefficiencies accruing from the coordination problem.

Worse than incurring inefficiencies from the coordination problem, the allocation of shared transmission costs may inhibit the behaviour of market participants, such that the competitive market model functions much less effectively. For example if costs are allocated on a nodal, *ex-post* basis, it may be impossible for market participants to agree terms of trade as if they agree a volume and price they may be exposed to the difference between this and the allocation of transmission costs. The allocation of shared transmission costs could become a risk that prevents a homogenous pool of buyers and sellers efficiently trading, thus negating the very benefits of the competitive market model, even if it overcomes the coordination problem somewhat.

If we apply this thinking to the NEM it is evident that a line has been drawn (possibly not intentionally) in encouraging trade between market participants and allocating transmission costs.

The NEM explicitly does so through regional settlement, marginal loss factors and dispatch risk[1] within the region. The regional nature of the NEM's competitive market model is evident through the development of voluntary exchanges where derivatives are traded on a regional basis.

The successful operation of exchanges and the level of over-the-counter trading suggests the "indirectly regulated" competitive market model is delivering reasonably efficient outcomes. The trade data on the SFE and OTC deals suggests there is no undue inefficiency in financial markets[2] presented by the NEM's regional settlement.

Of course, if the NEM did not have regional settlement, rather a single whole of NEM reference price, then we would expect the competitive market model to improve its efficiency. There would be more counterparties to compete and a more efficient spread of market and credit risk with deeper traded markets providing futures prices to underwrite investment. However, such a market would not effectively reflect scarcity conditions across the NEM, be they due to high demand, lack of supply or insufficient transmission capability. This would lead to inefficiencies.

As an extreme the NEM's geographic spread of South-Australia in the west, Tasmania to the South and Queensland to the north would prevent a single NEM competitive market model being efficient, unless the Rules administered further incentives to reflect these differences. The need to apply excessive incentives other than spot prices on market participants, (such as through TNUoS, Network Support Agreements, directions with constrained-on payments, FCAS directions) would indicate the wrong trade off has been made in encouraging the competitive market model and allocating costs.

In Queensland, Victoria and New South Wales the liquidity and number of participants in the market provide competitive, efficient outcomes and the regional pricing appears to have facilitated timely and efficient investment. This would suggest the regional market is succeeding in delivering productive, allocative and dynamic efficiencies.

In addition, there are few additional incentives applied to market participants to overcome any perceived inefficiencies in the regional competitive market model. The use of Network Support Agreements and instances of AEMO directing on plant are rare.

Overall, the NGF considers that the current regional market structure is providing the necessary incentives for market participants to minimise system costs, whilst still enabling reasonably efficient market outcomes to occur.

There has been some debate[3] over the efficiency of the Tasmanian and South Australian regions in delivering the competitive market model given the ownership structure of participants. The NGF does not wish for the Review to become entangled in structural issues, as it would be imprudent for the transmission frameworks to be biased to overcome a structural, ownership issue rather than a robust assessment of the need to encourage the competitive market model and minimise system costs. It would be imprudent for the regulator to "draw the line" between encouraging the competitive market model and minimising system costs on the basis of dealing with a possible structural issue: it would bias the decision towards the competitive market model at the risk of increasing system costs.

[1] In this response dispatch risk is a term used to describe being constrained off when the offer price is below the regional spot price. This differs from forced outage risk, which occurs when a generator reduces load due to a technical problem when the offer price is below the regional spot price.

[2] The Australian Financial Markets Association in their annual report on the markets calculated the NEM liquidity ratio to be 4.5 for 2010-11, increasing, even in light of uncertainty over carbon pricing.

[3] An Independent Assessment of the Tasmanian Electricity Supply Industry – Draft Report, 15th December 2011, Rule change Proposal "Potential Generator Market Power in the NEM" 14th April 2011

This point is important because there are other regulatory tools, such as divestment and competition legislation, for dealing with structural market issues, but few others for dealing with minimising total system costs.

Dispatch risk is a key incentive within the Region

There have been comments during this Review as to whether shared transmission costs have been avoided by the behaviour of market participants[4]. This would suggest there is no incentive upon market participants within the region to avoid transmission costs. It is at this point that the NGF wishes to discuss further the importance of dispatch risk within the region as the key incentive for market participant's behaviour to minimise transmission costs.

The regional price is the incentive to connect in a region, but with the NEM's regional competitive market model there is no sub-regional price to guide investors. Instead transmission costs are allocated on market participants through volume risks, when transmission constraints reduce output that may otherwise be dispatched from participants and settled at the Regional Reference Price (RRP).

This dispatch risk provides a clear indicator for entrants to connect in unconstrained sections of the grid, or at least in a location where the planner has indicated it will reinforce the network through applying an economic test, (such as through publication of its annual planning reports or the application of the RIT-T).

A clear contention of some respondents to the review[5] has been that dispatch risk has prevented generators selling an efficient level of financial contracts to manage market risk. In such an instance the dispatch risk is when a generator is constrained off "short" of its financial contracts, during high spot prices, where the losses are twofold: actual losses incurred against financial contracts due to a reduction in offsetting spot market revenues; opportunity costs of unconstrained revenues if the constraint occurred during a period of high demand (missing out on a "big pay-day").

The Review has consistently discussed[6] the problem of the NEM's unfirm access preventing generator selling contracts in the financial markets. It is the NGF's contention that dispatch risk has not done so as this risk is largely accounted for within forced outage risk, commonly used by generators to set a maximum hedge limit.

Forced outage risk

Forced outage risk is important to this debate because it inhibits a participant from selling a contract due to the risk of being unable to match it with an equivalent level of pool sales. This means transmission constraints need to constrain-off a generator to a greater extent than forced outage risk in order for the competitive market model to be impaired.

An argument may be used that dispatch and forced outage risk may occur simultaneously and the compound effect on the Market Participant would be deleterious. We refute this, because this would be equivalent to planning the system and trading in the market on the basis of N-3, which over expose participants to spot prices by failing to hedge forward. Using the previous constraint example this would be losing two circuits between Calvale and Tarong and then losing a Stanwell Corporation generator.

[4] AEMC First Interim Report 6.2.4, p. 60; AGL Issues Paper submission , pp.12-14
[5] AEMC First Interim Report, 3.2.1 P.20; 5.3.2 pp.51-52
[6] AEMC First Interim Report, 3.2.1 P.20; 5.3.2 pp.51-52

An instance where the transmission capability would be significantly reduced is under condition where two credible contingencies could be expected (N-2), such as during lighting storms over “vulnerable circuits”, or credible contingencies coupled with planned outages. For example the constraint equation Q_CS_1100 Qld Central to Qld South upper transfer limit of 1100MW reflects diminished capability between Calvale and Tarong, upon N-2 reclassified as a credible contingency. This equation constrains off generation north of Calvale, such as Gladstone, Yabulu, Callide, Mt Stuart, and Stanwell power stations. Previous to the restructure of QLD government owned generators on 1 July 2011, all of Stanwell Corporation’s generators were north of the constraint.

Upon the constraint equation binding in dispatch, Stanwell Corporation would “disorderly rebid” all generation to -$1,000/MWh to reduce the constrained volume. In addition CS Energy and Intergen would rebid Callide power stations to -$1,000/MWh as would AGL and Origin with Yabulu and Mt Stuart (should the RRP have been greater than their marginal cost to encourage them to start). Generators south of the constraint with higher offer prices would be dispatched (this is why the constraint is binding in the first place).

It does not matter whether the constrained generators’ dispatch is in excess of their financial hedge contracts for them to disorderly rebid. Should the RRP be higher than their marginal cost they will always compete for a share of the constrained volume, irrespective of their hedge contract position. The difference in settlement would be: if dispatch is less than financial hedge contracts (short), payments would be made to the counterparty, whereas if dispatch is greater than the financial hedge contracts (long), but less than available capacity, there is an opportunity cost for generators. Either way, the generator is worse off and should rebid disorderly.

Box 1: Outage risk versus dispatch risk, example of 19 November 2009

On Thursday 19 November 2009 the constraint Q_CS_1100 bound for 3 hours, during a period of coincidental very high pricing in NSW, which flowed through the QLD. Stanwell Corporation disorderly rebid its portfolio of generation, although experienced a significant reduction in dispatch at Gladstone, which has the highest constraint coefficient in the constraint equation (that is if pricing, ramping and automated generator control settings allow, it will be first constrained by the dispatch engine).

For some reason Stanwell power station only had 1260MW of 1410MW priced at -$1,000/MWh, leaving 150MW that could have been dispatched from the station on STAN-4. To compound this Stanwell Corporation did not rebid ramp rates down on Gladstone, leaving them at 5MW/min, rather than the minimum of 3MW/min. In addition Stanwell was slow in rebidding the capacity, such that as Gladstone’s dispatch targets were decreasing, Stanwell’s targets were not increasing even with Stanwell’s lower coefficient in the constraint. The reason for this was probably due to an expectation of the constraint equation being rescinded as the storm passed the circuits. If Stanwell Corporation had rebid its whole portfolio more aggressively it would have obtained a greater “share” of the constrained volume with other generators.

At the time Stanwell Corporation had an overall capacity of 2900MW, excluding one Gladstone unit on reserve shutdown (effectively mothballed), which after deducting losses and auxiliaries equates to a possible 2646MW of capacity that can be hedged with financial contracts. This may be discounted further depending on trading the output of the hydro stations, Barron Gorge and Kareeya (which total 150MW) although this may be on a seasonal basis. For simplicity we’ll keep them in the hedge limit. To account for forced outage risk, which is the loss of the largest generator in the portfolio; this is reduced further to over 2300MW to 2400MW. This approximates to an 80% maximum hedge level for the corporation.

Upon the constraint binding, Stanwell’s dispatch reduced to just over 2200MW, which with auxiliaries and losses deducted would equate to 2000MW. This is clearly below the maximum hedge level of the Corporation, thus probably leading to losses accruing against hedge contracts.

If we assume Stanwell was contracted at a maximum hedge level of 2300MW at a strike of $45 and the dispatched volume reduced by auxiliaries by 10%, then the losses accrued against these hedges would equate to $1M over the 3 hours the equation was binding.

Clearly this period would not have been a good outcome for Stanwell Corporation, but it would not have been calamitous. It could have been mitigated if Stanwell Corporation had actively increased its share of generation behind the constraint, by rebidding STAN-4, rather than allowing Gladstone to be constrained down to such an extent.

All the above is interesting, but not particularly illuminating unless we ask whether Stanwell Corporation was constrained from selling contracts at the RRN from this level due to dispatch risk arising from transmission network congestion. This may be evidence of unfirm generator access, reducing the efficiency of the competitive market model, which some have contended.

To help answer this question we should look at the very next day when higher prices in NSW resulted in high prices in QLD. The high prices in QLD were contingent on QLD generators pricing up to NSW generators to ensure the interconnector circuits remained unconstrained. The Q_CS_1100 constraint was not invoked and therefore all Stanwell Corporation's generation was free to be dispatched.

Stanwell had an incentive to withdraw capacity down to its hedge position, sacrificing quantity sold to support the price paid on the remaining quantity not hedged by contracts. Stanwell withdrew capacity at Gladstone to a level of dispatch 1200MW that, with the other units equated to approximately 2300MW – 2400MW (if we deduct 10% for losses and auxiliaries). Unfortunately for Stanwell Corporation, this was not enough to receive a loss adjusted price of that in NSW of $10,000/MWh. This clearly indicates Stanwell Corporation had a hedge position of the order of 2200-2400MW over the two days in question (otherwise it should have withdrawn more quantity) and therefore the dispatch risk of Q_CS_1100 had not prevented Stanwell Corporation contracting in the financial market in the first instance. In other words, the maximum hedge level was not set by Q_CS_1100's network congestion (dispatch risk), but by generator forced outage risk.

Costs are likely to outweigh gains of firming trading arrangements

We have discussed the relative importance of dispatch and forced outage risk in order to lead onto the following question: would there be an efficiency gain of firming the trading arrangements?

If we consider the previous example, a very aggressive N-2 constraint equation had not limited Stanwell Corporation's participation in the regional financial market any more than the risk of losing its largest generating unit. This suggests there is little to be gained in financial trade from firming up the transmission arrangements from that today. This is because generators' hedge limits are more sensitive to analysis of forced outage rates rather than dispatch risk due to network congestion.

The NGF considers generator participants are unlikely to enter into more hedge contracts than that today. Therefore, should the Commission wish to increase participation in the contract market it probably requires mandating of trade by market participants. This is the model adopted in power markets in the European Union, where an EU Directive specifies the use of a bilateral traded market with imbalance settlement. This is often called "net pooling" when compared to the NEM's "gross pooling" design. The quid-pro-quo of mandating financial trade for full output would be to remove dispatch risk from the market design altogether. This of course would enable trading of energy contracts, but would not provide a signal for investors to connect to unconstrained sections of the regional transmission grid. This would therefore require another incentive out with the market to overcome this efficiency, such as G-TNUoS and a "closed access" model. The NGF notes that a bilateral traded market design is not on the table in this review and therefore we will not discuss it further. For clarity, NGF does not support investigation of this option.

The "cost" of firmer trading arrangements

We raise the point of "closed access" because firmer trading arrangements, although giving a signal to entrants, allow for the greatest competition between incumbents. This is because the provision of firm access requires either the funding of compensation to incumbents or the prohibition of access to an entrant. By definition, firm access will need to be protected, otherwise it is un-firm. This can be managed through prohibiting access, such as by forcing entrants to pay compensation or having to wait to connect to an unconstrained grid. Such an approach would reduce the dynamic efficiency of the market when compared to the NEM's present "open access" arrangements: it is therefore not supported by the NGF.

The other option is for consumers to fund compensation to incumbents, as in theory, they will be the beneficiaries of firmer trading arrangements. By funding the compensation payable for firm access for generators, consumers will be underwriting transmission risk but should benefit from efficiencies from the competitive market model.

Requiring consumers to underwrite firm trading is a sensible solution when compared to prohibiting access to entrants, although a problem with doing this is that another administered incentive is needed to reflect transmission costs on market participants as it is no longer reflected in the market signal of dispatch risk. In such an instance we would have consumers exposed to transmission risk so market participants would need to be exposed to an administered incentive, such as G-TNUoS. In addition, by requiring consumers to underwrite firm trading, market participants will have an incentive to game compensation payments (this is explained in consideration of package 5 later in this response).

The NGF is of the view it would be simpler to expose participants to dispatch risk; in the way the NEM currently does, seeing that the market has experienced few material inefficiencies under existing planning, investment and dispatch arrangements.

If this Review determines that it is appropriate for consumers to underwrite firm access, we believe there may be material inefficiencies presented by either the administered incentives or other market incentives placed on market participants to reflect regional transmission costs. Administered incentives may just be inaccurate, such as error in G-TNUoS charges to actual costs. New market incentives, such as compensation payments from unfirm generators, may encourage inefficient behaviour if "game-able" by participants.

These problems may lead to unintended inefficiencies, negating the very benefit of firming up the trading arrangements in the first instance. This leads the NGF to believe the NEM's open access arrangements are broadly appropriate.

NGF view of current NEM incentive framework

It is the NGF's contention that the NEM has facilitated reasonably efficient outcomes that balance the competing goals of encouraging the regional competitive market model and avoiding transmission costs.

The NGF says this because the NEM encourages the competitive market model on a regional basis, which results in regional incentives to minimise total system costs. For example a generator will invest in a region with higher spot prices. In addition, there is dispatch risk that plays an important role in minimising within region transmission costs. By facilitating the regional competitive market model, minor inefficiencies remain such as: managing constrained on payments, network support agreements and the much demonised disorderly rebidding. However, the productive inefficiencies that arise from AEMO directing on plant and mispricing when disorderly rebidding are a trivial when compared to the efficiencies gained from the regional competitive market model.

It is worth stepping back and considering whether the NEM's efficient performance is happenstance or clever design. If we consider the earlier discussion over facilitating the competitive market model yet still trying to reduce system and transmission costs, we could question whether the NEM's regional design with dispatch risk focuses too much on allocating costs rather than encouraging the competitive market model. We say this because it has been the contention of other respondents to the transmission review, who suggest the NEM requires firmer trading arrangements within the region.

A first observation would be whether the regional boundaries are reflective of differences in the supply-demand fundamentals and differences transmission costs? This was debated by the Tasmanian Expert Panel where they investigated the merger of the Vic-Tas regions. The report discussed the differences in market fundamentals and transmission costs. The option of merging the regions, although obviously beneficial in terms of facilitating a competitive contract market outcome, was considered unworkable in practice because a Vic-Tas region would not be able to provide necessary market incentives on Market Participants to derive an efficient spot outcome. That is to minimise system costs within the two regions, including transmission.

However, if we were to redesign the NEM on the basis of drawing a line between allocating underlying costs or encouraging a competitive market, what would the regions be? The NGF believes, with evidence of increasing contracting market liquidity and volume, existing regions have been sufficient to develop effective and competitive markets. There is no evidence that administered incentives in the form of constrained-on payments and network support agreements are unduly high.

There has been discussion that the NEM has excessive productive inefficiencies through disorderly rebidding, which probably isn't true. Previous studies undertaken by the AEMC assessed the economic cost due to network congestion at only $8.01M[7]. Given the overall dispatch costs of the NEM dispatch inefficiencies represent less than 0.1% of NEM trade, an insignificant amount by any measure. The Northern Group[8], using AEMO mispricing data, proved that under constrained circumstances generators often do not rebid disorderly.

This leads us to consider disorderly rebidding, where mispricing occurs when regional participants aim to increase dispatch. In some instances disorderly rebidding can reduce interregional flows (as generation in the adjacent region cannot disorderly rebid), albeit capped by negative settlement residue constraints at $100,000 that subsequently prevent counter-price flows[9]. To date the Review and some respondents have considered this behaviour[10] as simply a productive inefficiency that should be removed from the Rules. This is simplistic.

Considering the earlier discussion on tradeoffs, it is the NGF's contention that disorderly rebidding should allow intra-regional generators to displace interregional generators in dispatch should the disorderly rebidding be <u>protecting an efficient level of contracts</u> sold by regional generators against the RRP.

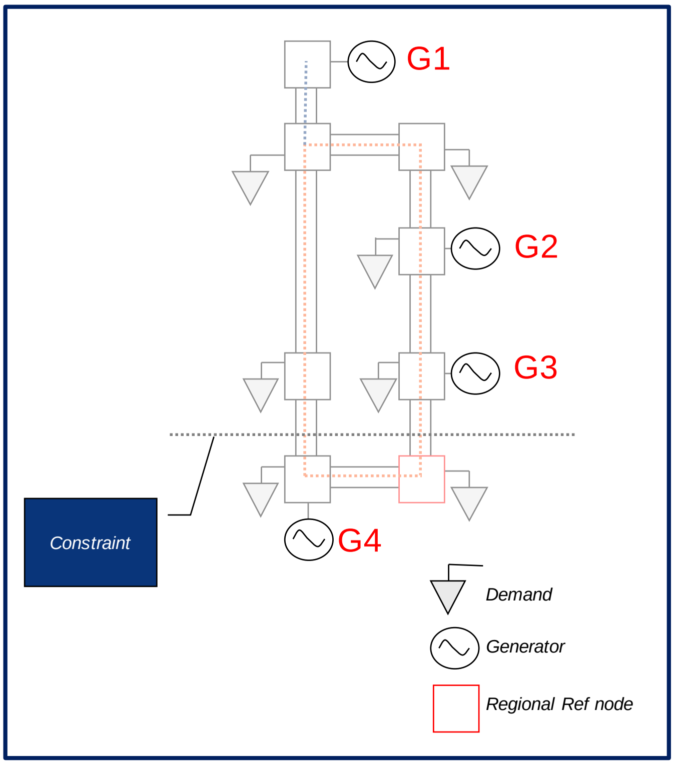
If "efficient level of contracts" in the preceding sentence is substituted for "facilitating the regional competitive market model", then one should understand disorderly rebidding is a behaviour that results in a minor productive inefficiency surpassed by productive, allocative and dynamic efficiencies of encouraging regional trading. Clearly, should inefficient counter price flows allow regional dispatch to a level greater than the efficient level of contracts then this is profiteering by regional generators. We shall explore this point further in the consideration of package 2.

[7] AEMC Appendix B, Final Report, Congestion Management Review 2008 P.96, Frontier Economics modelling
[8] Response to AEMC Issues Paper, Northern Group, p.36-37
[9] AEMO, SO_OP3705 v72, 21.1 Negative Settlement Residues, p.23-24
[10] AEMC First Interim Report 5.4, p.53; AEMO response to AEMC Issues Paper, 6.Network Congestion, p.20-23

Assessment of Package 2: Shared Access Congestion Pricing

The NGF considers that the SACP model unnecessarily allocates costs on a sub-regional basis in an attempt to try to resolve the minor inefficiencies of disorderly rebidding whilst creating inefficiencies in the regional competitive market model. Even then, we have doubts whether it will work when disorderly bidding incentives emerge.

To explore the SACP model, the following schematic has 4 incumbent generators where short-run marginal cost increases G1 to G4. In unconstrained circumstances we would see G1, G2 & G3 dispatched. However actual dispatch results in G1-3 constrained off, therefore G4 can meet demand, setting RRP.



At present Rules encourage G1, G2 & G3 to price -$1,000/MWh in order to reduce being constrained off, with this called "disorderly" bidding.

If we assume all these units have equal impact on constraint then the transmission capacity is rationed equally. With G1 cheapest, it is inefficient to constrain it off in tandem with G3, as G3 should be constrained off first. The difference in marginal cost of G1 and G3 is called "mis-pricing". The mis-pricing is a productive inefficiency with the existing Rules. This is what package 2 is purported to solve.

The Interim Report suggests under SACP G1& G2 would be dispatched, but not G3, although all would receive a share of the "residues" between the local price and the RRP on the basis of available capacity.

In this example, G1, G2 & G3 have an incentive to declare availability (and ramping) as high as possible to maximise their share of rents available through the constraint. There is no possible way for the market to "test" the participants' word on their available capacity as in most instances the capacity of G3 will not be dispatched. Therefore the SACP will encourage out-of-the-money generators such as G3 to over declare availability for share of capacity allocation, knowing full well it will not be utilised. At the same time well in-the-money generators behind the constraint, such as G1 will often have their available capacity tested by the market (as it is economic to be dispatched). The allocation of residues on the basis of available capacity will, over time, encourage G1 to price some capacity at SRMC, but if there are doubts over the reliability of capacity, it will price this at a price hopefully higher than G3. This will allow G1 to claim residues on the capacity without fear of being dispatched and having their true availability tested or high levels of generation leading to an unplanned outage. G1 runs the risk of lower dispatch and the constraint not binding, but this is probably worth it in some instances. In other words, G1, G2 and G3 will be incentivised to use price to determine their availability to the market rather than their true availability.

This will have implications for monitoring reserve conditions and ensuring reliability as in aggregate generators behind a constraint will be incentivised to over-declare unreliable capacity as available and price it up so it is not dispatched.

This leads onto another behaviour that may occur, which is for participants to withdraw capacity to avoid the local price and therefore prevent any residues accruing. In the above example, G1 may avoid local price by not dispatching plant fully, effectively pricing up capacity to the price of G4 in order to ease the constraint. To some extent this already occurs in the NEM, when generators in one region, withdraw capacity and price up to the adjoining region. G1 will do this where the energy payments on a reduced quantity dispatched exceed that of the payments it would receive on a higher quantity dispatched under constrained conditions, where it is subject to a local price and residues are shared with G2 and G3. Under such conditions the amount G1 will have to withdraw will probably be quite small so the profitability of this strategy will be high. G3's response would be to offer capacity below the price of G1, but at least at its SRMC in order to constrain the circuits. In this instance a productive inefficiency would occur because the SRMC of G3 is higher than G1.

The above behaviours are very similar, but have differing goals. The first is to try to gain a share of the residues with capacity that is unreliable; the second is to try avoiding accruing residues to prevent a dilution in profits of the plant already dispatched. It may be said that these behaviours may not be sustained once the market develops a competitive equilibrium behind a constraint. However we would disagree, because transmission constraints are transitory in nature; the system is dynamic, not static; and generator availability and pricing will change depending on prevailing conditions.

There has been debate (summarised in the Interim Report's Appendix A) over whether this model would encourage unreliable generators with a higher SRMC cost to locate behind a constraint in order to obtain a share of congestion residues. It is the NGF's view that this is hypothesizing about a theoretical abstract that is unlikely to occur. We do not see how an investor could attract finance for a high cost, unreliable plant simply because it would obtain a share of congestion rents. The very reason why the NEM has delivered efficient outcomes to date is that investors will discount revenues if they expect to be constrained and this leads to generators locating in parts of the grid that are largely unconstrained.

There is also another problem with the SACP model, which can be shown if the above example is changed so G4 is cheaper than G3. By doing this the system is not therefore unconstrained as G1, G2 and G4 supply demand at the RRN.

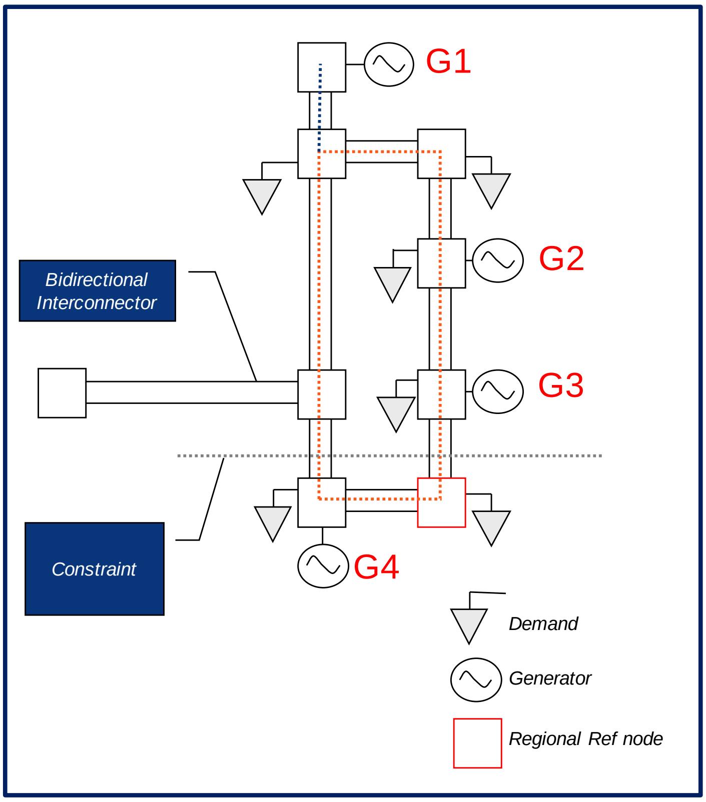
Under this scenario, G3 is receiving no payments, be they energy or congestion residues. It will therefore have the incentive to submit an offer price for a proportion of its capacity to constrain the circuit. This is disorderly rebidding as it will price below SRMC, although the difference will be that it will paid the offer price not the RRP on its dispatch volume. It will therefore lose money on its dispatch volume, but will more than offset this loss for this with congestion residues. The SACP model therefore encourages generators that are out-of-the-money to offer capacity below marginal cost to obtain some allocation of the congestion rents allocated on available capacity.

Given the above issues we question whether SACP could work effectively.

Generators price at SRMC when constrained

If generators do not disorderly rebid when constrained, the priority of dispatch will change from the regional bias it has today. We should expect greater flows from competing regions into the higher priced region and reduced dispatch for the regional generators. The regional generators will be exposed to greater dispatch risk against contracts settled on their RRP and will, all other things being equal, reduce their hedge levels. The interregional generator will have "firmer" access to the other region and may increase their exposure to the adjoining region's RRP.

In order to consider this further it is best to elaborate on the previous example with the inclusion of an interconnector, which is also behind the constraint.



Under the existing Rules, in order to gain a share of dispatch across constraint G1, G2 & G3 rebid disorderly to -$1,000/MWh. The interconnector remains priced as before as that generation is exposed to local price (adjoining RRP).

As with before, G4 continues to set (a high) price but flows across the interconnector are now counter to price as the -$1,000/MWh generation in the higher priced region has priority. There arises "negative settlement residues", which if they reach $100,000 AEMO will seek to reduce, by adjusting interconnector flows to zero.

What is evident from the example is that G1, G2 & G3 could be dispatched to a greater extent than without the interconnector because the interconnector can flow backwards. In effect the interconnector could act like "safety valve" for G1-3. Should generators have sold a level of contracts at the RRP to their level of dispatch, reversing the flow on the interconnector will help manage their financial exposure. This would be an efficient outcome of the regional competitive market model provided this maximised the level of contract trading for the region.

Should the disorderly rebidding change the flow on the interconnector to the extent that G1, G2 & G3 are generating well in excess of an efficient level of contracts at the RRP, then the disorderly rebidding will have resulted in profiteering. They will be "long to the pool" when their dispatch is above their volume of sold swaps against the RRP. This is likely to be inefficient behaviour and probably why it is necessary to "clamp" counter price flows and stop negative settlement residues accruing past $100,000. Excessive negative settlement residues are inefficient as consumers in the importing region receive little benefit. As previously mentioned, it may be that the local TNSP could more effectively manage the constraint using a network support agreement, although has no incentive to do so under the present NEM design.

Given the above discussion, the question that this review should be asking is whether the level of intra-regional congestion is preventing an efficient level of swaps to be sold against the RRN. If so, then clamping flows to prevent negative settlement residues may be inefficient. If we consider the constraint equation Q>>NIL_855_871, this equation includes an interconnector term on the LHS and can, (if other LHS terms are also constrained with high prices in QLD), result in negative settlement residues. Whereas some counter price flows may be efficient, it is unlikely the NSW1-QLD1 interconnector importing (that is flow to NSW) at 1GW would be efficient as this would support an excessive volume of contracts in QLD, probably not required by the underlying demand for contracts by retailers.

If we consider the other constraint equation Q_CS_1100, which constrains off generation north of Calvale in Central Queensland, if this is preventing an efficient level of contracts it would indicate a failure in the incentives on planners to invest to upgrade the capacity of the circuits. This is because the equation has no interconnector terms on the LHS and therefore the regional dispatch cannot be increased by reversing the flow of an interconnector.

Under the SACP proposal, incentives for “disorderly” rebidding will be reduced and trading by regional market Participants will diminish. The NGF believes this reduced contracting within the region will prevent the regional competitive market model delivering an efficient outcome. This is because we do not expect interregional generators to make up the shortfall in trade, even though interconnectors will be granted a yet to be determined “capacity allocation” of congestion residues.

Firstly, using the example above, the adoption of a SACP model where there is very significant intra-regional congestion, there would be more generation competing to flow through the constraint (the regional generator plus the exports from the adjoining region). This exacerbates the constraint compared to the status quo, as under disorderly rebidding the interconnector exports would be prohibited.

It is the NGF’s contention that should there be very material intra-regional congestion, that is restricting the efficiency of the regional traded market, then the last thing the Rules should do is allow for more generation to compete to flow through it. Instead it is more efficient to allow the interconnectors to reverse until negative settlement residue constraints settle the flow to zero.

Seen in this light, the NGF considers the clamping of negative settlement residues as an unwillingness of consumers to accept regional transmission risk by underwriting firmer regional trading. In effect the Rules say consumers will take $100,000 of transmission risk, but no more, the rest must be managed by regional participants. If this prevents the selling of contracts against the RRP, (which is the diminishment of the regional competitive market model), then so be it.

Other reasons why we consider interregional trading will not replace regional trading are that these interconnector circuits are not as reliable as intraregional circuits. For example the NSW1-QLD1 interconnector is a long skinny circuit subject to reclassification as credible contingency (vulnerable to lightning). This is also true of the intra-regional network, although power flows are usually associated with a greater number of circuits. In addition AEMO co-optimises interconnector circuits with FCAS dispatch upon risk of separation and islanding constraints. It is also likely that generators within an adjoining region will, based on plant risk hedge limits, seek to satisfy the hedging requirements of their own region first.

Assessment of Package 3: Reliability Standard and TNUoS

The NGF was disappointed to see this option included in the Interim Report because we consider it represents an inappropriate allocation of regional transmission costs. We believe it allocates transmission costs through two incentives on market participants so they "pay twice". This will lead to inefficient outcomes because by over-allocating transmission costs to market participants who will seek to avoid them thus not enabling an efficient level of costs to be incurred.

The two incentives placed on generators in this package are regional dispatch risk and the levying of transmission charges (G-TNUoS[11]), which are both incentives to minimise transmission cost. For example an investor will discount potential revenues by dispatch risk and increase annual fixed costs through a TNUoS charge in its investment decision. The investors will also factor in the cost of transporting fuel to the generating site, such as the cost of a gas pipeline. Should they have assessed the cost of the gas transportation system accurately, this model will encourage them to make inefficient investments in gas pipelines to an unconstrained section of the electricity transmission grid, rather than incur the efficient cost of electricity transmission. This is because the cost of transmission access has been overpriced by use of discounting revenues by dispatch risk and including the cost of G-TNUoS.

As discussed in the first section of this report, the NGF only sees a non-market incentive reflecting transmission costs to be necessary if there is no market incentive on market participants. Our view is that transmission outage dispatch risk is an incentive that manifests itself in the market and therefore the non-market incentive of G-TNUoS is unnecessary to incentivise efficient outcomes.

The NGF believes that this package will not lead to more regional trading of contracts, because we do not consider transmission dispatch risk is presently limiting regional trading. Therefore we see little value in firmer access to the regional reference node.

There is some discussion in the Interim Report[12] of a willingness to pay as a "certainty premia" for firmer trading, which we do not recognise. If we, as the user of the access cannot value this, then there is no way a "certainty premia" may be quantified by Planner in a network monopoly to determine whether an investment is economic.

To be clear, NGF members are not willing to pay as we see no value in firmer trading. Members already manage forced outage risk, which is typically greater than transmission congestion risk. This means under this proposal members will incur costs to receiving something they do not want, for no benefit Thus leading the NGF to conclude any extra transmission would not be wanted by consumers either: by deduction it would be inefficient.

If the Commission were to implement this model, the NGF would expect an increase in the Market Price Cap (MPC) commensurate with TNUoS recovery. This will result in the energy market increasing volatility significantly because transmission costs in Australia are extremely high. If the market is working as designed, the times of when the pool clears at the MPC will result in additional transportation revenues churned through the gross pool. This would significantly increase market risks and revenue recovery issues for generators requiring a higher cost of capital due to a higher risk premium. As a result the NGF considers it would be inefficient for a significant share of fixed transmission costs be included in wholesale pool prices.

The question that arises is what share of transmission costs should be allocated to wholesale energy costs? Considering the NGF's earlier statements we recommend it be zero.

[11] Generator Transmission Network Use of System Charges

[12] AEMC, First Interim Report, 8.2 Key Features of generator reliability standards p.78

What about weaker sections of the grid?

The above being said, the imposition of the non-market incentive G-TNUoS to reflect transmission costs would solve any issues over poor administered incentives in the weaker sections of the grid where participants are constrained on. It is at this point that we should compare the treatment of dispatch risk in being constrained on and off.

The Rules presently require those to be constrained on to be subject to administered payments either through a direction by AEMO or though agreeing to Network Support Agreements with the TNSP. Under this package, with the imposition of a G-TNUoS charge you would not expect the existing non-market, administered "constrained on incentives" of the present regime to remain. This is because it would be akin to "paying twice" to incentivise generators to be located or dispatched in the weaker part of the grid.

This logic should be applied to the allocation of transmission cost via being constrained-off, which is a market incentive on participants. Surely one can see it is incoherent to apply G-TNUoS and a market incentive for constrained-off sections of the grid: just as it is incoherent to have two administered incentives reflecting transmission costs for constrained-on sections of the grid.

Maintaining the Reliability Standard

The Interim Report discusses the potential for generation to connect prior to further investments in the transmission system, which would be needed to retain the Standard. At first we considered this model would require closing access, which would be implementing a connection regime where an investor would have to wait for shared transmission reinforcements to be constructed before it was allowed to connect. Due to the package over allocating transmission costs by reflecting the cost of transmission in an administered incentive (G-TNUoS) we think this is only a hypothetical problem. By over allocating transmission costs it is likely generators would wait for the transmission investment to maintain the Standard prior to connecting. This is because both G-TNUoS and dispatch risk would encourage them not to connect in locations where there is inadequate transmission capacity.

Of course, there may be a mismatch between the G-TNUoS charge levied on participants and the investments that need be made to satisfy the Reliability Standard, which may encourage an investor to connect in the wrong location at the wrong time. For example a G-TNUoS may be reflective of average $/MWkm costs across the system at that voltage, yet the local investment average cost may be far greater. As mentioned in the first section of this response, the NGF considers the costs of a shared transmission system are impossible to capture and allocate for any discernable period.

The NGF considers there may be instances where administered incentives would not work properly, but generally allocating transmission costs through G-TNUoS and dispatch risk would have the other effect: generators would not connect when and where it is efficient to do so. Instead they would bypass the electricity transmission network by inefficiently investing in access competitively priced fuel.

Assessment of Package 4: Optional “firmer” access

The NGF considers the Optional Firm Access (OFA) model suffers from the same problems as the generator Reliability Standard. It over allocates regional transmission costs through the administered incentive of transmission charges (G-TNUoS or deep access charges) and a market incentive of regional dispatch risk. That some generators may opt-out of paying the administered incentive to face a sharper market incentive does not resolve this fundamental problem.

Before we go any further, the NGF must make a comment on the choice of deep access charges and G-TNUoS for this model. The NGF considers levying an administered incentive on “sunk” investments will lead to no immediate efficiency gain, yet place an immediate financial impost (a wealth transfer from incumbent investors) with unforeseen negative consequences for the competitive market. We recognise incumbents have to make closure decisions that should include the cost of transmission. This cost can be reflected in a financial impost they seek to avoid; a tradeable right they can sell; or it can be reflected in a deterioration of transmission access in the NEM’s open access arrangements (as the planner no longer builds assets to support the now out-of-the-money generator).

The NGF believes we already have sufficient market incentive reflective of regional transmission costs[13] (dispatch risk) so market participants require no additional administered incentive for an efficient outcome to be achieved. Of course, should the regional transmission costs not be allocated on market participants through firm trading being provided, then we see an administered incentive (tradeable access rights or G-TNUoS) as necessary.

There are clear transitional issues if a firm access model is adopted. This is because the financial impost market participants seek to avoid (G-TNUoS) or a tradeable right they can sell will present a one-off wealth transfer problem. Aside from the problem of managing a wealth transfer between participants, there lies the real risk of error in administering the incentive. This is because the cost of the shared transmission system is impossible to allocate on an ex-ante basis. These errors will deepen inequities in the wealth transfer and may give rise to inefficiencies themselves.

Considering the Commission’s comments in Appendix D of the First Interim Report, all further comments on the OFA model are premised on the administered incentive placed on generators being G-TNUoS and not deep access charges.

NGF’s view on clause 5.4A

The NGF believes Rule clause 5.4A does not work because if a market participant is willing to pay for something on the shared network but consumers are not then this can only be for private benefit at the expense of market participants. It is a zero-sum exercise, where one market participant may be “gain” access at another’s expense. A good example is the Yallourn 1 switching, which in effect stole access from Hazelwood Terminal Station 220/500 KV transformer connected market participants, when consumers were indifferent to whichever market participant provided a reliable supply.

The only argument for clause 5.4A would be that it is a safety net for a generator where planners have not recognised the need for consumers to have a higher level of access from that generator participant (this would evidenced by the participant being able to sell financial contracts over and above its “access” to the RRN over an investment timeframe). The market participant could then invest to meet consumers’ needs because the planner has failed to do so. We think this is a poor argument, because the planner should have correct incentives so they adequately invest in a reliable transmission system reflective of the consumers’ willingness to pay.

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[13] We also have the constrained on administered incentive of AEMO directions and TNSP network Support Agreements, but these are not important to the point being made

Gaming the compensation by operating in a discretionary price auction

The OFA model requires, under constrained circumstances, the non-firm generator to compete in a discretionary auction, rather than uniform. There arises transient market power for the unfirm generators as they have the opportunity to control the price they are paid and the compensation payable to the firm generator they are constraining. This was discussed in the report, but not in any great detail.

The following table uses the example in Appendix A of the Interim Report to show how this can occur. In the example, G4 is the “unfirm” generator that must pay compensation to the firm generator constrained off by G4’s dispatch. The generator constrained off in this instance is G2 with a price of $40. Under the top table, which is the same as the Appendix A example, it is expected G4 will price at $30 and this will determine the local price it will receive and the compensation payable to G2. In this table, G4 receives no profit and G2 is held firm, i.e. it is a profitable as if it were dispatched.

Under the bottom table, G4 changes its offer price to $39, which still ensures that it is dispatched ahead of G2, but changes the local price to $39 and reduces the compensation payable to G2. In this instance G2 is obviously not held firm by the compensation as G4 has exercise transient market power, by offering capacity at a price above its marginal cost. This has come at the expense of the “firm” generator.

Under this model there is every incentive for the non-firm generator to “price up” to the highest price behind a constraint as it will be “paid as bid” in a local discretionary auction. This will act to increase the local price and reduce the firm generator's profits. The firm generator has no way of managing this apart from decreasing their price below cost to be dispatched before the unfirm generator.

AEMC formulate the constraint as :				1000>=(G1x1)+(G2x1)+(G4x1)					
This assumes G3 is at the RRN									
As per example in Appendix A									
		Spot Book							
Generator	Capacity (MW)	SRMC ($/MWh)	Offer price ($/MWh)	Access Rights (MW)	Dispatch volume (MW)	Resource cost ($)	Revenue from dispatch ($)	Compensation received ($)	Profit ($)
G1	500	$20	$20	500	500	$10,000	$25,000	$0	$15,000
G2	500	$40	$40	500	0	$0	$0	$10,000	$10,000
G3	2000	$50	$50		1600	$80,000	$80,000		$0
G4	1500	$30	$30		500	$15,000	$25,000	-$10,000	$0
Total	4500			1000	2600	$105,000			$25,000
Adjusted with different offer prices									
		Spot Book							
Generator	Capacity (MW)	SRMC ($/MWh)	Offer price ($/MWh)	Access Rights (MW)	Dispatch volume (MW)	Resource cost ($)	Revenue from dispatch ($)	Compensation received ($)	Profit ($)
G1	500	$20	$20	500	500	$10,000	$25,000	$0	$15,000
G2	500	$40	$40	500	0	$0	$0	$5,500	$5,500
G3	2000	$50	$50		1600	$80,000	$80,000		$0
G4	1500	$30	$39		500	$15,000	$25,000	-$5,500	$4,500
Total	4500			1000	2600	$105,000			$25,000

On a more general note, the use of auction design is extremely important for the overall efficiency of the market. Markets may use discriminatory pricing or uniform pricing: in discriminatory price auctions, where bidders get paid what they bid[14] (pay-as-bid), the use of bids for signalling purposes will carry a much higher cost, because the bid may well be accepted.

Discriminatory auctions are sometimes considered more efficient when market power, especially collusive behaviour, is an issue because discriminatory auctions remove the guarantee that all will get the same, and increases the cost of signalling behaviour. The problem with discriminatory auction pricing is that participants will "price up" to what they believe to be the marginal price and in some instances may not have an offer price accepted even if they are lower cost than those others dispatched. By contrast a uniform auction, those with lower cost will submit prices below the marginal price, knowing they will be paid at the highest offer.

The very rationale for using discriminatory auctions, which is that is more difficult to behave in a collusive manner is not important in the case of determining compensation behind a constraint This is because it is a zero-sum game between Market Participants behind a constraint, to which consumers cannot be harmed (at least in the short term) by the collusive behaviour: it is the very opposite behaviour that will be incentivised behind a constraint in order to game the compensation payable between participants.

On a general note the NGF considers the Commission should consider the efficiency of using discriminatory auctions behind constraints and uniform price auctions otherwise. In this case, rather than help overcome uncompetitive behaviour discriminatory price auction behind a constraint appears to give rise to the opportunity to exercise inefficient behaviour by unfirm generators.

Compatibility with the energy-only NEM

As with package 3, this option would require an increase in the MPC to recover TNUoS, but there arises a problem in that unfirm generators will also benefit from higher MPC, yet not pay G-TNUoS. This would be an incentive for participants to avoid the administered incentive of G-TNUoS and run the risk of the market incentive of dispatch risk and the OFA compensation payments to firm generators.

Difficulties exercising the option and free-riding

The NGF expects the OFA model to be "no regrets", that is once a generator has committed to paying an administered incentive, it must remain doing so. Our rationale for this is that otherwise it would be subject to free-riding, because a firm generator could accept to pay G-TNUoS in the expectation that this may incentivise the planner to respond by committing to some investments (to maintain the Reliability Standard), which would be "sunk" and therefore could be "stranded" if the firm generators opt out of the administered incentive of G-TNUoS. The stranded assets would have to be paid for by consumers.

We also consider there to be the opportunity for free-riding on network investments, even if the firm option is "no-regrets". This is because the firm access may trigger a new "lump" of transmission to be built. This may provide excess system capability that will benefit unfirm generators that free ride on the G-TNUoS payments of the firm generator.

A problem members have discussed, but have yet to come to a firm conclusion, is that choice in the OFA model may represent regulatory risk and prisoners' dilemma: we may all be better off not

[14] It really should be offer price, although Bid and Offer terms are used interchangeably by market participants

paying, but all end up electing to pay for firm access, because the risk of not doing so (especially over an extended period) may be too high. That being said, with the NEM's low Market Price Cap and external policy intrusions, (such as the RET, FiTs, DSM initiatives), members are of the general view that there would be difficulties recovering the G-TNUoS costs and generators' may be forced into being unfirm.

<u>As with the other packages, problems arise in weaker sections of the grid</u>

The Interim Report rarely considers incentives within constrained-on, weaker sections of the grid and the OFA package is a casing point. In some sections of the Grid, such as north Queensland, and Western South Australia generators should be able to opt to be paid TNUoS and be firm. Under such an instance, if another firm generator connects in the area, the payments to the generator are superfluous and the generator should probably pay TNUoS. Will the original payments be funded by the entrant in addition to the additional transmission costs that reflect the need for new transmission to export power from the area (rather than import)? Or will the incumbent see the G-TNUoS turn positive, in that it should then start paying for the use of grid to reflect the additional transmission required to support the additional generators.

Assessment of Package 5: Locational marginal pricing with capacity auctions

Throughout this response the NGF's assessment of packages 2, 3 and 4 have been wholly negative. This is because we believe they do not facilitate the competitive market model properly or they inappropriately administer incentives on Market Participants to overcome the coordination problem between planners and market participants. By contrast, a Locational Marginal Pricing model with auctioned firm transmission rights "LMP-FTR" does appear to recognise this trade off and therefore is a coherent market design from our point of view.

This is because the LMP-FTR offers firm trading to market participants, with the quid pro quo being generators pay auction fees for these FTRs. This means generators are not exposed to transmission outage risks but are still incentivised to minimise transmission costs by buying FTRs. This means there is only a single incentive to minimise transmission costs, thereby avoiding the "paying twice" problem of packages 3 & 4.

What is also good about this model is that it extends the competitive market model to the allocation of transmission capacity – that is the FTRs are auctioned to those willing to pay. This should improve the coordination problem between planners and market participants because the planner now has a market signal as an incentive to invest in transmission capacity.

This incentive on the planner includes a decision as to whether it is efficient to incur the cost of investing in the transmission or incurring the cost of paying compensation to market participants, with this called "uplift" in the Interim report. Technically the consumers' overall exposure is the difference between the auction proceeds from market participants when compared to the expense of investment costs in incremental transmission and/or compensation payable to market participants.

The NGF has some reservations over the whether it is fit-for-purpose for the NEM and whether there is any case to change. We have previous stated that our members see no need for firmer trading arrangements, therefore we can see no case in firming the arrangements with this more complex model. In addition, overcoming the coordination problem is the theoretical benefit of this model, although we see no evidence of the NEM's planners systematically falling short in providing an economic level of transmission to market participants.

We also have some concerns over the implementation of this model. We should expect the model to provide a sufficient level of firm trading capacity, which consumers underwrite through uplift payments. However this is not properly expressed in the Interim Report.

For example there is no mention as to the efficiency of consumers taking transmission outage risk through uplift charges, to allow fully-firm trading. The Report does not mention whether this will encourage more financial trading and improved efficiency of the competitive market model. Should generators continue to restrict their participation in the traded markets by accounting for forced outage risk, (which is our contention) this model may not lead to additional trading.

Central to this model is the role of the planner in how it manages the transmission incentive received from Market Participants when auctioning FTRs. The NGF is concerned by the auction design and TNSPs' role because there is the risk of too few rights being auctioned. This would result in a high proportion of residual dispatch exposed to the risk of receiving a local price. For example TNSPs may auction FTRs against overly conservative ratings or post-outage conditions, leaving a significant residual of dispatch being exposed to the risk of a local price, without accompanying FTRs.

Auctioning too few rights, would be akin to consumers refusing to take on transmission outage risk and placing it back on market participants. This would restrict contract trade, as although there may be more capacity available on the day, (so there would not be a local price after all), there may not be and this will be exposed to basis and volume risk. In effect the competitive market model, which is the derivative financial market, would be "capped" at the level of FTRs that were auctioned in advance. This is because the risk of receiving the local price and being constrained off would be too great to contract at a higher level than FTRs. The NGF believes this would be far more inefficient than the current NEM approach to rationing capacity in the Dispatch Interval and allowing the constrained capacity to be priced at the RRP.

We would therefore recommend the volume of FTRs auctioned being generous to encourage the efficient level of financial trading to the trading hub. This would mean that the FTRs are not "self-funding" and the planner's job is not to reduce uplift, but to optimise it for the most efficient outcome.

The difference is however, in granting a generous allowance of FTRs to market participants is that there is incentive for these participants to maximise uplift payments to the harm of consumers (who take the risk of uplift payments). This is because the uplift compensation payable is directly influenced by the LMP, set by the local generator in a discretionary auction.

For constrained-off sections of the grid the generator can decrease the LMP on constrained energy volumes, offering very low prices in a form of disorderly bidding. If the FTRs are well in excess of constrained energy volumes (which they would be if the FTRs have been over allocated against transmission capability) the difference in the LMP and SMP will be refunded against the volume of FTRs, which is greater than energy volume. This will result in profits on the net of energy and FTR cash-flows, be funded via uplift.

For constrained-on sections of the grid, the generator's LMP different to the SMP retailers pay (which is calculated using an unconstrained offer stack). If the constrained-on generator has a very high offer price, payments equivalent to the difference between the generator's LMP and the SMP will need to be funded through uplift payments. An option to solve this, as mentioned in the report is to issue "negative rights" for constrained on generators which aim to prohibit this behaviour, (or minimise the amount of uplift payable) but will inhibit these generators from participating in the market. The application of negative rights would be unfair of the constrained-on generator had avoidable costs in excess of the SMP (as it would not recover its costs).

The rub therein with the LMP-FTR model is that for an efficient market to occur a reasonable level of FTRs need to be provided to market participants, however any error in over allocating them will result in opportunities for market participants to "game" uplift payments at consumers' expense. This means that the LMP-FTR model needs to be fully-funding. If the LMP-FTR model is fully funding the NGF believes it would inhibit the regional competitive market model.

Given the above, it is sufficient to say that the NGF has a myriad of concerns over the design of any auction for the allocation of FTRs. Reserve prices, available volumes, reserved capacities for entrants and questions over full firmness all represent regulatory risk to our members, who believe such auctions would be subject to the "regulatory bargain" of the existing NEM being diluted.

On a more general note, the LMP-FTR model outlined by in the Interim Report has different only generator market participants receiving the local marginal price. From our reading load market participants will be charged a single price. From our limited understanding of how LMP-FTR markets work, this will not be efficient. We believe this because, by settling sellers on a LMP and buyers on a single price creates a barrier upon which these Market Participants can trade. The FTR is supposed to overcome this, although clearly a FTR from Barron Gorge in Queensland to a node near Sydney is likely to be heavily constrained, such that it may be near zero. There is also the problem of all customers not being exposed to the local supply demand conditions, and will not encourage efficient use of electrical services in the longer term. The key problem is that in doing this there is no homogeneity between buyers and sellers. Therefore load should be exposed to a LMP.

By exposing load to LMP, where these prices are either very similar or there are plenty of FTRs, trading "hubs" would develop where non-regulated derivative markets can develop. By contrast a national "hub" is false and different to load settled on RRP.

Possible areas for incremental improvement to the existing NEM incentive structure

The NEM's regional market model coupled with dispatch risk could be characterised as regional settlement but nodal dispatch. That is the price paid is for half hourly "trading interval" volume delivered to the RRN, but the <u>dispatch</u> of participants' plants is on the basis of dispatch at the local node in the five minute "dispatch interval". For example, transmission capacity is rationed on the basis of nodal coefficients and plants' prices are adjusted by a nodal marginal loss factor.

There arises an obvious disjunct between the regional competitive market model and nodal dispatch manifesting itself in participant behaviour when dispatch instructions allocate transmission costs by the dispatch interval but profits are determined from contracts settled regionally on the trading interval. This disjunct should be recognised as AEMO trying to extract the greatest productive efficiency in the dispatch of plant based on bids and offers submitted by participants for that dispatch interval.

The NGF does not want to criticise AEMO for trying to dispatch plant in the most efficient manner. AEMO's goal should be the delivery of electricity at the lowest cost given the prevailing Rules, as the very premise of the competitive market model is market participants' competitive advantage will be rewarded with dispatch (share) in the market. AEMO does this very well.

However the NGF is disappointed when AEMO advocates a reform agenda[15] premised solely on the basis of least cost dispatch without considering efficient behaviour of market participants in the regional competitive market model. By looking only at spot market costs, suggesting smaller regions and calculating dispatch re-runs purported to "save" $300M. This number is completely misleading, inferring that customers ended up paying this additional amount. It does not provide any indication of the likely productive efficiency cost during these trading intervals, estimated by Frontier Economics to be in order of $200,000. More importantly, it fails to take explain the role of derivative contracts and the net financial position of generators post settlement.

<u>Constraint equations</u>

Constraint equations use a general formulation, such as LHS<=RHS, where the RHS consists of inputs to the dispatch engine (limits, demand, flow) and the LHS consists of outputs of the dispatch engine (generator and interconnector targets). The dispatch engine adjusts the terms on the LHS to ensure the constraint equation is satisfied. These LHS terms all tend to have a different effect on the equation, with this reflected by the "constraint coefficient" which is a scaled ratio to which a change in the LHS term compares against the RHS. The dispatch engine is a linear programme, which means that it will resolve dispatch in a linear fashion, so the LHS term with the highest coefficient (all other things being equal) will be fully dispatched before the next. The constraint coefficients typically go to four decimal places, for instance Directlink term N-Q-MNSP-1 had a coefficient of 0.1211 for the equation Q>>NIL_855_871[16] during 2009. This means for a change in the RHS of 1MW the N-Q-MNSP-1 would have to change 8.26MW to effectively manage the constraint. Alternatively, Callide B and C have co-efficient of 1 and Stanwell and Gladstone generators have coefficients of close to -1, thus output at these units would only need to move 1 MW in response to a change of 1 MW on the RHS of the equation..

The above discussion on constraints all sounds reasonable if you are trying to extract the maximum productive efficiency without running a regional competitive market model. However these constraint coefficients are rationing transmission capacity to Market Participants who are managing their exposure to contracts in the regional financial markets. A difference of 0.0001 in the constraint coefficient would be enough for the linear programme to determine that one

[15] AEMO, Issues Paper response, section 6.41 "Inefficient use of plant" p.23; 7.5.5 "Smaller Regions" p.30; Appendix p.11 5. "Re-run" of 7/12/2009 saving $300M

[16] Out = Nil, avoid overload on Calvale to Wurdong (871) line on trip of Calvale to Stanwell (855) line, Feedback

generator is constrained down below contracts (at a cost of (MW x (RRP – Strike)) / 2 for the Trading Interval and another not. It may be sensible for AEMO to approximate these constraint equations somewhat to improve overall regional market outcomes rather than productive efficiency in the spot market.

Interestingly AEMO decides whether a term is on the LHS or taken as an input on the RHS by using an arbitrary 0.07 rule. This is clearly inconsistent with the above mentioned accuracy of constraint coefficients (to 4 decimal places, or 0.0001). This means AEMO rations transmission capacity to 700 times the accuracy of whether or not it decides a Participant should be included in the rationing in the first place[17].

Take for example N-Q-MNSP-1, which had a coefficient of 0.1211 for the equation Q>>NIL_855_871 during 2009, but on the 12th December 2009 was removed from the LHS and then used as an input on the RHS. AEMO advised Participants through the MMS[18] data tables this was due to "*update to current conditions*". This either means they just recalculated it using different assumptions or AEMO received new limit advice from Powerlink, the local TNSP. If this were a Participant it would have direct implications for trading outcomes. Being an interconnector it affects trading outcomes because they are important to setting price.

This issue is particularly important to the treatment of a second interconnector, where the first interconnector is included on the LHS and the latter is not. To continue our example, this is the case for the transmission constraint Q>>NIL_855_871, where NSW1-QLD1 is on the LHS but N-Q-MNSP-1 is no longer. Considering unconstrained circumstances the two interconnector terms are correlated, as should the dispatch of the NSW1-QLD1 change usually the dispatch of N-Q-MNSP1 changes too. This is the logical outcome as there is no particular difference in the costs associated in doing so (because they are both connected to NSW and QLD) apart from the different losses incurred on the circuits.

Often the dispatch engine is constraining the NSW1-QLD1 due to it being a LHS term on Q>>NIL_855_871, but not N-Q-MNSP1. This results in the NSW1-QLD1 export limit and N-Q-MNSP1 export limits having no relationship, yet the flows being correlated.

The limits of the N-Q-MNSP-1 are often set by the ramping limits when it is unconstrained (i.e. it has no other equations setting the limits), such that it floats between the regions. By having one interconnector on the LHS of the equation, but not the other, suggests the N-Q-MNSP1 can change by over 80MW and still not affect the equation, but the NSW1-QLD1 can't change by 0.0001MW without binding the constraint equation.

There are 52 LHS terms on the equation Q>>NIL_855_871, with only four unconstrained connection points in Queensland,, N-Q-MNSP-1, Wivenhoe, Swanbank E and Swanbank A. The generating units are usually constrained, or pricing at a higher level, so the upon the equation binding N-Q-MNSP1 is free to set the RRP in QLD. A more realistic price would be reflect a change in the dispatch of LHS terms in order to simultaneously resolve both the marginal MW calculation (price) and the Q>>NIL_855_871 equation.

To simplify this example, dispatch is calculated by changing 93% of dispatchable terms in QLD, yet the RRP is not. This means 93% of the regional market are being constrained-on at either a price they are not willing to sell at or constrained off at a price they are willing to receive. This is because the price does not include the marginal value of the constraint and is therefore not reflective of the transmission costs incurred during the dispatch period.

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[17] Originally, this arbitrary value was 0.2. It was changed during upon implementation of Option 4 fully-co-optimised constraint equations with no prior consultation with Market Participants.

[18] Market Management Systems

Although we have argued for some regional approximations earlier in this response in order to encourage regional trading at the expense of productive efficiencies, this does not mean we support the application of an arbitrary rule on interconnectors that excludes nearly all the region's market participants (and those from the adjoining region) from participating in the spot market because only one of two interconnectors is included on the LHS. There may be a case to calculate the constraint coefficient for the two interconnectors in aggregate and then to include both on the LHS, or not apply the 0.07 rule to interconnectors. The case for changing the 0.07 rule for being on the LHS for generator terms to something higher, (maybe 0.1 or 0.2), is different, because these coefficients directly affect participants trading risks. By contrast interconnector terms represent Market Participants in aggregate.

Further, AEMO has recently consulted on its vision for automating constraint equations[19]. Under AEMO's proposals there would be the likelihood of new versions of constraint equations (that is new terms on the LHS or RHS and different coefficients) introduced whenever new limit advice, outages etc are advised. The NGF responded to this consultation and said there may be some benefits (not in the least because outage constraints and normal constraints would not need to be different), but warned AEMO that it should manage the introduction of constraint equations to ensure efficient trading outcomes in the regional competitive market model.

Another example of AEMO and TNSPs focusing on productive efficiency in dispatch is the use of live-line ratings in setting the RHS of constraint equations. Again, the Q>>NIL_855_871 equation is a good example as live line ratings are used for this equation. The reason for doing this to try to extract a greater line flow from the circuits due to changing ambient conditions such as wind speed. The problem with doing this is dispatch targets and marginal values change every five minutes as the transmission capacity is constantly "re-rationed" to Participants. As a result Market Participants are forced into making sub Trading Interval dispatch decisions to manage their position and respond to their allocation of transmission capacity.

AEMO has recently published a pricing event report[20] where it discussed an NGF member's rebidding activity in response 5 minute dispatch of the equation Q>>NIL_855_871. AEMO stated:

> *"Gladstone power station rebid 440 MW of generation into bands priced at over $1300 per MWh for DIs 0935 to 1000 hrs. With some units being ramp rate constrained, these expensive offers set the price for one DI. Predispatch did not forecast the high prices, as the new generation offers were received at approximately 0925 hrs."*

This suggests AEMO expects participants not to respond to the allocation of transmission within the 5-minute Dispatch Interval. Clearly if AEMO does not want participants to respond to 5 minute allocation of transmission capacity then it should not incentivise participants to do so. To incentivise participants with real time allocation of transmission capability and then suggest it is inefficient behaviour in a pricing report suggests AEMO does not understand its actions on the broader market.

<u>*Operational incentives on TNSPs*</u>

Similar to the discussion on live line ratings we believe the Market Impact Parameter Scheme (MIPS) promotes poor planning of outages by TNSP's and does not encourage efficient trading behaviour by Market Participants, in fact it incentivises riskier trading behaviour by some participants. The MIPS is supposed to overcome the coordination problem arising from TNSPs arranging transmission outages at periods when transmission is extremely valuable through

[19] AEMO, Constraint Automation - Closing the Loop - Discussion Paper, 8th July 2011
[20] Price Event Report, Friday, 13 January 2012, can be found http://www.aemo.com.au/reports/pricing_jan.html

incentivising them to cancel outages if spot market prices increase. The problem with the MIPS is it does not remove dispatch risk on Market Participants from the outage.

For example, should a significant transmission outage be planned for a week, the MIPS encourages the local TNSP to rearrange the outage in real time due to an expectation of actual increases in price of $10/MWh, as otherwise the outage would contribute to their annual target. This discourages a generator or retailer that may be affected by the reduced transmission capacity from entering into financial contracts, such as buying back previous sold swaps to reduce the exposure to dispatch risk against the RRN, caused by the outage. This is because market participants the trades will be effective as the TNSP may cancel or move the outage at short or nil notice, to a period where the trades were not in effect.

This model would work properly if the TNSP sold the swaps to the constrained Participants and therefore carried the financial risk of deviation against the RRP. The TNSP would therefore be exposed to the market costs of the outage and the risk would be taken from the participants. The TNSP could then decide whether to reschedule the outage if these costs were too excessive.

An alternative proposal would be to require TNSPs to submit prices and timings for the reinstatement of circuits with reference to the impact of dispatch prices. For instance when the TNSPs submit outages in the Network Outage Schedule they could associate the outage with a resource “value” upon which they will rearrange the outage. Should the dispatch price be influenced by the constraint equation (i.e. the dispatch price, not just the marginal value) and exceed the price submitted by the TNSP, then the circuit would be reinstated. These prices could be submitted publically through the MMS data exchange to indicate at what “cost” the outage will be cancelled.

We have to realise when a market incentive is placed on the planner it becomes a “player” in the market whilst remaining extraneous to it. This will distort the incentives to the planner, in particular to effectively plan and communicate outages to the market and may distort market outcomes, leading to inefficient behaviour by market participants. A transfer of wealth may occur from participants (or consumers) to the external player either through poor design of the incentive or opportunities to game the scheme. For example TNSPs provide the limit advice to AEMO when they formulate the constraint equations. Being a “player” there is clearly an incentive to revise limits to reduce the market impact of constraints, although the NGF has no evidence that they do so.

A viable alternative would be to modify the MIPS whereby the penalty associated with markets outcomes is reduced based on the length of notice provided by the TNSP. This would allow market participants to prudently manage risks associated with network outages and penalise risky behaviour thus reducing overall physical and financial settlement risk in the NEM.

Negative settlement residues

An important feature of regional settlement and dispatch risk is the management of Negative Settlement Residues. These “NSRs” occur when an intraregional constraint equation encourages regional generators to disorderly rebid to a price lower than the adjoining region, thus forcing interconnector flows counter-price. AEMO is required to implement constraint equations to limit this flow upon reaching or possibly reaching $100,000 of NSRs. This often requires AEMO to consider what the price would be if the NSR equation was not in place - i.e. the counterfactual price. This can often lead to pricing outcomes where a NSR constraint results in the exporting region having a lower price than the importing region (the opposite of what is intended!). This can be as inefficient as the counter price flow in the first place and gives the impression that AEMO is “punishing” the regional generators for accruing the NSRs. By deduction the price should at least be floored at adjoining region’s price to stop this inefficiency occurring. There should also be open debate over the amount of NSRs that an efficient regionally settled market should incur (this is discussed further in the consideration of package 2).

Priority of non-scheduled plant

The dispatch arrangements presently prioritise non-scheduled plant, even if the plant affects the dispatch of scheduled plant. This has been highlighted by AGL in discussion of their operation of Oakey, where a constraint equation reduced output from Oakey after the connection of the Daandine gas turbines. Daandine is registered as non-scheduled, market, which means they receive the spot price, but don't have to respond to dispatch instructions and are not exposed to dispatch risk.

It is small wonder that there results dispatch inefficiencies because the investor in the non-scheduled, market plant did not have to consider transmission implications, even if the connection of the plant has implications for the transmission system. These plants are not necessarily small: for instance Daandine is 30MW and Yarwun, connected in the Gladstone area is typically operated at 155MW and provides steam to the industrial facilities.

The solution here is to either include the plant in the LHS of the constraint equation, (that is make then Scheduled), or to prohibit connection if the investor wishes to remain non-scheduled. The NGF has previous stated a preference for retaining the current arrangements which would therefore be making them Scheduled and exposed to dispatch risk with all other generators. Should that prevent them connecting, then so be it, as an efficient outcome will have occurred.

Inefficient allocation of transmission risk: high impact outages

At present the Rules allow for TNSPs to mandate tripping schemes with no compensation to generators for non-credible contingencies they consider to have a high-impact on system security. This is placing the risk directly onto one Participant without any compensation, should the tripping scheme be utilised. It is usually one participant because the nature of the contingency requires an almost instantaneous trip a unit to maintain the reliability of the system. For example only tripping the Callide power stations can manage the non credible contingency of the loss of both Calvale to Tarong circuits.

Inefficient allocation of transmission risk: risk of separation

AEMO dispatches frequency response services and energy simultaneously through a process known as co-optimisation. In theory this should ensure the cheapest dispatch solution is achieved between the services, which are sometimes competing for resources. For example, the interconnector limits may be adjusted, affecting the price in each region in order to manage the risk of separation after a credible contingency (or reclassification of a non-credible contingency as credible). Market Participants must respond to this reduction in transmission capability by managing their offered volumes into the FCAS and energy markets against their liabilities in these markets be they FCAS expenses or difference payments on energy swaps.

The drafting of 3.15.6A of the Rules ensures when there is a risk of separation or an islanding event the costs of raise services are recovered from the importing region(s) which may be separated upon the loss of the second transmission element (credible contingency).

The principle underpinning the recovery of FCAS raise services is that the credible contingency for which raise services are procured is typically the loss of the largest generating unit on the system. Thus all the costs of FCAS raise services are recovered from the generator participants. This principle does not hold for those instances where the raise services are procured to cover the credible contingency of loss of the second transmission element, which is the case for a risk of separation event. This logic can be extended to the recovery of costs upon islanding, where the island requirement is based on the largest generator after the loss of a transmission element. Therefore the underlying cause is the loss of the transmission circuit and the symptom is ensuring there are adequate raise services upon the loss of the largest generator.

This allocation of costs is relevant to the Review because it is an allocation of transmission costs on Market Participants that increases dispatch risk, especially those generators unable to participate in the FCAS market, due to being the other side of the outage constraint. For example the high impact outage of circuits between Loy Yang and Hazelwood result in generation connected to the Loy Yang node being liable for a service they cannot participate in.

A solution would be to change the 3.15.6 (f), so the FCAS raise costs associated with risk of separation and island events are both recovered from Market Customers in the same manner as contingency lower services for high frequency events.

Does the NEM deal adequately with weaker sections of grid?

The NGF considers there are inefficiencies arising from applying the competitive market model on the regional basis in the NEM. As mentioned some of these inefficiencies may be overcome by incentives on planners. An example of which is the lack of market incentives in weaker sections of the grid, where generation efficiently displaces transmission. We expect these inefficiencies are more than offset by encouraging regional trading.

With the NEMs regional pricing, there are no constrained units setting prices, providing little incentive to locate in weaker sections of the regional grid. It is not evident that TNSPs are effective in implementing non-network options as few investments have been made to displace transmission investments with generation. The Commission may wish to consider whether planners are administering these incentives adequately.

The NGF notes a lack of incentive on a TNSP to build out or manage weaker sections of the grid through the use of network support contracts in the presence of negative settlement residues accruing from intra-regional congestion. The “local” TNSP bears none of the costs which are transferred to consumers in the importing region or generators in the exporting region. Using the previous Q>>NIL_855_871 constraint example, a network support agreement with the operator of Callide, Gladstone or Stanwell power stations would have a significant impact on the binding of this constraint and minimise (remove) periods of when this constraint binds. Negative residues could be paid by the TNSP in the exporting region. This would create the right incentive on the TNSP to examine network support agreements with generators or to move to examine and more closely quantify the capability of their network.

Transmission Frameworks Review – 1st Interim Report

A REPORT PREPARED FOR THE NATIONAL GENERATORS FORUM

January 2012

Transmission Frameworks Review – 1st Interim Report

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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.

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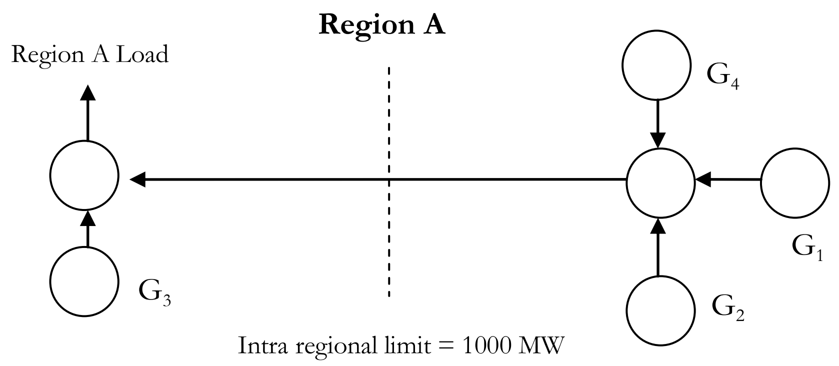
1 1st Interim Report, p.73.

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)

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 <u>not</u> 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

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 less 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

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.

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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.

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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 400 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 and G3 would dispatched to 1800 MW. Dispatch resource costs would be minimised at $114,000 (being 400 x 20 + 400 x 40 + 1800 x 50).

However, under Package 4, G4 would get 600 MW 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 allow G4 to earn:

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

600 x (50-40) = $6,000

= $2,000 profit

Dispatch resource costs would rise to $116,000 (being 400 x 20 + 400 x 40 + 200 x 60 + 1600 x 50).

This simple change to the example illustrates the incentives for disorderly bidding 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.

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 and G4 would be settled for their dispatched output on their LMP, which would be $30/MWh if they bid in line with their SRMCs.

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

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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

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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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