3 August 2009

Dr John Tamblyn
Chairman, AEMC
By email: submissions@aemc.gov.au

Dear Dr Tamblyn

AEMC Market Framework Review

We write in relation to the Australian Energy Market Commission's (AEMC) Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report dated 30 June 2008. Please find enclosed our collective submission in response to the proposals contained in the aforementioned report.

This submission builds upon our responses to the 1st Interim Report and reflects ongoing discussions between our respective companies and the AEMC directly and in conjunction with the National Generators Forum. Our submission endeavours to make constructive enhancements to the body of analysis conducted by the AEMC and highlight possible improvements.

In particular we have raised a number of concerns with the AEMC's analysis of the efficient utilisation and provision of the network and the G-TUOS mechanism. While we believe the AEMC has identified the symptoms of this problem in the market we believe the AEMC has mischaracterised the actual problem and its drivers. Therefore, we suggest the AEMC has developed an incomplete set of recommendations.

Our position on this matter is informed by our significant expertise and experiences as National Electricity Market participants, our detailed discussions with other generator participants, transmission bodies, regulatory agencies and independent economic analysis. We believe our conclusions and views on the AEMC's G-TUOS proposal are widely shared by the market.

It is our view that at the very least the AEMC needs to engage in detailed further discussions with market participants capable of resolving the issues at hand. For too long the issue of efficient utilisation and provision of the network has been stymied by misinformation and an absence of constructive engagement between market participants and the AEMC. This has made the issues confronting the AEMC all the more difficult to resolve. In this regard we offer our continued assistance.

We look forward to your positive consideration of the suggested enhancements and welcome any further discussions or queries you may have.

Please direct your response or any questions regarding this submission to the undersigned on (03) 9612 2236

Yours faithfully,

Jamie Lowe
Manager, Regulation
Loy Yang Marketing Management Company Pty Ltd
Level 27, 459 Collins Street, Melbourne, Victoria 3000

On behalf of:

Alex Cruickshank General Manager, Energy Regulation AGL Energy Limited	**David Hoch** Regulatory Policy Manager International Power
Mark Frewin Manager, Wholesale Market Regulation TRUenergy Pty. Ltd.	**David Bowker** Manager, Regulatory Affairs Hydro Tasmania

1 Submission Information

Submission in response to:

Australian Energy Market Commission
Review of Energy Market Frameworks in light of Climate Change Policies
2nd Interim Report, 30 June 2000

Submission lodged 3 August 2009 via submissions@aemc.com.au

2 Company Information

AGL Energy Limited, International Power Australia, Loy Yang Marketing Management Company Limited and TRUenergy Propriety Limited represent the largest collection of private investment in electricity generation in Australia. Hydro Tasmania is a major Tasmanian Government owned renewable generator, with significant consulting expertise in the area of power system planning and development.

AGL Energy Limited is Australia's largest integrated energy company with a full suite of renewable generation, providing natural gas and electricity to more than six million Australians and with major investments in the supply of gas and electricity, as well as a substantial base of customers across Australia. Listed on the Australian Securities Exchange, AGL has a market capitalisation of about A$5.2 billion. The company has been operating in Australia for 170 years and was one of its first listed companies.

Hydro Tasmania is Australia's leading renewable energy business. The value of Hydro Tasmania's total power system is realised through trading electricity and energy products as a participant in the National Electricity Market with total generating capacity of 2615 MW and assets worth approximately $4.8 billion. Hydro Tasmania is a Government Business Enterprise, owned by the State of Tasmania.

International Power Australia is Australia's largest private producer of electricity, producing 24 TWh in 2008 or about 11 per cent of all electricity in the NEM. It has a portfolio of around 3,200MW (equity owned) of diverse fuel and technology generating capacity across Victoria, South Australia and Western Australia including 1,177MW of wind farms. This portfolio is complemented by the IPRA-owned Simply Energy, an electricity and gas retail business which currently represents around 7-10 per cent of the Victorian and South Australian retail markets.

Loy Yang Marketing Management Company (LYMMCO) trades the largest privately-owned generator in the NEM. In total, LYMMCO trades in excess of 2,200 MW and represents around one third of Victoria's electricity needs and more than 8% of the total generation for the south-east of Australia.

TRUenergy Propriety Limited supplies gas and electricity to homes in Victoria, South Australia, New South Wales and Queensland and generates electricity in Victoria, South Australia and New South Wales. TRUenergy manages a diverse energy portfolio covering $5 billion of assets that includes electricity generation, energy contracts management and trading, gas storage and retail energy services employing over 1000 people.

The outcomes of the AEMC Review of Energy Market Frameworks in light of Climate Change Policies are directly relevant to sustainability of ongoing investments in this market, and the regulatory and sovereign risks that face investors. These businesses have prepared this joint submission to the AEMC as they share a common interest and common concerns in the sustainability of the NEM.

3 Table of Contents

4 Executive Summary

Efficient utilisation and provision of the network

The AEMC indicates that its G-TUOS proposal is driven by the need to create an efficient locational price signal for new and retiring generation investment in the NEM. Each NEM region would be divided in to G-TUOS zones, which would be charged a positive or negative fixed transmission charge, depending on the level of projected transmission congestion. As outlined below there are significant objections to the G-TUOS proposal; both from a theoretical and practical perspective.

The AEMC's G-TUOS proposal does not provides appropriate investor certainty as it:

- undermines financial viability of projects by introducing a new variable cost that cannot be hedged;
- is not credible that an arbitrary and variable charge would facilitate long-term generation investment decisions; and
- the G-TUOS charge is simply a wealth transfer between generators and does nothing to address the underlying problem of lack of transmission.

The AEMC's G-TUOS proposal does not support decentralised decision-making as:

- relative (not absolute) charges do not provide least cost delivered energy – charges need to reflect absolute costs;
- it provides no mechanism to support decentralised investment in generation and transmission and investment disincentives remain; and
- it promotes a centrally planned and regulated approach to all transmission decisions and undermines private investment in the NEM.

The AEMC's G-TUOS proposal does not provide a credible long-run locational transmission cost signal:

- because it is a scaled charge, the G-TUOS charge would not be cost-reflective, and is not an efficient signal;
- because it is forward-looking, the G-TUOS charge is highly dependent on the underlying assumptions that are adopted, and will also not be stable; and
- therefore such a charge is ineffective as a long-term signal.

The AEMC's G-TUOS proposal does not ensure new transmission investment matches the preferences of new generation investment given:

- the charge does not provide TNSPs with recourse to any additional funds to build out congestion (i.e. does not fund augmentation of network to accommodate new entrants);
- congestion build out remains dependent on the existing RIT-T process; and
- the proposal fails to satisfy the real problem: lack of transmission investment to match the needs determined by a generation investor.

The AEMC's G-TUOS proposal is not appropriate as:

- it is not economically efficient, misinterprets the problem and creates a signal for signals sake;
- it ignores principles of dynamic efficiency and is only relevant from a static perspective; and
- existing generators can not effectively respond to the locational price signal.

The AEMC's analysis does not support the introduction of the proposed G-TUOS mechanism and we strongly recommend the AEMC undertake a more appropriate level of analysis in conjunction with market participants.

Clause 5.4A of the NER

We do not support the removal of clause 5.4A. We support the AEMC taking proactive steps to ensure the NER require TNSPs to comply with their obligations under 5.4A. This failure on the part of TNSPs to implement 5.4A and not the rule itself is undermining the negotiated access framework

Generation Capacity in the short-term

We are concerned with the AEMC's proposals to increase regulatory responses in this area. We do not support the AEMC's suggested approach to procuring reserve capacity and do not support load shedding management in the manner outlined by the AEMC. We believe further interventions in the market are likely to undermine investor confidence.

We support improvements in the area of demand side capability reporting and suggest demand side participants should have information obligations that are comparable to those of generators; however we note this recommendation may raise some issues for retailers.

Connecting remote generation

We are concerned that the NERG proposal:

- is regulatory not market driven and therefore will not be appropriate;
- is not cost reflective;
- does not resolve concerns in the shared network that flow from new connections and impact both incumbents and new entrants; and
- is not consistent with the G-TUOS proposal and that these two issues should be jointly resolved.

Inter-regional TUOS

We support inter-regional TUOS but suggest the link between inter-regional TUOS and augmentation of the shared network requires ongoing observation to ensure the proposed charging mechanism is effective.

5 Submission Introduction

The AEMC's Review of Energy Market Frameworks in Light of Climate Change Policies (the Review) is tasked with examining the implications of Government climate change policies that will fundamentally alter the operation of the Australian economy. In doing so the AEMC is further tasked with developing recommendations which go to the heart of the NEM design and therefore the risks to participants, particularly private investors, are significant.

Our submission addresses those concerns which are of greatest significance and which we believe require further consideration. The release of the 2nd Interim Report (the Report) on 30 June provided some useful insights into the AEMC's thinking; however, a number of the findings and draft recommendations, in our view, require further analysis and consideration.

In this submission we have shown particular interest in the following matters:

- efficient utlisation and investment in the network;
- generation capacity in the short-term;
- connecting remote generation; and
- system operation with intermittent generation.

We welcome the AEMC's work in these areas and note the difficulty and complexity surrounding a number of these matters. Nevertheless, we suggest that especially as it relates to these issues further consideration of the implications of the AEMC's preliminary findings and compatibility with the National Electricity Objective (NEO) and current market design is essential.

We continue to make ourselves available through public forums, via submissions and through direct consultations to assist the AEMC with its consideration of these matters.

6 Efficient Utlisation and Investment in the Network - AEMC G-TUOS model

Introduction

The AEMC provides that the existing frameworks are inadequate as:

- congestion is likely to be more material moving forward;
- congestion reduces generator certainty around access to market;
- congestion increases dispatch risks; and
- these risks and lack of certainty of access distort locational signals and delay new entry.[1]

To overcome these issues the AEMC has proposed a model of G-TUOS whereby:

- each NEM region is divided into several zones, to represent different levels of potential congestion;
- over each NEM region, the G-TUOS measure would be revenue neutral, but generators in some zones would receive payment and others would pay (if they were assessed to be in a potentially high-cost zone) while customer TUOS would be unaffected;
- the charges would reflect the change in the net present value of future network investment due to the projected change in generation capacity at each location, based on the forward-looking, long run incremental network costs. However, scaling would be needed to achieve the zero-sum outcome. The charge would be on an installed capacity basis, rather than on generated energy; and
- the G-TUOS charges would be reviewed annually on the basis of a revised assessment of future generation investment.[2]

Discussion

We agree with the AEMC that change is needed to improve investment in and efficient use of generation and transmission networks. However, we do not believe that the AEMC's G-TUOS proposal is the required change. Before detailing the ways in which we believe the AEMC has misconstrued the issue of generator access to transmission and our suggested way forward, we outline our specific concerns with the AEMC G-TUOS proposal.

In this section we discuss the:

- application and limitation of annual fees;
- problems with the proposed "zones";
- supposed benefit of G-TUOS as a retirement signal;
- size of the potential G-TUOS charge; and
- role of CPRS and RET in setting the retirement rate.

[1] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 23 – 29.
[2] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 31 – 33.

Annual fees

The application of a variable annual fee is extremely problematic. Merchant investors, and their financiers, require stability and predictability in policy, regulation and cost to facilitate investment in the NEM. Previously, the AEMC has indicated that stability, predictability and transparency are necessary factors in pricing regimes.[3]

Therefore, a yearly fee which changes as network and generation investment occurs and is subject to the effects of future individual investment, does not provide stability or predictability. Interestingly, the Scottish Government noted that the G-TUOS model developed in the United Kingdom, on which this proposal is based, resulted in high charges which were unstable, unpredictable and highly volatile year-on-year.[4] We note that the National Grid does not consider this to be the case; however, the National grid did concede that there were legitimate concerns regarding transparency of pricing arrangements.[5]

It is interesting to note that a similar arrangement existed in Queensland prior to the commencement of the NEM. We understand this model was abandoned and was not adopted at the commencement of the NEM as it was not stable or effective[6]

In addition to these concerns, a basic assessment of the realities of network investment raises further issues. As the AEMC has noted in other areas of its report, network investment is often “lumpy” (i.e. it comes in large increments, often in excess of the marginal requirement). This property means that an area currently congested (and therefore paying fees under the G-TUOS approach), could swiftly change to be one of the least congested areas on the network when/if an augmentation proceeded. In this circumstance the generator that was paying G-TUOS could then find themselves receiving payments (as their zone is now amongst the least congested in the network). The contrary case is the area of major concern, as a generator that had responded to the G-TUOS signal and invested in an area receiving payments, could quickly find itself in a paying zone due to investments made to relieve congestion in other more congested zones. Clearly this possibility raises questions over the practicality of the G-TUOS as an investment signal.

The G-TUOS model proposed is not suitably transparent, is not predictable, undermines investment, penalises incumbents already subject to economic losses as a consequence of congestion that is not being built out by the RIT-T, and increases the markets regulatory dependence contrary to the intention of the NEM at market start[7].

We do note that in discussions with the AEMC it was suggested that the fee may not vary as often as generators and investors may fear. Leaving aside the value of these types of assurances provide investors trying to bank future projects or refinance existing projects it appears inherently contradictory to suggest on one hand the RIT-T will build out intra-regional congestion and on the other hand charges will be stable as such stability requires that conditions do not materially change (i.e. enduring congestion remains in-line with planner expectations and new congestion is not created by new entrants or incumbents).

---

[3] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.2

[4] National Grid (2009), *Transmission Charging – a new approach*, May, p.30

[5] National Grid (2009), *Transmission Charging – a new approach*, May, p.23

[6] On 14 July 2009 LYMMCo representatives, on behalf of the NGF, asked the AEMC to provide qualification as to how the AEMC G-TUOS model differed materially from the Queensland scheme.

[7] “The arrangements for connection and access to the national grid by distributors, contestable customers and generators are based on these functions being negotiated on a competitive and commercial basis.” See Media Release ‘Rules for electricity market under scrutiny’ http://www.accc.gov.au/content/index.phtml/itemId/86917/fromItemId/621761.

Structure of zones

We believe the construction of zones with varying charges is a blunt instrument to send potential investors a signal as to where to efficiently locate. Leaving aside the value of the tool for the moment, the construction of the zones themselves is highly problematic in that the treatment of any given generator could alter depending on their inclusion in any given zone. (Controversy over regional boundaries in the NEM we suggest is indicative of the difficulties such a model would present).

There will be acute sensitivity to any opportunity or decision to include a generator in any given zone if it is seen as disadvantageous. Therefore, both at the initiation of this model and moving forward there will significant debate as to structure of the zones. For instance, one can imagine a circumstance where inclusion at the fringes of one zone results in a G-TUOS charge whereas inclusion in an adjacent zone would not. Apart from demonstrating such a model does not expose generators to "the marginal cost their use (or intended use) imposes on the network" as previously supported by the AEMC[8] it ensures a yearly and ongoing debate around zonal structures will ensue in what is becoming an increasingly regulated market.

In sizing zones one is in effect making a trade-off between the marginal impacts of a unique connection point and the variability of the fee. As in large zones that cover an entire region[9] will have relatively stable costs that do not reflect the individual impacts of a connection. Whereas zones which represent individual power plant connection points, should reflect the marginal cost of the connection of a plant of that size and type at that specific location. Administratively, the first may be the simplest, but on efficiency grounds the latter is more appropriate and reflects the desire by many generators for marginal cost pricing principles to prevail, whereby existing and new generators face the cost of their investment decisions.

Retirement signals

In a climate where there are growing concerns about the security of supply of electricity in light of the impact of climate change policies[10] on coal-fired plant which supplies around 85% of Australia's energy need the suggestion that the theoretical benefits of a static trade-off between augmentation and early retirement seem misconceived at best. Furthermore, the AEMC has not detailed the "potentially high network or market costs" that may occur as a consequence of generator retirement.[11] The benefits of a retirement in a congested zone may be the removal of existing congestion and the avoidance of the augmentation costs required to remove the congestion at that point in time. However, additional charges will possibly exacerbate the stranding of assets and it remains unclear on what basis the AEMC is trying to "better inform retirement decisions" while fundamentally misconceiving the reason a stronger locational signal is required (to prevent congestion occurring).

In any case, let us assume for a moment that a transmission infrastructure decision was a simple trade-off between an incumbent's retirement and bringing forward augmentation of the network. We must assume a circumstance would arise where congestion would only remain as the RIT-T would not be

[8] AEMC (2005), *Review of the Electricity Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper*, November, pp.31-32

[9] For G-TUOS to have any effect there must be more than one zone per NEM region. The Annual National Transmission Statement (ANTS) zones have been suggested as the basis for G-TUOS pricing. This leads to a problem in Tasmania, which constitutes a single ANTS zone. See http://www.aemo.com.au/planning/040-0053.pdf for definition of the 17 ANTS zones.

[10] See current Terms of Reference for Senate Select Committee on Fuel and Energy.

[11] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p. 28.

satisfied under the circumstances.[12] This means without recourse to the RIT-T an incumbent facing a G-TUOS penalty would have three options: (a) ignore congestion and continue to generate and bid on that basis; (b) retire existing plant and alleviate local congestion; or (c) fund an augmentation in order to build-out congestion.

By ignoring the congestion and continuing to generate and bid under the risks of constraints the generators current position will not be altered (apart from reduced profitability assuming an inability to achieve full cost recovery of G-TUOS cost). The only differences will be that the affected generator will be further penalised with a G-TUOS charge until such time as that congestion is relieved in some manner. On the plus side, the G-TUOS charge will act as an additional disincentive (to the existing congestion) to further connections but unfortunately this requires the level of G-TUOS to be significantly high. Therefore, in such circumstances there is no notable benefit to the incumbent of the new G-TUOS regime as: the congestion remains; the generator does not have call upon the RIT-T; the charge forms an incumbency tax; the risk of congestion already acts as a disincentive to invest unless the new connection can displace the incumbent at dispatch and in those circumstances G-TUOS will disincentivise new connection only to the extent that that displacement does not exceed the G-TUOS charge levied against the new connection (which again penalises the incumbent).[13]

If a generator decides to retire plant facing a G-TUOS charge then the congestion may be alleviated and they receive the economic benefit of not paying the G-TUOS charge but lose the economic benefit of generation. On that basis, it is difficult to assume that a profitable generator would retire on the basis of G-TUOS and therefore the G-TUOS represents an additional regulatory cost of doing business. If a generator was nearing retirement the cost would need to make retirement economically beneficial. Surely, even a significant cost would not expedite retirement by more than months given the relativity between a scaled G-TUOS charge and the capitol locked up in a major power station (i.e. at least $100 million for a small station, and in many cases billions). The cost-benefit trade-offs across the NEM of this outcome are questionable at best.

If the ongoing cost of G-TUOS exceeds the costs of funding an augmentation to relieve congestion then it is conceivable a generator or group of generators in an effected zone or zones will fund such an augmentation. If a sunk investment, faced with congestion not built out by the RIT-T and not wanting to retire is faced with a significantly high charge, one that deters new connections and reflects the cost of transporting each megawatt from each zone to the Regional Reference Node (RRN),[14] their only alternative to doing nothing is to fund augmentation. This outcome does not seem appropriate if the AEMC intends that: load covers the cost of transmission networks; and that transmission pricing should be informed by a causer-pays principle. In this circumstance, a generator constrained off through subsequent investment is being penalised on multiple fronts.

The reason stakeholders have raised particular concerns with new generator locational investment decisions is the failure to build sufficient network capacity so as to ensure incumbent generators are not constrained off. It is the impacts of new investment decisions (by new entrants and incumbents), and the lack of transfer capability available to new connections in certain locations which is the primary issue of concern; not encouraging retirement as a means to avoid the costs of augmentation.

---

[12] Note: If the RIT-T was expected to build out congestion there would be little need for the AEMC's G-TUOS proposal. It suggests as disconnect between what the RIT-T does do, should do and is believed to do by the AEMC.

[13] In essence the incumbent's location is made less attractive to protect the incumbent from the competition which would occur if the incumbent was located in a better part of the network. The NEM equivalent to someone cutting off your nose to spite your face.

[14] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p. 30

Size of the fee

As detailed above we have significant concerns about the size of the fee which will be inefficiently levied against generators whose investments are sunk, on the basis that it encourages a trade-off between augmentation and retirement.

Similarly, for the fee to be reflective of long-run marginal cost it will need to replicate, as closely as is possible, the full costs to a new connection, of connecting at a specific location, on the NEM (and the full costs of existing generator future expansions in operations). That is it will need to reflect the marginal cost of connection for a causer of further congestion otherwise the incentive to connect at a constrained point may continue to be more economically beneficial then accepting the non-congestion costs associated with a non-preferred location.

This reflects the principle that only by facing the absolute costs (i.e. the true costs) of their actions can the relevant party be induced to make the most efficient decisions.

Carbon policies not G-TUOS will determine retirement and location trade-off

We agree that stronger price signals can influence behaviour and deliver more efficient decisions particularly for new connections where an investment is not sunk. However, the argument that retirement of sunk assets should be encouraged to free up scarce transmission capacity, while theoretically possible at the margin, does not reduce overall inefficient outcomes. To do this access arrangements need to ensure all generators when making investment decisions take account of their impact on the capability of the network to support efficient dispatch and avoid congestion.

Furthermore, in light of CPRS and RET policies, old plant will continue until the carbon costs rise to a level where that plant is no longer viable. Hence, the RET and CPRS policy will determine the retirement rate. Therefore, the primary reason for a G-TUOS charge should be encouraging new entrants to make a trade-off between efficient and inefficient locations based on the price duration curve of a location and absolute costs of a location.

We doubt the AEMC G-TUOS charge will even deliver this unless G-TUOS represents the absolute (or as close there to) long-run marginal costs of transmission so as to drive dynamic efficiency. Hence, our belief the proposal is poorly framed and is unlikely to provide the outcomes desired while inefficiently penalising generators who cannot respond to any additional signals.

7 Apparent reasoning behind the AEMC's proposal

Discussion

Recently, the AEMC commissioned Dr Darryl Biggar to undertake a paper on transmission investment and cost recovery principles and practice. In this work, it was noted that whereas traditionally coordination between generation and transmission investment was achieved through vertical integration, in a liberalised electricity market, such as the NEM, where generation and transmission are under separate ownership, that coordination must take place through other mechanisms – such as price signalling, contractual arrangements, and explicit coordination rules and processes.[15]

The AEMC's G-TUOS and the CSP/CSC proposal to deal with disorderly bidding appear to be the responses to this work and an attempt to differentiate between short-run and long-term pricing signals. However, it not only fails to appropriately consider the matters raised by Biggar, the AEMC fundamentally fails to understand the nature of the problem of generator access to transmission, given

[15] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.5.

it has determined that a relative non-credible charge should be the main mechanisms for promoting outcomes that are supposedly consistent with the NEO.

The AEMC correctly identifies the need for more efficient decisions[16], and this is consistent with Biggar's analysis, which as indicated above requires the consideration of both investment decisions and operational decisions. However, the paper incorrectly identifies the problem as 'changes in this area, with particular focus on the incentives on generators, are likely to promote more efficient outcomes in the presence of congestion.'[17] This is a fundamental misconception of the problem.

The existing market framework is inadequate because current transmission access arrangements are unlikely to build the additional transmission capacity required to ensure that congestion does not increase for incumbents when a new entrant connects to the network or an incumbent expands its operations. This is the primary concern for incumbents and new entrant investors alike.

A reason, it appears, why the AEMC fails to conceive the problem in the manner outlined repeatedly by generators is that the AEMC appears to suggest that the provision of and investment in regulated network services by TNSPs plays a primary role in addressing congestion created by new entrants (when this is not the case), and that transmission investment is effectively divorced from locational decisions.[18] The AEMC highlights that congestion creates an uncertainty around access to the market[19]; however, they do not appropriately articulate the significance of this risk or that it is effectively creating a barrier to entry as new entrants can not manage or appropriately hedge this uncertainty that arises from new entry (as distinct from the natural variability of network capability)

Except where congestion occurs we believe the existing framework for providing short-run marginal cost signals to generators is robust. In congested situations a change to the market incentives is required to address disorderly bidding. This is clearly the purpose of a range of possible CSP/CSC type schemes, including both that proposed by the AEMC and the congestion management without rights proposal of a group of generators[20].

Regarding the need for a locational signal, the AEMC do not appear to differ between the need for a locational transmission pricing signal which reflects the impacts of a new entrants (or an incumbents' expansion) decisions versus locational signals in areas of congestion per se. This includes the purpose of those signals to relieve congestion[21] versus other locational specific costs.[22]

The AEMC correctly indicates that stonger price signals will induce certain behaviours.[23] However, the AEMC does not make a connection between the quantum of signal and the extent of the impact on the

[16] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.23.

[17] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.23.

[18] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.25.

[19] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.27.

[20] See power point presentation from AGL, IPA, LYMMCo, Flinders Power and TRUenergy located at: http://www.aemc.gov.au/Media/docs/International%20Power,%20AGL,%20TRUenergy,%20Flinders%20Power,%20Loy%20Yang%20submission%204%20April%202008-6fd45aa2-5e10-4485-8f46-94244b4064f0-0.pdf

[21] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.27-28.

[22] The AEMC endures with the term "non pricing signals". Whilst this term appears confused we note that locational signals relating to fuel, water, labour, planning approvals are costs and they also have a price. One which is considered in a individual investors business model.

[23] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.27-28.

network by the causer of congestion from their poor location choice. The AEMC also fails to capture how transmission access that reflects the true costs of that access will deliver more efficient location and retirement decisions. This will arise as a consequence of a decentralised decision-making process, which considers other location specific costs so as to minimise generation and investment costs overall.

Interestingly, the AEMC goes on to suggest a choice must be made between a generator facing short-run marginal costs and long-run marginal costs of transmission. Given these decisions are made in different timeframes we are unclear why the AEMC would depart from its previous analysis in the Transmission Pricing Review which suggested:

- when making a short-run decision it is appropriate for generators to face the short-run transmission costs, in the NEM these costs are made up of congestion costs and losses; and
- when making a long-run investment decision it is appropriate for generators to face the long-run transmission costs and short-run transmission costs.

Generators already face efficient signals in a regionally priced market where congestion does not occur. Therefore, the issue would appear to be not a choice between signals but ensuring the right signal is provided in the right timeframe.

Summary

The AEMC's conclusions appear to be that:

- a speculative proportional charge smeared over a region as a substitute for absolute costs is able to promote efficient locational decisions,
- congestion only needs to be addressed at the margins once it is occurring, and
- this can be done by managing disorderly bidding instead of stopping increases in congestion and subsequent disorderly bidding arising at the investment and planning stages.

These conclusions are not correct.

8 What is the actual problem what should the objective of a framework for generator access to transmission be?

Problems with the current framework

The NEO is to:

> . . . promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system.[24]

In order to achieve the NEO the NEM:

- should be competitive;
- customers should be able to choose which supplier (including generators and retailers) they will trade with;
- should facilitate access to the interconnected transmission and distribution network; and

[24] Section 7, National Electricity Law

- be non-discriminatory between location, fuel type and existing participants and new entrants.[25]

This occurs via:

- exchange between electricity producers and electricity consumers through the spot market;
- wholesale contract market operation to manage financial risk and encourage competition;
- price signals for future investment in generation and transmission[26];
- decentralised decision-making based on legitimate price signals[27]; and
- transparent provision of all necessary information in a timely manner.

Currently problems arise where:

- competition in the wholesale contract market may be reduced by preventing generators from competing with their full capacity – stranded asset problem;
- the National Electricity Rules do not encourage efficient decentralised transmission and generation investment decision making through the competitive supply side of the NEM;
- generators are not provided with appropriate price signals at the time they are making their own investment decisions to drive dynamic efficiency and when congestion occurs operation decisions do not drive productive efficiency; and
- transmission investment fails to meet the needs of new entrants.

To resolve these issues we need to assess the manner in which investment decisions, operation decisions, and access to transmission decisions are made and how this satisfies the customer's interests.

Customer's interests in efficient investment decisions

The customer is best served by a NEM structure which ensures that:

(a) the least cost energy is delivered from the energy producer to the customer; and
(b) meets the NEO and promotes efficiency, including dynamic efficiency[28].

This can only occur when investors consider the total delivered cost of energy for their project from fuel source through to delivery of the product at the RRN at the time they are making an investment decisions. This means generation investors need to face the absolute value of all the costs associated with transmission and generation at a specific location. Absolute transmission costs are required to ensure neutrality with other location specific costs so investment decisions are not skewed.

A Framework for Generator Access to Transmission

A framework for generator access to transmission that is consistent with the NEO must:

1. provide appropriate investor certainty;
2. support efficient decentralised decision-making;
3. provide a long-run location specific transmission signal;
4. provide funding for new transmission investment; and
5. ensure new transmission investment matches the preferences of new generation investment.

[25] National Electricity Code Administrator at http://www.neca.com.au/NEM/index.html
[26] NEMMC0 (2008), *An introduction to Australia's national electricity market*
[27] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices.*
[28] The AEMC noted in the Final report of the Congestion Management Review that dynamic efficiency should be addressed in future reviews.

Investor certainty means:

- with a high degree of certainty to know or be able to forecast with confidence the cost of their access to the transmission system; and
- with a high degree of certainty forecast short run transmission costs and hence revenue. The short-run marginal cost of transmission is made up of congestion and losses, generators need to understand the extent to which the plant my have restricted access to the RRN due to congestion and as a consequence the extent to which their revenue may be curtailed as a result.

Support efficient decentralised-decision making means:

- generation investors need to face the true value of all the costs associated with a specific location which include:
    - o the long-run and short-run fuel supply costs for that location;
    - o location specific site costs such as, water, access and environmental costs;
    - o long-run and short-run transmission costs for that location;
    - o the ability to forecast with certainty the long-run transmission costs; and
    - o the ability to forecast with certainty short-run transmission cost (congestion and losses) and the price duration curve to facilitate the forecasting of likely revenue and to assist in the selection of plant type.

Investors already face a short-run marginal cost transmission signal; however, this needs to be reinforced through exposure to an absolute long-run location specific transmission signal to be consistent with other location specific costs (which are absolute costs).

Ensure new transmission investment matches the preferences of new generation investment means:

- new generators have flexibility with respect to transmission access to match that access and cost with the size and nature and operation of their plant and know with confidence that this level of access will be provided over the life of the generation asset.

The tailoring of transmission access, represented through augmentation costs can fund the TNSP to build new transmission that matches new generation needs (while not having impacting on existing network users)

Hence, all these elements combined produce a transmission access regime designed to maximise competition in the wholesale contract market, to support decentralised decision-making in the competitive supply-side of the NEM and ultimately benefit customers by satisfying the NEO.

<u>Therefore, from a generators point of view, the essential features of an access regime are the ability to choose a level of access that will be provided at a known cost, with certainty for the life of the plant</u>. This will ensure that wholesale competition will be maximised and generation and transmission investment is made at least cost. These essential features are consistent with the NEO (and with the AEMC's proposal in relation to NERGs).

These essential features can be provided by either a combination of (depending on the variables and methods of implementation) a deep connection charges regime (associated with a recognised transfer capability), nodal pricing/financial transmission rights or a CSP/CSC regime..

To ensure economically efficient investment under a deep connection charges regime or CSP/CSC or nodal pricing and financial transmission rights regime a new entrant or expansion generator would in addition to the payment of extension and connection assets be required to:

- pay to augment the transmission network by an agreed capacity, and
- when any generator generated in excess of their access quantity provide compensation to other generators who are constrained on or off as a result.

This would provide all generators (new and existing) with non–firm access to the transmission system (generators could in theory purchase additional insurance from a TNSP to protect against lack of access due to transmission failure or maintenance activities but this would appear beyond the scope of this submission and the current AEMC review).

Operational decisions

Likewise, when making operational decisions, generators should see the short run marginal costs of transmission which includes congestion and losses. The NEM already provides this signal which, except in the case when congestion occurs, drives efficient outcomes.

Consistency with Market Objectives

The above framework provides for a competitive market response and addresses the market objectives identified by Biggar, which are:

a) short-term operational objectives for generators and loads (dispatch efficiency, unit commitment, etc);
b) long-term investment decisions for generators (location, size, type of plant); and
c) both operation and investment decision by transmission network (co-optimised with generation investment/operation decisions).

Our outlined approach is the preferable method for satisfying these objectives. We note that the Biggar paper focussed on a regulated approach to transmission access. A regulated approach suffers from information asymmetries and weaker incentives so as to make transmission and generation investment decisions efficient a TNSP needs to have access to new entrant confidential and technical plant details and costs and the same wherewithal on how to best utilise that information. This will never be the case.

9 Way forward

The AEMC has taken the first step to resolving the generator access to transmission issue and indicated that further work is needed in this area before a final rule change can be developed. In this regard we support the AEMC's endeavors and continue to make ourselves available for the dialogue ahead. Our objective is to develop a framework for generator access to transmission that, consistent with the NEO:

- provides appropriate investor certainty;
- supports efficient decentralised decision-making;
- provides a long-run location specific transmission signal;
- provides funding for new transmission investment; and
- ensures new transmission investment matches the preferences of new generation investment.

While we have not ruled out any specific models, we have a framework upon which an efficient model should be based (as detailed above). Nevertheless, we are open to discussion of a number of options and support work, currently being undertaken by the NGF, to analyse the following:

- financial transmission rights;
- allocated congestion residues – a form of CSP/CSC ;
- new generators pay for network augmentations – deep connection charge approach or similar;
- generator contributions linked to augmentations – i.e. a revised G-TUOS model; and
- application of clause 5.4A of NER.

We are also examining the option of amending the RIT-T which, while arguably less efficient for customers and not meeting the objective and pre-requisites of the discussed framework, is possibly implementable and supported by some market participants as it can meet generator investment requirements.

An initial comparison of the outcomes expected under the various available models, as compared with the AEMC's G-TUOS model, is in Table 1 – Matrix of Models.

A response to some of the recent concerns regarding the deep connection costs models forms Appendix A.

A discussion of a number of relevant transmission pricing principles developed by the AEMC forms Appendix B.

An outline of our concerns with the RIT-T forms Appendix C.

10 Congestion Pricing Mechanism

We support exploration of the possibility of introducing a congestion pricing regime. This group of generators have previously proposed an arrangement of this nature to the AEMC Congestion Management Review. The arrangement presented had the objective of ensuring that congestion did not occur or at least was managed to be at an "efficient" level.

The AEMC have proposed exploration of the possibility of including a short term congestion pricing mechanism because "the long term G-TUOS charge may not signal all the short term inefficiencies caused by generator operational decisions"[29]. We would expect that G-TUOS would have no impact on operational decisions because these decisions occur in a different time frame to that proposed for the calculation of G-TUOS charges.

We note that the scheme proposed by the AEMC is to be limited to addressing operational efficiency after congestion has occurred. In the context expressed by the AEMC a congestion pricing regime will only address the mis-pricing issue that leads to disorderly bidding when congestion occurs so will only improve productive efficiency at the margin. The gross inefficiencies that result from lack of transmission capacity will remain.

We remind the AEMC that this congestion has not been caused by generator investment or operational decisions but by inefficient access arrangements which do not provide investors with appropriate price signals or fund transmission capacity to support the new supply investment.

[29] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.33.

We would however support an arrangement of this nature to address the disorderly bidding problem which can arise from both insufficient transmission investment and for transmission operational failures or maintenance outages. We see little other value in this proposal if it is applied after congestion has occurred because it will not address the productive inefficiencies due to the failure of the access arrangements to provide sufficient transmission capacity for new generation investment.

11 Connecting Remote Generation

The AEMC states that the desired market outcome is for efficient and timely connections to energy networks, and that this will occur when:

- NSPs consider applications in a timely manner;
- new connections are provided on a cost reflective basis; and
- investment in connection assets is efficiently sized.

NSPs consider applications in a timely manner

This generic statement has little direct relevance to the NERG proposal and is something of interest to all parties seeking to connect in all circumstances.

By deeming that the National Transmission Planner (NTP) will select NERG locations the AEMC has avoided detailing how market-led selection of remote location sites will be handled where there is a potential for multiple connections. Both the potential need to rely on selection of NERG zones by the NTP and the AEMC's failure to conceive of market-led selection of multiple connection sites makes it unclear how the connection process will be expedited. In fact, the pre-planning and planning stages alone present major time delays which will increase where commercial parties have identified sites not identified by the NTP. In fact, our main concern with the NERG proposal is the lack of transparency on how the NTP will determine how many NERG zones are required and where such zones should be located.

New connections are provided on a cost reflective basis

The major advantage of the NERG proposal and the feature we most support is the underwriting of the 'overbuild' by customers. Clearly, in circumstances where realising economies of scale in transmission provide a cost benefit to consumers and does not remove the need for new entrants to face their connection costs there are potential efficiencies. In this instance we suggest that a cost within a price band, similar to that identified by Biggar[30], between the incremental cost and the stand-alone cost of an asset should be allocated to the new entrant.

Interestingly, this underwriting model, in our view, could be rolled out more broadly in relation to efficient utilisation and investment in the network so if deep connection costs were attributed to a new entrant the portion over the increment that it was in the customers interests to build (due to economies of scale, routine network maintenance, or part of long-term planning) would be funded by customers and not the new entrant who would pay the approximate incremental costs (or a cost within the price band identified by Biggar). The additional funds covered by the customer would be recouped from subsequent connections.

Where the NERG model falls down is that is does not make new entrants face their absolute costs of transmission. That is, while attempting to develop a locational signal for the broader network, the NERG proposal fails to dwell on the impacts of new NERG connection on congestion deeper in the

[30] See Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices*

shared network and how such congestion will be removed. In essence, this means NERG connections are not cost reflective as they do not apply marginal cost pricing principals across the wider network.

Just as facing absolute long-run location specific transmission in the shared network will facilitate dynamic efficiency through improved locational decisions the same is true of potential NERG locations and NERG connections. Therefore, to improve the NERG proposal the charges to new connection should reflect impacts on the shared network.

Investment in connection assets is efficiently sized.

As discussed we support the NERG consumer 'underwriting' concept as a mechanism to overcome lumpiness and realise economies of scale. However, it fails on other grounds. While economies of scale will be realised for all new connections drawn to the NERG hub the interaction with the wider network and efficient trade-offs more generally have not been considered at length in the AEMC's analysis.

Consider the AEMC primary assumption:

> The entry of renewable generation is likely to be clustered in certain geographic areas that are remote to the existing networks.[31]

This conclusion glosses over a number of issues.

We all acknowledge that the RET and CPRS will stimulate significant investment in renewable capacity. However, what we imply by this is that the RET is bringing forward a significant amount of renewable investment. As such, given that wind power (in the absence of any new large scale hydro facilities) is the most commercially viable form of renewable generation, the RET is likely to result in a significant increase in wind farms. Up until this point we would be in general agreement.

However, it is not automatically conclusive that wind farms will locate in certain geographic clusters. What is correct is that the best wind is located in certain geographic clusters. Therefore, if other costs are not a factor for a new entrant, then every new entrant would obviously choose the location where wind (fuel) is at its best. Hence the AEMC has failed to consider trade-offs between locational costs like labour, planning, and most notably transmission and the price duration curve of a location.

Wind is available everywhere; however, the quality of that wind varies. Hence, if a wind farm had to elect between a location with no transmission costs and 11 kilometres per hour average wind and a second location with 15 kilometres per hour average wind but high labour costs and high transmission costs it may be that the least cost delivered to customers would flow from the location with 11 kilometre per hour wind. Such an outcome would be consistent with the NEO. Therefore, by not incentivising this trade-off, (and only presuming NERG zones transmission savings are the most critical issue) the AEMC may be failing to deliver the least cost delivered energy to consumers.

This is not to say that no NERG type projects should occur but to indicate the formalisation of such a strict policy has significant downsides, which the AEMC has not addressed in its reports or in discussions with members of the relevant consultative sub-committee.

A separate issue, and one where the AEMC's thinking is appropriate, is the treatment of the marginal connection once capacity on the connection asset is full. We support the approach that the marginal

[31] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p 13.

connection either: (a) pays compensation in the event an existing generator is constrained; (b) agrees to fund an augmentation; or (c) agrees to be constrained off.

Interestingly, this efficient allocation of costs is entirely consistent with clause 5.4A of the National Electricity Rules. A section the AEMC has suggested should be removed. We would suggest the distinction between the shared network and NERG connection assets is essentially arbitrary. What needs to be resolved is how to develop a measurement protocol for system normal transfer capacity for both existing and new generation.

Attachment D provides an alternative long-term locational signals framework for network connection based on the proposed NERG principles but applicable across the network. While we would require further time to finalise an alternative model along the lines proposed we suggest a version of this framework could be evolved to better satisfy the objectives of the NERG and G-TUOS principles outlined by the AEMC thus far.

12 5.4A of the National Electricity Rules

As the AEMC has noted clause 5.4A is part of the access arrangements and that "These arrangements arguably would lower generator dispatch risk by providing certainty of either dispatch or financial compensation. Firm financial access would also provide greater certainty to investors."[32]

Application of these provisions as originally intended would therefore have significant market benefits, by lowering current barriers to entry, ensuring congestion was at an "efficient" level and promoting dynamic efficiency. This provision forms an important part of the negotiated access provisions which are a central part of the decentralised decision making process that are intended to drive dynamic efficiency.

Despite the significant benefits of the access provisions of which this clause forms a part the AEMC has decided that that individual access negotiations are unable to work in practice as it is difficult to identify the "causer" of reduced access on the shared network.[33] This is not correct and has little to do with the open access regime.

Based on the limited analysis in the Report we are of the view that the AEMC has not considered this issue in appropriate depth. Therefore, we do not support the removal of clause 5.4A. We support the AEMC taking proactive steps to ensure the NER require TNSPs to comply with their obligations under 5.4A. This failure on the part of TNSPs to implement 5.4A and not the rule itself is undermining the negotiated access framework.

The causer of the congestion can be readily identified at time of connection when it concerns a new entrant. The system can be measured under normal conditions (a measurement protocol will need to be agreed) which recognises the transfer capability of existing generators as detailed in their connection (agreements).

It has been suggested that TNSPs have sought not to utilise 5.4A because they are overly risk-averse to the detriment of the market. However, if TNSPs undertook the required planning and measurement of the network at a new or existing generators expense, the TNSP would only be exposed if it incorrectly augmented the network. Therefore this risk aversion should not be satisfactory grounds to avoid their responsibilities under Chapter 5.4A. The reality is that TNSPs have endeavoured to use ambiguities in

[32] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p 37.

[33] AEMC presentation to NGF, CEC and Geothermal Association, 15 July 2009

the National Electricity Rules to circumvent their responsibilities. This mindset and an unwillingness to recognise transfer capabilities and not 5.4A itself has undermined negotiated financial access.

A measure that the AEMC could implement to address the claimed "workability" problems with this clause is rules that bound all generators in a congested region to be party to compensation payments in the event of congestion. This would overcome the claimed "inability to dispatch" problem noted by the AEMC, by removing any percieved need for the TNSP to get involved in dispatch, and containing the impact of implementing the scheme into a settlement issue for administration by the NSP. Resolving this issue would also appear to require resolving the capacity measurement definitional issue discussed above, and providing some guidance on initial capacity allocation. We note that in effect this implementation (achieved through an incremental change to address implementation issue in the existing rules regime) would be almost identical to the CSC/CSP issues the AEMC has already determined to address (but which would require much more complex rule reconstruction).

Attachment E reproduces a document provided to VENCorp, now part of AEMO, on compensation arrangements consistent with 5.4A.

13 Generation capacity in short-term

The AEMC appears to make three recommendations as set out below.

1. The set of options available that AEMO can call upon to procure reserve be expanded further than the current RERT mechanism.[34]
2. To facilitate more accurate reporting of demand side capacity.[35]
3. To better manage load shedding by providing an avenue for it to contract for load reducing capability, which it can deploy when the only alternative is involuntary load shedding.[36]

While the AEMC has noted that the Reliabiltiy Panel is now taking the lead on the "short notice reserve contracting" proposal, it continues to believe there are benefits in this proposal.

On the contrary, we are concerned that the shorter term panel approach is likely to leave AEMO with little option but to sign contracts with panel members at exorbitant and uncapped prices if short term unforseen difficulties result in near term reserve shortfalls. These will appear in the market as unhedgeable uplifts which will be passed to end use customers bringing the industry into disrepute.

We note that this mechanism is a significant departure from compensation mechanisms in existing short term intervention mechanism (ie. directions) which are carefully designed to provide strong incentives for participants to remain in the market and avoid Direction. Specifically these compensation mechanisms only pay actual costs that have to be substantiated by an independent expert.

The possibility of panel members making significant windfall profits in the event of a short term intervention (in excess of the market price cap) are likely to induce these reserve providers to hold back from the market rather than seeking to uncover commercial arrangements within the existing market parameters. For these reasons we remain unsupportive of this proposal.

[34] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.64.
[35] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.67.
[36] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.172.

Reporting of demand side capacity

We agree with the principle that greater accuracy of input information into the reserve assessment process would be beneficial including a general belief that demand side participants should have comparable information obligations to those of generators. However, we note there exist concerns, from retail businesses, concerns about the practicality of this proposal.

Load shedding management

We understand the mechanism would work by contracting with participants to shed load at their declared value of reliability.[37]

Like many policy proposals, in isolation this proposal is implicitly appealing. It attempts to remedy concerns regarding load shedding in a seemingly orderly way. However, like many policy proposals created in isolation it may undermine or interfere with higher order objectives and efficient outcomes.

As it currently stands, retailers, generators and load have the option to engage in market solutions to demand side management arrangements. It is in many retailers' interests to engage in demand side management to minimise exposure to higher prices. Likewise, when a generator is highly contracted, they have an incentive to enter into demand-side management arrangements to avoid high prices. Load has the incentive to enter into such arrangements where it is in their economic interests to reduce use in time of high prices.

Load does not respond to high prices as readily as could be expected, because electricity demand is reasonably inelastic. To overcome this, the proposal suggests that as load values the ability to use electricity more than demand side management, load will be paid the opportunity costs of not using energy.

This is a major departure from the current operation of the NEM. It is unclear how this will improve efficiency. And we believe it is not appropriate. In that regard, the AEMC's claims that load shedding management is more economically and socially desirable than involuntary load shedding[38] is far from justified.

Interestingly, the Reliability Panel has undertaken significant work in this area including in considering the implications of NEM reliability settings on demand-side management. It determined that the benefits of a higher Market Price Cap that will induce more demand-side participation did not exceed the costs and risks.

We do not support this proposal and suggest it is not consistent with the current market design as it:

- it further distorts the efficient operation of the market;
- it undermines current demand side management incentives;
- it introduces additional cost that needs to be recovered from market customers through retailers – this undermines retailer certainty and presents another unhedgeable market risk; and
- has an unclear and potentially perverse interaction with existing interventionist mechanisms, like the RERT, which already present a number of problems of their own.

---

[37] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.69, 172-173.

[38] AEMC (2009), Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report, 30 June, p. 69.

14 Inter-regional TUOS

We broadly support the development of an inter-regional TUOS charge. In supporting this proposal we agree with the AEMC's findings that transmission investment to support flows between regions is currently inhibited by the absence of an inter-regional TUOS mechanism.

We agree with the NGF's position that some shared network augmentations have not been considered due to the lack of inter-regional transmission charging[39] and the AEMC's position that absence of such a charge is a barrier to improved coordinated network planning.[40]

We agree that a load export charge is an appropriate and proportionate response at this point in time but note the Report does not signal to the required degree of confidence whether the AEMC and NGF concerns will be resolved following the adoption of a load export charge. That is, will the load export charge create the incentive to consider such augmentations and will it improve coordinated planning or will it simply shift cost allocations without improving outcomes?

We expect the charge will make a positive difference but this is dependant upon pricing methodologies and therefore believe the issue requires ongoing monitoring.

15 System operation with intermittent generation

Reactive Power

We note the ongoing issue with reactive power, which is likely to be aggravated by the addition of more intermittent generation.

The current mix of compulsory acquisition via technical standards and provision by network service providers using regulated charges seems unlikely to promote overall efficiency in accordance with the National Electricity Objective. In particular the dual role of TNSPs in approving performance standards for generators and as providers in their own right is questionable.

While we accept that this issue may not be of sufficient importance to justify a place in this frameworks review, it nevertheless should be reviewed before long.

Inertia

In relation to inertia, we note that AEMO currently go to significant lengths to eliminate the benefits due to generator inertia from the measured products traded under the market ancillary services regime.

We suggest that a simple change in the Rules would allow these benefits of inertia to be included in these products, thus providing a market signal for the connection of inertia to the electrical network. We believe this would simplify both the process of defining the FCAS requirements and the process of determining the amount of FCAS service actually delivered.

.

[39] NGF, Public Forum Discussion Paper submission, p 6.

[40] AEMC (2009), Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report, 30 June, p. 44.

Appendix A – Response to criticism of Deep Connection Charges

Deep connection charges have been proposed as one way of achieving the "spatially differentiated fixed transmission charges" proposed by Dr Biggar. While we believe there are a number of methods for achieving generator access to transmission; DCC and protection of incumbents and new entrants level of transfer capability forms a fundamental basis for the bulk of many of those methods as it is essential in driving dynamic efficiency.

One way of implementing deep connection charges is through clarification of the intent of Clause 5.4A of the NEM Rules, with subsequent modification of the Rules if required to achieve that intent.

In Section 3.3.6 of the 2nd Interim Paper, two arguments are presented to suggest that institution of DCC through 5.4A is unworkable. These arguments are:

1. Difficulty of identifying the causer of reduced access on the shared network, and
2. Inability to allocate access, due to inability to "isolate" access capability on a particular network asset.

We believe that these objections are based on a flawed understanding of the transmission planning process.

<u>Assessing Power System Transfer Capacity</u>

Critical to any discussion on network transfer capacity is a shared understanding of the conditions under which the defined access is to be available. For purposes of discussion, let us define a "stressed system normal" condition, ie with all transmission elements in service and peak load conditions. For any given system state it is possible to perform power system studies to determine the appropriate levels of power transfer, maintaining appropriate margins. These studies can also be used to determine the available nodal point headroom, i.e. the ability of the power system to accept additional generation injection, at a given location and voltage level, without dispatch constraint.

<u>The Connection Process</u>

A deep connection charges process would result in a zero charge (in relation to shared network assets) on new generation locating at points with adequate injection capability. It would not provide "firm access", because all connected parties would remain at risk form normal network variability, eg due to lines forced out of service, lightning/bushfires, or forced outages. However, deep connection charges would provide certainty to all (existing and proposed) generators that they will not face enduring congestion (ie under "stressed system normal" conditions).

Where a new entrant wished, (for reasons other than transmission, such as fuel source) to connect at a node with limited (or zero) headroom, then they would need to negotiate with the TNSP to do one of four things:

1. agree a physical run-back scheme to limit congestion at times of constraint;
2. compensate existing parties for constraining them off from their existing access[41];
3. fund a shared network network augmentation to increase the headroom to the required amount[42]; or
4. re-locate their connection application to another system node, eg different voltage level at the same location.

Identifying the Causer

Given an agreed power system condition, (or set of conditions), the TNSP can readily determine the required network investment to cater for the proposed generation injection, (allowing standard tolerances for stability and thermal ratings). That is, the required network augmentation to incorporate new generation investment could be determined by the TNSP in the same way in which it used to be done in a vertically integrated system, prior to the market, and in fact in the same way that is proposed in order to determine the G-TUOS charge[43].

Addressing the "Difficulties with deep connection charges"

Consequently, it is incorrect to assert that it is impossible to identify the causer – the causer is clearly the connection applicant. With regard to allocation of access, the process is one of ensuring that under the defined "stressed system normal" condition the new generator is able to fully dispatch their plant. All existing generation would retain the existing full access under the benchmark system condition(s).

In summary, the proposed deep connection charges process would provide the required locational signal, through a spatially differentiated fixed transmission charge. We argue that it is more effective than the proposed G-TUOS arrangement, and should not be dismissed in the cursory manner of Section 3.3.6 of the 2nd Interim report. The deep connection charges process does not protect incumbents from competition. It protects incumbents from inefficient congestion by ensuring an incumbent's transfer capability is recognised at the planning stage. It does not guarantee dispatch and still requires all generators to compete in the pool based on their offer prices[44].

The deep connection charges is a mechanism which requires investors to face the actual costs (or an appropriate fraction in the case of an overbuild) of their investment decisions on the NEM, so as to ensure transmission decisions can be tailored to meet generation decisions. It builds on and extends reliability based transmission investment, funded by customers.

---

[41] One way of doing this is through some form of allocated non-firm congestion residues.

[42] It is possible, due to the lumpiness of transmission investment, that the optimal augmentation is greater than that required. In such a case, a process similar to than envisaged for the NERGs could be used to determine if the connection proposal proceeds at a higher level with the "overbuild" funded by (a) another generator or (b) customers.

[43] With the advantage that in the case of a connection application, the TNSP is proceeding on the basis of a well defined application, whereas in the case of G-TUOS, the TNSP would need to look forward and make forecasts regarding future network usage, and/or generation technology/location.

[44] In fact the G-TUOS proposal is more likely to extend the practice of 'disorderly bidding' under system normal conditions, because the localised congestion will persist, there being no funding to relieve it.

The alternative is a reactive planning approach, where a non-market facing body makes transmission investment decisions funded by customers either in anticipation of or subsequent to generation decisions. As identified by Biggar (2009), this provides relatively inefficient outcomes due to lack of information on the part of the central planner.[45] As Biggar stated "one of the primary benefits of vertical separation is that it creates strong incentives for private generation entrepreneurs to discover and make use of new information – including possible new generation locations, new technologies, or new ways of operating old technologies."

Deep connection charges and the RIT-T

The RIT-T will allow a certain amount of network augmentation. This will be justified in terms of benefits to loads, and will be paid for by loads under the existing network pricing arrangements. However, in spite of the RIT-T, congestion will still occur for three reasons:

- Evaluation basis – The RIT – T evaluates congestion on the "central planning" basis of comparing marginal generation cost outcomes, whereas participant will value congestion based on market prices
- Time delays – There will be significant delay between the first appearance of congestion and the identification of the potential augmentation as a candidate for the RIT-T. Then further delays will occur until the detailed design, planning and construction is completed. This could be a period of years.
- RIT-T Shortfalls - Some congestion may be short-lived and just fall below the threshold of the RIT-T. [However, an individual generator could make a valid business decision to fund the gap, in order to provide comfort to their contract traders, who might otherwise be exposed to an inability to back contracts].

The economies of scale and lumpiness issues go to the heart of the difficulties in making a deep connection charges regime work. However, they do not negate the benefits of a deep connection charges regime which relies on non-discriminatory marginal cost pricing principals. Unfortunately 'economies of scale' and 'lumpiness' are implementation issues which have undermined discussion on the benefits of a deep connection charges model.

There are a number of tools available to overcome these issues and they include the tools used by the AEMC for the NERG proposal and the pricing arrangements discussed by Biggar (2009). The latter suggests an appropriate new entrant price sits within a negotiated price band from the incremental cost of use of the network to stand-alone cost for transfer capability to the RRN and that this price band reflects an appropriate share of an augmentation. When undertaking an augmentation the cost to the generator would depend on whether the TNSP/NTP is undertaking the augmentation for the sole benefit of the generator or as part of a wider transmission plan to realise economies of scale, reliability matters, general upgrades etc (i.e. if there are broader or

[45] Biggar – Draft Frameworks paper – 23 April 2009, pg 29 –"in practice, this approach raises certain issues, particularly regarding access to information. In effect, the transmission planner must decide which generation locations will be exploited in the long-term efficient expansion path and which locations will not be socially beneficial to exploit. The transmission planner therefore must indirectly determine which potential generation resources will be exploited and which will not. …. the transmission planner needs information on the location, type, cost, and size of all possible future generation expansion opportunities."

other reasons to augment that part of the network). A generator only driven augmentation would likely cost more that an augmentation that was already deemed worthwhile by the NTP/TNSP.

The deep connection charges and common carriage

Deep connection charges are not a barrier to entry in that the costs of entry do not reflect a loss in consumer and producer surplus as a result of charging costs or paying costs which exceed marginal costs or alternatively using a strategy of limit pricing to prevent entry. Deep connection charges are the explicit cost of entering the industry. Use of the phrase, "barrier to entry" infers that there is an unsubstantiated cost. It suggests that DCC attributed to new entrants are inefficient when they are clearly not. They are the marginal costs and such costs are non-discriminatory.

Hence, we believe that deep connection charges is not a barrier to entry when it provides generators with access to the network, it is a reasonable cost of entry which ensures a new entrant will not face enduring congestion because transmission capacity will be built to accommodate new supply. The alternative cost of entry is unpredictable and unmanageable (from the generator's perspective) reduction in revenue due to congestion caused by investment decisions of others. The current regime ensures the latter occurs, the deep connection charges removes this uncertainty by eliminating enduring congestion.

Deep connection charges and retirement signals

The AEMC states that deep connection charges do not inform retirement decisions, this is not necessarily correct. If the generator access arrangements provided for trading of generator access rights then a generator retirement decision would be informed by the market value of selling the access right to newer more efficient generator. This would efficiently provide an appropriate retirement signal through a competitive market approach rather than a regulated approach as proposed.

Appendix B – Transmission Pricing Principles

In 2006, the AEMC in discussing transmission pricing noted that the NEO "has implications for the *means* by which regulatory arrangements operate as well as their intended *ends*."[46] In this regard, the AEMC provided that transmission pricing arrangements should promote good regulatory practice by enhancing:

- stability and predictability – "that is, transmission prices should be stable and predictable enough to enable market participants to make long term decisions"; and
- transparency – "the process for setting prices should be as transparent as practicable to give market confidence that outcomes would be consistent with the NEO.[47]

The AEMC went on to state that the NER should "provide appropriate signals to avoid either under or over investment" with the AEMC noting that these outcomes could be best achieved by "encouraging transmission prices to provide efficient locational and investment signals to participants."[48] In determining its position the AEMC noted that it "considers that the causer pays principle should be used as a guide to whether, in general, consumers or producers should contribute towards the recovery of particular costs."

In setting transmission prices the AEMC stated that four related issues need to be noted. These being:

1. the basis for charging;
2. the approach to sunk cost recovery;
3. the need to provide efficient longer term locational and investment signals; and
4. the need to take account of other aspects of transmission regulation.[49]

We consider that the matters outlined above are still valid and hence the proposal to charge G-TUOS should be considered on this basis.

<u>Basis for charging</u>

The key issue for resolution in transmission charging is "who should pay for transmission" and "how should prices be structured".[50] The basis for determining the answers to these questions should be concerned with three issues:

---

[46] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.10.
[47] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.2
[48] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, pp.2-3
[49] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.20

- how the assets are used;
- who benefits from the asset; and
- whose behaviour causes an expense to be incurred.[51]

"At the simplest level, efficiency is concerned with allocating limited resources in a way to best satisfy unlimited wants."[52] This means consumption and production decisions in a given market will be consistent with efficient outcomes where the price of the given good or service equals its marginal cost. For transmission networks this means generators, loads and potential investors should make decisions based on "the marginal cost their use (or intended use) imposes on the network."[53] This reflects the marginal cost pricing principle and is the most effective way of promoting allocative efficiency.[54] Likewise, dynamic efficiency is driven by the cost that transmission users face in circumstances where long-run decision making, market performance and changes in the use and provision on infrastructure can be influenced.[55]

In the recent AEMC Market Frameworks Review 2nd Interim Report, the AEMC noted that:

> The most effective way to address the increased congestion arising following the introduction of the CPRS and expanded RET is through providing cost reflective price signals to generation. This will ensure that generators correctly factor in the total costs caused by their decisions, thereby promoting more efficient behaviour and more efficient utilisation of the network.[56]

However, the AEMC went on to suggest that it is difficult to attribute the need for actual network augmentation to a particular new entrant.

This assumption, that it may not be possible to allocate transmission costs to individual network users solely based on causation has not been robustly tested. Arguably recognition of transfer capacity is fundamental to the provision of efficient generation and transmission investment i.e. supporting dynamic efficiency and maintaining an efficient level of congestion. Therefore, we fully support a practical and rigorous review of this critical assumption.

---

[50] AEMC (2005), *Review of the Electricity Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper*, November, pp.8, 31

[51] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.20

[52] AEMC (2005), *Review of the Electricity Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper*, November, p. 32

[53] AEMC (2005), *Review of the Electricity Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper*, November, pp.31-32

[54] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.20

[55] AGL, Energy, International Power Australia, LYMMCO & TRUenergy, *Submission to 1st Interim Report, Parts A1-A7*, pp.19-30

[56] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.29

Despite this assumption the AEMC in the past or participants still held the view that the causer pays principle, "whether, in general, consumers or producers of electricity should contribute towards recovery of particular costs" should apply.[57]

In that regard it was previously concluded by the AEMC that a beneficiary pays arrangement was not suitable, as it would require an allocation of transmission costs between load and generators who both benefit from transmission investment and such an allocation against generators would not be efficient. This is particularly the case when we consider that most transmission investment is caused by load rather than generation.[58] In fact, it is relatively self-evident that generation investment is a consequence of load requirements at the societal level and therefore it is appropriate to allocate transmission costs to customers.

The issue for generators then, is how they can be encouraged to make most efficient use of existing scarce transmission resources and how, in line with the third dot point above; and how they can be moved to face their behaviour where that behaviour result in a cost. The AEMC previously concluded that G-TUOS was not the appropriate mechanism for these purposes and that in fact G-TUOS may "most likely be ultimately passed on to loads, potentially distorting bidding and dispatch in the process".[59] <u>In that regard, the mechanisms to induce more efficient behaviour remains marginal cost pricing principals not a discriminatory charge</u>.

Nevertheless, in the 2nd Interim Report the AEMC moved away from these well concluded arguments by supporting an arbitrary form of G-TUOS in the belief that these new charges would provide a cost reflective signal that will inform both location and retirement decisions for all generators. This is not correct.

[57] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.21

[58] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.21

[59] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.22

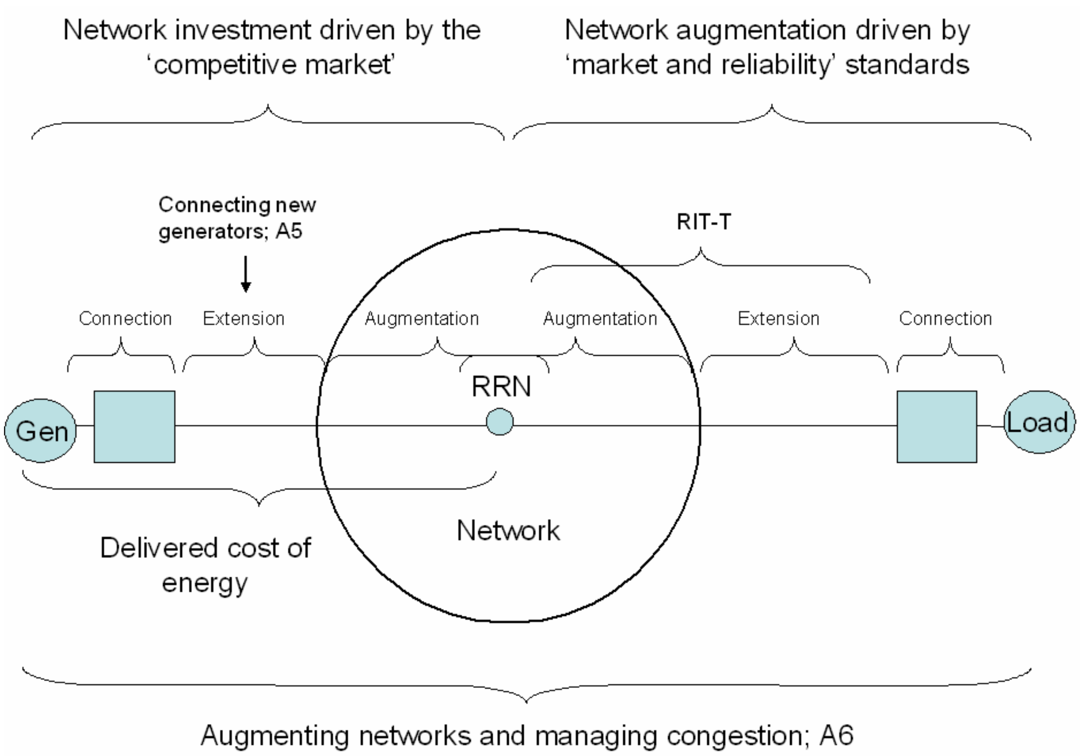
Appendix C - Regulatory Investment Test for Transmission

RIT-T and Market Congestion

We contend that network augmentation under the RIT-T is primarily driven by customer requirements. A position supported by the AEMC's analysis and a reason behind the purpose of allocating regulated transmission charges to load not generation.

Likewise the RIT-T responds to the requirements of small customers in a different manner to the access arrangements for incumbents, new connections and large loads. This separation is represented by AGL Energy, International Power Australia, LYMMCO, and TRUEnergy[60] as follows:

Diagram 1 – Investment framework



This representation suggests augmentation for generators, where they occur, are driven by new connections arising through the competitive market.

As it relates to TNSPs, regulated investment in the network requires TNSP's to have the right incentives to operate and invest in networks over time. At present the incentives are created through regulatory obligations, and network charges. The regulated network framework is robust and in broad terms needs no further consideration as it pertains to reliability standards.

[60] See AGL, Energy, International Power Australia, LYMMCO & TRUenergy, *Submission to 1st Interim Report, Parts A1-A7*

However, the AEMC appears to suggest the RIT-T will address market congestion. While we agree the RIT-T plays a key role in justifying augmentation to the network for load customers, it provides only incidental benefits in building out supply -side congestion arising through the competitive market. Furthermore, it can be argued that it is an inappropriate tool for this purpose.

Therefore, while we support the AEMC's assumptions concerning the need for correct financial incentives for use of the network and location of new generation capacity; we contend that decentralised decision-making will better support the combination of generation, loads and transmission assets that provide the least cost delivered energy to consumers if generators and other investors in the competitive market are fully informed as to the relationship between their investments and congestion.

This will not occur with the proposed G-TUOS model and congestion will continue if the current RIT-T continues to apply.

<u>TNSP Planning Arrangements and responsibilities</u>

The role of the regulatory test in addressing supply side congestion

The AEMC has identified that a rapid increases in generation investment under the CPRS and expanded RET may place new challenges on TNSPs in ensuring the timely supply of electricity to customers.

The AEMC notes that the market framework including the National Transmission Planner, the Last Resort Planning Power and the RIT-T will facilitate the development of market benefit projects in the future. However the AEMC then questions whether the NTP, LRPP and RIT-T framework will provide sufficient incentives for TNSPs to consider market benefits projects given the TNSPs overriding objective is to plan and develop the network to meet reliability obligations that are customer driven.

Further the AEMC suggests that the introduction of more supply side driven congestion and new network flows from existing generation will lead to an increase in the need for the regulatory test to include market benefits to manage the added congestion because the RIT-T, using the reliability limb alone is unlikely to address this congestion

The implication of this section is that the AEMC considers that market benefits projects are to address supply side driven congestion. <u>We note that with respect to intra-regional congestion:</u>

- the primary role of the regulatory test is to select the least cost option from a number of alternatives to address customer reliability standards for inclusion of that project in the regulated asset base, however with respect to intra-regional congestion any market benefits included in the assessment are likely to be negligible;
- the RIT-T does not have any direct role in the negotiated transmission access process (i.e. connecting new generators) nor is it used by new entrants in their decentralized decision making;
- the regulatory test can be gamed by generation investors to transfer transmission costs to consumers:
    - by "early commitment"; and

  - by "nearly committing" to influence a TNSP to include investment decisions;

  relying on the RIT-T supports non commercial behavior historically this has occurred with government owned entities; and

- if the test is relied upon to address supply driven congestion the test can lead to the selection of inefficient generation and transmission investment. This is demonstrated in the IES modeling where reliance on the regulatory test to address supply driven congestion rather than new entrants paying for transmission through negotiated services results in less efficient investments and higher costs to consumers.

For the above reasons we believe that the RIT-T cannot be relied on to efficiently manage supply side driven intra-regional congestion. The idea that any material supply side congestion caused by the introduction of the RET will be managed adequately because of an improved market framework that applies to regulated investment and TNSP planning arrangements is an unsound assumption.

Appendix D - Alternative Long-Term Locational Signals

Attachment D provides an alternative long-term locational signals framework for network connection based on the proposed NERG principles but applicable across the network. This has been provided for illustrative purposes; further time would be required to finalise any alternative model along these lines. However, we suggest a version of this framework could be developed to better satisfy the objectives of the NERG and G-TUOS proposals outlined by the AEMC.

Discussion

In section 3.3.3 of the 2nd interim report, the option of making the existing connection charging arrangements apply in practice is set aside as not providing an appropriate a long-term locational signal (This is referred to as reforms to the connection charging arrangements, although the proposal referred to is simply clarification of the existing Rules).

In considering long-term locational signals, an important consideration is consistency between the proposed arrangements for remote generation (NERG) and the arrangements for the shared network in general. This is important because the NERG arrangements, to be genuinely effective, need to extend into existing shared network, and because the distinction between the cases of remote generation and other new entry is not as clear-cut as has been portrayed. The proposed differences in treatment between these cases are therefore likely to prove problematic over time.

Parts on the network that start as connection for remote generation may evolve into indistinguishable parts of the shared network as further augmentations occur. Conversely, a part of the shared network developed initially to serve remote customers may be developed over time to serve remote generation, and hence be effectively a NERG situation. Hence a common set of principles in relation to network planning and charging is needed to ensure that overall the arrangements are robust in the face of evolution of the network over time.

Such a common set of principles is proposed and has been based predominantly on the NERG regime as proposed by AEMC, and the existing principles evident in Chapter 5 of the Rules.

The proposed common principles for network connection are :

- all network planning for generator connection be based on measurement of capability in relation to a defined set of conditions (a measurement protocol), which represents stressful, but reasonably likely conditions, and assumes that all elements of the network are in service. The network must effectively be dealt with as a whole in this analysis;
- all agreed network access must be capable of being provided simultaneously, under this measurement protocol;
- if network augmentation is required to allow access, it will be planned to an economic size in relation to both the current application and the expected future developments relevant to that location;

- a generator that utilises only part of the capability added by a network augmentation would pay a fraction of its cost at least proportional to its extent of utilisation (but not more that the cost of a stand-alone augmentation);
- the cost of that part of a network augmentation that leads to an excess capability would be charged to customers while it remains unused, and to a subsequent entrant generator based on the same cost allocation principles that apply to the first mover;
- a generator may utilise opportunistic access by accepting an access level which is less than its plant capacity, and thus reducing the cost of access. In this case the generator must -
    - agree to limit its offered availability as necessary to avoid congestion, except that it may always offer up to its agreed access level, and
    - failing compliance with this condition must compensate the TNSP to the extent of revenue earned by non-compliance (which the TNSP will use to compensate those generators adversely affected by this non-compliance).

These principles are consistent with the proposals for NERG and the current (although not implemented) regime for connection charging, and represent a more complete form of each. They also overcome the objections cited in the Report against the connection charging regime, as discussed below.

The objections as set out in section 3.3.3 of this report are first repeated and then compared with the principles set out above.

> The nature of transmission investment makes it hard to size accurately the shared network augmentation and determine the costs. This makes it difficult to determine the cost reflective signal caused by the new entrant.[61]

The principles set out above allow for an augmentation to be knowingly oversized and for the cost sharing to reflect this. This is consistent with the proposals by the AEMC in relation to NERG, but extends this concept more broadly.

The cost would be determined as it would be for any network augmentation, and this is a necessary part of the RIT – T test and hence the application of these principles places no greater burden than normal on the planning NSP. The cost reflective signal is appropriately specific to each new entrant generator, as each is considered in turn based on a common set of principles.

> The benefits of any augmentation are likely to be shared by all existing and new generation. Therefore it is appropriate for all generators to contribute to the costs of the augmentation. However if instead all the costs are exposed to the new connecting party this may encourage inefficient behaviour by existing users.[62]

Under the proposal all generators have access for their agreed access level under the conditions defined by the measurement protocol. Hence under these conditions there is no benefit to existing generators and no reason for them to contribute to the costs.

[61] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 30-31.
[62] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 30-31.

The question of whether an augmentation to allow a new entrant generator will benefit other generators at times of reduced network capability (relative to measurement protocol conditions) does not have a general answer. It may or may not, depending on the configuration of the network and the particular circumstances. Therefore there is no clear case for charging existing generators in relation to this condition. Furthermore, the level of congestion under conditions of reduced network capability is not assured under either the current regime or under the regime advocated here.

Risks related to the variability of network capability currently fall on generators through the effects of congestion. Provided that the base level of congestion is not affected by new entry (as these principles provide) then the continued exposure of generators to the variability of network capability would form a natural part of locational signals.

> Under a deep connection policy, these costs would be charged to the new customer despite the fact that they will be shared by other users. Given the lumpy nature of connection investments subsequent new users may be able to connect at a relatively low cost. Such arrangements will distort competition and create a potential gaming problem in which new generators strive to avoid being the party that gets “tagged” with the deep upgrade costs.[63]

The proposal made here uses the principles proposed for the NERG case to provide an appropriate distribution of cost between the initial new customer and subsequent entrants. This avoids both adverse effects on competition and the perceived problem of gaming. The important element of the proposed principles in this context is the application of common cost allocation principles to first movers and later entrants alike.

These proposed principles not only overcome the objections that were cited by AEMC, but have substantial positive benefits.

- The locational signals are based on differences in augmentation costs between alternative locations, which are well defined at the time when a locational decision must be made.
- The separate consideration of the base level of congestion under defined network conditions allows protection from changes to this level without the complexity of dealing with variable congestion due to the frequent variations in network capability. The protection against changes in the base level of congestion allows a degree of access certainty that facilitates timely and efficient investment in generation.
- The freedom to chose the level of network access that is desired, with an appropriate consequential responsibility, allows a greater optimisation of network capability to suit participant’s needs.

In summary, this proposal, would appear to overcome the perceived barriers identified by the AEMC, but also has positive advantages over the proposals currently suggested in the Report.

---

[63] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 30-31.

Appendix E - Note to Vencorp – Compensation Arrangements

This attachment reproduces a note provided to Vencorp, now part of AEMO, outlining a compensation method under connection agreements produced in October 2008. This relates to 5.4A and further illustrates the alternatives to the models proposed by the AEMC.

Proposal on compensation arrangements under a connection agreement

29 October 2008

<u>Background</u>

The NER envisage that a generator can arrange connection with a power transfer capability that is less than the maximum input to the network from that generation.

The NER also envisages compensation from a generator <u>to</u> a TNSP if that generator causes other generators to be constrained, and also compensation <u>from</u> a TNSP to a generator that is affected by congestion caused, or aggravated, by others.

However, the form that specific rights and obligations in relation to these issues might take is not described.

The aim of this note is to suggest in more detail how such provisions could operate. It is consistent with the NER 5.4A (h) and (i), but goes beyond these provisions in terms of detail.

<u>Terminology</u>

For the purpose of this discussion I will use the following terminology –

- "Access level" is the agreed power transfer capability for a generating system as defined under its connection agreement.
- "Explicit constraint" for a generator is a constraint that has that generator on the LHS. The alternative is a constraint that limits a generator without explicitly including it (e.g. an interconnector constraint that limits the total generation within a region, and perhaps limits other generators explicitly, but not the one of interest).

The discussion here will focus on a constrained-off case, with the possible extension to constrained-on to be considered separately.

<u>Anticipated connection conditions</u>

This proposal is designed to operate under particular connection conditions for new generators.

The main condition envisaged is that VENCorp will ensure that its network is capable (with all elements in service) of accepting power input simultaneously from all generators at their agreed access levels. This condition can be satisfied by VENCorp through –

- Allocation of uncommitted capability, or
- Augmentation of the network to accommodate the desired access level of the new generator, or
- Restriction of the access level to match the remaining uncommitted capability

<u>Proposal</u>

If a generator enters a connection agreement that specifies an access level less than the potential output of the generator, then the connection agreement should include a requirement that the generator must limit its offered availability to its access level whenever it is affected by an explicit constraint.

The connection agreement should also specify that such a generator owes compensation to VENCorp if –

- It offers availability to the market greater that its access level when affected by an explicit constraint (contrary to its connection agreement), or
- It resists dispatch in accordance with the reduced availability (by offering a low rate of change, for example), or
- It fails to comply reasonably with its dispatch targets

<u>Payments to VENCorp</u>

The amount of compensation owed is equal to the additional revenue earned by the failure to comply. Hence a hypothetical dispatch, with compliance, needs to be considered to calculate the compensation payable.

It should be noted that dispatch based on availability equal to the access level does not imply generation at that access level. For example, in the case of disorderly bidding by a group of constrained generators, each of these will be reduced in dispatch to a fraction of their availability. The relevant hypothetical case would be dispatch at the relevant fraction of the reduced availability (i.e. this fraction calculated as it would be with the reduced availability – since a reduction in this availability would alter the fraction). This hypothetical dispatch outcome would form the basis for calculation of compensation.

<u>Payments from VENCorp</u>

Where compensation is owed to VENCorp, as outlined above, the other generators impacted by event that led to compensation **<u>to</u>** VENCorp, should have a provision making compensation payable **<u>by</u>** VENCorp. This would be based on their individual loss of revenue relative to the same hypothetical case of compliance, as used above.

These payments are considered further in section 6 below in relation to making the compensation regime financially balanced for VENCorp

Discussion

The AEMC has described the “open access” regime as determining transmission access through the market dispatch process. Hence if a reduced access level is to be meaningful it must have an obligation that impacts in dispatch. This is the basis for the obligation to reduce availability.

On the other hand, it would be inefficient to force a reduction in availability when congestion was not an issue (for example when generating unit outages have freed up network capability). Hence the requirement to limit availability only when subject to an explicit constraint.

The suggested compensation regime is deliberately not tied to “system normal” network conditions, that is with all network equipment in-service. This tie should be avoided because the common (or “normal”) situation in reality will often include some outages, so a restriction to system normal would significantly, and needlessly, restrict the application of compensation.

The compensation regime proposed does rely on the access level which, in turn, should be defined by reference to “system normal” conditions, but any direct linkage between the state of outages and the compensation regime is deliberately avoided.

As a result the proposed compensation regime would continue to apply, but in an automatically “scaled-down” form, when network capability is reduced by outages, whether planned or forced.

Financial balance

For a radial part of the network, a limitation on the radial connection will limit the attached generation in aggregate. Hence an “over-generation” by one generator in the group will lead to an equal reduction in aggregate among the other generators. The gains and losses in revenue will thus sum to zero.

In this case, a compensation regime that includes the whole group of generators will be financially balanced.

However, in the case of a looped network, different generators will have different coefficients in any constraint within the loop. These coefficients will depend on location within the loop. In this case an increase in generation by one generator may result in a greater or lesser total reduction by other generators in complying with the constraint.

In this case a compensation regime based on the gains and losses within the group of constrained generators will not automatically balance. Balance can be achieved in a number of ways. The proposed method is –

- Determine the compensation owed to VENCorp as the total revenue achieved by generation in excess of generating station’s respective access levels, and

- Determine compensation owed by VENCorp to affected generators as a fraction of the compensation owed to VENCorp, with the fraction determined by the fraction that an individual station's loss is of the aggregate of losses for all affected stations

In the above discussion, the issue of financial balance for VENCorp has been discussed in the context of congestion affecting a group of generators. This discussion now needs to be extended to deal with non-generator entities affected by congestion along with one or more generators that are subject to a VENCorp compensation scheme.

In the case of a scheduled network service, it is proposed that it be treated in the same way as a generator. It will have an access level, and if this is less than its power transfer capability it may be liable to pay compensation. If disadvantaged by a generator's over-generation it will be owed compensation, as for a generator.

In the case of a regulated interconnector, there will be no access level and hence no liability for "over-generation", but it may be damaged by the over-generation of others and hence arguably due compensation. The loss can be measured as the difference in the interconnector settlement residue as a result of the over-generation. It is proposed that regulated interconnectors be included on a similar basis as generators that are owed compensation. Any amounts owed to a regulated interconnector would be credited to the relevant interconnector residue fund managed by NEMMCO.

Summary

The proposal is based on the measurement of gain or loss by comparison of the actual outcome with the hypothetical case of each relevant generator abiding by an obligation to restrict its offered availability to its access level when an explicit constraint applies.

Financial balance is assured by fixing the amounts owed to VENCorp, but adjusting the amounts owed by VENCorp to match the amount received.

This proposal naturally extends to either scheduled network services, or to regulated interconnectors where these are impacted by a constraint that also constrains generators.

Table 1 – Matrix of Models **Criteria**	**NEM without DCC and no application of 5.4A**	**Deep Connection Charges (DCC) and application of 5.4A (compensation)**	**NERG**	**LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)**	**LMP; FTRs; CSC/CSP and variants with DCC**	**G contributions model (alternative G-TUOS)**	**Amended RIT-T (to build out intra-regional congestion)**	**AEMC G-TUOS Model – 2nd Interim Report**
T LRMC allocation issues	N/a.	Yes.	Yes.	N/a.	Yes.	Yes.	N/a.	Yes.
Non-discriminatory pricing	No.	Yes.	Yes.	No	Yes	Yes.	No.	No.
Barriers to entry	Yes.	No.	No.	Yes	No	Variable but probable no.	No.	Yes.
Provides a credible long-term locational signal	No credible locational price signal. Relevant signals are not "priced".	Yes. Provides long-term cost signal which is locked in at project start.	Yes. Provides long-term cost signal which is locked in at project start.	No credible locational price signal. Relevant signals are not "priced".	Yes. Provides long-term cost signal which is locked in a project start.	Yes. Locational tariff provides a strong signal which is locked in a project start.	No. Not based on long-term signals to new entrants. Possible gaming by G must be managed.	No. Signal does not reflect absolute cost and is subject to unknown variation.
Provides investor certainty	No. T congestion costs <u>not</u> known for life of plant.	Yes. Transmission costs known for life of plant.	Only for connection. Transmission costs beyond connection <u>not</u> known for life of plant.	No. T congestion costs <u>not</u> known for life of plant. Threat of congestion negates benefit.	Yes. Transmission costs known for life of plant.	Yes. Transmission costs known for life of plant.	Improved subject to regulatory build out.	No. Transmission costs <u>not</u> known for life of plant.
Supports decentralised decision-making	No.	Yes. Investors face absolute costs.	No. Joint connections are not market driven but planner driven.	No.	Yes. Investors face absolute costs.	Yes.	No.	No. Does not reflect absolute costs over life of project or development of desired T assets.
Disorderly bidding solved	No	No	No	Yes. Provides framework.	Yes. Provides framework.	No	No	No

Criteria	**NEM without DCC and no application of 5.4A**	**Deep Connection Charges (DCC) and application of 5.4A**	**NERG**	**LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)**	**LMP; FTRs; CSC/CSP and variants with DCC**	**G contributions model (alternative G-TUOS)**	**Amended RIT-T (to build out intra-regional congestion)**	**AEMC G-TUOS Model – 2nd Interim Report**
Ability to forecast the impact of congestion on revenue[64]	No. Incumbents and new entrants subject to unknown impacts of future connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	Yes. Incumbents and new entrants transfer capacity is assured in the planning domain.	No. G and new entrants subject to unknown impacts of future shared network connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	No. Incumbents and new entrants subject to unknown impacts of future connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	Yes. Incumbents and new entrants transfer capacity is assured in the planning domain.	Yes. Congestion, as a general principle, will be built out with a generator contribution	Variable. Generators subject to unknown impacts of future connections until regulatory decision to built based on amended RIT-T.	No. G and new entrants subject to unknown impacts of future connections.
Ensures new T investment can match preferences of new G investment	No. Constrains investment to available T capacity.	Yes. G can choose level of access.	No. Only applies to connection assets.	No. Constrains investment to available T capacity. Fewer inefficient locational decisions but LMP does not reflect all T charges. Needs to coupled with DCC	Yes. G can choose level of access.	Yes. G can choose level of access.	Variable.	No. Constrains investment to available T capacity.

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	Generator contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Promotes wholesale market competition	Variable. At present minimal impact; but congestion undermines competition.	Yes. Provides greatest investor certainty through access to markets.	Yes.	No.	Yes.	Yes. Provides reasonable investor certainty through access to markets.	Yes. Assumes all congestion will be built out even if inefficient and at no cost to G.	No. Increases financial uncertainty as well as existing issues with congestion.
Decentralised decisions in generation only. (no dynamic efficiency)	Yes. But T uncertainties creates a barrier to entry.	Yes.	Does not facilitate market driven multiple connections.	Yes. But T uncertainties creates a barrier to entry.	Yes.	Yes.	RIT-T can be gamed and this may create uncertainty.	Yes. But T uncertainties creates a barrier to entry and G-TUOS charge a new unhedgeable risk.
Decentralised decision-making in generation <u>and</u> transmission. (dynamically efficient)	No. Creates barriers for G considering T investment at time of G investment.	Yes. Requires consideration of G and T absolute costs.	No. Only relates to connection assets.	No. Creates barriers for G considering T investment at time of G investment.	Yes. Requires consideration of G and T absolute costs.	Yes. Ensures consideration of absolute G costs and proportion of T costs.	No. Does not realise efficiencies which result from an investor facing the absolute cost or as close there to.	No. Does not reflect absolute costs over life of project.
Cost of access to T[65] **(excluding operational issues, credible outages and plant failure)**	Not possible to hedge against congestion, i.e. provides investors with revenue uncertainty and indeterminate access costs at time of investment.	Capacity defined in Connection or UOS agreement paid and maintained for life of the plant. Costs of access know with certainty at time of investment.	Connection costs only. Total costs of access determined by shared network regime.	FTR means it is not necessary for TNSP to build T if there is another source of revenue to fund FTR. However works best if coupled with some form of DCC.	Capacity defined in Connection or UOS Agreement paid for and maintained for life of the plant. Access costs know with at time of investment.	Capacity not necessarily defined; however, access costs known and locked in at time of investment.	N/a. Build out policy assigns cost to consumers.	No. Subject to an unhedgeable financial risk and an unknown future congestion risk.

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	Generator contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Dispatch efficient	No. Results in inefficient dispatch due to congestion in the shared network. An additional CSC CSP would be required to address inefficiencies at the margin.	Yes. G are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin (i.e. disorderly bidding)	No. Results in inefficient dispatch due to congestion in the shared network.	Inefficient dispatch due to congestion in the shared network remains. However, G receive CSP when generate above the CSC. (i.e. addresses disorderly bidding).	Yes. G are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP Yes. G receive CSP when generate above the CSC at the margin.	Yes. Generators are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin.	Yes. Generators are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin.	No. Results in inefficient dispatch due to congestion in the shared network. An additional CSC CSP would be required to address inefficiencies at the margin.
Dynamic efficiency –G face absolute LRMC location costs?	No. Probable inefficient operational outcomes and lack of T.	Yes.	No.	No.	Yes.	Variable.	No. Probable inefficient transmission costs.	No. Probable inefficient operational outcomes and lack of T.
LR/SR fuel costs	Yes	Yes	Yes	Yes	Yes.	Yes	Yes	Yes
site costs	Yes	Yes	Yes	Yes	Yes.	Yes	Yes	Yes
SR T costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
LR T costs	No	Yes	No	No	Yes	Variable	No	No

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	G contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Ability to forecast with certainty LR T costs (revenue uncertainty)	No. Exposed to congestion.	Yes	No	No. Exposed to congestion.	Yes.	Yes	N/a.	No. Exposed to additional regulatory risk.
Ability to forecast with certainty SR T costs (dispatch uncertainty)	No. Exposed to congestion.	Yes	No	Improved.	Yes	Yes	No. Poor locational decisions still a risk, but will be built out more.	No.
Transparency of T framework	Poor.	High.	Outside NERG zone remains poor.	Poor for augmentations.	High.	High.	Poor. Subject to regulatory decision-making..	Poor.
Allocation of augmentation costs possible	N/a. Connection costs only.	Yes. Price band between incremental cost and stand-alone cost.	N/a. Connection costs only.	N/a. Connection costs only.	Yes. Price band between incremental cost and stand-alone cost.	Yes. Tariff based. Should reflect price band between incremental cost and stand-alone cost.	No. Augmentations not attributed to individual generators.	N/a. Connection costs only. Model does not provide specific augmentation to match G investment.
Can overcome scale effects/ realise economies of scale in network augmentation.	T investment is not occurring to support new entrants. Sacrificing competitive market efficiency.	Yes. Price band between incremental cost and stand-alone cost reflects share of an augmentation the TNSP/NTP elects to build.	N/a. Workable costing model but only applies to connection assets.	T investment is not occurring to support new entrants. Sacrificing competitive market efficiency.	Yes. Price band between incremental cost and stand-alone cost reflects share of augmentation the TNSP/NTP elects to build.	Yes. Tariff reflects share of an augmentation the TNSP/NTP elects to build on greater scale.	Regulatory planned model caters for realising T economies of scale (at expense of dynamic efficiency)	Regulatory planned model caters for realising T economies of scale (at expense of dynamic efficiency)