23 February 2009

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

Dear Dr Tamblyn

AEMC Market Framework Review

I write on behalf of the above listed generators in response to the AEMC Review of Energy Market Frameworks in light of Climate Change Policies, 1st Interim Report, dated 23 December 2008.

Please find enclosed a submission in response to parts A1 through to A7 of the aforementioned report. Please direct your response or any questions regarding this submission to the undersigned on (03) 9612 2236

Yours faithfully,

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On behalf of:

Alex Cruickshank Manager, Wholesale Markets Regulation AGL Energy Limited	**David Hoch** Regulatory Policy Manger International Power
Mark Frewin Regulatory Manager TRUenergy Pty. Ltd.	**Roger Oakley** Manager, Market Development LYMMCo

International Power TRU energy AGL LOY YANG Marketing Management Company

AGL Energy

International Power Australia

Loy Yang Marketing

TRUenergy

Submission in response to the:

AEMC

Review of Energy Markets in light of Climate Change Policies,

1st Interim Report of 23 December 2008

Parts A1-A7

February 2009

Executive Summary

AGL Energy Limited, International Power Australia, Loy Yang Marketing Management Company Limited and TRUenergy Propriety Limited make this joint submission reflecting their common views regarding the risks to market sustainability and long-term provision of reliability under the current NEM arrangements and our common interest in the efficient operation and sustainability of a competitive electricity market.

We make the key points outlined below in our submission.

Convergence of gas and electricity markets

- Planning and investment in the Victorian gas transmission investment regime is reactive, and is likely to lead to costly project delays as CPRS inspired power generation and gas production seeks connection over the coming decade.

Generation Capacity in the short term

- It appears unlikely that any conceivable variation to the RERT would be able to deal with any short-term reserve shortfall more efficiently than the existing market framework.

- Additional capacity and maintenance of existing plant will eventuate in the absence of government intervention so long as the market operates effectively and efficiently and policy uncertainty is resolved.

Investment to meet reliability standards with increased use of renewables

- Further consideration of the interaction of MPL, CPT and APC is warranted to ensure an appropriate balance between: encouraging the operation of contract markets and investment; and discouraging participation in the market due to excessive risk.

System operation and intermittent generation

- Current mandatory provision of some ancillary services creates incentives to minimise their provision, leading to inefficient investment outcomes for both fossil fuelled and renewable generators and energy networks.

- Provision of a wider range of ancillary services, like reactive power and inertia, through market arrangements will help maintain system reliability and security in an economically efficient manner and could increase the life of plant providing these services that may otherwise have closed due to the CPRS and MRET.

Connecting new generators to energy networks

- Economies of scale in transmission investment may be available if processes for co-ordination of connection applications could be improved without impacting on decentralised decision-making. A variant of options 2/3, which would provide predictable generation access in exchange for funding network assets should be further explored, and may allow these economies to be realised.

Augmenting networks and managing congestion

- A failure to manage congestion undermines desired market outcomes and leads to suboptimal performance.

- Economically efficient congestion flows from economically efficient investment in generation transmission and distribution supported by a framework which permits market participants to make informed decisions. Economically efficient investment decisions are driven by both short-run transmission costs and long-run locational costs.

- The 'open access' regime has been established so that any applicant is provided access to the NEM if they meet the mandated access standards; however, access is also premised on not materially or adversely affecting the levels of service and quality of supply to other network users.

- Uncertain access to the regional reference node is a material barrier to entry for generation investors. Additionally, incumbent generators unable to manage congestion may be forced to reduce contracting levels to the system node. Both outcomes hamper competitive contract markets, with resulting impacts on customer prices, and negative impacts on the NEM objective.

- The upcoming surge in connections driven by the RET and the CPRS, along with excess capacity in the exiting network being largely exhausted, provides a setting in which congestion will be an increasing problem. Given its role as a barrier to entry, the inability to enjoy predictable levels of access for the life of a project could compromise the efficient delivery of capacity needed in light of the CPRS and RET.

- The Regulatory Investment Test for Transmission is not suitable for building out supply side congestion arising through the competitive market.

- A detailed analysis of the NER and their application concludes that a framework can be implemented that delivers access certainty. Implementation of this existing framework would enhance dynamic efficiency in the NEM, mitigate negative impacts on the critical contract market, and remove current barriers to generation investment.

- The AEMC is encouraged to review the application of the NER concerning transmission and connection to ensure that any impediments to their appropriate implementation are removed.

Retailing

- Increased flexibility in tariff setting arrangements and progress toward a more effective ROLR mechanism is urgently required in light of the introduction of the CPRS and MRET.

- It is unclear if liquidity of carbon markets will be sufficient to support ongoing forward sale of electricity in the volumes that are currently assumed in many regulated tariff-setting arrangements. Sufficient flexibility in any regulated tariffs setting arrangements is required to ensure that reduced forward contracting levels can be accommodated.

Introduction

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.

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.

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 trades the largest privately-owned generator in the NEM. In total, Loy Yang Marketing Management Company 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 and New South Wales and generates electricity in both Victoria and South Australia. 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 as they share a common interest and common concerns in the sustainability of the NEM market.

Issues A1: Convergence of gas and electricity markets

AEMC position

The AEMC provides that the market outcome "is for market arrangements to support competitive and efficient and timely trading and investment in gas and electricity markets across a wide geographical area and for a range of demand profiles."

We are of the view that there exist no fundamental concerns arising from the convergence of the gas and electricity markets; however, we do not suggest that greater convergence should be viewed as a necessary outcome.

Imbalance between the markets

We agree with the AEMC that gas markets need to be flexible and responsive. We also note the need to eliminate any potential risks arising from imbalances between the two markets. Hence, if market setting arrangements distort incentives to invest in either electricity or gas this may create arbitrage opportunities and these incentives may undermine system security. This is a concern given the expectation that the CPRS and MRET will encourage gas fired generation.

Victorian gas transmission investment environment

The key gas related issue that will be of concern as a result of the CPRS is the Victorian gas transmission investment environment. With a large increase in gas generation connections expected, it is unclear that gas transmission infrastructure will be developed in a timely manner. Delays in gas infrastructure run the risk of delaying the delivery of new generation investment. Given the identified threats to reliability identified by the Commission in the Vic/SA regions, delays of this nature could have severe impacts on electricity market reliability outcomes.

The Victorian gas transmission investment regime, much like the electricity transmission regime, currently relies on the independent planner VENCorp to undertake a market benefits test to justify transmission investment. Unfortunately, VENCorp has applied this test in a conservative manner by failing to capture highly likely outcomes (such as imminent connection of large quantities of gas fired generation due to the CPRS), and only factors in load growth once connection applications are received. Since development timeframes for gas infrastructure (eg. compressor stations, new pipelines) are similar or longer than for power station developments, the risk of gas infrastructure not being available to support generation developments is significant.

Because the market benefit approach is unlikely to be successful in anticipating generation developments, the next option for developers is an extension or expansion of the transmission system under the National Gas Rules. Unfortunately, participants who contribute to augmentations obtain insufficient rights over transmission assets to make business cases for such funding viable.

> A failure to provide participants with gas transmission rights undermines the potential for participant funded infrastructure investment.

Hence the gas transmission development regime is locked in a reactive cycle that is highly likely to delay generation development, and will at a minimum increase risk for gas fired developers.

Parallels can be drawn between the gas transmission regime and the electricity regime – in which a lack of rights on generator funded augmentations, is a significant disincentive to participant funded investment.

Issues A2: Generation capacity in the short term

AEMC position

The AEMC provides that the desired market outcome is for “installed generation capacity to track required levels over time through decentralised decision-making of individual market participants.” We endorse the market objective outlined by the AEMC.

The AEMC’s proposition is that additional mechanisms may be required to support actual or anticipated large reserve shortfalls by complementing the current reliability and emergency reserve trader and NEMMCO’s powers of direction because:

- the SOO is currently indicating low reserve conditions in South Australia and Victoria until at least 2010/11, which is unlikely to be addressed by a supply side market response due to the lead time required to deliver new plant;
- there is a residual risk of early retirement of plant following a serious technical failure which would result in a material reserve shortfall; and
- NEMMCO’s RERT is not capable of dealing with substantial reserve shortfalls.

Concerns over Vic/SA short term reserve shortfalls

While noting the AEMC’s concerns we believe none of these issues is any more problematic in the current circumstances than in the absence of the introduction of CPRS and MRET.

The market design assumes that in the long term average USE will be .002% and therefore, some supply shortfalls may occur. A change to the market framework to ensure there is sufficient reserve capacity under all circumstance implies a fundamental change to this basic reliability setting. If this was the intent, then an adjustment to the Market Price Limit (MPL) and other reliability parameters would be a more appropriate response within the existing market framework than modifying the RERT. Indeed it is unlikely the RERT would be effective at all in delivering greater reliability over the longer term, all other market parameters being equal.

We would agree with the AEMC’s discussion regarding the NEMMCO deterministic reserve levels being misleading. The correct decision not to reserve trade in the 2008/9 summer was based on the fact that NEMMCO itself identified that the deterministic indicators were overconservative and not aligned with the probabilistic reliability standard. For this reason we urge caution in interpretation of SOO or PASA reserve indications (i.e. as flagged by the AEMC in relation to Vic/SA).

How would the RERT be modified to deal with identified concerns?

The AEMC has not identified how the RERT could be modified to deal with the flagged Vic/SA reserve shortfall.

Since there is no prospect of the RERT being able to elicit a supply side response (other than in the unlikely event that a generator voluntarily retired in the face of a impending supply shortfall – which is counter-intuitive since such an outlook would presumably present the generator with a profitable opportunity), it is assumed that the AEMC may believe the RERT could have a greater role in facilitating demand side response from the market.

This assumption deserves careful examination. We would urge the AEMC not to mistake a lack of transparency over demand side participation with a lack of demand side arrangements being established. A number of demand side services are being used by retailers via custom arrangements through retail and other agreements.

We also reflect that historic levels of demand side arrangements are not necessarily indicative of future behaviour. In particular, the NEM to date has had relatively low contract prices, which have meant that more expensive demand side options have not been of value to retailers in constructing their hedge portfolios. As historic capacity surpluses are now largely soaked up – particularly in SA/Vic – it is likely that contract prices may trend up to levels that make demand options more attractive.

We note that the AEMC is currently undertaking the Review of Demand Side Participation in the National Electricity Market. It is unclear the extent to which the work of the AEMC in this area has been appropriately considered. The range of possible proposals arising from this separate review should be considered in this context.

The concept of letting the market discover and construct relevant demand side opportunities would appear more aligned with the AEMC's vision of a decentralised decision-making environment. Any move to try to force more demand side into the market via the RERT, or any other means, is likely to be less efficient in the long-term, as it would be likely to create inefficient vested interests which would be difficult to unwind once established.

In this context the role of the RERT needs to be considered. In particular, we note that the current RERT allows contracting of demand side services should they be competitive. It is unclear what further modifications to the mechanism are contemplated by the AEMC that could increase market efficiency in this area.

It appears unlikely that any conceivable variation to the RERT would be likely to be able to deal with any short-term reserve shortfall more efficiently than the existing market framework. For these reasons, we see no reason for the AEMC to further pursue this area.

Potential early retirements in the face of technical failures

It is reasonable of the AEMC to suggest that faced with imminent retirement due to the impact of the CPRS, owners of high emissions plant would logically give careful consideration to repairing any unforeseen major technical failures of units.

While we agree this is a relevant scenario, we again see little role for a modified RERT in dealing with it. In particular, we note that the existing RERT could be used to funnel additional funding into a project to restore a plant subject to technical failure, if such an action was needed to support reliability, and if the underlying business case required to do the work was not adequate. It is not clear why any change would be needed to the RERT to allow it to deal with this situation (although noting that the costs of such an outcome would likely be very high).

Again we remain unconvinced that a case has been made to modify the RERT, and unless a clear case can be made, would suggest the AEMC ceases this line of inquiry and focuses its efforts on other areas of the review.

A case has not been made to warrant modification of the RERT, or that any further consideration in this area is required. Attempting to use a RERT variant to deal with the issues identified by the AEMC would be likely to reduce market efficiency and not be compatible with the NEM objective.

Investment

While adjustments to the MPL may have the potential to increase generation capacity, notably peaking generation, the risks associated with such an increase can act to discourage non-peaking investment and expose existing market participants, especially base loading wind and thermal generators, to greater financial uncertainty. These risks represent significant penalties, which can lead to serious financial shortfalls for generators and retailers, which it can be argued are in excess of the benefits provided to the market.

More broadly, while noting the AEMC's concerns, we believe issues of generation capacity are no more problematic in the current circumstances than in the absence of the introduction of CPRS and MRET. In that regard, an absence of investment leads to a risk of a shortfall in generation capacity on an ongoing basis.

We suggest the factors outside of regulatory risk which undermine investment in generation capacity include:

- the issues of connection of new generators including congestion and the absence of revenue certainty;
- the absence of a pass through of increased wholesale costs will, create growing uncertainty amongst retailers;
- opportunity costs of supporting generators in an uncertain climate if more productive investment opportunities lie elsewhere; and
- the secondary impacts on contractual positions.

The issue of connection and its impacts on investment incentives and investment risk is discussed at A6.

Contractual positions

We believe the absence of a pass through of increased wholesale costs will, create growing uncertainty amongst retailers. This reduces a retailer's capacity to enter into long-term contracts. In the absence of long-term contracts, new generation capacity will not be built given that it is the revenue certainty of long-term contracts (or long-term retail positions) which underpins the significant investment required to fund new generation.

Loss of equity

The Commission has suggested that the ESAS proposal from government is likely to reduce the possibility of short-term finance related impacts on power station operation. However, the package as currently constructed, will still negatively impact on equity invested in existing projects which is likely to impact on the ability of firms to continue to invest adequately in maintenance and on the appetite for future investment. The risk of these effects impacting on reliability therefore continues to exist.

At present, impacted firms are still assessing the likely effects of the CPRS on the future investment and maintenance plans of their assets (a complex task given the need to forecast global carbon prices). The ESAS is further explored in the discussion of the investment environment in section A8 below.

Additional capacity and maintenance of existing plant will eventuate in the absence of government intervention so long as the market operates effectively and efficiently and regulatory uncertainty is resolved.

Issues A3: Investing to meet reliability standards with increased use of renewables

AEMC position

This chapter considers the ability of the existing frameworks to support the efficient and timely delivery of new generation capacity, including complementing potentially large volumes of new wind generation capacity.

The AEMC proposition is that the existing framework is capable of delivering economically efficient and timely investment including: fast response plant to manage fluctuations from larger volumes of intermittent generation. This general proposition is accepted with significant exceptions addressed in response to issues A4, A5 and A6.

MPL (VoLL)

We consider that the role of the MPL (VoLL) needs to be considered as part of the AEMC's ongoing analysis. While MPL limits price excursions during a single dispatch interval it is not the only mechanism for controlling market risk. The Cumulative Price Threshold and the Administered Price Caps regime play a primary role in managing risk within the market. The interaction of these instruments, and there impacts on the market, warrants further analysis.

Further consideration of the interaction of MPL, CPT and APC is warranted to ensure an appropriate balance between: encouraging the operation of contract markets and investment; and discouraging participation in the market due to excessive risk.

In relation to MPL, we broadly accept the outcomes of the theoretical modelling that show that an increase to $12,500 will encourage the requisite investment.

We note; however, that there are a number of real world issues not captured in the modelling which are relevant to appropriate setting of reliability parameters. These include:

- the role the contracts market plays in facilitating investment;
- the impacts of network outages and other events outside the normal operating envelope which are not able to be modelled in idealised studies;
- disincentives to investment caused by a lack of certainty over generation access to regional reference nodes; and
- most significantly, the assumption that external policy interventions will not undermine the assumptions built into the modelling.

While adjustments to the MPL may have the potential to increase generation capacity, notably peaking generation, the risks associated with such an increase also need to be considered. These risks represent significant penalties, which can lead to serious financial shortfalls for generators and retailers, which may increase risk premiums factored into market investments.

Nevertheless, we support the periodic review and amendment of market settings as an appropriate way of ensuring reliability of supply is maintained.

Reliability shortfalls

The CPRS and MRET, in conjunction with a market which provides appropriate investment signals, we believe, will facilitate investment in the manner outlined by the AEMC once congestion, access and connection issues discussed throughout the submission are resolved.

However, we are concerned that the quality of supply which is largely dependent on the current mandated ancillary services to the network from base load generators, usually coal-fired generators, will not be meet under the current framework. This is a consequence of the increased need for ancillary services by generators, for example wind generation plant, that do not share the same characteristics as thermal plant.

System reliability is dependent, for the foreseeable future, on a plant mix which includes coal-fired generators.

Issues A4: System operation and intermittent generation

AEMC position

The AEMC states that the desired market outcome is "to maintain a secure operating system that facilitates competitive energy markets in the context of large variability in generation outputs."

The AEMC's proposition is that the existing framework, with some adjustments to the technical standards and ancillary services, is capable of maintaining a secure operating system in the context of large increases in intermittent generation.

Ancillary services market

To give the existing framework the greatest opportunity to facilitate investment and to change to the plant mix driven by the climate change policies as well as operate with increased intermittent generation increased levels of FCAS, inertia and reactive power will be required.

Reactive power and inertia that are provided by some generators for free to maintain system security must be provided through new ancillary services markets. This will encourage generators to provide the services (or not retire the plant that provides them from service) and ensure that reliability is delivered in an economically efficient manner.

A commercial incentive to provide reactive power could be expected to effectively remove the need for the heavy handed licensing requirements in this regard in South Australia. This would occur because a commercial incentive to provide reactive could encourage additional low cost reactive investment into the market. Currently the incentive on generators is to minimise the amount of reactive required in technical standards as these standards create an obligation without remuneration. Should the prospect of a reasonable return be presented, it is likely that generator investors could supply additional reactive at relatively low cost which currently they have no incentive to do.

Current mandated provision of some ancillary services disincentivises the production of some ancillary services to the disbenefit of the NEM and renewable energy plant.

Removal of technical requirements for reactive would allow commercial agreement between NSP's and generators for reactive provision although as with all NSP activities, careful independent supervision would be required to ensure that competitive neutrality between network and market procurement options were adopted by the NSP.

The concept of inertia ancillary services has also been proposed on many occasions to NEMMCO, who have not adopted this option. In fact, NEMMCO has currently removed the impact of inertia from frequency control markets by specifically subtracting an allowance for inertial response from the frequency response of generators (and FCAS requirements).

The basis for this approach – which is what fundamentally creates the lack of remuneration for inertia at the moment – has never been adequately justified. At a minimum the AEMC should direct NEMMCO to ensure that inertia is remunerated in

FCAS markets and not regarded as freely available in establishing FCAS requirements.

The benefits of a fully costed market for ancillary services, as detailed above, are:

- enabling connection of new generators to a standard consistent with individual business and investment decisions;
- new connections able to purchase ancillary services that ensure system reliability at a price which reduces overall plant costs;
- incentives for providing generators to provide additional capacity, including via plant upgrades where possible;
- increases economic life of plants that may otherwise close as a consequence of the CPRS, while supporting investment in renewable generation; and
- ensures provision of ancillary services with the most economically efficient generator.

Provision of a wider range of ancillary services through market arrangements will help maintain system reliability and security in an economically efficient manner and increase the life of plant that provides these services that may otherwise have closed pursuant to the CPRS and MRET.

Other options to an ancillary services market

While an ancillary services market or similar is preferred it may be determined that such an option is difficult to administer. While we refute this proposition an alternative option is for NEMMCO to compensate generators directly for the provisions of ancillary services in excess of the minimum technical standard required of each individual connection.

Such an approach would still reward generators with excess capacity and maintain system stability, it; however, places payment obligations upon NEMMCO directly. The form and quantum of compensation would require further negotiation.

Issues A5: Connecting new generators to energy networks

AEMC position

The AEMC states that the desired market outcome is "that the connection of new generation to the energy networks is efficient and timely." The AEMC goes on to provide that the connection process needs to promote:

- a timely consideration of connection applications by TNSPs;
- efficient cost-reflective pricing for new connections which reflects locational pricing; and
- efficient investment in network infrastructure and connection assets, which includes multiple connections.

We agree with the principal but hold a number of reservations arsing from the proposals contained within the Review. The options are set out below.

1. Maintain bilateral negotiations over new connections, but declare an 'open season' for connections in certain geographic areas. Once the season closes, new applications would not be accepted.
2. Create 'hubs' to service clusters of remote generators with separate investment arrangements for network extensions to create hubs and generator connections to the hub:
   - investment between generators and hubs would continue to be bilaterally negotiated; while
   - investment between hubs and the shared (the network extension) would be subject to new regime for planning, charging and revenue recovery in which:
     - extensions could proceed, underwritten by load customers if they met an 'economic test' requiring at least 50% funding commitments from prospective generators;
     - charges to generators would be based on full cost recovery if all anticipated generators materialised; and
     - risk of actual connections being below anticipated would be borne by load customers.
3. Same as Option 2 except the economic criterion would be approved by the National Transmission Planner.
4. Same as Option 3 except that consumers would pay for new extensions (i.e. all between-hub investment) rather than by the remote generators. A variant could be funding by Infrastructure Australia.

Drivers of current proposals

The proposals developed by the AEMC appear to be driven by:

- a belief that an effective approach to cost and risk allocation is not in place;
- confidentiality requirements acting as a barrier to a coordinated approach to new connection for more then one participant at a common location;
- an unwillingness by TNSPs to take the risk of developing network capacity in case new generators do not materialise;
- the desire by some participants to spread the costs of new connections across customers and the market; and
- an unwillingness to attribute full connection costs to connecting participants.

Inefficiencies in the regulated network

We acknowledge that multiple applications for connection could be better coordinated.

However in considering this matter, the basis on which the NEM was originally conceived needs to be considered. The decision to apply a competitive model and to regulate networks was based on the idea that it would provide an overall benefit to the market. At the time, it was recognised that, by their very nature, regulated network monopolies give rise to a number of inefficiencies. However, in some instances those inefficiencies provide for a more effective and competitive market for power supply and should be accepted.

Hence, any network proposals which aid the work of NSPs but takes away the benefit of locational price signals or interferes with the competitive operation of the market in areas of generation should not be supported. While such proposals may improve economic outcomes for NSPs they may reduce efficiency and distort cost and risk allocation within the market. Therefore, such proposals are likely to reduce the overall market benefit and undermine investment signals particularly in jurisdictions reliant on private investment for generation capacity.

The key objective of the NEM is to increase productivity and efficiency which is largely driven by competition in energy generation. This benefit should not be compromised by attempts to reduce minor inefficiencies affecting regulated monopoly providers.

Guiding principles

We acknowledge the issues expressed by the AEMC and note that the key benefit of the proposed options is the realisation of economies of scale. In reviewing the analysis and options that have been presented we have a preference for:

- options that require generators to pay for connection, extension and augmentation, where necessary;
- any option that requires a generator to pay needs to be linked to efficient and predictable access for the economic life of the project;
- is capable of alleviating future congestion;
- arrangements that ensure the integrity of the dynamic efficiency incentives remain; and

- options which are consistent with low cost connection for applicants where there is space but higher costs to be borne by applicants for connection in locations where congestion will arise due to a connection application.

Our position in A6 is relevant here and these parts should be read in conjunction with one another.

Response to options presented

On this basis option 1 is inconsistent with the current framework in that an open season has the effect of locking out connection applications in the "closed season" and creates a definitive barrier to entry.

While the concept of an open season is intrinsically appealing, it gears generation investment to a finite window of time and emphasises centralised planning and the realisation of economies of scale by TNSPs over the benefit of decentralised decision-making by existing businesses and potential investors on an ongoing basis.

The major benefit of option 1 is that is attempts to overcome the information sharing concerns of the TNSPs. In that regard, it would appear improved information sharing arrangements and not the creation of an open season would likely solve the issue without interfering with the competitive dynamics of the NEM.

We note that there may be capacity for NSPs to coordinate multiple applications where those applications occur within a similar timeframe should the information sharing concerns be addressed. However, we also note that private parties who presently choose not to coordinate there decision to connect to the transmission system with other parties do so on the basis that they do not wish to share that information. This is an economic decision. If there were significant economic benefits that favoured cooperation one could argue that private interests are best placed to exploit those synergies.

For these reasons, we do not favour an open season and in the absence of an alternative encourage greater coordination by TNSPs in the limited circumstances in which it may arise while leaving decisions to coordinate timing to private providers should they wish to pursue such opportunities.

Similarly, option 4 is not supported as it fails to meet the principles outlined above, in particular those related to efficient cost allocation to drive locational decision making.

Option 2 and 3 also raise a number of concerns; however, if applied in a very limited range of circumstances and developed in conjunction with the resolution of the issue of access rights, then further consideration of an option 2 type model, or option 3 with a role for the National Transmission, is encouraged.

In this regard, should the development of an "option 3a" which includes credible access rights proceed, the economic and other tests for selection of a location and size of a proposed 'hub', become critical considerations. Our concerns with such tests would need to be resolved before we could provide in-principle support.

The development of new arrangements to realise economies of scale needs to provide incentives for generators to engage in funding extensions and augmentations. Access rights are the primary incentive.

More broadly, we would be concerned that such an approach may have wider application. We believe that outside of these special cases if a TNSP wishes to take steps to forward build network capacity in the absence of connection applications or reliability requirements, which is akin to central planning, the TNSP should bear the risk of stranded assets. While we acknowledge this creates less incentives for TNSPs it promotes market based efficiencies over regulated network planning improvements.

NSPs are the best placed to mange the risk of stranded assets should they wish to undertake network augmentations that have not arisen as a result of a connection application or load customer requirements.

Issues A6: Augmenting Networks and Managing Congestion

AEMC position

The AEMC states that the "desired market outcome is for energy market frameworks to promote efficient use of and investment in the network through decentralised decision-making by individual market participants." The AEMC provides that this is reliant on the right financial incentives on how to use the network and where to locate generation capacity.

Need for predictable access levels for generators

As noted by the AEMC on page 46 of its interim report, generators currently face the risk of their access level being adversely affected by the actions of other market participants. The AEMC characterises this area of the regime as an area where the market "signals are relatively weak".

In order for a market signal to be useful, it must be able to drive efficient behaviour. Put another way, a signal must be able to be managed, if it is to deliver efficient outcomes.

Given the way current access arrangements are being interpreted it is not possible for generators to manage the risk of being congested at some time in the future. This has the following impacts on generators:

- new entrant generators are unable to manage their access to the reference node for the life of the project, and therefore will face difficulty in justifying the investment (or at a minimum will have to factor a significant risk premium into their investment decision); and

- incumbent generators face unmanageable risks, and may be forced to (should congestion arise) reduce their levels of contracting at the system node as the only way to minimise exposure to congestion.

Both of these outcomes are not consistent with facilitating a deep and efficient contract market at the reference node, and consequently are likely to push up energy prices in the longer-term.

Investors funding a generation project need to be comfortable that they can secure long-term access to fuel, and a predictable revenue source. Under the current NEM framework, access to fuel can be managed, and market risk at the system node can be managed (via the contract market); however, predictable levels of access to the node are not manageable.

In the light of the high levels of investment that will be required to meet the RET and CPRS targets, the possibility of connection by others that could create congestion is material. Overall, this is an environment where predictable generation revenue for the life of a project is not available – and this is why the current congestion regime is a significant barrier to investment.

In order to ensure that generation investors can invest with confidence in the NEM, it is necessary to ensure the access regime can deliver adequate predictability of transmission access for generators over the life of their assets.

In the discussion below, we explore how the existing rules can be implemented to deliver a regime that delivers adequate levels of predictability for generation investors. In addition, we outline how this implementation is consistent with the AEMC's objective of providing a framework that drives efficient outcomes through a decentralised decision-making framework.

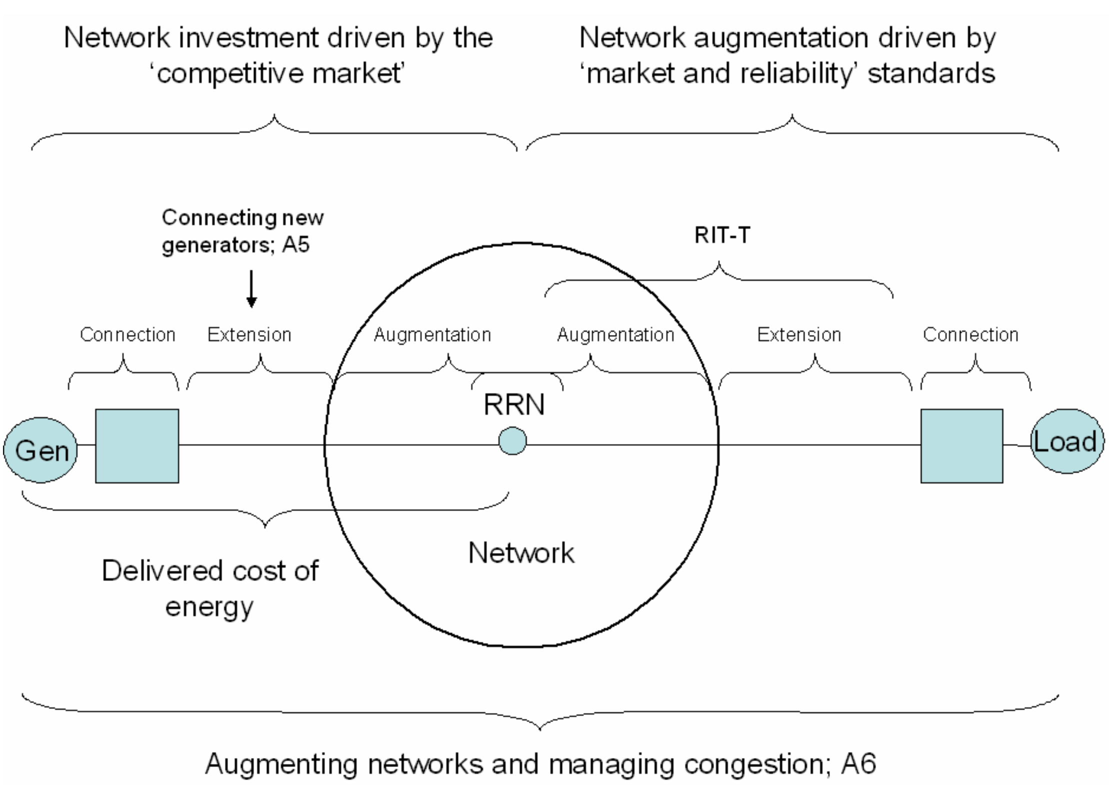
We also note that while this is within the scope of the existing rules (in our view), it has yet to be implemented indicating that some clarification may be required in this area of the NER.

Discussion

Network augmentation is primarily driven by reliability standards and the competitive market. The current arrangements respond to requirements of small customers in a different manner to the access arrangements for incumbent generators and for new generators and large loads.

This separation is represented in Diagram 1 below.

Diagram 1 – Investment framework



Augmentations for customers are largely driven by load customer requirements. Augmentation for generators is driven by new connections arising through the competitive market.

Network augmentation driven by reliability standards

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.

Regulatory Investment Test for Transmission (RIT)

The AEMC appears to suggest the RIT will address market congestion. While we agree the RIT plays a key role in justifying augmentation to the network for load customers, it provides a limited benefit in building out supply side congestion arising through the competitive market as it is an inappropriate tool for this purpose.

On this basis, consideration of the network investment driven by the competitive market must be analysed separately to the RIT. A more detailed analysis of the RIT's inability to deal market congestion as it arises is attached in Appendix 5.

The Regulatory Investment Test for Transmission is not suitable for building out supply side congestion arising through the competitive market.

Network investment driven by the competitive market

We support the market outcome put forward by the AEMC and the assumptions concerning the correct financial incentives for use of the network and location of new generation capacity are also supported.

Furthermore, we contend that such decentralised decision-making supports the combination of generation, loads and transmission assets that provide the least cost delivered energy to consumers. In our view, this requires generators and other investors in the competitive market to be in a position to make investment decisions which are fully informed as to the relationship between their investments and congestion.

Connecting new generators to the energy networks is a key consideration in the management of congestion and network augmentations.

Consequences of congestion

The AEMC is correct in describing congestion as an occurrence where the cheapest mix of generation cannot be used to meet demand because of network limits on electricity flows. The consequences of congestion include:

- discouraging new investment and unnecessary or inefficient network investment;
- suboptimal management of trading risks;
- reduced efficiency due to the effects of congestion; and
- further inefficiencies that result from the "disorderly bidding" incentivised by the current market arrangements (which leads to an inefficient distribution of dispatch within a group of generators that are jointly limited by congestion).

In essence, putting aside the minimum level of congestion which reflects balance within an efficient network, congestion undermines the desired market outcome and does not best serve market participants or customers.

A failure to manage congestion undermines desired market outcomes and leads to suboptimal performance.

Productive efficiency and dynamic efficiency

Congestion is driven by a number of factors. The static factors, that represent congestion outcomes at a point in time, include: size and location of load, generation and network capacity, rules for operating the system and market, and bidding behaviour of participants pursuant to market rules.

Of these concerns only the latter two items, operating rules and bidding behaviour, can be addressed directly by intervention in the short to medium term. However, these are not the primary drivers of congestion. Primarily, congestion is driven by higher order decisions that can not be readily changed in the short-run, concerning plant size, location and network capability, namely:

- transmission and generation investment decisions;
- regulatory framework for transmission access; and
- operation of a competitive market.

In other words, the primary drivers of congestion are determined by business decisions which given the nature of the investment required to develop generation capacity, can not be easily amended or revised. As such, dynamic efficiency, which concerns the efficiency of long-run decision-making and market performance, when infrastructure can be changed, is critical to ensuring congestion issues do not continue to arise. This does not mean existing congestion management cannot be improved; however, it does suggest congestion will continue to be an issue if long-run concerns are not resolved.

Long-run concerns have a greater overall impact on the extent of congestion and the outlook for future trends in congestion across the market. Addressing these concerns will determine whether inefficient congestion occurs in the first place.

Promoting economically efficient outcomes

As such our approach in defining the problem is to acknowledge that congestion is an outcome of the interaction of the higher order factors which determine decisions which are dynamically efficient. In other words, investment in generation and transmission and the regulatory framework which links these investment streams determines congestion. Therefore, providing the appropriate signals to enable potential and actual market participants to make decisions which eliminate inefficient congestion must be a primary aim.

Economically inefficient congestion represents a failure to appropriately invest in the market and as a consequence suggests the market is failing to avoid a series of unnecessarily high costs. Conversely, economically efficient congestion:

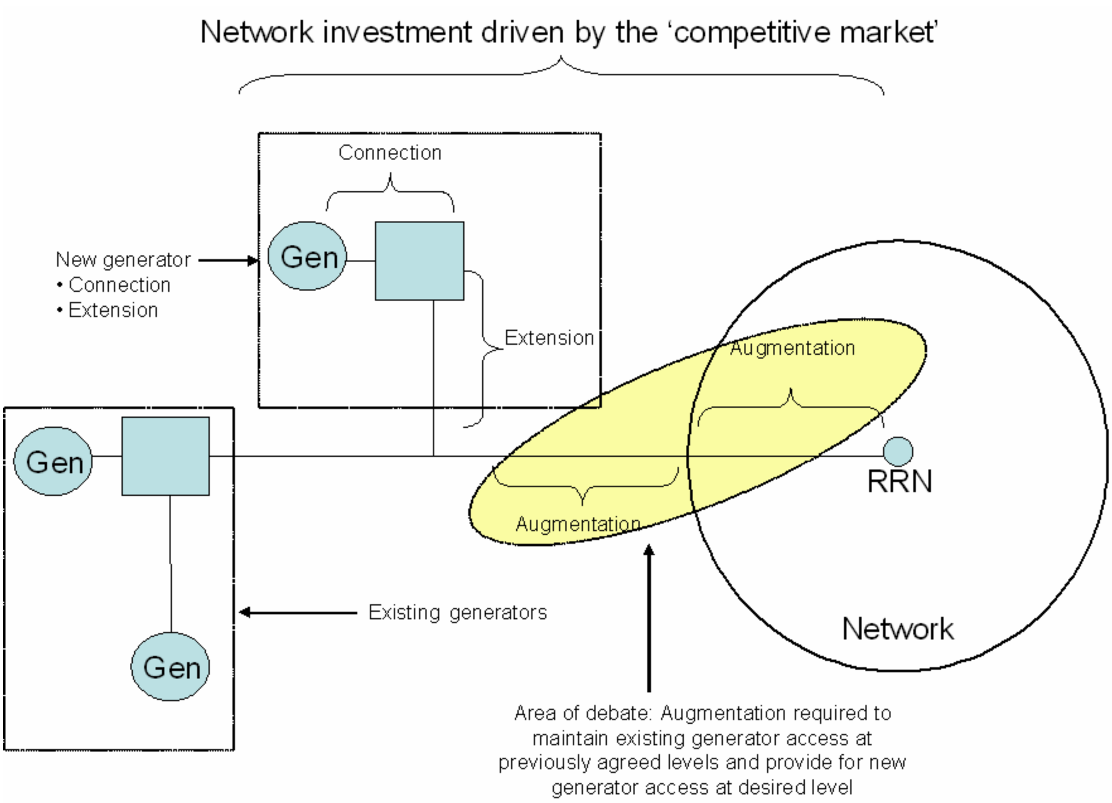
- will occur when overall investment in transmission and generation is economically efficient;
- will result from a framework which permits market participants to make appropriately informed and fully costed transmission and investment decisions; and

- is representative of markets outcomes that provide the lowest cost delivered energy to consumers.

Economically efficient congestion flows from economically efficient investment in transmission and distribution supported by a framework which permits market participants to make informed decisions.

Economically efficient investment

Diagram 2 – Augmentation requirements



We contend that to ensure economically efficient outcomes including economically efficient levels of congestion, decentralised investment decisions must:

- take into account all fixed costs, including transmission, associated with a investment; and

- be informed by a regional forecast price duration curve, that can be forecast by new entrants with a high degree of certainty, to determine the nature and timing of an investment, and that has a high degree of revenue certainty.

What do the rules currently provide for?

Clause 5.4A of the NER detail access arrangements relating to transmission networks. This clause facilitates new connections and provides:

- that TNSPs must negotiate in good faith with a connection applicant;

- that TNSPs must take reasonable steps to provide access arrangements consistent with the connection application;

- that TNSPs must take into account the amount of power transfer capability being provided to existing generators under existing access agreements;

- that in relation to the three points above, TNSPs must consider potential augmentations and extensions required to be undertaken on all affected shared infrastructure; and

- that TNSPs calculate the charges to be paid by the connection applicant concerning connection and as a consequence of required augmentations and extensions.

Independent legal advice supports our view that the abovementioned NER provide for transmission capacity to be built and the shared network to be augmented to a level agreed in connection agreements so that the agreed levels of access for existing generators will not be reduced as a consequence of a new connection (excluding changes in dispatch).

Furthermore, the NER also provide that where a connection applicant is a generator:

- the TNSP is to determine the amounts to be paid by the connection applicant to the TNSP in regards to compensation for existing generators;

- the compensation to be provided by the TNSP to the existing generator in the event that generator has units constrained on or off as a consequence of the connecting applicants connection; and

- the compensation to be paid to the TNSP by the generator in the event that the dispatch of the generator's generating units cause other generators to be constrained off or on.

The economic effect of charges and compensation are effectively the same; however, providing compensation is likely to apply in a broader range of circumstance than augmenting the network and consistent with independent economic advice provides stronger incentives.

The 'open access' regime has been established so that any applicant is provided access to the NEM if they meet the mandated access standards; however, access is also premised on not materially or adversely affecting the levels of service and quality of supply to other network users.

A more detailed analysis of the open access regime in NEM forms Appendix 1; an analysis of the intent of the NEM open access regime forms Appendix 2; the aforementioned legal advice forms Attachment 1; and our recent letter to the AEMC concerning the application of the NER forms Attachment 3.

The NER are consistent with the AEMC pricing principles

As part of the Review of Electricity Transmission Pricing and Revenue Rules the AEMC outlined the economic theory and principles relevant to setting short-run and long-run transmission prices which will promote both economically efficient operation and investment in the NEM. The focus was on the compromises which must be made in applying marginal cost pricing theory to consumers; however, the discussion is also relevant to generators and large loads.

In addition, because generation investment is usually in large discrete amount it is easier to structure the pricing signals to drive both short-run and long-run efficient outcomes without making the compromises necessary for charging smaller customers. A further discussion of these principles forms Appendix 3.

The current NER provisions are consistent with these principles in that incumbent generators are not required to pay long-run transmission costs and new entrants can access surplus network capacity, to ensure the sunk assets are fully utilised. However, when the network capacity is fully utilised new entrants are required to pay for transmission to avoid creating congestion or alternatively must pay compensation if they constrain others off or on. In the event that the sunk assets are fully utilised new entrants are provided location specific transmission signals about the long-run implications of their investment decisions at the time they are making these decisions. Because these long-run signals are applied at the appropriate time they will promote dynamic efficiency.

The transmission pricing signals have been specifically oriented for generators to the type and timing of the decisions they make, specifically the NER ensure that when making:

- long-term locational investment decisions; generators face the location specific short-run signals provided by transmission congestion and losses or location specific long-run cost of any transmission investment required which reflects the cost of removing that congestion; and

- short-term production and consumption decisions generators face the location specific short-run signals provided by transmission congestion and losses.

The access provisions in the NER are therefore consistent with the AEMC efficiency and transmission pricing key concepts.

Economically efficient investment decisions are driven by both short-run transmission costs and long-run locational costs. Consistent with the rules, this should include the long-run and short-run costs of congestion.

The existing NER will facilitate efficient outcomes

New entrants are an important part of the NEM; however, each investment decision must be considered in the context of the applications of the wider market. Current transmission pricing arrangements that tend to ignore augmentation costs and access charges for new generators do not deliver efficient transmission and generation investment or the lowest cost supply to consumers. This encourages suboptimal investment. Access provisions that ignore transmission and congestion costs do not provide incentives for generators to fund additional transmission capacity, leave generators open to the risk of being constrained off, and facilitate inefficient investment.

Current transmission pricing practice does not deliver efficient investment or lowest cost supply to consumers and expose generators to significant risks.

The NER provide that the entire cost of transmission connection must be incorporated into an investment decision. In our view this is what the NER intended but is not what is being applied. This means the costs of deep connection should no longer be avoided by new entrants. While we note that some would argue that deep connection costs form a barrier to entry, the current practices:

- require subsidisation by the market of generators that are creating congestion at the expense of incumbents;

- provide no incentive to address congestion inefficiencies in the long-run and continue to have associated short-run costs;

- do not enable any generators to invest in transmission without the value of that investment being eroded;

- exacerbate a number of generator investment risks; and

- leave investors with few options but to ignore transmission congestion (due to an inability to manage risk) which leads to an inappropriate and inefficient plant mix.

Ensuring that each investment decision bears the full cost, if any, of the congestion arising from reduced access for existing generators and/or the cost of building transmission and providing access certainty will resolve these concerns.

Furthermore, in addition to providing the most appropriate investment signal, an improved access regime, would enable all generators to consider further investment in transmission. This will ensure access certainty for new and existing generators and will have the effect of reducing investment risk; which is a significant benefit for potential entrants. Increased access certainty will mean that investors can forecast future prices with a greater degree of certainty.

Market based investment decisions should include the full costs of deep connection to the transmission network to facilitate efficient market outcomes. This will provide the right plant mix, the lowest cost delivered energy and drive efficient investment in the network.

Why the NER are not being applied

While the NER are (in our view) relatively clear in regard to the above rules, TNSPs appear reluctant to use these provisions as a basis of funding augmentation and have completely avoided the compensation provisions. We believe this is a consequence of:

- TNSP's being able to connect new entrants to the network with relative ease because there has been surplus transmission capacity and there has be no need to consider augmentation and or access charges in negotiating connection agreements to date,

- TNSP's have been able to avoid congestion by funding transmission upgrades by other means,

- a preference from some TNSPs for a greater role in locational planning which has the effect of distorting the decentralised investment decision-making the NEM is based upon;

- a misunderstanding of the rules and a failure to appreciate the intentions of the original decision outlining the 'open access' regime;

- the absence of financial benefits for TNSPs in administering the compensation regime as provided in the NER, with an additional concern that while the provisions are intended to provide cost-neutral outcomes for TNSPs they may fail to do so. In this regard, we note that calculating the access charges or compensation payments based on market outcomes is outside the TNSP's area of expertise;

- a wider unwillingness to discuss access rights in any form, with a belief that open access regime and access rights are mutually exclusive (which is incorrect);
- a failure to appreciate the economic and investment certainty applying the rules would provide to existing and potential participants based on a number of incorrect assumptions concerning barriers to entry; and
- a strong push by new entrants (i.e. new project developers) to avoid additional costs despite the longer-term implications for their projects. Evidence suggests new entrants' positions on this issue soon change once they fully appreciate the uncertainty that such an outcome provides.

As a consequence some TNSPs appear to be taking positions which see them acting in a manner which is not consistent with their role in the NEM. This includes a reliance on the 'good faith' and 'reasonable endeavours' clauses as a means of circumventing TNSP obligations where they believe those obligations are avoidable.

There has been a complete failure by TNSPs to apply the rules consistent with their objectives and sound economic policy.

A regime with access rights

We have already established that if efficient transmission investment does not occur an inefficient level of congestion may result. Beyond the issue of connection which incorporates extension and augmentation as per rule 5.3.5, as already detailed above, there are no incentives for generators to augment the network where there are no access rights.

Hence, the current position for generators is that there is investment uncertainty, no incentive to augment the network and the continual risk of being constrained on or off. We believe access rights in the form outlined above, would be achieved through the implementation of clause 5.4A as intended.

To achieve such an outcome the current unproductive position on access rights must be abandoned. We recommend the issue be opened for discussion noting there are a range of possible solutions that may overcome any remaining concerns held by the AEMC.

Efficient transmission investment is required to alleviate future congestion. Access rights underpin generator incentives to augment the network.

By access rights we mean a non-common financial (not physical) right related to access to and use of intra-regional shared transmission network.

Access rights are not a barrier to entry

It has been previously proposed that transmission rights, as described in the NER, be resisted to address pricing and congestion management and these proposals have been resisted on the grounds that they may create additional barriers to entry, undermine the open access regime and common carriage and do not promote the NEM objective.

Conversely, we say access rights, in a number of forms, lower barriers to entry and support the NEM objective. For instance, as it relates to barriers to entry we believe access rights would:

- reduce investment and operational uncertainty for new entrants, thereby improving the investment environment;
- prevent the long-term degradation of the network through decisions which maximise short-term individual benefits (i.e. tragedy of the commons);
- make funding augmentation a practical option for market participants and potential investors; and
- eliminate regulatory uncertainty.

While the debate concerning barriers to entry, which exist in some form in all markets, are important, it is not of itself the only indicator of whether access rights should be developed. The ultimate objective remains the one put forward by the AEMC, namely: energy market frameworks should promote efficient use of and investment in the network through decentralised decision-making by market participants.

Uncertainty is a major constraint on investment decisions. Any measure which improves certainty reduces barriers to entry. Therefore, we strongly believe that an informed potential investor will anticipate the risk associated with the absence of access rights and constrain their investment accordingly.

Once a potential investor elects to become a market participant they immediately share the concerns of existing incumbents. Hence, the issue of network degradation and congestion is considered in one's investment decisions as a downside risk. Therefore, where an investor has the chance to purchase rights, this uncertainty will be removed and the costs of any rights will be factored into location specific decisions. In this instance, price not risk, is a more appropriate indicator.

Transmission access rights have the effect of reducing investment risk when costs are factored into locational specific decisions and access is protected.

Negotiated access charges depend on the location in question. Appropriately, where there exists spare capacity or low cost augmentation options this cost will be minimal. Where capacity is already at risk or augmentation is difficult costs will be higher. Appropriately, this will provide investors will strong location specific signals.

Existing NER provisions provide flexibility for new entrants

For incumbents, congestion or access rights would need to be allocated based on existing access (the rules already foreshadow grandfathered rights corresponding to access arrangements prior to the NEM). In these circumstances, a new entrant would:

- compensate the incumbent for the extra congestion or loss of access created; and/or

- purchase the transmission access off the incumbent; and/or
- pay for transmission augmentation; and /or
- ensure it reduced output to relieve any congestion occurring.

As a consequence the:

- new entrant would only invest if there is a genuine market benefit (i.e. if its private benefit exceeds the cost of the above);
- incumbent will be protected against uncertainty and arbitrary loss of value due to loss of utility from a common resource; and
- new entrant will in turn be provided with a level of certainty which the current framework does not provide.

This model:

- maintains TNSP obligations to economically expand the network to accommodate growth;
- provides access arrangements consistent with the NER and the NEM design which envisaged rights;
- provides appropriate signals based on price not risk;
- recognises the circumstances of incumbents without economically penalising incumbents financial position; and
- allows for the development of a model which minimises regulatory complexity.

Access rights allocated to incumbents based on the existing rules could be purchased or compensated for, should a new entrant not wish to augment the network to avoid congestion.

On this basis, we argue that access rights in the manner conceived above are entirely consistent with open access and common carriage principles. Furthermore, the cost of acquiring rights is not a barrier to efficient investment and the treatment of incumbents would improve, not distort, the operation of a competitive market. While arguably recognising rights may create some initial regulatory complexity, this is more than offset by the increase in commercial certainty, reduction in investment risk and improved management of congestion.

Modelled economic outcomes associated with access rights

Intelligent Energy systems undertook a modelling exercise for a group of generators with the objective was of assessing the potential economic benefits to the market as a whole of locational signals incorporating both energy and transmission costs. The modelling compared the current arrangements with two alternative arrangements which had varying degrees of locational signals.

The modelling results show that congestion costs are reduced and new generation projects are made in locations optimal to the industry as a whole if new generation projects fully encompass the costs of congestion and the quality of supply to network users. Appendix 4 outlines these results.

Attachment 2 provides the results of additional modelling undertaken by Synergies Economic Consultants. The results detail the investment risk to new generators and the revenue risk to existing generators. The Synergies report demonstrates that if the NER applied as drafted they support efficient outcomes.

Summary of discussion on congestion and access

As outlined above, it is essential that the AEMC ensure that predictable levels of access are provided through the NER. This is consistent with the initial intention of the NEC when the NEM was first established, would deliver efficient investment outcomes, reduce barriers to entry for generation developers and advance the NEM objective. Congestion is likely to increase with the RET and CPRS implementation, and the transmission regime should be clarified, along the lines we outlined above, now to ensure CPRS and RET investments can be delivered and reliability maintained.

Other matters raised by the AEMC in section A6

Transmission Loss Factors

We note the AEMC's concerns in relation to the uncertain locational signals provided by the static loss factors (SLF) that are applied within regions. We believe that the uncertainty in these values arises almost entirely from the uncertainty in the underlying physical losses that these SLF values are designed to approximate.

We note in passing that the approximation inherent in using SLF values has had increasing impact in the market with the inclusion of long, high-loss lines with highly variable flows into this system, and hence we suggest that some means of reducing the adverse effects of using SLF values (rather that the true loss values) may be worthwhile.

A significant factor in the sensitivity of the underlying physical losses to new entrant generation is the provision of access to new entrants without network augmentation even if this results in reduced access to incumbent generators. This leads to a pattern of higher loading of the existing network access and hence higher losses, which can be significant due to the "square-law" relationship between line loading and losses.

We argue elsewhere that to promote economically efficient investment decisions, the true cost of locational decision (in terms of either augmentation or compensation for congestion) should be reflected to new entrants. We note here that if this were adopted it would, as a secondary benefit, have the effect of minimising the changes in actual transmission losses due to new entrants and thus provide a more stable locational signal through the SLF values.

Congestion and CPRS and MRET

Incentives for low carbon emissions and renewable energy will facilitate market entry for a range of technologies, existing and new, which are less carbon dioxide intensive. Under the current transmission pricing arrangements there is a risk that this new investment activity will not align with current transmission flow paths and could increase congestion and risk for incumbents. Transmission pricing reform is therefore seen as critical at this point in time.

TNSP planning arrangements and responsibilities

Improved augmentation can result from a number of mechanisms. First, non-common financial rights, discussed above as access rights, for new and incumbent generators. Second, a reconsideration of the customers charging mechanisms, through TUOS, across regions for transmission augmentations which benefit the entire network or benefit customers in regions outside the location of the augmentation.

Additionally, in some instances TNSPs may seek to develop remote areas of the network to take advantage of economies of scale.

These matters are discussed in further detail in the response to A5.

TUOS charges

Existing generators are exempt from the shared TUOS charges. This position was argued by the existing generators (and accepted by the ACCC at the time of the establishment of the NEM) on the basis that:

- the level of access available to generators was constructed at the time the generator was constructed and it was difficult to determine a fair share of costs now. Generators that had been sold to private parties had included their purchase price the level of access that was defined in the NER at the time; and

- no economic advantage would arise from applying a transmission charge to incumbent generators, which is a locational signal, to generators that had already been constructed since moving them was impossible.

At the time of market start the shared TUOS charge (a sunk cost) should be treated as a large fixed amount that should be allocated in an economically efficient way, that is with least distortion, and that implied as need to the final consumers as possible. In our opinion nothing has changed to suggest this position is incorrect.

Issues A7: Retailing

AEMC position

The AEMC provides that the market outcome in this instance is to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers. We support this objective and second the proposition that competitive retailers must be capable of charging cost reflective prices, which includes appropriate incorporation of transmission charges attributable to customers.

The AEMC also notes: that it is not certain that the ROLR arrangements will be adequate to address the failure of a large retailer operating across multiple jurisdictions; and that the absence of pass throughs for CPRS and RET costs may lead to significant financial distress in the retail sector.

Need for urgent action on retail tariff regulation & ROLR schemes

We strongly support the AEMCs contention that:

- more flexible retail tariff setting process are required to deal with the cost imposts that will be imposed on the market by the CPRS and RET schemes; and

- ROLR events will be become more likely as general costs for retailers increase and that existing schemes are not likely to result in an efficient or effective transition for customers.

While, as the AEMC has identified, there are current high level commitments and processes in place to deal with these issues, we note that progress in these areas has been inadequate. Indeed as things stand, there would appear no prospect of the existing processes addressing these issues prior to the end of 2009, which is when retail tariffs for 2010 will be finalised in many jurisdictional environments.

As the CPRS is scheduled to commence mid-2010, it is therefore critical that adequate clarity about how the resulting cost imposts from the scheme be established by the end of 2009. We strongly urge the AEMC to take a pro-active role in progressing these arrangements. At a minimum, it is incumbent on the AEMC to point out the urgency of timing with respect to this matter to the MCE during the course of this review.

With regard to the ROLR arrangements, we are aware that significant work has already been undertaken in this area over a period of years, and that currently its implementation is dependant on drafting and passing appropriate NEL/NER amendments. Again we urge the AEMC to point out to the jurisdictions the need to rapidly progress this work item, ideally to have reformed arrangements in place prior to CPRS commencement in June 2010.

Increased flexibility in tariff setting arrangements and progress of the ROLR mechanism is needed in light of the introduction of the CPRS and MRET.

Other concerns that may impact on retail arrangements

The AEMC has identified the risk that the costs of carbon permits are likely to have working capital impacts on participants in the NEM.

This issue warrants further consideration by the AEMC. Under current market arrangements (which are assumed in most regulated retail tariff setting processes), retailers can purchase hedge cover for their entire load at fixed prices prior to the commencement of the year for which tariffs are to apply. Depending on how the CPRS is implemented, this assumption could no longer apply.

For example, to enable a generator to fix a price for sales going forward, the generator needs to establish a carbon position. This is likely to require the generator to fix a price for the carbon permits that it will require to support the sale of contracts. Should insufficient permits be released for circulation, and speculators are unwilling to take short positions on permits of sufficient volume to underwrite generator needs, then generators may be reluctant to continue to offer firm prices for future years.

Lack of availability of carbon permits will have significant flow-on effects in the contracts market.

The options available to generators under this scenario would be either:

- not to contract if insufficient permit price certainty cannot be achieved; or
- contract for underlying supply of energy, but with a carbon cost pass-through clause.

Either of these options is not compatible with the existing approach to setting regulated retail tariffs (which use firm contract prices as the basis for their wholesale costs, or in some cases long run generator cost estimates). The only sustainable option, should this situation eventuate, would be to include regular ex-post pass-throughs into regulated tariffs so retailers can recover the carbon cost once it is determined.

Such an outcome would appear inconsistent with the idea of retailer's role as a price risk service manager for customers in the NEM.

Whether or not this is likely will depend on the supply demand position of permits in the market, the willingness of financial speculators to take naked forward positions on permit prices, and the availability of international permits to meet domestic requirements.

In relation to the first of these points, we note that generators are likely to require around 50% of the permits to be issued under the CPRS scheme in order to fully cover their liability, and that the CPRS scheme as proposed will only auction 3/16th of a years permits prior to vintage. In addition to this 3/16th of permits available, there may also be some free permits in circulation, and in later years the possibility of banked permits. However, it would appear unlikely that there will be sufficient permits available to allow the generation sector to fully cover its requirements prior to the start of a year.

The second points notes that while there may be a lack of physical permits in circulation to underwrite forward sales, financial speculators could take naked trading positions to offer price certainty to generators. While this would be expected to a degree, we note that the shortage of permits is likely to be most acute in early years of the scheme prior to any significant banking of permits being available, and that this is most likely to correspond to the current risk aversion in financial markets as a result of the global financial crisis.

International permit availability is also under question, given question marks over the form of any post Kyoto international market, and the price of any resulting permits. In this context the assumptions about international permit availability driving Treasury modelling outcomes is being widely questioned. Modelling of the electricity sector by the NGF illustrates that should the large supply of low cost international permits assumed by Treasury not be readily available, the impacts on the electricity generation sector are likely to be dramatically worse than predicted by Treasury. In this context, ongoing forward sale of electricity by generators remains questionable.

On balance there would appear to be a reasonable likelihood that generators may not be able to source firm carbon prices to sufficient volumes to allow the sale of electricity contracts with firm prices prior to a particular year. It would be valuable for the AEMC to consider this permit supply demand position, and the potential impact on retailer's ability to source sufficient forward carbon inclusive electricity prices to allow regulated tariffs to be fixed prior to the year.

Ongoing forward sale of electricity generation is uncertain given the real concerns over the availability of permits, particularly at the commencement of the CPRS and if international permits do not materialise to the required degree.

In addition to uncertainty in retail pricing related to the CPRS impacts, it can also be noted that a lack of clarity about how costs of the expanded RET scheme will be factored in is also an issue. Given that the RET scheme costs may eclipse CPRS impacts in the early years of the scheme, it is critical that certainty of retail price cost recovery is achieved early to ensure recovery risk in this area does not impact on the willingness of retailers to enter contracts needed to fund the required generation development.

Summary

In summary, we support the AEMC pro-actively working to bring forward the implementation of more flexible regulated tariff setting processes, and the implementation of enhanced ROLR arrangements. At a minimum the MCE should be advised of the critical nature of timing in regard to these reforms, and in particular that the pricing arrangements need to be put in place prior to the end of 2009.

Consideration of the likely future ability of generators to offer firm carbon inclusive electricity prices for their full volume is also warranted.

Appendix 1: The Open Access regime in the NEM

The following summary and overview of the provisions in the rules relevant to customer and generator access shows that:

- The objective of the access provisions is to ensure that the agreed level of access for existing generators and customers will not be reduced as a consequence of the new connection; but only to the extent that all facilities or equipment associated with the power system are in service;
- for customers this is achieved by new customers paying to augment the shared network so that other generators or customers level of access is not impacted;
- The provisions for generators mirror the provisions for customers, (Except for the addition of 5.4A(h) which provides compensation for generators constrained on or off);
- access certainty for generators is achieved by new generators paying to augment the shared network so that other generators or customers level of access is not impacted and/or the payment of compensation should another generators access be reduced.

Customer clauses

The obligation to connection customers, and to charge for any augmentations necessary to maintain supply to others is contained in:

- Rule 5.1.3(a) to (c), which covers the right of access and that access is to be in under commercial terms;
- Rule 5.2.3(e) and (e1), which covers the requirement to document and maintain agreed transfer capability;
- Rule 5.2.4, which requires a connecting customer to provide forecasts as part of its application to connect;
- Rule 5.3.5(d), which requires an NSP to assess requirement for (and the costs of) all necessary augmentations to ensure that the levels of service and supply are maintained for existing customers; and
- Rule 5.3.6, which requires an offer to connect to include necessary charging detail.

For almost all customers rule 5.3.5(d), is of little significance since they have little impact on their neighbours but for large customers the cost of any deep augmentation to connect, and to maintain supply to neighbours, is currently included in the connection and TUOS charges. This can include what is termed “capital contributions”.

Generator access provisions

A more complete description of the generator access provisions is provided in the attached legal advice to the Victorian generators from Norton Gledhill.[1]

Generators access is defined by the following clauses:

- Rule 5.1.3(a) to (c), which covers the right of access and that access is to be in under commercial terms;

[1] See Norton Gledhill advice to the Victorian Generators dated 10th April 2008

- Rule 5.2.3(e) and (e1), which covers the requirement to document and maintain agreed transfer capability;
- Rule 5.2.5, which requires a connecting generator to provide forecasts as part of its application to connect;
- Rule 5.3.5(d), which requires an NSP to assess requirement for (and the costs of) all necessary augmentations to ensure that the levels of service and supply are maintained for existing customers;
- Rule 5.3.6, which requires an offer to connect to include necessary charges and also a requirement to conform to Rule 5.4A; and
- Rule 5.4A, which:
    - o reiterates the requirement to assess changes to networks from Rule 5.3.5 (d), in f.4A (e); but
    - o which allows negotiated levels of service from forecasts and charging for the agreed capability 5.4A (f) (3), including
    - o negotiated variations from forecasts are supplemented by an ability to gain payments from the generators where the agreed transfer capability required under Rule 5.2.3(e) is reduced for another party 5.4A(h); and
    - o payment to that other party under the same clauses where the agreed transfer capability cannot be maintained.

Except for the addition of 5.4A(h) these provisions mirror the provisions for customers. They make economic sense since the cost of connection for generators can be large and when included as part of the project cost which will influence investors to locate in positions that minimise the total project cost and ensure the delivered cost of energy to consumers is considered in making investment decisions.

The access charges or the costs that are directly attributable to a generator participant's connection to a network include the cost of *connection, extension, augmentation* and *access charges* in accordance with Rule 5.4A(h). (Refer also to the Victorian Generators letter to the AEMC dated 3 Feb 2009 re Clarification of the terms used by the AEMC in Issue A6 – Augmenting networks and managing congestion.)

Rule 5.4A(h) has the effect that if congestion occurs as a consequence of a new generator creating a constraint the full cost of that congestion will be allocated to the causer and not distributed to other participants. This is most likely to occur if a generator elects not to pay for augmentations.

It makes sense for large generators (and large customers) to locate where there is surplus capacity on the network or where their location would reduce constraints. This allows maximum use of the network. If additional network was to be constructed to allow connection then the newly connecting party should pay those costs since it was an additional cost solely due to them. In time it was considered that generators would be paying an appropriate proportion of all network augmentations.

Existing generators were exempt from the shared TUOS charges. This position was argued by the existing generators (and accepted by the ACCC) on the basis that:

- the level of access available to generators was constructed at the time the generator was constructed and it was difficult to determine a fair share of costs now. Generators that had been sold to private parties had included their purchase price the level of access that was defined in the Code; and

- no economic advantage would arise from applying a transmission charge to incumbent generators, which is a locational signal, to generators that had already been constructed since moving them was impossible.

At the time of market start the shared TUOS charge (a sunk cost) should be treated as a large fixed amount that should be allocated in an economically efficient way, that is with least distortion, and that implied as need to allocate the cost to the final consumers as far as possible

In negotiating access the Rules provide for:

- transmission capacity to be built and the shared network to be augmented to a level agreed in the connection agreement so that other generators agreed level of access will not be reduced as a consequence of the new connection (only to the extent that all facilities or equipment associated with the power system are in service) ; and
- a right to compensation where a generator's output is reduced in the presence of a network constraint, due to the output of another generator or on the occasions when it was constrained off due to a failure of the NSP to meet the minimum standards of performance set by the Rules.

(The economic effect of these two provisions is essentially the same however providing compensation has the potential to apply in a broader range of circumstances than augmenting the network and therefore has been described as being "stronger". The effect of these two types of access is discussed in more detail in the advice provided by Synergies economic consulting to the NGF included as Attachment 5.)

The Rules require the TNSP to provide the cost of *connection* and *extension assets* as well as *augmentation* and *access charges* in accordance with Rule 5.4A(h), and for generators to pay them. If a new generator does not pay for *connection* and *extension assets* it is unlikely that it would be connected to the network, however in practice it appears that at least in some cases, TNSP's see no obligation to include the cost of *augmentation* and *access charges in connection agreements*. The reasons for this are not clear.

Possible reasons for neither TNSP's nor new entrants to include *augmentation* and or *access charges* in connection agreements may be:

- It is commonly accepted view that in an open access regime generators have no access rights,
- New entrants wish to avoid the additional costs and don't understand the consequences,
- TNSP's have been able to connect new entrants because there has been surplus transmission capacity and there has be no need to consider *augmentation* and or *access charges* in negotiating connection agreements,
- TNSP's have been able to avoid congestion by funding transmission upgrades by other means,
- Calculating the access charges or compensation payments based on market outcomes is outside the TNSP's area of expertise.

A more complete description of the access provisions in the Rules is provided in the attached legal advice from Norton Gledhill to the Victorian generators dated 10th April 2008 included at Attachment 1.

The generator access provisions are also consistent with the “Efficiency and Transmission Pricing Key Concepts” that guided the AEMC in their recent Transmission Pricing Review. This is discussed in more detail in Appendix 3.

Appendix 2: Analysis of the intent of the access of the NEM "open access" regime as described in the "NEM access code - Decision (16 September 1998)" with respect to generator access.

This analysis in our view;

- demonstrates that there is at least consistency between the Rules as interpreted in this submission and the ACCC access code decision and
- the ACCC's objective was that in the 'open access" regime described by the ACCC any person seeking access to the network must not materially or adversely affect the levels of service and quality of supply to other network users

The following is a review of the relevant extracts from the NEM access code - Decision which describes the NER 'open access regime'.

Although the Rules may not suffer from any of the particular kinds of problems for which it is valid to turn to extrinsic material, this information has been provided because it appears that their may be different views as to the collective effect of the Rules.

The ACCC considered that the access provisions in the Rules are consistent with the Commissions objectives and in particular that incumbent generators are entitled to have their access protected. It can also be seen that the NEM access code - Decision is consistent with;

- the economic analysis by Synergies Economic Consulting for the NGF which provides economic argument supporting the provisions in the Rules and hence the Commissions view, (Attachment 5), and
- legal advice form Norton Gledhill that identifies the relevant Rules, describes the nature of the generator access provisions and shows that the Rules are consistent with the Decision (Attachment 6).

4.1 Overview of connection and use of system arrangements

The following statements appear in the introductory section:

"The code aims to create a workable, non-discriminatory right of access to the physical 'natural monopoly' network which enables users to participate in the competitive electricity market."[2]

"These procedures are governed by a set of connection principles, objectives and obligations (see Box 4.1). In bringing these procedures together in the access code, the applicant (sub. p. 216) argued that:

> It needs to be recognised that arrangements and procedures for connection to transmission and distribution networks have existed for many years but these differ between jurisdictions and between Network Service Providers. One objective of these provisions is to provide a common set of procedures for connection to simplify entry for parties seeking access."[3]

and

> "Connection to a network at the wholesale level typically will be covered by a connection agreement between an NSP (transmitter or distributor), a generator or a customer (eg a mine or industrial plant). Provided other users are not

[2] NEM access code - Decision (16 September 1998) Page 75
[3] ibid Page 75

adversely affected, the connection agreement may override code provisions and must include:

- the legal and financial terms and conditions of the connection;
- service standards for ongoing use of the network;
- technical specifications for the type of connection involved and its operation; and
- details on payment for connection and network service".[4]

It is clear then from the summary that creating a workable, non-discriminatory right of access to the physical 'natural monopoly' network is not inconsistent with ensuring existing users are not adversely affected.

Also it was noted that that the intent was to provide a standardised set of that arrangements and procedures for connection to transmission and distribution networks that replicate those that have existed for many years, . Replicating these historical arrangements would also mean an incumbent's access would be protected.

4.2 Connection negotiation procedures

4.2.1 Issue for the Commission

In accepting the Code the major issues that the Commission assessment focused on were;

- The impact on barriers to entry, i.e. ensuring that the Code did not create a barrier to entry, and
- Spill over effects, i.e. protecting the legitimate business interests of incumbents, (both network owners and users), from the impact of new entrants

This is demonstrated from the following statements"

'The Commission's assessment of the access code's connection arrangements focuses on their likely impact on entry barriers and spillover effects. The assessment criteria of particular importance addresses the issue of how the connection arrangements:

- promote the public interest by not unnecessarily adding to entry barriers which would reduce contestability in other markets;
- protect the legitimate business interests of:
  - the existing network owners and users from potential spillover effects from the operation of new connections; and
  - new connectors from potential spillover effects from the operations of existing network owners and users."[5]

"In terms of the network connection procedures, the Commission has focussed on whether the connection procedures create an entry barrier and, if so, whether these entry barriers are non-discriminatory between existing, new and potential entrants and between differing technologies."[6]

[4] ibid Page 76
[5] ibid Page 76
[6] ibid Page 77

In its assessment the Commission did not find that the access arrangements created a barrier to entry or were discriminatory and therefore accepted the access arrangements proposed by NECA, the applicant.

4.2.2 What the applicant says.

The following extracts demonstrate that NECA, (the applicant), also noted that the a major principle in formulating the Code was that connection arrangements were not to materially or adversely affect the level of service to others, but new entrants could obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the necessary assets to allow connection at the specified capacity and level of performance. This means that incumbent generators have their access protected from degradation by new entrants and new entrants would pay for the assets required so that others level of service would not be materially or adversely affected.

In the decision the Commission noted that"

"The applicant indicated that (sub. p. 216):

> The major principle of the connection requirements provisions is that a party is to be provided physical access to a transmission or distribution network on a fair and reasonable basis provided that the connection arrangements do not materially or adversely affect the levels of service and quality of supply to other network users."[7]

"The applicant stated (sub. p. 220) the connection requirements are based on the principle of commercial negotiation and are synonymous with the concept of 'light handed regulation' as:

- NSPs and parties seeking access must negotiate a connection agreement that:
  - meets the needs of the connection applicant; and
  - does not adversely or materially affect the levels of service and quality of supply received by other network users."[8]

Clause 5.3.5d is consistent with this argument and the following position.

> "In addition, the applicant (sub. p. 221) argued that these arrangements give participants full control over network service options, with scope to make appropriate trade-offs between cost and the performance and reliability of the network service provided, for instance: New entrants can seek access to a transmission or distribution network and will be able to obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the necessary assets to allow connection at the specified capacity and level of performance."[9]

The ACCC acknowledged NECA's intention that the compensation provisions in the Code (clause 5.5f now 5.4Ah) provided generators with "firm access", and NSPs are also required to negotiate in good faith to in relation to augmentations and other "firm access" agreements, which could also be based on the compensation provisions in 5.4Ah.

[7] ibid Page 77
[8] ibid Page 80 & 81
[9] ibid Page 81

'The applicant also argued (sub. pp. 158–9) that the code provides the option of 'firm access' arrangements for generators. NSPs are to negotiate in good faith to provide compensation in the event that a generator is constrained-off because the level of service and capability of the network is not consistent with the terms of the connection agreement.[10]

They are also required to provide adequate information to support negotiations and use best endeavours to meet each generator's request, consistent with good industry practice and related decisions on augmentations and other firm access agreements. NSPs can also negotiate similar arrangements with customers and other NSPs but they are not obliged to do this:

> A major concern for generators arises from the possibility that such an outage could coincide with a high pool price incident in the energy sub-market. This would expose generators with contracts for differences in the energy sub-market with very high difference payments.
>
> The compensation provisions in clause 5.5(f) are to enable the generator and the Network Service Provider to come to an appropriate risk sharing arrangement...[11]

Neither the ACCC nor NECA distinguished between different levels of "firm access" discussed in the decision; however the discussion demonstrates that that there could be different levels of "firm access". The Code provisions provide one level of firm access under 5.3.5d and 5.5f (i.e. 5.4Ah). That the term "firm access" can encompass a range of different levels or conditions of access is evident in the discussion below on the "Commissions considerations".

4.2.4 The consultant's views

These consultants' views as elaborated below are consistent with the applicants and the Commissions objectives and are embodied in the Code.

> "Nevertheless, Western Power argued that the code's connection inquiry and offer process would be improved if:
>
> - existing agreements were honoured when affected by someone else's new connection, unless the parties agree otherwise or the change is to ensure the safety, quality and reliability of supply;
> - any new agreement should not, as far as possible, impose a barrier to entry to future participants;"[12]

4.2.5 The Commission's considerations

Firm access

> "The Commission is aware that firm access is much debated and the current code provisions are the latest of several versions. In addition there has been a profound change in the commercial relationship between generators and transmission networks, as well as others in the industry, as a result of structural separation and privatisation along with the wholesale markets and access arrangements. Previously, firm access arrangements were determined

[10] ibid Page 82
[11] ibid Page 82
[12] ibid Page 84 & 85

by administrative decisions, often internalised in a single organisation or at least in a public sector framework."

The Commission noted that NSPs were not obliged to provide firm access in every case however the Commission did note that the Code contained some "firm access" provisions (it would appear that the access provisions in the Code generally replicate in an economic sense at least the access provisions previously determined by administrative decisions, i.e. the central planner). The Commission described the "firm access" provisions generally as follows;

"Although NSPs are not obliged to provide firm access in every case, the code includes a set of obligations in terms of negotiation, information and compensation arrangements. Similarly, generators are limited to their maximum power input and any arrangements must account for its impact on firm access for other generators."

The provisions to which the Commission was referring are those in chapter 5 of the Rules that define generator access provisions, the operation of which is described in detail in the Norton Gledhill legal advice.[13]

Strengthening of the Firm Access Provisions

During the consultation process on the application by NECA, generators sought a significant strengthening of the firm access provisions in clause 5.5 (now 5.4A). The Commission summarised the generators position as follows;

"For instance, at the pre-decision conference and in subsequent submissions8, generators argued for a significant strengthening of the firm access provisions in clause 5.5. They requested that NSPs be obliged under the code to negotiate and offer firm access hedge arrangements with compensation whenever generators are constrained-off the network. They argue that, under the present provisions, NSPs presently negotiate from a monopoly position and thus have no incentive to bear extra risk of network constraints and the adverse impact these constraints can have on access to favourable pool prices. The incumbent generators argue that NSPs should offer a choice of access arrangements including, but not restricted to, firm access. They also argue that obliging NSPs to offer firm access would be the most efficient allocation of network risks to the party most able to bear the risks and would reinforce locational pricing on different parts of the network, thus removing uncertainty for new generators connecting to the network."[14]

The Commission noted that the Code supported negotiations between NSPs and generators to provide generators with a "firmer" level of access than that defined as a minimum level of service.

"Improved cash flow provides a major incentive for both generators and NSPs to bargain firm access. Generators are either compensated when constrained-off or are able to bid unconstrained (because of network improvements) when spot prices are favourable; and NSPs derive revenue from the sale of firm access rights which can partly fund those network improvements. Consistent with these incentives, the code provides for maximum prices for a defined (minimum) network service. It also envisages that participants can negotiate

[13] Refer to the section in this submission headed "The Open Access regime in the NEM"

[14] NEM access code - Decision (16 September 1998) Page 91

> discounts for the defined service or can negotiate for an improved level of service but at a higher price. In this context it should be remembered that generators pay little in the way of TUOS charges."[15]

The Commission further stated;

> "However, firm access and insurance arrangements will make the relationships between generators and NSPs more complex due to the sharing of risk. Consequently, the Commission believes that while the code is largely neutral on firm access arrangements, the code includes sufficient flexibility for generators and NSPs to negotiate access arrangements (including firm access) which is in the commercial interests of both parties. Nevertheless, if the generators' concerns are realised, and the NSPs refuse to negotiate terms and conditions, then at that stage it may be appropriate for the Code Change Panel to consider alterations to the code which provide NSPs with additional incentives or obligations to provide firm access arrangements."[16]

The Commission declined to address the generators requests for a significant strengthening of the firm access provisions in clause 5.5 (now 5.4A), and instead referred the issue to NECA.

> "At an appropriate time after the commencement of the market, the national Electricity Code Administrator should review the arrangements for firm access so the code change processes can consider any amendments required to introduce further incentives and/or obligations regarding the provision of firm access."

This review therefore was to be in relation to "further" incentives and/or obligations regarding the provision of "firm access", i.e. in relation to the feasibility of and options for increasing the firmness of the access provisions already in the Code or Rules.

The fact that the Commission did not support the "further firm access" provisions does negate the firm access provisions in the Code/Rules.

[15] ibid Page 89
[16] ibid Page 90

Appendix 3: AEMC Efficiency and Transmission Pricing – Key Concepts

The following discussion demonstrates how the current transmission pricing arrangements are consistent with AEMC Efficiency and Transmission Pricing – Key Concepts and hence will drive economically efficient outcomes.

The extracts below are taken from the AEMC transmission pricing issues paper[17].

In Chapter 5 the AEMC outlines the economic theory and principles relevant to setting short run and long run transmission prices which will promote both economically efficient operation and investment in the NEM. The focus of the chapter is on the compromises which must be made in applying marginal cost pricing theory to consumers however the discussion is also relevant to generators and large loads.

In addition because generation investment is usually in large discrete amount it is easier to structure the pricing signals to drive both short run and long run efficient outcomes without making the compromises necessary for charging smaller customers.

The focus of the following section is in relation to long run transmission pricing.

"5.2.4 Long Run Marginal Costs and Efficient Pricing [18]

Policy makers may be concerned that prices designed to signal the SRMC of using the network and recover remaining costs on a least-distortionary basis provide inadequate signals to actual and potential network users of the future cost implications of network use. An alternative is to charge users on the basis of the LRMC of using the grid. Energy Australia's submission supported consideration of LRMC as a basis for transmission pricing for this reason.25

Such a methodology considers the effect of network usage on all costs, including physical infrastructure. The rationale for prices based on LRMC is that it signals the full costs of network use that would be incurred in the long run. This is intended to provide efficient signals for participants' longer term decisions.

Importantly, setting prices in order to positively influence future decisions is the opposite of setting prices to minimise their impact on future decisions. This highlights the need for transmission pricing arrangements to consider trade-offs between short run and long run efficiency.

- On the one hand, transmission prices should be structured in such a way that they do not deter the utilisation of network assets that are already in existence and have no alternative use. This is often referred to as static efficiency because it takes the existing (sunk) network as a given and avoids consideration of future investment.

- On the other hand, setting prices to maximise utilisation of the existing network may not provide actual and potential network users with appropriate signals about the implications of their locational, consumption and production

[17] AEMC Review of the Electricity Transmission and Pricing Rules Transmission Pricing Issue Paper Nov 2005 - Chapter 5 Efficiency and Transmission Pricing – Key Concepts

[18] ibid - Page 35.

> decisions for the need for future network investment. Prices that do provide appropriate long run signals promote dynamic efficiency."

The current Rules provisions are consistent with these principles in that incumbent generators are not required to pay long run transmission costs and new entrants can access surplus network capacity, to ensure the sunk assets are fully utilised, however when the network capacity is fully utilised new entrants are required to pay for transmission to avoid creating congestion or alternatively must pay compensation if they constrain others off or on.

In the event that the sunk assets are fully utilised new entrants are provided location specific transmission signals about the long run implications of their investment decisions at the time they are making these decisions. Because these long run signals are applied at the appropriate time they will promote dynamic efficiency.

> "An important consideration in this context is the importance of transmission pricing to different types of participant decisions and the timeframe of those decisions. For example, transmission prices may be of varying importance to participants when they make:
>
> - (short term) production and consumption decisions
> - (long term) locational investment decisions; and
>
> If transmission prices are relevant to investment decisions but not operational decisions, it may be appropriate for prices to favour towards long run efficiency considerations. On the other hand, if transmission prices are relevant to consumption and production decisions but not investment decisions, it may be more appropriate to orientate prices towards maximising efficiency in the short run."

The transmission pricing signals have been specifically oriented for generators to the type and timing of the decisions they make, specifically the Rules ensure that when making;

- (long term) locational investment decisions; generators face the location specific short run signals provided by transmission congestion and losses or location specific long run cost of any transmission investment required which reflects the cost of removing that congestion.
- (short term) production and consumption decisions generators face the location specific short run signals provided by transmission congestion and losses.

The access provisions in the Rules are therefore consistent with the AEMC efficiency and transmission pricing key concepts.

Appendix 4: Dynamic Efficiency and Transmission Pricing – Modelling of Transmission Pricing and Congestion Management Regimes.

The following modelling results show that if new generators make transmission investment so as not to materially or adversely affect the levels of service and quality of supply to other network users, congestion costs are reduced and new generation projects are made in locations optimal to the industry as a whole i.e. including minimising transmission investment. Dynamic efficiency is increased and barriers to entry are minimised.

The modelling also demonstrates that access provisions in the Rules as described in this submission are more likely than the RIT-T to address congestion caused by supply side investment in an efficient manner and promote dynamic efficiency.

In the Congestion Management review Draft report the Commission stated that:

> *"The Commission recognises that the dynamic efficiency aspect of congestion could have the largest effect on economic efficiency. Furthermore, with significant investment planned in the energy sector over the next 5 to 15 years, there will be potentially considerable dynamic efficiency effects for the NEM".*

and has defined dynamic efficiency and the drivers for dynamic efficiency as follows;

> *"Dynamic efficiency concerns the efficiency of decision-making and market outcomes over time, when network, load and generation infrastructure can change."*

We agree that the consideration of the dynamic efficiency impact of the NEM arrangements is critical to determining the level and location of congestion. For this reason, in a supplementary submission to the CMR Draft Report dated 22 December 2006, the LATIN Group presented a report entitled "Modelling of Transmission Pricing and Congestion Management Regime", prepared by Intelligent Energy Systems (IES). Included here as Attachment 4. This work was undertaken to demonstrate the impact on dynamic efficiency of alternative transmission pricing arrangements which included stronger locational transmission pricing signals, i.e. new generators funding the network assets required to support their output and more granular pricing for generators.

This report estimated the extent of dynamic inefficiencies arising under the application of the current Rules arising through the sub-optimal location and timing of generation investment, which arise because generators may, but do not need to consider transmission costs in making an investment decision.

Efficiency requires an integrated approach where new generation investment decisions would;

- take into account all fixed costs including transmission associated with the investment; and
- be informed by a location specific forecast price duration curve to determine the nature and timing of the investment

The objective was to assess the potential economic benefits to the market as a whole of locational signals incorporating both energy and transmission costs. The issues addressed in this report are also relevant to this review and therefore a copy is attached to this submission.

The modelling compared a Base Case with two alternative access arrangements which had varying degrees of locational signals.

The Base case (also called the current arrangements) represents an interpretation of the access arrangements as they have been applied historically or as commonly described as providing “non firm access” for generators. In this case all generators face the costs of congestion created by new entrants until transmission is upgraded based on the application of the regulatory test to meet reliability or market benefits criteria.

Case 2 case represents an interpretation of the access arrangements as they are written in the Rules (as described in Appendix 1, and as intended in the NEM Access code decision, Appendix 2).

Nodal pricing has been used in the modelling approach in order to assess and value transmission constraints in a regime (i.e. the NEM) where the opportunity-cost value of those constraints is masked. IES have used a nodal network representation of transmission network to calculate nodal or “shadow” prices (marginal costs) to represent those that currently exist in the NEM as calculated values for individual constraints, and which can be extracted from the NEMDE dispatch calculations published by NEMMCO.

We are not however advocating the application of nodal pricing to generators.

In Case 2 because transmission capacity has been built to match new generation capacity, congestion will be minimal and the difference between the nodal prices and the regional price will be primarily due to losses. The modelling in this case therefore represents a reasonable approximation to a regionally priced regime.

Overview of Cases modelled

Base Case (also called the “current arrangements”)

This case represents an interpretation of the access arrangements as they have been applied historically or as commonly described as providing “non firm access” for generators;

- new entry is made on the basis of the regional price duration curve,
- new entrant costs include locational fuel costs but do not include electricity transmission augmentation costs except for connection assets costs which are assumed to be included in the generator capital cost,
- transmission expansions, other than those committed in the Annual Planning Review, have been made on the basis of meeting the reliability criteria in the regulatory test, i.e. new transmission is built when congestion reaches a point that customer reliability is impacted or when the network is excessively constrained.

Case 1 Locational pricing for generators

Case 1 assumes that generators are subject to a locational pricing regime, or nodal pricing for generators and a full regime of constraint support pricing. Case 1 is designed to reflect the impact of this implementation of constraint support pricing across the NEM. This case could be considered an assessment of the impact of just short run (spot market) locational signals on timing and location of new entry.

- new entry is made on the basis of the nodal price duration curve,
- new generation entrant costs are the same as the Base Case,
- all transmission expansion has been made on the same methodology as applied in the Base Case.

Case 2 Transferring the Cost of transmission to generators under a locational Pricing regime

This case overlays the locational pricing regime investigated in Case 1 with a congestion cost levied upon new entrant generators that reflects long run locational costs based on future transmission costs.

- new entrant generation is made on the basis of the nodal price duration curve;
- new generation entry capital costs are increased from the Base case to account for the expected costs of network upgrades; and
- the other transmission expansion costs not funded by increased new entry costs has been made on the same methodology as applied in the Base Case.

Modelling Results

A summary of he modeling results is shown in the following tables.

Both Cases 1 & 2 deliver a Total Cost Reduction compared to the Base Case. The Total Cost is the sum of the dispatch costs and generation and transmission capital costs which represents the total delivered cost of energy to consumers,

This demonstrates that 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.

In the Base Case the low fuel cost plant is displacing incumbents, suppressing the pool price however TUOS is higher because generators are not locating optimally to reduce transmission costs. This results in a higher delivered cost of energy to consumers than the other cases.

In Case's 1 & 2 the load growth is met with better located gas plant thereby reducing the total delivered cost. Both generation and transmission capital costs are lower.

Table A - Cost of alternative access arrangements compared to the Base Case

(All Costs Annual equivalent costs in $M)	Dispatch Costs	Gen Capital Costs	Transmission Costs	Total Cost Reduction
Case 1	132	-277	-396	-541
Case 2	984	-1161	-403	-580
Case1 NPV	58	-131	-122	-195
Case 2 NPV	366	-464	-124	-223

Both cases 1 and 2 provide an increase in OCGT and CCGT plant and a reduction base load plant. This change in plant mix provides a better match to the demand profile, reduces the total capacity of the plant and increases dynamic efficiency.

Table B - Summary of new investment by plant type for each case

	Base Case (MW)	**Case 1** (MW)	**Case 2** (MW)
OCGT	750	1050	1350
CCGT	640	1340	1440
Coal	2500	2000	500
TOTAL	3860	4390	3290

Discussion

On the previous submission to the CMR a number of issues were raised by the Commission and others in the CMR draft report dated 27th September 2007.

Our response to the issues raised was included in the Loy Yang Marketing Management Company Pty. Ltd., AGL Energy Pty. Ltd., International Power (Hazelwood, Synergen, Pelican Point and Loy Yang B), Flinders Power, Intergen Australia and Hydro Tasmania response to the Congestion Management Review – Draft Report; Section 4.1 Review of the IES report, Section 3.2.3.1.

We believe that the issues raised do not undermine the validity of the results or the economic principle which the modelling demonstrates.

Appendix 5: TNSP Planning Arrangements and responsibilities

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 Regulatory Investment Test (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”
    - by “nearly committing” to influence a TNSP to include investment decisions

  Relying on the Regulatory Test supports non commercial behavior historically this has occurred with government owned entities.
- 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 RITT 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.

<u>With respect to inter-regional congestion</u>

The regulatory test (when evaluating inter-connector upgrades to avoid congestion), selects from a number of projects, the one that maximizes the NPV of the investment. A TNSP will apply a cost benefit analysis to a range of investment options (including demand side, market based generation and network based investments) to determine the investment option that maximises the net economic benefits to the market.

In undertaking these assessments the market benefits are primarily the deferred cost of generation investment (generally about 90% of the benefit and increases in productive efficiency about 10%). In this role the transmission investment is in competition with generation investment.

In our view the recent reforms to the RIT-T provide a suitable framework and sufficient incentives for TNSPs to meet their reliability obligations and sufficient incentives to include market benefits to support economically efficient inter-connector investment.

Conclusion

The assumption that the current market framework for transmission planning arrangements including the National Transmission Planner, the Last Resort Planning Power and the Regulatory Investment Test (RIT-T) will facilitate the development of market benefit projects in the future to adequately deal with any material congestion that arises from the introduction of the CPRS & the expanded RET is flawed. The evidence presented in this paper above substantiates this.

Our position is that market based investors prefer to empower themselves to deal with any congestion which impacts on their ability to get their product to the market in a CPRS & expanded RET regime. Relying on the current RIT-T framework for transmission planning arrangements (that forces generators to rely on market benefits projects to build out material supply side congestion) creates an unacceptable level of risk to potential generators. Generators need certainty in the networks ability to deliver their product to the market. Accordingly, we believe the issue of potential material congestion which acts as a threat to the major generation investments should be dealt with within the framework of “negotiated services.” Investors in generation projects who are willing to pay for “augmentations” and “extensions” to the transmission system should be rewarded with greater certainty in knowing that they will be able to transport their product to the market. This approach provides certainty of access for incumbents and gives potential generation investors better insurance against the problems that congestion creates for them in a revised CPRS & expanded ERT regime.

Attachment 1: Norton Gledhill Legal Advice

The attached legal advice provides a comprehensive overview of the NEM access arrangements.

Attachment 2: Synergies Economic Consulting Report

The Synergies Economic consulting report was submitted to the AEMC CMR by the NGF regarding Rule 5.4A Access Arrangements Relating to Transmission Networks. The NGF engaged Synergies Economic Consultants to consider the issue of market access and provide some suggestions for strengthening Rule 5.4A. Their report to the NGF is attached. The Synergies work clarifies the issues associated with Rule 5.4A and provides two potential solutions for the purpose of comparison – the Strong Model and the Weak Model.

This report has been included in this submission because it addresses the two access issues that are of relevance to generators in connecting to the network.

- First, prospective new generators face investment risk because they face uncertainty over their long-term access to customers — appearing as a risk of lower prices and reduced output even when the generator is not technologically outdated.
- Secondly, existing generators face revenue risks which they are unable to manage because it is caused by third party investment decisions, and because the consequences of those investment decisions may be massively 'leveraged' due to detailed and specific features of the transmission network.

We agree with the NGF view that this Rule has proved ineffective and consideration needs to be given to strengthening current arrangements to allow generators to put in place workable access agreements with network service providers where necessary.

We also note that the recommendations in the Final Congestion Management Review did not address the issues raised in the Synergies report regarding the administrative and efficiency limitations of the current arrangements.

The report provides the economic argument for the inclusion in the Rules of both

- *network augmentations,* which are equivalent to the Weak Model, and
- *access charges* (Rule 5.4A), which are similar to the access arrangements described in the Strong Model and which have the same economic effect as the weak model and hence can be an alternative to *network augmentations*.

In our view the Synergies review of Rule 5.4A supports the view that the Rules if applied as drafted support efficient outcomes and if necessary it also provides a good starting point for discussion of possible ways to provide more clarity as to the access provisions for generators seeking to negotiate the minimum level of market access or a higher level of access.

Attachment 3: Letter from Generators to AEMC

As attached.

Attachment 4: Transmission Pricing and congestion management Regimes-IES Report on the estimation of dynamic inefficiencies

As attached.