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29 September 2010

Mr John Pierce
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

AEMC Reference: ERP0019

Dear Mr Pierce

RE: ERP0019 Transmission Frameworks Review – Issues Paper

Please find attached Alinta Energy Limited's (AEL) submission into the Australian Energy Market Commission's ("the Commission") Transmission Frameworks Review (TFR). The current breadth of issues under consideration by the Commission together with the National Electricity Market (NEM) entering into the next phase of its development life cycle presents a unique opportunity to refine the operation of transmission within the NEM to better meet the needs of market participants and ultimately end users for today and in the future.

Attachment A provides AELs response to the Commission's issues paper, where appropriate AEL have provided explicit examples of their experience to assist in the AEMCs understanding of current market issues. Should the AEMC wish to discuss AELs submission further please contact James Reynolds on (07) 3011 7646 or Lance Brooks (07) 3011 7667.

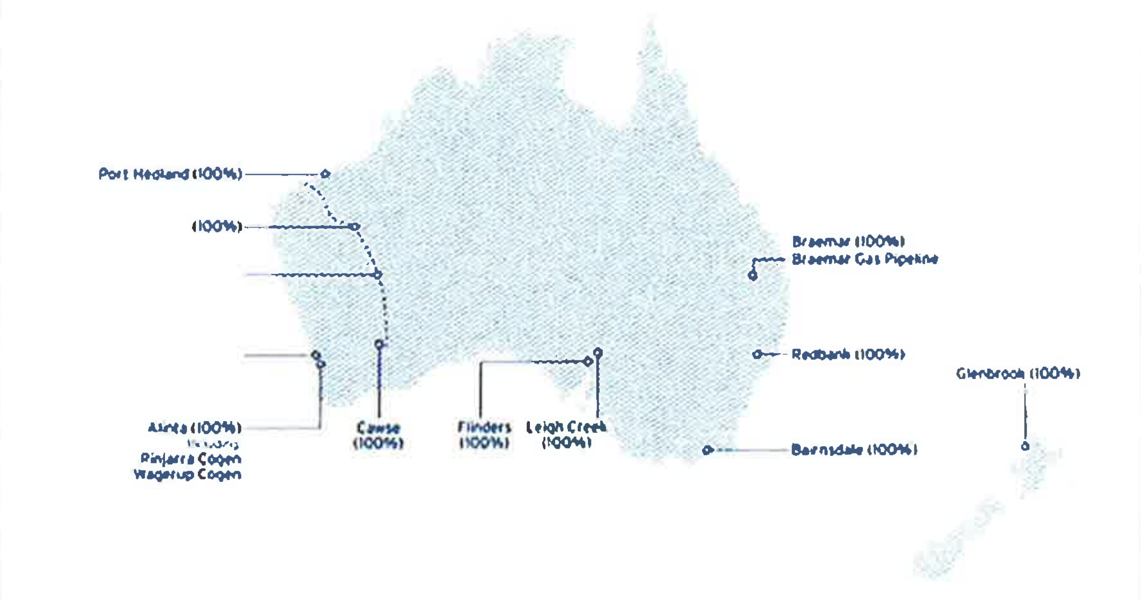
Yours sincerely

Scott Turner
Executive General Manager
Energy Markets
Alinta Energy

Attachment A – Alinta Energy's Response to AEMC Issues Paper

Alinta Energy Limited (AEL) is an ASX-listed generation and retail business. Our business is diversified by geographic location, fuel source, customers, contract type and operation mode. We own and operate around 3,000MW of generation across the range of technology types, and service around 600,000 retail gas customers in Western Australia, as well as around 32,000 electricity retail customers in Victoria[1].

Figure 1 outlines AEL's asset holdings.



Source: http://www.alintaenergy.com/about-us/overview.aspx

Figure 1 – Alinta's Asset Holdings 2010

As a natural monopoly technology, transmission networks through providing critical infrastructure enable the operation of a competitive electricity market, namely wholesale generation and ultimately retail through distribution electricity networks. To determine the best structure for the provision of transmission network services we need to critically examine the role and purpose of transmission network services in light of the National Electricity Objective (NEO).

As a generator operating within the National Electricity Market (NEM), AEL has first hand experience of the competition faced by market participants within the wholesale generation market. Evidence of the competitiveness of the generation market in the NEM is that since 1998 the market has:

- delivered around $18 billion and 12,100MW of new capacity since market start[2];
- achieved the unserved energy (USE) reliability standard ensuring that there is enough generation to meet consumer load and a sufficient excess capacity cushion to accommodate contingencies[3];

[1] Neighbourhood Energy Pty Ltd is a wholly owned subsidiary of AEL.
[2] Paul Simshauser, 2009, Capital adequacy, ETS and investment uncertainty, Working paper no.15.

- achieved the second lowest electricity prices in the world, and been considered to be an example of a market framework that delivers competitive outcomes[4].

As a competitive market dependent on using transmission services we have a specific interest in ensuring that the current framework delivers these services at least cost. We consider that the current transmission framework may not represent the best model to meet the challenges faced by the competitive markets in the NEM. Accordingly, AEL considers that the Commission's Transmission Framework Review (TFR or the Review) represents an important review in the development of the NEM, and Australia's energy markets.

Our submission is subsequently set out as follows:

- **Section 1:** AEL sets out our understanding of the future challenges faced by the NEM, and the alternative governance models that the Commission should explore when determining the best transmission framework to best address these future challenges

- **Section 2:** provides AEL's specific response to the Commission's consultation paper questions.

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[3] AEMC (2010), "Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events", under the current market arrangements there have been noted times when MRL measures have noted short falls, however, AEMO (NEMMCO) have only used the reserve trader mechanism twice.
[4] http://www.esaa.com.au/index.php?option=com_content&task=view&id=188&Itemid=2

Section 1: Is there a need for wholesale reform?

Achieving the NEO effectively requires the minimisation of total system costs across the electricity value chain whilst having regard to the quality of the services being delivered. In the NEM, the current frameworks being applied across the electricity supply chain include:

- supporting competition in fuel supply;
- supporting competition in generation;
- setting exclusive licensing and having economic regulation of transmission and distribution; and
- supporting competition in retail.

Minimising the NEM's total system costs in the future will depend largely on the conduct (behaviour), performance and interaction of each of the current frameworks in meeting the challenges from:

- Australia's carbon policy and the implemented expanded RET
- the final level of vertical integration between generation and retail currently being led by Origin Energy Limited and AGL and its impact on market concentration in the competitive retail and generation markets
- the ongoing attractiveness of Australia's electricity market as a destination for international capital[5]
- the market structure of upstream fuel supply options
- the provision of transmission services from two interrelated perspectives:
    - new capacity, such as the introduction of new generation locating beyond the current network footprint and to deal with potential future bottlenecks that cause congestion on the transmission network
    - operationally, in terms of dependable and reliable transmission services.

Getting TNSPs economic regulatory framework right is critical given the scale of the forecast capital investment requirements of networks. An Electricity Supply Association of Australia (2009) survey highlighting that over the next five years (to 2014) the NEM's capital investment needs include:

- generation around $37 billion consisting of $19 billion on refinancing of existing generators, and capital expenditure on existing and new generators of $18 billion
- energy networks around $60 billion consisting of $29 billion on refinancing of existing networks, and capital expenditure on existing and new network assets of $31 billion, of which around $8.3 billion has been approved by the Australian Energy Regulator (AER) for transmission networks alone
- initial capital for purchase emissions permits of $10 billion.

Importantly, the levels of capital expenditure for new NEM assets are likely to add around $650 per annum per household (with new transmission capital expenditure representing around $105), and if current

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[5] See Paul Simshauser presentation 20 October 2009 [http://www.agl.com.au/Downloads/AustraliasEnergyChallenge_ASXPresentation.pdf] – key take outs, generation sector requires substantial capital (capital intensity as high as finance sector) and Australia is highly depending on international capital to finance its investment needs. In this climate, Australian industry's ongoing investment attractiveness is critical.

forecasts of further new investment patterns to 2025 prove correct then the burden on households could be up to ten times this amount. In contrast TNSPs historic rates of capital investment have been around 10% of forecasts future capital expenditure investment. Figure 2 illustrates.

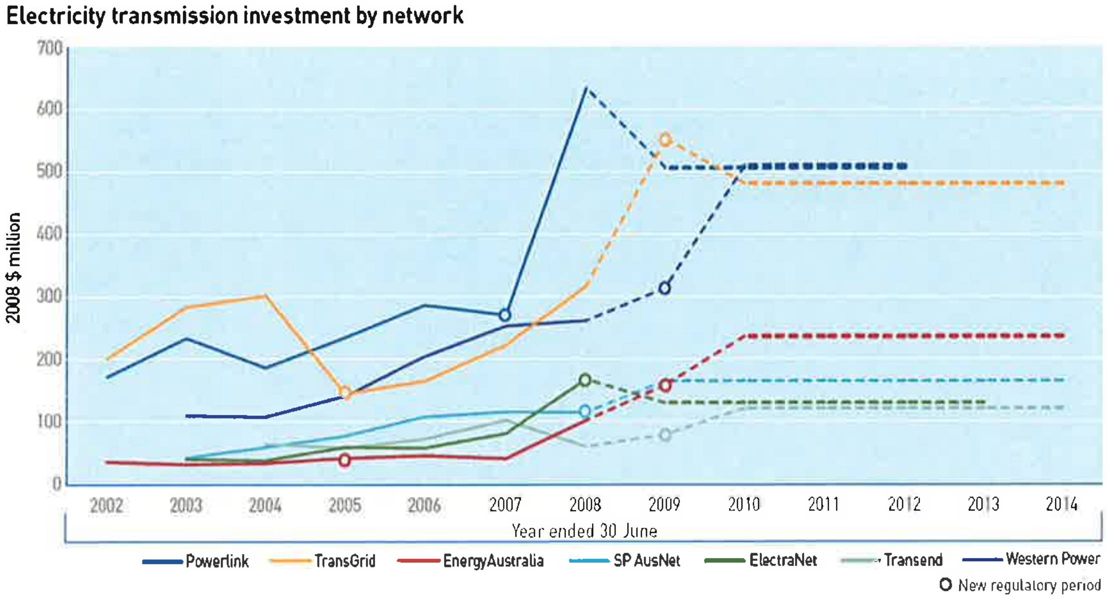

Figure 2 – AER Reported Electricity Transmission Network Investments to FY2014

Beyond the next five years to 2025 the estimated level of investment required in new low emissions baseload, intermediate and renewable generation could be up to $50 billion (investment in renewable energy generation alone is estimate to be around $30 billion). Much of this generation will require further investment in direct connection transmission assets to remote locations to simply carry energy back to customer loads as well as reinforcement of the existing shared transmission network, and to also be able to manage the increased volatility that intermittent generation has on network operations.

The generation market is competitive ensuring that the costs of generation as reflected in wholesale electricity prices are efficient. Ensuring that the transmission framework continues to deliver the least cost of supply in the planning, design, building, and operation of transmission assets is essential – and a role that the Commission must continually reprise given the assumption that the current economic regulation of the six TNSPs represents the best means for achieving efficiency as per the NEO.

The current conduct of TNSPs under the current framework is mixed. AEL provides details around current experience in responses within Section 2 of this submission but notes the high level concerns include:

- poor information provision in terms of quality, consistency and timeliness whether relating to connection services, prescribed services or with regard to regulatory tests for new investment;
- inconsistent application of Rule functions and service offerings;
- undertaking activities which inherently represent a conflict of interest.

Furthermore the performance or efficiency outcomes of TNSPs are mixed. In terms of relative efficiency, TNSPs perform relatively well as presented by the various benchmarking undertaken by the AER when reviewing revenue proposals. Despite these outcomes, it is important to recognise on efficiency grounds that it is difficult to ascertain whether the long run average cost (LRAC) function of a single TNSP for the NEM would be lower than the LRAC of the separate TNSPs. AEL considers this an important avenue of review for the Commission within this process.

In terms of the reliability of services, overall TNSPs have had a range of mixed results at meeting a range of different reliability performance standards targets.

AEL propose that the Commission apply the following alternative transmission frameworks to assess the conduct and performance of the current transmission framework:

- the adoption of single asset owner and operator model consistent with the fundamental principle of economic regulation of natural monopoly infrastructure and as applied throughout Europe; or
- supporting competition between TNSPs (in doing so removing the exclusivity of areas away from asset owner and operator).

Moreover, in terms of definition of services and criteria on services we propose that our proposed alternative frameworks the asset owner and operator would have no role in network planning, development (deciding where new assets are built), setting of reliability or performance standards, and no regulatory approval functions. Figure 2 illustrates how a modified framework would be applied to the current framework and proposed alternative frameworks to assess likely outcomes.

	Structure & Governance			Definition & Criteria on services		
Framework	State based franchise areas	Asset Owner / Operator	Network Planning & Development	Reliability Standard Setting (National)	Reliability Standard Setting (State)	Regulatory Approval
Current Framework	✓	✓	✓	✓	✓	✓
TNSP Competition	×	✓	×	✓	×	×
Single Entity (ATNB)	×	✓*	×**	✓	×	×***

Figure 2 – Model Transmission Framework & Assessing Framework Outcomes

* Asset ownership and operation transferred to single entity – Australian Transmission Network Business.
** Network planning and development responsibilities transferred to AEMO.
*** All regulatory approval responsibilities transferred to AEMO and the AER or independent transmission regulatory body.

The alternative frameworks are models, which are potential options for frameworks, and provide the Commission with a clear reference point to compare and contrast to determine the efficacy of the current framework at:

- ensuring transmission costs are minimised within total system costs compared to the alternatives;
- determining whether the provision of transmission services reflect the level and types of access (transmission products) that users require;
- information provision to the market to allow informed decisions; and
- limiting transmission impact on outcomes in competitive markets in the NEM.

Section 2 – AEL Response to Commission Questions

Question 1: Application of the NEO

Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?

Summary of Key Points

- Minimisation of total system costs is achieved by facilitating continued competition in both generation and retail segments, and by having a robust economic regulatory framework applied to transmission
- The current transmission framework can only be producing the most efficient outcomes for a 'natural monopoly' where the conceptual long run average cost (LRAC) function for a single TNSP (servicing all six TNSPs areas) is greater than the current :RAC function for each TNSP; and
- Subjective evidence would suggest the current framework is resulting in dis-economies of scale and scope or that there may be sufficient countervailing power being applied to TNSPs warranting assessment of the sustainability of the current economic framework.

AEL considers that there are several inherent conflicts in the current frameworks governing transmission.

At a higher level the minimisation of total system costs is achieved by: facilitating competition in generation and retail, and having a robust economic regulatory framework for transmission, as a natural monopoly technology. At the moment there is sufficient competition in generation delivering efficient costs for wholesale energy. In retail a range of recent analysis carried out by the AER have identified that there is adequate competition in retail markets.

In transmission we have six TNSPs in the NEM delivering a natural monopoly technology to around ten million customers or a population of around 21 million. Economically, this transmission framework can only be producing the most efficient outcome for a 'natural monopoly' where the conceptual long run average cost (LRAC) function for all six TNSPs has to be greater than each TNSPs individual LRAC function.

This is a striking contrast when compared to the electricity market structures of the United Kingdom, New Zealand, and countries of the European Union where a single transmission entity is the asset owner and operator subject to a similar form of economic regulation applied to Australian TNSPs[6]. Apart from the political structure of Australia's federalist model AEL are unaware of any economic efficiency reasons why the current transmission framework is six TNSPs versus a single TNSP. The Commission's Review provides an opportunity to address which model best suits the future needs of the NEM.

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[6] In Spain its Red Electrica de Espana (45.5 million people), National Grid UK (61.4 million people), Elia – Belgium (10.7 million people), Tennet – Netherlands (16.4 million people), Landsnet – Iceland (0.3 million people), ESB – Ireland (4.4 million people), Rede Electrica Nacional SA – Portugal (10.6 million people), Statnett – Finland (5.3 million people), E.On-Netz – Germany (82.1 million people), Terna – Italy (59.8 million people), Energinet.dk – Denmark (5.4 million people).

Anecdotal evidence would suggest the current transmission framework is resulting in dis-economies of scale and scope or that there may be sufficient countervailing power being applied by suppliers to TNSPs to warrant a total re-consideration of the form of regulation being applied to TNSPs.

For example, in PowerLink's Revenue Proposal (April 2006) for the period 1 July 2007 to 30 June 2012 the Queensland TNSP argued for capital expenditure project escalation rates above inflation on the basis that it has 'no control' over input costs, such as labour, core materials for transmission assets, and more critically, that the [input] market was moving from a buyer to seller market. TransGrid's most recent Revenue Proposal (31 May 2008) argued for higher rates of price escalation for labour and inputs for capital expenditures and operating programs as they had limited buying power, and are in effect price takers.

AEL notes that these claims by TNSPs highlight that the current framework may be limited to the extent that:

- the dilution of the NEM's TNSPs into six owner / operator entities is affecting the industry's natural scale economies. In doing so most likely producing a level of costs that are higher than what they otherwise should be; or
- if input markets supplying TNSPs have bargaining power, ie TNSPs are price takers then Australian TNSPs may face countervailing market power, which would represent a form of discipline on their monopoly behaviour. It is critical for the Commission to determine whether countervailing market power exists as the current form of revenue regulation would need to be change to ensure the continued minimisation of costs of supply for users[7].

In power economics generation and transmission investments are substitutes. Minimising total system costs to end users is a function of ensuring that the system installs the minimum efficient scale in capacity in both asset classes to meet load. The current transmission framework may not necessarily allow for this substitution effect between generation and transmission assets to emerge.

The current transmission framework requires a TNSP to be:

- responsible for network planning and the provision of information around required planning outcomes;
- able to deterministically plan the assessment framework to assess investment options;
- able to choose the best investment solution for the identified need;
- the body that approves the final investment on the network.

The incentives created by this framework potentially encourage over-investment in network assets rather than new generation. For example, in ElectraNet's recent Regulatory Application Notice titled New Large Network Asset – Cultana Augmentation (29 July 2009), under the previous version of the Regulatory

[7] Where regulators continue with a form of regulation based on a revenue cap arrangement and the regulated business is in fact experiencing countervailing power from suppliers then the continued use of this form of regulation may result in behaviour similar to double marginalisation, ie the regulator approves the rate of return and cost allowances of TNSPs which effective incorporate the input suppliers' pricing incorporating maximisation of above normal economic profits.

Investment Test (RIT), for investments on the Eyre Peninsula ElectraNet identified the following issues as the basis for the notice:

> *"...emerging limitation within the transmission network which supplies the Eyre Peninsula region of South Australia. Power transfer at times of high load on the Eyre Peninsula is becoming increasingly difficult to manage under single contingency operating conditions potentially leading to voltage collapse on the entire Eyre Peninsula."*[8]

In addressing this issue ElectraNet make note of several network and non-network alternatives considered as part of their assessment. From this assessment ElectraNet have proposed the following draft recommendation with an estimated total capital cost of $65.4m ($2010/11):

- replacement of the existing transformer at Cultana substation with 2 x 200 MV.A 275/132 kV transformers;
- breakout of the second Davenport to Cultana 275 kV transmission line to create a double circuit;
- installation of a breaker at Davenport substation in order to connect the existing Cultana line exit to the East bus; and
- reconfiguration of the 132 kV Davenport to Whyalla Terminal transmission lines

AEL note this issue has been identified by ElectraNet in several of the previous year Annual Planning Reviews / Reports, each time having ElectraNet provide a similar proposed network solution.

A simple review of the recent planning documents provided by ElectraNet to the market including the June 2006 ElectraNet Annual Planning Review, May 2009 Annual Planning Review and June 2010 Annual Planning Report, each of which have been summarised below, highlight key discrepancy's in the proposed costing of the solution and potential over-investment, the most recent of which fails to provide an estimated cost.

- in June 2006, as part of ElectraNet's Annual Planning Review for the period 2006 to 2016, a very similar project consisting of the same network assets was identified and scheduled for inclusion within the 2008 – 2013 Regulatory Revue period and capital costed at between $11.4 million and $16 million;
- in May 2009 as part of ElectraNet's Annual Planning Review for the period 2009 to 2029 a similar project consisting of similar network assets scheduled for 2013 was costed at $37m
- in June 2010 as part of ElectraNet's Annual Planning Report for the period 2010 to 2030 for the same project consisting of similar network assets and again scheduled for October 2013 was proposed this time not having been valued
- in July 2010 as part of ElectraNet's Regulatory Application Notice the same project but with up-rated network assets scheduled for October 2013 was valued at $65.4 million.

In all cases the demand forecasts for 'emerging' load consistently changed, and followed growth patterns that were greater than historically experienced, and subject to constant downward revision between

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[8] Regulatory Test Application Notice – Cultana Augmentation page 6

information releases. AEL notes that this example is indicative of TNSPs use of the previous RIT[9], and results in two negative impacts on efficiency in the NEM in terms of minimising total system costs, namely:

- continued increase in capital expenditure associated with RIT approval process simply increasing a TNSPs maximum revenue requirements – there is no real way to know whether the final costs reflect a minimum cost
- the initial information disclosure under-states the potential value of the network investment, which effectively signals to a potential alternative project proponent, ie local generation option, that there is no commercial opportunity. Once the 'accurate' cost estimate for the network solution is disclosed (often after time has elapsed and in this case 43 days post release of the Annual Planning Report) the RIT procedure effectively forecloses the generator option out – there is no opportunity to attempt to minimise total system costs by allowing substitution between network and generation investments.

[9] A recent joint PowerLink and Ergon Energy RIT RFI and Application Notice process commenced by not even noting a value for the preferred network investment solution to meet forecast loads in the Surat area, which was subsequently advised to be around $80 million, then $140 million, until in the Application Notice the network project option was the least cost solution valued at $231 million.

Question 2: The role of transmission
Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?

Summary of Key Points

- Lack of clarity regarding roles and responsibilities of both TNSPs and to lesser extent AEMO around key aspects of a generators compliance with the NER; and
- TNSPs should not be responsible for network planning, reliability performance standards, and approving new investments that are to occur on their network.

AEL considers that under the current arrangements TNSPs have multiple roles. Figure 3 illustrates the roles of transmission adopted in each State.

Responsibility	Planning	Reliability Performance Standards	Approve New Investment	Approve New Connections	Asset Owner & Operator	Asset Manager
AEMO	VIC, SA	VIC, SA	VIC	×	×	×
TNSP	QLD, NSW, TAS	QLD, NSW, TAS	QLD, NSW, SA, TAS	QLD, NSW, VIC, SA, TAS	QLD, NSW, VIC, SA, TAS	QLD, NSW, VIC, SA, TAS

Figure 3 – Current arrangements for Transmission

AEL also notes that there is interdependency between AEMO and TNSPs in terms of information sharing, and undertaking 'joint' approval processes around key aspects of generator's compliance with the requirements of the NER. For example, a new generator or an existing generator alters equipment they must undertake network modelling to determine generator access standards. It is often the case that the TNSP will provide modelling services under a 'contestable service' banner, whilst at the same time be carrying out 'due diligence' approval around how the power station interacts with the system over the planning horizon prior to seeking agreement from AEMO.

AEL's experience of such processes has been:

- a lack of clarity between TNSP and AEMO's role;
- a noticeable degree of the same personnel performing both the 'contestable' service and also performing the review and due diligence of the modelling results;
- un-mitigated cost escalation for the exercise;
- despite being the client and paying for the Intellectual Property (ie system models for around specific areas of network performance), which is sometimes outsourced, this is effectively expropriated by the TNSP.

The important distinction between the Victoria and South Australia transmission groups and the Queensland, NSW, and Tasmania transmission groups is the role separation of planning and reliability standards. Despite these differences, AEL notes that each TNSP is consistent in terms of:

- despite the service definition in the NER each TNSP acknowledges that under 6A of the NER there is scope to interpret and apply these service product definitions differently[10]
- as part of access to the TNSP not defining and setting out operational criteria that constitutes a minimum or standard level of service from the TNSP.

These arrangements could be substantially improved.

Firstly, TNSPs should not be responsible for network planning, reliability performance standards, and approving new investments that are to occur on their network – in fact any role that has approval or quasi-regulatory approval should be passed to an independent agent such as AEMO or an equivalent agency. In the current arrangements TNSPs that are asset owners and operators and approving key aspects around the network development represents a potential conflict of interest, and provides the TNSPs with a substantial advantage, particularly, where generation may in fact be a least cost alternative to the proposed network investment.

In considering the role of transmission the Commission should explore the following:

- clearly defining minimum levels of transmission service provision for prescribed services, negotiated services and contestable services;
- examining amending the current connection agreement process to explicitly take account of providing to new generators and load with a minimum or base line level of transmission services expected for the life of the agreement;
- examining the merits of allowing users of transmission services to negotiate around the minimum or base line levels of transmission service defined as being the transmission service;
- looking at opportunities to strengthen the AER's powers to focus on the operational performance of TNSPs when interacting with the market, and particularly where regulatory functions remain with TNSPs (the operation of clauses 4.1.1, 4.2.2, 4.3.1, 4.3.3, and 4.3.4 of the NER).

[10] Grid Australia, August 2010, Categorisation of Transmission Services Guideline v 1.

Question 3: Transmission Planning Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market based signals might be beneficial?

Summary of Key Points

- Difficult to measure a TNSPs response to separate service quality and reliability performance standards as jurisdictions are responsible for setting service, quality, reliability performance and planning standards;
- The planning frameworks adopted can be broadly categorised as deterministic or probabilistic in approach. As part of this review the Commission has an opportunity to settle the debate on which planning approach provides the best outcomes to the market in terms of meeting reliability performance standards at least cost; and
- Generators require a TNSP in developing a network plan to start to take into account the impact that transmission has on market outcomes for generators.

Determining whether the current transmission planning framework is responsive or adequate to meeting the needs of market participants and end users depends largely on the level of services, and the quality of services that transmission services are expected to meet. This is difficult to measure as each TNSP responds to separate service quality and reliability performance standards as set by State jurisdictions. To this end much of TNSPs planning framework addresses these jurisdictional requirements and largely reflects the needs of load without appropriately reflecting the needs of generators and demand side response participants.

Furthermore the additional tools recently adopted by the industry in forming appropriate network plans, that being the National Transmission Network Development Plan (NTNDP) and Regulatory Test for Transmission (RIT-T), remain untested within the NEM framework. The inaugural NTNDP is to be released in the December 2010 and until this time it remains unclear as to how this tool will interact with the current planning tools, such as APRs, the ESOO and Power System Adequacy (2yr Outlook), used by the industry.

Currently, as jurisdictional governments, own and control TNSPs (apart from SA and VIC), and also set service quality, reliability performance requirements, and planning standards in response the following board principles:

- Economic imperative – substantial energy consuming load, industrial and commercial loads have reliable and secure access to electricity supply at an affordable price; and
- Political imperative – consumers (voters) receive electricity in a reliable and secure manner.

The planning frameworks adopted can be broadly categorised as deterministic or probabilistic in approach. The deterministic approach simply requires that the TNSP invest in additional network capacity where the electricity load reaches a point where existing spare transmission capacity is utilised according to some standard, the most common being N-1. The probabilistic approach utilises the deterministic 'trigger' around use of spare transmission capacity, but it also includes a value of loss load at risk to ensure that any new investment in additional capacity is appropriately timed. This approach assumes that there is value in delaying an investment decision providing that the risks around not meeting the reliability standard can be minimised to an acceptable level.

Much of the power economics literature identifies that there is a clear causality link between the planning and reliability standards set for network businesses and the ultimate cost of supplying transmission assets[11]. For instance, the N – 1 planning standard or deterministic standard[12] when compared to the probabilistic planning standard[13] requires and compels the construction of more transmission network assets. To date, there has yet to be a comprehensive assessment as to which planning standard represents the best value for money invested, having regard to expected reliability standard performance for transmission assets.

AEL considers that the Commission as part of this review has an opportunity to settle the debate on which planning approach provides the best outcomes to the market in terms of meeting reliability performance standards at least cost.

Furthermore as a result of the interaction between the transmission network and the generators operating in the NEM, a generator implicitly requires a TNSP to be aware of the competitive pressures facing a generator within the market. As a natural monopoly technology with a single asset owner, operator (and in some states planner) a generator is potentially adversely exposed to the planning and operation decisions of a TNSP. In developing a network plan a TNSP needs to start to take into account the impact that transmission has on market outcomes for generators.

For instance, a substantial proportion of pricing events, and disorderly bidding, is recognised to be a consequence of transmission related issues. For instance, the Commission's Reliability Panel Draft Report Reviewing the Reliability Settings in the NEM examining the reliability standard in terms of extreme weather events found that:

- events of the 29 and 31 January 2009 in Victoria and South Australia where a lack of electricity supply resulted in widespread load shedding was attributable to the reliability of transmission networks – that is there was sufficient generation capacity but not enough physical routes to market or as depicted by the AEMC 'security events'; and

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[11] The IPART commissioned Wilson Cook & Co study of DNSP Cost Pass Through Applications (April 2006) provides a very coherent discussion of how planning standards can alter the need for capital expenditure and operating expenditure investment in networks, please see http://www.ipart.nsw.gov.au/files/Network%20Cost%20Pass%20Through%20Review%20-%20Wilson%20Cook%20Final%20Report%20-%2028%20April%202006.PDF

[12] Deterministic planning standard means that the business measures how much spare capacity it has compared to actual demand and forecast demand, and based on this assessment compared to additional capacity investment rule (generally the time it takes to plan, design, build the next increment of spare capacity compared to the rate at which growing demand is taking up existing capacity) the decisions is made to invest.

[13] Probabilistic planning standard effectively means that they complete the cycle as per the deterministic planning standard but then undertake sophisticated planning, forecasting and asset assessments as the basis to delay or mitigate the need for the additional investment in capacity identified under the deterministic planning standard.

- left the operation of 'acts of god' within the reliability standard unchanged or excluded for the purposes of setting the reliability standard on the basis that its inclusion would require an increase in the MPC and the USE to accommodate.

A more recent example of this has been the markets experience in response and operation in managing loading on the Mt Piper to Wallerawang (70 and 71 lines) within the TransGrid network[14] which resulted in significant price volatility within the wholesale market.

In addition, as noted by Biggar (2009) AEMO continues to adopt an appropriate operation response to a lack of network planning having regard to generation by adopting the practice of including generator parameters on the left-hand side of transmission constraint equations[15]. AEL argues that this approach represents a good operational outcome, however over the long term it represents a second best outcome that potentially creates additional costs to the market that are greater than simply requiring that TNSPs or AEMO plan the network by having regard to transmission constraint impacts on generation and market impacts.

Information of future generation entry intentions should be used when available to inform decisions on the scale of any network augmentation or extension. Early information collection will support efficient outcomes in an environment where the lead times for construction may be long. Beyond the specific information available, transmission planning may need to consider a variety of plausible scenarios in relation to future generator installation.

In order to allow for greater information transparency AEL considers a national harmonisation of these frameworks in order to make planning frameworks consistent all network service providers would enhance market outcomes. We also expect there to be improvements in the information disclosure of TNSPs on new generator locations as a result of the AEMOs publication of the NTNDP.

Setting national service quality and performance standards has the potential to provide substantial gains to the NEO providing that the standards have regard to:

- examining the outcomes or performance of the current service quality and performance requirements across the NEM;
- identifying the future needs or demands that Australian industry and the community will require from a TNSP network electricity service;
- completion of a costs benefit analysis that looks to identify the best bundle of service quality and performance requirements and the associated requirements on network planning requirements able to meet future needs and provide the greatest benefit gain above costs; and
- support AEMO's NTDP role move all planning responsibilities to AEMO (already have role for VIC and SA) – having TNSPs be responsible for planning represents a distortion of incentives.

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[14] AEL note that as of [insert date] the contingency constrains issue on the 70/71 line has since been resolved by TransGgrid and AMEO.

[15] Biggar (2009), "A Framework for Analysing Transmission Policies in Light of Climate Change Policies", page 50.

Question 4: Promoting efficient transmission investment Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?

Summary of Key Points

- A dis-connect between the National Electricity Rules (NER) and jurisdictional planning and reliability standards has lead to the adoption of differing planning approaches in the build, operation and maintenance of individual TNSP networks;
- A residual risk to the successful implementation of the AER's RIT-T remains in the manner in which TNSPs apply the guidelines; and
- The information requirements of TNSPs under the RIT-T should require equal disclosure detail for on-network and network investment options.

The current network investment framework within the NEM consists of planning standards identifying network investments needs in response to serving load, a five year revenue re-setting framework in which TNSPS are able to set out their capital investment plans in response to the planning standards and have these capital plans pre-approved by the AER and use of the RIT (now the RIT-T) where a capital projects total investment is greater than $15m.

The AEMO adoption of its role as National Transmission Planner, and in particular its development of the National Transmission Network Development Plan (NTNDP) and its interaction with other planning tools remains untested as a market tool. Furthermore whilst the National Electricity Rules (NER) requires each TNSP to meet certain planning and reliability standards there remains' a disjoint between those standards and the jurisdiction specific requirements of state based requirements. This disjoint has resulted in TNSPs, depending on the region they operate in, adopting differing planning approaches (namely probabilistic vs. deterministic planning) in the build, operation and maintenance of their network.

AEL's recent experience with the former RIT, and as confirmed by the AER's recent review of TransGrid's compliance with clause 5.6.6 of the NER[16], has been that TNSPs invariably provide limited and inadequate information around potential network investment options, particularly, on how their own network solution technically complies, and how the forecasts network costs represents the least cost solution. Critically,

[16] Broadly, the AER found that the:

- application notice did not contain an adequate analysis of all reasonable network and non-network options
- neither the application notice (April 2008) nor the final report (March 2009) adequately examined the potential for material inter-network impacts
- the final report did not summarise or respond to submissions on the application notice
- the decision to limit the Regulatory Test analysis to a single reasonable scenario was inadequately justified and did not meet the requirement to provide a detailed description on why TransGrid consider the asset passed the Regulatory Test.

AEL notes that despite finding these compliance irregularities the AER had no means to apply a penalty to TransGrid – a potential limitation within the current NER[17].

The next version of the RIT, the RIT–T, is intended to identify the credible option that maximises the present value of net economic benefit to all those who consume and transport electricity in the market as defined under clause 5.6.5B of the National Electricity Rules (NER). AEL broadly agree in principle with the RIT–T and application guideline as drafted and consider its application in the planning and development of the transmission network vital in ensuring optimal investment moving forward we do hold reservations.

AEL considers a residual risk to the successful implementation of the AER's RIT-T remains in the manner in which TNSPs apply the guidelines. Our recent experience with the approach of TNSPs to examining alternative non-network investment options has demonstrated that TNSPs still have substantial discretion in how they apply the regulatory investment tests. AEL's concerns include:

- *Timing and process deadlines* – TNSPs still have discretion on whether they apply the timeframes and deadlines
- *Information disclosure* – TNSPs continue to provide inadequate disclosure around: actual identified technical need triggering the requirement for investment; actual accurate capital cost information associated with their 'own' preferred network solution / option; realistic and sensitivity tested demand forecasts
- *Scenario testing* – a substantive consideration of a range of alternative options.

The opportunity to contribute a non-network solution to a proposed investment has the ability to materially impact the economics of future investment options under consideration by non-network proponents. In particular, AEL notes the opportunity to earn an annuity income from a TNSP as a result of deferring the timing of a network investment options has the potential to significantly enhance the financial viability of proposed generation projects.

AEL notes the current RIT and proposed RIT–T requires a TNSP at the RFI stage to seek submissions relating to 'credible options', as opposed to a "committed project" only submission. A credible option is commercially and technically feasible, and able to be delivered on time. The information requirements for the committed projects is clearly more substantive requiring that the any alternative option to the network solution be well-advanced or actually in operation. Moreover, while TNSPs annual planning reports may provide an idea on the technical aspects of the project the disclosure is often deficient in terms of the forecasts capital investment costs often under-estimating values to an extent that a non-network proponent would not register interest (see ElectraNet example in Question 1).

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[17] AEL notes that obviously the Commission needs to carefully design an incentive arrangement to ensure that fair and adequate information on network needs and potential investment options be provided to the market. Penalising TNSPs in the same manner in which market participants are penalised may prove ineffective as TNSPs may simply look to absorb such costs through operation expenditure cost recovery through the current regulatory process, ie from consumers ultimately. Whether a scheme designed around monitoring the frequency or performance of future RIT-T applications through the year is adopted with a penalty levied as a percentage of the TNSPs next year MAR prove to be more effective.

Further to this, AEL is of the belief that by seeking a level of project disclosure by non-network proponents, without providing the same disclosure for the TNSP's own network solution could be seen as conflict of interest. AEL considers that the Commission should examine the efficiency benefits and any costs of having the AER undertake the assessment of alternative options under the RIT-T.

Question 5: Economic regulation of TNSPs Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?

Summary of Key Points

- At principle, to achieve the NEO, it would require believing that the current transmission framework ensures productive efficiencies are achieved in NEM by having six TNSPs with discrete supply areas compared to a single TNSP (a natural monopoly) delivering transmission services;
- Getting TNSPs economic regulation 'right' is critical given the scale of the forecast capital investment requirements of networks; and
- Current economic regulation of transmission networks within the NEM may be distorting TNSPs' incentives.

TNSPs are subject to economic regulation on the basis that as an industry the long run average costs for transmission services falls over a wide range of output levels such that there may be room for only a single supplier to fully exploit all of the internal economies of scale, reaching minimum efficient scales and achieving productive efficiencies. The natural monopoly doctrine has been used as the basis for economic regulation of these 'essential' facilities, and been applied not just to electricity transmission networks, but to distribution electricity networks, gas distribution networks, gas transmission networks (to lesser extent), fixed line telecommunications, airports, and ports.

At principle, to achieve the NEO, it would require believing that the current transmission framework ensures productive efficiencies are achieved in NEM by having six TNSPs with discrete supply areas as being superior to a single TNSP (a natural monopoly) delivering transmission services in the NEM. AEL would argue this current framework is not conducive to achieving the NEO and efficient investment outcomes and in turn minimising the total system costs of a natural monopoly technology.

We also consider that the majority of the challenges that the Commission focuses on are a direct by-product of the present application of the natural monopoly regulation on electricity transmission in Australia. Practically, AEL notes that the barriers to careful consideration of the transmission framework and form of regulation are political and reflect Australia's federalist model and legacy issues associated with ownership and structure of TNSPs. While these reasons explain why we have six TNSPs operating the majority of the NEMs natural monopoly electricity transmission network we consider that the Commission by having regard to the NEO has an opportunity through the TFR to complete a comprehensive review in order to examine the efficiency merits of the current framework.

As stated in our response to Question 1, it is arguable that the current form of economic regulation as applied to TNSPs may be approving cost allowances that are inefficient when compared to a form of regulation that:

- aims to minimise the NEM's LRAC for transmission services over all levels of production;
- examines the potential existence of countervailing market power in TNSPs supplier markets, which would potentially require the application of an alternative form of regulation.

Getting TNSPs economic regulation 'right' is critical given the scale of the forecast capital investment requirements of networks. An Electricity Supply Association of Australia (2009) survey highlighting that over the next five years (to 2014) the NEM's capital investment needs include:

- generation around $37 billion consisting of $19 billion on refinancing of existing generators, and capital expenditure on existing and new generators of $18 billion
- energy networks around $60 billion consisting of $29 billion on refinancing of existing networks, and capital expenditure on existing and new network assets of $31 billion, of which around $8.3 billion has been approved by the Australian Energy Regulator (AER) for transmission networks alone
- initial capital for purchase emissions permits of $10 billion.

Importantly, the levels of capital expenditure for new NEM assets amount to around $650 per annum per household (with new transmission capital expenditure representing around $105), and if current forecasts of further new investment patterns to 2025 prove correct then the burden on households could be up to ten times this amount. Given the markets' challenges, and the expected costs to meet these challenges falling on Australian households, AEL considers that there is substantial merit in the Commission taking every opportunity to ensure that the current arrangements continue to achieve the NEO at least cost.

Furthermore, AEL would argue the current economic regulation of transmission networks within the NEM further distorts the incentives facing a TNSP. Firstly, economic regulation is difficult – regulated TNSPs have a substantial information asymmetry whereby the regulator, the AER, is unable to observe a TNSPs true cost to serve.

In recent times the AER (and previously the ACCC) have sought increasing amounts of verifiable information from TNSPs as the basis to breach this information gap, and achieve a better outcome for consumers. Despite the AERs attempts and the frameworks they have put in place there remains a degree of flexibility displayed by individual TNSPs which distorts the AERs ability to appropriately determine with the same degree of precision to determine whether these costs are reflective of the efficient cost to serve.

In effect, TNSPs must respond to set planning and reliability performance standards, which affect the level of proposed capital expenditure to be approved by the AER, and finally are provided as financial returns that flow back to owners that originally set the planning and reliability performance standards. Consider Figure 4 as an illustrative example examining Powerlink's planning, reliability, allowed revenues and returns to shareholding Ministers.

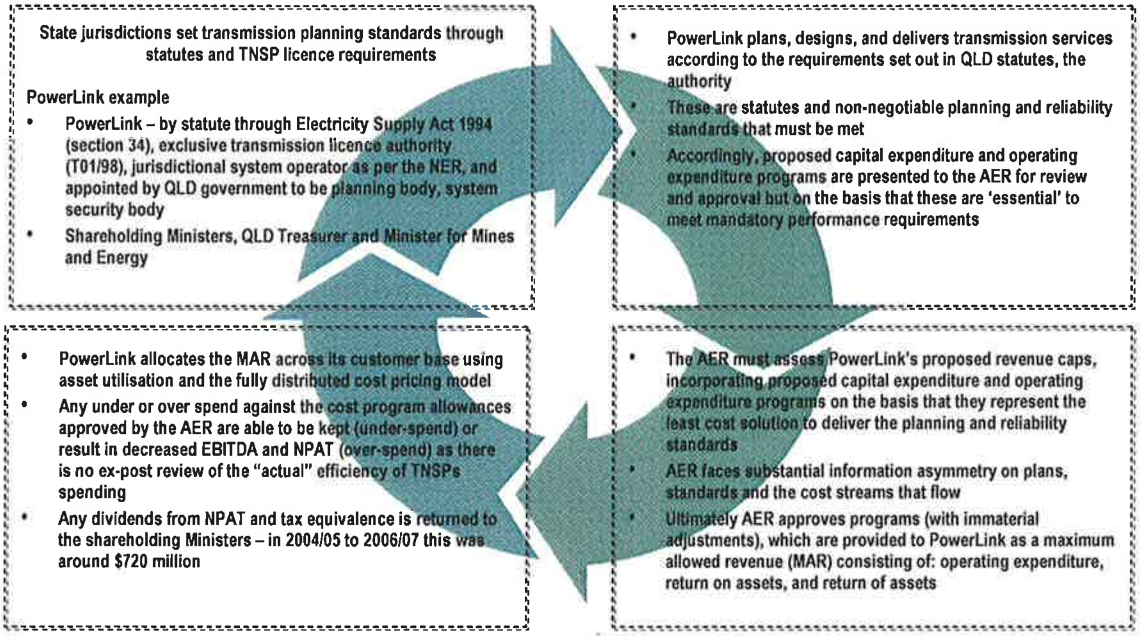

Figure 4 – Current Transmission Framework Planning and Reliability Settings interactions with the Form of Regulation – Could they be distorting incentives?

The relationship outlined above is atypical for some TNSPs, and potentially distorts the efficiency seeking incentives that economic regulation is intended to facilitate.

Question 6:	**Network charging for generation and loads**

Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?

Summary of Key Points

- A G-TUOS arrangement on existing generators will not improve the efficiency of the NEM as the decision to locate and the subsequent investment has been made;
- To apply a G-TUOS to existing generators would not improve the use of the shared network apart from using the regulatory framework as the basis for 'sharpen' early power station retirement signals – this carries substantial sovereign risks;
- There is merit in examining a G-TUOS structure with firm access rights, however before doing so broad based agreement must be reached across the market in the critical areas of: identifying, monitoring, and reporting on transmission congestion and the adoption of appropriate penalty schemes.

A G-TUOS arrangement on existing generators will not improve the efficiency of the NEM. A G-TOUS on new generators is likely to provide minimal efficiency gains, and may be less than the costs imposed on generators and the potential inefficiencies associated with G-TOUS being apart of the current regulatory regime.

Setting a price signal for existing generators to reflect the generators' use of shared transmission would provide no efficiency signal as the decision to locate has been made[18]. To apply a G-TUOS to existing generators would not improve the use of the shared network apart from using the regulatory framework as the basis for 'sharpen' early power station retirement signals. AEL considers that a deliberate change in the NER to affect a policy objective[19] of closing down existing generators early to free transmission capacity is mis-guided and for debt and equity owners represents a loss of value akin to sovereign risk.

G-TUOS for new generation will signal its cost or use of the shared network. This may mean that less new generation is built, and that these generators look to locate more closely to load rather than to be closer to the cheapest fuel source. The efficiency losses that occur as a result of the delays in new investment are difficult to estimate, along with identifying and estimating the various externalities (positive and negative) that are likely to emerge as a result of this significant change.

Setting a G-TUOS for new generation, and then allowing the G-TOUS to oscillate to reflect scarcity value of available transmission capacity would inherently make the G-TUOS a variable charge, which the new generator would not be able to forecast, or be able to effectively hedge. It would make financing of new generation difficult.

AEL considers that there is merit in examining the G-TUOS with firm access rights, however, AEL notes that there are several matters that require broad based agreement before such an arrangement could be considered. These being:

- a transparent, consistent and respected means of identifying or defining transmission congestion, its root cause, and then having a monitoring or reporting framework on transmission congestion
- the establishment of an appropriate penalty scheme whereby the TNSP does not provide the 'firm access' being paid for then there is an arrangement that provides for the timely provision of a financial penalty to compensate the affected generator.

[18] AEL notes that arguing for G-TUOS to apply to existing generators on the basis that a new generator on equity grounds is a consideration beyond the scope of the NEO. The NEO does not require the Commission to determine policy outcomes to achieve 'equity outcomes'.
[19] AEMC, (2010), Issues Paper – Transmission Frameworks Review.

Question 7: Nature of access
Would it be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service? Would this help generators to manage risks around constraints and dispatch uncertainty?

Summary of Key Points

- An enhanced level of transmission service cannot be provided without first having defined what constitutes a minimum or base-line level of transmission service and how this may be reflected within arrangements;
- As part of the review the Commission has to fully explore the efficiency properties provided under a firm or open access transmission framework.

AEL considers that this represents a novel idea considering that TNSPs' do not define what constitutes a minimum or base-line level of transmission service associated with the different types of services set in the NER. As per our response to Question 2, the transmission framework represents an open access regime, and on this standard AEL considers that there is merit in the Commission exploring options to:

- clearly define minimum levels of transmission service provision for prescribed services, negotiated services and contestable services
- examine amending the current connection agreement process to explicitly take account of providing to new generators and load with a minimum or base line level of transmission services expected for the life of the agreement
- examine the merits of allowing users of transmission services to negotiate around the minimum or base line levels of transmission service defined as being the transmission service – adopt clause 5.4A of the NER
- looking at opportunities to strengthen the AER's powers to focus on the operational performance of TNSPs when interacting with the market, and particularly where regulatory functions remain with TNSPs (the operation of clauses 4.1.1, 4.2.2, 4.3.1, 4.3.3, and 4.3.4 of the NER).

AEL considers that the Commission has to fully explore the efficiency properties provided under a firm or open access transmission framework. By firm access we define this to be:

- at time of connection the TNSP provides a guaranteed level of transmission services applicable for the term of the agreement
- when generating the generators output is carried as per the transmission service level to the regional reference node – where there are transmission constraints the TNSP compensates the generator for the loss of generation
- the generator pays for the level of transmission service – towards the use of the shared network assets being utilised, hence facing a from of locational signal
- as the generator pays for the level of transmission service then the generator is able to 'trade' this right or sell its share of the transmission capacity back to the TNSP.

Open access is taken to mean the current transmission services that generators receive.

Generally, the choice of access regime is viewed as a means to address volatility in earnings caused by unplanned transmission congestion, which ultimately raises a generator's risk profile and the required rate of return on investment. AEL observes that in terms of network congestion, it is important to note that after 12 years the market seems unable to agree to a real measure of transmission congestion.

Given the problem solving capabilities of the electricity market the lack of a consensus on transmission congestion measurement and monitoring to improve operational and market outcomes can mean a few things:

- current levels of transmission congestion are immaterial
- the market doesn't have the information and engineering know how to solve the problem
- governance arrangements are poor allowing regulatory institutions to avoid making a decision
- participants' are satisfied that their commercial interests are aligned with the volatility and randomness of the market outcomes experienced when transmission constraints bind.

With market forecasts predicting material levels of transmission congestion to emerge as a consequence of the impact of the Commonwealth Government's RET Scheme, as intermittent generation capacity in installed, there is an increasing need to decide whether the current regime is robust in supporting the achievement of the NEO. It is important to note that while intermittent generation supports the achievement of the RET it is arguable whether it meets the reliability elements of the NEO.

On this basis, AEL considers that the Commission needs to explore the efficiency properties associated with either a firm or open access regime. Critically, AEL does not support the application of a firm access regime to existing generators as there limited efficiency benefits from doing so.

AEL also notes with concern the Commission's, and the AER's stance in relation to clause 5.4A of the NER. The Commission contends that using this mechanism to facilitate from access negotiations an identified level of reduced or unaffected access to the transmission network from a connecting generator on the basis that it is difficult to identify the 'causer' of congestion[20].

It is AEL's experience that within the TNSP's process of undertaking network modelling to determine the new generator or altered generator's impact on network reliability performance as the basis for agreeing to Generator Performance Standards there is sufficient scope to identify likely congestion impacts on existing generators from new generators. As highlighted in the NGF submission on this issue, the problem is that the ambiguities in the NER have undermined 5.4A, and more importantly, TNSPs have been unwilling to recognise the importance of clause 5.4A at being a mechanism to provide a localised signal to connecting generators.

On this basis, AEL supports the NGF's position that the Commission continue to include the operationalisation of clause 5.4A of the NER as the basis for resolving some of the challenges associated with network access in the NEM.

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

Question 8: Connection arrangements Do current arrangements for the connection of generators and large end-users reflect the needs of the market? To the extent that more fundamental reforms to the transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

Summary of Key Points

- A lack of clarity and transparency exists within the NER provisions around connections and the allocation of reasonable costs by a TNSP;
- Current arrangements whereby a TNSP procures NSCAS from market participants for free through their connection agreements effectively under-values these important services.

AEL refers the Commission to the NGF's submission and response to Question 8, particularly, Attachment A to the NGF's submission. AEL reiterates that in its experience the current connection arrangements:

- lack clarity around connections in the NER provisions
- lack of transparency around the allocation of "reasonable costs"
- are ambiguous around information sharing and/or timing issues
- are challenging given the transmission arrangements in Victoria
- TNSP resourcing issues with respect to processing connection enquiries and applications
- The limited scope for dispute resolution.

Within the current connection agreement process TNSPs procure a significant amount of NSCAS, specifically reactive power capabilities plus other fault ride through capabilities, through mandatory service acquisition as detailed within the connection agreements and agreed Generator Performance Standards of generators. In doing so, a TNSP obtains these services for 'free' from registered scheduled generators, and to lesser extent semi-scheduled generators.

The provision of NSCAS, either by AEMO or the TNSPs, is by definition essential to maintaining power system security and reliability in the NEM. The current arrangement ensures that these services are not valued through a process that effectively uses of regulatory powers to procure valued services free of charge.

AEL notes AEMO's recent proposals to:

- identify all future NSCAS requirements as part of the annual development of the National Transmission Network Development Plan (NTNDP)
- allow TNSPs to have primary responsibility for the procurement of NSCAS
- but where an NSCAS requirement has been identified and remains unmet by a TNSP for a period of 18 months, AEMO is able to tender for NSCAS.

Despite these improvements, AEL maintains that the effectiveness of any structure is diminished while TNSPs, and AEMO to a lesser extent, are able to procure these NSCAS services for free through the use of regulatory approval processes applied at the time the generator connects. AEL considers that this represents an important area for resolution by the Commission as part of its review of current connection arrangements.

Question 9: **Network operation**
Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?

Summary of Key Points

- Conflicts of interest, distorted incentives and inefficient outcomes remain within the current framework;
- Separating TNSPs from their planning, and quasi-regulatory function, and requiring them to only operate as asset owners / operators may present a first best solution for the market;
- Opportunity to explore as part of the review whether there are efficiency benefits, particularly, positive externalities by transferring the real time operation of the national transmission network system to AEMO.

In previous responses, we have highlighted that the multiple roles carried out by TNSPs are the basis for conflicts of interests, distorted incentives, and inefficiency outcomes. As outlined in our response to Question 1 and 2, AEL considers the first best solution is to separate TNSPs from their planning, and quasi-regulatory function, and have them operate as asset owners / operators.

AEL considers that there may be merit in exploring whether there are efficiency benefits, particularly, positive externalities by transferring the real time operation of the national transmission network to AEMO. Firstly, how TNSPs interact with the market can impose significant costs and benefits particularly in the disclosure of timely information around transmission relate to:

- planned outage scheduling;
- maintenance of design ratings and performance;
- management of dynamic ratings; and
- application of network contingencies.

There would be enormous benefits to the market by having AEMO deliver these services on the basis of the NER requiring TNSPs provide the information, and operate their various networks according to AEMO's operational control and direction. Importantly, by having a single operator there are opportunities to minimise system costs as the operator solves demand and supply imbalances by taking account of generation and transmission capacities.

To support the arrangements the AER could be provided with enhanced monitoring powers to monitor and enforce TNSPs behaviour to ensure that information relating to the operation of the transmission networks is provided to AEMO, and that TNSPs respond to AEMO's direction.

Question 10: Dispatch of the market and management of congestion
Is there a need for material congestion to be more efficiently managed in the NEM?

Summary of Key Points

- Opportunity exists to examine the merits of a comprehensive congestion management scheme, however before doing so a broad based agreement must be reached on what constitutes congestion.

AEL considers that there is merit in examining a comprehensive congestion management scheme. However, as indicated to our response to Question 6, there needs to be broad based agreement on what constitutes transmission congestion prior to there being a management scheme implemented. We note the points made in the NGF's submission and consider that the existing regime applied to TNSPs by the AER could be enhanced as an interim step until such time the market reaches a consensus on identifying, measuring and reporting transmission congestion.

In terms of the design principles to be applied to a congestion management scheme we put forward the following:

- that the congestion management process or pricing depends only on actual congestion, not on predicted congestion (which essentially means that a complete regime is required)
- that the regime maintains or enhances the trading benefits of the regional market design in relation to hedging
- that any settlement under the new regime is financially balanced, so that it does not draw upon or add to existing settlement flows: including existing settlement residues
- that access to the regional market for existing market participants is, to the extent practical and reasonable, preserved under the new regime.