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

Lodged via www.aemc.gov.au

Reference: EPR0019

Dear Mr Pierce

TRANSMISSION FRAMEWORKS REVIEW

CS Energy, Delta Electricity, Eraring Energy, Macquarie Generation and Snowy Hydro, Stanwell Corporation and Tarong Energy (the 'Northern Group') welcome the opportunity to make a submission to the AEMC's Transmission Framework Review Issues Paper, as published on 18 August 2010.

The AEMC's Issues Paper highlights a number of key transmission-related challenges arising under the current market and regulatory design of the NEM, particularly in light of the implementation of climate change policies. The Issues Paper then discusses aspects of the current arrangements that may fall short of providing ideal incentives or signals in these areas, highlighting the need for sufficient certainty to support new investment in generation.

At the same time, the Issues Paper does not address the fundamental issue of continuing uncertainty around the form and timing of a carbon price in the Australian economy. In the view of the Group, the lack of a clear climate change policy framework is the single biggest source of uncertainty and risk facing the electricity sector at this time. All other factors referred to in the Issues Paper pale in comparison against this overriding issue.

In contrast, and as is set out in the submission, the governance and investment arrangements for transmission have been developed and refined over the life of the NEM and are broadly satisfactory. The Group submits that the key underlying reasons that account for different industry views on the need for changes to the current NEM framework are differences in transmission planning standards between regions. Specifically, the Group considers that planning processes in Queensland and NSW provide the right incentives for TNSPs to invest in transmission network where it is efficient to build out points of congestion.

The Issues Paper furthermore fails to acknowledge certain strengths of the existing transmission arrangements that help ameliorate many of the concerns that the AEMC has raised. In particular, the Issues Paper understates the importance and effectiveness of the various price and non-price signals and incentives provided in the NEM, including the nature of dispatch risks, locational NEM price signals and the regulatory test for transmission.

Relatedly, the initiatives described in the Issues Paper reopen a number of aspects of the NEM governance arrangements, which the AEMC has reviewed and consulted on only very recently, and for which Rules changes have been developed and put in place. These reviews have generally only resulted in relatively minor enhancements to the current arrangements. In the Group's view, a decision to revisit these recent decisions raises questions about the longer term certainty of the NEM governance framework under which NEM participants and institutions operate and invest.

The matters raised in the Issues Paper are broad in terms of their scope and implications for the NEM. The options contemplated by the AEMC would imply fundamental changes to the present governance framework for transmission in the NEM that would affect all aspects of transmission planning, investment and operations. In addition, any shift to a more granular pricing of congestion in the NEM will have significant impacts on the liquidity and operations of the contract market.

The Issues Paper appears to give little thought to the considerable implementation and transitional costs that a number of these options that are canvassed would imply. The Issues Paper also does not address the inevitable tradeoffs that characterise different market designs, in terms of their implications for efficient investment and market operations. These questions are all the more relevant since a number of the issues raised by the AEMC are transitional in nature, and may only become relevant if and when a climate change policy is implemented in the NEM and/or in the wider economy.

In our view, the appropriate question for the Commission is therefore whether changes to the existing frameworks are likely to be worthwhile, given fundamental policy uncertainties and given the considerable implementation and transitional issues that would inevitably accompany any such changes. Based on the evidence to date, we are not convinced that substantial changes to the existing arrangements are likely to be worthwhile.

The Group therefore submits that far reaching changes to the NEM design of the type contemplated by the AEMC should only be undertaken on the basis of a whole-of-market analysis that would need to assess the risks and trade-offs of alternative market design options. To date, such an analysis has not been undertaken.

The Group is currently considering whether to commission some independent modelling work to examine the possible incidence and materiality of congestion in the NEM under various climate change policy scenarios. This work is not without its limits given the difficulty of identifying the likely transmission and generation investment responses at a sub-regional level in the NEM, particularly over the medium to longer term. We are in ongoing discussions with a consultancy team specialising in this type of analysis to develop an appropriate modelling methodology. We would welcome the opportunity to discuss our proposed approach with the Commission to ensure that any modelling usefully contributes to the Commission's assessment framework.

The attached submission outlines the Group's view in more detail and addresses the specific questions posed by the AEMC. The Group looks forward to participating in the next stages of the review process.

RUSSELL SKELTON
MANAGER MARKETING & TRADING
MACQUARIE GENERATION

ON BEHALF OF THE NORTHERN GROUP

13 October 2010

c/- P O Box 38,
Hunter Region MC NSW 2310

Transmission Frameworks Review

Submission by the Northern Generators Group

29 September 2010

Contents

1. Summary

Application of the NEO

The Group agrees that the basis for any review of NEM arrangements should be the national electricity objective (NEO) of minimising total system (generation and transmission) costs for consumers. This is the fundamental principle that underpins the NEM Rules, which define a consistent governance framework for the NEM, as well as the rights and responsibilities of all NEM participants.

The Group submits that, given the inherent complexities in regulating transmission in a market context, the NEM arrangements have worked well, and have broadly supported efficient outcomes for consumers in accordance with the NEO.

The role of transmission

The Group submits that the role of transmission should be assessed with reference to the NEO. A move away from a central focus on consumers compromises the central objective of ensuring least cost supply of electricity to consumers over the long term.

Transmission planning

The Group does not support the view that additional market-based signals might be required to strengthen transmission planning. Since inception, the NEM transmission arrangements have successfully accommodated substantial changes in power flows and new generation investment. The quality and transparency of NEM planning arrangements has been considerably strengthened in recent years, as has the RIT-T, which sets out a comprehensive framework for identifying efficient transmission investment.

It should be recognised that different transmission planning approaches, such as the more proactive approach contemplated by the AEMC imply different costs benefit trade-offs, including in terms of stranding risks and/or additional incentives for generation investment. The Group considers that the existing NEM framework, specifically the RIT-T, which explicitly deals with future uncertainty and risk is entirely consistent with more proactive planning and investment.

Economic regulation of TNSPs

The Group considers that the current regime for the economic regulation of transmission broadly leads to efficient network investment. The Group would not support a significant change in the structure and governance of NEM institutions.

Network charging for generation and load

In the Group’s view, the AEMC’s assessment of the merits of locational charging for generators fails to recognise the range of price and non-price locational signals that already exist in the NEM. Potential investors have a vital interest in locating in parts of the network:

- which are (and are likely to remain) relatively unconstrained, so as to manage dispatch risks;

- where losses are relatively low, to maximise revenues for their output; and/or
- where augmentations are relatively low cost and would likely pass the RIT-T.

In addition, TNSPs can and do enter into network support agreements (NSAs) and other non-network options with generators whose output is required to support the reliable operation of the network.

A generator transmission charge would therefore, at best, duplicate existing strong price and non-price signals that already exist in the NEM. In addition, as its has been described by the AEMC to date, the charge would likely be neither effective nor efficient:

- As a ‘forward-looking’ charge it would be, by design, unstable, and would not therefore represent a credible long-term signal for future generators. Whether such a charge could be designed to be sufficiently material has also not been tested. For these reasons, the charge would also be ineffective as an investment and retirement signal.
- More generally, and unlike the RIT-T, such a charge may lead to inefficient investment (or retirement) outcomes, since it only approximates one (the transmission) component of costs, rather than system costs as a whole.

Nature of access

As noted above, the Group submits that there is no evidence to suggest that investment in both transmission and generation in the NEM has not occurred in a timely and efficient manner, and in response to market trends.

The Group submits that privately sponsored investment in the shared transmission network where a corresponding private transmission right is assigned potentially conflicts with the NEO and fundamentally implies a shift to a different market design. Furthermore, the different physical or financial network access models create very difficult conceptual and practical implementation issues; and may not be consistent with the NEO:

- Physical firm access can only be achieved by building out transmission constraints, either at a local or regional level, and is unlikely to be efficient and consistent with the NEO.
- Financial firm access rights arrangements cannot be defined in a way that is durable, and, unless customers are charged an uplift payment to fund these rights, provide only a partial hedge against congestion. In practice, the implementation of these rights has also proved to be extremely complex and controversial.
- CSP/CSC arrangements suffer from similar drawbacks, and would likely imply an additional layer of complexity, particularly in the allocation process.

Connection arrangements

The Group is not convinced that current unregulated arrangements in relation to connection services are appropriate, given the strong negotiating position of TNSPs.

Beyond this issue, the Group considers that the broader framework for connections results in efficient outcomes and can be applied sufficiently flexibly to address a range of circumstances. The Group would caution against the introduction of additional regulated mechanisms where there are no obstacles to negotiated commercial agreements between market participants.

Network operation

The Group is supportive of changes to the transmission arrangements that could improve the operational incentives of TNSPs and the quality of information about network outages.

Dispatch of the market and the management of congestion

The Group disagrees with the AEMC's conclusion that congestion in the NEM is increasing and will pose significant challenges. Network congestion in 2008-09 fell significantly relative to earlier years.

Going forward, recent NEM modelling studies suggest that the extent of future NEM congestion is highly uncertain and dependent on factors such as the carbon price, the locational decisions of renewable generators, and the administrative arrangements of any carbon price mechanism. Given that there is currently no evidence of increasing congestion trends, and that there are fundamental uncertainties about future climate change policies (and therefore about any transitional congestion issues that may arise in the course of their implementation), changes to the NEM design are not warranted.

The Group furthermore considers that given the causes of NEM congestion and in particular the importance of network outages, the negligible amount of dispatch inefficiency costs due to mis-pricing, the effectiveness of the congestion pricing mechanisms such as the CSP/CSC as canvassed by the AEMC is doubtful. Aside from considerable implementation and ongoing costs, the costs of moving toward more granular pricing of congestion in the NEM may be far outweighed by adverse competitive effects in the spot and contract markets.

2. Relevant context to the review

In its Issues Paper, the AEMC states that, going forward, investment in and the operation of the NEM transmission network must address a number of challenges. The Group acknowledges that NEM institutions and market participants will need to respond flexibly to continued load growth and the impact of climate change policies – as and when these have been developed and put into place – to deliver security of supply and reliability at least cost to consumers.

However, as set out in the following, the approach taken by the AEMC in drafting the Issues Paper raises a number of broader concerns.

2.1 Stability of the NEM governance and investment framework

In its Issues Paper the AEMC highlights the importance of providing a stable framework to promote overall efficiency and a more certain investment climate. The Group strongly concurs with this principle.

Nonetheless, the initiatives described in the Issues Paper revisit and reopen a number of aspects of the NEM governance arrangements, which the AEMC has reviewed and consulted on only very recently, and for which Rules changes have been developed and put in place. These include:

- The review of Last Resort Planning Power Guidelines (May 2010);
- The Review of Energy Market Frameworks in the light of Climate Change Policies (September 2009);
- The Transmission Reliability Standards Review (2008);
- The National Transmission Planning Arrangements (June 2008);
- The Congestion Management Review (CMR, June 2008); and
- The Abolition of Snowy Region (August 2007).

The Group submits that a number of the matters raised in the Issues Paper have been assessed in depth and addressed in the course of these reviews and associated consultations. These reviews have generally only resulted in minor enhancements to the current arrangements. A number of the AEMC's recommendations have only been implemented very recently or are in the process of being implemented, so that reopening these matters would be precipitous. In the view of the Group, the AEMC's approach to revisit these recent decisions therefore raises fundamental questions about the longer term certainty of the NEM governance framework under which NEM participants and institutions operate and invest.

2.2 Performance of the NEM to date

The Issues Paper identifies a number of future uncertainties and risks:

- more congestion as new generators locate in the network to meet growing electricity demand;
- more investment in renewable energy, reflecting the planned shift to less carbon intensive generation; and
- a risk that the transmission network will be affected by extreme weather events, with implications for network investment, maintenance and operational requirements, as well as for generation patterns.

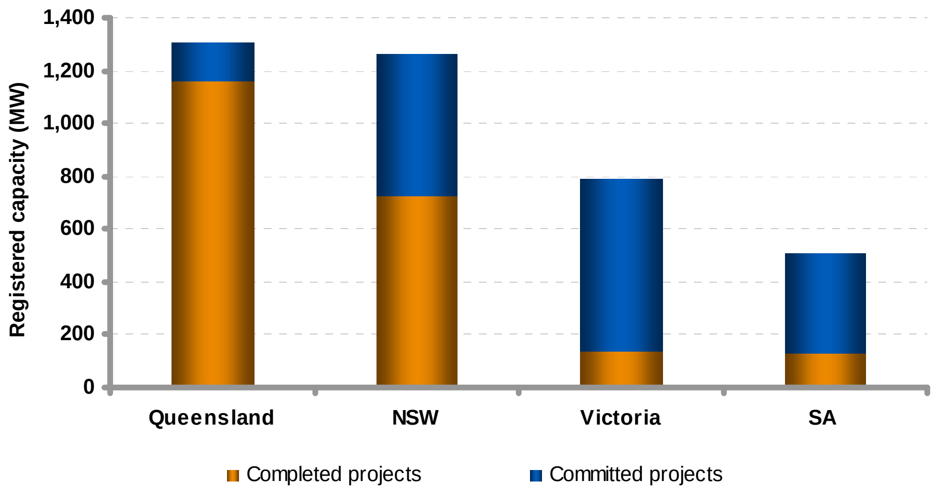
However, in the view of the Group, there is little evidence to suggest that the NEM governance arrangements as they stand (and as further strengthened by recent Rules changes) would not be sufficiently flexible to accommodate future challenges.

Generation investment and reliability

There is no evidence that generation investment in the NEM has not kept pace with load growth, or that this is likely to change going forward.

Significant generation investment to meet growing demand has occurred in the NEM since its inception. The AER's most recent State of the Market report (2009) highlights that from the inception of the NEM in 1999 to July 2009, almost 10,300 MW of new registered generation capacity was commissioned. AEMO's most recent Electricity Statement of Opportunities (ESOO, 2010) shows that since 2009, almost 3,900MW of new capacity was either completed or committed (Figure 1).

FIGURE 1: COMPLETED AND COMMITTED GENERATION PROJECTS SINCE 2009



Source: AEMO ESOO (2010)

Notes: 9MW of capacity were committed in Tasmania, which has significant excess generation capacity.

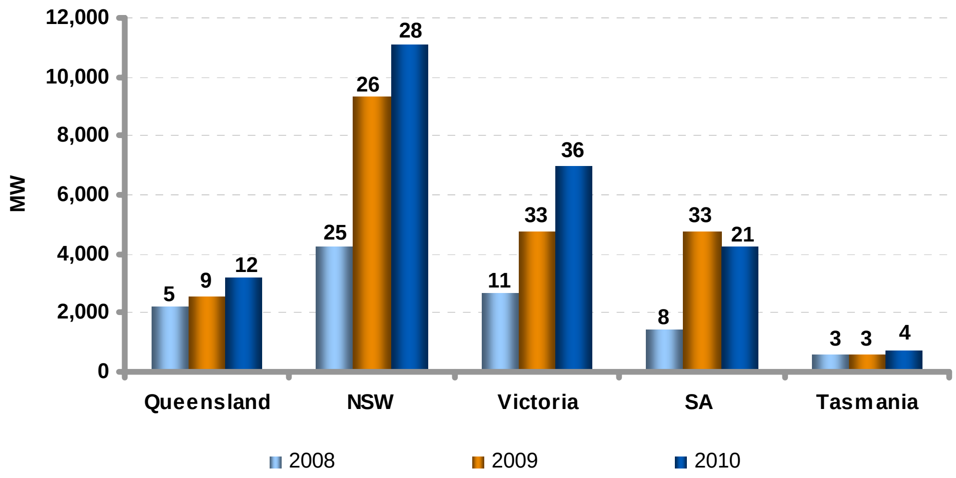
Since market start in December 1998, the long-term moving average of actual annual unserved energy for (USE) for the most recent ten financial years was 0 per cent for New South Wales, Queensland and Tasmania, 0.00051 per cent for South Australia, and 0.00044 per cent for Victoria (AER Reliability Panel 2009). These figures are well below the NEM criterion of a maximum permissible USE of 0.002 per cent of annual energy consumption for a region.

AEMO's most recent Electricity Statement of Opportunities (ESOO, 2010) indicates that under medium economic growth projections, the first region expected to require new generation investment is Queensland, but that new generation is not required until 2013/14.[1] Victoria and South Australia do not require new generation investment until 2015/16, New South Wales until 2016/17, and Tasmania has sufficient capacity until 2019/20.

Furthermore, Figure 2 below shows that there is no shortage of additional investment proposals going forward. Notably, the pipeline of announced and proposed projects comprises planned investments in all NEM regions, and includes diverse projects of different sizes and fuel types, including thermal and renewable projects. As commented by AER in its discussion around the demand and generation capacity outlook to 2014-15 (2009, P.69):

> While the uncertain nature of proposed projects means they cannot be factored into AEMO's reliability equations, they indicate the market's awareness of future capacity needs. In particular, they indicate the extent of competition in the market to develop electricity infrastructure. ... While many proposed projects may never be constructed, only a relatively small percentage would need to occur to meet demand and reliability requirements into the next decade.

FIGURE 2: ADVANCED AND PUBLICLY ANNOUNCED GENERATION PROPOSALS – COMBINED CAPACITY AND NUMBERS OF PROJECTS



Source: AEMO ESOO (2010)

Notes: 2010 figures include advanced and publicly announced projects. Earlier years are advanced projects only. Projects are classified based on AEMO's commitment criteria (site acquisition, contracts for major components, planning approval, financing, and the date set for

[1] AEMO's determination in relation to the timing when new investment is required in Queensland reflects to key factors – a change in the minimum reserve level (MRL) for Queensland that was introduced in the 2010 ESOO, and which has advanced the timing of a potential reserve shortfall by a year, as well as a high demand forecast prepared by the Queensland network businesses.

construction. Advanced proposals meet at least three commitment criteria, and publicly announced proposals meet less than three.

NEM congestion

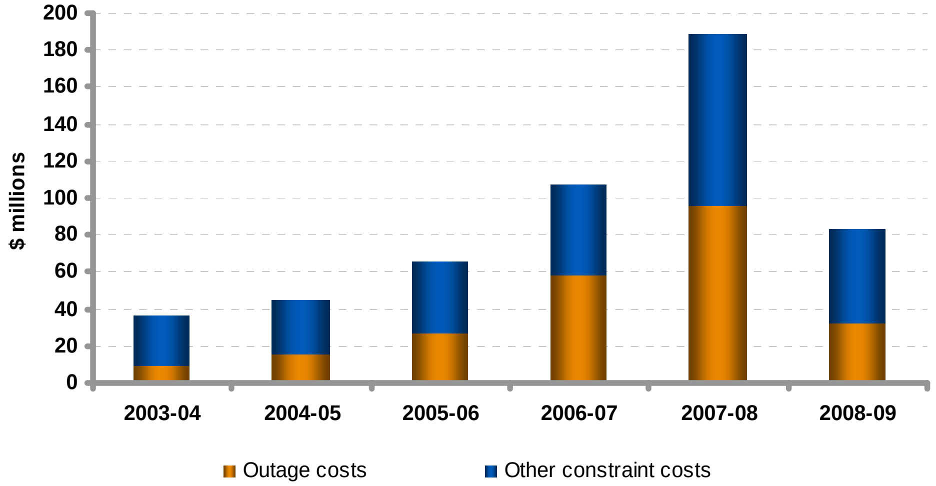
The Issues Paper highlights as a key concern the risk of increasing NEM congestion, stating that in recent years annual costs have been "generally trending upwards" (P.38).

The most recent regulatory publication that assesses NEM congestion costs is the AER's 2009 State of the Energy Market report. In that report, the AER found a material *decrease* in congestion in 2008-09. The AER also found that:

- most congestion costs typically accumulate on just a handful of days;
- a significant portion arise as a result of transmission outages (which would not be affected by any type of pricing reform); and that
- these costs are relatively modest given the scale of the market.

It should also be noted that where high congestion costs in South Australia/Victoria are concerned, the Electricity Supply Industry Planning Council of South Australia (ESIPC 2009) has commented that outcomes from about early 2007 to 2008 coincided with the drought in those years in all Eastern Seaboard states. This highlights the importance of unpredictable and transitory congestion events.

FIGURE 3: COSTS OF TRANSMISSION CONGESTION ($ MILLIONS)



Notes: Congestion in the Tasmanian transmission network are included from 2005/06 onwards. Split between outage and other constraint costs estimated for 2007-08 and 2008-09.

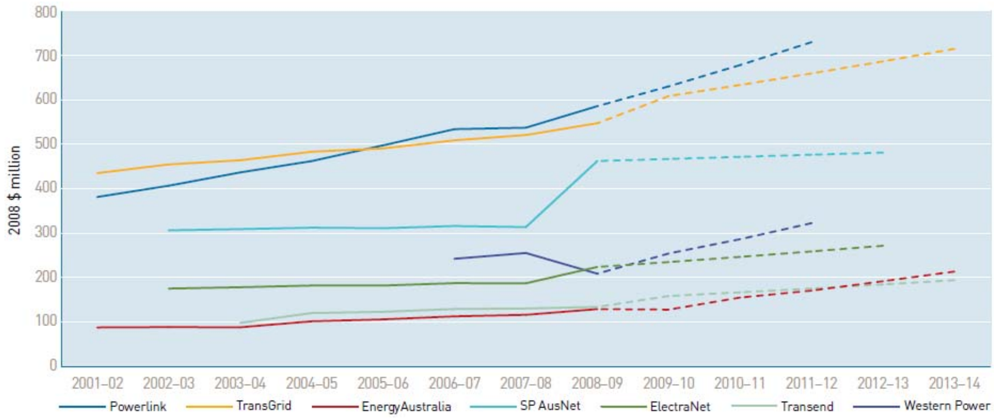
Source: AER, 2009. State of the Energy Market. AER, Indicators of the market impact of transmission congestion, reports for 2003/04 (9 June 2006), 2004/05 (10 October 2006), 2005/06 (February 2007), 2006/07 (November 2007).

Going forward, the indications are that increased network investment by TNSPs may continue to limit network congestion in the NEM. Figure 4 below (reproduced from the AER's 2009 State of the Market report) charts past and forecast regulated revenues for the NEM TNSPs. The AER notes that its recent revenue cap decisions project significantly higher investment into the next decade, with investment over the 10 years to 2011-12 forecast a around $12.4 billion.

Where expenditures by individual TNSPs is concerned:

- Powerlink's projects capital spending from 2007-08 to 2011-12 (5 years) of $2.6 billion, an 80 per cent increase on the previous regulatory period;
- TransGrid projects capital spending from 2009-10 to 2013-14 (5 years) of $2.4 billon, a 72 per cent increase on the previous period; and
- SP AusNet projects capital spending from 1 April 2008 to 31 March 2014 (6 years) of $750 million, a 57 per cent increase on the previous period.

FIGURE 4: ELECTRICITY TRANSMISSION REVENUE (2008 $ MILLIONS)



Notes: Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years. All values in June 2008 dollars.

Source: AER, 2009. State of the Energy Market. AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

While increased investment in transmission infrastructure does not automatically imply that congestion will not become an issue in future years, it will tend to alleviate the incidence of congestion across the NEM. The AER similarly concludes (2009, P.143):

> Recent regulatory decisions have provided for increased transmission investment that may help to address capacity issues and reduce congestion costs over time.

2.3 Importance of cost trade-offs

As it is set out in the Issues Paper, the scope of the Transmission Frameworks Review is extraordinarily broad in its scope and implications. Taken at face value, the options contemplated in the Issues Paper would imply fundamental changes to the present governance framework for transmission in the NEM that would affect all aspects of transmission investment and operations. In addition, the introduction of a congestion management regime would also have consequences for the liquidity and efficiency of NEM contract markets.

However, the Issues Paper appears to give little consideration to the considerable implementation and transitional costs that would inevitably accompany the types of changes that are apparently contemplated. A number of proposals imply step changes in the complexity of the current arrangements, and would require significant further changes to wholesale and retail market, as well as trading arrangements. New interventions and regulations risk undermining the efficient operation of the market, which the Group contends, has broadly served Australian consumers well.

It is also misleading to suggest that there are immediate solutions to any potential shortcomings of the present NEM arrangements. The experience with wholesale markets to date has shown that different organisational and governance arrangements invariably imply trade-offs. There is no such thing as a ‘perfect’ electricity wholesale market, and there can be little doubt that a number of the changes contemplated by the AEMC will create new problems and risks further down the line. The Group therefore considers that any changes and corresponding benefits posited by the AEMC should be tested against the costs that they will entail, both in the short and over the longer term.

Importantly, the AEMC requires an analytical framework to analyse the efficiency trade-offs that some of contemplated design changes imply. In the NEM, a lack of firm access and corresponding dispatch risks provide a strong (dynamic efficiency) incentive on generators to locate in uncongested parts of the network. At the same time, the NEM’s regional structure generally supports liquidity in the contract market, although this is less than would be the case if the NEM was defined as a single large region. Overall, this market design essentially trades off efficient investment (and the broader benefits of a relatively liquid contract market) with occasional allocative and (less frequently) productive inefficiencies when congestion arises.

Other wholesale market designs attach different weights to these efficiency objectives, and it can be argued that the outcomes are often markedly inferior to those in the NEM. Locational marginal pricing (LMP) markets, such as those operating in the US, emphasise ‘theoretically correct’ spot prices (that is, allocative efficiency), but suffer from illiquid contract markets that impede investment and from concerns about the exercise of local generator market power (so that price caps are pervasive). Markets that provide some form of firm dispatch right may reduce or remove the incentive on generators to make efficient locational decisions by socialising network augmentation costs, and therefore provide few or no dynamic efficiency incentives. These are fundamental efficiency trade-offs that should be explicitly recognised by the AEMC.

3. Issues for consultation

3.1 Appropriate role of transmission

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?

The AEMC notes that the framework and incentives governing transmission investment and operation will impact on the costs of generation investment and operation and vice versa. Accordingly, the AEMC intends to 'properly define' the role of transmission as a service provider in the NEM, including to generation and load, and to determine whether existing or new services could be provided more efficiently.

The Group agrees that the basis for any review of NEM arrangements should be the national electricity objective (NEO) of minimising total system (generation and transmission) costs for consumers. This is the fundamental principle that underpins the NEM Rules, which define a consistent governance framework for the NEM, as well as the rights and responsibilities of all NEM participants.

The Group also concedes that the existing NEM transmission framework is not perfect, certainly not as measured against a highly idealised paradigm in which generation and transmission investment are co-optimised. Arguably, such an outcome can only be achieved in a centrally planned and operated electricity system. However, such centrally planned arrangements have been shown to encourage a range of other inefficiencies, as well as being prone to the influence of vested interests and political error/interference.

That said, defining the role and governance of transmission is one of the most difficult challenges in any wholesale market design. Transmission has strong natural monopoly characteristics and must therefore be regulated. Transmission services can also complement and substitute unregulated services such as generation, creating complex interdependencies in the planning and operations of transmission networks. In this context, the RIT-T plays a central role in balancing the costs and benefits of transmission against non-network alternatives, or of access to more remote versus local generation.

The NEM Rules relating to transmission therefore provide for a number of obligations on TNSPs (as well a AEMO), as well as a mix of price and non-price signals and incentives with the objective of promoting efficient decision making and aligning generation and transmission investment. While there is always room for improvement, key elements of the transmission framework have been significantly strengthened in recent years. They include the publication of regional and NEM-wide transmission development plans, the revised RIT-T as a consistent evaluation framework to determine (reliability and market) investment in the shared grid, and an incentive regulation framework that aims to improve the accountability of TNSPs (see Question 3).

Furthermore, and as outlined in Section 2.2, the NEM – and therefore NEM governance arrangements, including those related to transmission – have broadly performed well to date. Transmission investment has generally kept pace with new generation investment, so that consumers have benefited from competitive electricity supplies in an interconnected market. There is little or no evidence to suggest that the existing framework is encouraging systematically poor operational or investment outcomes.

The NEM experience, while not perfect, contrasts with the experience in other electricity wholesale markets where governance and organisational arrangements around transmission have been beset with difficulties and have required significant ongoing reforms. In US power markets that initially relied on price differentials between LMPs and financial rights to finance transmission investment, very little transmission investment occurred until the Federal Energy Regulatory Commission (FERC) intervened to significantly amend the investment framework for transmission to facilitate urgently needed new generation investment. In PJM, the cost of transmission congestion therefore reached 9 per cent of market turnover (around USD2.1 billion) in 2005. In the New Zealand Electricity Market (NZEM), which initially relied solely on LMP price differentials to fund transmission investment, Transpower did not augment the core grid for around 10 years. Over the 10 years to 2007, the annual value of loss and congestion rentals increased to 7.4 per cent of turnover.

In summary, the Group submits that, given the inherent complexities in regulating transmission in a market context, market dispatch and participant investment outcomes in the NEM have worked well, and have broadly supported efficient outcomes in accordance with the NEO.

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?

The AEMC sets out that under the current NEM arrangements, TNSPs invest in and operate the network so as to meet current and forecast demand of customers subject to jurisdictional reliability standards. Generators therefore face the risk of being constrained on- or off if the (transmission) network is congested. The AEMC is concerned that constraint risks may discourage efficient generation investment, and asks whether additional or different future transmission services should be provided to the competitive sectors of the NEM.

The Group takes issue with the suggestion in the Issues Paper that future (efficient) generation investment is at risk if far-reaching reforms to the transmission planning and operating arrangements are not put in place. As highlighted in Section 2.2:

- there is no indication that insufficient investment in generation has occurred in the NEM historically;
- a record amount of new capacity comprising a diverse range of fuel types and size increments was commissioned in the NEM in 2008-09; and
- looking forward, the capacity and number of proposed generation projects in all regions of the NEM further suggests that there is no shortage of proponents of new generation investment.

In the Group’s view, considering the role of transmission by reference to particular participants or groups of participants is also of limited value. All aspects of NEM governance, planning and operational arrangements rely on a consistent overarching objective, namely the NEO. Given that objective, transmission augmentations will take place if they are required to deliver electricity to consumers in a secure and reliable manner, and consumers therefore bear the cost of that investment.

A move away from a central focus on consumers, as it is expressed in the NEO, to ‘the competitive sector’ risks confusing the overarching objective of the NEM with the means of achieving that objective. Shifting the focus of services provided by TNSPs from consumers to the commercial sector will compromise the NEO’s central focus. The interests of customers and the commercial sector as a whole are not aligned, nor are the commercial interests of individual market participants. A NEO that encompasses conflicting aims will therefore reduce the clarity of the governance framework and compromise the central objective of ensuring least cost supply of electricity to consumers over the long term.

3.2 Key issues for efficient investment

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?

The AEMC identifies a number of future challenges to efficient generation and transmission investment:

- the potential for significantly changed flows on the transmission network and therefore a requirement for substantial transmission investment;
- the need for a greater responsiveness on the part of TNSPs to market developments and a corresponding need to undertake timely investment; and
- potentially greater uncertainty about network flows and therefore investment requirements, in particular as a result of renewables.

Changed power flows

The Group questions the AEMC's premise that the issues facing TNSPs will change materially going forward. Patterns of power flows across the transmission network have already undergone substantial changes since commencement of the NEM:

- on NEM commencement, power flows changed from those arising from centrally dispatched regional systems to those arising from dispatch in a NEM-wide market on the basis of competitive bids;
- the commissioning of QNI and Basslink and expanded interconnection capacity between NSW and Victoria and between Victoria and South Australia have seen power flows change from predominantly state-based country-to-city flows to now substantially inter-state flows;
- further changes have occurred as a result of existing State and Commonwealth-based renewable energy target schemes, such as the national MRET, the Victorian VRET, and the various state-based feed-in-tariff schemes; and
- the Queensland Gas Electricity Scheme has altered the fuel mix of the NEM and impacted power flows within Queensland.

AEMO's analysis of historical flow patterns across national transmission flow paths and interconnectors correspondingly shows significant shifts in flows, as well as considerable year-on-year variability in flow patterns (Appendix C and Appendix D in the most recent National Transmission Statement (NTS 2009)).

Changes in investment patterns and network utilisation have therefore been ongoing over the life of the NEM, and NEM transmission planning arrangements have accommodated these changed flow patterns. In the Group's view, there is little reason to believe or any supporting evidence that the growth of remote renewable generation will create more difficult challenges than the NEM transmission planning arrangements have successfully met to date.

Furthermore, while it may be the case that the advent of more renewable generation capacity will require transmission augmentations (as well as creating challenges for system control), none of these developments are in any way surprising or unexpected. The Australian electricity supply industry, including the transmission sector, has had some years to prepare for the impact of climate change policies, and considerable analysis has been done to anticipate its effects within the industry. The NTS (2009), for instance contains a detailed analysis and implications for generation and transmission investment for carbon price scenarios. TNSPs are therefore well aware of potential changes that will affect the industry. Specifically where renewables are concerned, TNSPs already manage their planning activities around commercial projects that are associated with varying degrees of uncertainty.

Going forward, greater uncertainty may pose some challenges for TNSPs, but none that, in the Group's opinion, cannot be managed within the existing governance framework. A more proactive planning environment may facilitate some forms of investment or reduce some costs, but also creates greater asset stranding risks. The converse is true for a more cautious, conservative approach to transmission investment. The RIT-T already provides a framework whereby TNSPs can develop reasonable scenarios that weigh the future costs and benefits of different projects going forward. There is nothing in the Rules to say that these planning processes cannot work in a (more uncertain) future environment where a NEM-wide climate change policy is applied. TNSPs can invest on the basis of expected future generation investment so long as their forecast scenarios are reasonable and defensible.

Transmission planning arrangements

Overall, therefore, the Group believes that current transmission planning arrangements are broadly reasonable. Current planning arrangements operate at a regional and a NEM wide level, and have become increasingly transparent and comprehensive since the inception of the NEM. At the regional level, the planning process involves multiple rounds of interaction between regulated TNSPs and existing and prospective market participants. TNSPs provide considerable information about their thinking on future investment through their Annual Planning Report (APR) publications. Market participants respond to this information as well as information in the ESOO and market spot and forward prices by making investment decisions, which in turn influence future APRs. At a NEM-wide level, these regional planning arrangements are complemented by the activities of AEMO, namely the ESOO, the NTS and the National Transmission Development Plan (NTNDP), which considers network developments over a long term planning horizon.

The Group notes that the planning standards adopted by TNSPs at a regional level will inevitably affect the number of constraints to which NEM generators are exposed. Broadly speaking, both TransGrid and Powerlink apply a deterministic (N-n) reliability standard to planning in their network , as prescribed in the relevant jurisdictional regulations. The South Australian Transmission Code sets out highly prescriptive reliability standards for each connection point, ranging from N-0 to N-2. Unlike other jurisdictions AEMO applies a probabilistic planning standard to network augmentation in Victoria, whereby the probability of an outage is assessed against the likely severity of an outage event.

As far as the Group is aware, AEMO is the only network planning body in Australia and internationally that consistently applies this type of probabilistic planning standard (in Victoria). In all other markets (including the US LMP markets) planning standards are based on deterministic criteria, which are inherently more conservative than the probabilistic standard. In the NZEM, the Electricity Commission initially proposed a probabilistic standard for grid planning purposes, but given concerns about reliability outcomes, it adopted a minimum deterministic standard with additional scope to undertake investment if it can be shown to be net beneficial under the grid investment test (GIT).

The Group therefore considers that differences in deterministic versus probabilistic transmission planning standards between regions may be the key underlying reason for the different industry views on the need for change to the current transmission framework. A significant factor in this regard is although the Victorian transmission network is planned on a probabilistic standard, AEMO manages line flows on the network in real time on a deterministic (credible contingency) basis. Unlike generation asset owners in Victoria, the Northern Group considers that existing planning processes in Queensland and NSW provide the appropriate transmission planning and investment incentives. This suggests that the probabilistic planning standard regime may be the primary cause of concern.

The Group notes that in its Transmission Reliability Standards Review (2008) the AEMC recommended a national framework to promote consistency in transmission reliability standards and for the implementation of this framework. The Review recommended a hybrid standard where connection points were allocated a deterministic standard (N-n) based on an economic test of the cost of interrupting supply at the connection point. Implementing these recommendations may allay concerns about varying regional reliability standards and corresponding investment trends.

Role of the RIT-T

The Issues Paper refers to the potential need for additional ‘market-based’ signals for would-be generation investors, but makes no reference to NEM mechanisms. such as the RIT-T and NSAs.

A profit-seeking TNSP will seek to invest in any project – whether driven by reliability standards or market benefits – so long as it stands to make a reasonable return. Before committing to a shared transmission network investment, a TNSP must apply the RIT-T to that investment. The purpose of the RIT-T is to ensure that a transmission investment is only undertaken where it offers the greatest net benefits in addressing a particular congestion issue. This requires TNSPs to trade-off the expected future costs of congestion with the costs of a proposed augmentation, as well as against the costs of alternative options. The RIT-T process provides several opportunities for participants and prospective investors to propose non-network options or dispute the TNSP's assumptions.

Although there may be some scope to improve on the corresponding processes, the requirement on TNSPs to consider non-network solutions (and the corresponding ability of new generators to enter into an NSA) also creates a strong signal for a new generator to locate in a part of the network where this is efficient. These arrangements potentially allow generators to compete for stable, regulated cash flows that would serve to underpin efficient investment.

The Issues Paper also suggests that TNSPs have relatively weak incentives to invest in inter-regional transfer capability. Such investment is less likely than intra-regional investment to be used to meet jurisdictional reliability standards. To the extent that TNSPs are motivated by satisfying jurisdictional reliability standards, they will prioritise investment in intra- regional projects. If there are concerns about the focus of TNSP planning and investment (i.e., intra- versus inter-regional), these are therefore not a reflection of planning processes per se, but of existing NEM governance arrangements.

More generally, however, the Group would argue that the main reason why inter-regional investment has not been undertaken in recent years is because the resulting benefits have not merited the very significant investment in major new transmission lines, for instance, because of similar fuel costs in adjacent regions. We note that Powerlink/TransGrid have regularly reviewed upgrade options for QNI in recent years, but have not found these to be net beneficial. Similarly, VENCorp has reviewed upgrades to the Heyward interconnector on a number of occasions; this investment is also currently the subject of a study by ElectraNet/AEMO.

NEM demand forecasts

One shortcoming with the current planning arrangements is the formulation of official demand forecasts under the auspices of the Demand Forecasting Reference Group. Figure 1 through Figure 9 in Appendix A show comparisons between demand projections from the SOO/ESOO from 1999 to the present. The figures compare actual demand outcomes with 10 per cent and 90 per cent probability of exceedance (POE) forecasts. It is apparent from these figures that the SOO/ESOO forecasts have systematically over-stated actual demand since the NEM commenced, both on a system-wide and on a regional basis. It appears that this is at least in part a consequence of the fact that the demand forecasts are based on economic growth forecasts that have themselves been consistently too high. The reasons for the consistent over-estimation of electricity demand are unclear.

While TNSPs may have an incentive to overstate demand in order to justify more transmission investment, as a not-for-profit body, AEMO does not have such an incentive. Similarly, the private consultants hired to prepare the economic growth forecasts do not benefit from over-estimating demand. It may be that the culture within AEMO is excessively conservative or risk-averse. But for whatever reason, we consider that the demand forecasting methodology needs to be improved to avoid any unnecessary over-build of transmission.

To summarise, the Group is strongly of the view that the current transmission planning framework appropriately reflect the objectives of the NEO – that is, the long term interest of consumers.

The Group does not support the view that additional market-based signals might be required. Since inception, the transmission arrangements have successfully accommodated substantial changes in power flows and new generation investment. The RIT-T provides clear framework for identifying efficient transmission investment or non-network solutions. Additionally, transmission planning arrangements have been considerably strengthened, both at a regional and a system-wide level.

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?

The AEMC refers to comments by market participants that question whether the RIT-T would facilitate the timely build-out of intra-regional congestion where it delivered net market benefits. The Last Resort Planning Power (LRPP) vested in the AEMC is a mechanism for triggering cost-benefit assessments of potential projects if TNSPs are not responding to a material problem is a timely manner. However, the AEMC notes that these reforms do not extend as far as ensuring that TNSPs will undertake all such investments.

As contended in our response to Question 3, the Group considers that the RIT-T, in combination with the incentives provided by the transmission building block regulatory regime, is capable of promoting timely and net beneficial transmission investment. Furthermore, there is no reason why TNSPs should not be willing to apply the RIT-T to investments geared towards producing net market benefits. As long as the regulatory rate of return is sufficient and/or the incentives for good service performance are attractive, TNSPs should be willing to invest in all types of regulated projects irrespective of the investment driver.

The Issues Paper notes that market benefit-driven transmission projects may be more subject to challenge than reliability-driven projects. However, the RIT-T now requires a market benefits framework to be applied to all types of transmission investment, including those for ‘reliability corrective action’. Therefore, the obstacles and challenges to market benefit-driven investment should no longer be substantially greater than for reliability-driven investment. If there is a problem with TNSPs’ incentives to pursue market benefit investments, this is more likely to relate to commercial factors. If that is the case, it would be better to address those issues directly, rather than further amend the RIT-T or surrounding regulatory arrangements.

The Group further notes that requiring TNSPs to undertake certain investments risks undermining the existing governance and accountability framework. As it stands, the transmission framework requires TNSPs to deliver certain reliability and other outcomes, and to invest in and manage their networks accordingly. A requirement to undertake certain investments would undermine this linkage; if the investment was ineffective or otherwise inefficient, no party could be held accountable. This further highlights the Group’s fundamental view that if there is perceived to be an investment problem, TNSP’s governance arrangements should be amended, rather than imposing relatively arbitrary investment requirements on them.

In summary, the Group is not convinced of the need for an obligation on TNSPs to undertake investments that produce net market benefits. Rather, the regulatory framework should set out clear objectives and provide the appropriate incentives to achieve a desired reliability or other outcome.

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?

The AEMC sets out that the current regulatory framework for TNSPs is designed to balance the need to encourage investment in new capacity by lowering regulatory risk faced by TNSPs when investing while ensuring that TNSPs undertake such investment efficiently. The lack of an ex post prudency test provides a more certain investment environment for TNSPs, but weakens incentives to minimise capital expenditure. However, on area of concern to the Group is that TNSPs are currently not held accountable for a particular investment delivering its design capability. The development of robust financial incentives may help to improve the timing and efficiency of investment decisions, increasing certainty for generation and load over transmission service levels.

As noted above, the Group believes that the existing regulatory arrangements for TNSPs broadly promote efficient network investment, subject to any non-economic incentives applying to TNSP decision-making or governance. The existing arrangements also provide TNSPs with some incentives to minimise capital expenditure, although we agree with the Issues Paper that these incentives are relatively weak. This is because the AEMC (following the approach of the ACCC in its Statement of Regulatory Principles) deliberately adopted a ‘low powered’ capex incentive regime in its review of transmission revenue in 2005-06. The existing arrangements also provide TNSPs with incentives to maximise service performance through the AER’s Service Target Performance Incentive Scheme (STPIS). At this stage, therefore, the Group does not have firm views on whether the incentives provided under the capex incentive regime or the STPIS need to be strengthened in order to encourage TNSPs to maximise the value of their network services.

The Group agrees in principle that it would be desirable to hold TNSPs accountable for ensuring that transmission investments deliver their design capability. However, the Group is cognisant of the fact that the concept of transmission ‘capability’ or ‘capacity’ is complex and has multiple and time-varying dimensions. In an interconnected network with loop flows, there are numerous interacting and non-linear constraints that limit the operations of the power system and define what transmission capacity is at any one point in time. These include, among other things, network component ratings, the dynamics of generating units, existing control mechanisms, operational ranges for quantities such as frequency and voltage, and the tolerance of the system to outages. For these reasons, transmission capacity varies in response to short term developments, such as network or generator planned and unplanned outages, but also as a result of load growth, generation or transmission investment, or changes in market Rules. Transmission capacity cannot therefore be defined in isolation from other network events (such as ‘system normal’ conditions). While some of these factors can be controlled by network/system operators, many others cannot. It is the complexity of these interactions that complicate efforts to achieve a greater accountability of TNSPs and system operators such as AEMO, or create a stronger linkage between commercial returns paid to these entities and system outcomes.

The Issues Paper discusses the lack of an ex-post prudency test on assets that pass into the Regulated Asset base (RAB) of TNSPs. The question whether assets that have been commissioned in accordance with regulatory processes such as the RIT-T was reviewed in some depth by the Australian Competition and Consumer Commission (ACCC) when it developed the regulatory framework for transmission. The Commission concluded that there would be no gain from subjecting assets that had undergone a proper and comprehensive ex ante evaluation to stranding risks, and that instead TNSPs’ cost of capital (and therefore costs to consumers) would rise.

The Group considers that there is little merit in applying an ex post prudency test to transmission assets that have undergone the ex ante scrutiny that is prescribed under the Rules. The RIT-T expressly requires TNSPs to make investment decisions with the most accurate and reasonable assumptions available at the time. The future is inherently uncertain, and the RIT-T correspondingly requires TNSPs to evaluate a number of scenarios to assess the corresponding risks for the investment. These processes imply prudent decision-making and considerable public scrutiny. Providing for an ex post reopening of an investment decision with the wisdom of hindsight simply creates and unreasonably high bar of what constitutes an 'efficient' investment. Applying a test of this type would almost certainly force TNSPs to adopt a very conservative approach, which would directly conflict with the suggestion in the Issues Paper that, going forward, transmission planning and investment may need to be more proactive.

In summary, the Group considers that the current regime for the economic regulation of transmission broadly leads to efficient network investment. The focus of the regulatory process should be to ensure that the RIT-T is applied and administered correctly and consistently. Introducing additional incentives to expose TNSPs to greater risks are contrary to the broader regulatory framework, which is intended to reduce costs and create a stable investment environment.

Question 6: Network charging for generation and load

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?

The AEMC states that the costs of the prescribed shared transmission network are currently recovered solely from load, and that generators therefore do not see the costs they 'impose' on the shared network through their locational decision.

Role of generators in the NEM

It should be clarified that within the NEM governance framework, generators cannot 'impose' costs on the transmission network. TNSPs invest to meet reliability standards or to release market benefits; they do not invest to enable generators to export their output. A generator proponent may locate where it wishes in the network, but has no dispatch 'rights' of any kind. Unless a required augmentation passes the RIT-T and is therefore shown to confer net benefits on customers (or unless the augmentation is funded by the generator) the network investment to enable that generator to be dispatched will not take place.[2]

[2] The only way a generator proponent can effectively 'force' a TNSP to invest is if the proponent undertakes its investment prior to the TNSP investing in transmission capacity. In this case, when the TNSP performs its RIT-T analysis of an augmentation to that generator, the TNSP will need to ignore the generator's fixed costs, because they have been expended and are hence 'sunk'. Ignoring the generator's fixed costs may make an augmentation seem net beneficial, even though it would not have been beneficial if those fixed costs were taken into account. Such a (highly unlikely) 'gaming' scenario is the only way in which a generator can be said to impose costs on the network.

NEM price and non-price locational signals

The AEMC's discussion of the factors determining generator locational decisions suggests that generators have no incentive to locate at points in the network where there is excess capacity so that their output can be exported. The Group strongly disagrees with this assessment.

Any rational investor considering a generation investment whose value is sunk if the generated power cannot be exported will clearly assess the capability of the network at different locations very carefully. While it is clear that fuel, water and other inputs are essential for the profitable operation of a power station, so is its location, which will determine the quantity of power that can be exported and the loss factors that will applied to that power. A power station locating in a part of the network that cannot accommodate its output is simply stranded.

In contrast to what is claimed by the AEMC, therefore, the existing open access arrangement, which offers no dispatch certainty, provides investors with very strong incentives to locate a power station in an unconstrained part of the network. A potential generation investor would consider, among other things:

- the existence of suitable sites as regards key inputs, such as fuel, power infrastructure and water;
- the general incidence of network constraints in the vicinity of a particular sites;
- load flow analyses to assess marginal loss factors and constraints over the different time horizons;
- TNSPs'/AEMO's relevant forecasts, planning and investment programmes.

As noted in the Group's response to Question 3, TNSPs and AEMO publish a range of documents to facilitate such a locational decisions and will clearly also advise would-be investors as to network locations.

Beyond this fundamental commercial imperative of avoiding locations where constraints will arise, the existing wholesale market and transmission arrangements provide a mix of price and non-price signals and incentives to market participants regarding their locational decisions. Regional reference prices (RRPs) broadly signal the demand supply balance in a particular region, while static marginal loss factors signal an important component of transmission costs by over-signalling average losses at a particular location by a factor of approximately two. In addition, NSAs[3] provide additional revenues to generation investors in locations where generation is an efficient alternative to transmission investment. In particular the RIT-T sends a strong non-price signal to potential investors to invest in locations where this is likely to be efficient. A prospective generation investor will have incentives to participate in, and pay close attention to, the outcomes of a RIT-T evaluation and make its investment decision accordingly. The RIT-T framework and associated processes have been considerably strengthened since the inception of the NEM and arguably provide the most robust and transparent information for a potential investor considering a particular location.

G-TUOS charge

In its climate change report, the AEMC recommended the application of a transmission charge on generation (G-TUOS) to address what it considered 'the absence of a price signal to generators of transmission network costs.

In the Group's view, the AEMC's assessment of the merits of locational charging for generators fails to recognise the range of price and non-price locational signals in the NEM. As described above, potential investors have a vital interest in locating in parts of the network:

- which are (and are likely to remain) relatively unconstrained, so as to manage dispatch risks;
- where losses are relatively low, to maximise revenues for their output; and/or
- where augmentations are relatively low cost and would likely pass the RIT-T.

In addition, TNSPs can and do enter into network support agreements (NSAs) and other non-network options with generators whose output is required to support the reliable operation of the network. A G-TUOS charge would therefore duplicate existing strong price and non-price signals that already exist in the NEM.

As described by the AEMC in its Review of Energy Market Frameworks in the light of Climate Change Policies (September 2009), the G-TUOS charge would be reflective of the forward looking long run incremental network costs at a particular location, set on an annual basis, and be revenue neutral in aggregate. The G-TUOS charge was characterised as a 'long term', 'cost reflective' price signal to generators.

In the view of the Group, these comments mischaracterise the effectiveness of such a charge:

[3] Network Support Agreements are contractual arrangements where TNSPs pay generators to operate at particular times to offset the need to invest in transmission infrastructure, or to enable outages during capital investment.

- Because they are intended to provide a forward-looking signal, LRMC charges must be recalculated as network conditions and therefore costs going forward change. There is therefore an inherent contradiction in the AEMC's claim that a 'long term' signal is required to provide generators with stable pricing signals. Forward-looking locational (LRMC) charges are, by design, unstable over time, since they will change as new generators locate in different parts of the network or as networks are re-configured to meet jurisdictional reliability planning standards. This instability is compounded if locational charges must meet a total revenue requirement (as is the intention here), since a change in costs in one part of the network will trigger a rebalancing of all other charges.

- Given that the G-TUOS charge would be a scaled charge, it is not possible to determine without further analysis, whether the eventual magnitude of such a charge would be sufficient (or 'too' low or 'too' high) to make a material difference in relation to generator location.

- The G-TUOS charge would furthermore rely on forecasts of network flows and of the costs of grid augmentations, conferring substantial responsibility on the TNSP to make detailed future forecasts. This raises serious concerns about the transparency of this charge.

For these same reasons, it is also unlikely that a G-TUOS charge could create an effective retirement signal as the AEMC seems to suggest. In the absence of detailed calculations, it is impossible to know whether LRMC charges that are derived by scaling average charges to zero would be effective, in the sense that they would influence either the decisions of generators to locate or to retire in a meaningful way. This is all the more the case, since G-TUOS charges at a particular location will vary over time, in response to changing network trends and variations in grid augmentation costs across all parts of the network.

Even if G-TUOS charges were both stable and effective, it is unclear whether they would represent an efficient mechanism for allocating scarce network resources. The fact that significant transmission expenditure may be required does not imply that no new generation should locate in a particular place. If fuel, water, or other inputs are cheap, it may well be efficient to augment transmission capacity so as to facilitate low cost generation going forward. Theoretically, at least, a transmission investment should then pass the RIT-T, and a G-TUOS price signal might in fact be misleading while introducing additional costs and uncertainty into the market.

New Zealand analysis

New Zealand's Electricity Commission (2010) recently assessed the merits of locational signalling for generation by modelling the likely responses to generators to different locational transmission charges. The Commission compared:

- the net present value (NPV) of future system costs if transmission costs are not considered when generation investments are made; with

- the NPV of future system costs if generation and transmission investment are perfectly co-optimised.

This analysis was done to derive an upper bound on the expected benefits that might be expected from locational signalling of transmission costs.

The Commission's modelling suggested that the benefits of implementing locational signals via transmission prices to signal to generation the cost of economic transmission investment are very small, given current and future generation and transmission expansion options. The modelling in fact produced an NPV difference of only around $14 million from moving to an ideal pricing methodology. The Commission therefore concluded that:

- given the margin of error associated with estimating the input parameters for the modelling, it would be reasonable to interpret the $14 million as being zero; and
- given the imprecision of a locational charge, there was a risk a transmission pricing regime with locationally-varying charges would lead to unintended inefficiencies by over-signalling location costs leading to poor investment decisions around the type, timing and location of generation.

This result was fundamentally driven by the fact that remote generation investments are likely in the short to medium term to be driven by factors such as fuel costs, fuel availability, and resource consents.

In summary, in the Group's view, the AEMC's assessment of the merits of locational charging fails to recognise the range of price and non-price locational signals that already exist in the NEM:

- Contrary to what is claimed by the AEMC, potential investors have a vital interest in locating in unconstrained parts of the network, in parts of the network where losses are low and/or in locations where augmentations are relatively low cost and would therefore pass the RIT-T. There is therefore no evidence to suggest that a price signal of locational network costs for generators is required to promote market efficiency.
- As a 'forward-looking' charge designed to signal the costs of incremental network capacity, the AEMC's G-TUOS charge is, by design, unstable, and would not therefore represent a credible long-term signal for future generators. Given that this would be a scaled charge, it is unclear without detailed modelling whether such a charge would have a material effect on locational decisions for different types of technologies.

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?

The AEMC argues that since generators cannot currently manage their exposure to dispatch uncertainty, the development of firmer intra-regional access rights may provide more certainty for generators and therefore facilitate investment in new generation facilities.

Generator access and shared transmission investment

The Group submits that there is no evidence that the current open access arrangements in the NEM have affected generation investment. As set out in Section 2.2, substantial new generation capacity was commissioned in the NEM in 2009, and there is no shortage of investment proposals going forward.

The extent of new generation investment in the NEM (and the existence of numerous new proposed and committed projects) may in fact suggest that the NEM open access arrangements encourage generators to locate where there is excess transmission capacity and have deterred generation investment in constrained parts of the network. This is an efficient outcome that should be acknowledged by the AEMC. More generally of course, a would be investor can request that a shared network augmentations to support a new connection be assessed under the RIT-T, in which case the transmission investment would go ahead if it was found to be efficient.

A more likely source of uncertainty affecting investment in the NEM relates to uncertainty about the direction of future climate change policies, rather than the nature of access arrangements. While investment in gas-fired generation has been ongoing in the NEM, there can be little doubt that investment in certain types of renewables and new technologies that might support future coal-fired generation is stalled pending the introduction of a carbon price. Furthermore, given the current uncertain political climate, the controversies surrounding the Carbon Pollution Reduction Scheme (CPRS) and the complexities of designing a revised/different climate change mechanism, it is difficult to see how this uncertainty will be resolved even over the medium term. The Group therefore questions the merits of pursuing very substantial changes to the NEM framework in the absence of any indication of future climate change policies and their consequential effects.

The Group questions whether privately sponsored investment in the shared transmission network where a corresponding private transmission right is assigned potentially conflicts with the NEO. The economics of shared transmission networks are such that it is not physically possible to undertake a specific investment or other measure that will affect (benefit) only one market participant (who may have paid for the service). Knock-on effects (or externalities) are a fundamental feature of all shared transmission networks. It is therefore easy to show that a transmission investment, which may favour, say, a generator (for instance, by strengthening a transmission line), is detrimental to other parties and reduces overall welfare, in the sense that it results in an overall increase in the cost of supplying electricity to consumers (e.g. Bushnell and Stoft 1995). Theoretically, this problem is addressed by compensating the parties that have been harmed by an investment; in practice, of course, such a compensation approach is contentious and difficult to devise. This also accounts for the difficulties that arise in assigning private transmission rights on the shared transmission network. Nevertheless, the Group does not object to the AEMC considering the issue and exploring the benefits and limitations of more defined access.

Physical or financial network access

The AEMC provides no detail on the nature of any firm access arrangements it may contemplate, but the resulting consequences for the NEM market design are potentially profound. As discussed in Section 2.3, different wholesale market designs imply fundamental trade-offs between longer term (dynamic) and short term (allocative and productive) efficiency objectives. The NEM market design reflects a compromise that encourages efficient investment at an (occasional and limited) cost to short run efficiency. Other wholesale market designs that provide for some form of firm access (such as those discussed below) attach a greater weight to outcomes that are deemed to be efficient in the short run, but at the cost of material dynamic inefficiencies.

Notwithstanding these more general comments about the broader market context in which firm generator access can be provided, it should be clearly understood at the outset that:

- implementing any type of firm access arrangement in the NEM would require a complete overhaul of the current NEM design;
- physical generator access arrangements are not consistent with the NEO; and
- while superficially appealing, financial firm access arrangements create very difficult conceptual and practical implementation issues.

Firm access arrangements for generators can be ‘physical’ or ‘financial’. Physical rights of access do not represent a right to be dispatched, but only provide for some quantity of transmission capacity that is available to enable a generator to export power and that is preserved in the planning domain. These rights can be defined explicitly, for instance in terms of the MW of network capacity that is available during certain system conditions, or implicitly, with reference to some broader planning criterion that defines a target for the capability of the network.

There are two broad models where firm physical access arrangements have been implemented – in the UK and in the Alberta wholesale markets. Both models imply significantly weaker dynamic efficiency incentives than exist in the NEM:

- In the UK model, a single integrated combined ISO/TNSP entity (NGC) plans, invests in and operates the network so as to provide an agreed level of physical network access to generators. Generators require agreement by NGC before they are permitted to connect to the network, and pay a contribution towards the cost of the network. It is this prohibition of access, where the total quantity of firm access is restricted to the underlying capability of the network, that makes us categorise this as a ‘physical’ firm access model. In reality, NGC compensates generators whose output is curtailed, the costs of which is socialised across all market participants. In addition to reducing the incentive of generators to make efficient locational decisions, the UK model also implies a fundamentally different organisational and regulatory framework than what exists in the NEM.

- In the Alberta model, access rights are maintained implicitly via a high-level policy target that sets an overall network congestion standard. Individual generators can rely on the existence of a relatively uncongested network, but not on the absence of any congestion in a particular location. However, in general, the costs of building the additional transmission required to eliminate most or all congestion is likely to (far) exceed the cost of that congestion, so that the NEO and the principles underlying the RIT-T would be breached.

Financial rights of access also do not imply dispatch rights, but compensate the generator for any price differences between its location and other points in the network. These rights, sometimes referred to as financial transmission rights (FTRs) have often been implemented in LMP markets, and confer the right to a payment of the price difference two specified locations in the network.[4] While theoretically appealing, the practical implementation of FTRs and similar instruments has been beset with difficulties. Markets such as PJM that pioneered a financial rights framework have had to develop increasingly complex rules to overcome these implementation problems:

- FTRs are generally designed to be 'self-financing' to protect the system operator who issues them from uncertain (and potentially very large) liabilities. In simple terms, this requires that the set of FTRs that are issued must be 'simultaneously feasible' and therefore defined very conservatively so that they only compensate the holder for congestion in a very narrow set of system conditions. The practical reality, at least in PJM, is also that historically FTRs provided only a poor match of congestion costs. In markets where FTRs are not self-financing, for instance in the New York wholesale market, customers are liable for unfunded congestion via an uplift charge for shortfalls in congestion rentals.
- FTRs are not durable but are generally reviewed and reconfigured annually to ensure that they match the evolving physical capability of the network. FTRs can and often are downrated in the course of such an assessment. A complex and contentious reallocation process therefore takes place annually in all US LMP markets.
- While FTRs can theoretically be constructed to create hedges between all points in the transmission network, in practice FTR markets have not been sufficiently liquid to enable such trades. In PJM, for instance, locations have therefore had to be aggregated to create more liquid 'hubs' to enable trading.

Overall, and for these reasons, the effectiveness of FTRs as a mechanism to provide long term financial rights of access (and certainly as a mechanism for financing new investment) has been discounted. In recognition of this, FERC, which initially supported an LMP/FTR framework has introduced a requirement on all US power markets to offer long term physical access rights to generators who are accredited as a 'capacity resource'; that is, a generators whose output is required to serve designated loads reliably.

4 Similar instruments have been introduced under different names in the various LMP markets – FTRs in PJM and the New England electricity wholesale market, 'transmission congestion contracts' (TCCs) in the New York electricity wholesale market, and 'transmission congestion rights' (TCRs) in the Electric Reliability Council of Texas (ERCOT).

More broadly, the introduction of an FTR regime in the NEM would require a major overhaul of the existing regional market design. The many impacts that would need to be considered include the effects of introducing new price risks for generators, the consequences for liquidity in the contract markets, and the additional risks for retailers or hedging locational price risks.

Constraint support pricing and constraint support contracting

In the Group's view, similar concerns as for LMP/FTRs would be expected to arise if a constraint support pricing/constraint support contract (CSP/CSC) framework were adopted to manage intra-regional congestion. The CSP/CSC model defines locational prices for individual generators, in combination with a mechanism for distributing the rights to newly created settlement residues. This model therefore represents a localised LMP/FTR approach.

CSP/CSC arrangements would also need to be reviewed regularly to assess the effects of any underlying transmission constraints on individual locational prices, and to reallocate congestion rentals in line with the capability of the network. How well any corresponding rentals that would be paid to generators would match congestion costs is unclear. The administrative and technical complexities of a location signal would also clearly increase with the number of applications of a CSP/CSC-type mechanism.

It is worth revisiting the experience with the Snowy CSP/CSC trial to understand the implications of this approach. In its submissions to the CMR (2006, 2007), NEMMCO highlighted the complexity of this type of arrangement, noting that:

- CSP/CSC arrangements would need to be customised to individual instances of congestion;
- this complexity would be compounded if CSP/CSC arrangements encompassed different combinations of inter- and intra regional constraints, and multiple generators contributing to a constraint;
- multiple CSP/CSC arrangements operating simultaneously throughout the NEM would affect the incentive signals of individual CSP/CSC arrangements, and would create a risk of conflicting interaction of signals; and
- where multiple generators contribute to a constraint, the allocation of CSCs would become very contentious.

Beyond the added complexity that CSP/CSC arrangements would entail from a design and systems operations point of view, the effects on market participants would be similar to those of introducing LMP/FTR arrangements. An increase in the number of pricing points in the market implies that a generator would need to manage the risk of price separation between RRPs, as well as between its location and its RPP. Affected generators will therefore contract their output more conservatively, which may lead to a less liquid contract market. Additionally, CSC rights will equally need to be defined conservatively, and may not fund the difference between the local nodal price and the RRP unless access to an uplift payment funded by consumers was implemented in conjunction with any CSC/CSC regime.

To summarise, the Group considers that there is no evidence to suggest that investment in the NEM has not occurred in a timely and efficient manner, and in response to market trends. Introducing any type of firm access arrangement – be it physical or financial – implies a fundamental shift in the underlying efficiency drivers of the NEM, as would affect all aspects of NEM operations. In addition:

- Physical firm access can only be achieved by building out transmission constraints, either at a local or regional level. An unqualified transmission investment program is unlikely to be efficient and therefore inconsistent with the NEO.
- Financial firm access rights arrangements cannot be defined in a way that is durable, and, unless customers are charged an uplift payment, provide only a partial hedge against congestion. This would likely have negative effects on the contract markets. In practice, the implementation of these rights has also proved to be complex and controversial, and therefore costly. CSP/CSC arrangements suffer from the same drawbacks, and would likely imply an additional layer of complexity.

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 transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

The AEMC notes that the regulatory regime for negotiated services is less intrusive than that for prescribed services. It highlights the Scale Efficient Network Extensions (SENE) proposals as a mechanism to address the connection of clusters of renewable generation. Nonetheless, the AEMC is concerned that the existing framework may not adequately address the potential for connection assets to be shared between a number of users or to be subsequently absorbed into the shared network.

The Group is unconvinced that current unregulated arrangements in relation to connection services are appropriate, and that provision of these services should not continue to be left to negotiation. TNSPs have a much greater degree of market power in the provision of these services than was assumed by the AEMC during its review of transmission pricing in 2006. There are typically very few alternatives for new connecting parties with the technical capabilities for sourcing these services.

The Group considers that the broader framework under which connection services are currently provided and paid for is appropriate. The role of the RIT-T in defining the extent of prescribed shared services means that it is appropriate that consumers do not fund the cost of new connections. In contrast to shared transmission services, connection services directly benefit one or more identifiable customer(s) or generator(s), and these costs should therefore be recovered from these beneficiaries.

Furthermore, the current arrangements around these services provide considerable flexibility in how these services are procured and paid for. The Issues Paper is strictly correct in stating that generators pay only their direct or 'shallow' connection costs to the network. However, there is no technological limitation on what such direct costs may include. This is because a connection point is defined simply as 'the agreed point of supply' established between a TNSP/DNSP and a market participant, while a connection service is simply an entry or exit service to one or more generator(s) or customer(s) at a single connection point. Therefore, a 500 km transmission line extension to connect a remote area to the shared network may either be providing a connection (negotiated) service or a shared (prescribed) service. Whether such an asset is funded through prescribed or negotiated charges fundamentally depends on whether the investment satisfies the RIT-T – if it does, its cost can be recovered by TNSPs from consumers via transmission charges, if it does not, then the customer(s) or generator(s) must fund it. This is a broadly appropriate set of arrangements.

The Group is concerned that additional or wider reaching modifications to connection arrangements will increasingly blur the distinction between dedicated assets whose costs can and should be attributed to particular beneficiaries, and shared assets where this is not the case. Greater socialisation of costs of assets/ services that clearly benefit some market participants but provide questionable benefits to consumers as a whole will lead to inefficient investment decisions. If certain types of connections attract an implicit subsidy of this type, the effect may well be to further encourage costly connections in remote locations.

In summary, in the Group's view, existing arrangements regarding connection agreements could be improved. However, the Group would caution against the introduction of additional regulated mechanisms where there are no obstacles to negotiated commercial agreements between market participants.

3.3 Key issues for efficient operation

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?

The AEMC sets out that TNSPs should have incentives and obligations to operate their network to make capacity available during periods of forecast high demand and facilitate effective competition between market participants. Accordingly, TNSPs are subject to the STPIS, whereby up to 5 per cent of a TNSP's regulated revenue can be put at risk if performance measures are not met. In addition, the AEMC recommended that AEMO publish a single central resource for congestion-related information – the Congestion Information Resource (CIR). The AEMC's question then relates to whether there are further options for information release to support the underlying operation of the market.

As discussed in the Group's response to Question 5, transmission capacity varies in response to short and long term factors, some of which are under the control of TNSPs/AEMO. It is the complexity of these interactions that complicate efforts to achieve a greater accountability of TNSPs and system operators such as AEMO, or create a stronger linkage between commercial returns paid to these entities and system outcomes.

Nevertheless, the Group is supportive of changes to the transmission arrangements that could improve the operational incentives of TNSPs and the quality of information about network outages.

Any scheme that provides incentives for TNSPs to improve network capability at short notice needs to be carefully designed. In the case of the Market Impact Component of the STPIS, TNSPS receive a financial reward (of up to 2% of regulated revenues) by minimising the number of outages that result in constraints with a marginal cost exceeding $10/MWh. While this should reduce the incidence of constraints, the financial reward is tied to market price outcomes. The TNSP is no longer just a service provider but also exposed to market outcomes.

Service incentive schemes should not dampen the incentives for participants to carefully monitor and analyse outage schedules and their likely impact on transmission flows and market prices. A prudent trader should be rewarded for making contracting decisions based on anticipated network capabilities. Market impact schemes may have the unintended consequence of encouraging some traders to rely on the actions of the TNSP to manage the incidence and financial impact of constraints on their behalf. There is a fine balancing act between giving advance notice of outage schedules and allowing participants to make informed contracting decisions to prudentially manage risks against the benefits of moderating the short-term impact of constraints that may influence spot prices. The current Market Impact Component provides no reward for TNSPs that carefully assess the impact of outages schedules well in advance of the actual event. A key concern for the Group is the lack of transparency in the outage scheduling process.

The Group is supportive of improvements to the quality of information about network outages. The Group notes that AEMO's Network Outage Schedule (NOS) does not contain information about changes to outage dates made to reduce the market impacts of congestion. The Group considers that the NOS should include fields that show:

- The original date for a planned outage
- Date of last change
- How many times the scheduled outage had changed
- Who initiated the change (TNSP or AEMO)
- Description of the reason for the change.

The Group considers that the market currently lacks information about the interactions between AEMO and the TNSPs that affect network transfer capability. To improve transparency, the Group considers that AEMO should be obliged to publish a market notice when an outage is scheduled or re-scheduled with less than one week's notice. The market notice should detail the change to the outage date, who initiated the change and why the change was considered necessary.

Appendix B sets out a case study on the conversion of the NSW western ring to 500kV during 2009-10. It highlights the importance for co-ordinated network planning and operation between AEMO and TNSPs.

The 70/71 cut-set bound for some 70 hours during 2009-10. The total cost of constraints during that period for that particular constraint was in the order of $6.4 million – out of a total NEM turnover of $9.5 billion.

The Group believes that the constraint issues associated with the new transmission line 70/71 cut-set could have been avoided had TransGrid adequately identified a scenario in its planning on the conversion of the 500kV ring where the Wallerwang power station was <u>not</u> running at full output.

Had TransGrid or AEMO identified this plausible scenario TransGrid could have replaced the under-rated current transformers or alternatively converted the Mt Piper to Marulan transmission lines prior to the Bayswater to Mt Piper conversion. Either of these re-scheduling works would have avoided the network constraint issues associated with the new transmission line 70/71 cut-set.

Furthermore the constraint issues associated with the new line 70/71 cut-set <u>cannot</u> be credibly described as "system normal" constraints. These constraints were transitionary in nature as a result of the conversion to a 500kV operation and could have been avoided altogether had the works been re-configured differently.

The Group considers that any participant that advocates the introduction of a congestion management regime on the basis of the constraint issues associated with the 70/71 cut-set has failed to recognise the root cause of the constraint (inadequate AEMO network management) and the transitory nature of the relevant constraints.

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

In its discussion of congestion in the NEM, the AEMC points to the potential costs of congestion, in terms of the need to operate higher cost generation plant, as well as other undesirable effects, such as the mispricing of generator offers and disorderly bidding. As a result, the AEMC recommends that prices paid to generators should reflect congestion costs, in particular in circumstances where there are 'pockets of material and transitory congestion'.

Materiality of NEM congestion

The Group takes issue with the assertion that between 2003-04 and 2008-09 transmission congestion costs in the NEM have followed an upward trend (P.38), and, more generally, the AEMC's implicit assertion that congestion in the NEM is sufficiently material to warrant a fundamental change in NEM wholesale pricing arrangements. These claims are neither consistent with the research done to date, nor do they reflect previous statements made by the AEMC in this context.

As set out in Section 2.2, the AER found a material *decrease* in congestion in 2008-09. The AER also found that most congestion costs typically accumulate on just a handful of days, that a significant portion arise as a result of transmission outages (which would not be affected by any type of pricing reform), and that these costs are relatively modest given the scale of the market.

The AER's findings are consistent with previous statements made by the AEMC. In its final report on the CMR (2008), the AEMC concluded that congestion in the NEM was not sufficiently material and sustained to warrant the introduction of a congestion pricing regime and risk instruments (P.13):

> The data from the last four to five years showed that congestion in the NEM was unpredictable, with both the location and duration of significant binding constraints varying significantly. Also, most constraints had a relatively short "life–cycle", in that they caused some mis-pricing for only one or two years before being largely addressed by investment in transmission or generation infrastructure. There were only a few locations where congestion was persistent. Overall, with the exception of the Snowy region, congestion did not appear to be a major problem in the NEM.

The AEMC's Survey of Evidence on the Implications of Climate Change Policies for Energy Markets (December 2008) similarly adopted a qualified view. In that survey, AEMC staff concluded that (P.68):

> At this stage, it is not clear whether material and persistent congestion will arise as a result of these [climate change] policies. This will depend upon the response of network service providers and renewable generators are unlikely to locate in areas where there is weak available transmission capability.

NEM congestion going forward

As also discussed in Section 2.2, the significant program of network investment that has been approved by the AER could be expected to reduce the incidence and materiality of network congestion going forward. The AER has made similar comments that support this view.

In its 2009 Climate Change Policies the AEMC nonetheless went on to recommend that generator prices should reflect congestion costs, albeit on the basis of evidence that, at best, highlights the degree of uncertainty around the question of whether climate change policies will materially affects NEM congestion:

- Analysis prepared by IES on behalf of the AEMC (2009) concluded that there could be a significant increase in transmission congestion *if* new entry generation locates without regard to intraregional constraints. IES modelling of various generation and transmission development scenarios showed only very small differences in net present values (NPVs) of total system costs (USE, dispatch costs, capital costs, interconnector costs, and transmission costs) – in the order of $18-$36 million, suggesting that the incremental benefits of changed NEM arrangements for transmission investment are small.
- Analysis undertaken by ROAM on behalf of the AEMC (2009) showed that all major interconnectors would experience varying degrees of congestion, but that the materiality of congestion was directly related to the underlying assumptions, namely:
  - whether new renewable energy projects are distributed around the NEM or concentrated in one region, since distributed generation implies no significant or persistent economic cost associated with transmission congestion between NEM regions; and
  - whether high or low levels of RECs banking are allowed, since lower banking slows the rate of installation of renewable technologies and favours schedulable renewable technologies that impose a lower cost on the system.

  ROAM expected significant network congestion on the South Australia to Victoria interconnector in all cases as a result of the expected entry of large amounts of wind and geothermal generation. However, given dramatic volume reductions and significant technical issues with erratic and reduced dispatch for existing thermal power stations, which could result in the closure or relocation of gas fired plant, it is unclear whether such an outcome can realistically be expected.

More generally, analysis of NEM network congestion undertaken by AEMO (ESOO 2010) also highlights the uncertainty surrounding projections of NEM congestion. Specifically, the NPVs of market benefits from removing congestion vary significantly, depending on, among other things, the carbon price.

There is also limited evidence to support the AEMC's claim that congestion will lead to material mispricing and disorderly bidding. The analysis prepared by Frontier Economics on behalf of the AEMC (2008) in fact showed that additional generation costs due to disorderly bidding were around $8 million, or 0.47 per cent of total production costs across the NEM, suggesting that dispatch inefficiencies from mispricing were small.

AEMO provides quarterly information on bidding under constrained conditions in the NEM. The report is somewhat misleading in that it is titled ‘Mis-Pricing due to Network Congestion’ yet does not reflect the actual loss through mispricing as quantified by Frontier Economics. The analysis calculates mispricing as the difference between the 5-min spot price and the generator's offer price, which varies from -$1,000 to $10,000/MWh and is subject to Constraint Violation Penalty Factors when one constraint equation prevents another from being resolved. Rather than mispricing, this calculation is more reflective of the incidence and magnitude of disorderly bidding in the NEM, when generators are incentivised to submit offer prices that do not reflect the actual SRMC of operating.

Generators do not submit offers reflective of their SRMC for two reasons: unfirm access to the RRN encourages generators to rebid to the MPC or MPF when constrained-on or -off; and the energy only market design incentivises economic withholding of capacity to recover fixed costs.

Due to generators’ disorderly bidding there are productive efficiency losses when generators are constrained on or off together as the difference in SRMC is ignored. The difference in SRMC is the relevant productive efficiency cost of mis-pricing, not the costs as measured by AEMO.

If all generators submitted offers reflective of SRMC, then this value would reflect the true "cost" of the constraint binding as the RRP is reflective of the marginal generator required to replace the constrained off generator (this is the offer spread between the constrained generators). Please note the costs of constraints when priced at the SRMC offer spread is efficient when it is more economic to incur operational costs rather than capital investment costs of transmission.

One must realise that generators do not always disorderly bid when constrained because: they may lack information; the constraint is transitory; commercial implications may be low from a portfolio basis; or (most importantly) the underlying difference in SRMC between the constrained-on and -off generators is low.

The AEMO data is presented in the table below. Note when a generator is constrained-off, (its offer price is below the 5 min RRP and is not dispatched), the difference between the offer price and RRP is the level of positive mis-pricing.

The data shows that the incidence of constraint equations binding dispatch in 3% to 4% of the time either positively or negatively. The true resultant average value of positive and negative mis-pricing is relatively low, once you take into account the additional multiplication factors resulting from Constraint Violation Penalty factors used to prioritise the solving of dispatch with violated constraints.

The low average value in the 3rd and 4th columns shows generators do not disorderly bid offers in every constrained instance. The lack of disorderly bidding is an indicator that significant mispricing is not occurring and the level of productive inefficiency is low.

Region	Quarter	Average amount of positive mis-pricing	Average amount of negative mis-pricing	Average duration of positive mis-pricing	Average duration of Negative mis-pricing	Incidence of need to disorderly bid to MPF	Incidence of need to disorderly bid to MPC
NEM	2008 Q3	$113	-$39	47.99	47.53	2%	2%
NEM	2008 Q4	$417	-$105	78.99	95.26	4%	4%
NEM	2009 Q1	$448	-$157	35.78	51.62	2%	2%
NEM	2009 Q2	$207	-$435	20.40	70.66	1%	3%
NEM	2009 Q3	$63	-$44	127.82	92.19	6%	4%
NEM	2009 Q4	$351	-$308	80.97	73.92	4%	3%
NEM	2010 Q1	$843	-$526	70.70	58.23	3%	3%
NEM	2010 Q2	$116	-$173	72.40	93.86	3%	4%
2008 Q3 - 2010 Q2	QLD	$188	-$175	75.21	85.28	3%	4%
2008 Q3 - 2010 Q2	NSW	$561	-$162	34.51	37.08	2%	2%
2008 Q3 - 2010 Q2	VIC	$179	-$53	92.23	126.08	4%	6%
2008 Q3 - 2010 Q2	SA	$777	-$1,049	60.30	11.93	3%	1%
2008 Q3 - 2010 Q2	TAS	$149	-$384	60.39	61.34	3%	3%
2008 Q3 - 2010 Q2	NEM	$324	-$240	68.50	73.63	3.1%	3.4%

More generally, and while it may be the case that wind and OCGT plant may be faster to build (as the AEMC seems to suggest), even the ‘worst case’ scenario modelled by ROAM – the connection of new renewables in concentrated areas – is unlikely to materialise rapidly. Irrespective of commissioning timelines, these plant still require a connection to the existing network. To the extent that wind plant is located remote from the existing network, they will only be able to generate after any required connection assets (such as lengthy extensions) have been installed. This may delay the timing of connection and give TNSPs sufficient time to make any downstream network upgrades required to facilitate changed or additional power flows.

Need for congestion pricing

Irrespective of whether or not (unpriced) congestion is set to increase materially in the NEM – and the evidence for this is at best ambiguous – the Group does not concur with the AEMC’s view that congestion pricing would contribute to more efficient or certain dispatch outcomes.

First, Figure 3 shows that a significant proportion of NEM congestion is the result of unplanned outages, and is inherently unpredictable. AEMO’s most recent ‘Mis-Pricing due to Network Congestion’ publication (Quarter 1 2010) similarly shows that at a NEM-wide level and in all regions except Tasmania, outages accounted for more than half of the instances where mispricing was deemed to have occurred at certain connection points. In circumstances where congestion is unexpected and unpredictable, localised congestion pricing serves no purpose.

NEMMCO reached a similar conclusion in its submission to the CMR (2007). In NEMMCO’s view, and while the effect on spot prices could be significant, congestion arising from outages could be infrequent and unpredictable in their location. NEMMCO cited the AER’s studies on constraint costs and associated mis-pricing, noting that an increasingly significant proportion of constraint costs are outage driven, and that therefore the CSP/CSC approach would not be relevant when outages are dispersed through the NEM.

Second, and while localised congestion pricing may eliminate incentives for constrained generators to manipulate their offers to ensure dispatch, it creates new incentives for generators to withdraw capacity so as to prevent localised constraints from binding in the first place. The AEMC recognised this in its determination to abolish the Snowy Region (2007). In that review, the AEMC assessed two alternatives against the Snowy Hydro – splitting the Snowy region and the CSP/CSC proposal. Both of these alternatives would have resulted in Snowy Hydro receiving a more granular price. The AEMC then concluded (2007, P.18):

> More granular pricing may reduce the effect that the exercise of transient market power has on prices faced by market participants in other locations. On the other hand, generators facing a local nodal price may find it profitable to withhold production (or maintain “headroom”) in order manage their basis risk by preventing constraints from binding that might otherwise reduce their own settlement price. To the extent withholding occurs, it may diminish or reverse the productive and dynamic efficiency benefits of greater pricing granularity

The AEMC highlighted that it had undertaken quantitative modelling to inform its analysis. Snowy Hydro (2006) similarly highlighted that LMP pricing arrangements would give it a strong incentive to withdraw generation from the Victorian market. The underlying reason for this is that LMP prices are reduced when a generator’s output creates a constraint. In such circumstances, generators have an incentive to reduce their output to minimise inter-regional price separation, and therefore achieve a higher settlement price. In circumstances where generators withdraw capacity to prevent constraints from binding, competition is immediately reduced.

Third, the above reduction in wholesale market competition would be expected to have similar effects in the contract market. Generators that face localised congestion prices in some circumstances have a strong incentive to sell fewer contracts, so that competition in the contract market will be affected. A generator faced with a localised congestion price during certain system conditions is exposed to basis risk and, to the extent that its output is reduced, to unfunded difference payments arising from any contracts it may have entered into.

It could be argued that the apportionment (or allocation) of transmission rights would allow generators to manage the risk, however, there is considerable uncertainty about how an allocation process would operate and its level of complexity. This uncertainty does not assist market participants wishing to hedge trading positions several years ahead, and could in fact increase contract prices (due to higher risk premiums) and limit the overall level of market liquidity. There is no evidence to suggest financial market liquidity has been materially impacted by the current transmission arrangements. In fact the according to recent Australian Financial Market Association Reports market liquidity has generally increased over the last five years.

As previously mentioned, it is highly questionable whether the introduction of locational marginal pricing in other markets has delivered benefits when these broader issues are considered.

To summarise, the most recent evidence from the AER does not bear out the AEMC claim that NEM congestion is on an upward trend or that mispricing/disorderly bidding have been a material issue to date. Recent NEM modelling studies that have been undertaken on behalf of the AEMC suggest that the extent of future NEM congestion is instead highly dependent on factors such as the carbon price, the locational decisions of renewable generators, and the administrative arrangements surrounding climate change mechanisms. Given the cause of NEM congestion and the importance of outages, the negligible static efficiency loss, the effectiveness of congestion pricing is doubtful, and may be outweighed by adverse competitive effects on the spot and contract market.

References

AEMC Reliability Panel, 2009. Annual Market Performance Review 2008-09, 2 December 2009.

AEMC 2008, Survey of Evidence on the Implications of Climate Change Policies for Energy Markets, December.

AEMC 2009, Review of Energy Market Frameworks in light of Climate Change Policies: Final Report, September.

AEMC 2007, Abolition of Snowy Region, Rule Determination, 30 August.

AEMC 2006, Final Report, Congestion Management Review, June 2008.

AEMO, 2010. Mis-Pricing due to Network Congestion: 2010 Quarter 1.

AER, 2009. State of the Energy Market.

AER, Indicators of the market impact of transmission congestion, reports for 2003/04 (9 June 2006), 2004/05 (10 October 2006), 2005/06 (February 2007), 2006/07 (November 2007).

AFMA 2010, Australian Financial Markets Report.

Biggar, D. 2006. Congestion Management Issues: How Significant is the Mis-Pricing Impact of Intra-Regional Congestion in the NEM?, 25 October.

Bushnell, James, and Steven Stoft, ‘Transmission and Generation Investment In a Competitive Electric Power Industry’, for the California Energy Commission, Interagency Agreement 700-93-003, May 1995.

Electricity Commission, 2010. Consultation Paper. Transmission Pricing Review: Stage 2 Options, July.

Electricity Supply Industry Planning Council, 2009. “Annual Planning Report”, June.

Intelligent Energy Systems (IES), Modelling of Transmission Pricing and Congestion Management Regimes, Report, 22 December 2006.

IES, 2009. Future Congestion Patterns & Network Augmentation, Report on Assignment A: Transmission Development Framework Scenarios, 25 June.

NEMMCO, 2006. Submission on the Congestion Management Review, 13 April.

NEMMCO, 2007. submission on the Congestion Management Review Directions Paper, 20 April.

ROAM Consulting 2009. Network Augmentation and Congestion Modelling, June 2009.

ROAM Consulting 2008. National Electricity Market Development, Market impacts of CPRS and RET, 17 December.

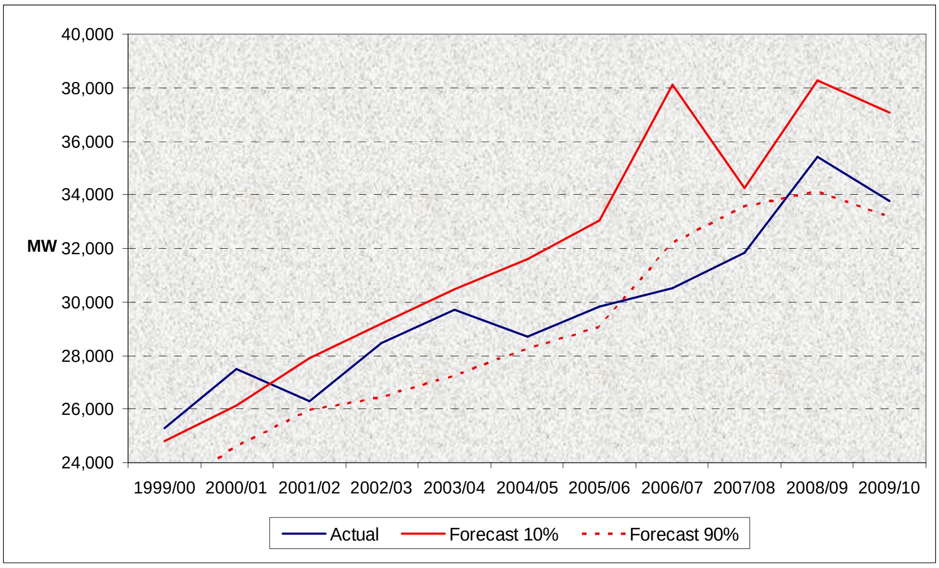
Snowy Hydro Limited, 2006. Submission to: Draft Rule Determination – Management of Negative Settlement Residues by Re-orientation, 26th October.

Appendix A NEM demand forecasts

A.1 NEM system

Figure 1

NEM SUMMER PEAK DEMAND – ACTUAL VS SOO FORECASTS

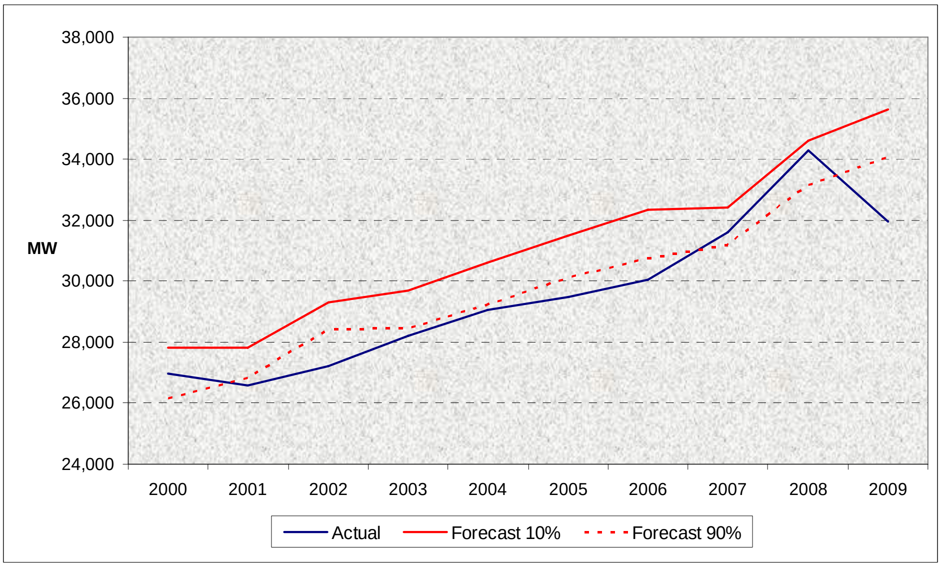


Notes: SOO forecast used is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 1999/00 is from the 1999 SOO, the forecast for 2009/10 is from the 2009 ESOO.

Source: SOO/ESOO.

Figure 2

NEM WINTER PEAK DEMAND – ACTUAL VS SOO FORECASTS



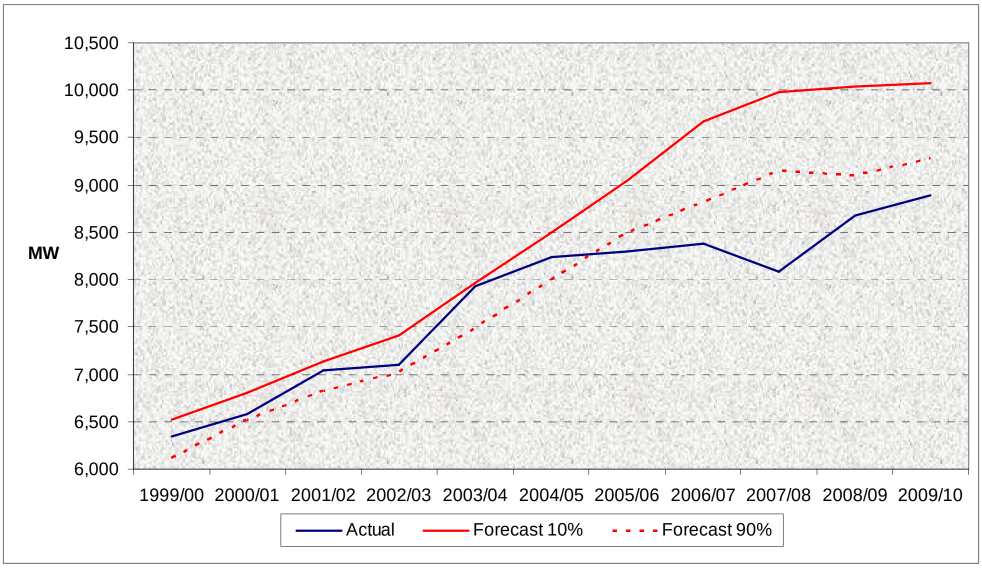
Notes: SOO forecast used up to 2007 is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 2000 is from the 1999 SOO; however, from 2008 the forecast is from the SOO for that year, i.e. the forecast for 2009 is from the 2009 SOO.

Source: SOO/ESOO

A.2 Queensland

Figure 3

QUEENSLAND SUMMER PEAK DEMAND – ACTUAL VS SOO FORECASTS

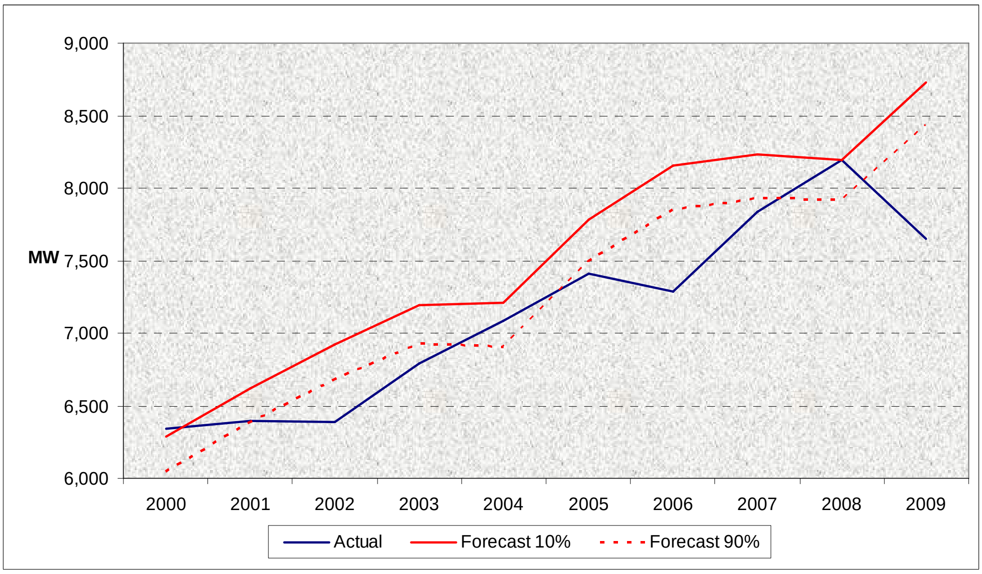


Notes: SOO forecast used is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 1999/00 is from the 1999 SOO, the forecast for 2009/10 is from the 2009 ESOO.

Source: SOO/ESOO

Figure 4

QUEENSLAND WINTER PEAK DEMAND – ACTUAL VS SOO FORECASTS



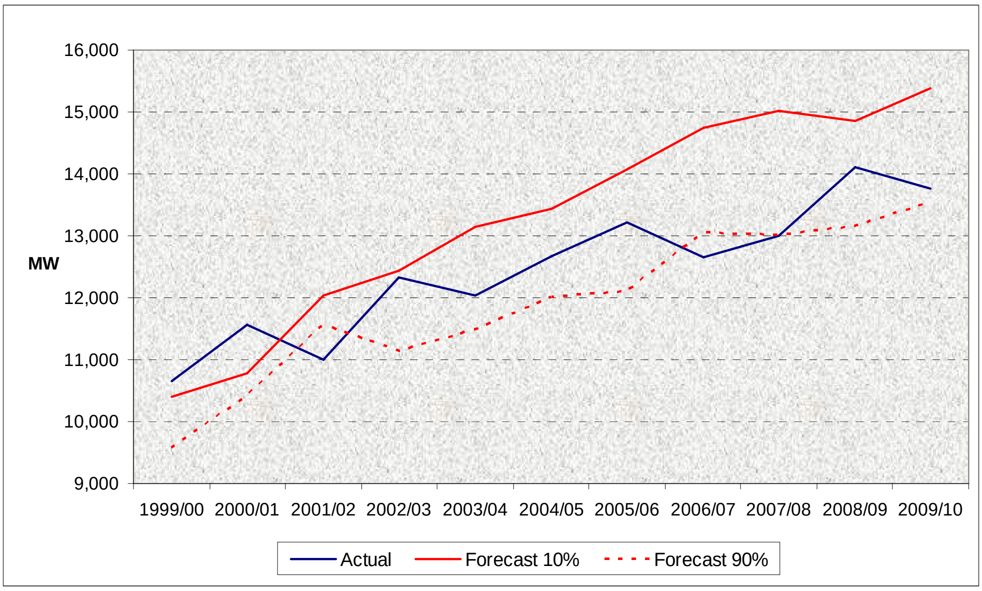
Notes: SOO forecast used up to 2007 is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 2000 is from the 1999 SOO; however, from 2008 the forecast is from the SOO for that year, i.e. the forecast for 2009 is from the 2009 SOO.

Source: SOO/ESOO

A.3 New South Wales

Figure 5

NSW SUMMER PEAK DEMAND – ACTUAL VS SOO FORECASTS

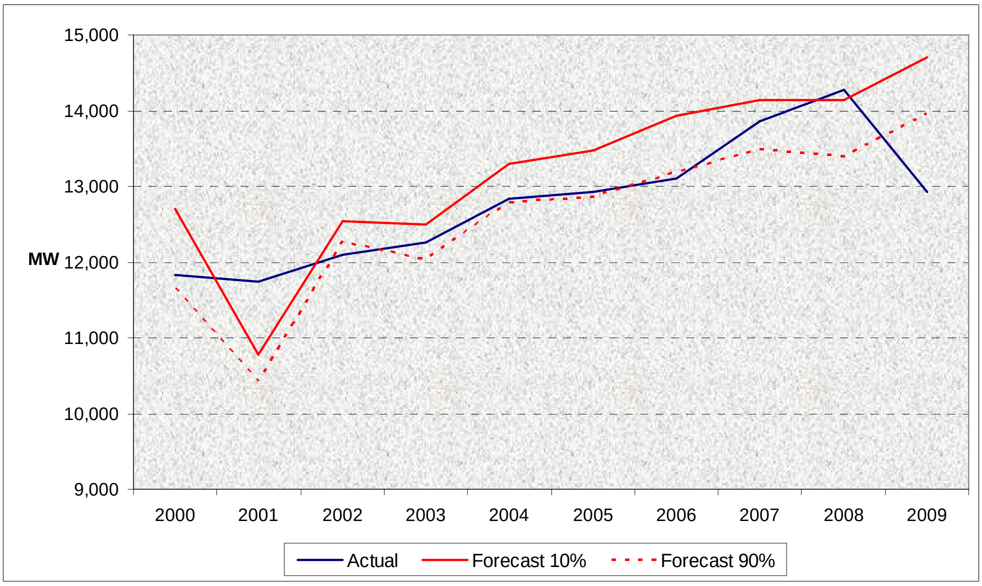


Notes: SOO forecast used is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 1999/00 is from the 1999 SOO, the forecast for 2009/10 is from the 2009 ESOO.

Source: SOO/ESOO.

Figure 6

NSW WINTER PEAK DEMAND – ACTUAL VS SOO FORECASTS



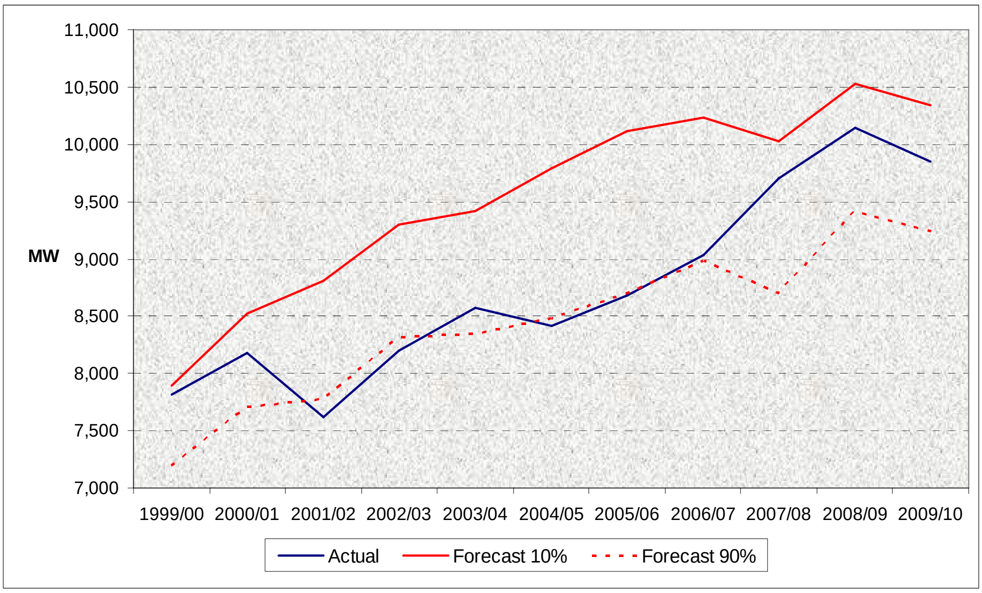
Notes: SOO forecast used up to 2007 is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 2000 is from the 1999 SOO; however, from 2008 the forecast is from the SOO for that year, i.e. the forecast for 2009 is from the 2009 SOO.

Source: SOO/ESOO

A.4 Victoria

Figure A.1

VICTORIAN SUMMER PEAK DEMAND – ACTUAL VS SOO FORECASTS

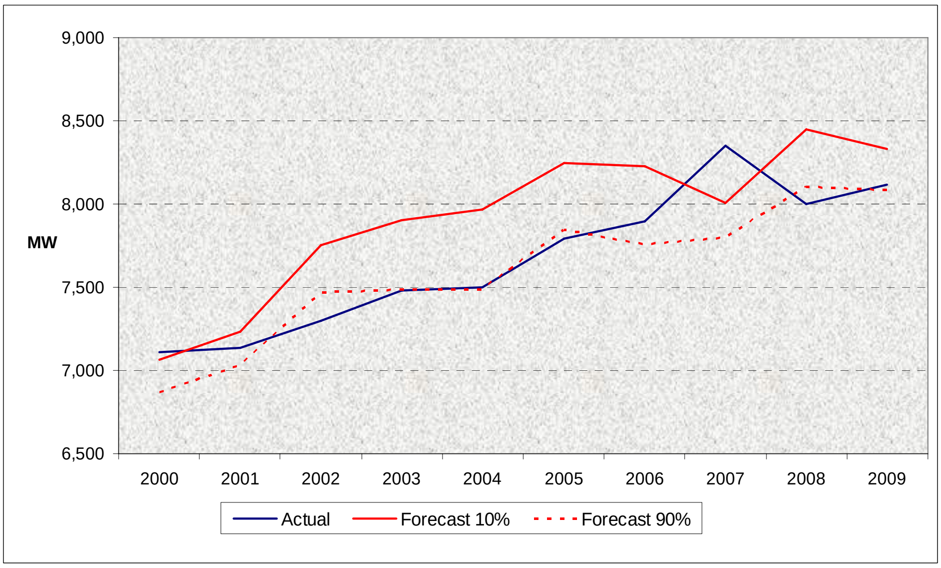


Notes: SOO forecast used up to 2007 is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 2000 is from the 1999 SOO; however, from 2008 the forecast is from the SOO for that year, i.e. the forecast for 2009 is from the 2009 SOO.

Source: SOO/ESOO

Figure 7

VICTORIAN WINTER PEAK DEMAND – ACTUAL VS SOO FORECASTS



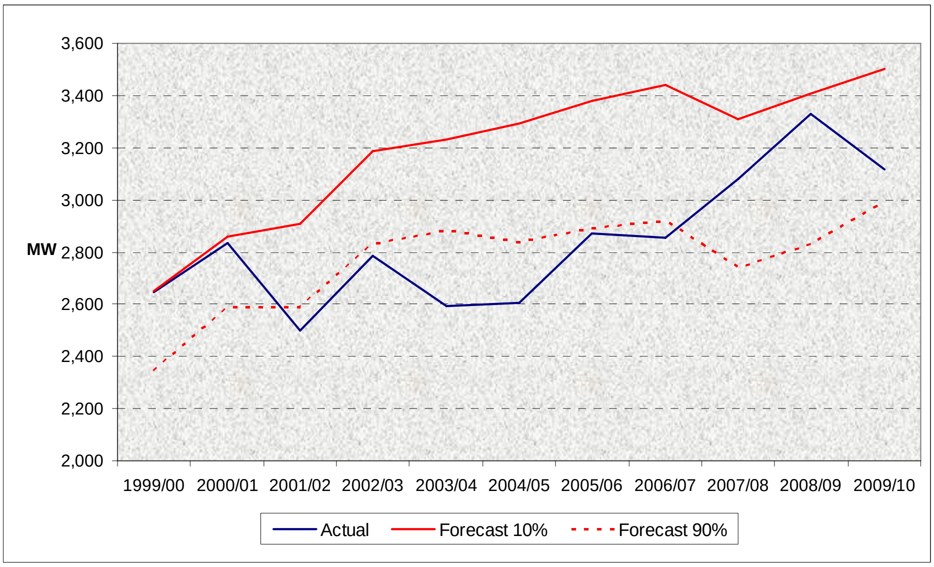
Notes: SOO forecast used is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 1999/00 is from the 1999 SOO, the forecast for 2009/10 is from the 2009 ESOO.

Source: SOO/ESOO.

A.5 South Australia

Figure 8

SOUTH AUSTRALIAN SUMMER PEAK DEMAND – ACTUAL VS SOO FORECASTS

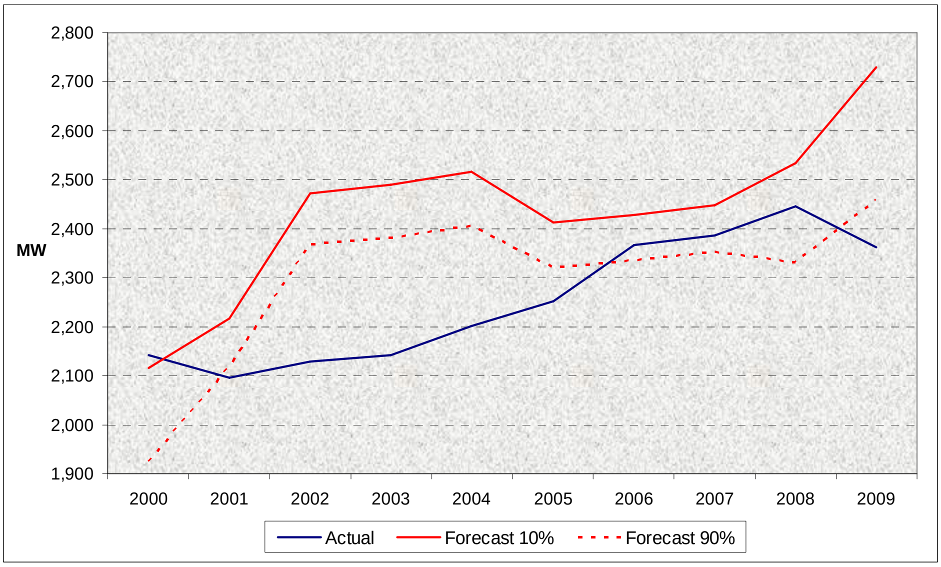


Notes: SOO forecast used is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 1999/00 is from the 1999 SOO, the forecast for 2009/10 is from the 2009 ESOO. On a statistical basis, the probability of actual demand falling below the 90% POE for 6 years from 2001-02 to 2006-07 is one in one million.

Source: SOO/ESOO.

Figure 9

SOUTH AUSTRALIAN WINTER PEAK DEMAND – ACTUAL VS SOO FORECASTS



Notes: SOO forecast used up to 2007 is from the SOO issued for the year immediately prior to the nominated year, i.e. the forecast for 2000 is from the 1999 SOO; however, from 2008 the forecast is from the SOO for that year, i.e. the forecast for 2009 is from the 2009 SOO.

Source: SOO/ESOO.

Appendix B Case study of the 70/71 line cut set

TransGrid undertook a major upgrade of the NSW Western Ring of transmission lines during 2009 and 2010. The project involved:

- new 330/500 kV switchyards and associated transformers and switching components at Bayswater, Wollar, Mt Piper, Bannaby and Marulan
- rearrangement of transmission line connections at Bayswater, Wollar, Mt Piper, Wallerawang, Bannaby and Marulan
- transmission line realignment works between Mt Piper and Wallerawang, Yass and Bannaby, and Bannaby and Sydney West, and
- transfer of BW3 and BW4 to the new 500 kV switchyard at Bayswater.

Previously:

- one 330 kV transmission line connected Bayswater to Mt Piper and one 330 kV transmission line connected Bayswater to Wallerawang.
- one 330 kV transmission line (TL71) and one 132 kV transmission line (TL94E) connected Mt Piper to Wallerawang

Prior to the upgrade, with only one Wallerawang unit in-service at full load, during high demand periods and heavy import from south NSW, the system normal constraint for overload of 94E for trip of 71 would bind. This would constrain output over the Queensland to NSW and Victoria to NSW interconnectors plus generation at Liddell, Bayswater, Mount Piper, Tumut and Uranquinty.

Conversion of the two existing 330 kV transmission lines between Bayswater and Wallerawang/Mt Piper to a 500 kV operation with both transmission lines connecting directly to Mt Piper resulted in an extra 350 MW of flow on these transmission lines. Transfer of BW4 to the 500 kV switchyard resulted in an addition 150 MW flow. As part of the project, TransGrid realigned and reconnected the remaining section of the old Bayswater to Wallerawang transmission line as an additional 330 kV transmission line (TL70) between Mt Piper and Wallerawang. The double 330 kV lines between Mt Piper and Wallerawang also remove the “system normal” constraint for overload of TL94E.

In May/June 2010 BW3 was connected to the BW 500 kV switchyard, further increasing the flow towards Mt Piper from Bayswater by approximately 150 MW to a total of 650 MW.

Between August 2009 and early August 2010, TransGrid had not completed works to convert the two 330 kV transmission lines between Mt Piper and Marulan. The higher impedance on these lines remained, limiting the ability to transfer any of the additional power flow (initially 500 MW and then 650 MW) between Mt Piper and Marulan. This increased flow across the newly formed 70/71 cut-set.

An issue identified by TransGrid during the upgrade planning was that the fault limits on the current transformers on the Bay Coupler circuit breakers were unsatisfactory low and these current transformers would need to be replaced as part of the upgrade works in order to utilise the full ratings of TL70/71. In late May 2010 TransGrid put in place a network reconfiguration in the Wallerawang and Mt

Piper switchyards that resulted in only a small amount of NSW customer load being at risk in the event of most network contingency events. This allowed the full transmission line ratings to be utilised by AEMO.[5]

Had TransGrid replaced the current transformers or converted the Mt Piper to Marulan transmission lines prior to the Bayswater to Mt Piper conversion, it would have avoided network constraint issues with the new TL70/71 cut-set.

To describe these transmission network conditions as being "system normal" would ignore the transitory nature of the network conditions that existed as a result of changes to line flows and lower rating of key lines during the conversion of the NSW Western Ring to a 500 kV operation.

Drought conditions impacting operation of Wallerawang

During 2007 to mid 2010, the mid western area of NSW suffered a severe 1 in 100 year drought, severely impacting the operation of Wallerawang Power Station. For long periods, Delta was forced to lower production at Wallerawang due to a high salt content of water in Delta's storages and a shortage of good quality water from Oberon Dam to dilute the high salt levels.

The output from Wallerawang units have the most significant impact on the operation of the network constraints under both the pre and post Western Ring conversion of the transmission cutest between Mt Piper and Wallerawang. The constraint co-efficient for Wallerawang is -1.000, requiring increased output, or 'constrained-on", at Wallerawang to prevent binding of constraint associated with these transmission lines. Alternatively, if increased output at Wallerawang was not possible, the same could be achieved by a reduction in output at Mt Piper of 1.4 MW, or 5 MW on the Victoria to NSW interconnector or Tumut 3 or 4 MW on QNI or BW/LD.

A simple view is that the constraint can be managed by increasing output to full load at Wallerawang. Given the operational restrictions forced on Wallerawang at the time, increased output may not have been possible or only at high cost.

Possible impact of constraint management mechanism on NSW generator bidding

Given the physical limits on the output of Wallerawang, a congestion management regime would not have a significant impact on the bids at Wallerawang.

Given the "meshed network" nature of the constraint, it is unclear whether a congestion management regime would alter bidding incentives for other NSW generators in NSW in the constraint equation.

With the exception of Mt Piper with a co-efficient of 0.72, all other generators in the constraint equation have fairly similar co-efficients. Any adjustments to bids by one generator would lead to a similar sized change in dispatch outcomes for another generator. Given that fuel costs of these generators are similar, it is highly improbable that a significant increase in dispatch efficiency would be achieved during periods where constraint N>>N-NIL_S had bound.

[5] Notwithstanding, had a fault on the MT Piper generator bus occurred, both Mt Piper generators would have tripped, most likely resulting in a large loss of customer load in NSW due to under frequency load shedding.