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Mr John Pierce
Chairman
Australian Energy Market Commission
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Dear Mr Pierce

TRANSMISSION FRAMEWORKS DIRECTIONS PAPER

Delta Electricity, Macquarie Generation and Snowy Hydro (the 'Northern Group') welcome the opportunity to make a submission to the AEMC's *Transmission Framework Review Directions Paper*, as published on 14 April 2010.

The Northern Group is supportive of the Commission's indication in the Directions Paper that it has no intention of fundamentally changing the NEM arrangements without substantiated evidence and clear economic reason for doing so. We believe that the Commission has appropriately identified the advantages and disadvantages of various access, network charging and congestion management proposals. The Options Paper will need to balance, measure and consider all of the trade-offs involved in any redesign of the current arrangements when considering any 'package' of new measures.

We welcome the Commission's much more considered assessment of the need for change in the Directions Paper. The Commission's *Review of the NEM in light of Climate Change Policies, 2009* made recommendations indicating support for a congestion management regime and the application of a fixed use of system charge. The AEMC's Directions Paper is much more circumspect on the merits and limits of such changes and recognises that a change in one area cannot be considered in isolation. The Group submits that far reaching changes to the NEM design should only be undertaken on the basis of a whole-of-market assessment.

The AEMC requires an analytical framework that considers the efficiency trade-offs that some of the 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. Overall, this market design essentially trades off efficient investment and the broader benefits of a relatively liquid contract market with occasional allocative and immaterial productive inefficiencies when congestion arises.

The question for the Commission is whether changes to the existing frameworks are at all necessary, given the short and longer term efficiency trade-offs and the considerable implementation and transitional issues that would inevitably accompany any such change. There can be no doubt that a number of the changes contemplated by the AEMC will create new problems and risks further down the line. Based on the evidence to date, we are not convinced that substantial changes to the existing arrangements are likely to be worthwhile.

Yours faithfully

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GENERAL MANAGER MARKETING
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(on behalf of THE NORTHERN GROUP)

9 June 2011

Key messages

The Northern Group considers that the following key points should be taken into account in any consideration of possible changes to access, network charging and congestion management arrangements in the NEM.

- 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.

- There is little or no evidence to suggest that the existing framework is encouraging systematically poor locational, operational or investment outcomes.

- 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 has been a material issue to date.

- Going forward, the indications are that increased network investment by TNSPs will continue to limit network congestion in the NEM.

- The existing open access arrangement, which offers no dispatch certainty, provides investors with strong incentives to locate a power station in a generally unconstrained part of the network. A potential generator investor would consider, among other things:
  - The existence of suitable sites as regards key inputs, such as fuel, environmental approvals, power infrastructure and water;
  - The general incidence of network constraints in the vicinity of particular sites;
  - Load flow analyses to assess marginal loss factors and constraints over the different time horizons;
  - TNSP's/AEMO's relevant forecasts, planning and investment programmes.

- 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. TNSPs provide considerable information about their thinking on future investment through their Annual Planning Report publications. At a NEM-wide level, these regional planning arrangements are complemented by the ESOO and NTNDP which consider network developments over a longer term planning horizon.

- As far as the Group is aware, AEMO is the only network planning body in Australia and internationally that consistently applies a probabilistic planning standard to network augmentation. In all other markets planning standards are based on deterministic criteria, which are inherently more conservative than the probabilistic approach.

- The 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 is planned on a probabilistic standard, AEMO manages line flows on the network in real time on deterministic (credible contingency) basis. The Group considers that the planning processes in Queensland and NSW provide the appropriate transmission planning and investment incentives.

- 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. As long as the regulatory rate of return is sufficient and the incentives for service performance are attractive, TNSPs should be willing to invest in all types of regulated projects irrespective of the investment driver.

- As a forward-looking network charge designed to signal the costs of incremental network capacity, 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 technology types.

- High volatility market events which draw the attention of Market Stakeholders are predominantly driven by network outages. In many cases multiple network outages. It is therefore crucial that any change to the transmission frameworks recognises appropriate risk allocation. It is the Group's view that the current regulatory arrangements strike the appropriate balance by incentivising TNSPs to plan network outages at times of low demand to maintain competitive tension between generators. However, as demonstrated from the AEMO case studies on their Issues Paper submission this incentive can be sharpened to encourage TNSPs to be more market aware of the consequences of their actions and therefore plan network outages at more appropriate times of low spot price sensitivity or to schedule their scope of works in a manner that minimises the market impact.

- Privately sponsored investment in the shared transmission network where a corresponding private transmission right is assigned potentially conflicts with the National Electricity Objective and fundamentally implies a shift to a different market design. Furthermore, the different physical or financial access models create very difficult conceptual and practical implementation issues.
  - 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.
  - Financial firm access right 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.

<u>Efficiency trade-offs</u>

The Group believes that difficulties arise in facilitating investment through maximising competitive trade and minimising transmission costs. To derive the maximum benefit of competition, wholesale market design may aim to replicate financial commodity markets through encouraging homogeneity between products traded. However an obvious problem with such a goal is underlying transmission costs: If such costs are priced, for example through some type of congestion management regime, they reduce the homogeneity and effectiveness of the market.

Policy makers must ask: 'are underlying costs more significant than fostering investment and competition through a successful financial market?' They must also consider whether underlying costs can actually be priced or signalled on a shared transmission network. The second question is important because if underlying transmission costs can be priced or signalled ex-ante they may be avoided without restricting trade and investment in the market. The rub is course that underlying transmission costs are difficult to forecast with any accuracy – in planning, operating and investment timescales.

Any analysis must consider the potential inefficiencies presented in the NEM design that explicitly restrict the financial markets but seek to minimise underlying transmission costs. The NEM design has five financial markets for settlement purposes; each financial market has different underlying physical size and number of counterparties; the settlement prices differ with losses and congestion; non-firm financial contracts exist to reduce basis risk of trading between regions, but remain subject to volume risk; generators are not obliged/incentivised to trade full physical dispatch in the financial market; gross pool design encourages physical rather than financial trade; and forced outage risk reduces liquidity.

The following table simplifies the economic gain and loss from the features of the NEM design.

| NEM features | Gain | Loss |
|---|---|---|
| Marginal loss factors and IRLF allocations | Restricting trade to where underlying costs are similar; provides economic signal for marginal MW | Inaccuracy in forward looking calculations; over-allocation of losses on an average basis |
| Regional prices, inter-regional basis & volume risk | Restricting trade to where underlying costs are similar | Restricting trade to within region |
| Intra-regional dispatch risk due to constraints | Disciplining investors to avoid congested parts of network | Preventing trade in financial market, exposing participants |
| Mispricing when disorderly bidding | Disciplining investors not to crowd out local incumbents | Mispricing when constrained |
| Open access | Investment and competition in generation | Investor uncertainty, especially for incumbents |

The Group's view is that these physical market restrictions appear not to have overly inhibited the development of derivative markets. Specifically we contend that dispatch risk created by network congestion is likely to have less of an impact on financial markets than forced outage risk at the generator level.

Dispatch risk is when a generator is constrained off short of its financial contracts. This is similar to the impact of forced outages where a unit may trip resulting in higher spot prices and an inability to cover hedge contracts. In either case there may also be opportunity costs of lost revenues if spot prices were high during these periods.

The level of dispatch risk reflects the operation of the power system which accommodates the loss of single elements in the transmission network such as a circuit or a transformer or the loss of a single generating unit. These are referred to as 'credible contingency events and the system is known as remaining in a 'secure operating state'. AEMO plans for the loss of a transmission element and implements constraints to modify physical dispatch of scheduled units.

However the power system is not operated so it can guarantee to withstand the simultaneous loss of multiple transmission elements and generating units or the loss of more secure elements such as busbars (referred to as 'non-credible contingency events'). Under abnormal conditions where the likelihood of multiple failures becomes more likely, AEMO is permitted to temporarily adjust the operation of the power system so that it would be able to withstand the loss of certain multiple elements which are at that time exposed to increased threat. This is known as the 'reclassification of a contingency event'.

We contend that any analysis of the impact of dispatch risk on generator contracting behaviour must not be assessed in isolation from a consideration of forced outage risk. For major baseload plant, particularly for a single station business, there is always the risk of a unit failure that exposes the plant owner to shortfalls against hedge contract liabilities. Generators will adjust their contracting positions to reflect the likelihood of such plant problems. Our preliminary assessment indicates that outage risk has a far greater influence on limiting a generator's willingness to enter into to derivatives contracts than any measurable level of dispatch risk created by congestion in the NEM.

In those cases where the likelihood of dispatch risk exceeds expected outage risks, and generators are constrained off in a way that may limit their ability to fully meet contract positions, generators may bid a way that is not reflective of underlying costs. Any assessment of whether this behaviour is materially inefficient must take into account the relative differences in short-run marginal costs of those generators bidding in this way. We would argue that it is the ability to rebid to ensure some access to limited transmission capacity that allows generators within the local region to which their financial contracts are settled to manage some dispatch risk. The costs of this behaviour in terms of additional resource costs in dispatch must be assessed against the benefits of greater trade in contract markets.

Detractors from the NEM cite the requirement for "bankable access rights" or privately sponsored transmission to improve investment. We argue that the NEM allows for a liquid financial market where investors can price and hedge risks, facilitating investment even without bankable firm access. The Group considers firmer trading arrangements may discourage new entrants if they are required to purchase access rights or if such property rights are assigned to incumbents.

In contrast, we argue it is efficient for the NEM to provide no certainty over transmission access: the key premise is that a rational investor will not congest the network and the ability for incumbents to bid in a way that prevents unnecessary crowding out. 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.

We believe the Commission has wrongly accepted the premise of dispatch risk prohibiting investment through impeding financial markets. In contrast, the Group believes open access, tempered by dispatch risk and NEM's regional pricing has simultaneously encouraged investment in generation without incurring inefficient levels of transmission cost.

Impact of AEMO and TNSP actions

The AEMC cited an example provided by AEMO detailing the market outcomes from the constraint triggered on the 7 December 2009 on a transmission line between Wallerawang and Mt Piper. AEMO relied heavily on this case study in its response to the Issues Paper to justify a number of changes to market design including the introduction of congestion management schemes.

Our analysis of the 70/71 line example provided by AEMO showed that this upgrade could not be considered as a “system normal” condition as it involved a transitionary upgrade works to a major part of the transmission network. This is an important observation since under system normal conditions the NEM is designed robustly enough to ensure that the market settles in an orderly and predictable manner. In non “system normal” events the market is less informed and prepared and as a consequence spot market outcomes tend to be much more volatile and unpredictable. The Group argues that it would be more productive to address the root causes of non “system normal” events as opposed to modifying the transmission frameworks to rectify symptoms arising as a result of these events.

The Group believes better co-ordination and communication between AEMO and the relevant TNSPs, and the proper implementation of operational procedures within AEMO (such as avoiding step changes in transmission ratings without adequately informing the market), could have significantly reduced the impact of upgrades work around the 70/71 line. This was a one-off project involving a major strengthening of the NSW system that could have been staged and organised in a way to avoid or minimise congestion problems.

The conversion of the MT Piper to Bannaby 500kV upgrade and the installation of new current transformers at Wallerawang was completed in mid 2010. Since that time the 70/71 line cut-set has appeared in 6 constraint equations and there have been nil trading intervals of constraint. We expect that this would be case even with a single credible contingency. The only way the constraint equations would bind would be under some multiple credible contingency events.

It is the Northern Group’s view that high volatility market events which draw the attention of all market participants are predominantly driven by network outages and in many cases multiple network outages. We believe that the current regulatory arrangements strike the appropriate balance by incentivising TNSPs to plan network outages at time of low demand to maintain competitive tension between generators. Notwithstanding, the Group also suggests that application of additional incentives on TNSP’s in the area of outage planning and outage notification is warranted. In order to facilitate this it will also require upgrades to AEMO’s network outage advice systems to more accurately inform market participants and allow better analysis of TNSP performance by regulators.

In addition, as demonstrated from the AEMO case studies this incentive can be sharpened to encourage TNSPs to be more aware of the market consequences of their actions and therefore plan network outages at more appropriate times of low demand or to schedule their scope of works in a manner that minimises the market impact.