Australian Energy Market Commission

REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

Agenda Paper:

Industry Forum - generator transmission use of system charges

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

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1 Introduction

The purpose of this paper is to inform discussion at an industry forum to be held by the Australian Energy Market Commission (AEMC) on 17 August 2009. The intention of the forum is to discuss the locational pricing issues raised in the 2nd Interim Report to the Review of Energy Market Frameworks in light of Climate Change Policies (the Review).

The AEMC published its 2nd Interim Report on 30 June 2009. The Final Report for the Review is due to be submitted to the Ministerial Council for Energy (MCE) by 30 September this year.

Among other matters, the 2nd Interim Report set out a draft recommendation to implement generator transmission use of system (G-TUOS) charges in the National Electricity Market (NEM). This recommendation reflected our finding that there is a high likelihood of congestion - and its associated economic costs - increasing as a result of behaviour brought about in response to climate change policies. We also found that there is currently a lack of effective long term locational pricing signals.

The implementation of G-TUOS charges would represent a significant change to the market frameworks and would impact upon many industry participants. The consultation and analysis in relation to this proposal is at an earlier stage of development than other areas of the Review.

Discussions with stakeholders and submissions to the 2nd Interim Report suggest there is general agreement that the frameworks for the efficient utilisation and provision of the network could be strengthened, and that there is a lack of effective locational signals.

However, many stakeholders, particularly generators, disagree with the AEMC's characterisation of the problem and the proposed solution outlined in the 2nd Interim Report. Some generators have argued that the key problem is not around locational signals but around the broader, related issues of certainty of access to the network and insufficient investment in transmission capacity to support new generation investment. Some stakeholders have also commented that although reforms are required, alternative solutions to G-TUOS charges, such as deep connection charges and financial transmission rights, are preferred.

In light of the current state of development of this issue the AEMC does not intend to recommend a final policy position and a rule change in the Final Report to the MCE.

Instead, the recommendation is likely to take the form of a proposal for a new work program to further explore the problem of locational signals and related issues such as certainty of dispatch. Such a work program would involve extensive consultation with industry participants and further analysis of a spectrum of possible options for reform.

The remainder of this paper provides context and discussion points for the Industry Forum on G-TUOS and, more broadly, how to promote the efficient utilisation and provision of the transmission network in the National Electricity Market (NEM).

2 Background

This section describes the context that led to the AEMC's draft findings in the 2nd Interim Report, including:

- the process for undertaking this Review; and
- findings and outcomes from the Congestion Management Review (CMR).

2.1 Review of Energy Market Frameworks in light of Climate Change Policies

The AEMC is undertaking this Review as directed by the MCE. The Terms of Reference for the Review[1] require the AEMC to determine whether the existing energy market frameworks for the electricity and gas markets require amendment to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded Renewable Energy Target (expanded RET). Essentially the Review is to:

- examine the potential impacts of the CPRS and expanded RET on both the electricity and gas markets across all jurisdictions;
- determine what adjustments may be necessary to the energy market frameworks, having regard to the National Electricity Objective (NEO) and the National Gas Objective (NGO); and
- provide detailed advice to the MCE on the implementation of any amendments required.

The 2nd Interim Report for the Review was published on 30 June 2009, and contained our draft findings and recommendations. Our final report is due on 30 September this year.

2.2 The Congestion Management Review

In October 2005 the AEMC was directed by the MCE to review congestion management in the NEM. The Final Report was published in June 2008.[2] Much of the analysis contained in the Final Report contributed directly to the subsequent assessment of the efficient utilisation and provision of the network in this Review.

The CMR identified congestion as a problem because it can lead to economically inefficient outcomes associated with inefficient dispatch and "dis-orderly bidding".[3]

1 Available at www.aemc.gov.au.

2 AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney. Available at www.aemc.gov.au.

3 "Dis-orderly bidding" is when a generator is not offering its output at a "cost-reflective" price.

Network congestion occurs when the cheapest mix of generation cannot be used to meet demand because the network is not able to handle the consequent flows of electricity. Congestion can lead to generators being "constrained-on" or "constrained-off", i.e. either forced to supply more electricity or unable to supply as much electricity as they would like at the market price ("dispatch risk"). For end users, supply-driven congestion implies higher prices due to more expensive generators being dispatched.

Congestion also creates inefficiencies in the financial market. Congestion limits the amount of electricity that a generator can contract because of the risk that they will be constrained-off and therefore unable to meet their contractual obligations.

The CMR highlighted that market participants engage in strategies and activities to manage risks caused by congestion. This leads to behaviours – such as dis-orderly bidding by generators – that reduce the economic efficiency of the NEM in both the short and long term.

In the long run, dis-orderly bidding may distort the location, technology and timing of investment decisions by generators. For example, a new entrant may apply a higher discount rate if the level of dis-orderly bidding in an area makes it difficult to manage its own dispatch risk. In the longer term, this can weaken economic signals that support efficient locational decisions by generators.

The AEMC concluded that material congestion in the NEM had not been substantial to date. Therefore only incremental changes to the congestion management regime were recommended at that time.

The Terms of Reference for the CMR required us to examine and report on the feasibility of a constraint management mechanism for managing location-specific, material congestion. Given the complexities associated with designing a location-specific interim constraint management mechanism, the AEMC was not persuaded that implementing such a mechanism was likely to result in a net improvement in market efficiency at the time the CMR was undertaken.

However, the Final Report flagged that the economic costs associated with congestion would likely increase following the introduction of climate change policies and suggested that significant reforms may then be required to manage the anticipated effects.

3 What is the problem?

This section describes how the AEMC characterised the problems associated with the efficient use and provision of the network in the 2^{nd} Interim Report. It then summarises stakeholders' submissions to the 2^{nd} Interim Report to capture how other industry participants have perceived the problem.

3.1 Outcomes from the 2^{nd} Interim Report

The AEMC found in the 2^{nd} Interim Report that there is a lack of effective long term locational signals for both new and retiring generators. We presented our draft recommendation that framework changes, focussing on the incentives on generators, are likely to promote more efficient investment and retirement outcomes in the presence of congestion.

We concluded there is a high likelihood of increased economic costs associated with congestion following the implementation of the expanded RET and, to a lesser extent, the CPRS. Congestion is likely to be material and more persistent, driven by the significant level of new investment in generation required and the resultant changes to the flows on the network caused by changes in the dispatch of generation.

This increased incidence of congestion is likely to lead to material inefficiencies by increasing the likelihood of dis-orderly bidding and inefficient dispatch outcomes.

We concluded that the drivers behind the likely increased levels of congestion, and therefore the likely increase in economically inefficient outcomes, predominantly arise because of the lack of effective locational signals. These inefficient outcomes could be reduced by providing stronger pricing signals to entering and exiting generators regarding their impact on the capability of the network to support efficient dispatch. Such price signals should encourage more efficient generation location decisions and so reduce the incidence of inefficient congestion in future.

Generator behaviour can also affect the short run efficiency of networks through operational and bidding decisions. Hence price signals to generators can be based upon the long run network costs, short run dispatch costs or a combination of both.

Price differentials between regions currently provide generators with signals of which region to locate in, but not where to locate within that region. Loss factors do provide an intra-regional locational signal, however this is relatively weak.

We also concluded that the frameworks for transmission investment and operational decisions should result in the delivery of the efficient level of long term transmission capacity. Building out all network constraints would be inefficient and therefore inconsistent with the NEO. The Regulatory Investment Test for Transmission (RIT-T) is the new economic framework for identifying the most economic transmission projects and is supported by a suite of other reforms, such as the National Transmission Planner and Last Resort Planning Power, to deliver timely and efficient network investment.

3.2 Stakeholders' views

From submissions to the 2nd Interim Report and the Department of Resources, Energy and Tourism's *Energy White Paper*, it appears that stakeholders generally agree that insufficient locational signals are given to generators at the time they are making investment decisions. For example, the NGF note in their submission to the Energy White Paper: [4]

> *Promoting appropriate locational decisions is the key to managing generator access to transmissions and minimise inefficient congestion.*

However, some generators have characterised the consequent problem as uncertainty of access to the network as a result of insufficient new investment in transmission to support new entrant generators.

Some generators have argued that investment in generation requires firm access to the regional reference node to be able to compete in the wholesale market with certainty.[5] They suggest that certainty of dispatch will resolve the economic inefficiencies associated with congestion by:

- eliminating dis-orderly bidding and so improving the spot market price;
- reducing dispatch risk and so improving liquidity in the contract market;
- improving certainty of revenue and so facilitating investment; and
- exposing new entrants to the network cost consequences of their connection decisions.

The effect of weak locational signals is to reduce certainty of disptach as new entrants are not exposed to the costs that they impose on incumbent generators as a result of their locational decisions. Consequently new entrants may locate in areas that result in incumbent generators being constrained off.

Generators consider that there has been insufficient transmission investment to support new entry by generators,[6] which compounds the problems associated with weak locational signals. These generators maintain that transmission investment should match the preference of new generation investment.[7] While this may result in a level of transmission investment would not pass the RIT-T,[8] generators may be prepared to provide the necessary additional funding in return for financial access rights.

4 NGF, Energy White Paper, Submission, p.7.

5 NGF, Energy White Paper, Submission; NGF, 2nd Interim Report, Submission; AGL, Hydro Tasmania, International Power, Loy Yang, TRUenergy, 2nd Interim Report, Submission.

6 AGL, Hydro Tasmania, International Power, Loy Yang, TRUenergy, 2nd Interim Report, Submission, p.14.

7 NGF, 2nd Interim Report, Submission, Appendix A, p.6.

8 AGL, Hydro Tasmania, International Power, Loy Yang, TRUenergy, 2nd Interim Report, Submission, p.19.

However, we note that other stakeholders, including generators, disagree that changes to the frameworks are required. Snowy Hydro submitted that TNSPs already have sufficient incentives to build out transmission congestion.[9] They also consider that the NEM does not need further refinements to existing locational signals.[10]

While many other stakeholders commented on the G-TUOS proposal, they did not specifically address the underlying nature of the problem.

Questions for discussion:

1. Do you agree that locational signals need to be improved?
2. Have we correctly characterised stakeholders' views? How are the additional issues identified by stakeholders related to locational signals?

9 Snowy Hydro, 2nd Interim Report, Submission, p.2.

10 Snowy Hydro, 2nd Interim Report, Submission, p.3.

4 What are the possible solutions?

This section reviews the draft recommendation that a form of G-TUOS be introduced. It then addresses the issues and considerations associated with the design of alternative mechanisms for providing a locational signal for generation that reflects the long run cost imposed on the network. These include:

- the rationale for exposing generators to a long run cost signal;
- the different forms of a mechanism for signalling long run cost;
- the relationship between a long run cost signal and network planning and investment; and
- how long run cost should be measured and the issues to be considered.

4.1 Generator transmission use of system charges

The 2nd Interim Report proposed a package of measures to address the problems previously described. First, it proposed the introduction of an ongoing transmission price for generators that would be designed to signal the relative long run cost imposed by generators entering or continuing to use the network in different locations (referred to as G-TUOS charges in the 2nd Interim Report). It also discussed a number of possible attributes and issues to be resolved for the design of those prices.

Second, the 2nd Interim Report canvassed the relative merits of introducing a time-limited and location-specific congestion pricing mechanism and associated risk management instrument to complement the long term pricing signal. The AEMC noted that a long term signal would likely be more effective but posed this complementary measure as a short term solution until the long term signal took effect. While this is an important and related issue it is not the primary focus for this Agenda Paper and the Industry Forum.

The Commission’s draft proposal to introduce a form of transmission price for generators stimulated substantial interest amongst market participants. There was quite broad support across generators and customers for introducing a form of locational signal for generators that would signal the long term costs they cause.

However, there was substantial criticism of the form of the proposed charge. Many generators expressed the view that the signal should be provided by means of an upfront charge on new generators rather than an ongoing charge applied to all. Similarly, generators commented that a charge that could change over time would create uncertainty and therefore discount the effectiveness of the price signal.

In addition, generators suggested that the introduction of long term locational signals should be accompanied by measures to improve the certainty of dispatch for existing generators. This could be achieved through accelerating the build-out of constraints and introducing a mechanism that will compensate generators where network congestion (rather than network elements being unavailable) causes them to be constrained down. Stakeholders also commented on other aspects of the design options posed in the 2nd Interim Report.

4.2 Rationale for a price signal that reflects long run cost

One of the themes present in a number of submissions – and most notably in submissions from the majority of generators – is that it is appropriate for transmission investment to follow the locational decisions of generators. That is, generators decide which technology to construct and when and where to locate, and then transmission investment should follow.

While the AEMC does not consider the proposition that transmission should be 'passive' to be appropriate in all situations,[11] this description may well characterise the sequence of much of the transmission investment. A supporting paper to the 2nd Interim Report by Dr Biggar highlighted the difficulties with transmission pre-empting efficient generation entry in liberalised markets, including creating an information challenge for the transmission planner.[12]

The potential for transmission investment to follow decisions of generators makes it important that generators have the incentive to invest in the appropriate type of plant and to locate in the most efficient site, having regard to the network costs their location decisions will impose. Efficiency in this regard means that the combined cost of generation and subsequent transmission costs should be minimised.

The purpose of a price signal to generators that reflects the long term cost is to encourage generators to take account of transmission costs when making their decisions. In the absence of such a price signal, there is the potential for the combined cost of generation and transmission to be higher than is efficient, as well as for unnecessary network congestion to arise in the short term.

For such a pricing signal to improve efficiency, it would need to be of a level to change generators' decisions given the other factors that may affect the type and timing of their investment. These include access to fuel and generation sites.

The AEMC recognised that non-price signals strongly influence generator location decisions. However, as noted in the 2nd Interim Report, renewable plant may have a choice of location at the margin. Gas plant is also flexible in its location, effectively trading off use of the electricity network for the gas network. Timely retirement decisions may free up scarce capacity (this matter is discussed further below), which may be influenced by such a long term price signal. Ultimately, however, the potential for the long term cost signal to alter behaviour is an empirical matter.

11 In particular, the AEMC has stated that the option should exist for connections to remote generators to be built with spare capacity to meet future (prudently forecast) new generation entry, which is reflected in the 'NERG' proposal.

12 Biggar, D. 2009, *Framework for Analysing Transmission Policies in the Light of Climate Change Policies*, Final, June 2009, p.30.

4.3 Mechanisms for signalling long run cost to generators

As noted above, the form of the long term price signal proposed in the 2nd Interim Report was an ongoing charge levied on generators that reflected an estimate of the long run marginal cost at the relevant location. This form of charge was supported by user groups. In contrast, the major generators expressed a preference for a requirement on new connecting parties to make an upfront capital payment, or "deep connection charge".

In principle, both of these approaches could deliver the same locational price signal to a generator. (That is, if the same approach was used under each charging mechanism to calculate the generator's contribution to long run cost).[13] The main differences between the two charging mechanisms are:

- *Range of generator decisions influenced* – whereas an upfront connection charge will affect generators' entry decisions on the type and location of plant, an ongoing price will also influence the subsequent decision of whether to keep generation plant in service; and

- *Stability of price signal* – whereas an upfront charge is known at the time that an investment is made, an ongoing price has the potential to change over time. This may affect the extent to which participants will respond to the price signal.

Turning to the *range of decisions influenced*, the 2nd Interim Report noted that new entry could be accommodated on a congested network either by expanding transmission capacity or by an existing network user ceasing to generate and retiring its plant. Retirement of existing plant would be an efficient outcome if the value to the market from the generator continuing in service was less than the long term network cost.

Exposing generators to the long run network cost they cause would encourage them to consider its effect on the network when making such decisions. However, again, it is ultimately an empirical question about whether a well-designed locational price signal would be a decisive factor in generators' retirement decisions.

Turning to the *stability of the price signal*, the Commission noted in the 2nd Interim Report that there is a trade-off with respect to the stability of the price. A stable price is more likely to give participants confidence to invest. However, if prices are held artificially stable then the improvement in efficiency of decisions to continue to use the network or retire plant – which is the decision that is targeted by the long term price signal – will not eventuate.

If further assessment suggests that the price signal is likely to be unstable over time, an option would be to explore the possibility of creating a financial device for generators to hedge the future generation transmission price. The objective of such a

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13 The 2nd Interim Report discussed a number of practical issues associated with the calculation of deep connection charges using the method that was proposed by the major generators. This matter is addressed in the discussion of measuring long run cost below. The AEMC also observed that deep connection charges could form a barrier to entry.

device would be to permit a generator to lock-in its transmission price for an extended period, providing it with a transmission price hedge. If the instrument was tradeable, the generator would be expected to continue to take account of the most recent estimate of the long run cost that is caused in a particular location, while also having greater certainty over its long term cash flow.

To illustrate the above, at specified intervals a generator could be provided with an option either to pay an annual transmission charge that may vary over time, or to elect to pay a charge that is fixed for an extended period (for example, for 10 years). If transmission prices were subsequently to rise, the generator would continue to pay the fixed price for the period of the price hedge. However, the hedge would now be valuable (as it would give a right to pay a transmission charge that is lower than the prevailing price) and the generator would take account of the value of the hedge (and implicitly the prevailing transmission price) when deciding whether to retain plant in service or to retire that plant.

4.4 Certainty of dispatch

A theme in the submissions of several major generators was that a link should be drawn between the introduction of locational price signals for generators and the augmentation of the network to remove intra-regional constraints. These generators consider that the current arrangements for network augmentation provide little certainty about whether and when the network would be augmented to alleviate intra-regional constraints.

Part of the proposal for upfront deep connection charges was that the network would be augmented to alleviate constraints that a new entrant may cause. Similarly, some generators suggested that generator transmission charges could be designed to make a net contribution to revenue, with the proceeds used to fund supply side network augmentation. However, these proposed solutions would imply that additional network augmentation over and above the efficient level determined by the RIT-T is required.

As discussed in the previous section, the Commission noted in its 2nd Interim Report that there have been substantial reforms to the arrangements for delivering long term transmission capacity which remain to be fully implemented and tested. The Commission considers that these reforms should be given time to work before further change is considered. Its current view is that this framework should be effective in supporting efficient levels of long term transmission investment.

4.5 Calculation of long run cost

The technical characteristics of transmission networks mean that any system of long run charges is likely to involve a number of practical difficulties and compromises.

As noted above, many generators support charging new entrants for augmentations that are required to resolve any constraints that are caused as a result of their locational decision. However, as the Commission noted in the 2nd Interim Report, such a charging scheme is unreasonable where capacity comes in large lumps and augmentations typically would provide benefits to subsequent generators. Indeed, the proposition that a new generator would use existing spare capacity for free – but pay for the next augmentation if they cause a constraint – is likely to create an incentive for generators to delay entering until another party has funded the augmentation. This would not be consistent with the NEO.

An alterative method for estimating long run cost is based on the proposition that the entry and continued use of a network by a generator would cause the stream of future planned efficient augmentations to be brought forward. The additional cost (in present value terms) that is caused by a small increment of use of the network provides an estimate of the long run marginal cost caused by that use at that time.[14]

A benefit of this approach to defining long run cost is that it would be sensitive to the level of congestion on the network.[15] However, this definition of cost requires the credible forecasting of future network augmentations. It would also be more likely to generate charges that vary over time and may create ambiguous price signals if the size of generation entry is sufficient to cause a major change to charges.

A further alternative method for estimating long run cost would be to focus on the cost that would be caused over the long term, assuming that assets would be constructed today. This definition of long run cost would not be sensitive to the level of spare capacity on the network at any point in time, but would have the advantage of being stable. In addition, it would be easier to implement – while it would require an estimate of the additional cost that a unit of demand would cause over the long term, there would be less need for an accurate forecast of the relationship between demand and future augmentations.

Once the preferred method for estimating long run cost is identified, a range of further implementation issues would arise. These implementation issues will depend on the preferred solution, but may include factors such as treatment of spare capacity, the form of any charge (for instance, capacity or energy-based) and scaling to achieve revenue recovery.

Questions for discussion:

3. Should locational signals be improved by reflecting long run costs to generators?

4. If so, how can long run costs best be signalled?

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14 This method for estimating long run marginal cost is widely used for setting the usage or demand based component of energy network charges to final customers, as well as the variable component of water charges.

15 This is because the cost (in present value terms) of advancing an asset that was forecast to occur in year 20 would be lower than the cost of advancing an identical asset by the same period that was forecast to occur in year 10.

5 Principles for assessing possible solutions

This section sets out proposed principles against which the effectiveness of potential solutions to the problems identified could be assessed.

Any solution must promote the achievement of the NEO. However, in addition, we propose that consideration of the following key principles would also be important:

- *efficiency* – the preferred solution should result in outcomes that minimise costs to society, including by promoting effective competition. It should ensure that generators make efficient operational and investment decisions (for instance, in terms of location and retirement), and that appropriate investment in the network takes place in the longer term;

- *cost reflectivity* – any solution should give signals to participants that accurately reflect the forward looking costs they impose;

- *effectiveness* – solutions should be effective in addressing the problem identified, changing behaviour to an appropriate extent given the cost-reflective signals;

- *stability and predictability* – signals should not be volatile and should be reasonably predictable. Stability and predictability are important for providing certainty and ensuring that participants are able to respond to the signals given;

- *transparency* – any solution should be sufficiently transparent to allow an interested party to obtain a reasonable understanding of its derivation, to verify it has been implemented correctly and to assist in predicting future signals; and

- *proportionality* – solutions should be proportionate to the materiality of the problem, should have a positive net benefit, and should not result in unnecessary regulatory complexity or uncertainty.

There will inevitably be some trade-offs between these principles. For example, ensuring cost reflectivity might require the frequent revision of signals. In contrast, the requirement for stability and certainty over the long term implies that signals should be fixed for a reasonable length of time. In balancing such trade-offs the prevailing objective will be the NEO.

While each possible solution will need to be assessed against the agreed principles, it is also important to consider solutions in the context of related aspects of the energy market frameworks. In this instance, these are likely to include network charges and existing locational signals, such as loss factors and regional energy prices.

We recognise that any solution is likely to have significant impacts on both incumbents and new entrants. Consideration of transitional arrangements to move to any new regime will also form a central part of the proposed new work program.

Question for discussion:

Do you agree with the proposed principles? Should other principles be considered?

6 The way forward

The AEMC would like to explore with stakeholders the process for progressing the issues outlined in this paper.

In light of the current state of development of this issue the AEMC does not intend to recommend a rule change in the Final Report to the MCE.

Instead, the recommendation is likely to take the form of a proposal for a new work program to further explore the problem of locational signals and related issues such as certainty of dispatch. Such a work program would involve extensive consultation with industry participants to:

- identify the scope of the work program
- identify the spectrum of possible options for reform; and
- develop a process for assessing the proposed solutions.

Implementation and transitional issues will form an important part of the development of any future work program. Any solution is likely to represent a significant change to the market frameworks. Irrespective of the form of the preferred solution, careful consideration will need to be given to how the reforms can be implemented in practice, including an appropriate transition path to the new regime. We recognise that it is important to minimise regulatory uncertainty and risks to all market participants to promote stability in the market and for investment.

The Commission noted in the 2nd Interim Report that appropriate transitional arrangements would be an important feature of the final package of reforms for introducing any enhanced loactional signal.

Questions for discussion:

6. What issues should be included in the scope of any forward work program?

7. What factors are important to consider in the implementation of any solution?