grid australia
BACKBONE OF THE NEM

3 August 2009

Mr John Tamblyn
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000

Via website: www.aemc.gov.au

Dear John,

Review of Energy Market Frameworks in Light of Climate Change Policies

Grid Australia makes this submission in response to the AEMC's 2nd Interim Report released on 30 June 2009 in relation to its Review of Energy Market Frameworks in light of Climate Change Policies.

In this submission, Grid Australia has focused on the proposals put forward by the AEMC that have direct relevance to the future planning and development of electricity networks. The key area in this regard is the AEMC's proposal in relation to extensions to the network to connect new remote generation (i.e. 'the NERG model'). In summary, Grid Australia's comments in relation to the NERG model proposed by the AEMC include:

- The proposed NERG model represents an appropriate allocation of planning responsibilities between AEMO and NSPs;
- The requirement for NSPs to publish a Standard Contract for a particular NERG zone should be triggered by a generator connection application, rather than a connection enquiry;
- Grid Australia supports the AEMC's proposal that generators should be required to pay an enquiry fee, which should apply to enquiries made by both initial and future connection proponents who respond during the formal enquiry period for a specific NERG zone;
- The framework should ensure that NSPs can recover at least the efficient costs they incur in planning NERG extensions; and
- The proposals to guarantee NSPs cost recovery and to ensure a uniform revenue profile over the life of the NERG assets are appropriate, in order to address stranding risk and facilitate the up-front financing of network investment.

These comments, together with related issues, are set out in more detail within section 2 of the attached submission.

In relation to network utilisation and congestion management, Grid Australia supports the AEMC's proposal to delete the existing Rule 5.4A. Grid Australia considers the benefits of introducing a G-TUOS charge compared to the costs of implementation should be further considered, particularly given the potential for duplication with the locational signals already provided by marginal loss factors. These issues are discussed further in section 3 of the submission.

Finally, Grid Australia provides some comments in relation to the proposals for inter-regional transmission charging (in section 4), including detailed drafting comments in relation to the Draft Specification included as Appendix G of the AEMC's 2nd Interim Report.

Grid Australia notes that the AEMC's final advice to the MCE, due by 30 September 2009, will represent the final step in this review process. To the extent that the AEMC intends to propose Draft Rules as part of its final report that will impact on the operations of TNSPs, Grid Australia would welcome the opportunity to engage with the AEMC in relation to the detail in the proposed Draft Rules, ahead of the final report.

Grid Australia would also welcome the opportunity to discuss any aspect of this submission with the Commission or its staff.

Yours sincerely,

Rainer Korte

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group

Review of Energy Market Frameworks in Light of Climate Change Policies

Response to AEMC 2nd Interim Report

3 August 2009

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1. Introduction

Grid Australia makes this submission in response to the AEMC's 2nd Interim Report released on 30 June 2009 in relation to its Review of Energy Market Frameworks in light of Climate Change Policies.

Grid Australia comprises ElectraNet Pty Limited, Powerlink Queensland, SP AusNet, Transend Networks Pty Ltd and TransGrid. Collectively, this group owns and operates over 40,000 km of high voltage transmission lines and has assets in service with a current regulatory value in excess of $10 billion.

In this submission, Grid Australia has focused on the proposals put forward by the AEMC in its Report that have direct relevance to the future planning and development of electricity networks. The key area in this regard is the AEMC's proposal in relation to extensions to the network to connect new remote generation (i.e. 'the NERG model'). In summary, Grid Australia has the following comments in relation to the NERG model proposed by the AEMC:

- The proposed NERG model represents an appropriate allocation of planning responsibilities between AEMO and NSPs;
- The requirement for NSPs to publish a Standard Contract for a particular NERG zone should be triggered by a generator connection application, rather than a connection enquiry;
- Grid Australia supports the AEMC's proposal that generators should be required to pay an enquiry fee, which should apply to enquiries made by both initial and future connection proponents who respond during the formal enquiry period for a specific NERG zone;
- The framework should ensure that NSPs can recover at least the efficient costs they incur in planning NERG extensions;
- The proposals to guarantee NSPs cost recovery and to ensure a uniform revenue profile over the life of the NERG assets are appropriate, in order to address stranding risk and facilitate the up-front financing of network investment; and
- The five yearly reviews of Standard Contracts for NERG assets provide appropriate incentives for efficiency and should not be aligned, either with each other or with the review process for prescribed services (for the reasons set out in section 2.7).

These comments, together with related issues, are set out in more detail in section 2 of this submission.

In relation to network utilisation and congestion management, Grid Australia supports the AEMC's proposal to delete the existing Rule 5.4A. Grid Australia considers the benefits of introducing a G-TUOS charge compared to the costs of implementation should be further considered, particularly given the potential for duplication with the locational signals already provided by marginal loss factors. These issues are discussed further in section 3 of this submission.

Finally, Grid Australia provides some comments in relation to the proposals for inter-regional transmission charging (in section 4), including detailed drafting comments in relation to the Draft Specification included as Appendix G of the AEMC's 2nd Interim Report.

Grid Australia notes that the AEMC's final advice to the MCE, due by 30 September 2009, will represent the final step in this review process. To the extent that the AEMC intends to propose detailed Draft Rules as part of its final report that will impact on the operations of TNSPs, Grid Australia would welcome the opportunity to engage with the AEMC in relation to the detail in the proposed Draft Rules, ahead of the final report.

2. Extensions to the Framework to Connect Remote Generation

Grid Australia notes that the AEMC is recommending the adoption of a new regulatory framework to cover extensions of the network to connect remote generation. Grid Australia understands that the AEMC's intention is that a new type of network service in relation to Network Extensions for Remote Generation (i.e. NERGs) will form a sub-set of 'negotiated services' under the National Electricity Rules ('the Rules').

The recommended framework (the 'NERG model') is based on the AEMC's previous Option 2, as set out in the AEMC's 1st Interim Report. Grid Australia has previously indicated its support for Option 2, although it noted that it is important that the rate of return on NERG investments remains attractive relative to the actual cost of capital.[1] This remains a fundamental pre-condition to ensuring the delivery of the required network investment.

The AEMC has now provided further detail in relation to the proposed NERG model.

Grid Australia's key comments in relation to the proposed NERG model can be summarised as follows:

1. The proposed NERG model represents an appropriate allocation of planning responsibilities between AEMO and NSPs;
2. The requirement for NSPs to publish a Standard Contract for a particular NERG zone should be triggered by a generator connection application, rather than a connection enquiry;
3. Grid Australia supports the AEMC's proposal that generators should be required to pay an enquiry fee, which should apply to enquiries made by both

[1] Grid Australia, *Review of Energy Market Frameworks in Light of Climate Change Policies, Response to AEMC 1st Interim Report*, 20 February 2009, p. 4.

initial and future connection proponents who respond during the formal enquiry period for a specific NERG zone;

4. Grid Australia supports the AEMC's proposal that Standard Contracts should only be required where forecasts following the formal enquiry period indicate that there is likely further connection interest;

5. The framework should ensure that NSPs can recover at least the efficient costs they incur in planning NERG extensions (as required by the National Electricity Law);

6. The proposed process for the review of Standard Contracts is broadly appropriate, but could be improved by some minor modifications;

7. The proposals to guarantee NSPs cost recovery and to ensure a uniform revenue profile over the life of the NERG assets are appropriate in order to address stranding risk and facilitate the up-front financing of network investment; and

8. The five yearly reviews of Standard Contracts for NERG assets provide appropriate incentives for efficiency and should not be aligned, either with each other or with the review process for prescribed services (for the reasons set out in section 2.7).

The remainder of this section expands on these points. Responses to the specific questions raised by the AEMC in relation to NERGs in the 2nd Interim Report are set out in section 2.9.

2.1 Allocation of planning responsibilities for NERGs

Grid Australia notes that the AEMC's proposed framework for NERGs builds on the sound governance framework embodied in the existing regulatory framework, including the recently developed governance arrangements for the National Transmission Planner (NTP). Grid Australia considers it appropriate that the strategic role in identifying NERG zones lies with AEMO, while NSPs retain responsibility for planning extensions to NERG zones, both at an indicative level in the Annual Planning Reports (APRs) and also at a detailed level in response to specific connection enquiries. Grid Australia notes that, while the AEMC refers to the role for NSPs as the 'design component' of the planning framework, the role includes all of the necessary network investment planning that needs to occur before detailed design of the preferred development option.

In identifying NERG zones, AEMO will need to come to a view on the amount of possible generation capacity in different areas.[2] The AEMC notes in its Report that AEMO is already required in developing the National Transmission Network Development Plan (NTNDP) to consider credible generation supply scenarios.[3] The

[2] AEMC, 2nd Interim Report, p. 16.

[3] Op cit, p. 17.

AEMC is proposing that AEMO also be required to consider and consult on scenarios of large generation supply capacities remote from the shared network, as part of developing the NTNDP (and, presumably, the National Transmission Statement in 2009). Grid Australia supports this proposal.

As part of the development of a Standard Contract for a particular NERG zone, NSPs will be required to develop their own forecast of the likely future development of generation in that zone. In developing this forecast, the NSPs will be able to draw on AEMO's initial forecasts, updated to reflect interest that has been revealed as part of the formal notice period following an initial generator enquiry. Grid Australia notes that, under the NERG model proposed by the AEMC, AEMO then has a further role in relation to the reasonableness of the NSPs' generation forecasts. The public notice process also provides a basis for the NSP generation forecast. Grid Australia considers that the proposed transparency and consultation around AEMO's initial (as part of the NTNDP) generation forecasts for each NERG zone will assist in ensuring that the proposed model works effectively, and that the later NSP forecasts can build on this information.

Grid Australia notes that the criteria adopted by AEMO in identifying NERG zones will need to consider the extent to which future generating capacity in an area is expected to be developed by independent generating businesses. It would seem inappropriate for customers to underwrite development risks for a single generator, where that generator structures its business as a series of generation developments to qualify for consideration under the NERG framework.

2.2 Trigger for NSPs to publish a Standard Contract

The model proposed by the AEMC in its 2nd Interim Report requires an NSP to prepare a Standard Contract following a connection enquiry from a generator to locate in an area that has been identified by AEMO as a NERG zone,[4] provided that forecasts and the level of formal inquiries indicate likely future connection interest.[5]

2.2.1 Trigger should be related to a connection application rather than an enquiry

Grid Australia considers that it would be more appropriate for the NSP to be required to prepare a Standard Contract following a formal connection application from a generator intending to locate in a NERG zone.

Under the Rules, generators must make a connection enquiry before they can make a connection application.[6] However, connection enquiries need not result in a formal connection application, and in practice many enquiries do not proceed to the formal application stage. Generators may make a connection enquiry on a speculative basis

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4 Page 17 of the 2nd Interim Report states that NSPs need to publish a Standard Contract for each NERG. However, the process set out in Appendix F only requires a Standard Contract to be published following a connection enquiry. Grid Australia has confirmed with the AEMC that its intent is the latter.

5 AEMC 2nd Interim Report, Appendix F, p. 160

6 NER 5.3.2(a)

in order to find out more information, including in relation to connection requirements at different locations. For example, TransGrid states that more than half of its connection enquiries to date have not proceeded to a conforming connection application.

In response to a generator enquiry, NSPs are required to provide a range of information as set out in Rule 5.3.2. This information may determine whether the generator decides to proceed to lodge a formal connection application for that location. Requiring an NSP to prepare and publish a Standard Contract in response to an enquiry is likely to be inefficient, given that enquiries do not necessarily move to the next stage of a connection application for that particular location and timing.

Grid Australia notes that the AEMC is proposing that NSPs may charge enquiring generators a fee,[7] to recover any necessary costs and limit the scope for speculative or vexatious enquiries. Grid Australia supports this proposal. Among other matters, the number of enquiries supported by a fee, which could be developed as an 'option to participate' fee would inform the level of genuine interest in the future development of a generation zone.

Again, it would be more appropriate for the requirement to publish a Standard Contract to be triggered by a connection application. Grid Australia notes that a generator is not bound to accept a connection offer made following such an application, and so would not be 'locked in' to accepting the offer before the price in the Standard Contract had been published.

Under this revised trigger, following a connection enquiry the NSP would still be required to publish a notice inviting further enquiries by a specified date, as per the model set out by the AEMC.

2.2.2 No requirement to publish a Standard Contract where forecast limited to a single generator

Grid Australia notes that under the AEMC's proposed NERG model, an NSP is only required to develop and publish a Standard Contract 'if a generator enquiry has been made and forecasts indicate likely future connection interest'.[8] In the event that the NSP considers that there is unlikely to be future connection interest, the generator's application would be progressed under the existing bilateral arrangements for connection and extension rather than under the NERG framework.

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7 AEMC 2nd Interim Report, Appendix F, p. 160

8 AEMC 2nd Interim Report, Appendix F, p. 160.

2.3 Generators Pay an Enquiry Fee to Indicate Genuine Interest

The AEMC is proposing that NSPs may charge enquiring generators a fee,[9] to recover any necessary costs and limit the scope for speculative or vexatious enquiries.

Grid Australia strongly supports this proposal, and considers that it should apply to generator connection enquiries from both initial and future connection proponents who respond during the formal enquiry period relating to a particular NERG zone. The fee could in effect be a non-refundable option for the generator to be considered in the planning of the particular NERG. The number of generators paying such fee would also inform the 'forecasts' used to determine the future optimum size of the NERG.

This will assist in demonstrating that a generator's enquiry is genuine, which in turn will allow greater weight to be placed on that generator's enquiry in developing the forecast of future generating capacity in that NERG zone. Absent an enquiry fee, it is more likely that generators would indicate their potential interest in multiple NERG zones, when in reality their generation project might only proceed in one NERG zone, if at all.

2.4 Recovery of NSPs' costs in planning NERG extensions

The National Electricity Law requires that NSPs be able to recover at least the efficient costs they incur in meeting regulatory obligations. The mechanism(s) for cost recovery of the planning of NERGs should be specified by the AEMC as part of the detailed arrangements under the NERG framework.

The costs of providing indicative planning estimates in relation to all NERG zones in the TNSPs' APRs should be able to be recovered through regulated revenue for prescribed services as the requirement to undertake and publish this indicative planning represents a new regulatory obligation imposed on TNSPs.

The costs associated with the development of a Standard Contract to a particular NERG zone should in the first instance be recovered from the proposed connection enquiry (or 'option' to participate) fees referred to above. These costs include those associated with the detailed planning of the extension and with the regulatory process under which the Standard Contract is assessed.

In the event that the connection enquiry fees and any subsequent connection application fees are insufficient, there should be provision for the NSP to recover the costs of developing the Standard Contract.

However, Grid Australia considers that circumstances may arise where it may not be appropriate to charge initial applicants in relation to costs specifically associated with planning a larger sized NERG asset to accommodate future generation. In the event

9 AEMC 2nd Interim Report, Appendix F, p. 160.

that connection enquiry and application fees do not recover all of the TNSP's costs in developing a Standard Contract, there should be provision for the remainder to be recovered through the TNSP's regulated revenue.

2.5 Process for assessment of Standard Contracts

In general, Grid Australia members have found that intending generators are faced with commercial imperatives to move to connection fairly quickly once key approvals are locked in. Reducing the time frames for approving the Standard Contract is expected to become an important issue in removing impediments to remote generation connection.

In relation to the process for assessment of NSPs' Standard Contracts in relation to particular NERG zones, Grid Australia notes that the proposed timeframe is:

- 30 business days following the NSP's publication of the Standard Contract for disputes to be lodged and for the AER to receive from AEMO a review of the NSP's generation forecasts; and

- a further 40 business days for the AER to assess the Standard Contract (where applicable)

The overall timeframe for assessment is therefore 70 business days (approximately 14 weeks) in total. Grid Australia considers this timeframe could be somewhat shortened by allowing a period of 30 business days for the AER to assess the Standard Contract. This would be consistent with the time period allowed under the current Rules for the AER to assess a TNSP's contingent project application.[10]

Under the detailed specification of the NERG model set out in Appendix F of the 2nd Interim Report, the AER is required to indicate its intent to make a determination on the Standard Contract within 5 business days of a dispute being lodged. To accommodate the situation where more than one dispute is notified, Grid Australia considers that the process would be better streamlined if this requirement was changed to require the AER to indicate its intent within 5 business days of the end of the 30 day period within which disputes may be lodged.

Grid Australia notes that under the proposed detailed specification, the AER can only make a determination on the Standard Contract either if a party disputes the content or if there is an adverse finding from AEMO in relation to the NSP's forecasts of future generation. Grid Australia considers that this approach is appropriate, and that there should not be an automatic review role for the AER, consistent with the underlying arrangements for negotiated transmission services.

Grid Australia considers that it would improve transparency and further streamline the process for developing Standard Contracts if the AER is required under the Rules to develop a guideline as to how it intends to assess Standard Contracts in the event that it is required to make a determination. Currently the specification provides the

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10 Rule 6A.8.2(d).

AER with the option of developing a guideline,[11] but does not require it to do so. The AER's guideline should be developed in accordance to the transmission consultation procedures set out in Rule 6A.20.

2.6 NSPs to be guaranteed cost recovery and a uniform revenue profile

Grid Australia strongly supports the AEMC's proposal for the risks of under- or over-utilisation of the NERG assets to be borne by the ultimate beneficiaries of the arrangements, and for NSPs to be guaranteed cost recovery.[12]

Under the proposed NERG model, the trigger for the construction of the NERG assets is that at least one generator signs the Standard Contract for that NERG zone.[13] Generators are able to sign the contract once the AER has decided that its contents will not be disallowed. Grid Australia notes that the AEMC has decided not to include a requirement that a minimum proportion of the NERG assets be paid for by foundation generators.[14]

Grid Australia also strongly supports the proposal for the profile of the revenue stream received by NSPs to be uniform over the economic life of the NERG asset. The AEMC recognises in its report that there is a very real issue in relation to the up-front financing of network investment.[15] The proposal for a uniform revenue stream will go some way to addressing this issue.

The requirement for a uniform revenue stream means that there will need to be a mechanism for making transfer payments between customers and the NSP, over the life of the NERG assets.[16] Any under- or over- utilisation of the NERG assets compared with that which was forecast at the time at which the Standard Contract price was established would be reflected in payments between customers and the NSP. Grid Australia understands from the AEMC that the mechanism envisaged for facilitating these payments between the NSP and customers is a general adjustment to TUOS or DUOS charges (as appropriate). In the case of TUOS charges this implies that an additional term will need to be added to the MAR formula, to facilitate this approach. This is consistent with revenue under and over recovery arrangements such as is currently required to manage for example inter-regional settlements residue proceeds.

Grid Australia also notes that under the framework set out by the AEMC, NERG services are a form of negotiated service and the NSP and generators are free to

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11 AEMC, 2nd Interim Report, Appendix F, p. 162.

12 AEMC, 2nd Interim Report, p.19.

13 ibid

14 ibid

15 AEMC, 2nd Interim Report, p. 20.

16 This is reflected in the AEMC's discussion in the first part of Appendix F, 2nd Interim Report.

agree variations to the Standard Contract.[17] These variations may include (but are not limited to) service performance above the minimum provided in the Standard Contract, differences in the construction timetable, the agreement of a fixed price for the duration of the contract (i.e. rather than the price being subject to the outcomes of the five yearly review process) and any extension to the time period beyond that covered by the Standard Contract. Any additional payments made by the generator and/or additional costs incurred by the NSP as a result of these negotiated differences would not need to be disclosed to the AER. Rather any such payments would be treated as 'excluded income' and would not be taken into account in calculating the appropriate transfer payments from customers, which are based on the Standard Contract price. These provisions are appropriate and are supported by Grid Australia.

2.7 Five yearly review of Standard Contracts

Grid Australia notes that the AEMC is proposing that the price in the Standard Contract for each NERG would be reviewed every five years. The prices would be adjusted to reflect actual outturn capex (including replacements), revised opex forecasts for the next five years and changes in the regulatory WACC.

Grid Australia notes that under this proposed framework, TNSPs would wear the cost (or retain the gain) of any capex or opex in relation to NERG assets in excess of (below) the initial forecasts at the time of the previous contract review.[18]

Grid Australia considers that this approach provides appropriate incentives for NSPs to try to achieve efficiencies, both in relation to the initial capital investment and in relation to on-going opex. Where generators wish to avoid any exposure to actual outturn costs, they would be free to negotiate with the NSP an arrangement that would allow them to receive a fixed price for the duration of the contract. Such an arrangement would be outside the standard contract.

The 2nd Interim Report is silent on whether there should be alignment between the periodic review for NERG assets and the periodic review of the NSP's prescribed services. Grid Australia does not support such alignment. Rather, the review process for each NERG Standard Contract should be undertaken every five years from the date on which the relevant NERG assets are commissioned.

This approach may result in a slightly higher administrative burden on both NSPs and the AER in undertaking reviews of the NERG Standard Contracts at different times, and separate from the review process for prescribed services. However, any attempt to align the review periods would result in the period before review differing between Standard Contracts, and being shorter than five years in some instances. This would have implications for the overall strength of the incentives for efficiency discussed above, and the balance of those incentives between different NERG extensions.

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[17] AEMC, 2nd Interim Report, p. 20.

[18] Grid Australia notes that the risk-sharing described above does not result in generators bearing all over-run risk under the Standard Contract, as stated in the AEMC's 2nd Interim Report, page 20.

Where the AER disallows changes to the Standard Contract at the five yearly review, the NSP would need to revise and re-submit its proposal. Grid Australia understands that the existing prices in the Standard Contract would continue until new prices are approved by the AER. The AEMC has not proposed that the AER would have the right to substitute its own pricing statement. Grid Australia considers that the proposed approach is appropriate.

Grid Australia considers that a shorter timeframe than the 70 business day period allowed for the initial review of the Standard Contract would be appropriate for five yearly reviews.

2.8 Other issues

Grid Australia notes that if the proposed NERG model has a role to play in helping to achieve climate change policy targets then there is a need for the NERG model to be implemented as soon as possible, given the lead times for significant transmission investment. One option that could help with this is that while AEMO must first identify a NERG zone before a NERG can be progressed to the planning stage, it should be possible to do this without having to wait for the NERG zone to be published in the next annual NTNDP.

The NERG model should clearly set out the arrangements that are to apply to generators that have lodged connection applications in areas that AEMO has not designated as NERG zones but that later become designated by AEMO as NERG zones, prior to a connection agreement being signed by the generator. In particular, the model should make clear whether the NSP would be required to treat the re-classification as then triggering the NERG process for that area and to re-run planning studies on this basis to derive a Standard Contract. Alternatively, connection applications that had begun to be processed could be made exempt from the process and could continue under the existing bilateral connection process.

Grid Australia notes that this issue will arise in relation to connection applications lodged prior to the initial introduction of the new NERG framework and the first classification of NERG zones by AEMO. However, it may also arise on an on-going basis, as the areas classified as NERG zones may change over time to reflect changing expectations as to the commercial feasibility of future generation development.

Grid Australia notes that under the AEMC's proposed framework, generators can connect until the capacity of the NERG extension is reached. The AEMC then raises the possibility of three options for additional generators:[19]

(i) agreeing to be constrained-off when capacity is fully utilised;

(ii) paying compensation to other generators if they are constrained-off; or

(iii) funding an augmentation to the NERG.

[19] AEMC, 2nd Interim Report, Appendix F, p.163.

Grid Australia notes in relation to the first of these options that there would need to be a role for AEMO, as the market operator. There are examples of 'run-back' schemes that have been imposed to date for a small group of wind generators in South Australia and Tasmania, in co-ordination with the relevant TNSP. However, these arrangements should be considered the exception as it is not the role of NSPs to get involved with issues affecting market dispatch.

Finally, Grid Australia notes that the NERG model needs to cover what happens in the event that either:

- the NERG extension becomes used to provide shared network services; or
- a customer connects to the NERG extension, but the extension is not considered to become part of the shared network.

In the 2nd Interim Report, the AEMC indicates that the NERG model should cater for these circumstances consistent with the existing framework for negotiated distribution or transmission services.[20] Under Rule 6A9.1(6):

> "the price for a *negotiated transmission service* should be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment should reflect the extent to which the costs of that asset is being recovered through charges to that other person."

The point here is that the NERG Rules need to cover both of the situations described above, whereas currently the AEMC's drafting combines the two.

2.9 Response to specific AEMC questions

This section summarises Grid Australia's response to the specific issues raised by the AEMC in the 2nd Interim Report in relation to the NERG model.

(2a) Will the recommended model adequately address the deficiencies in the existing framework?

Grid Australia considers that the model will address the issues identified in relation to ensuring that extensions of the network to remote generators are sized appropriately. The model allows for improved co-ordination of generator connections in the same area and also ensures that NSPs are not exposed to stranding risk if the expected future generation does not in fact materialise.

Grid Australia notes that further improvements to the existing framework that are likely to address concerns in relation to the co-ordination of multiple connection applications more generally (ie, not only in remote areas) are:

20 AEMC, 2nd Interim Report, Appendix F, p.164. Note that it appears that the reference to 'shared connection services' in the first sentence is instead intended to be a reference to 'shared network services', consistent with the second sentence.

- the Grid Australia proposal to modify clause 5.3.8 of the Rules (the practicality NERG concept relies on open information and as minimum the proposed Rule change being made);21
- implementing the Reliability Panel's proposed 'top down' approach to establishing generator performance standards.

(2b) Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

Grid Australia considers that the proposed allocation of planning responsibilities between AEMO and NSPs is appropriate, with AEMO focusing on strategic issues whilst NSPs have responsibility for the 'design component' (which is taken to include investment planning) in relation to NERG extensions. See discussion in section 2.1.

Grid Australia notes that the NSP's forecasts of future generation and of the costs of the NERG extension will have oversight by AEMO and the AER.

(2c) Is there merit in allowing rival service providers to deliver network extensions for remote generation?

The framework for NERG's set out in the 2nd Interim Report assumes that NERG extensions are non-contestable. The extensions are proposed to fall within the Rules category of negotiated services and to be based on the existing connection framework that NSPs are obliged to follow to establish new connection to the network.

The proposed model would need to be substantially revised if NERG extensions were to be made contestable. Presumably under a contestability model the contestants could make their own decisions about the rates of return etc. they seek.

Notwithstanding the above points, Grid Australia notes that there is already provision for contestability for network augmentations where there is effective competition (e.g. dedicated extensions to new customers and generators in Victoria). Accordingly, the NERG model should not cut-across this approach and preclude contestability for NERG extensions.

3. Efficient Utilisation and Provision of the Network

The second area of the AEMC's review that is of most relevance to TNSPs is that relating to the efficient utilisation and provision of the transmission network.

Grid Australia notes that the AEMC's recommendations in this area in its 2nd Interim Report are focused on the following:

- the introduction of a G-TUOS charge to provide improved locational signals to generation, designed to be revenue neutral;

[21] Grid Australia Rule Change Proposal: Confidentiality Provisions Clause 5.3.8, 20 February 2009.

- the potential introduction of a short-term congestion-charging mechanism, focused on localised and time-limited intervention; and

- that the current provisions of Rule 5.4A be deleted, as the AEMC considers that they do not work.

Grid Australia's comments in relation to the first and last of these recommendations are set out below. Grid Australia's responses to the specific questions in the AEMC's 2nd Interim Report are given in section 3.3

3.1 G-TUOS

Grid Australia notes that the AEMC is proposing to introduce G-TUOS charges, in order to provide improved locational pricing signals to generators. TNSPs would be required to calculate and administer the proposed pricing regime.

Under the AEMC's proposal, the G-TUOS charge is intended to reflect the forward looking long run incremental network costs in particular 'zones' (which are to be determined). Charges would be calculated as a fixed charge per kilowatt of generating capacity and would be set on an annual basis. The G-TUOS charge is intended to be revenue neutral in aggregate, ie, positive charges for generators in locations which require network expenditure and negative charges (ie, payments) for generators who locate in areas that alleviate future network costs. Payment of G-TUOS is not intended to result in a firm access right.

The introduction of G-TUOS represents a significant change to existing frameworks, which may be more than proportionate to the issue being addressed. Grid Australia considers that further consideration by the AEMC of the benefits expected from this change compared to the costs of implementation is therefore warranted.

In particular, Grid Australia notes that there are existing signals for generator location provided by forward-looking marginal loss factors (MLFs).

Under the existing wholesale market rules, generators receive the price at the relevant regional reference node for their output, multiplied by the MLF applying to that generator. Purchasers then pay the price at the regional reference node multiplied by the MLF applying at their location. Because prices are determined using marginal losses and energy volumes are determined from actual losses there is an over-recovery of money that results in positive settlement residue. This is passed to the TNSP in that region and then taken into account in calculating TUOS charges (effectively reducing the TUOS charges that would otherwise apply). MLFs provide a locational pricing signal to generators to locate in areas where the MLF is closer to (or even greater than) one, and not to locate in areas with an MLF significantly below one. The strength of the locational pricing signal provided by MLFs is expected to increase as a result of climate change policies. Specifically, an increase in spot prices following the introduction of the CPRS would result in an increase in the absolute dollar value of the difference between the price a generator receives and the price at the regional reference node.

Although the basis for the calculation of MLFs and G-TUOS is different, they can both be expected to provide locational pricing signals that move in the same direction. It is not clear from the 2nd Interim Report the extent to which the AEMC has considered the potential duplication of locational pricing signals from the introduction of G-TUOS charges alongside the existing MLF arrangements.

In addition, if a generator is seeking connection at a constrained part of the network it is open to that generator to fund the augmentations to relieve congestion as a 'negotiated' service. This would apply where relieving network congestion is not economic under the Regulatory Test (or future RIT-T). This also provides a strong locational price signal.

Grid Australia also notes that the current provision for network support where this is more economic than transmission augmentation also provides a form of price signalling.

In the event that the AEMC in its final recommendations continues to be in favour of the introduction of G-TUOS, Grid Australia notes that the development of Rules in relation to G-TUOS could take one of three forms:

- a high degree of prescription in relation to the methodology and approach to be applied by NSPs;
- a set of broad principles, which provide NSPs with discretion in relation to implementation; or
- an approach that falls within the above two 'extremes'.

On balance, Grid Australia would support the first approach, which provides for a higher degree of prescription set out in the Rules, in a guideline or a pricing methodology approved by the AER. Such prescription lessens the scope for dispute around how TNSPs have derived G-TUOS charges.

Even where the methodology for deriving G-TUOS is specified, Grid Australia notes that the complex nature of the network modelling required to derive charges makes it difficult to demonstrate transparently the basis for particular charges.

Finally, Grid Australia notes that the G-TUOS mechanism is designed to be revenue neutral in principle. However, the revenue cap applying to TNSPs would need to be amended to allow for a 'truing-up' in circumstances in which G-TUOS payments and receipts do not in practice sum to zero in aggregate.

3.2 Deletion of Rule 5.4A

Grid Australia notes that the AEMC is proposing that Rule 5.4A be deleted, on the basis that it does not work in practice.[22]

Grid Australia strongly supports the deletion of Rule 5.4A, and notes that it is a potentially material barrier to new entrants which in the future includes a high proportion of renewable generators, and agrees with the AEMC's assessment that the existing arrangements do not work.

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[22] AEMC, 2nd Interim Report, p. 37.

3.3 Response to specific AEMC questions

(3a) Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?

The AEMC has concluded that providing enhanced incentives for generators is the appropriate approach to dealing with the issue of increased network congestion arising from CPRS and the expanded RET. The AEMC does not consider that the regulatory framework in relation to transmission investment needs to be amended, and notes that the framework for determining the WACC is robust and is not an issue for further consideration in this review.[23]

Grid Australia continues to consider that the arrangements for network augmentation need to be enhanced in response to the increase in network investment that is likely to result from the introduction of CPRS and the expanded RET scheme. However, Grid Australia recognises that these issues are not likely to be considered further by the AEMC in this review.

(3b) Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals?

As discussed in section 3.1, Grid Australia considers that further consideration should be given to the potential for the introduction of G-TUOS to duplicate the locational pricing signals already provided by marginal loss factors.

(3c) Given that G-TUOS is the preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short-term, intra-regional congestion in the most efficient way?

Grid Australia does not have any comments in relation to the proposed congestion pricing mechanism.

4. Inter-regional Transmission Charging

The AEMC is recommending that each TNSP be required to levy a load export charge for flows from its region to an adjoining region. This charge will be levied on the TNSP in the adjoining region. The load export charge will include both the locational and non-locational components of prescribed TUOS together with a prescribed common transmission services charge. This charge will be calculated using the TNSP's approved (or prevailing) pricing methodology as if the load export point was a load connection point.

Grid Australia supports the load export charge method for introducing an inter-regional TUOS charge (as indicated in previous submissions), and offers the following

[23] AEMC, 2nd Interim Report, p. 9.

comments on the practical implementation of the proposed arrangements detailed in the draft specification in Appendix G to the AEMC's report.

Under the proposed arrangements, the maximum allowable revenue (MAR) of the importing TNSP will be adjusted for the estimated load export charges to be levied on it by the adjoining region(s) with this additional revenue requirement being charged to its customers on the basis of their proportionate use of the network assets in the adjoining region(s) via their approved (or prevailing) pricing methodology, to the extent possible.

Grid Australia's concern with the draft specification is the use the term estimated load export charge to refer to both:

- An estimate made based on draft prices calculated <u>before</u> 15 May each year in order to allow the adjoining (importing) TNSP(s) to make an adjustment to its MAR (the first estimate); and

- An estimate made based on final prices calculated <u>by</u> 15 May each year in accordance with the TNSP's approved (or prevailing) pricing methodology which is charged to the adjoining (importing) TNSP(s) (the second estimate).

In addition the draft specification refers to an actual load export charge which would only vary from the second estimated load export charge for those TNSPs that include a metered as opposed to historic energy component in their transmission charging.

The under and over recovery provision in the draft specification is limited to the variance between the second estimate and the actual load export charge charged to the adjoining TNSP.

It is unclear how the likely variance between the exporting TNSP's first estimate used for adjusting the importing TNSP's MAR and the actual charges subsequently charged to the importing TNSP is to be reconciled on a year on year basis.

It is essential that this under and over recovery issue is addressed in the drafting of any subsequent rule change. Grid Australia suggests that the proposed clause 6A.7.5 could be suitably amended to achieve this outcome.

Grid Australia also notes the proposed treatment of connections between regions provided via a market network service provider (MNSP) is that the TNSP is charged not the MNSP. However, a footnote on page 165 notes:

> "Market interconnectors (i.e. Market Network Service Providers) will not be billed a load export charge. Instead, the CNSPs in two regions connected by a market interconnector will directly bill each other the respective load export charges, to the extent that costs have not been charged to the market interconnector."

The qualifying part of this sentence 'to the extent that costs have not been charged to the market interconnector' is unhelpful in clarifying the operation of this clause, as the NER does not presently provide for load export costs for MNSPs.

Grid Australia would welcome the opportunity to discuss these issues in further detail with the Commission.

4.1 Response to specific AEMC questions

Grid Australia's responses to the AEMC's specific questions are set out below.

(4a) Is the proposed design for the load export charge an appropriate and effective mechanism to address the identified problems?

Of the potential options considered for inter-regional transmission charging, Grid Australia maintains a preference for the load export charge approach as this appears relatively more straightforward to implement from a practical perspective.

As a mechanism does not exist for approved pricing methodologies to be amended during regulatory control periods the alignment of the methodology for calculation of load export prices and charges with the TNSP approved pricing methodology is prudent.

(4b) Is the suggested commencement date of 1 July 2011 achievable?

As the AEMC is aware, not all TNSPs are currently subject to the pricing provisions of Chapter 6A of the Rules. The last transitional arrangements conclude in the NEM on 1 July 2012.

While a 1 July 2011 commencement date should be achievable, there will need to be additional transitional provisions in the drafting of the required Rule change to refer to both Chapters 6 and 6A and ensuring that load export charges on either end of a notional interconnector are calculated on a substantially equivalent basis.

5. Innovation Allowance

In chapter 10, which addresses distribution networks, the concept of allowances for approved innovation projects is raised. The AEMC notes (page 101) that that there may be benefit in adopting an explicit framework for the treatment of relevant innovation costs for a limited period and goes on to say that innovative approaches to system operation and maintenance may increase the prospects of efficiency benefits being achieved.

Grid Australia agrees that there is merit in such a model. Given the interrelationship and (in some instances) technical similarity between transmission and distribution networks, Grid Australia considers that such a model is also likely to be appropriate for transmission networks.