grid australia
BACKBONE OF THE NEM

23 September 2011

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

Via website: www.aemc.gov.au

Dear John,

Inter-regional transmission charging discussion paper

Grid Australia welcomes the opportunity to comment on the Commission's discussion paper. A copy of our submission is attached.

Grid Australia's strong preference is that the Commission adopts the original load export charge proposal based on the locational component of prescribed transmission charges only.

Notwithstanding this preference, the members of Grid Australia are prepared to assume responsibility for the implementation of an alternative option, should the AEMC conclude that this would enhance the National Electricity Objective. The only qualification is that the associated implementation and ongoing administration costs are able to be fully included in transmission revenue cap determinations by the AER.

Grid Australia considers that the Options 2 and 3 in the discussion paper are either insufficiently scoped to enable informed comments, or impose an excessive additional administrative burden not offset by any obvious benefits.

The Grid Australia members look forward to continuing to work with the Commission through the further stages of the Rule change assessment process. If you require any further information, please do not hesitate to contact me on (02) 9284 3434.

Yours sincerely,

Philip Gall

Philip Gall

Acting Chairman
Grid Australia Regulatory Managers Group

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BACKBONE OF THE NEM

National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011

Discussion Paper

Grid Australia Submission

September 2011

1. Background

Grid Australia makes this submission in response to the AEMC's National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011 Discussion Paper.

Grid Australia and its members have participated in the development of the NEM transmission pricing arrangements since their inception. Grid Australia has actively engaged with the AEMC and policy makers to ensure that the proposed inter-regional transmission charging regime is able to be practically implemented.

Consistent with its previous submissions Grid Australia supports the implementation of a load export charge based on the locational component of prescribed transmission prices.

2. Introduction

In its Rule determination for Pricing of Prescribed transmission Services of 21 December 2006 the Commission highlighted as a key proposition of the new pricing regime:

> *"recasting the pricing rules to a principles-based form by removing unnecessary detail on implementation and administration matters, while confirming that existing arrangements may largely continue to apply and providing certainty regarding pricing outcomes. The pricing principles have also been designed to allow innovation for alternative pricing methodologies to emerge over time subject to constraints in the Rules;"*[1]

This determination acknowledged the tension between the desires for consistency both between the prevailing pricing methodologies and those resulting from the new arrangements and the innovation required to appropriately respond to the needs of customers in the regions in which the TNSPs operate.

Upon reviewing the discussion paper, Grid Australia is concerned that the Commission incorrectly formed the view that the relatively minor differences between the approved transmission pricing methodologies in the NEM were likely to undermine the credibility of the proposed inter-regional charging regime.

As highlighted in Grid Australia's previous submissions the differences between the pricing methodologies which would impact on the appropriate calculation of inter-regional transmission charges are limited. A central consideration is the choice of

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1 AEMC 2006, Rule Determination for National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006, p 26

operating conditions which would reasonably be expected to capture the peak loading conditions on all network elements. In this regard the 10 system peak day energy method used in the Victorian jurisdiction will not appropriately capture the peak loading of either the interconnector elements, or those major network elements which facilitate the flows from generators to customers.

With this exception there is no evidence that the minor differences between intra-regional pricing methodologies will impact materially on the original load export charge.

The new options appear to be administratively complex to implement as they represent a shift away from the existing methodology TNSPs use for their intra-regional charging. This will add further complexity to an already complex pricing regime which will note aid transparency to customers. In addition, it can be expected to take longer to implement the new options.

While Grid Australia strongly supports the implementation of a load export charge based on the locational component of prescribed transmission prices, its members stand ready to implement any Rule change enacted by the Commission. In the event that a national coordinated pricing run is required to effect the Rule change Grid Australia would be prepared to coordinate this on an annual basis.

3. Clarification of matters raised in the discussion paper

3.1 Modelling

The discussion paper states that, following consideration of stakeholder submissions, a set of specifications will be developed for a uniform national inter-regional transmission charging regime and that from this, *"modelling may be possible and presented in the second draft Rule determination"*.

While Grid Australia is supportive of the need for modelling, it doesn't believe that it is realistic to expect modelling of the possible specifications to be completed within this timeframe.

3.2 Cost reflective network pricing

Grid Australia would like to clarify a number of issues with the characterisation of various aspects of cost reflective network pricing (CRNP) in the discussion paper.

The discussion paper states[2]:

> *"the modified CRNP would be more complicated to apply than the standard CRNP as a certain level of subjectivity would be required to establish line ratings. These line ratings would be used by the TNSP as part of the process to determine the level of utilisation on a line."*

And in table 4.1:

> [modified CRNP is] *"More complicated to apply - a certain level of subjectivity would be required to establish line ratings"*

While the modified CRNP methodology is more slightly more complex than standard there is limited scope for subjectivity in the calculation of line ratings and utilisation factors.

The line ratings are those routinely used by the TNSP in network planning analysis while the utilisation adjustment factors for meshed network elements used by ElectraNet are the result of engineering contingency analysis. The utilisation adjustment for radial elements is calculated by TPRICE for both the ElectraNet and Transend modified methods.

The modified CRNP methodologies adopted by both ElectraNet and Transend deliver appropriate price signals to those customers on lightly loaded radial lines. It does not materially impact on the prices within the meshed network or points of connection to adjacent regions.

3.3 Operating conditions for cost allocation

The method of calculation used in Victoria is more correctly described as the "10 system peak day energy" method as opposed to the 365 day capacity method used elsewhere in the NEM.

The AEMO revised proposed pricing methodology[3] bases the load and generation conditions provided to TPRICE on the *"load and generation data for the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during Financial Year t-2."*. Grid Australia notes that this differs from using only the peak half hours on those days noted in the discussion paper.

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2 AEMC 2011, Inter-regional Transmission Charging, Discussion Paper, 25 August 2011, p 11

3 AEMO Revised Proposed Pricing Methodology Section 3.14.4 (http://www.aemo.com.au/registration/0120-0021.pdf)

There are several major problems with AEMO's 10 system peak day energy approach.

First, this approach effectively averages the utilisation of the network elements during those 10 peak days. The capacity method, used by the rest of the NEM, seeks to identify the peak loading on individual elements during the 365 days assessed.

As noted in previous submissions, while the times of system peak are of particular relevance to the energy market, they do not necessarily correlate with the times at which peak loading on network elements occur. Investment decisions for network augmentations are typically based on the loading of individual network elements rather than then size of the system peak.

Second, it is also clear that the 10 system peak day energy methodology doesn't capture the conditions necessary for a credible *inter*-regional charging methodology. As the number of days is extended to capture more operating conditions the averaging inherent in the energy method significantly reduces the cost reflectivity of the solution.

Third, the flows on interconnectors at times of system peak are not necessarily consistent with those expected to drive network investment.

Finally, Grid Australia members also consider that the use of the 10 system peak day energy method is inappropriate as a mechanism for sending demand side participation signals. To provide a meaningful signal, the network and the network elements which make it up must be constructed to satisfy the load requirements contracted for between the TNSP and the customer. In order to defer investment, demand side participation should be reliable and repeatable rather than merely serendipitous. These benefits are more reliably achieved by retaining flexibility in the structuring of prices[4] and ensuring connection agreements robustly define the service provided to customers.

3.4 Treatment of postage stamped components

As noted in previous submissions Grid Australia remains firmly of the view that the load export charge should be based on the locational component of prescribed transmission services only[5].

4 Including the negotiation of prudent discounts under clause 6A.26 of the Rules.

5 Inter-regional Transmission Charging Draft Rule 2010, Response to AEMC Draft Rule Determination, Grid Australia 25 February 2011, p4

3.5 Other differences between TNSPs' methodologies

__The measure of demand used to set prices__

The measure of demand used for the calculation of prices only affects customers within a region and is not expected to impact on the calculation of inter-regional charges.

The approved transmission pricing software, TPRICE, allocates locational charges to load connection points which are then converted to a prices based on a unit of measure which is expected to be stable during the period. So long as the load export charge is expressed as a lump sum annual charge and is not required to be converted to a price there is no issue to be resolved.

The unit of demand was relevant to the Commission's consideration of the inter-regional charging mechanism when the proposed framework sought to treat inter-regional connection points exactly as any other load connection points.

With the acceptance of the requirement to amend pricing methodologies to accommodate inter-regional charging there is longer a requirement for the circularity inherent in converting the load export charge to a price which is then converted to a charge on a monthly basis.

In the event the Commission elects to include the postage stamped components in inter-regional charges then consistent measures of demand __and energy__ would be required. This would also require that the measurements on either side of the regional boundary be consistent.

__Valuation of assets__

As noted in previous submissions[6], inconsistencies between replacement cost models used by TNSPs are to be expected but do not impact on the calculation of a load export charge at the boundary of a region.

The replacement costs of assets providing the various classes of prescribed transmission services are used to determine the ratios (the attributable cost shares) by which the annual aggregate revenue requirement (AARR) is split to derive the annual service revenue requirement (ASRR) for each category of prescribed transmission service.

The ASRR for each class of prescribed transmission service is then ultimately allocated to connection points based on the ratios of the replacement costs.

6 Inter-regional Transmission Charging Draft Rule – Supplementary Submission, Grid Australia 11 March 2011, p2

Under the current arrangements and the Commission's proposed option 1, variances in unit rates between regions should not materially affect the load export charges. By way of example, if South Australia increased its unit rates by 20% or decreased them by 20% the replacement cost ratios used to allocate revenues would be unaffected as would the load export charges calculated.

However, inconsistencies between replacement cost models present a fundamental obstacle to the Commission's proposed option 3. The NEM-wide CRNP run would require a consistent national valuation model and cost allocation model, not just consistent unit rates. For this reason we believe that option 3 would not be administratively efficient.

4. Response to questions arising from the Discussion Paper

4.1 Assessment Framework

Question 1. Is the assessment criteria identified in this Discussion Paper appropriate for developing a uniform national inter-regional transmission charging methodology?

The Commission suggests criteria for assessment as follows:

1. Achieving more cost-reflective price signals - this requires consideration whether the methodology:
   - (a) recovers the costs of the existing network;
   - (b) provides a signal for future investment; and
   - (c) reflects a "causer or beneficiary pays" approach; and
2. Procedural and implementation issues - this includes:
   - (a) administrative efficiency;
   - (b) transparency; and
   - (c) stability and regulatory certainty, including cost impacts.

The criteria proposed by the Commission do not appear to reflect the economic efficiency requirements embodied in the National Electricity Objective. In particular, "recovers the costs of an existing network" implies the (full) inclusion of sunk costs in prices on *all* occasions. Under the pricing principles set out in the National Electricity law, the recovery of sunk costs is required to be done only in a way that minimises distortion of the marginal cost price signals. It is also unclear to Grid Australia how a "causer or beneficiary pays" concept relates to marginal cost pricing.

Pragmatically, current transmission pricing methodologies are, at best, approximations to marginal cost pricing. Most demand for the use of transmission services is inelastic and, thus, unresponsive to pricing structures. In addition, transmission investment is indifferent to transmission price signals because of the role of the Regulatory Investment Test – Transmission in deciding which investment is to be undertaken. Taking all of this into account, Grid Australia submits that the Commission would find it difficult to demonstrate that extending the existing transmission pricing methods to inter-regional transmission pricing would in fact generate net benefits in accordance with the National Electricity Objective.

The actual development of a methodology that can be implemented in practice can only be achieved in close cooperation with the TNSPs and the AER.

Question 2 Are the proposed assessment criteria proposed appropriate for assessing the various options for a uniform national inter-regional transmission charging regime?

As noted above the criteria do not appear to properly reflect the economic efficiency focus of the National Electricity Objective and are not appropriate. For example there is no obvious economic benefit in pricing sunk costs at the boundary between regions.

The degree to which the Commission wishes to deal with the pricing of sunk costs could also be important in deciding between the CRNP based and cost sharing options. There may also be policy dimensions to these considerations e.g. the extent to which easement taxes in one jurisdiction are reflected in transmission prices paid by customers in another jurisdiction.

In addition, there is a need to consider this initiative in conjunction with possible future changes emanating from the Transmission Frameworks Review. Introducing a relatively simple arrangement now would not necessarily interfere with further changes required as a result of this Review e.g. generator TUOS. However, more complex far reaching options may create issues for future subsequent changes.

As the parties critical to the implementation of the regime determined by the Commission Grid Australia believes that the procedural and implementation issues are also important.

4.2 CRNP Methodology

Question 3. If a uniform national CRNP methodology were chosen, should the components of the methodology be specified in the NER or else left to the TNSPs to determine?

Grid Australia considers that the Commission should maintain the current principles based approach to pricing in the Rules.

The actual development of an implementable methodology to give effect to those principles must be done in close cooperation with the TNSPs and the AER. This must have regard to the existing pricing practices within the region and require minimal deviation from them.

Question 4. If a uniform national CRNP methodology were chosen, which components need to be determined as part of a uniform national CRNP methodology?

Grid Australia believes that any CRNP based methodology must have regard to the existing pricing practices within the region and require minimal deviation from them.

In the interests of administrative efficiency priority should be given to ensuring that most TNSPs would have the option of amending their pricing methodologies to the extent required to remove the requirement for a two step CRNP based options proposed by the Commission.

To this end the principles required to be incorporated in the Rules should be limited to:

- providing firm guidance on the choice of load conditions to be presented to the approved transmission pricing software. This guidance must require that priority be given to ensuring that peak loading on all network elements is captured. Grid Australia believes that only the 365 day capacity method is able to achieve this;
- ensuring that under/over recoveries relating to intra-regional and inter-regional charges should be quarantined from one another to the extent reasonably possible;
- ensuring that settlements residue auction proceeds only benefit customers in the region intended; and
- ensuring that only the prescribed locational component is to be charged across borders.

In practice, this should allow Victoria to maintain its 10 peak day energy method for intra-regional pricing and do a second run based on a methodology consistent with the national principle while all other TNSPs could reasonably expect to implement inter-regional charging via relatively minor amendments to their existing pricing methodologies.

In considering the level of prescription required, consideration should be given to the significant degree of consistency achieved under the principles based approach of the current pricing provisions of the Rules. This has been achieved by close cooperation between TNSPs and stands as a tribute to the principles based approach implemented by the AEMC in its pricing determination of 2006.

In the event that the Commission chose to mandate a NEM-wide CRNP methodology consistent with Option 3, significant additional prescription would appear necessary.

Question 5. If an inter-regional transmission methodology was chosen which required a consistent form of CRNP methodology, would the standard CRNP or modified methodology be the most appropriate to use for inter-regional transmission charging?

Under option 1 neither the standard CRNP nor modified CRNP would need to be mandated. TNSPs could apply their current methodology with the only change required being to ensure that the load conditions presented to the approved transmission pricing software ensures that peak loading on all network elements is captured.

Under option 3 clearly only one method can be used. Both have merits with no clear preference when applied solely to the calculation of the inter-regional charge.

Question 6. If an inter-regional transmission methodology was chosen which required a consistent form of methodology for determining the operating conditions for cost allocation, would the 10-day system peak methodology or 365-day element peak methodology be the most appropriate to use for inter-regional transmission charging? Or is there a more preferable alternative?

As noted in previous submissions while the times of system peak are of particular relevance to the energy market they do not necessarily correlate with the times at which peak loading on network elements occur. Investment decisions for network augmentations are typically based on the loading of individual network elements rather than then size of the system peak.

The 10 system peak day energy method does not capture the conditions necessary for a credible inter-regional charging methodology. As the number of days is extended to capture more operating conditions, the averaging inherent in the energy method significantly reduces the cost reflectivity of the solution. Also the flows on interconnectors at times of system peak are not necessarily consistent with those expected to drive network investment.

As previously noted, Grid Australia members believe that the use of the 10 system peak day energy method is inappropriate for sending signals for demand side participation. This is because the network and the network elements which make it up must be constructed to satisfy the load requirements contracted for between the TNSP and the customer. In order to defer investment demand side participation should be reliable and repeatable rather than serendipitous. These benefits are more reliably achieved by retaining flexibility in the structuring of prices[7] and ensuring connection agreements robustly define the service provided to customers.

Accordingly the 365 day capacity method is the only methodology appropriate for use in inter-regional charging.

<u>Question 7. To the extent that there are any differences between TNSPs' measure of demand for setting and calculating prescribed locational and non-locational TUOS services, and prescribed common transmission service prices and charges, is it necessary to have a single measure of demand in order to achieve a uniform inter-regional transmission charging regime?</u>

As previously noted the measure of demand used for the calculation of prices only affects customers within a region and is not expected to impact on the calculation of inter-regional charges.

The approved transmission pricing software, TPRICE, allocates locational charges to load connection points which are then converted to prices based on a unit of measure which is expected to be stable during the period. So long as the load export charge is expressed as a lump sum annual charge and not required to be converted to a price there is no issue to be resolved.

The unit of demand was relevant to the Commission's consideration of the inter-regional charging mechanism when the proposed framework sought to treat inter-regional connection points exactly as any other load connection points.

However, with the acceptance of the requirement to amend pricing methodologies to accommodate inter-regional charging there is longer a requirement for the circularity inherent in converting the load export charge to a price which is then converted to a charge on a monthly basis.

In the event the Commission elects to include the postage stamped components in inter-regional charges then consistent measures of demand <u>and energy</u> would be required. This would also require that the measurements on either side of the regional boundary were consistent.

<u>Question 8. To the extent that there are any differences between TNSPs' asset valuation methodologies, is it necessary to have a single methodology to achieve a uniform inter-regional transmission charging regime?</u>

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7 Including the negotiation of prudent discounts under clause 6A.26 of the Rules.

As noted in previous in previous submissions[8] inconsistencies between replacement cost models used by TNSPs are to be expected but do not impact on the calculation of a load export charge at the boundary of a region.

The replacement costs of assets providing the various classes of prescribed transmission services are used to determine the ratios (the attributable cost shares) by which the annual aggregate revenue requirement (AARR) is split to derive the annual service revenue requirement (ASRR) for each category of prescribed transmission service.

The ASRR for each class of prescribed transmission service is then ultimately allocated to connection points based on the ratios of the replacement costs.

Under the current arrangements and the Commission's proposed option 1, variances in unit rates between regions should not materially affect the load export charges. By way of example, if South Australia increased its unit rates by 20% or decreased them by 20% the replacement cost ratios used to allocate revenues would be unaffected as would the load export charges calculated.

Inconsistencies between replacement cost models present a fundamental obstacle to the Commission's proposed option 3. The NEM-wide CRNP run would require a consistent national valuation model and cost allocation model, not just consistent unit rates.

4.3 Option 1: Modified Load Export Charge

<u>Question 9. If a LEC were chosen, would the modified LEC be preferable to the original LEC proposed in the draft Rule determination?</u>

The modified LEC proposal may have an advantage in allowing the Victorian region to continue to use the 10 peak day energy method for intra-regional pricing while adopting a more nationally consistent approach for the calculation of inter-regional charges. This would allow Victoria to maintain its current methodology for intra-regional pricing and do a second run using the 365 day capacity method consistent with the national principles. All other TNSPs could reasonably expect to implement inter-regional charging via relatively minor amendments to their existing pricing methodologies.

Grid Australia does not believe the modified LEC is preferable to the original LEC proposal with only the locational component charged and a requirement to use the 365 day capacity method.

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8 Inter-regional Transmission Charging Draft Rule – Supplementary Submission, Grid Australia 11 March 2011, p2

Question 10. If a LEC were chosen, would there any other difficulties in applying the modified LEC?

Adopting the modified LEC would require all TNSPs to run two parallel sets of models with markedly different methodologies. This clearly calls into question the administrative efficiency of the option. A more pragmatic approach addressing only the major differences may reduce the significant administrative inefficiencies inherent in the proposal.

Question 11. Is the modified LEC preferable to the other inter-regional transmission charging options proposed in this Discussion Paper?

The modified LEC is preferable to the other options presented in the discussion paper.

4.4 Option 2: Cost Sharing

Question 12. If a Cost Sharing option was chosen as the inter-regional transmission charging approach, which methodology should be used to identify the assets which allow for inter-regional flows? For instance, could the assets be determined by a load flow analysis?

Grid Australia does not believe this option has been sufficiently developed to make informed comment.

A methodology based on load flow analysis is likely to produce the best representation of assets being utilised for inter-regional movements.

In the event the Commission chooses this option Grid Australia stands ready to coordinate this analysis on an annual basis.

Question 13 Which assets should be covered in an inter-regional transmission charging arrangement? Should the cost of existing transmission assets used to allow for inter-regional flows be included? Should there be a technical threshold applied in order for assets to be included?

The Commission's criterion "recovers the costs of an existing network" implies the inclusion of sunk costs in prices on all occasions. While the recovery of 'sunk costs' is required to meet the pricing principles set out in the National Electricity Law it must be done in a way that minimises distortion of the marginal cost price signals.

While Grid Australia does not believe this option has been sufficiently developed to make informed comment, it could allow for the establishment of a regime for inter-regional charging which excluded sunk assets. It could also be tailored to the transfer of costs associated with new investments to facilitate interstate energy transfer.

Question 14 In allocating costs under a Cost Sharing option, what methodology should be used? For instance, should it be allocated on a simple split based on the size of a TNSP's customer base? .

A simple splitting methodology is unlikely to display the rigour expected of an inter-regional charging regime.

Consistent with the response to question 12, a methodology based on load flow analysis is likely to produce the best representation of assets being utilised for inter-regional movements and allow the associated costs to be equitably allocated.

If a load flow basis for allocation is chosen then the Commission should be mindful of the significant fluctuations in flows on a year on year basis and ensure the impact of these on prices is sufficiently damped.

Question 15 Under a Cost Sharing option, how should the costs be recovered from customers? For instance, should it be recovered on a postage stamp or locational basis?

Grid Australia does not believe this option has been sufficiently developed to make informed comment.

It is not clear how the charge could be meaningfully allocated on a locational basis.

Question 16 Would a Cost Sharing option be preferable to the other options proposed?

Given the current level of development it is not possible to determine whether this is a preferable option to option 1.

4.5 Option 3: NEM-wide CRNP

Question 17. Would it be possible to apply a CRNP methodology on a NEM-wide basis? If so, what difficulties would be faced?

A number of significant difficulties would be faced in implementing option 3.

Inconsistencies between replacement cost models presents a fundamental obstacle to implementing the Commission's proposed option 3 in a timely fashion. The NEM-wide CRNP run would require a consistent national valuation model not just consistent unit rates.

Another significant difficulty would be the complexity of the cost allocation model required to allocate costs throughout the NEM.

Question 18. If so, how easy would it be for the transmission businesses in the NEM jointly to implement a NEM-wide CRNP methodology?

It is not clear how the NEM-wide CRNP methodology could be efficiently implemented. However, if required, and with adequate compensation for the cost and complexity of introducing this method, the transmission businesses have the capability to implement this method.

Question 19. Would a NEM-wide CRNP methodology be preferable to the other options proposed?

This option is not preferable to options 1 or 2.

Question 20. Are there any options for a uniform national inter-regional transmission methodology (other than the three options presented in this Discussion Paper) that should be considered?

Grid Australia supports the CRNP based methodology proposed in the draft Rule applied only to the locational component.

The principles defining this methodology should be defined in the Rules with the detail to be defined in the pricing methodology guideline and the pricing methodologies in consultation with the AER.