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4 October 2011

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
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SUBMITTED ONLINE

Dear John,

Submission – Response to Discussion Paper National Electricity Amendment (inter-regional Transmission Charging) Rule 2011- ERC0106

We appreciate the opportunity to respond to the AEMC's Discussion Paper on Inter-regional transmission charging. As noted in out response to the Draft Rule change in February 2011, transmission charging is a complicated aspect of the National Electricity Rules (NER) that has real financial consequences for end-users and that needs to send appropriate price signals that seeks to reflect their use of the transmission system and to reward efficient behaviour. Our modelling to date has also revealed the potential problems with taking a simplistic approach when projecting the impacts of a particular initiative in TUoS pricing. Greater analysis and consideration of alternative charging models is therefore warranted. That said, we should be mindful not to create unnecessary complexities in a process that should be as simple to implement as possible.

We put forward our analysis and opinions in response to the questions raised in the Discussion Paper and attach them for your consideration.

We look forward to working with the AEMC in developing the Rule change proposal. If you have any questions regarding this submission, please do not hesitate to contact me on (08) 8201 7371.

Yours sincerely

David Swift
Executive General Manager Corporate Development

SUBMISSION TO AEMC'S DISCUSSION PAPER ON INTER-REGIONAL TUOS CHARGING

4 October 2011

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1 General

In our submission to the Draft Rule, we stated that we support inter-regional TUOS charging provided the charges reflect efficient pricing and cost recovery and it results in minimal distortion. We also agree that in order to have a workable charging system, the underlying pricing methodologies need to be aligned and consistent between regions and ultimately nationally. In the context of inter-regional charging, this can be challenging because each region has differing network planning requirements, different TNSPs and divergent network cost recovery methodologies.

1.1 Efficient cost reflective allocation

The Discussion Paper sets out the criteria by which the implementation of an inter-regional (IR) TUOS regime can be assessed. From the TNSPs' perspective, TUoS prices are set to allow network owners to recover the historical, or sunk costs of investing in and operating the transmission network. However, if this was the only objective of TUOS pricing, then we would "postage stamp" all network costs to recover these costs with the minimum of distortion. The regime, however, also recognises the need to price a component of TUoS in a manner which reflects the efficient cost of supplying customers at each transmission connection point. By having a locational element to the pricing regime, we are attempting to deliver more efficient outcomes as customers make longer term responses to the transmission costs they cause. Ideally such a price would be calculated on a prospective basis, recognising the future costs that will be incurred as a result of additional load at a point on the network. Given the difficulties and vagaries of this theoretical approach, , we agree that in relation to ordinary customer load points, the cost reflective network pricing approach adopted is a reasonable proxy.

The cost reflective component of transmission charges applies only to customers, and conventional customers are always consumers (i.e. customers draw a load and therefore the assets supporting the load flow uni-directionally). Determining customers' use of the network at the times where it is under high demand conditions (however defined in detail) seeks to reflect in their price their contribution to the need for future network investment. It also can be used to cause new customers or existing ones that are relocating to consider locating in less stressed parts of the network by charging less in those areas. If this price signal is effective, it will reward customers whose behaviour contributes to deferring network investments. Therefore, by designing a regime that properly identifies the usage in relation to network capacity, and pricing accordingly, it will also indirectly inform the network investment required to accommodate those users.

In contrast, the investment drivers for interconnectors are not so clear. The use of interconnectors is not uni-directional as that of a conventional customer load points. Interconnector investment can depend on a number of factors but will usually have more to do with gaining access to more efficient reserves of generation from neighbouring regions than a region can provide on its own. Efficient IR TUoS pricing cannot therefore be assumed to be delivered by treating them as if they were a customer at the same point, as that approach may fail to signal contribution to the need for investment. Having a "net" load export charge at the border might provide unreliable and confusing investment signals. When, over the course of a year you have flows going in opposite directions, you are left with a net charge that does not necessarily inform investment needs.

Furthermore, as pointed out above, allocating interconnectors' historical costs is likely to provide very little information regarding the future investment necessity for the interconnection. We understand that the TUoS valuation methodology recognises this by requiring that asset costs be valued at Optimised Replacement Costs (ORC) and thereby charging present network price that reflects its future replacement cost. But it does not represent a cost that incorporates the value of future augmentations and upgrades. In this respect, Option 2 in the Discussion Paper has some appeal in that determining the need for an interconnector, the regions' responsibilities towards its construction and operation, and its pricing can be agreed or determined at the time that the investment is needed.

Nevertheless, there are limitations to Option 2 because from our understanding, such an agreement has been applied only once in the NEM and it needed to be entered into between the jurisdictions rather than the relevant TNSPs. The difficulty that Option 2 faces is that because usually, most of the benefit from interconnectors flows to one region, obtaining agreement to contribute to the costs from the region that enjoys the lesser benefits might prove to be a challenge.[1] However, if agreement could be reached, it could be the most accurate way of allocating interconnecting costs to the beneficiaries of the interconnector.

To avoid the difficulties of having jurisdictions reach agreement, on cost sharing, the Discussion Paper suggested a more formulaic cost sharing approaches but of course, this could run the risk of entrenching a less flexible and therefore less efficient pricing system. More analysis would need to be done to assess these options. Another limitation of Option 2 is that it does not take into account all network elements that may have contributed to inter-regional flows but are not technically considered “interconnectors”.[2]

In the response to the Draft Determination, AEMO stated that a single financially neutral entity (such as the AER) would be best placed to determine transmission prices (as a “single price setting authority model”). The reason for this is that a single body minimises the potential for jurisdictional variations in TUOS pricing and the locational portion of transmission prices should have a consistently applied cost allocation methodology. This entity would allocate costs by use of an integrated NEM-wide load flow model applied consistently. The role would be mechanistic in that it would allocate locational costs that have been gone through the valuation and apportionment[3] processes by CNSPs. It therefore requires that the valuation and apportionment processes are relatively standard across all jurisdictions but otherwise, CNSPs would continue to have responsibility to deliver critical pricing inputs. We think that this is a better option because not only would this approach ensure that each load point in the NEM is treated consistently, it dispenses with the necessity of having to treat interconnectors as notional connection points at the regions’ borders.

As noted in our submission to the Draft Determination, our analysis identified that treating a neighbouring region as a notional generator or load connection point creates the potential for inefficient charging. AEMO’s analysis concluded that, in relation to Victoria, the original IR TUoS proposal would allocate more costs to the interconnectors (i.e. importing regions) and blunt the intra-regional locational signals. In addition, in an IR TUoS model where a region is treated as a connection point at the border of its neighbouring region, differing valuation and apportionment methodologies between those regions, will cause customers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours. Ideally, customers utilising similar assets should face similar pricing outcomes irrespective of where they are located. Additionally, if allocation methodologies change over time, existing and potential customers will have no clear pathway to determining where to locate or relocate.

The Discussion Paper recognises these limitations and has put forward options that attempt to align methodologies and remove some inconsistencies for certain portions of the transmission networks. However, AEMO believes that subject to the caveat about how to treat interconnector investments, a single TUOS pricing authority would be the best method of maintaining an efficient inter-regional transmission pricing regime because it is able to align cost allocations for all transmission assets in the NEM more consistently and ensure that consistency is maintained for the longer term.

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[1] Another issue that this approach faces is that any net revenues should be returned to customers in the net exporting region and not charged to the customers in the net importing region. Any differences in the way that regions do this will, of course, have an impact on customer investment decisions.

[2] We note that the term “interconnector” is a legal construct for the purpose of the regulatory regime. Physically, an interconnector that has customers connected to it serves the same function as any other network asset, namely, delivering energy to the connected customers according to reliability and generator driven factors. It is true that interconnectors ultimately physically connect to an external system to enable reserve sharing and provide benefits other than reliability but other elements within the network will at times of import or export support the transfer of energy across region borders and should therefore be considered as forming part of the interconnector for cost sharing purposes.

[3] By “apportionment” we mean the process of allocating the annual revenue requirement across the prescribed entry and exit services, the prescribed common transmission services and prescribed TUoS services classifications.

AEMO recognises that the single pricing authority model faces similar implementation issues to the options suggested by the AEMC and that those issues might prove challenging. For instance, if a coincident peak method of determining cost allocations were adopted, there would need to be some agreed way of establishing meaningful peak periods common to the entire NEM. Also, if a Modified CRNP methodology were employed, how are ratings applied? .Lastly, the question regarding whether a load-flow or "TPRICE" allocation methodology results in the right allocation of interconnector costs is applies to this method as it does to Options 1 and 3 and if not implemented correctly, Option 2 as well. However, these difficulties are much easier and more effectively dealt with by a single TUOS pricing authority than they would be with separate CNSPs each calculating their own prices.

The Discussion Paper mentions two ways (Options 1 – Modified Load Export Charge and 3 – NEM-wide CRNP) of calculating locational inter-regional pricing that would separate **intra**-regional assets from **inter**-regional assets and enable CNSPs to maintain a separate and differentiated allocation methodology (to that implemented by other regions) with respect to intra-regional assets. It seems that this was done to enable the application of cost reflectivity and allocation methodology consistently over inter-regional assets and allow CNSPs to apply divergent methodologies to intra-regional assets.

We believe that these two alternative approaches create similar issues to the original IR TUOS proposal. While some methodologies are standardised, there is still the ability to differentiate approaches of determining which assets do and do not contribute to inter-regional flows.

Ultimately, classifying assets that are used for, or contribute to, inter-regional flows is a variable that each CNSP will need to interpret and apply to the transmission assets within its region. This can, particularly over time create inconsistencies with their regional neighbours. We accept that the Options are described at a high level and therefore open to interpretation. In order to reduce the potential for classifying assets arbitrarily, guidelines or rules would need to be developed to reduce inconsistency.

Assuming that there could be a consistent and relatively simple way of dividing up inter-regional assets from intra-regional ones, we note that Option 1 raises concerns that we mentioned our submission to the Draft Determination. The Discussion Paper states that Option 1 does not permit load export charges received from a neighbouring region to be passed on to a third region in accordance with load flow analysis.[4] Therefore, Option 1 is not suited to the Victorian and NSW regions because it does not allow those regions to charge other regions for energy wheeled across its network. In this respect, Option 3,despite its complexity might represent a better solution.

We would also add that network cost recovery should ultimately be based on service delivery. The most efficient way of recovering network costs is to only permit recovery for transmission services actually delivered to customers. AEMO understands that this will require a fundamental shift in the regulatory regime and is therefore a longer term ambition.

1.2 Administrative issues

The Discussion Paper also stated the objective that the pricing regime has to demonstrate administrative efficiency, transparency and provide stability and regulatory certainty. . Given the cost reflective pricing component in TuoS is attempting to drive longer term efficient decision making by customers, some level of stability and predictability would appear necessary in any solution. We think that the options proposed (Options 1 and 3) risk creating complexity without necessarily advancing these objectives. If the individual CNSPs remain responsible for making critical determinations the risk of intentionally or unintentionally diverging from consistency is heightened and transparency lessened. Audits may be implemented to minimise the risk of this occurring but this will raise transaction costs and time.

[4] Discussion Paper, p. 22.

2 Answers to Discussion Paper Questions

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

We comment on this in section 1.

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

We comment on this in section 1.

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?

AEMO agrees with and supports a single and consistently applied model and pricing methodology to achieve an efficient pricing regime. To the extent that flexibility may be desired, TNSPs may be given scope to determine some components. However, because the goal is to achieve greater consistency, then much of the detail might need to be more closely prescribed. We would urge the AEMC to consider having the AER develop guidelines and criteria rather than the prescription appearing in the NER.

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

Without having sufficient experience with the modified CRNP method, it is difficult to know what components are required to form part of a uniform national CRNP. That said, at a minimum, it would seem reasonable to assume that a common method be prescribed and if the modified CRNP is chosen as the best alternative, it would probably need:

- A standard way of determining line ratings that lessens the scope for TNSP subjectivity
- A standard way of measuring utilisation of the network elements.

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?

Without further analysis, this is difficult to assess. It is not immediately apparent that one would be better than the other, although when determining ratings for interconnectors, a CNSP would need to reach agreement with the adjoining CNSP to agree on the interconnector's ratings if one is not already established.

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 another more preferable alternative?

As stated in its submission to the Draft Determination, AEMO believes that a cost allocation methodology that allocates on the basis of system coincident peak rather than element peak provides the most efficient and most informative locational price signalling. It is our preferred allocation methodology. In an inter-regional context, this can create challenges but could be dealt with by agreeing an acceptable methodology to establish a useful system peak figure.

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?

This will require further analysis to determine whether it is material but on first assessment, it would seem different techniques for measuring demand would likely lead to different pricing results.

Given that non-locational and common service charge can represent anywhere between 60% and 75% of total TUOS costs, it could be material.

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?

AEMO considers this to be a material issue. We said the following in our submission to the Draft Determination.

“Some of the issues that AEMO considers significant are ... Consistent database of unit transmission elements’ ORC. The foundation blocks of the valuation process needs to be explored in order to be sure that each TNSP uses the same fundamental valuation base. We agree that each region may have different topography that affect base transmission costs. However, our understanding is that in an effort to standardise valuation in the past, two base methodologies were allowed – rural/non-rural, and flat/hilly terrain. Further, the current approach of requiring AER approval of individual TNSP pricing approaches is still likely to result in some inconsistent applications over time.”

Question 9: If a LEC were chosen, would the modified LEC be preferable to the original LEC proposed in the draft Rule determination?

The original LEC was simpler to implement but the inconsistencies in how key elements to transmission pricing were to be applied cast doubt on the validity of the pricing under that method. The new LEC does attempt to deal with the consistency issues but are more complicated to implement and introduce new steps and decision points which can also case doubt on the pricing outcomes.

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

We comment on this in section 1.

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

AEMO has difficulty with the modified LEC method because import charges from an exporting region cannot easily be followed through the importing region to a second adjoining importing region. It also adds complexity due to having to complete the cost allocation task twice and as noted earlier, a distinction between assets serving intra-regional load points and those serving inter-regional load points. AEMO believes that a single price setting authority model would be the best option.

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?

We comment on this in section 1. This can be difficult to determine as it is not static. Flows change with differing states of the system and differing dispatch scenarios. Ultimately some portion of the determination will be subjective and open to dispute.

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 difficulty with the approach is that it is unclear how assets that contribute to inter-regional flows should be accounted for and recovered. We discuss this in section 1. Further issues include the potential for double counting of assets (or portions of assets) that contribute to inter-regional flows. If this option is adopted, some form of technical guidance (perhaps via AER guidelines) is warranted. This will be a very difficult thing to implement and always risks of being conservative and not including assets that do contribute to inter-regional flows.

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?

We believe that under this option the criteria for allocating costs is no different to the criteria set out in the Discussion Paper, namely, causer pays. Because interconnectors are justified on a different set of criteria than the ones that TUOS replicate (i.e. bi-directional flows necessitate a net load export charge which may assist in informing investment decisions), they might need to be dealt with in a different context (see discussion in section 1).

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?

This would be the most simple method and to a degree reflects the benefits to the entire region of the exporting region's reserve benefits that the interconnector enables access to. However, as with all postage stamp recoveries, it does not send particularly efficient price signals.

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

We discuss this in section 1.

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

AEMO believes that this is plausible but it does have its issues. It requires a consistent approach applied by all CNSPs and agreeing a consistent approach, namely:

- system peak compared to element peak methodology
- modified or ordinary CRNP.

From our understanding of the option, it requires that the TNSPs make a determination (sometimes objective) as to what assets are included in the cost allocations and what are not.

It relies on each jurisdiction deriving a load export charge that would then need to be taken by the adjoining region as an input into its own locational intra-regional pricing. In this respect we see it as being compromised.

Lastly, we have outlined our concerns about what this means for interconnector investments.

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

This is difficult to judge but it could prove challenging.

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

According to our understanding of the model, it is probably the best option put forward. However, there are many difficulties with it as outlined above.

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?

AEMO supports a NEM-wide TUOS pricing regime where charges are levied inter-regionally. AEMO supports development of a single and consistently applied model and pricing methodology to achieve an efficient pricing regime. As part of this, AEMO believes that this would be best achieved with a single price setting authority model, based on information provided by CNSPs. However, we would need to resolve what the best solution would be to recover the costs of future interconnector so that it produces meaningful interconnector investment signals.