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Submitted online

Dear Mr Allan

Submission on the Second Draft Determination and Draft Ruling

We appreciate the opportunity to respond to the AEMC's Second Draft Determination and Draft Ruling on Inter-regional transmission charging. As noted in our previous responses to the First Draft Rule change in February 2011 and Discussion Paper in October 2011, transmission charging is a complicated aspect of the National Electricity Rules (NER) that has real financial consequences for end-users. We consider that this charging needs to be nationally consistent as well as seeking to deliver appropriate price signals that reflect the transmission system use and reward efficient behaviour.

The modelling undertaken by AEMO in 2011 revealed the potential problems with 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. While the AEMC have had consultant ROLIB calculate the historical revenue transfers that would have been delivered by each of a number of variants to the charging methodology, the results of this modelling have not been assessed against an efficient pricing objective.

We are mindful that this process should be as simple as possible to implement and should not create unnecessary complexities. In this respect we consider some changes to the detailed methodology and implementation approach are required if the AEMC's considers the overall methodology meets the National Electricity Objective.

Key points

- We support a national TOUS charging that takes into account the truly national the shared network assets within regions
- We support and need to have reflective efficient pricing and cost recovery that results in minimal distortion to encourage investment
- The underlying methodologies for pricing must be aligned nationally and reflect the historical cost of the asset
- An independent body (such as AEMO or AER) would need to work with state TNSPs to develop network pricing on a nationally consistent basis, to undertake the calculations and organise the transfers between regions.

Inter-regional TUoS charges are not sufficient to correct distortions when considering national projects where, as Garnaut explains in his Update Paper 8, "large amounts of money need to be spent long before flows actually occur, and the cost burden falls unequally". Therefore if transmission planning is to be conducted nationally using an independent national planner, the costs of all any new interstate transmission infrastructure should be recovered at a national level. The end-users in the NEM would receive substantial benefits from a truly nationally operating market wherever they are located within the market.

As noted in our submission to the 2011 Draft Determination and again in our submission to the 2011 Discussion Paper, our analysis identified that treating a neighbouring region simply as a notional generator or load connection point in each region without addressing the actual pricing methodology to be used creates the potential for inefficient charging. In relation to Victoria, the original IR TUoS proposal would allocate more costs to the importing region interconnectors and blunt the intra-regional locational signals. Differing valuation and apportionment methodologies between regions will cause end-users to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing distribution methods. And, if allocation methodologies change over time, existing and potential customers will have no clear pathway to determining where to locate or relocate. Therefore a national model would see end-users utilising similar assets facing similar pricing outcomes irrespective of where they are located in the NEM.

Single TUOS pricing authority

A single TUoS pricing authority would be able to align cost allocations for all transmission assets in the NEM more consistently as well as maintain consistency into the longer term.

AEMO continues to 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. A single TUoS pricing authority such as AEMO or the AER would still be more capable of delivering a rational and effective approach than having separate Co-ordinating Network Service Providers (CNSPs) each calculating their own prices. A simple settlements scheme could then be established to undertake the net transfers required to correct for each individual TNSPs over or under recovery.

TUOS adjustments

In the original proposed rule, the Load Export Charge (LEC) was proposed to be calculated based on adjustments to the locational and non-locational components of prescribed TUoS services and prescribed common services, where prescribed TUoS services and prescribed common services are two categories of the four categories of prescribed transmission services.

Under this second draft rule, the LEC is modified and called the Modified Load Export Charge (MLEC) and is proposed only to be calculated based upon adjustments to the locational component of prescribed TUoS services (as the more preferable rule).

We still 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.

In the second draft rule, assets are not explicitly classified. Instead all assets are included in the CRNP run used to calculate MLECs.

However it is still true that classifying assets that are used for, or contribute to, inter-regional flows is a variable and each CNSP will need to interpret and apply to the transmission assets within its region. This is likely to create inconsistencies with their regional neighbours, especially over time. It is still appropriate to develop guidelines or rules to reduce inconsistency and reduce the potential for classifying assets arbitrarily.

Long term calculations

The rule change requests states that:

> "the level of the load export charge would reflect the costs incurred in the use of the transmission network in the region to conduct electricity to the adjoining region"

Taken in the short term, the costs incurred in the use of the transmission system are the cost of congestion plus the cost of losses. These costs are already included in the market design. The capital cost of the network can be taken in an economic sense to be sunk and therefore it would be inappropriate to base efficient price signals directly on the return of sunk capital. Rather a longer term, efficient pricing structure should represent the future costs that would be incurred if network users continue the current pattern of use and current rate of growth. Efficient prices, by reflecting back to network users future rather than sunk costs, would then drive changes in behaviour and more efficient overall outcomes. This approach has been recognised in the detailed work being undertaken by the AEMC on transmission pricing for Optional Firm Access where long run incremental costing (LRIC) is proposed as the basis for generator access pricing; viz

> LRIC is defined to be the difference between two costs: the *baseline cost*, which is the NPV of the *baseline expansion plan* which is in place before the access request is received; and the higher *adjusted cost*, which is the NPV of the *adjusted expansion plan*: an amendment to the *baseline expansion plan* to accommodate the new access request:
>
> LRIC = adjusted cost – baseline cost

The problem with LRIC (which was provided for in the National Electricity Code) is that it requires the calculation of long run future cost differences driven by current decisions by generators or customers to use the network. These costs are inherently uncertain and difficult to calculate. As a result, in cases where LRIC has been applied to network pricing a methodology has been established which seeks in some way to simplify the calculation; viz:

> The expansion plans are derived using a stylised methodology which, by assuming away some of the complexity inherent in transmission planning, provides stable and smooth expansion outcomes. The methodology is unlikely to capture every aspect of the network and would involve some judgements about future outcomes, but within these limitations it should be a robust basis for determining access charges.
> To ensure that the calculated LRIC is nevertheless realistic and representative of actual expansion costs, critical features that determine LRIC characteristics are included in the methodology. These features include: the measurement of *existing spare capacity*; the *lumpiness* of transmission expansion; the *topology* of the existing transmission system; and the *background growth* of demand and firm generation.

Under the current Rules, TUoS pricing seeks to provide a coarse measure of the long run incremental costs through the locational component of prescribed TUOS. The Rules allow the CRNP methodology or the modified CRNP methodology to be used to calculate the locational component. The use of either technique is based on the presumption that the costs of maintaining and developing the system to a certain point is broadly related to the value of assets currently used to supply the point; i.e. a point which requires higher value assets to supply now will be more expensive to augment with load growth. With the CRNP methodology the locational component is calculated to recover half of the annual revenue requirement. The 50% factor seeks to reflect analysis and experience from international studies seeking to calculate the LRIC in a network which indicated that the incremental long run cost of supporting load growth on a network was significantly less than the average historical costs due to economies of scale and ongoing improvements in technology. The modified CRNP methodology uses the current utilisation of the network elements as the scaling factor in an attempt to recognise that the LRIC for various points in the network will reflect how soon augmentation costs would be incurred to meet expected load growth. That is recognised in the quote from the TFR above.

Understanding the background and the objectives of transmission pricing should then guide our approach to the selection of the most appropriate methodology. The approach currently in use is designed around pricing to customers and therefore reflects customer drivers on future network investment. This is why the original methodology allocated costs based on the proportionate use of the network at times at, or close to, the system peak. Especially in a ‘hub and spoke’ network layout, measuring each participant’s use of the network and their contribution to the system peak was seen to reasonably reflect the value of the network assets they are using under conditions which drive future expansion decisions and expenditure. A fraction of this, either half or the utilisation factor for those assets, is used as the locational component and seeks to approximately reflect the forward costs that would be incurred in maintaining their supply under growing demand.

Instead the allocated costs should be based on the optimised cost of the asset not the historical. This enables a much more efficient basis for the calculation and gives a much more accurate cost allocation.

The current methodology then can be seen to deliver a rough approximation of LRIC under a range of assumptions. The fact that the current arrangements only need to determine prices to customers (who generally use the network in a similar manner) and that it only applies within a region does make it easier to deliver reasonably efficient locational price signals. In extending the model across regional boundaries the methodology needs to deal with ‘tidal’ flows and those flows relate as much to generator behaviour as they do to customer demand.

Inter-connector assets

In applying a methodology to inter-connector assets, the assumption that expansion and hence augmentation costs are driven by consumption at the time of the coincident peak demand is also flawed as inter-connectors are expanded on the basis of economic benefits and those benefits may arise, for example, from using low cost generation available in a region when the wind is blowing or in off-peak periods. This is because any talk of inter-connectors must be tempered by the understanding that inter-connector assets, ie the assets involved in the flow path from generators in one region to customers in another, are generally the shared network assets within regions as both the AEMC and the Productivity Commission have recently acknowledged; viz

> “…the difficulty of considering intra-regional investments in isolation, since a very large proportion of all transmission investment with a mitigating impact on network constraints will have some inter-regional effect. This is illustrated by recent analysis performed for the [AEMC], which found that approximately two-thirds of all constraint

equations contain an inter-regional term." Transmission Frameworks Review interim report p. 136

"...referring to such 'notional' interconnectors is an abstraction from how interconnectors work. In fact, an interconnector can be composed of several lines — of varying capacity and location — linking generation and load centres." PC Draft Report p 153

The outline provided of what we are trying to achieve with the current method, its approximations and assumptions should guide our decision on how best to provide efficient transmission pricing across regional boundaries. Given the true nature of inter-connectors, we propose that the establishment of a special inter-regional TUoS fee is fraught. So is the whole concept of a modified load export charge appears to seek a level of equity or costs sharing rather than to aim at efficient price signals. "Cost reflectivity" does not appear an appropriate criteria where those costs are clearly sunk. Focusing on efficient network pricing is essential to deliver price signals which promote the appropriate response and hence the NEO. It is becoming even more important as we consider time of use pricing and demand side response.

Suggested solutions

A first principle assessment then suggests that a consistent approach to the calculation of TUoS that seeks to reflect the costs of customers' ongoing use of the national network. Recognising the limitations and assumptions in the current approach, some modifications to the current methodologies adopted would need to be determined. It is suggested that the modified CRNP methodology should be adopted as it should deliver more efficient prices. The option studied by ROLIB, however, limits the application of utilisation factors to radial lines without justification. Further, the use of elements at the time of their peak loading would appear to deliver more efficient price signals, reflecting the fact that some assets are most heavily loaded (and hence likely to need augmentation) at times other than the coincident peak demand. Further work is need on this option as we understand that it is different to the option modelled by ROLIB. This option would reflect prices based on each customers use of each element of the network when that element was at its peak loading for the years rather than the customer's peak use of that element (which may in fact punish off-peak use which efficient pricing would seek to reward).

In seeking to base the analysis on use during the peak demand on each element some averaging (as used in the 10 year peak demand model) and some simplification may be warranted to aim calculation and reduce the risk of volatility in transmission pricing based on too much reliance on one half hour interval a year .

A national TUoS approach could be delivered by AEMO and AER calculating connection point allocations nationally and then operating a form of "settlements" process to then swap net amounts between TNSPs required to reconcile the amounts each TNSP received for use of the national shared network by customers connected to their network and the amount they are due from all customers nationally for the use of their network. Individual TNSPs could still calculate and recover the general TUoS charge which recovers the remainder of sunk costs.

If you have any questions about the contents of this submission, please contact Louis Tirpcou, Group Manager Regulatory Policy Development on (03) 9609 8415 or via email louis.tirpcou@aemo.com.au.

Yours sincerely

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