NIE Energy Limited
Power Procurement Business (PPB)

Methodology Options to be considered for the Implementation of Locational Signals on the Island of Ireland

Consultation Paper

SEM-09-060

Response by NIE Energy (PPB)

10 July 2009.

Introduction

NIE Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper which seeks views on methodology options to be considered for the implementation of locational signals on the island of Ireland.

General Comments

At a strategic level, PPB is disappointed that the TSOs and RAs continue to ignore the comments from the majority of generator participants that locational TUoS charges and locational TLAFs have virtually no bearing on a generator's investment decision. This is one of the few issues upon which there has been consensus among the generators. In particular, the fact is that once the generator is connected, the commitment is made for a substantial period and the generator has no scope to respond to any "locational" signals thereafter. Under the existing arrangements the generator must merely accept variability in charges that may be caused by the decisions of other generators to connect in a particular location or from decisions of the TSOs in the development of the transmission network.

This clearly highlights that once connected, all a generator faces from the existing arrangements is risk which invariably increases costs that will ultimately be borne by customers. It also highlights that the critical "locational" decision is the one made when the point of connection is selected by the generator and that therefore it is this decision that must be influenced to ensure the overall costs of the electricity industry, that are ultimately reflected in customers' bills, are minimised.

As PPB have indicated in previous responses, we believe that the best means of ensuring that the development of electricity infrastructure (both generation and transmission assets) is conducted at least cost for customers is to ensure that there is full cost transparency and that any potential investor is exposed to the full cost of the consequences of their decisions. Inefficiencies will inevitably arise where such cost signals are diluted and attempts after the event to remedy such inefficiencies only adds to the risk to generators and ultimately further increases costs for customers.

The SEM High Level Design adopted a shallow connection policy but sought to include locational transmission signals in the market arrangements for charging for use of the transmission system. However, we note that the research into international best practice shows that only three of the markets (Denmark, NEA and GB) fully apply a shallow connection policy. Norway currently has a shallow policy but is considering moving to deep, Finland has a hybrid policy while the remaining markets all apply a deep policy. Hence the majority of the researched markets clearly seek to ensure the locational issue is addressed upfront at the point of connection.

In our view the primary focus of the review must be to identify how locational signals can be provided to potential investors with the objective of minimising future investment costs for customers. The consensus from the generators in the market is that locational TUoS charges and TLAFs do not deliver this result and the review of how to change should not be constrained by the shallow connection policy decision. However, if for example, it was felt that large upfront charges were not appropriate, an alternative may be to offer individual TUoS contracts to new generators that would exist for the life of the generator, and which recovers the full cost over that period. This would provide a locational signal that could fully be assessed by a prospective generator as part of their investment decision but paid for by the generator on a depreciation charge basis.

In relation to existing generators, the connection decisions have been made and are therefore sunk. It would be unfair to seek to apply different locational charges now and therefore a uniform charging arrangement should be adopted for existing generators. As at present, this should continue to apply on a jurisdictional basis, given the varying values of the transmission assets and indeed varying policies in respect of, for example, renewables where RoI have committed to major transmission investment. This is particularly important to ensure the is no cost transfer between customers in each jurisdiction where, for example, they are incurred to facilitate a wider member state policy objective.

Comments on the Losses Options

While the theory of applying losses to ensure efficient despatch is logical, the practical implementation of it is much more difficult. The current methodology for the derivation of TLAFs has major flaws given that it is based on scheduling forecasts determined by the TSOs that are invariably wrong. There has been no review of historic losses to compare against the derived TLAFs and therefore the scale of the error is unknown although we believe it has been substantial since actual plant scheduling has varied significantly. To be effective, there would need to be realtime loss data available to allow the correct loss factor at any point in time to be used. The variability of load flows will only increase as the level of wind generation increases. It should also be noted that network losses are also influenced by the network assets procured by the network owners and their investment decisions could have an equally large impact on network losses.

The paper also claims that loss factors are currently used to determine despatch. On the basis of our understanding of the MSP scheduling tool (and RCUC), that is incorrect and losses are only applied at the settlement stage under the SEM. From the commencement of the SEM, most generators inflated their bids by the TLAF factors to get around this problem and to ensure they were not incurring a loss. As a result of some inconsistent application by a few generators, the SEM Committee issued guidance on the application of TLAFs to commercial offer data (although that also requires TLAFs to be applied inconsistently).

The consultation paper states that the adoption of uniform losses leads to inefficient despatch. While conceptually this is true, it is not apparent what level of materiality this has and whether it is any worse that many of the other market design or unit commitment inefficiencies. For example, it is acknowledged that the current scheduling engines are incapable of modelling the full characteristics of the generating units (e.g. costs that are not monotonically increasing, use of a single composite ramp rate, or solving the schedule over only 30 hours, etc.).

A further consideration is that there is asymmetry in the treatment of losses for generation and demand since the TLAFs for demand are uniform. This would create a distortion between the jurisdictions if global aggregation were employed although with the current arrangement, where the residual demand units are allocated to the former PESs, that anomaly is overcome.

In conclusion PPB consider that the current TLAFs are arbitrary and that uniform loss factors provides the most appropriate solution for the market. We are also confused why the implementation date shown in Table 4 indicates it could not be implemented until post Q4 2010. If TLAFs are to be retained, PPB's preference would be for zonal TLAFs with either a single zone or two jurisdictional zones.

Comments on the Tariff Options

As outlined in our general comments above, PPB do not believe locational TUoS charges provide the answer to the main strategic objective of minimising the costs of serving customers - in this instance through minimising overall generation and transmission investment costs.

Options 1 to 4 all suffer from a dependence on load flow analysis and ex-ante scenario modelling of potential load flows that will invariably be wrong. Also such analysis is inherently volatile and the rates derived will vary as the transmission network develops, generators connect or close down, demand appears or disappears, etc. Furthermore many of these factors will be influenced by wider policy decisions e.g. support mechanisms for renewables, regional development of the economy, etc., none of which an existing generator has any control over.

PPB consider option 5 to be the most appropriate option although because of the shallow connection policy, it does not address the wider strategic objective of minimising infrastructure costs for customers.

In the absence of changing to a deep connection policy, we consider option 6 could form the basis of a potential alternative. However, we believe it would need to operate such that both incentive discounts and disincentive premiums can be applied. This would allow discounts to be provided where generators locate in a beneficial location and premiums to be applied where location at that site will incur inefficient costs. The consultation paper contemplates that the discount would not be known in advance. However, for this to provide any definitive signal that can be properly costed in any investment decision, this should be a firm offer for a number of years (whether the delta be a discount or a premium). In terms of implementation, it would be unfair to retrospectively apply such an arrangement to existing generators but it could be implemented for all new connections.