The Single Electricity Market:

Transmission Use of System Charging Tariff Methodology

Consultation Paper

AIP-SEM-07-262

18th June 2007

Summary

In March 2007, the Commission for Energy Regulation ("CER") and the Northern Ireland Authority for Utility Regulation ("NIAUR"), collectively known as the Regulatory Authorities, published a decision document on transmission use of system charging.

Whilst this decision document established that, under the Single Electricity Market, generators should pay locational transmission use of system charges calculated using a methodology based on that presently employed by EirGrid in the Republic of Ireland, it was recognised that there was further work to be done on a number of details of the application this methodology. In particular, it was recognised that the choice of generator dispatch used in the tariff calculation had the potential to affect the materiality of the resulting tariffs.

This current document consults on the details of the method that the system operators intend to use in the derivation the transmission use of system tariff for generators, in particular:

(1) proposals for the choice of generator scenarios and the method by which it is proposed to combine them to derive a single all-island TUoS tariff;

(2) outline proposals for the costing of network components.

Views are invited by 9 July 2007.

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I INTRODUCTION

In March 2007, the Commission for Energy Regulation (the "CER") and the Northern Ireland Authority for Utility Regulation (the "NIAUR"), collectively known as the Regulatory Authorities, published a decision document[1] (the "March 2007 decision document ") concerning Transmission Use of System Charging for the island of Ireland. The paper stated that under the SEM, "*Generators should pay a locational transmission use of system charge calculated using a methodology based on that presently employed by EirGrid in the Republic of Ireland*".

However, the Regulator Authorities stated also that they considered "*that further work is required on the generation scenarios to be used in the derivation the use of system tariff*", and that the Regulatory Authorities would "*take a view on the appropriateness of further consultation when the options and their impacts are better understood*".

The Regulatory Authorities now feel that decision to use a methodology based on the EirGrid methodology leaves scope for a range of possible outcomes in terms of the tariffs that could result for any given generator on the all-island system. Accordingly, the purpose of this document is to consult on detailed aspects of method that the system operators are intending to employ in determining the all-island locational generation transmission use of system tariff for application from 1 January 2008 onwards.

The Regulatory Authorities welcome the views and comments of interested parties on the proposals contained within this paper. The Regulatory Authorities intend to publish all comments received. If any respondent wishes certain sections of their submission to remain confidential these sections should be submitted as an appendix marked confidential.

Comments, preferably in electronic form, should be forwarded not later than 5.00pm on the 9 July 2007 to:

[1] "The Single Electricity Market: Transmission Use of System Charging. Decision Paper", AIP-SEM-07-50, 15th March 2007.

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II BACKGROUND

In June 2005, the Regulatory Authorities published a decision document (the "SEM High-Level Design Decision document")[2] outlining the design for the Single Electricity Market (the "SEM") for the island of Ireland, and including a decision that the SEM should include shallow connection charging together with locational use of system charges for generation.

Following the publication of this document, the Regulatory Authorities had extensive discussions with EirGrid and SONI, as the system operators for the island of Ireland, on the implementation of this policy, culminating in the publication in July 2006, of a consultation paper[3] (the "July paper"). Having reviewed responses to this consultation, the Regulatory Authorities made a number of decisions, as published in the March 2007 decision document including:

(i) Generators should pay a locational transmission use of system charge calculated using a methodology based on that presently employed by EirGrid in the Republic of Ireland.

(ii) That the Regulatory Authorities consider that further work is required on the generation scenarios to be used in the derivation the use of system tariff, and will take a view on the appropriateness of further consultation when the options and their impacts are better understood. The Regulatory Authorities will pursue with the system operators options for giving greater transparency, whether through: the publication of, and/or consultation on, input assumptions; enabling participants to reproduce results; or the auditing of the calculations.

(iii) It is appropriate that the costing of network components for the purpose of calculating the TUoS tariffs should use a number of standardised categories of transmission assets. The exact number and definition of such categories will emerge with further work, but the Regulatory Authorities will consider it appropriate if these cost categories are jurisdictionally specific.

It was also noted that the legislative and regulatory framework for the SEM was still under development and, in particular, the means precisely by which a

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[2] "The Single Electricity Market (SEM) High Level Design Decision Paper", 10 June 2005, AIP/SEM/42/05.

[3] "Single Electricity Market Connections and Transmission Use of System for Generation: A Consultation Paper", July 2006, AIP/SEM/72/06.

combined all-island use of system and connection charging framework would be enshrined was not decided. However, it was suggested that each transmission company would continue to publish its own statement of charges, approved by the respective Regulatory Authority, and in accordance with the respective statutory or licence obligations. When taken together, the two sets of charges would form a combined set of charges calculated in accordance with the all-island methodology.

III DISCUSSION

III.1 Choice of Generator Tariff

III.1.1 The July Paper

The July paper described how an important aspect in the application of EirGrid's "reverse MW-mile" methodology is the assumed pattern of generation and demand. It noted that EirGrid's explanatory document is not explicit on how this pattern of generation and demand is derived, but that the Regulatory Authorities understood that the method used is to use a forecast of peak demand, allocated to each demand node, and then to scale the generation (both directly-connected and embedded) at each node pro-rata, in proportion to the Maximum Export Capacities, such that total generation meets total demand.

It was noted that the plant margin on the all-island system had increased recently to over 40%, and that whilst the plant margins in Northern Ireland (NI) and Republic of Ireland (ROI) are similar, the system in the ROI has a higher proportion of wind generation as well as plant that, on an all-island basis, has the lowest merit. Thus pro-rata scaling of generation, on an all-island system, led to low assumed flows on the interconnector that were considered to be unrepresentative of typical conditions, and unrepresentative of the basis on which investment in the transmission network is planned.

A number of possible alternatives to pro-rata scaling of generation had been suggested including:

(i) classifying generation into a number of categories: baseload; mid-merit; low merit; and wind, and scaling the generator Maximum Export Capacities (MECs) by load factor representative of the category, before these scaled MECs were then all scaled again uniformly to meet peak demand;

(ii) using an economic dispatch from the Plexos modelling corresponding to a peak demand condition. Any generation not running in the chosen dispatch would be assigned the smallest possible MEC of 1MW in order that a TUoS tariff were calculated for that generator;

(iii) modelling two conditions - winter peak and summer peak, say - and using an average of the two dispatches.

The paper stated that further work was required on the choice of generation dispatch and that the Regulatory Authorities regard it as desirable as a principle that the dispatches used for developing generator TUoS tariffs reflect the generation scenarios used for investment planning.

III.1.2 Proposed Approach

Method

The system operators have been discussing with the Regulatory Authorities how a pattern of generation and demand could be developed for use with the reverse MW-mile methodology. The system operators have emphasised that, until tariffs have been produced, it is difficult to be certain that there will be no unanticipated effects and that thus any given method must be regarded as 'work in progress'. Nevertheless, the system operators have suggested a method that seems to the Regulatory Authorities to embody the principle of reflecting the generation scenarios used for investment planning.

The method comprises:

Step 1: Define a set of several generation scenarios, which are plausible system running conditions that, in aggregate, represent the spectrum of operating conditions used in investment planning analysis[4];

Step 2: For each scenario, perform a load flow analysis. Each such load flow:

(a) will represent an operating condition that makes heavy usage of the transmission system and may even be a condition that would have led to the identification of reinforcements[5]; and

(b) is used to calculate a value for the transmission use of system tariff for each generator on the transmission system using the reverse MW-mile methodology;

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[4] Note that, in planning the system, the system operators consider a range of contingencies, which consist of credible faults on transmission system circuits and other transmission equipment and also credible losses of generation in-feed to the system, against all of which the system is required to be robust. For each scenario, it is the load flows identified under each of these fault conditions that determine whether a reinforcement may be required. For the purposes of calculating a tariff, however, it is only the usage made of the transmission system in the "pre-fault" condition for each of these scenarios that is studied.

[5] Note that studies that lead to the identification of system reinforcements will have been performed well in advance of the reinforcements being made, whereas the tariff calculation applies to the system that already exists or to reinforcement that are expected to be completed in the following tariff year.

Step 3: For each generator, take the maximum - i.e. the most positive - value from each of the tariffs calculated in step (2)(b);

Step 4: Take the tariff comprised of the maximum value in (3) for each generator, calculate the revenue recovery and shift the tariff (as expressed in €/kW) uniformly across all generators to obtain the target revenue recovery for the two jurisdictions combined. The resulting shifted tariff is the transmission use of system tariff.

Note that in step (3) it is important that each tariff calculated in step (2)(b) is 'normalised' to generate the same revenue recovery. Otherwise the choice of maximum value could be distorted by the fact that the various tariffs may be shifted relative to each other by some arbitrary amount.

Rationale

The rationale for this method is that the need for any reinforcement of the transmission system or use made of the existing transmission system may be driven by any of the plausible scenarios; the reverse MW-mile methodology then determines how the need for that reinforcement or existing system is shared between generators.

Taking the maximum value for each generator across the set of scenarios is also considered an appropriate means of combining the individual tariffs calculated for each scenario. A consequence of this approach is that, whilst in an individual tariff, a generation node may have a high value as compared to any given other node, the amount by which it exceeds the maximum value, taken across all the scenarios, at that given other node is likely to be less. Thus the tariff comprising the maximum values for all generation nodes may be significantly "flattened", i.e. with lower overall locational differentials, in comparison to individual tariffs. However, this flattening of the tariff is rational to the extent that high usage of the transmission system has been demonstrated by generators under one system running condition or another, regardless of location.

For the development of the transmission use of system tariffs for 2008, the system operators have initially suggested a set of scenarios as shown in Appendix A. The addition of further scenarios that do not 'stretch' the capabilities of the transmission system would be unlikely to affect the final tariff as such scenarios would be unlikely to contribute to the maximum value for any generator. Similarly, if it transpires that any scenario included in the set used does not stretch the transmission system capabilities to the same extent as other scenarios then, again, its inclusion will not bias the results.

Consequently the outcome is not highly dependent on the design of a scenario that has to be chosen so as to be representative of a wide range of conditions, nor on the relative weightings attached to different scenarios were a set of scenarios 'blended' in some way. Instead the method requires only that the range of scenarios chosen should span the range of scenarios that drive the identification of transmission investment. The system operators have advised that this is achieved by the range of scenarios shown in Appendix A. Thus, the Regulatory Authorities consider that the basis upon which the system operators are progressing the dispatches for the derivation of tariffs appears to be well founded.

III.2 Network Costing

III.2.1 The July paper

As described in the July paper, the reverse MW-mile requires a cost to be assigned to each transmission circuit and that the sum of all these circuit costs, each multiplied by the flow caused by any given generator, expressed as a proportion of the circuit's capacity, gives the locational element of the tariff for that given generator. The paper explained that the existing EirGrid methodology uses a replacement cost for each circuit, whilst replacement costs for each transmission station were also allocated to the circuits that are connected to that station. It was noted also that a suitable database of replacement costs does not exist for NIE's system and that EirGrid considered that the replacement costs used for its system are now due for review and amendment.

Alternatives to actual replacement costs were considered, including:

(i) using a number of categories, giving a reasonable approximation to actual costs, varying by voltage level, and by type of construction;

(ii) as (i) but using a different figure in each jurisdiction for a given asset type should there be a difference in costs between the two jurisdictions; or

(iii) a single figure for the whole system, derived by dividing a total all-island system cost by the total all-island MW-miles.

The subsequent decision document stated that it was appropriate that a number of standardised categories of transmission assets should be used on the grounds that it would provide the most accurate tariffs, in that the tariffs would best reflect the long-run marginal cost imposed by each generator, to the extent that the standardised costs reflected actual costs. It was noted that the exact number and definition of such categories would emerge with further work, but the Regulatory Authorities would consider it appropriate if these cost categories are jurisdictionally specific.

III.2.2 Proposal

The system operators have been considering the cost categories that it would be appropriate to use in the calculation of network tariffs. Work is ongoing on identifying the appropriate cost of in various categories. As this work progresses, it may transpire that some categories can be merged where a combined merged category is still representative of the assets in that category.

Nevertheless, the categories under consideration are

1. For circuits:
   - i. Cost per km by
     - a. OHL / Cable (including cable end costs)
     - b. 110kV / 220kV / 275 kV / 400kV
     - c. NI / ROI
2. For transmission stations:
   - i. Switchgear costs, covering switchgear bay costs including civil works, protection and auxiliaries categorised by
     - a. bay costs
     - b. 110kV / 220kV / 275 kV / 400kV
     - c. NI / ROI
   - ii. Transformer costs, by
     - a. voltage, i.e. 110/220kV / 110/275kV 220/400 kV
     - b. capacity, either

       Option 1: per MVA cost; or

       Option 2: specific costs for standard sizes, e.g. 63 MVA / 125 MVA / 250 MVA / 500 MVA.
     - c. NI / ROI
   - iii. General station costs apportioned across the transmission circuits, and including buildings, fencing, earthing and station supplies.

Pending work to determine the costings to be used in each of the categories, it is the current view of the system operators that the above classification provides a manageable number of categories whilst still reflecting the actual costs that users impose on the system.

Also still under consideration is whether the costs of assets such as capacitors, SVCs, interbus reactors and phase-shift transformers should be factored into the above categories, or ignored. These assets are necessary in order to provide system support. The case for factoring these costs into the above costings is that major network components will inevitably give rise to the need for these other ancillary components. The case against is that the cost of system support provided by users is not charged for locationally and hence it would be inconsistent to do so for system support provided by components of the transmission system itself.

III.3 Other Issues

III.3.1 Harmonisation of wires and non-wires costs.

The March 2007 decision document stated that the costs recovered through generation TUoS charges should be equivalent as between the two jurisdictions.

This issue is still outstanding. Clearly, in developing a Statement of Charges, the system operators will have to propose harmonising costs by one means or the other. However, the Regulatory Authorities remain open-minded as to whether it is EirGrid system operator costs that should be omitted from generation TUoS charges or SONI costs that should be included. The Regulatory Authorities consider that, at this stage, the main priority is to avoid the situation where costs incurred in one jurisdiction are borne by users in that jurisdiction whilst like costs incurred in the other jurisdiction are shared across the two jurisdictions.

III.3.2 Cross-Border Revenue Adjustment

The March 2007 decision document stated that in order to offset any increase in costs to NI consumers relative to consumers in ROI, the Regulatory Authorities consider it appropriate to make an adjustment, up until the first of the cancellation dates in the PPB contracts, calculated each year as part of derivation of the annual TUoS tariffs and taking into account the locational generation TUoS tariff.

The detail of such calculation is beyond the scope of this paper. Nevertheless, the Regulatory Authorities consider that the effects that need to be taken into consideration are:

(i) the impact on demand in NI vis-à-vis demand in ROI of the interaction of locational charges on PPB-contracted generators in NI with the NI PSO levy;

(ii) the impact on demand in one jurisdiction vis-à-vis the other of harmonising the classification of 'wires' and 'non-wires' costs through the transfer of costs either from demand in one jurisdiction or to demand in the other; and

(iii) the pooling between the jurisdictions through generator TUoS charges of a proportion of the costs of the former North-South interconnector; and consequential effect on NI generators and, via the PSO levy, on NI demand.

It has been noted that, under the SEM, it is no longer the case that the revenue recovered from the users connected in a given jurisdiction is equal to the allowable revenues associated with the transmission system in that jurisdiction. (It is equally true, pre-SEM, that the revenue recovered from users connected in a given part of the transmission system in a single jurisdiction generally is not equal to the allowable revenues associated with that part of that transmission system)[6]. Thus, on the assumption that generator TUoS tariffs will be higher in NI than ROI, then there will be a surplus of revenues recovered from users connected to the transmission system in NI and a corresponding deficit in ROI. Accordingly, it is expected that, under the terms of the System Operators' Agreement, there will be a payment from one system operator to the other. The magnitude of this transfer will depend on the generator TUoS tariff. It is expected that any cross-border adjustment will go to reduce partially the magnitude of this transfer.

III.3.3 Enshrining the All-Island Generator Tariff

It was noted in the March decision document that the legislative and regulatory framework for the SEM was, at that stage, still under development, and specifically the means by which a combined all-island use of system and connection charging framework would be enshrined had not yet been decided.

Since March 2007, legislation has been enacted and draft licences have been published, including for the transmission system operators in each jurisdiction. In the legislation and the proposed amendments to licences, the existing

[6] The exception being the interconnecting circuits between NI and RO which currently are paid for only by users of these circuits.

obligations on each licensee to prepare, have approved and publish a statement of charges for use of system remain. Thus the approach suggested in the March 2007 decision document, of having two sets of charges that, when taken together, form a combined set of charges calculated in accordance with the all-island methodology, has been adopted.

IV NEXT STEPS

Views are invited on the proposals described in this paper. In particular, views are invited on the substantive issue of the selection of the generator scenarios and the method of combining them into a single use of system tariff. Views on the categorisation of costs would also be welcomed, including on whether the costs of components providing system support should be factored into circuit costs.

Comments are requested by 9 July. The system operators are then expected to come submit draft statements of charges by the end of July. These draft statements will be subject to the approval of the respective Regulatory Authorities. It should be noted that the system operators are continuing to refine the suggested approach and hence further information may still come to light and details of the proposed methodology are still subject to potential change. Consequentially, in approving these statements, the Regulatory Authorities, will take into account any such further information from the system operators as well as the responses to this consultation.

Approved statements of charges are planned for publication in September.

APPENDIX A

Indicative Set of Generation Dispatches													
Studies	**Time of Year**			**Dispatch**									**Comment**
	Winter Peak	**Summer Max**	**Summer Min**	**Conventional Generation**		**Wind Power**				**Interconnecting Circuit Flow**[7]			
				Pro-rata	**Merit Order**	**Pro-rata**	**100 %**	**35%**	**0%**	**N-S**	**S-N**	**As Merit Order**	
1	Y				Y				Y	Y			Cold, still winter's day. Represents worse case with maximum flow bulk flow from conventional generators, with no wind/embedded generation.
2	Y				Y				Y		Y		
3	Y				Y				Y			Y	
4		Y			Y		Y			Y			Average system load. Represents a high load with equipment at reduced summer rating.
5		Y			Y		Y				Y		
6		Y			Y		Y					Y	
7		Y			Y				Y	Y			
8		Y			Y				Y		Y		
9		Y			Y				Y			Y	
10			Y		Y		Y			Y			Minimum system load. maximum wind.embedded generation. Represents overstressed network with equipment at reduced rating.
11			Y		Y		Y				Y		
12			Y		Y		Y					Y	

[7] Although the flow on the interconnecting circuits between the transmission systems in NI and ROI is determined by the merit order in conjunction with pattern of demand across the island of Ireland, investment planning analysis has generally considered also the effect of the plausible extremes in these circuit flows, and is likely to continue to do so for the immediate future. These conditions are therefore at least worthy of consideration prior to the derivation of tariffs.