Response to SEM Consultation Paper SEM-11-036

Generator Transmission Use of System Charging – 2011/12 Indicative Tariffs

on behalf of

AES Kilroot Power Ltd and AES Ballylumford Ltd

25 July 2011

1.0 Introduction

AES Kilroot Power Limited and AES Ballylumford Limited (collectively "AES") welcome the opportunity to comment on the consultation on Generator Transmission Use of System Charging – 2011/12 Indicative Tariffs and the associated Eirgrid/SONI paper (SEM-11-037) - All-Island Generator TUoS Methodology.

2.0 Summary

AES has substantial concerns in relation to the proposed indicative Generator Transmission Use of System (GTUoS) Tariffs for 2011/12. AES does not believe that the methodology adopted by the TSO to determine the tariffs is appropriate and would suggest that it is fundamentally flawed as it:

- Disproportionally levies charges on Nothern Ireland (NI) generation which do not appropriately or accurately reflect the use of the transmission system by many NI generators, particularly those owned by AES. On average, the indicative tariffs for NI generators are 23% higher than in the Republic of Ireland (ROI);
- Creates an explicit €7m cross subsidy from NI generators to ROI generators;
- Arbitrarily derives a locational charge for NI generators which are out of merit and likely only to be dispatched in the Summer Min scenario on a constrained on basis to support the system; and
- Determines GTUoS tariffs which are inconsistent with TLAF locational signals.

AES contends that the proposed tariffs would provide a flawed signal to new investors indicating that new generation should be located in ROI and is contradictory to the most recent BNE consultation paper SEM-11-025, which indicates that a BNE peaker would be located in NI. This could give rise to significant challenges in terms of NI meeting its own renewable targets and also in the longer term, to generation capacity issues for NI.

AES would strongly urge the SEM Committee to recalculate the cost of the BNE peaking plant using, as a minimum, the indicative GTUoS outlined in SEM-11-036. However, since the Annual Capacity Payment Sum (ACPS) will not be finalised until the end of November when the Annual Capacity Exchange Rate is calculated, then AES sees no reason why the BNE peaking plant cost should not also be updated at this time for the actual 2011/12 GTUoS tariffs, as decided by the RAs.

3.0 Generator TUoS Methodology

General

In our response to SEM-11-18, AES agreed that it was appropriate to harmonise the charging methodologies so that it is consistent between both NI and ROI. However, we argued that it was not reasonable or prudent to aggregate the allowed revenue on an all island basis as this would give rise to an explicit need for cross-border financial flows resulting in cross subsidies between one jurisdiction and other. The proposed GTUoS tariffs confirm that this is indeed the out-turn result from the TSO proposed methodology and also confirms the extent to this cross border flow at approximately €7m/year.

The allowed revenue in each jurisdiction will be separately determined by NIAUR and CER to support distinct Government energy and renewable policy and similar policies may not be adopted in each jurisdiction. Consequently the energy policy of one jurisdiction may result in substantive/aggressive infrastructure investment whilst the other jurisdiction may choose a more prudent/cautious approach. Either way, aggregating the allowed revenue on an all island basis will result in one set of generators

subsidising another and AES does not support this approach.

Since the allowed revenue is determined by each Regulatory Authority (RA) on an autonomous, jurisdictional specific basis, each RA may adopt a different regulatory approach which may have an impact on allowed revenue which is inconsistent or divergent with the trajectory of the allowed revenue in the other jurisdiction. Again, under this charging method a cross-subsidy will be established.

Given the above, as a general point of principle, AES believes the proposed methodology is fundamentally flawed.

Postalisation of Existing All Island MEAV

Based on our analysis, the postalised element of the indicative tariffs results in NI generators paying approximately an additional €3.4m, above what they are paying under the current NI GTUoS tariff regime. We believe that this is a direct cross subsidy being paid by NI generators as it does not relate in any way to their use of the All Island transmission system and believe this to be flawed and inappropriate.

Dynamic Tariff Modelling and Methodology

As stated previously, we do not have sufficient information to comment on the accuracy or robustness of the TSOs modelling in relation to cost files, power flow analysis and Plexos modelling however we would make comment as follows.

Dispatch Scenarios

The TSOs have indicated that a dispatch file for each generator was created against four scenarios:

- Winter Peak with 0% wind;
- Summer Peak with 80% wind;
- Summer Peak with 0% wind; and
- Summer Min with 80% wind.

The TSOs have explained that the rationale behind these four scenarios is that they are used within Network Planning analysis by both SONI and Eirgrid. We have reviewed both Eirgrid's Transmission Forecast Statement 2011-17 and SONI's Transmission Seven Year Statement 2009-2015 and we can only identify three scenarios – Winter Peak, Summer Peak and Summer Minimum with no explicit reference to wind capacity assumptions.

AES have significant concerns with respect to the TSOs wind assumptions. We would welcome some detailed clarification as to why the TSOs believe it is appropriate to use an 80% wind capacity figure within the GTUoS methodology. We would also welcome clarification as to whether this 80% figure is based on overall installed wind capacity or only wind installations connected to the transmission system.

AES would agree that it may be appropriate to use such a figure within transmission network analysis, particularly in terms of assessing the technical impact of maximum wind generation output on overall system capability, compliance with planning standards and short circuit current ratings. However, such exceptional levels of wind output coinciding with periods of minimum summer demand, occurs only rarely and even then for a very short period of time. Consequently, AES would suggest that even when it comes to network planning and transmission investment decision making, it is not economically prudent to base decisions on a deterministic worst case approach. Rather, a more probabilistic approach should be adopted which quantifies the risks to the system within an overall balanced

investment framework.

AES would argue strongly that it is inappropriate to base wind assumptions within the GTUoS tariff methodology on wind output scenarios which are rare and often distinct from other system variables. We would suggest it would be more appropriate to utilise historic wind capacity factors which have occurred previously during each dispatch scenario.

Load Flow Analysis

The TSOs have confirmed that the load flow analysis is based on first establishing the dominant flows on transmission network via a base case model. Subsequently the methodology then establishes the contributory flow from each individual generator across the network, given the dominant flows.

This analysis is based on an Plexos forecast of unconstrained dispatch and whilst we have not been provided with the Plexos analysis, SONI have confirmed that in the Summer Min scenario, many generating units in NI (including all units at Kilroot and most at Ballylumford) are out of merit and not dispatched. However, the TSOs have decided to arbitrarily allocate a 1MW dispatch to out-of-merit units "in order to derive a tariff for every unit in all scenarios". AES believes that this logic is fundamentally flawed.

Firstly, if units are out-of-merit in a scenario then it would be logical to say that the locational element of the tariff should be zero, as they are not making use of the system or contributing to the dominant flow. 1MW does not need to be added to derive a tariff - the tariff should essentially be set at the postalised figure.

Secondly, AES agrees that most units in NI are out of merit in the Summer Min scenario (our analysis supports this in the near and medium term). However, such units will only be dispatched on a constraint basis to support the system, due to either established transmission constraints (which are a result of insufficient transmission infrastructure) and/or to offer reserve and reactive power to assist with the management of wind. It is illogical and perverse to then allocate a penal locational charge on such generation when the system is actually reliant on such generation to ensure system integrity and security.

And thirdly, it is evident that in the Summer Min scenario, there is a dominant flow N-S and SONI have confirmed that this is due to Moyle imports. Moyle imports are not charged GTUoS, however these imports are driving the dominant flow in this dispatch scenario and this, combined with the arbitrary allocation of 1MW to out-of-merit units, is setting the locational tariff for all NI Generation. We believe that this approach is fundamentally unfair and does not represent an appropriate method for allocating costs in using the transmission system.

Assets within the Cost File

Both TSOs have confirmed that a main contributory factor behind the high locational charges for NI generators is the inclusion of the second N-S interconnector and associated ROI transmission circuit between Cavan-Woodland. AES are aware that the ROI Government has just appointed a Commission to investigate the feasibility of using underground cabling within the southern section of the route corridor and the findings of this Commission could have far reaching implications for both the cost and timescales for the overall N-S interconnector project. Furthermore, both jurisdictions are holding Planning Enquiries in relation to the project and this in itself adds considerable uncertainty in relation to overall timing and commissioning of the project. Given the substantive uncertainty in relation to the costs and commissioning date of the second N-S interconnector, AES would suggest that it is inappropriate to include these costs within the cost file for this upcoming tariff year.

AES also consider that existing thermal generators in NI (and indeed ROI) are not driving the need for investing in the second N-S interconnector. The RAs in their introduction to SEM-11-036 state that "those participants that drive investment pay higher tariffs". The need for the second N-S is primarily being driven by both Governments' targets in relation to renewable generation, and also an overall strategic ambition to improve the efficiency and security of the transmission systems on the Island. We believe that a more equitable solution must be found in relation to recovering the costs of the second N-S interconnector, and that NI generators should not have to shoulder the burden of investment costs which they are not driving.

4.0 Indicative Tariffs

As indicated above, AES believes that the flawed methodology has resulted in excessive GTUoS tariffs for NI generators.

Specifically in relation to AES generating units, the proposed tariffs result in almost an 80% increase in use of system costs compared to what we have had to pay for the year 2010-2011. This increase is not only a result of the locational element of the tariff but also due to the all Island postalised element.

More generally SONI have confirmed that the average ROI tariff is approx €4.8/kW/year whilst the average NI tariff is approx €5.9/kW/year i.e. NI generators are paying on average 23% more for the use of the transmission system than generators in ROI. The overall net effect of the proposed tariffs is that NI generators will be making a €7m/year contribution to ROI generators.

AES also has concerns in relation to the consistency of locational signals provided by TLAFs and the proposed GTUoS tariffs. For example, TLAFs for Whitegate and Aghada are amongst the worst on the Island, yet the indicative GTUoS tariff is in no way consistent with this. Conversely, Ballylumford and Kilroot have 'good' TLAFs (greater than 1) yet have a very penal GTUoS tariff. We understand that TLAFs are addressing more short term dispatch efficiencies however we would expect there to be a much stronger correlation between TLAFs and GTUoS tariffs given that they are both important locational signals.

Given the above, and also our concerns raised in relation to the methodology in section 4.0, we do not believe that the proposed tariffs represent a fair or reasonable apportionment of cost for using the transmission system. Furthermore, we would suggest that the proposed tariffs would provide a flawed signal to new investors indicating that new generation should be located in ROI. This could give rise to significant challenges in terms of NI meeting its own renewable targets and also in the longer term, in relation generation capacity and system security issues for NI.

5.0 Consultation and Regulatory Process

Previous SEM Committee Paper – SEM-11-018

The RA's recently consulted on GTUoS in its April 2011 paper SEM-11-018. AES responded to this paper in May 2011 however the RAs have yet to issue any decision, indicative or otherwise, as to what options detailed in SEM-11-018 are to be implemented. AES has therefore found it difficult to thoroughly assess the impacts of these most recent GTUoS consultation papers, as there are a number of variables which still remain subject to change. It would have been preferable if SEM-11-018 and SEM-11-036 had been published contemporaneously.

In our response to SEM-11-018 and the options relating to tariff fixing we indicated a preference for a term of five years, however that view was expressed in advance of the current papers setting out the

indicative tariffs and methodology. Having reviewed the methodology and indicative tariffs, we now have substantial concerns that fixing the tariff for a period of five years is inappropriate, given the weakness in the GTUoS calculation methodology. Whilst it would afford predictability it will lock in NI generators into GTUoS tariffs which are not cost reflective and substantially higher than those generators located in the ROI.

Transparency

AES considers that the TSOs have provided insufficient detail on the assumptions and methodology used for calculating the indicative tariffs and the TSOs should have provided a detailed breakdown of the locational and postalised tariff elements for every generator and specifically the assets contributing to the locational charge and the 'share' of this asset each generator is to pay for.

AES requested additional information from SONI on the 14th June and eventually received a response to all our queries on the 8th July, over three weeks later. SONI's response is attached as Appendix A and you will note that in terms of our queries relating to commodity assumptions, COD, TOD and Plexos analysis, we have been referred to Appendix 1 of the "Transmission System Operators' Submission for Dispatch Balancing Costs October 2011 – September 2012". This document does not provide any detail as to the commodity prices, COD, TOD, wind generation or Plexos results that we requested. We note that it is not even clear if the TSOs utilised the RAs Validated SEM Generator Data Parameters as the TSOs have amended elements of production costs 'where necessary' (page 24 of the TSOs Dispatch Balancing Costs response). In the absence of this requested information, we have found it difficult to determine the veracity of the TSO analysis particularly in relation to the Plexos assumptions and modelling and the impact of assuming an 80% capacity factor for wind.

We note that the SEM-11-037 is a TSO paper which has been used as a basis for the RAs consultation paper SEM-11-036. AES would welcome confirmation from the RAs that they have reviewed and are satisfied with the robustness and accuracy of the TSOs' cost files, technical assumptions (particularly in relation to wind), power flow analysis and Plexos modelling.

Best New Entrant

In our response to SEM-11-025 "Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2012" consultation paper, AES drew attention to the fact that the proposed indicative GTUoS tariffs were not included within the calculation to determine that the cost of the Best New Entrant (BNE) Peaking Plant.

AES would strongly urge the SEM Committee to recalculate the cost of the BNE peaking plant using, as a minimum, the indicative Generator TUoS outlined in SEM-11-036. However, since the Annual Capacity Payment Sum (ACPS) will not be finalised until the end of November when the Annual Capacity Exchange Rate is calculated, the AES sees no reason why the BNE peaking plant cost should not also be updated at this time for the actual 2011/12 Generator TUoS tariffs, as decided by the RAs. AES does not consider there to be any justification for calculating the BNE peaking plant using the historic GTUoS tariffs for 2010/11.

Appendix A – Additional Information provided by SONI

Ian Luney

From: Lewis, Dick [Dick.Lewis@soni.ltd.uk]
Sent: 05 July 2011 17:04
To: Ian Luney
Cc: Tanya Wishart; Corbett, Juliet; Walker, Billy; pbrandon@cer.ie; Needham, Mark; Magorrian, Helen
Subject: AES TUoS questions
Attachments: SEM-11-054a_Imperfections_charges_appendix_1[1].pdf; SO response to AES Questions (July '11).docx

Ian,
Please find attached a document responding to the questions you asked regarding generator TUoS charges. There is still an outstanding matter regarding the Kilroot locational component that we will respond to tomorrow.

Regards,
Dick

Link to the RAs' consultation on 2011/2012 DBCs consultation and find TSOs' submission on same attached:

http://www.allislandproject.org/en/smo_current_consultations.aspx?article=47dc382e-85b8-4342-82eb-eee9ce9dbfb6&mode=author

Questions and answers
AES

1. What is the tariff breakdown for each AES connected node between the locational element and postage stamp element?

Generator	Postage stamp	locational	Total
Ballylumford	€3.5416	€2.0710	€5.6117
Kilroot	€3.5416	€1.9844	€5.5260

2. The locational element is based on Plexos modeling – what is the source data for this modeling in terms of TOD, COD and commodity assumptions?

Data used is as per the Dispatch Balancing Costs Plexos model, please see section 4.2 and Appendix 1 of "Transmission System Operators' Submission for Dispatch Balancing Costs October 2011 – September 2012" SEM-11-054a for details on assumptions used in the DBC Plexos model.

3. Have you included the impact of the Carbon Price Floor?

The cost of carbon is included in the model however the impact of the Carbon Price Floor in NI which is due to come into effect in 2013 has not been included.

4. Can you also confirm that the Plexos modeling is on an unconstrained basis?

The Plexos modeling is on an unconstrained basis. Also please note that the Plexos model was used only to create the all-island merit order stack which lists the generators on the island on the basis of their efficiency.

5. Was the RA Validated Data Set used?

The Dispatch Balancing Costs Plexos model was used to derive the all island merit order stack.

6. In terms of transparency, it would be helpful if you could provide the Plexos analysis and also the detail of the network investment & costs in the period up to 2016/17.

While the DBC Plexos model itself is not available, model details are included in the attached document "Transmission System Operators' Submission for Dispatch Balancing Costs October 2011 – September 2012" SEM-11-054a. The network developments are as per those listed in the Transmission Forecast Statement (EirGrid) and the Transmission Seven Year Capacity Statement (SONI).

7. **Does the methodology and tariff determination include the construction and commissioning of second N-S transmission line? If so when is it assumed to be commissioned?**

Yes, this is included in cost and network file. It is assumed that the circuit will be commissioned by winter 2016.

8. **What is the 'agent cost' referred to in the paper?**

This is a term that is used in Integra the DC load flow software and tariff calculation tool. It is the cost that is attributable to the generator in question for its usage of new assets.

9. **Our TUoS agreements in relation to K1 & K2 specify in Schedule 2 that "The Maximum Export Capacity upon which the use of system charge is calculated for each of the Generating Units is 240 MW". Can you confirm the logic behind moving to a figure of 260MW? AES hold the view that for all units, charging will continue to be based on the MEC figures stated in the TUOS Agreements. If this is not the case, the TUOSAs will need to be renegotiated.**

There was an error in the MECs used for NI generators when calculating indicative tariffs. The calculations should indeed be based on the export capacity stated in TUoS Agreements and this will be rectified.

10. **We note that the NI TUoS tariffs are substantially higher than in ROI – are the TSOs indicating that new generation should be located in ROI? We would also welcome some comment on the apparent inconsistency between TLAF signals and TUoS signals e.g. Aghada Station**

NI tariffs are not substantially higher than ROI tariffs. The average ROI tariff is approx €4.8/kW/year while the average NI tariff is approx €5.9/kW/year. The indicative tariffs in N Ireland using the all-island methodology are higher than they were under the previous methodology used in N Ireland.

It should be noted that TLAFs are not meant to be a long term signal, they are there to provide a short run dispatch signal while TUoS is intended to be a long term signal.

11. **The TSOs are proposing almost a doubling of Generator TUoS charging to generators in NI, resulting in an over-recovery in NI against NI revenue entitlement. It is proposed that this over-recovery will then be passed to the ROI. So year on year, under this proposal, NI Generators will be subsidizing ROI generators to the tune of over €6m/year (based on our initial analysis). Could you confirm that your analysis aligns with our understanding?**

Based on the indicative tariffs for 2011/2012 there would be a cross border flow from north to south which results in approx €7m more than the NI revenue entitlement being recovered from NI generators. This is as a result of the usage that the NI generators are seen to make of the all island transmission system to export generation.

23 June Questions (following workshop)

I wanted to follow-up on yesterdays GTUoS workshop, primarily in relation to AES's questions which we previously submitted last week.

For the most part, the workshop provided clarification on some of our queries, however a number of important points remain out-standing:

1. Can you confirm what MEC is going to be used at Kilroot – we are currently charged on the basis of 238MW (260MW generated). Is the 260MW figure in the consultation paper an error?

   See above - There was an error in the MECs used for NI generators when calculating indicative tariffs. The calculations should indeed be based on the export capacity stated in TUoS Agreements and this will be rectified.

2. Plexos modeling results and assumptions – there was significant discussion around this issue at the workshop and in order to allow meaningful comment on the proposed methodology and tariff, the TSOs agreed to make available the modeling results and assumptions (including commodity prices, sensitivity analysis in relation to the impact of carbon price floor, timeframe etc etc).

   See above - data used is as per the Dispatch Balancing Costs Plexos model, please see section 4.2 and Appendix 1 of "Transmission System Operators' Submission for Dispatch Balancing Costs October 2011 – September 2012" SEM-11-054a for details on assumptions used in the DBC Plexos model.

3. Can you provide a breakdown for the Kilroot and Ballylumford nodes in terms of how the locational element has been calculated (including the breakdown for each of the four scenarios). In addition it would be really helpful if an example could be provided for a single Kilroot node in terms of the derivation of the locational element.

Node	WP tariff	SMin Tariff	SP0%W Tariff	SP80%W Tariff	Max tariff	Adjusted Tariff	Adj + PS Tariff	Final Tariff
Kilroot	-1.95184	4.2709	-2.9535	-3.74188	4.2709	€1.9844	€5.5260	€5.5260

Node	WP tariff	SMin Tariff	SP0%W Tariff	SP80%W Tariff	Max tariff	Adjusted Tariff	Adj + PS Tariff	Final Tariff
Ballylumford	-1.84486	4.45523	-2.84904	-3.61739	4.45523	€2.0700	€5.6117	€5.6117

   The details behind the locational tariff for Kilroot will be provided tomorrow.

4. By way of clarification, is it right that each node's locational element is based on the worst case scenario? i.e. each node code have locational tariff based on scenario different to other nodes?

The locational element is based on the highest tariff over the four scenarios. The tariff applicable results from the flows that are driving investment in the network. The locational tariff at each node is therefore based on the generator in questions contribution to the most testing or onerous condition.

Ian Luney

From: Magorrian, Helen [Helen.Magorrian@soni.ltd.uk]
Sent: 07 July 2011 16:29
To: Ian Luney
Cc: Tanya Wishart; Corbett, Juliet; Walker, Billy; pbrandon@cer.ie; Needham, Mark; Lewis, Dick
Subject: Tariff breakdown
Attachments: Kilroot Locational tariff.docx

Ian

As requested please find attached the breakdown of the Kilroot locational tariff.

Regards

Helen

Helen Magorrian

Assistant Manager
Grid Operations Planning
SONI Ltd

☎ Internal: 22548
☎ DDI: 02890 707548
☎ Fax: 02890 707560
✉ E-mail: helen.magorrian@soni.ltd.uk

Following on from the information provided 05/07/11, here is the derivation of the locational element for a single Kilroot node as requested:

Node	WP tariff	SMin Tariff	SP0%W Tariff	SP80%W Tariff	Max tariff	Adjusted Tariff	Adj + PS Tariff	Final Tariff
Kilroot	-1.95184	4.2709	-2.9535	-3.74188	4.2709	€1.9844	€5.5260	€5.5260

The tariff for Kilroot is set during the Summer Min. scenario
Kilroot locational tariff equals €4.2709/kW/year, it is derived as follows:
Total agent costs = €4,270.9
Generator dispatch = 1MW
Locational Tariff = €4.2709/kW/year

Here are the main circuits that Kilroot is seen to contribute to the dominant flow on:

BUS NUM.	FROM NAME	BUS NUM.	TO NAME	UNIT COST €/kW	BASE FLOW MW	AGENT FLOW MW	AGENT COST (€'000s)
3774	CAVAN	90440	TURL4-	6.27	-31.28	-0.36	2.25
3774	CAVAN	5464	Woodland	5.13	70	0.34	1.74
85020	MAGF2-	90420	TURL2-	1.78	32.67	0.17	0.31
2841	Gorman	3821	Meath	5.39	-16.88	-0.02	0.13
90320	TAMN2-	90420	TURL2-	0.49	68.32	0.17	0.08
90420	TURL2-	90440	TURL4-	0.57	10.43	0.12	0.07
90420	TURL2-	90440	TURL4-	0.57	10.43	0.12	0.07
90420	TURL2-	90440	TURL4-	0.57	10.43	0.12	0.07

Here are the main circuits that Kilroot is seen to offset the dominant flow on:

BUS NUM.	FROM NAME	BUS NUM.	TO NAME	UNIT COST €/kW	BASE FLOW MW	AGENT FLOW MW	AGENT COST (€'000s)
3192	Knockanu	3462	Kilpaddo	0.44	144.35	-0.04	-0.02
3942	Moneypoi	3941	Moneypoi	2.39	-19.08	0.01	-0.02
2522	Flagford	3772	CAVAN	0.44	109.51	-0.08	-0.03
3772	CAVAN	3522	Louth	0.44	70.79	-0.06	-0.03
3192	Knockanu	3191	Knockanu	2.39	-53.99	0.01	-0.03
3774	CAVAN	3772	CAVAN	2.05	-38.72	0.02	-0.04
1181	Arva	4961	Shankill	3.87	18.93	-0.01	-0.05
3554	Laois	3551	Laois	3.12	-9.94	0.02	-0.05
3944	MNYPG3	3942	Moneypoi	2.17	-113.81	0.04	-0.09
3462	Kilpaddo	3942	Moneypoi	2.34	234.33	-0.09	-0.21

From above the main contributors to the locational tariff are the

- 2nd north – south interconnector and associated ROI circuit between Cavan and Woodland.