Locational Signals Project: All-Island Generator TUoS

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1. Introduction and Background

The SEM Committee endorsed the proposal of the TSOs to proceed with a “dynamic” forward looking locational signal model of tariffing, as outlined in “All-Island Generator Transmission Use of System Charging” decision paper (SEM/010/081). The all-island Generator TUoS charges will be levied on the basis of recovering 25% of the allowed revenue for network costs on the island.

The overarching objective of the locational signals project was to introduce harmonised all-island Generator TUoS tariffs to provide participants in the SEM with a competitive level playing field. The intention was to design a tariff that provided a long term signal to generators regarding their decision to locate on the network system in order to promote efficient network development and investment. This would be undertaken by designing a cost reflective tariff which would not create undue instability, which, if it were present, could undermine the signal being sent.

The “dynamic” forward looking locational signal model was selected by the SEM Committee to achieve the above objectives. In particular tariffs charged to generators would now reflect, to some degree, the cost that they will impose upon the system in the future, thereby, internalising the future costs of the required network development. This approach creates both entry and exit signals to participants. The tariff design also includes an element associated with recovering costs of today’s network socialised among all generators; the postage stamp element. This was incorporated to assist in achieving a more overall stable tariff as opposed to a tariff fully reflecting future forecast costs together with relating the charge to the level of service provided today.

Details to be finalised

The following document discusses the detail required to implement the SEM Committee decision. The document has been formulated by the TSOs (EirGrid and SONI) with input and advice from the RAs (Regulatory Authorities – Commission for Energy Regulation and Northern Ireland Authority for Utility Regulation). The following sections discuss and provide TSOs recommendations on a number of specific issues:

- Calculation methods for All-Island Generator TUoS Tariffs
- Fixed Tariff Options
- Non Firm Generator TUoS
- Distribution Connected Generators TUoS – Threshold Level

An overview of the items of detail and associated recommendations are outlined below with further information provided in the following sections.

Calculation method for All-Island Generator TUoS Tariffs

The harmonised all-island Generator TUoS must ultimately recover the allowable transmission revenue requirement relating to network costs. The application of all-island calculated tariffs, which are collected jurisdictionally, will result in one jurisdiction under-recovering compared to their jurisdictional allowed revenue and the other over-recovering. Consequentially cross-border financial flows will occur to ensure adequate revenue recovery in each jurisdiction.

Section 2, entitled “Calculation Methods for All-Island Generator TUoS Tariffs”, discusses the implications of cross-border financial flows, and the options, if desired, to remove the need for such flows. A recommendation is given that the cross-border financial flows should be managed by the TSOs with the support of a provision, or another means, to handle the exchange rate risk inherently created.

Stability - Fixed Tariff Options

A key concern of the SEM Committee relates to the potential for year to year volatility as a result of the location signal algorithm. Therefore, the SEM Committee indicated in their decision paper that tariffs should be fixed for a period of five years. However, a fixed tariff methodology may materially impact the 75:25 split between supplier and generation TUoS. The SEM Committee requested that the TSOs prepare a recommendation on how this can be best be dealt with or to develop alternative options to achieve the appropriate level of stability. It is in this context that the TSOs recommend that the fixed option, termed “fixing the tariff relativity”, be adopted. This solution avoids any negative implications for suppliers/demand and achieves the objective of significantly increasing tariff stability. Section 3 “Fixed Tariff Options” outlines the basis of this recommendation.

Non Firm Generator TUoS

The fourth section “Non Firm Generator Tariffs” considers the appropriateness of levying TUoS tariffs on non firm generators, which to date has not been dealt with by the project. It sets out the status quo and its evolution, the lenses for consideration and an outline evaluation against both the SEM arrangements and the changing philosophy of generator TUoS charging. It concludes that, on balance, charging both firm and non firm on the same capacity (MW) basis is the most appropriate approach.

Distribution Connected Generators TUoS – Threshold Level

The fifth section “Distribution Connected Generators TUoS – Threshold Level” assesses the appropriateness of the current threshold level for charging TUoS to distributed connected generators.

This discussion is pertinent given the changing generation portfolio, where a considerable number of smaller generators are connecting, may mean that the original threshold of 10MW is no longer considered suitable. Certain participants have, as part of the consultation process, requested that the threshold level be lowered. Based on this assessment the TSOs recommend that due consideration should be given by the SEM committee to lowering the threshold to 5MW with incremental MW charging to avoid step changes around the threshold value.

2. Calculation Methods for All-Island Generator TUoS Tariffs

This section examines a number of different approaches for calculation of all-island generator TUoS tariffs with a view to ensuring each regulated entity ultimately receives its revenue entitlement regarding network costs, i.e. controllable costs. The options include:

1. Generator tariffs calculated on an all-island basis with supplier tariffs calculated jurisdictionally as today; consequential cross-border revenue flows between TSOs ("All-Island Generation Adjustment");

2. Generator tariffs calculated on an all-island basis; supplier tariffs adjusted in each jurisdiction to ensure no requirement for cross-border flow ("Jurisdictional Supplier Adjustment"); and

3. Generator tariffs initially calculated on an all-island basis but subsequently adjusted to ensure no requirement for cross-border revenue flows ("Jurisdictional Generator Adjustment)

The full characteristics of these options are summarised below. Each of these options has different implications for supplier tariffs, cross-border revenue flows, under/ over recovery and the differences in tariffs between generators. In all instances we are assuming the locational algorithm has already been determined and it is not the purpose of this paper to consider this.

2.1 Option Characteristics

Option 1: All-island Generation Adjustment

- Characteristics;

1. 25% of all-island network revenue requirement is charged and collected from all-island generators - an all-island generator pot.
2. 75% of ROI revenue requirement is charged and collected from ROI suppliers.
   75% of NI revenue requirement is charged and collected from NI suppliers.
3. All billing and collection remains on a jurisdictional basis.

- This means that 25% of the NI TUoS revenue requirement will not necessarily be collected from NI generators and visa versa; rather the all-island generation pot is assumed to be collected from all-island generators with one jurisdiction setting out to collect more than 25% of the revenue requirement from generators within that jurisdiction and the other jurisdiction by definition less. Financial cross-border flows will therefore be required to ensure each jurisdiction recovers their regulated revenue requirement.

Option 2 Jurisdictional Supplier Adjustment

- Characteristics;
  1. 25% of all-island network revenue requirement is charged to all-island generators - an all-island generator pot. Ex-ante generator all-island tariffs are calculated based on this pot.
  2. Supplier revenue requirement:
     - NI supplier = Total NI revenue requirement *less* ex-ante NI all-island generator tariff total.
     - ROI supplier = Total ROI revenue requirement *less* ex-ante ROI all-island generator tariff total.
  3. All billing and collection will remain on a jurisdictional basis.
- This option ensures no financial cross-border flows occur as the totality of each jurisdiction's tariffs is designed to recover the jurisdiction's revenue requirement.
- On an all-island basis the ratio split between suppliers and generation remains at 75:25. However, the ratio split in a given jurisdiction will be different.

Option 3 Jurisdictional Generator Adjustment

- Characteristics;
  1. 25% of all-island network revenue requirement is charged to all-island generators - an all-island generator pot. Ex-ante generator all-island tariffs are calculated based on this pot.
  2. Following this if a given jurisdiction's generator tariffs do not equal 25% of that jurisdiction's revenue requirement a further adjustment is made to the respective generator tariffs to ensure an ex ante 25% is recovered in each jurisdiction.
  3. 75% of ROI revenue requirement is charged and collected from ROI suppliers.
     75% of NI revenue requirement is charged and collected from NI suppliers.
  4. All billing and collection will remain on a jurisdictional basis.
- This option ensures no financial cross-border flows occur as the totality of each jurisdiction's tariffs is designed to recover the jurisdiction's revenue requirement.
- This results in the ratio split between suppliers and generation, on both an all-island basis and jurisdictional basis, remaining at the 75:25 level.

2.2 Basis of Assessment

EirGrid and SONI has considered and assessed against the following criteria:

1. The degree to which the option fulfils the purpose of all-island locational tariffs;
2. The extent to which the option increases the risk of revenue recovery for the parties;

3. The implications on Supplier TUoS.

Criteria 1 - The Purpose of All-Island Location Tariffs

The purpose of harmonised all-island tariffs is that generators that participate in the SEM can compete on a level playing field while taking into account the different impacts their location has on the operation and development of the network. Therefore, for the objective of the project to be fulfilled it is important that they are treated “equally” when deriving their tariff. For example, a generator in one jurisdiction is located in a ‘good’ area and receives a lower tariff then it is important that another generator located in the other jurisdiction also receives a lower tariff if it is also in a similarly ‘good’ location. Option 1 and Option 2 both derive generator tariffs on an all-island basis from a single all-island generation recovery requirement. Option 3, however, adjusts recovery for generators within a jurisdiction and also adjusts the differentials between them which have been calculated by virtue of the locational model. Essentially, this option fundamentally undermines harmonised all-island tariffs and were it to be employed would call into question the purpose of having harmonised all-island tariffs in the first place. On this basis alone the TSOs therefore believe Option 3 can be removed from further consideration.

Criteria 2 - The Extent to which the Approach Increases the Risk of Revenue Recovery

Both Option 1 and Option 2 will see some degree of greater risk associated with recovery when compared to the current situation.

In Option 1 the requirement for cross-border revenue flows introduces exchange rate risk between the time the tariffs are set and their ultimate billing and receipt[1]. Euro and Sterling exchange rates have recently been quite volatile. Moreover, while the exchange rate risk will be bounded by the extent of cross border flows, small changes in revenue can have a large impact on each TSO licensee as they are both asset light in nature and have insignificant underlying equity returns with which to balance any cashflow mismatch which may result. This is discussed further below.

Under Option 2 exchange rate risk is eliminated but at least one TSO is likely to see an increased exposure to underlying volumetric risk. This results as a greater proportion of supplier TUoS is collected on a kWh basis than generator TUoS which, at least for those generators with firm access, has been largely capacity based. Under Option 2 one jurisdiction will more than likely see greater than 75% of their recovery coming from supplier TUoS. While mis-forecasting of capacity, which is significantly lumpy in nature can have a bigger individual effect, the overall fluctuation in demand due to changing macroeconomic conditions is likely to be more prevalent.

[1] Note a number of a number of SEM work streams also have exchange rate risk. It is important to acknowledge that any given solution may not necessarily be appropriate for another work stream given the specific circumstances.

In both instances the effect for the TSO is significantly leveraged to the degree it is (i) highly operationally geared and (ii) faces significant fixed outgoings to the Transmission Owner irrespective of income. As an example, in the RoI case a 5% under recovery in generator tariffs is approximately equal to 250% of the underlying equity return to the EirGrid TSO licensee on its Regulatory Asset Base. It is important that regardless of the model chosen that the TSO licensees are appropriately compensated for the resulting risks which occur.[2]

Criteria 3 - The Impact on Supplier TUoS

While Option 1 will see supplier TUoS in each jurisdiction unchanged, Option 2 would result in changes to supplier TUoS both initially, and over time, dependent upon the revenue recovery from generators within that jurisdiction and therefore imposes that inherent volatility upon suppliers.

It can be argued that adjusting jurisdictional suppliers for the opposite of the jurisdictional Generator acts as a proxy for full Demand/Generation locational signals. In other words both are in effect two sides of the same coin; if generation is located in a bad area (tariffs are high) then demand would be considered to be in a good area (tariffs would be low). However, traditionally suppliers, and ultimately customers, have paid the same tariffs whether they are located in Cork or Cavan, Larne or Limavady and supplier TUoS was indeed specifically excluded from the scope of this project. It is questionable therefore whether this is, in fact, appropriate.

Moreover the resultant volatility may be both hard to explain and largely unjustified; this is particularly true to the extent generator tariffs are fixed on the other side thus passing all such volatility back to supply.

2.3 Assessment

This section has outlined the characteristics of and assessed three options, All-Island Generation Adjustment, Jurisdictional Supplier Adjustment and Jurisdictional Generation Adjustment:

- Option 1 is deemed to best represent the original intent and overall objective of harmonised all-island generator TUoS tariffs.
- Jurisdictional generation adjustment was dismissed on the basis that it cuts against the purpose of the all-island locational tariffs;
- The other two options both introduce greater risks to revenue recovery than the status quo; All-Island Generation Adjustment probably more so than Jurisdictional Supplier Adjustment;

[2] In the recent TUoS revenue determination the CER recognised the impact of such risks on the TSO when a TUoS margin mechanism was introduced in addition to another working capital measure already in place. Such measures may or may not be sufficient but are nonetheless designed to mitigate this type of risk. No such similar arrangements have currently been provided by the Utility Regulator for SONI.

- Jurisdictional Supplier adjustment provides jurisdictional locational signals to demand (which could affect national competitiveness and given it was beyond the scope of this project questionable as to whether it is appropriate), however, more concerning this option also introduces significant volatility into supplier TUoS in each jurisdiction.

TSOs Recommendation: Implement Option 1 – All-Island Generation Adjustment

2.4 Mechanics of Option 1: All-Island Generation Adjustment

The mechanics of the recommended Option 1 "All-Island Generation adjustment" will now be explored. Firstly, this involves a discussion of the management of the risks associated with financial cross-border flows. Secondly, the inter year recovery mechanisms, which aim to solve the issue of over/under recovery of the network revenue requirement in a given year, will be discussed.

Jurisdictional revenue recovery

Each jurisdiction has a networks revenue requirement for the year and the all-island generator tariffs, in totality, set out to recover 25% of this all-island networks revenue requirement. The tariffs are collected jurisdictionally by each TSO. As the tariffs are calculated on all-island basis, for each jurisdiction the tariffs of a given month/year will not match the revenue requirement for that same month/year if the forecasts are accurate. One TSO will collect too little while the other will, by definition, collect too much compared to their own revenue requirement. Financial cross border flows will therefore be required between the TSOs to ensure that each jurisdiction can meet its revenue requirement.

The difference between tariff collection and the revenue requirement will be assessed at the time of tariff calculations. The TSO that sets out to collect too much will be required to transfer funds across to the other TSO to ensure the other TSO can reconcile their revenue requirements. Such cross-border flows will be identified in the annual all-island Generator TUoS rates decision paper. There is a risk, however, that the tariffs may not recover the revenue requirement amount.

Recovery mismatch can arise due to:

- Non-firm tariffs, if kWh[3], may not collect enough revenue if kWhs, for a given generator, differ from the capacity factor assumed for that generator.

[3] Note the TSOs have recommended non-firm TUoS tariffs to be applied on a kW basis. This is outlined further in section 3 of this paper.

- A generator defaulting. The risk of occurrence can be considered low but the impact will be high.
- Exchange rate risk. There is a risk that the revenue collected in one jurisdiction will not equal the revenue requirement in the other.
- Connection timing of new generators. If additional generators are added during the year, with consequential higher income following their addition, this will, *ceteris paribis*, lead to under recovery in the first part of the year.

While these risks may appear small in an industry context nonetheless they are a significant matter for both EirGrid and SONI. Any variation with these factors will be of a large magnitude compared to return on equity earned by both companies and moreover to their respective balance sheets. Both companies are asset light in nature meaning that the resources available to handle unforeseen events are limited. It is assumed the regulatory model on both jurisdictions will be amended to provide appropriate arrangements for the remuneration of these risks, through review of additional TSO working capital requirements.

Timing of transfer

Moreover, even in the event that the forecast prove to be accurate, and none of the risks outlined above transpire, it is important to note the difference in TUoS collection cycle in ROI and NI. Effectively the ROI TSO collects the tariffs 35 working days after the month of service. In NI the TSO collects TUoS 10 working days after the month of service. The timing of the transfer can have a bearing on the risk profile of each TSO. This is a significant issue for the TSOs and is likely to require additional working capital provisions. The implications need to be considered alongside the other risks as part of a working capital requirements review.

Cross-border flow risk- who should bear it?

The risk, of over/under recovery, for each TSO regarding the cross border flows needs to considered and managed. In principle risk should be borne by the party best able to manage it. Moreover, a party responsible for a forecast should be in general be the party who should bear the consequences of that forecast.

There are three options;

1) Receiver of funds bears the risk.
2) Transferring TSO bears the risk.
3) Both TSOs share the risk.

Option 1 - Receiver of funds bears the risk

Under this scenario the receiving TSO must manage the risk of not receiving funds and handle the payments it owes from its own resources. It can be argued that this stark approach is contrary to the rationale/principles of TUoS collection in general. In today's model the receiver of funds is not put at risk i.e. TAO receivers payments regardless of actual collection, as it has no control or responsibility regarding tariff arrangements or collection.

Option 2 - Transferring TSO bears the risk

Under this scenario the recipient TSO receives funds regardless of actual collection of tariffs by the other TSO. Again this is a stark approach and a question of equitability arises as to whether it is appropriate for one TSO to bear all the risk and cost when it is effectively acting on behalf of the other party to assist in revenue reconciliation in a separate jurisdiction.

Option 3 - Both TSOs share the risk

This option seeks to address the limitations of both approaches above through sharing the risk. This means that under/over recovery is shared by both parties. The sharing mechanism could be a function of either;

a) Transferred sum is adjusted to reflect total collection shortfall/over recovery percentage
b) A 50:50 sharing of over/under recovery of transfer element of tariff collection
c) A sharing ratio that reflects demand usage on the island e.g. ROI 75% & NI 25%

As there is a requirement on the regulatory model to provide, and therefore ultimately the customer, for the management of the risk, it is critical that a sharing method reflects this underlying support. In particular of all the risks identified, exchange rate risk is likely to be the most volatile. By necessity arrangements for this will span both jurisdictions and currencies and therefore it is appropriate that customers in both jurisdictions contribute towards the arrangements. It is considered that a reflection of the all-island demand usage would represent the most equitable sharing between jurisdictions. Option c) allocates this sharing ratio. Customers in both jurisdictions would then contribute to the management of the risk in a balanced manner.

TSOs Recommendation: Jurisdictional revenue recovery

It is recommended that both TSO share the risk of the cross border flows to some degree (Option 3). It is a matter of circumstances which determines which TSO sets out to recover more than their jurisdictional revenue requirement. Moreover, the regulator must provide appropriate mechanisms to ensure such risks are recognised and appropriate recovery structure in place. Option 3 is recommended as it equitably shares the burden of the introduction of new risk into the regulatory model.

TSOs Recommendation: Implement Option 3) c) – both TSOs share the recovery risk of cross-border flows on a ratio reflecting demand usage on the island e.g. ROI 75% & NI 25%, subject to the RAs providing for the appropriate support.

Inter year recovery

An over/under recovery mechanism is required as the ex-post collection of tariff revenue may not deliver the revenue requirement total. This section is focused on the collection of the total revenue requirement and not the issue of jurisdictional tariffs differing from jurisdictional revenue requirement.

The all-island generator pot in a subsequent tariff period needs to be adapted to recover the over/under recovery of revenue. Two approaches can be taken;

a) Over/under recovery from generation added/subtracted to generation element of network revenue recovery in the subsequent year;
b) Over/under recovery from generation added/subtracted in assessing total over/under recovery in each jurisdiction. [Implicitly 25% of this is then allocated to the all-island generation element of revenue requirement.]

TSOs Recommendation: Inter year recovery

It is recommended that option (a) is chosen. It is appropriate that the network revenue requirement initially apportioned to generators is ultimately recovered from them. This is the principle that is currently followed in NI regarding over/under recovery. A recovery period of +1 year is also appropriate, if it is practical to implement. The practicality depends on the regulatory authorities' revenue requirement determination timelines.The chosen mechanism also needs to be consistent with the application of "Fixed Tariffs". Section 3 Fixed Tariff Options outlines the TSOs recommendation of "Fixed tariff relativity". The inter year recovery mechanism recommendation is consistent with this. This recommendation may not appropriate if a different fixed tariff option was chosen.

TSOs Recommendation: Inter year over/under recovery from generation to be added/subtracted to generation element of network revenue recovery in the subsequent year

2.5 Conclusion

Therefore EirGrid and SONI believe Option 1; the calculation of all-island generation tariffs on an all-island basis with resulting cross-border revenue flows is that which is most appropriate. This does however introduce additional exchange rate risk into the process of recovery which must be provided or compensated for. There are a number of sub questions which arise: the management between the parties of mismatch in expected and actual recovery and the treatment of under/ over recovery both within and between years. Recommendations have been provided for these matters, as outlined above. EirGrid and SONI have also produced a recommendation which considers the options and their impact for the SEM Committee’s proposal of fixing generator tariffs (see Section 3).

3. Fixed Tariff Options

Background

The SEM Committee decided to endorse the proposal of the TSOs to proceed with a "dynamic" forward looking locational signal model of tariffing, as outlined in "All-Island Generator Transmission Use of System Charging" decision paper (SEM/010/081). This paper also indicated that the generator TUoS tariffs should be fixed for a period of five years. The SEM Committee were aware that such an approach could increase the tariffs charged to suppliers/demand, and therefore impact the 75:25 split between supplier TUoS and generator TUoS, and stated that the objective would be to reduce and/or minimise this disruption to suppliers if possible. If a material variation to the split was expected the TSOs were asked to "*prepare a recommendation for the SEM Committee on how this can best be dealt with or alternative options to achieve the appropriate level of stability".*

It would appear that a key concern the SEM Committee has in applying a locational signal model is that the location signal algorithm may drive volatility from one year to another. The tariff model proposed by TSOs dealt with this to some degree by limiting to 30% the extent that the "dynamic" locational element contributes to the overall revenue recovery. The remaining revenue requirement is collected through a postage stamp tariff model. The addition of 'fixing' the tariff further complements this objective of reducing the impact of any volatility which may remain. However, its introduction, or at least the method of its application, needs to be considered carefully to ensure it does not create unnecessary negative consequences. This section explores a number of fixed tariff options that could be utilised by the SEM Committee in order to achieve the objective of minimising the impact of volatility.

The options include:

1) Fixing the absolute tariff today.

The seemingly simplest fixed tariff option involves fixing the absolute tariff attributable to a given generator for a total period of 5 years. Supplier tariffs would be adjusted if the generator tariffs do not recover the revenue requirement[4].

2) Fixing the absolute tariff based on anticipated future requirements

This option involves fixing the generators absolute tariff today but the tariff would forecast future anticipated changes to revenue requirements and/or system developments over the following 5 years.

[4] The term 'revenue requirement' is used in this section in relation to the network costs revenue requirement that is applicable to generators. This is 25% of the ROI and NI network revenue requirement pot.

Again supplier tariffs would be adjusted if the generator tariffs do not recover the revenue requirement.

3) Fixing the tariff relativity

This option keeps the relativity between generators' tariff similar rather than fixing the specific tariff. This allows for the generators' tariffs to evolve along with system developments including a changing generation portfolio and the TUoS revenue requirement. Under this option no specific adjustment to supplier tariffs is required as a result of generator tariff fixing.

Illustration of Option 3: Fixing the tariff relativity

Process:

Year 1: Run model and derive tariffs. This tariff will be the base tariff for each generator connected at this point.

Year 2: Run model. Only new generators will receive the tariff calculated from this run. If the revenue requirement has changed then an adjustment is made to previous years' generators' tariffs to make up the difference. Scaling will undertaken to ensure the relativity between these generators remains the same.

Formula: Change to previous Generators' tariffs = Revenue Requirement *less* new Generator tariff collection

Year 3: No new connections. If the revenue requirement has changed then all generator tariffs are scaled to keep the relativity between the tariffs the same. This would mean both Year 1 generators and Year 2 generators would be treated as one group when scaling.

3.1 Basis of assessment

EirGrid and SONI believe the options above should be considered and assessed against the following criteria:

1. The degree to which the objective of promoting stability and predictability is achieved
2. The implications on suppliers

3. The extent to which the option increases the revenue recovery risk
4. Practicality of implementation

Criteria 1 - Achieving the objective of promoting stability and predictability

A key reason for variations of locational tariffs from year to year is the load flow model. This can be seen with either a "static" or "dynamic" load flow model. It occurs as the load flow model is reflective of a dynamic and evolving system. In addition, tariffs, in general, will increase/decrease along with changes to the revenue requirement.

Option 1: Fixing the absolute tariff today

Option 1 removes the potential negative implications of yearly tariff volatility for a period of 5 years. This provides absolute certainty to generators regarding their tariffs for this period. However, it creates the potential for a significant step change in their tariff after the 5 year period is completed. The load flow model would be expected to have evolved significantly from year 1 to year 6 (when new tariffs would be applied to a given generator) and the generator would incur this variation in one instance.

In addition, under option 1, the tariff charged to a given generator would not reflect any changes to the revenue requirement over the period. Again it would face this change at one point in time rather than a more granular year by year change. In ROI, the network cost allowed revenue provided for by the CER is expected to increase by c.30%[5] from 2011 to 2015. This is a very significant step change.

During the 5 year period supplier tariffs recover any revenue recovery shortfall from generators and therefore leading to increased volatility for suppliers. Regarding the step change faced by generators at the end of the 5 year period; suppliers would experience the countervailing volatility in their tariff, albeit implications of the volatility would not be expected to be quite as severe for suppliers as the revenue requirement base is much greater and thus dilutes, to some degree, any impact. Therefore, it can be seen that option 1, "Fixing the absolute tariff" only removes the potential volatility for generators for a period of 5 years; introduces a new step change risk at the end of the period; and creates increased volatility for suppliers during and at the end of the fixed period.

Option 2: Fixing the absolute tariff based on anticipated future requirements

This option seeks to overcome a number of the issues identified above with option 1. The tariff attributable to a given generator still remains fixed for a period of 5 years. However, the calculation that derives this tariff would now reflect anticipated future requirements. For example, it would reflect

[5] CER/10/206, Decision on TSO and TAO transmission revenue for 2011 to 2015.

the forecast revenue recovery expected over the period. In addition, it could incorporate changes expected on the network which would include changes to the generation portfolio i.e. as more MWs are connected it would be expected, *ceteris paribus*, that a generator's tariff would decrease. These reflections are aimed at reducing the impact for generators of the step change that occurs at the end of the fixed period. Furthermore, it would also reduce but does not remove the volatility for suppliers, as supplier tariffs will still be adjusted for any shortfalls.

Nevertheless, the ability of this option to overcome the issues created by option 1 is bounded by the accuracy of the ex-ante assumptions. These will always, at best, be estimates. Assumptions are likely to be subject to debate with the possibility that an agreement would be difficult to achieve or at least take some time to reach an agreement. However, with this option generators still receive certainty for the period and it is expected that the step change impact will be negated to some degree (it is assumed the estimates will be a closer, though not perfect, representation of what will occur as compared to a model that makes no attempt to forecast changes). This option improves upon option 1 but limitations remain.

Option 3: Fixing the tariff relativity

The "Fixing the tariff relativity" option is designed to resolve the issues above to the greatest extent possible. It fixes the result of the load flow model for a given generator – driven by changes in network assumptions and generation portfolio with potentially large effects in any given location - and effectively removes the negative impact of storing a changing revenue requirement and system developments, largely non location specific system wide effects, for the fixed period which is then subsequently incorporated in a generators tariff as a step change. In other words, the magnitude of the step change is reduced with any change reflecting the new load flow result. As the tariffs evolve along with the revenue requirement the option removes the necessity of any adjustment to supplier tariffs.

While generators' tariffs are not fixed in absolute terms for the period, they are nonetheless relatively predictable, with a reduction in the step change evident. Moreover, all generator tariffs are largely adjusted to the same extent and therefore the competitive position between generators should not be significantly impacted with generators continuing to contribute appropriately towards network costs with the tariffs reflecting an increasing/decreasing network revenue requirement.

Criteria 2 - The implications on suppliers

When considering the implications for supplier and therefore *de facto* demand it is important that the context and evolution of the locational signals project is respected. During the project the RAs requested that the TSOs do not produce indicative supplier tariffs, as all-island supplier tariffs were seen to be outside of the scope (SEM/09/107). As a result it could be argued that suppliers would not have given the proposals due consideration as the implications for them could have been expected to be negligible.

As noted above both Option 1 and Option 2 increase the volatility for suppliers. As a consequence it increases suppliers risk profile and also potentially increases the burden of the revenue requirement. Their introduction would have large implications for suppliers, which may change their view of the selected all-island generator TUoS tariff model as different models could have varying risk consequences for them. This raises a question of transparency.

In addition, with the introduction of these specific options a further issue arises of whether suppliers/demand should fully contribute towards the provision of greater certainty to generators by becoming the recipient of the additional recovery risk created. If the additional certainty is valued by generators it may be appropriate that they financially contribute up to this particular value.

In fact, suppliers/demand would effectively contribute twice for any revenue recovery shortfall due from generators that may occur with the introduction of Option 1 and to a lesser extent with Option 2. Firstly, they would contribute through the direct adjustment to their TUoS tariff. Secondly, due to the composition of the Capacity Payment Mechanism (CPM); which includes a TUoS charge in the calculation of the Best New Entrant (BNE).

The BNE is based on the current applicable TUoS tariff. However, with an increasing network revenue requirement, generators with a fixed tariff will have a lower charge as compared to future tariffs included in the BNE. This creates a distortion as it means that generators, with a fixed tariff from a previous period, will capture as rent the difference between their lower fixed tariff and the higher BNE tariff, at the expense of suppliers/demand[6]. It can be argued that the BNE which seeks to reflect the present efficient level of fixed cost for a new generator would over reward existing generators, which have a tariff that does not reflect the current network revenue requirement.

A further issue to consider is the manner of applying a supplier adjustment in practice. There are two approaches outlined below. The supplier adjustment for under recovery of the generators contribution can be;

a) shared between jurisdictions' demand usage i.e. 75% ROI and 25% NI;
b) made in specific reference to jurisdictional revenue recovery shortfall i.e. a tailored jurisdictional supplier adjustment.

The first approach is essentially a step closer towards all-island supplier tariffs which could also potentially result in supplier cross-border flows. Regarding the second approach there were

[6] While under the current model generators' tariff differ from that of the BNE TUoS allocation, the tariffs are nevertheless calculated using the same revenue requirement and therefore suppliers and *de facto* demand do not pay twice for any generator shortfall in contributing towards the revenue requirement.

discussions with the regulatory authorities on adjusting suppliers jurisdictionally, outlined in the section “Calculation Methods for All-Island Generator TUoS Tariffs”, in order to ensure no financial cross-border flows occurred. This approach was ruled out on the basis that it was not consistent with the overall objective of all-island generator tariffs.

Option 3 does not have any implications for suppliers/demand relative to today’s tariff arrangements.

Criteria 3 - Revenue Recovery

Option 1 and Option 2 have the potential to increase the TSOs exposure to underlying volumetric risk as it is likely that they would lead to an under/over recovery of the revenue requirement and thereby require an adjustment to be made to supplier tariffs, which is largely energy based. Also, were supplier adjustments to be undertaken on an all-island basis; exchange rate risk would be introduced. Due consideration is required on whether further alterations are required to the regulatory model applied to both TSOs to provide for this risk.

Option 3 does not have implications for revenue recovery with the volumetric exposure remaining as today. The tariffs are derived using the relevant revenue requirement for a given year.

Criteria 4 - Practicality of Implementation

It is important to consider the practicality of implementing the above options, both in terms of the ability to calculate the tariffs in their own right and how such calculations can be incorporated into the May 2011 consultation, which will include indicative tariffs.

Both Option 1 and Option 3 do not create any significant additional practicality issues in terms of tariff calculation. The indicative tariffs will be the same for either of these options, and indeed if no fixing was undertaken, as they represent the first year of the new tariff regime. The fixing of tariffs will only effectively come into force in the following years. This is not expected to create any difficulties in the calculation of generation tariffs with any required adjustment to supplier tariffs also not creating any undue tariff calculation practicality burden.

However, the implementation of Option 2 may prove more problematic. It requires an assessment of the expected revenue requirement over the next five years. A consistent approach is made complex by the differing timelines for the price reviews of the various licensees in NI and ROI. Additionally, in order to adjust the generator tariffs that would be applied today, an estimation of the tariffs that would be charged to future connecting generators is required. Given the forward looking nature of the new tariff design difficulties arise, due to data limitations, to accurately assess the tariff future connected generators would be charged. The time horizon used by tariff design is currently at the boundary limit and therefore restricting the ability to compose tariffs that would apply in the future. Option 2 would require a different set of indicative tariffs to any other option as they would be reflecting a future forecast today.

3.2 Conclusion

This paper explored a number of options that are designed to meet the SEM Committee's objective of ensuring generator TUoS are predictable;

- Option 1: Fixing the absolute tariff today
- Option 2: Fixing the absolute tariff based on anticipated future requirements
- Option 3: Fixing the tariff relativity

The SEM Committee was concerned about the impact a fixed tariff option may have on suppliers/demand. It is TSOs view that Option 1 could result in a material variation to the generator supplier split. This view is centred on the expectation that the network costs revenue requirement will increase by c.30%[7] from 2011 to 2015. Fixing the absolute tariff at today's revenue requirement level can only lead to a significant short fall which would be recovered by suppliers and materially distorting the 75%:25% split.

Option 2 seeks to solve some of the issues associated with Option 1. However, it is a limited solution as there will be difference between the assumptions and the actual outturn with any differences still being recouped by suppliers/demand. In addition, practical issues remain with the introduction of Option 2 regarding the calculation of the generator tariffs themselves.

Option 3 overcomes all of the negative consequences associated with Option 1 and Option 2 while still supporting the objective of reducing generator TUoS volatility. The load flow model result is fixed for the 5 year period with an adjustment only being made to ensure adequate revenue recovery. Such an adjustment will have a similar impact upon all generators and thereby keeping the competitive level amongst generators constant. In addition, there are no implications for suppliers/demand.

Therefore the TSOs recommend the introduction of Option 3 "Fixing the tariff relativity".

TSOs Recommendation: Implement Option 3 "Fixing the tariff relativity".

[7] CER/10/206, Decision on TSO and TAO transmission revenue for 2011 to 2015.

4. Non Firm Generator TUoS

Introduction

This section considers the appropriate approach for levying TUoS tariffs on non firm generators. The treatment of non firm generators on an all-island basis is an important aspect of the introduction of all-island generator tariffs. For these tariffs to be effective all generators on the island need to be treated by the same tariff framework otherwise distortions will be created. This consultation provides an opportune time for the SEM Committee to make a decision on this matter.

The note sets out the status quo and its evolution, the lenses for consideration and an outline evaluation against both the SEM arrangements and the changing philosophy of generator TUoS charging more generally. It concludes that as a “minded to” and developing position, the TSOs believe that the most appropriate approach is one of no distinction in the tariffing arrangements for firm and non firm and that both should be levied a fixed capacity based locational charge.

Tariff Design

The purpose of generator TUoS is multi-faceted;

a) Appropriate and fair revenue collection mechanism;
b) Differentiation in tariffing to send signals, particularly locational signals;
c) Reflecting the level of service provided; physical service/ access to the Transmission system , but particularly access to the Market/ Market schedule itself.

Both firm and non firm tariffs ought to reflect these overarching principles.

Generator TUoS tariffs are usually charged on capacity basis (MW). This is appropriate considering that transmission costs are largely associated with the recovery of lumpy fixed investments. Therefore, the cost is not linearly related to the actual usage by the generator but to the requirement to put in place the network to facilitate that usage, as and when required. Thus, firm generators pay a fixed, capacity based, TUoS charge regardless of whether or not they are competitively priced in order to access the market schedule.

It can be argued that a differentiation should be made for non firm generators given that they in some way receive a “lesser” service than those that are firm. In particular non firm generators are not entitled to compensation in the event that physical access to the transmission system is denied to them, or unavailable, and therefore restricts their access to the Market Schedule.

Current Approach to Non Firm Generators

Currently different approaches apply in ROI and NI. Non firm generators in the Republic of Ireland (RoI) currently pay a per MWh TUoS charge calculated on the basis of dividing the fixed capacity based firm locational charge by an assumed capacity factor – typically 100% in the case of conventional plant and 33% in the case of renewables.

In Northern Ireland there is only 1 non firm plant connected at transmission: this plant pays the same Transmission charge as an equivalent firm plant. All plant presently connected at distribution voltages are assumed to be firm from a TUoS tariffing perspective although the capacity of the transmission system to accommodate them has not been completely assessed and the associated infrastructure developments have not necessarily been approved for completion. It is therefore worth noting that firm and non-firm concepts are not fully translated to Distribution connections in Northern Ireland. However, with the advent of a number of non firm units connecting in the very near future this is/will become a more imperative matter.

Basis of per MWh Charges

When the concept of non firm tariffing was introduced in RoI on a per MWh basis, it was associated with the bi-lateral contracts market which existed pre-SEM. In this particular market, non firm units would be "pulled back" if there was insufficient transmission capacity available for them, regardless of their competitive position. Therefore, a non firm unit would be in a less advantageous trading position than its firm counter part.

Correspondingly they paid lower TUoS charges as they received a "lesser" service. These charges were levied on a MWh basis meaning a non firm unit effectively paid TUoS when the transmission system was available to them. They did not pay when it was not available or when they did not wish to avail of it. Given that the network developed for firm generators was always available to them, they were obliged to pay regardless of whether they wished to use the system or not. This distinction regarding non firm and firm generators was not considered to be a significant issue as the number of non firm generators was small, and they tended to be cost competitive base load plant. However, with increasing numbers of renewable plant, and plant with different load factors, the robustness of the approach was increasingly called into question.

Impact of the SEM

The appropriateness of this approach is also questionable given the changes in market design and operation of the system established by SEM. As set out in the SEM Committee's decision on Scheduling, Dispatch and Access non firm generators are effectively granted access to the Market Schedule by virtue of the dispatch decision. The TSOs are now charged with dispatching the system on a least cost basis without regard to the firm or non firm status of the generator.

Therefore, with the SEM in place, all generators effectively get access to the Market Schedule by virtue of the overall competitive position in the merit order[8]. This means the distinction between the "service" provided to firm and non firm generators is less clear cut than it was in the past in a bilateral markets context.

All-Island Generator TUoS Methodology

The SEM Committee endorsed the proposal to proceed with a "dynamic" forward looking model of tariffing as part of their decision paper "All-Island Generator Transmission Use of System Charging" (SEM/010/081). This model apportions the basis of recovery less upon the service received today, and more upon the drivers of marginal investment decisions into the future. The application of tariffs is premised upon the assumed usage of the lines under the future network scenarios examined by the TSOs. Both firm and non firm generators can, and do, make a similar contribution in this regard. As they both make a similar contribution it is important that all generators see the full locational signal regardless of their access right "status".

Interaction with Scheduling, Dispatch and Access

There is another argument and one which has surfaced in the Scheduling, Dispatch and Access debate as to whether non firm generators are, under the SEM arrangements, getting "undue" access to the market i.e. they can have access even when insufficient transmission is available to accommodate all in merit generation, and can as a result, impose as an externality, higher constraints cost on system users as a whole, either end users or other non firm generators. This could imply that non firm generation ought to pay higher TUoS charges than their firm counterparts in order to cater for this factor.

Assessment

On balance, based on these factors above, the TSOs are minded towards arrangements which see a fixed locational MW charge levied on all generators regardless of their access rights status. However, before arriving at a recommendation it is important to assess whether the impact of such a change is warranted in the context of the overall objective of the locational signals project. An overview impact analysis, on those most likely to be significantly affected, is outlined below.

[8] While this is in general the case, the situation can pertain whereby an in merit non firm generator is adversely affected when a more competitive firm or non firm generator is dispatched instead of it due to transmission constraints in a given area i.e. while it is competitive in the overall sense, as it is not included in the least cost constrained dispatch it is therefore not in the market schedule.

Impact analysis of proposal

This proposal will have implications for the various types of non firm units and also firm units connected to the system. However, there will be no impact for the NI non firm generator currently connected. This is because it is already charged TUoS on a MW basis. Essentially, in ROI, any non firm generator which has a running regime that is lower than the assumed capacity factor used to calculate its MWh charge will be discommoded through a higher TUoS charge. In particular the following:

- conventional low merit order plant; and
- units with high levels of constraints.

A non firm conventional low merit order plant in RoI will likely see an increase in its TUoS charge. However, its position today may be considered anomalously favourable given that it largely has the option to access the market but only contributes TUoS when it does in fact access the market. Its firm counterpart must fully pay for this option regardless of whether it is availed of or not. This was always seen as a deficiency of the existing ROI arrangement.

Non firm units with high levels of constraints will also likely pay more for what may be deemed a lower “level of service”. If the level of service was the only lens of analysis then this could give rise to concern. However, the “lesser” service impact is also counterbalanced by the other objectives in the TUoS charging model: the selection of the “dynamic” forward looking tariff model where it is appropriate that firm and non firm generators make a similar contribution with regard to the future network development; equally, consideration of the arrangements pertaining that provide access to the SEM market schedule (e.g. least cost dispatch) regardless of firm and non firm status. Of course, these factors could be outweighed were the expected level of constraint to be very high and therefore the level of service much diminished; however, as it is likely that generators with high levels of constraint may, for reasons far more significant than TUoS charges, find it unattractive to connect while such constraints persist, there is likely to be a natural limit to the level of constraint experienced by non firm plant.

Firm generators will benefit through lower tariffs as a greater amount of the assumed collection will be derived from the non firm units; particularly those that have a lower running regime than that assumed in their TUoS charge capacity factor.

Summary

None of the potential options: the situation currently in RoI; a higher TUoS charge for non firm premised upon the costs that they impose, or an arrangement whereby firm and non-firm generators pay on the same basis represents a perfect solution. Nonetheless the changing arrangements under SEM, and the evolving philosophy with respect to generator TUoS tariffs more generally both point to a situation where the TUoS charging regime ought to be more similar for firm and non firm than it was in the past. As we noted at the outset the purpose of TUoS tariffs is multi-faceted:

a. Appropriate and fair revenue collection mechanism;
b. Differentiation in tariffing to send signals, particularly locational signals;
c. Reflecting the level of service provided; physical service/ access to the Transmission system, but particularly access to the Market/ Market schedule itself.

Taking these three objectives into account and notwithstanding the impact on certain non firm units, as an ongoing and developing position, the TSOs are minded at this time towards arrangements which see a fixed locational MW charge levied on all generators regardless of their access rights status.

TSOs Recommendation: The TSOs are minded at this time towards arrangement which see a fixed locational MW charge levied on all generators regardless of their access rights status.

5. Distribution Connected Generators TUoS – Threshold Level

Introduction & Background

The distribution network in NI covers all voltage levels below 110kV. In ROI the distribution network includes the 110kV network in Dublin and 110kV tailed stations with connected load and all network at voltage levels below 110kV. The distribution network is primarily used to transport power from the transmission network to domestic, commercial and industrial customers supplied at various distribution voltage levels. With increasing levels of generation connected to the distribution network in both jurisdictions this conventional direction of flow is, in some cases, being reversed. To better capture this collective impact the TSOs are suggesting that the present 10MW threshold for the levying of TUoS tariffs on generators should be reviewed.

Currently all generators connected directly to the transmission system pay transmission use-of-system (TUoS) charges. The TUoS tariff allows the TSOs to collect revenue to cover the cost of maintenance, planning and development of the transmission system.

In both ROI and NI distribution connected generators over 10MW are also charged TUoS. Distribution connected generators that have a contracted export capacity of less than 10MW have been charged a zero rate of TUoS. The current 10MW threshold was adopted in 2007. Historically the combined impact of smaller generators exporting power onto the transmission system was minimal. These small generators were mainly supplying local distribution system load, with many, particularly in NI, having contractual arrangements with suppliers and hence were not required to contribute towards transmission costs. However, there continues to be an increase in smaller generators connected to the distribution network. While the amount of generation connecting to the distribution network is increasing the level of demand has not changed in the same proportions thus causing increased effects and increasing levels of export onto the transmission system.

During the Locational Signals Project consultation process a number of participants suggested that the threshold for participants to pay TUoS should be lowered. Reducing the threshold would remove the potential TUoS charging distortion that arises when smaller schemes pay no contribution to common costs seen by other generators who then have the total cost to be recovered across a smaller charging base.

The TSOs believe that it is important generator TUoS represents an appropriate and equitable means of revenue collection while also providing a differentiation in tariffs to send signals, particularly locational signals. With this in mind the TSOs believe it is appropriate to further consider the impact of non de minimis embedded generation on the transmission system.

5.1 Basis for Reduction of 10MW Threshold

The TSOs are increasingly aware of the impact on the transmission network of these ever increasing levels of embedded generation. The indications are that the aggregate effect of this generation exporting onto the transmission system is having a significant impact on the transmission network and is leading to development requirements. Furthermore, it is anticipated that the impact will grow year on year with NI and ROI Government policies to reduce CO2 emissions leading to renewable energy targets of 40% by 2020. The need for the transmission system to be developed and reinforced has been recognised in the investment plans for both ROI and NI transmission systems. A significant level of this investment is to facilitate the increased levels of renewable generation including that from distribution connected generators. This embedded generation is often located at nodes in remote areas which have limited demand available to absorb generation locally.

To take just one example, evidence of distribution connected wind generation using the transmission system in NI is apparent in SONI's 2009/2016 7 Year Statement by examining flows on the 110kV network in both 2010 and 2012.

The results of a load flow study of the 2010 network using the Summer Min scenario is shown on page 181 (Diagram H2) of the statement – this is modelled using 30% wind load factor with total wind capacity in NI at 300MW therefore assuming 100MW of actual wind generation in NI.

There is a large concentration of wind generation in areas in the west of the province such as Omagh. It can be observed at the OMAH1-DUNG1 110KV circuit there is a total of 24MW exporting from this node – i.e. 24MW of flowing across the transmission network as a result of generation embedded in the distribution network.

When the network is modelled for 2012 for the same Summer Min scenario this flow across the transmission network is shown to have more than doubled. The 2012 Summer Min study is shown on Page 187 (Diagram H5) again this is modelled with 30% wind load factor. The total NI wind capacity for NI in 2012 is 600MW so in this study 180MW of wind generation is assumed on in NI.

Again observing the OMAH1-DUNG1 110KV circuit there is a total of almost 50MW exporting from distribution wind farms– i.e. 50MW of flowing across the transmission network as a result of generation embedded in the distribution Network.

The nature of the ROI network and the connection process in ROI means the effect in ROI will be even more pronounced. In ROI the majority of renewable generators are connected under Group Processing Approach. Group processing means that connection applications are processed in batches known as gates. The rationale behind this approach is that it lends itself to organised and efficient development on the network to accommodate generation. Under group processing EirGrid has observed clusters of distribution connected generators sharing connections to the transmission system that are larger in size than some generators directly connected to the transmission system.

The generation connected to the distribution system exceeds the local demand and therefore the power flows from the distribution network to the transmission system. There are many examples of generators connected at 20kV in a 110/20kV substation where the power flows directly up the 110/20kV transformer to the transmission network and where no local load is present.

It is worth noting that in group processing the deep transmission works associated with projects in a particular area are the same regardless if they are distribution or transmission connected. The cumulative effect of the distribution connected generators can be significant and it is considered equitable to associate them with deep transmission works, as they are contributing to the requirement for these works and benefiting from their completion. Similar to the transmission connected generators, distribution generators are not charged for any transmission deep reinforcements that are necessary to provide them with transmission access. The charge for these deep reinforcements must be recovered through TUoS.

The TSOs believe if a distribution connected generator increases the level of flows on the transmission system then it would seem a reasonable position that that generator should be charged for the benefits of using the system.

This is also consistent with the SEM High Level Design of 2005 which stated:

- "As a corollary of shallow connection charges, generators should pay a locational charge as part of their TUoS"
- "The Regulatory Authorities' propose that the details of TUoS locational charges be considered in parallel with the development of the detailed rules"

The TSOs understand that this is because the RAs believed that it is important that TUoS be charged to participants that have an impact on transmission investment programmes in order to incentivise efficient grid development. In the event that distribution connected generation were not to be fully considered (through a reduction in the threshold below 10MW) it is likely that the tariffs being produced by the TSOs would be both less cost reflective and ultimately less equitable. The SEM Committee should consider whether this is in line with their original intent.

5.2 Lowering the threshold for TUoS charging to 5MW

To better capture this collective impact the TSOs are suggesting that the threshold could be lowered to 5MW. This level will gather a larger part of this collective impact of smaller generators capturing c.90% of All-Island wind generation. For planning purposes all distribution connected embedded generators would be taken into account, however, the benefit of further reducing the threshold may be limited. It is proposed that a reduction of the TUoS charging threshold to 5MW and above would capture a significant amount of the embedded generation that has an impact on the transmission system, while also recognising and according some benefit to local demand suppression by distribution connected generation.

Distribution connected generators between 5MW and 10MW account for approximately an additional 300MW. Capacity of this magnitude could have the effect of displacing significant conventional or renewable generator(s) in the merit order. In other words not taking this level of embedded generation into account would create a situation which is less reflective of reality.

In addition to lowering the TUoS charging threshold a further amendment is suggested in relation to how the threshold shall be applied. This change has been made in response to industry feedback and indeed appears sensible to the TSOs. Currently generators with MEC equal to or above the threshold pay TUoS on the full amount of their MEC. This creates a level of capacity where the generator can see a substantial step increase if it were to increase its export capacity, say from 9MW to 10MW.

In order to address this issue and avoid a level of contracted capacity with a substantial step increase in TUoS charges, the TSOs propose that the SEM Committee consider applying TUoS charges to distribution connected generators for capacity in excess of the 5MW threshold. So, for example, a unit with a contracted capacity of 6MW would only pay TUoS based on 1MW and a unit with a contracted capacity of 10MW would only pay TUoS based on 5MW, whereas before the 10MW unit would have been charged TUoS for the full 10MW of capacity. Appendix 1 sets out the effect of both lowering the charging threshold and the introduction of incremental charging on wind generators. However, this threshold would apply to all embedded generation.

All generators connected to the transmission system would continue to pay TUoS based on the full amount of their contracted export capacity; this reflects the use these units make of the transmission system given that transmission connected units output all generation directly onto the transmission system.

5.3 Impact of lowering threshold and incremental TUoS charging

If the threshold was reduced to 5MW, it would be necessary that distribution connected generators with contracted capacity greater than 5MW enter into a TUoS agreement with their respective TSO, so that there is an obligation for these units to pay the relevant TUoS amounts.

Reducing the threshold to 5MW and implementing the new rule to avoid the step change actually decreases the amount of embedded generation MW's paying TUoS but applies it on a more equitable basis. This proposed threshold and charging rule has not therefore been designed to increase TUoS revenue from distribution connected generation, but rather to bring about fairness in the charging policy (by removing the step change) and removing the apparent anomaly that exists for generators to set a 9.9MW MEC and avoid TUoS.

TSOs Recommendation: The TSOs recommend that due consideration should be given by the SEM committee to lowering the threshold to 5MW with incremental MW charging to avoid step changes around the threshold value.

Appendix 1 - Wind farm threshold analysis

The table below provides a breakdown of the levels of wind generation at each capacity level greater than 1MW.
As shown in the table below, generation between 5MW and the current charging threshold of 10MW adds up to 298MW of capacity, which could have the effect of displacing a sizeable conventional generator of the market schedule.

This table also shows that while lowering the threshold for generator TUoS charging does spread the recovery across a greater number of generator units the introduction of the incremental charging of the number of MWs over 5MW reduces the capacity across which it is recovered.

	All -island chargeable capacity values for windfarms 1MW and over			
TUoS Threshold	Total capacity for units equal to and above this threshold MW	Distribution connected Chargeable capacity MW	% of total capacity paying TUoS	Notes
10	826	826	66.29%	under the current approach where units over 10MW pays for full MEC
5	1124	669	53.69%	reflects that each unit does not pay for the 1st 5MW of its capacity
4	1164	760	61.00%	reflects that each unit does not pay for the 1st 4MW of its capacity
3	1215	861	69.10%	reflects that each unit does not pay for the 1st 3MW of its capacity
2	1239	979	78.57%	reflects that each unit does not pay for the 1st 2MW of its capacity
1	1246	1109	89.00%	reflects fact every unit will not pay for 1st MW of capacity

54% of the capacity from gens 1MW and above would be liable for TUoS charges

This 1246 value means there is 1246 MW of capacity connected to the distribution system from windfarms 1MW and over

of the 1246 MW on the system only 669 MW would be liable to TUoS charges as 91 gen units would get 5MW of capacity which did not have to pay TUoS (and 122MW of capacity is from units less than 5MW)

There is 1124MW of capacity connected to the distribution system from units with MEC 5MW and above

Capacity of wind farms between 10MW and 5 MW equals 298MW