nationalgrid

CONCLUSIONS REPORT

GB ECM-08

For the introduction of charging arrangements associated with Offshore Transmission Networks

30 December 2008

Table of Contents

1. Executive Summary

This conclusions reports sets out National Grid's proposals for the charging arrangements for offshore transmission networks, which will apply following the commencement of the forthcoming regulatory regime for offshore transmission.

This charging consultation process is running in parallel with the Ofgem/ DECC consultative process to introduce a regulatory regime for offshore transmission. National Grid is adopting the same principle as used by Ofgem/ DECC in this development, namely that existing onshore arrangements should apply offshore unless there is good reason for them not to be.

National Grid has previously published a pre-consultation document (in July 2007), which sought the industry's opinion on potential high level approaches for offshore charging and the more specific areas of; offshore expansion factors, treatment of High Voltage Direct Current equipment and the offshore connection / use of system asset boundary. This was followed by an initial consultation document (in December 2007), which collated the comments raised in responses to the preconsultation and presented National Grid's detailed proposals for the offshore charging methodology which took account of the issues raised.

Ofgem wrote to National Grid on 30 May 2008, identifying two main concerns and requested that National Grid undertake a further consultative process to address them. The concerns related to how the split between the locational and non-locational (residual) elements of the OFTO's allowed revenue would be identified as part of the tender process and the basis of the split between locational and residual charging elements. National Grid published a further consultation (in November 2008) which considered these issues along with the others required to introduce offshore transmission into the transmission charging methodology.

The final proposals being presented in this conclusions report represent the output of the further consultation. Such charging proposals replicate the onshore principle of charging offshore assets local to generation as infrastructure and split the locational signal into wider and local components, whilst applying a connection specific treatment to the local offshore component. The expansion factors applied are directly derived from the OFTO's annual permitted revenue and the security factor is calculated from the entry capacity of the generators and the capability of the offshore circuits. Such a specific treatment ensures a highly cost reflective signal.

This approach would be implemented in conjunction with a local substation tariff, reflecting onto the User the cost of the use of the primary transmission assets and platform at the offshore connection substation. The substation tariff is nodally specific and is derived from an apportionment of the OFTO revenue using the relative capital costs for the locational and non-locational assets.

It is National Grid's view that the charging arrangements proposed in this report represent the appropriate balance between our licence obligations of cost-reflectivity and facilitating competition (by ensuring offshore generators are charged consistently and equitably with those onshore). Cost reflectivity is achieved with the application of specific expansion and security factors and a local substation tariff, whereas by only charging offshore users for the Transmission Export Capacity booked, rather than for the full capacity installed, both onshore and offshore users remain protected from the consequences of decisions made by other parties. Such arrangements ensure parity between onshore and offshore generation and avoids inappropriate cross subsidisation.

The charging proposals seek to target the incremental local substation and circuit costs of the offshore connection through the locational element of TNUoS. A concern raised by a number of respondents with an interest in offshore development projects is that the targeting of such costs will have a detrimental impact on the development of offshore generation. National Grid does not believe that these arguments can be justifiably applied to TNUoS charges in order to introduce a subsidy for a specific class of generation. If subsidies are required then these should be pursued via other routes.

Further consideration is being given to the charges that will be levied on National Grid by DNOs for Embedded Transmission and whether they best fit within the Transmission Licence definition of 'use of system charges'. National Grid does not however wish to unduly delay the issuing of this report whilst this issue is considered and is therefore proposing two options:

- Option 1 This option includes all elements of the offshore transmission charging proposals that were consulted upon
- Option 2 This option excludes the Embedded Transmission element of the proposals

National Grid recommends Option 1 if it is considered by the Authority that the proposals for Embedded Transmission best fit within use of system charges, and recommends Option 2 if it is considered by the Authority that the proposals for Embedded Transmission cannot and should not fall within use of system charges.

National Grid consequently believe the proposals made are justified and, on balance best meet the Transmission Licence Relevant Objectives and provides a charging methodology that is appropriate to all users, both on and offshore.

This document has been published on the National Grid charging website at the following address:

http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

2. Introduction

As the transmission licensee, authorised to co-ordinate and direct the flow of electricity onto and over the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

Along with these high level duties, National Grid is obliged under its transmission licence:

(i) to keep the Use of System Charging and Connection Charging Methodologies at all times under review

(ii) to make such modifications of the Use of System Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

a) to facilitate effective competition in generation and supply;

b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses.

(iii) to make such modifications of the Connection Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are

a) to facilitate effective competition in generation and supply;

b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses;

d) in so far as is consistent with a), b) and c) above, of facilitating competition in the carrying out of works for connection to the GB transmission system.

In addition to the relevant objectives above, the transmission licence also prohibits National Grid from discriminating against any user or class of users unless such different treatment reasonably reflects differences in the costs of providing a service.

The purpose of this document is to set out National Grid's final proposals for the charging arrangements for offshore transmission networks for the Authority to give direction. The modification will apply following the commencement of the forthcoming regulatory regime for offshore transmission.

2 Terms of the original proposed modification

Explanation of the issue

In March 2006, the government concluded[1] that offshore electricity transmission should be regulated under a licensed price control approach.

In May 2006, the government informed interested parties that the Secretary of State was minded to extend the role of the current onshore GB System Operator (GBSO) – occupied by National Grid – offshore. On 2 August 2006 the Secretary of State issued a statement confirming National Grid as offshore GBSO designate.

In March 2007, the government decided that the offshore electricity transmission regime should be a competitive, or non-exclusive, rather than an exclusive monopoly activity. Following this decision, Ofgem published a second scoping document[2] setting out some initial views as to how a competitive transmission regime, under the auspices of a licensed price control, might work. The second scoping document set out Ofgem's "initial thoughts" in each of the work streams established to deliver the offshore transmission project.

In terms of charging, Ofgem proposed that the current licence driven approach applied onshore would be an appropriate basis for developing offshore charging arrangements and expected that the current GB charging methodology will be used as the basis for the development of offshore arrangements. Ofgem stated that National Grid, as onshore GBSO and offshore GBSO designate, should consider the detailed changes required to apply the charging methodologies offshore, the timescales for implementing these, and the consequential changes to the onshore arrangements.

Ofgem have since confirmed that they believe that the onshore licence based approach will best deliver the appropriate charging arrangements for offshore transmission within the available timescales. Ofgem have also agreed that National Grid, as onshore GBSO and offshore GBSO designate, will be responsible for developing open, non-discriminatory charging methodologies that apply to those wishing to connect to and use the offshore transmission systems.

Ofgem and National Grid have agreed that, in progressing the development of an offshore charging regime, National Grid will apply the same primary objectives as for onshore (described in Introduction above).

In considering the application of the onshore charging regime offshore, National Grid identified a number of issues that require further attention, and issued a pre-consultation document[3] in July 2007 to discuss these. Following consideration of the resulting responses, National Grid issued a consultation document[4] in December 2007 setting out National Grid's proposals to modify the Use of System Charging

[1] http://www.dti.gov.uk/energy/sources/renewables/policy/offshore-transmission/offshore-tranmission-consultation-decision/page28690.html
[2] http://www.ofgem.gov.uk/Networks/Trans/Offshore/ConsultationDecisionsResponses/Documents1/070330_2ndOffshoreScopingDoc_final_am.pdf
[3] http://www.nationalgrid.com/NR/rdonlyres/0DF19996-2131-406A-B6C2-28C31C5ABBE4/18307/OffshoreChargingPreconsultationGBECM08.pdf
[4] http://www.nationalgrid.com/NR/rdonlyres/5A5364ED-5EF5-4D37-9FA6-DEB41C16F717/22313/GBECM08OffshoreChargingConsultation.pdf

Methodology to implement a charging regime offshore.

On 30 May 2008 Ofgem wrote to National Grid to highlight certain concerns with National Grid's proposals. They requested that a supplementary consultative process be undertaken, and the further consultation published in October 2008 formed that further consultation, discussing Ofgem's concerns and setting out for consultation National Grid's revised proposals.

This further consultation also considered the charging arrangements required to address situations where offshore transmission networks at 132kV connect to onshore distribution networks ("Embedded Transmission"). This was not included in the December 2007 consultation, due the formation of the Offshore Transmission Embedded Transmission Working Group ("OTETWG") in January 2008. Following the conclusion of this group, the further consultation set out National Grid's proposals in this area and this document concludes on the issue.

Description of proposed modification to the Use of System Charging Methodology

National Grid is proposing to modify the TNUoS Charging Methodology to establish a charging regime for offshore transmission connected generation.

Identification of Infrastructure/ connection asset boundary
As consistent with the current onshore arrangements, the offshore connection / use of system boundary would be at the offshore substation LV busbar.

Offshore Expansion Factors, Security Factors and Substation Tariffs
Offshore Transmission Owner (OFTO) specific circuit expansion factors will be applied in the Investment Cost Related Pricing (ICRP) transport model. Such expansion factors are derived by the GBSO from a breakdown of the OFTO annual revenue requirement apportioned on the basis of the cost of installed assets, through a process to be established in the STC. The Offshore Grid Code subgroup recommended that reactive capability be provided by the OFTO. Therefore, we expect that a potential OFTO will include the costs of reactive compensation equipment in its submission of revenue requirements as part of its tender and, reactive compensation equipment would be included in the calculation of the expansion factors.

Where additional capacity is constructed than is required by a generator or more than one generator is connected to an OFTO network, it will be necessary apportion the OFTO costs. Consistent with onshore the cost of additional circuit capacity is funded via the residual. If multiple generators are connected by the same circuit, charges would be pro-rated by the TEC of all the offshore generators connected to that offshore network. (A number of CUSC amendments currently under development to reform the transmission access arrangements propose the introduction of a new capacity term, the Local Capacity Nomination (LCN). It is envisaged that, if approved, the apportionment methodology would be modified to refer to LCN rather than TEC.)

Except in the first year of connection, the OFTO revenue associated with cables and reactive compensation over the remainder of the onshore TO price control period would be averaged, and divided by the capability and length of the offshore connection, to produce an equivalent expansion constant in £/MWkm. This would then be divided by the 400kV overhead line expansion constant to produce the OFTO specific circuit expansion factor.

Given that it is unlikely that the offshore connection will be commissioned on a 1 April, in the first year a separate expansion factor will be calculated using the part year value of revenues. The offshore generator would, as onshore, pay charges from the time of connection, but these would recover the correct, lower revenue requirement of the OFTO for that year. Consequently, it can be assumed that the monthly charge levied on an offshore generator would remain broadly the same between the first and second charging years.

It is proposed that specific circuit security factors would be also calculated for each offshore connection, comparing the rating of the cable with the capacity of the power station(s) connected by it. In the event the connection was via a single cable, the security factor would be 1.0. If the connection was via multiple cables, a ratio between the capability of the cables and the capacity of the generator(s) would be calculated, to a maximum of 1.8 (the wider locational security factor). Upon the connection of additional generation at an offshore node and/or the construction of additional offshore circuits, the circuit security factor would be recalculated.

It is further proposed that substation tariffs would be calculated for, and levied on, each offshore generator. Using the same proposed STC mechanism through which OFTOs would report to National Grid (as GBSO) the costs of cables and reactive compensation equipment to calculate expansion factors, OFTOs would also report the costs and capability of transformers, switchgear and the offshore platform. This would be used by National Grid to derive the OFTO's revenue associated with each asset component and each averaged over the price control period.

The substation tariff will be sum of separate £/kW components calculated for transformers, switchgear and platform by dividing the relevant asset revenue by the relevant asset capability. For offshore platforms, the capability would be the higher of the capability of the transformers and switchgear.

Additionally, to ensure both offshore and onshore charges are on the same basis an adjustment equivalent to the average cost of civil engineering costs for onshore substations would be deducted from the substation tariff. Consequently, the offshore substation tariff will reflect the incremental cost rather than including asset costs that are socialised onshore. The level of the adjustment will be set at the start of each Price Control period and will be subject to an annual RPI increase. The initial level of the discount will be £0.35/kW which was determined from the analysis of a number of recent connections.

The offshore generator pays a substation local tariff for the offshore connection substation only and therefore the only contribution to the cost of all other substations will be through the residual element of TNUoS. The substation tariff would be levied on all generators connected to that OFTO connection by multiplying by each generator's TEC.

HVDC
The cost of offshore HVDC links are to be recovered through specific expansion factors, including the cost of converter stations, consistent with the proposed process for offshore AC circuits.

Embedded Transmission
In order for the GBSO to pass through charges levied on it by Distribution Network Owners (DNOs), a new type of Use of System charge, Embedded Transmission Use of System charges ("ETUoS"), is to be established in the Use of System Charging Methodology. Through this mechanism, DNO charges are passed through directly by National Grid to the relevant offshore embedded transmission generators, ensuring consistency with onshore embedded generation. The charge will reflect the cost of the DNO's provision of distribution infrastructure and may take the form of a capital contribution and/or ongoing Use of System charges. The specific timescales and nature of the charge depends upon the charging arrangements of the relevant DNO and reference should be made to the relevant DNO's charging statement.

Ofgem is currently consulting upon the required changes to the Transmission Licence which includes, an additional term to the Pass Through (PT) Items will be added to Special Condition D4 of National Grid's Electricity Transmission to include the cost of Embedded Transmission to National Grid's TO revenue restriction.

Where more than one generator is connected to an OFTO network, the ETUoS charges are apportioned by pro-rata of the TEC of the offshore generators connected to that offshore network. 132kV connected exemptible power stations offshore will be levied transmission charges, consistent with transmission connected onshore power stations.

The existing TNUoS transport model assumes a contiguous transmission network, so in the case of embedded transmission within the transport and tariff model, the disconnect between the transmission networks will be ignored and the length of the offshore transmission network will be multiplied by the expansion factor, and added to the relevant onshore marginal cost.

Generation zoning

As consistent with an onshore generator, zonal boundaries for offshore generators will be determined from the 'wider' component of generators marginal cost, after the removal of the 'local' circuit flow cost. For the avoidance of doubt, an offshore generator would therefore be in the same TNUoS generation zone as the first onshore MITS substation to which it connects.

National Grid is proposing to modify Chapter 2: Derivation of the Transmission Network Use of System Tariff and Chapter 5: Generation charges, of the Statement of the Use of System Charging Methodology to include a mechanism by which a Transmission Use of System tariff can be calculated for generation connecting onto the offshore transmission network.

The proposed Statement of Use of System Charging Methodology drafting for this modification is included in Appendix 1

Justification for proposed modification

National Grid's proposal to modify the TNUoS Charging Methodology will provide charging arrangements for offshore generators connecting onto the offshore transmission network which will allow National Grid to better meets its Relevant Objectives in Licence Conditions C5 5(a), 5(b) and C5 5(c). Namely to ensure National Grid applies charges which facilitate effective competition in generation and supply, to reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and properly takes account of the developments in transmission licensees' transmission businesses.

Connection/ Use of system boundary

The boundary between connection assets and transmission system infrastructure assets is defined in the Connection Charging Methodology. In general, connection assets are defined as those assets solely required to connect an individual User to the GB transmission system, which are not and would not normally be used by any other connected party (i.e. "single user assets").

The costs of transmission system infrastructure assets are recovered through Transmission Network Use of System (TNUoS) charges, levied on all Users of the transmission system. The underlying rationale behind TNUoS charges is that efficient, economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, relative tariffs should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems.

Since the offshore cables, switchgear, transformers and platform are all sharable or potentially sharable with the standard design considered by the GBSQSS Subgroup[5], the application of the existing onshore connection / use of system boundary would result in almost all assets being treated as transmission system infrastructure assets, which would be recovered through TNUoS charges. Although sharing has not been observed in the projects connected to date under the interim merchant regime, proponents of the enduring offshore transmission regime point to the increased co-ordination that would result from the new arrangements as better facilitating sharing.

Adoption of the LV busbar boundary maintains the existing "plugs" shallow connection charging regime offshore, avoiding potentially shareable assets being recovered through connection charges. This avoids the requirement for, a charging methodology for shared connection assets between multiple users. This would expose users to the actions of other generators, a key reason for the move to the "plugs" shallow regime onshore. Offshore generators would also be fully exposed to costs resulting from wider OFTO decisions to provide additional assets for future connectees, as the costs of these additional assets, including substation assets, would be included in the connection charge.

Consistent with our proposals for Charging Arrangements for Generator Local Assets, National Grid believes that it would be more appropriate to reflect the costs of substation assets through TNUoS charges rather than connection charges, including the targeting of costs, as this would protect generators both from the actions of other generators and from the over-provision of assets by OFTOs.

[5] www.ofgem.gov.uk/Networks/offtrans/pfd/gbssqs/Documents1/Security%20Recommendations.pdf

Offshore Expansion Factors, Security Factors and Substation Tariffs
Two potential approaches were considered including the costs of offshore cables in the derivation of TNUoS charges. A generic approach would have the advantage of simplicity, and would give certainty and predictability to developers. However, there would be an inherent averaging of costs, resulting in a lack of cost reflectivity. There is currently very little data on which to base generic expansion factors, and periodic reviews of the factors would also be required.

For these reasons, the specific approach is being proposed. Specific locational expansion factors would be highly cost reflective, which could be particularly important given the likely material differences in costs between offshore projects. Expansion factors onshore are defined by TO, although currently the only difference is the amount of 132kV circuits that it is assumed will be uprated to 400kV. Therefore, a TO specific approach would not be inconsistent with the onshore arrangements.

In addition to the costs of cables, the specific locational expansion factors would also include the costs of reactive compensation equipment. As the current requirements of Grid Code paragraph CC.6.3.2 specifying reactive power capability would be met for offshore generators by the OFTO (at the Onshore Grid Entry Point, under an obligation set out in the STC), as opposed to the generator itself, National Grid is proposing that the costs of any reactive compensation equipment installed by the OFTO should fall on the offshore generator. This will be consistent with an onshore generator, who would be required to provide plant to meet the reactive compensation requirements within the Grid Code. Under the current offshore code drafting offshore generation would receive an income from reactive power generated in meeting their own contribution to the net reactive capability of the offshore system although the procedure for the procurement and resultant income from the OFTO provided reactive power is currently being considered by National Grid on the request of Ofgem.

The security factor is used to take account of increased circuit flows following circuit outages. If the connection was by a single cable, a locational security factor of 1.0, as opposed to the global locational security factor of 1.8, would be applied to the offshore cable. For connections via multiple cables, nodal specific factors would be calculated by dividing the capability of the cables by the capacity of the generators connected by them. This would be capped at 1.8.

This factor would ensure that offshore charges accurately reflect the lower costs associated with the lower security standards applied offshore. Additionally, the capping would protect generators from investment made by OFTOs for strategic purposes.

The substation local tariff targets the incremental non locational asset cost of the generator's local transmission substation, as consistent with onshore (GBECM-11). Although potentially sharable, offshore substation assets will only be used by offshore generators (as opposed to demand or being installed for wider system reasons). Therefore, in such circumstances, consistent with the proposed treatment

[6] British Electrotechnical and Allied Manufacturers' Association
[7] These may include upfront charges, capital contributions as well as the ongoing Distribution Generation Use of System charges.

of remote substations onshore, it is appropriate that costs should be targeted at the relevant generators, rather than being socialised over all users.

However, by reflecting these costs through an infrastructure, rather than connection, charge, generators are protected both from the actions of other generators and from OFTO investment made for wider strategic reasons (in that the generator only pays for that proportion of the assets that it is using). The cost of the capacity that is not used by the generator is recovered through the TNUoS residual, as is consistent with the onshore arrangements. The application of a local security factor ensures all feasible capacity that could be used by a generator, including during outage conditions, is reflected into the TNUoS tariff and therefore the generator receives the appropriate incentive to minimise both targeted and socialised costs.

The onshore substation local tariff, as introduced by GB ECM-11, targets the incremental cost of non locational primary transmission asset onto a generator but does not include generic costs such as civil works. Given the very high costs associated with offshore platforms (£5m plus £20/kVA has been suggested), National Grid believe that an alternative approach offshore as compared to onshore is justified, in that the incremental costs of offshore platforms would be reflected through a specific offshore platform tariff. However, an adjustment equivalent to the average cost of onshore civil engineering costs would ensure the offshore generators would only pay the incremental cost of being located offshore as opposed to onshore. As consistent with the cost of onshore civil works, this offshore adjustment is therefore funded through the TNUoS residual element.

By charging substation, as well as cable assets, on a cost reflective basis to the relevant generator(s), the incentive for any misallocation of costs by the OFTO will be much reduced. By reflecting the difference between offshore platform costs and onshore civil engineering costs through an adjustment based on onshore costs and determined by the GBSO, there would be no opportunity for OFTOs to influence this element.

HVDC

HVDC links differ from an AC equivalent in that as well as generic substation assets there is an additional converter station at both circuit ends. The cost of the required substation infrastructure is consequently far higher, although this results in a reduced cost per km for the cable. In order to ensure consistency and avoid the risk of discrimination, these additional converter station costs are to be included in the expansion factor calculation for HVDC circuits.

Whilst the converter station assets are not locationally varying, National Grid believes that they should be treated as locational because they are interactive with the cost of the associated cable (i.e. the use of HVDC means that the cable cost per km is lower than the AC equivalent).

The cost of HVDC links could be recovered though generic or specific expansion factors. A generic approach gives certainty and predictability, however, the inclusion of converter station costs in a generic expansion factor would lead to projects with longer connections subsidising those with shorter connections. This would not be cost reflective, and would particularly penalise the use of HVDC for “far offshore” connections, which would be the primary use of the technology.

Given the significant discrepancy between converter capital cost estimates (£110/kW was suggested to OTEG by BEAMA[6] and this could be annuitised to £9.2-11.8/kW depending on assumed asset life) and the generation TNUoS residual charge (of £3.87/kW in 2007/08), National Grid believes that there is a clear case that converter costs should not be recovered through the residual charge. In that converter stations are intrinsically linked to a specific line, they are also fundamentally locational. Furthermore, they would be additional to AC assets at the relevant substations.

Embedded Transmission
National Grid believes that a new type of Use of System charge will provide the transparency, cost-reflectivity and flexibility required to charge all the relevant DNO charges[7] that are levied on the GBSO through to the offshore generator. Additionally, as this represents a new area where National Grid is passing through charges levied on it by DNOs, and is therefore different from other TNUoS charges, a separate use of system charge is justified. The Charging Methodology covers all transmission network services, except excluded services and balancing services and therefore National Grid believes introducing ETUoS charges does not require the Transmission Licence to be changed in order to establish an additional, discrete charging methodology, except for the addition of the Pass Through item into NGET's TO revenue restriction.

The creation of the new ETUoS charge is cost reflective, and allows for the establishment of a bespoke charging timetable, separate from TNUoS, that would more effectively mesh with that of DNOs.

National Grid expects that it will enter into a Construction Agreement with a DNO to facilitate the connection of the embedded transmission system, and National Grid intends to reflect through the terms of this Construction Agreement in the Bilateral Connection Agreement it enters into with the offshore generator (this will be put in place via an Agreement to Vary the initial Bilateral Connection Agreement).

Given the multiple parties and multiple industry documents involved, we believe that the importance of aligning the charging processes and timetable should not be underestimated. Any changes of the charges levied by the DNO, will directly flow through to the connected Offshore generators and therefore additional risk will not be socialised across all users.

Generation zoning
Performing generation zoning on a wider nodal marginal cost basis, after the local marginal cost component has been discounted, ensures the same principle is applied both offshore and onshore, namely that nodes with similar marginal cost are grouped into a zone, increasing tariff stability and predictability.

Suggested alternatives

- The boundary between connection assets and transmission system infrastructure assets should be at the onshore connection node, and consequently offshore transmission assets should be charged as connection assets
- Either; (i) The cost of OFTO provided reactive compensation assets should be socialised across all Users or (ii) a generator should be able to instruct an OFTO to provide reactive provision and all benefits flow back to the generator
- The substation charging arrangements should be implemented without a substation element and therefore the cost of all the offshore non-locational

assets should be socialised
- The cost of Embedded Transmission should be socialised

Implementation date

The implementation date for the proposed change will be 28 days after furnishing the conclusions report to the Authority, subject to non-veto (or 3 months if the Authority decides to undertake an Impact Assessment). However, the modification would have no practical effect (as there would be no licensed offshore transmission systems) until the offshore transmission regime reaches "go-live". This is currently planned for June 2010.

Proposed changes to the Statement of the Use of System Charging Methodology

Option 1 requires all the changes shown in Appendix 1.

Option 2 requires all the changes shown in Appendix 1 except the new Embedded Transmission section (5.22 – 5.27)

Impacts on other Industry Documents

An additional process will be required whereby OFTOs will provide the capital cost breakdown and physical capabilities of their offshore transmission network disaggregated into a number of elements (cables, reactive compensation, transformers, switchgear and platform costs). This will be specified in a STC Procedure.

The proposal relating to Embedded Transmission would require an additional Pass Through item to be added to Special Condition D4 of National Grid's transmission licence.

Consequential changes to the CUSC are driven by the proposed new ETUoS charge which needs to be defined and described in Section 3 of the CUSC. New provisions are required which introduce ETUoS charges as a subset of TNUoS charges (in a similar way to STTEC and LDTEC charges) as described in the TNUoS charging methodology.

Further new provisions are required in Paragraph 6.6, firstly setting the timescales for National Grid to issue invoices for ETUoS and secondly the timescales for the User to pay.

Additionally, In order to allow National Grid is efficiently meet its obligations under the CUSC, regarding the ETUoS charge, it may be appropriate to place two obligations on DNOs, either in the CUSC or in the Distribution Connection and Use of System Agreement (DCUSA). The obligations being:

- To produce a schedule of charges which can be used in deriving transmission charging statements; and
- To invoice National Grid for any charges relating to the relevant embedded transmission connection.

In turn, it is assumed that the relevant connection agreements include an obligation on National Grid to pay charges.

National Grid recommends that the changes to codes and licences required to facilitate the proposals contained within this conclusions report should be progressed as part of the Ofgem/DECC project to implement the offshore transmission regime.

3 Responses to the modification proposal

National Grid published a consultation document in December 2007 which set out the options for establishing the charging arrangements to implement a transmission charging regime offshore, in four broad sections:

- Offshore Connection/ Use of System Boundary
- Offshore Expansion Factors
- High Voltage Direct Current (HVDC)
- Other issues

National Grid received 10 written responses to this consultation document. The consultation document and industry responses can be viewed on the National Grid charging website.

Ofgem letter

Ofgem wrote to National Grid on 30 May 2008 setting out their views on the development, progression and timely delivery of the charging methodology to apply offshore.[8] Ofgem highlighted two main concerns about the basis and justification for National Grid's proposals:

- The assumption that information relating to the split between the locational and non-locational (residual) elements of the OFTO's allowed revenue would be collected as part of the tender process; and
- The basis (definition of and justification for) of the split between locational and residual charging elements.

Ofgem requested that National Grid undertake further analysis to also consider charging options offshore that may contain elements that diverge from the existing onshore approach. In particular, the following questions should be addressed:

- Whether a charging option that promotes the socialisation of offshore platform costs is appropriate for the development of offshore charging arrangements? If so, how would the split in locational and non-locational revenue be accommodated so as not to lead to a distortion in the tender process?
- What is the financial significance of not socialising offshore platform costs and platform assets through the residual charge (e.g. adopting an approach to include offshore substation costs within the locational element of the TNUoS charge)?
- What is the financial effect of all offshore charging options on the onshore charging base and onshore tariffs?
- Do any of the charging options adversely impact the ability of all parties to realise the economic benefits in sharing offshore assets?
- What arrangements are required to determine the split between infrastructure and connection revenue to determine connection charges?
- What interaction is envisaged between GBECM-11 (Charging Arrangements for Generator Local Assets) and GBECM-08 and the possible application of a local charging approach (identical to the approach that is envisaged to apply to "local" assets onshore) to offshore platform assets?

[8] http://www.nationalgrid.com/NR/rdonlyres/08880813-81D6-45B9-8867-9DB13951FA42/26376/3052008LettertoHeddRobertsFINAL.pdf

- What methodology is envisaged for deriving a TNUoS tariff for “partially” redundant and single circuit offshore connection designs and for “discounting” the tariff to be paid by the offshore generator for such connections?

Ofgem also requested that National Grid gave further consideration to the development of alternative mechanisms to facilitate the proposed split of locational and non-locational revenue, and how it was proposed that the required asset information be gathered outside of the tender process.

Finally, Ofgem stated an expectation that National Grid would submit a charging methodology modification proposal to Ofgem in December 2008 and no later than 1 January 2009, to allow the Authority to make a decision before 1 April 2009.

Further consultation
National Grid has carefully considered the issues raised by Ofgem in its letter and published a further consultation outlining proposals reflecting the comments. It is believed that the revised proposals addressed the Ofgem’s two main concerns relating to the split of the OFTO’s allowed revenue and the split between locational and residual charging elements. Additionally, in establishing the revised proposals, National Grid considered the specific questions contained within Ofgem’s letter.

National Grid received 8 written responses to this further consultation document. The further consultation document and industry responses can also be viewed on the National Grid charging website.

Presented below is a summary of the industry responses received to both the original and further consultation, divided into the broad categories of offshore consultation.

3.1 Offshore Connection / Use of System Boundary

Respondents’ Views – Original Consultation
Seven respondents to the consultation believed that the offshore connection / use of system boundary should be at the offshore substation LV busbar (option 1). These respondents believed that this would be consistent with the onshore arrangements, and with the principle that circuits greater than 2km in length are treated as infrastructure, even if they are not potentially shareable (circuits less than 2km in length are treated as connection assets). One respondent further noted that treatment of offshore substation assets as infrastructure would also protect the generator from the potential cost of overprovision of connection assets by the OFTO in anticipation of future connections.

However, other respondents noted a number of perceived disadvantages with the proposal. One pointed to the additional complexities and costs offshore, and considered that, as it would be the choice of the user to locate offshore, it would not be reasonable to expect onshore users to incur additional charges as a result. Other respondents also suggested that the nature, and costs, of offshore assets is very different to onshore, and that socialising such costs would result in an inappropriate subsidy for offshore generators. These respondents believed that offshore transmission assets, although potentially shareable, are in practice unlikely to be shared with other users. Two of the three respondents not in support of the proposal suggested that National Grid revisit option 3 from the pre-consultation, the connection boundary at the onshore connection point.

Finally, another respondent highlighted that the connection of new offshore connections in the middle of the charging year could result in the resetting of TNUoS tariffs (with greater frequency than the current annual publication) and that this would also have implications for price controls.

Respondents' Views – Further Consultation
Several respondents expressed support for the extension of the onshore arrangements offshore and agreed that the offshore boundary should be at the LV busbar as is consistent with onshore.

A respondent continues to believe that the additional complexities and cost of the offshore network, makes it difficult to treat offshore the same as onshore and therefore connection/ use of system boundary should be at the onshore connection point. Furthermore, an onshore boundary is believed by the respondent to best meet the different offshore regulatory regime and it was noted that a user must choose to locate offshore.

National Grid's View
Offshore transmission networks are shareable and adoption the LV busbar boundary maintains the existing "plugs" shallow connection boundary. This ensures users are not exposed to the actions of other users or network owners and avoids the requirement for a charging methodology for shared connection assets between multiple users. While a User may actively choose to locate offshore it can not determine whether an OFTO makes additional strategic investment or if an adjacent project fails to connect (or is decommissioned).

3.2 Offshore Expansion Factors, Security Factors and Substation Tariffs

Respondents' Views – Original Consultation
Seven respondents to the consultation expressed support for the use of a specific approach for calculating offshore expansion factors, at least initially (although one of these would have preferred the treatment of all offshore assets as connection rather than infrastructure).

A number of respondents believed that there would be a risk of significant variation between the actual costs of individual offshore connections and the charges that would be levied via a generic methodology, and that the use of generic offshore expansion factors would weaken cost reflectivity. Some of these respondents also agreed that there is currently insufficient data available to set generic offshore circuit expansion factors. However, three respondents were also supportive of a move to a generic approach, if appropriate, once sufficient knowledge and experience had been gained.

Of the three respondents not to support the use of a specific approach for calculating offshore expansion factors, one supported a generic approach and two did not express an opinion because they did not support the concept of the offshore cables being treated as infrastructure assets. The respondent supporting the generic approach accepted that, as with any averaging, there is the possibility for individual circumstances not to be reflected accurately. However, the respondent highlighted that such averaging occurs onshore, and believed that the greater stability that averaging provides makes this trade off worthwhile.

Five of the ten respondents to the consultation expressed a view on the classification of reactive compensation equipment as locational assets. Of these five, one was supportive, believing that such an approach would ensure consistency with the treatment of onshore generators. Three respondents not supporting the proposal believed that offshore generators will comply with the Grid Code at their point of connection to the transmission system, and that charging offshore generators for equipment provided to meet a requirement at a point remote from their connection points would be discriminatory. It was suggested that the transmission system would benefit from the reactive capability irrespective of the offshore generator being operational and that it would therefore be appropriate to socialise the bulk of the costs. One respondent was not clear as to why the treatment of offshore reactive compensation equipment as a locational asset was being proposed, or why this was different to onshore.

Respondents' Views – Further Consultation

Expansion Factors: Six of the seven responses that expressed an opinion on specific expansion factors derived from OFTO revenue supported their use. Three respondents agreed that there is a lack of accurate historic data and one respondent stated that costs may also materially vary between projects. A respondent further stated that in future years it may be possible to derive generic expansion factors. Another respondent stated that the use of generic expansion factors would be a move away from cost reflectivity and increase uncertainty in investment appraisal and that specific expansion factors should be used to apportion costs between connected generators and the cost of unused capacity socialised.

The respondent that did not support the use of generic expansion factors was concerned that the proposed offshore charging methodology is not consistent with the onshore charging methodology. The respondent continued that this may contravene National Grid's license obligation to not discriminate between any class of person and Article 7 of the Renewables Directive. It is believed that the use of circuit specific expansion factors and security factors and the substation tariff means that the OFTO revenue requirement would, in most circumstances, be fully recovered from the offshore generation users, in effect a 'deep' connection charge. In addition, the offshore generation user would be charged based on historic investment costs and actual ongoing running costs for local infrastructure, whereas onshore generation users are charged on the basis of the incremental current cost of supplying the service which the respondent felt not to be justified. The respondent continued that that the offshore charging proposals requires, and expects, a non-veto decision for GBECM-11 (Local Charging). Consistent with a charging proposal the respondent has recently proposed (GBECM-17[9]), support was given for an alternative approach that combines a shallowish connection charging policy with a uniform commodity charge for use of system.

Two respondents commented that there has been a lack of detail, to date, regarding the proposed STC technical data collection process, one of which expressed concern that it would not be done in an open and transparent manner .

A respondent noted that the long term future for offshore transmission is likely to involve interconnected projects and that the offshore network would form part of the MITS and that the proposals do not appear to recognise this.

Security Factors: A respondent who expressed support for specific security factors continued that such arrangements should in fact be applied both onshore and offshore, in order to increase cost reflectivity.

[9] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

Another respondent stated that the MITS node definition proposed in GBECM-11 may class not just design variation connections as local but wider infrastructure as well. The respondent stated that further work is required to clarify the consequential implications, both onshore and offshore, for locational signals and incentives to connect to the transmission system economically and efficiently.

Reactive: Two respondents agreed that the cost of reactive compensation assets provided by the OFTO on behalf of the connecting offshore generators should be included in the calculation of the specific Expansion Factors. One of which agreed such an approach was synonymous with the onshore generator investing to meet reactive capability requirements at the connection point although it was questioned how the day to day reactive requirements would be procured. The respondent suggested the GBSO should pay the offshore user for funding the reactive asset provision in order to not undermine the existing reactive market, by the provision of a 'free' service.

A further respondent identified that in order to achieve parity with onshore arrangements any commercial benefit to the OFTO for the provision of reactive capability should be recoverable by the generator. The difficulty at such an approach was stated to be that the generator will not be in control of the reactive plant – and the OFTO will not gain any benefit from bidding its reactive capability. The proposal was made that the generator would instruct the OFTO to provide reactive capability for the GBSO and all the benefits could be passed to the generator after the OFTO is permitted reasonable costs.

The same respondent believes the targeting of all the reactive costs into locational charge discriminates against offshore users, as there inconsistencies between the onshore and offshore approach, the significant examples given were:

- The Connection Conditions are local for an onshore generator and at the remote landing point for an offshore generator
- Onshore reactive capability must be provided for deficiencies in machine characteristics and not for support of the passive network (e.g. submarine cable). The passive network can require significant plant.
- System voltage swings will lead to changes to voltage on the passive network which increases the requirements from a SVC.

Substation tariff: Three respondents expressed support for the application of an offshore substation tariff, stating its consistency with the local charging arrangements onshore. One such respondent also expressed concern that such a tariff may stifle development offshore. Another of these three agreed non-locational costs should be targeted to generation who trigger investment and clearly offshore substations are only provided for offshore generation.

Five respondents do not support the local substation tariff. One respondent stated that the introduction of a substation locational tariff offshore was a significant and detrimental change, creating a major additional cost to generators at a crucial moment of development and charging equivalence on and offshore would be lost. Another of these respondents stated three issues; the cost burden on offshore projects is increased, it is not clear if the generator will also be liable for the cost of the onshore point of connection substation and its incompatibility with the principles within a shallow charging methodology.

Another respondent believes the proposals pre-empt the Authority decision on GBECM-11 and if the proposal is subject to a veto the offshore generator will be subject to a substation charge whist those onshore will not, which would not follow the principle of having a consistent regime. The respondent also believes that it is not appropriate to based offshore tariffs on historic costs will those onshore being based on current cost data.

A further respondent was disappointed by the move away from the shallow charging methodology and that transmission charging needs to be stable, predictable and rational in order to provide certainty for investors. The respondent is strongly against the direct targeting of substation costs as it will have a material impact of the viability of existing and future projects and is a form of discrimination when compared to the existing onshore regime. In addition it will be the OFTO who decides on specification, design and capital expenditure and therefore inappropriate for a generator to be exposed to the cost of these assets and the local charge should be applied without a substation element.

The final respondent who did not support the offshore substation tariff believed the removal of the socialisation is a major change at this late stage and that socialisation was one of the main justifications for the proposed regulatory regime to the wider industry. The respondent noted that the proposed adjustment for 'typical' onshore civil costs does not allow for elements such as land costs, landscaping, or special situations such as gas insulated switchgear. It was proposed that just as the onshore charging arrangements do not differential between users with air insulated switchgear (AIS) or those with gas insulated switchgear (GIS), even though there is a clear cost differential, the proposal for an offshore substation tariff is not justified.

Two respondents commented on the proposed part year charging arrangements, both expressing support, one of which suggesting such arrangements could also be applied for part year onshore connections.

National Grid's View

Expansion and Security factors: National Grid has a licensee obligation to keep its Charging Methodology under constant review and therefore if at a point in the future sufficient offshore transmission circuits have been constructed with comparable unit costs, then generic expansion factors will be assessed in conjunction with the industry.

National Grid strongly believes the onshore and offshore charging regimes should be based on the same principles and consistent as possible, unless sufficient justification exists for an alternative treatment. In addition National Grid has a transmission licence obligation to avoid undue discrimination between classes of user.

The Authority wrote to National Grid on 15 December 2008, providing a non-veto decision for GBECM-11 (Local Charging) on the grounds that the proposals better meet National Grid's Relevant Objectives. In which Ofgem stated "we feel it is correct that generator TNUoS charges should as far as reasonably practical reflect the costs imposed on the system arising from a generators' connection design and connection on the network." National Grid supports this view and believes an offshore generator should be exposed to the cost reflective marginal cost for both the local substation and circuit assets used for its connection to the onshore MITS, as is consistent with an onshore generator.

It is not accurate to state that, in most cases, all the OFTO revenue will be recovered from the offshore generators. Whilst it is true that the relative locational signal between the offshore generator and a generator at the onshore connection point is wholly cost reflective of booked capability of the offshore cable, it should be noted that generation (as a whole) will only be exposed to 27% of its cost. By reducing the generation TNUoS residual (including that of the offshore user) and increasing the demand residual 73% of the OFTO permitted revenue is funded by demand users.

The scale and variability of costs and the specific and easily identifiable purpose of an offshore transmission network provided by an OFTO justify the use of specific expansion factors as compared to the generic expansion factors. The specific expansion factors will be determined by the permitted revenue flow as presented in the historically successful OFTO tender submission. This ensures ongoing cost reflectivity.

Whilst basing offshore expansion factors on historic costs, as opposed to the forward looking costs used onshore, may introduce a difference of treatment, National Grid believe this is second order when compared to the risk of using generic expansion factors at this point associated with cost reflectivity.

The pre-consultation for the charging modification GBECM-17, "Transmission Charging – A New Approach", closed on 4 December 2008 and the industry responses received and the appropriate next steps will be discussed at the January 2009 Transmission Charging Methodology Forum. The implementation of the charging arrangement proposed, would result in fundamental change to the charging methodology as applied across both onshore and offshore generators, which would require expensive further consideration and therefore National Grid does not believe consideration is required at this time within the conclusions report.

Within the GBECM-11 decision letter, Ofgem described a specific request made to National Grid to keep under review the development of more specific security factors for the local network to onshore generators, to which National Grid agreed.

National Grid believes the MITS node definition implemented through GBECM-11, appears to give an appropriate balance of transparency/predictability and cost reflectivity in identifying circuits local to a generator's connection and therefore provides a signal that reflects the infrastructure investment over which a generator has influence. An offshore spur would be classified as 'local', reflecting both the generator ability to influence the length and redundancy of the circuit and its fundamental requirement for the generators 'local only' connection.

The EU Renewables Directive 2001/77/EC[10] was intended to aid with the creation of a framework for promoting renewable energy sources for electricity production. Article 7 specifically concerns grid connection issues, in which a member state's obligation is outlined to connect renewable projects, set up transparent, cost reflective and non-discriminatory Use of System and connection charges, and reinforcement the transmission network in order to allow new renewable generation connections. National Grid believes this charging modification in conjunction with its Charging Methodology and the ongoing work of the Transmission Access Review only further facilitates our ability to meet such obligations.

[10] http://eur-lex.europa.eu/smartapi/cgi/sga_doc?smartapi!celexplus!prod!DocNumber&lg=en&type_doc=Directive&an_doc=2001&nu_doc=77

The STC Committee has asked National Grid to lead the development of the required STC drafting, including the STC procedure, STCP14-1. This procedure outlines the data request process the GBSO will submit to the OFTO regarding the provision of the technical capabilities of its assets in order to determine specific expansion factors, security factors and the substation tariff. The proposed draft STCP will be published on National Grid's offshore charging page in the near future to permit industry comment. It should be noted that whilst the OFTO data request process must be open and transparent, it is also important not to undermine the commercial sensitivity of the procurement process.

The offshore charging arrangements proposed allow any number of generators to connect via a shared and interconnected offshore network, assuming a single landing node. This assumption can be made, based on the drafting of the offshore SQSS where if the offshore network were to parallel the onshore, it would be required to meet the more onerous onshore SQSS standards. Under the approved Local Charging arrangements, an offshore node could indeed be considered MITS if it was either a Grid Supply Point or had greater than four transmission circuits connected.

Reactive: The Offshore Grid Code Subgroup concluded that the most economic generic arrangement was to allow an offshore generator to meet its reactive power capability at the Onshore Grid Entry Point (by means of an obligation placed upon OFTOs in the SO TO Code) as opposed to at the offshore generator platform. It was concluded there would be significant savings in terms of avoiding enhanced cable ratings and offshore platform costs.

Consequently, National Grid continues to believe that the costs of any reactive compensation equipment installed by the OFTO should be reflected onto the connected offshore generators who otherwise would have been required to provide and fund reactive capability at the offshore platform, which was concluded to be a higher cost solution by the Subgroup.

National Grid agrees that a proportion of the reactive capability provided by the OFTO may be required for support of the passive network (i.e. offshore transformer and cables), and hence believes that this equipment should be treated in the same way as the other network components and reflected on the connected offshore generators.

National Grid also believes that it is appropriate to reflect the costs of reactive capability provided by OFTOs, as a surrogate for generator capability, on the connected offshore generators. Given this, National Grid is investigating options for ongoing remuneration for this reactive capability which are consistent with arrangements for the capability currently provided by onshore generators.,

Substation: The non-veto decision for the GBECM-11 Local Charging modification, ensures that all onshore generators will be subject to a cost reflective signal reflecting their use of the local transmission substation to which they connect. National Grid agrees that onshore and offshore charging arrangements should be consistent where feasible and therefore an offshore local substation tariff for offshore generators has been proposed. National Grid agrees the implementation of GBECM-11 may lead to a step change in tariffs for current and imminent generation connection but agree with the position stated in the Authority decision letter that only those generators that have not been previously exposed to the full cost of their connection that will now see an increased TNUoS charge.

National Grid believes a cost reflective locational signal for the substation assets local to a generator is compatible with a shallow charging methodology, incentivising generation to efficiently influence levels of transmission investment by, for example, selecting the most efficient level of redundancy. Socialisation of all substation asset costs does not incentive efficient and effective investment.

The charging proposals made are not equivalent to a deep charging boundary and by maintaining the shallow connection boundary, the generator is still only subject to the cost of substation capacity booked (rather than installed) and the shallow boundary benefits are maintained, namely protection from the consequence of other Users decisions. National Grid does not believe that such an approach is any less predictable, rational or stable.

National Grid agrees the successful OFTO's tender submission will determine the specification, capital cost and therefore offshore Use of System charge for the offshore transmission network. That withstanding, the fundamental justification for the regulator's decision to select OFTO by tender is to ensure the most efficient and economic solution is selected which will be reflected directly in the generator's tariff.

Under the recently approved Local Charging arrangements, all onshore directly connected generators are subject to a substation local tariff. The substation tariffs were derived from the primary asset bay capital costs for four generic connection configurations. A GB average was used for each of the three transmission voltages. This reflected the incremental cost of non locational primary transmission assets onto a generator but does not include generic costs such as civil works. The application of a GB (onshore and offshore) average or even an offshore average substation tariff would not be cost reflective because of the greater magnitude and variability of the platform costs. The proposed adjustment for 'typical' civil works costs ensures the offshore specific substation tariff only reflects the incremental cost between onshore and offshore generations and the tariff is on an equal basis.

Onshore a User's substation tariff varies with three cost determining factors, namely connection voltage, level of substation redundancy and total site export capacity. Consequently, a GIS connected user does not pay a higher substation tariff than one connected by AIS and if this was raised as a material issue, National Grid would consider the issue under its obligation to keep the Charging Methodology under constant review.

For the avoidance of doubt, consistent with an onshore spur, an offshore generator will only pay a local substation tariff at the offshore connection substation and the cost of its onshore connection node will not be directly targeted.

3.3 High Voltage Direct Current (HVDC)

Respondents' Views- Original Consultation

Of the ten responses to the consultation, four respondents supported the proposed approach (although one of these would have preferred the treatment of all offshore assets as connection rather than infrastructure), and a further two respondents expressed support with some qualifications. Two respondents did not support the proposal, and two did not express a view.

Respondents supporting the proposal, believed that, although converter stations are not locationally varying in practice, they should be treated as locational due to their interaction with the cost of the associated cable. Another believed that HVDC converter stations are an intrinsic part of the provision of a cable connection and should therefore be treated as “locational” assets.

Two respondents gave qualified support to the proposal, with one suggesting that there are advantages in terms of reactive capability and fault levels to the wider system of installing HVDC links, and that there is therefore an argument for allocating some of the costs of converter stations to non-locational costs. The other agreed with the rationale for the inclusion of the costs of HVDC converter stations in the derivation of specific expansion factors for offshore circuits but believed that, given no HVDC links are currently under development, it would be inappropriate and unnecessary to determine such charging arrangements now.

Of the two respondents opposed to the proposal, one questioned the logic of treating DC converter stations as locational, when AC substations are non-locational, considering that this might lead to the selection of AC in preference to DC because of the differences in charging allocation, rather than the underlying economics. The other respondent not to support the proposal questioned why DC converter station costs should be treated differently from substation assets. Although the presence of DC converter stations would allow the use of potentially cheaper DC cable, the respondent believed that this argument could be extended to onshore AC transformers, as these are necessary to allow for the lower cost per MWkm that higher voltage lines and cables provide.

Respondents’ Views – Further Consultation
Three respondents continued to support the inclusion of converter station costs into the locational signal, through their inclusion in Expansion Factor calculations. One of which, supported the development of HVDC and believes it may bring increased efficiency although the choice to use such technology is with the user and therefore the costs should be borne by the user and agree the converter costs should not be recovered through the residual as they are locational.

One respondent does not see any difference between substation assets and HVDC converter stations and strongly believes such costs should not be targeted directly on the offshore generator but should be socialised through the residual. Targeting the costs is a form of discrimination when compared to the current onshore regime.

A further respondent, who does not support the targeting of converter station costs, stated that as HVDC is likely to be the main mechanism by which large and remote wind farm clusters connect. The respondent noted that HVDC technologies have additional consequential advantages to all users in terms of reactive capability and faults levels for the onshore wider system and by allocation of 100% of the converter costs, these factors are not recognised in the signal.

National Grid’s View
National Grid continues to believe that whilst HVDC converter station assets are similar to non-locational substation assets, they are an inherent component of a HVDC circuit, whose capacity and therefore cost is directly matched to the length and capability of the link and therefore should be included in the circuit expansion factor. In addition, whilst the per unit £/MWkm cost of a HVDC cable is lower, compared to an AC circuit, this has to be considered alongside the additional cost of the converter stations which are only required for DC transmission. Consequently without the full signal being reflected upon the user, the ‘break even’ circuit length, at which HVDC

becomes the most efficient and economic medium will be artificially distorted and shortened.

The use of HVDC technology may have the potential to provide marginal system operation advantages such as limiting system in-feed fault levels, although National Grid believes that the accurate assessment of the materiality of such second order effects cannot be accurately performed at this early stage in the development of the technology. Consequently, National Grid will keep the charging proposals under review as analysis and developments are undertaken. Any ability to provide reactive capability from the HVDC link will net off the requirement at the onshore connection point, reducing the cost of the required reactive compensation the OFTO is required to install which consequently is reflected to the User via a lower expansion factor and therefore TNUoS locational signal.

3.4 Embedded Transmission

Respondents' Views- Original Consultation

A number of respondents to the original consultation raised the issue that charging arrangements for Embedded Transmission had not been consulted on, as a result of the formation of the Offshore Transmission Embedded Transmission Working Group. One of these respondents went on to note that this group did not appear to cover any material consideration of charging issues. Consequently the area was induced in the further consultation document.

Respondents' Views – Further Consultation

All respondents except one who expressed an opinion generally supported the principle of the creation of a new charge for embedded transmission, namely ETUoS. One respondent agreed that DNO charges must flow directly to the offshore generators to avoid socialisation of additional risk across all users and another believed such arrangements are transparent. A respondent also noted that for particular projects there is some uncertainty on the future costs associated with DNO charging for generation although it may be a matter for the regulator.

A further respondent had concerns around the impact of the ETUoS proposals on the early mover licence exempt projects. Such projects look and behave like onshore LEEMPS generators but are disadvantaged as it is subject to TNUoS charges as well as the ETUoS element. The respondent continues to support their alternative "embedded benefits" strawman as the charging arrangements for sub 100MW offshore generators would be akin to exempt onshore distribution connection generators. Under such a model the Exempt (or Exemptible) offshore generators pay a deep connection charge which includes the distribution network connection costs, instead of ongoing TNUoS charges but would not gain an explicit right to access the onshore transmission network.

A respondent whilst recognising that a separate charge for embedded transmission is required, was unclear why the GBSO must be party to the DNO charges and why the OFTO is not responsible. Another respondent supported a review of the charging arrangements for embedded transmission in relation to embedded benefits.

The respondent who did not support the pass through of the cost of embedded transmission believed it was a perverse incentive to connect to the transmission network, as the reinforcement costs are socialised, as opposed to connecting to embedded transmission, that may be the most cost effective solution overall. It was noted that NGET has no licence obligation to consider the most economic solution overall.

National Grid's View
The levying of transmission charges on exemptible power stations offshore is inherent in classifying offshore 132kV connections as "transmission" and is consistent with onshore arrangements. This situation already occurs in Scotland, where such power stations are connected to the transmission network at 132kV. These generators are eligible for discounted Generation TNUoS charges (by one-quarter of the total TNUoS residual charge) via the Licence Condition C13 "small generators discount scheme", which sits outside of the governance of the Use of System Charging methodology.

We therefore continue to believe that any treatment of exemptible power stations offshore is a wider regulatory issue, and that any alternative arrangements, such as those proposed under the "embedded benefits" strawman would therefore not best be given effect in the Use of System Charging Methodology.

The Authority recently published an industry consultation[11] relating to the future of the small generator TNUoS discount which is due to close on 5 Jan 2009.

Under the shallow "plugs" connection boundary a user does not fund specific transmission system reinforcements that are triggered by its use of the transmission network but is subject to a TNUoS tariff that contains a locational signal representing the incremental long run cost of the services provided to the user at its location including investment costs. The shared and interconnected nature of the onshore transmission system will result in many users benefiting from a specific reinforcement and therefore rather than targeting specific reinforcement works to specific connections, a socialised tariff with a cost reflective locational element is appropriate. Clearly, reinforcements to a distribution network triggered by an embedded transmission connection will only be used by the offshore generators and therefore National Grid believes it is both possible and appropriate to directly pass through the cost of provision of distribution infrastructure.

National Grid has a licence obligation to consider the efficient and economic connection solution for users connecting onto the transmission system and it is difficult to see how such an obligation could be widen to include the use of distribution network, without the provision of significant additional information. The Embedded Transmission proposals have been made to give a generator the ability to consider a wider range of connection options.

3.5 Generation Zoning

Respondents' Views- Original Consultation
Generation Zoning was not discussed in the original consultation document.

Respondents' Views- Further Consultation
Two respondents supported the proposed inclusion of offshore generators into onshore generation TNUoS zones but performing zoning on the wider TNUoS

[11] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=80&refer=Networks/Trans/ElecTransPolicy/TADG

component. One such respondent acknowledged the key principles of increased stability and predictability of tariffs that this approach delivers

One respondent believed that the proposed revision to the generation zoning methodology appears to pre-empt the decision on GB ECM-11 (Local Charging) and that if not implemented, then discordance in the treatment of onshore and offshore users would arise.

National Grid's View
National Grid believes performing generation zoning for offshore generation based on 'wider' marginal costs ensures consistency between onshore and offshore charging and therefore maintains our recommended approach.

4 Changes to the proposal in light of representations made

Further consideration is being given to the charges that will be levied on National Grid by DNOs for Embedded Transmission and whether they best fit within the Transmission Licence definition of 'use of system charges'. National Grid does not however wish to unduly delay the issuing of this report whilst this issue is considered and is therefore proposing two options:

- Option 1 This option includes all elements of the offshore transmission charging proposals that were consulted upon
- Option 2 This option excludes the Embedded Transmission element of the proposals

National Grid recommends Option 1 if it is considered by the Authority that the proposals for Embedded Transmission best fit within use of system charges, and recommends Option 2 if it is considered by the Authority that the proposals for Embedded Transmission cannot and should not fall within use of system charges.

5 How the proposed modification better meets the relevant licence objectives

National Grid's proposal to modify the TNUoS Charging Methodology to provide charging arrangements for offshore generators connecting onto the offshore transmission network, to better meets the relevant objectives in Licence Conditions C5 5(a), 5(b) and C5 5(c). Namely to ensure National Grid applies charges which facilitate effective competition in generation and supply, to reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and properly takes account of the developments in transmission licensees' transmission businesses.

C5 5(a) Facilitating Competition
Facilitates competition in generation and supply by:

- Provides the charging arrangement required to permit an additional class of generation to enter the GB market, namely offshore generation.
- Expands the current charging methodology with the provision of a cost reflective signal for the marginal cost for use of offshore transmission networks, ensuring onshore and offshore generation compete within consistent arrangements.

C5 5(b) Cost Reflectivity
Improves the cost reflectivity of charging for assets local to generation connections by:

- Applies specific local expansion factors and local security factors for local offshore circuit flows, derived from the annual permitted revenue for the OFTO.
- Implements an offshore local substation charge, which charges a User for its use of the primary assets and platform at the connection site

C5 5(c) Developments in Transmission Business
Takes account of development in the TLs' transmission business:

- Provides the Use of System charging arrangements required for the introduction of the regulated offshore transmission network in 2010/11

6 Timetable for implementation

The implementation date for the proposed change will be 28 days after furnishing the conclusions report to the Authority, subject to non-veto (or 3 months if the Authority decides to undertake an Impact Assessment). National Grid currently anticipates that the conclusions report would be issued in November 2008. However, the modification would have no practical effect (as there would be no licensed offshore transmission systems) until the offshore transmission regime reaches "go-live". This is currently planned for April 2010.

A general suggestion made within a further consultation response identified that as a result of the number of simultaneous charging consultations, there may be a requirement for their impact to be communicated to the wider industry via forums or presentations early in 2009. It was also suggested that an updated version of the DC Load Flow (DCLF) model be made available to the industry, reflecting the proposed changes.

Previously, after the implementation of complex or technical charging modifications National Grid has provided industry tutorials and seminars. In addition, it is anticipated that the external version of the DCLF model will be updated as soon as possible after the Authority decision to allow scenario analysis to be performed.

Appendix 1 - Proposed drafting of the Statement of the Use of System Charging Methodology for Offshore Transmission

Chapter 2: Derivation of the Transmission Network Use of System Tariff

2.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff. The process for calculating the TNUoS tariff is described below.

The Transport Model

<u>Model Inputs</u>

2.2 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

2.3 The transport model requires a set of inputs representative of peak conditions on the transmission system:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The ratio of each of 132kV overhead line, 132kV cable, 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line costs to give circuit expansion factors
- Identification of a reference node

2.4 For 2008/9, the nodal generation data for the transport model will be derived from the GB Seven Year Statement, which will contain the contracted generation Transmission Entry Capacity (TEC) and include all notification of changes in generating capacity received by 23 December 2007. Thereafter, for charging year "t", the nodal TEC figure at each node will be based on the Applicable Value for year "t" in the GB Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs in the GB Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2009/10 charges, the nodal generation data is based on the forecast for 2009/10 in the 2008 GB Seven Year Statement plus any data included in the quarterly updates to October 2008.

2.5 Nodal demand data for the transport model for 2008/9 will initially be based on GSP demand that Users have forecast to occur at the National Grid Peak Average Cold Spell (ACS) demand. Thereafter, for year "t", data will be based upon the GSP demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

2.6 Transmission circuit data for charging year 2008/9 will initially be based on data taken from National Grid's April 2007 GB Seven Year Statement complemented with the October updates. Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April GB Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the GB Seven Year Statement, National Grid will use the best information available.

2.7 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

2.8 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 132kV and 275kV routes, (iii) 275kV routes and 400kV routes, and (iv), uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically 400kV cable, 275kV overhead line, 275kV cable, 132kV overhead line and 132kV cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line.

2.9 A reference node is required as a basis point for the calculation of marginal costs. It determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of Scotland, all nodal generation marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal generation marginal costs would be positive. However, the relativity of costs between nodes would stay the same. For information purposes the reference node for 2008/9 is West Burton 400kV (WBUR40).

Model Outputs

2.10 The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national generation (sum of contracted TECs) equals total national ACS Demand. The model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. Then it calculates the resultant total network MWkm, using the relevant circuit expansion factors as appropriate.

2.11 Using this baseline network, the model calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node. The marginal km cost for demand at each node is then equal and opposite to, the nodal marginal km for generation. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

2.12 An example is contained in **Appendix TN-1: Transport Model Example.**

Calculation of zonal marginal km

2.13 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 2.17. The number of generation zones set for 2008/9 is 20.

2.14 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

2.15 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity. Firstly the zonal marginal km for generation is calculated as:

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j$$

Where

Gi	=	Generation zone
j	=	Node
NMkm	=	Nodal marginal km from transport model
WNMkm	=	Weighted nodal marginal km
ZMkm	=	Zonal Marginal km
Gen	=	Nodal Generation from the transport model

2.16 The zonal marginal km for demand zones are calculated as follows:

$$WNMkm_j = \frac{-1 * NMkm_j * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j$$

Where

Di	=	Demand zone
Dem	=	Nodal Demand from transport model

2.17 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of National Grid that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zones should contain relevant nodes whose wider marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

2.18 The process behind the criteria in 2.17 is driven by initially applying the nodal marginal costs from the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs for guidance.

2.19 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by National Grid to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, National Grid determines and uses the one that best reflects the physical system boundaries.

2.20 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

Deriving the Final £/kW Tariff

2.21 The zonal marginal km are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below).

The Expansion Constant

2.24 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

2.25 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 2.42, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 2.47.

2.26 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents National Grid's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

2.27 For each circuit type and voltage used onshore. an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 2.35. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

2.28 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

400kV OHL expansion constant calculation					
MW	**Type**	£(000)/km	Circuit km*	**£/MWkm**	**Weight**
A	B	C	D	E = C/A	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750
5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
sum			**2500 (G)**		**285400 (H)**
				Weighted Average (J= H/G):	**114.160 (J)**

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

2.29 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

2.30 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the National Grid regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

2.31 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2008/9 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

2.32 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

400kV OHL expansion constant calculation	
	Ave £/MWkm
OHL	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

2.33 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 2.35, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for offshore TO (OFTO) networks is described in ●.

2.34 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in National Grid's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2008/9 is 10.289.

Onshore Circuit Expansion Factors

2.35 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

2.34 In calculating the onshore cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

2.35 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

2.36 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

2.37 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

2.38 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

400kV cable factor:	22.39
275kV cable factor:	22.39
132kV cable factor:	27.79
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.24

Scottish Power & National Grid Regions

400kV cable factor:	22.39
275kV cable factor:	22.39
132kV cable factor:	30.22
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.80

Offshore Circuit Expansion Factors

2.39 Offshore expansion factors (£/MWkm) are derived from information provided by OFTOs for each offshore circuit. Offshore expansion factors are OFTO and circuit specific. Each OFTO will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the OFTO's reactive compensation equipment.

2.40 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div \text{Onshore 400kV OHL Expansion Constant}$$

Where:

CRevOFTO1 = The offshore circuit revenue in £ for Year 1

L = The total circuit length in km of the offshore circuit

CircRat = The continuous rating of the offshore circuit

2.41 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvC\operatorname{Re}vOFTO}{L \times CircRat} \div \text{Onshore 400kV OHL Expansion Constant}$$

Where:

AvCRevOFTO = The annual offshore circuit revenue averaged over the remaining years of the onshore GBSO price control

L = The total circuit length in km of the offshore circuit

CircRat = The continuous rating of the offshore circuit

2.42 Prevailing OFTO specific circuit expansion factors will be published in this Statement. These shall be re-calculated each price control when then onshore expansion constants are revisited.

The Locational Onshore Security Factor

2.39 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

2.40 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[12].

2.43 The locational onshore security factor derived for 2008/9 is 1.8 and is based on an average from a number of studies conducted by National Grid to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

The Offshore Security Factor

[12] http://www.nationalgrid.com/uk/Electricity/Charges/

2.44 A circuit specific offshore security factor (OffSF) will be calculated for each offshore connection using the following methodology:

$$OffSF = \frac{CircRat}{\sum_k Gen_k}$$

Where:

k = the generation connected to the offshore network

2.45 The offshore security factor for single circuits will be 1.0 and for multiple circuit connections will be capped at the locational security factor, derived as 1.8 for 2008/9.

Initial Transport Tariff

2.42 First an Initial Transport Tariff (ITT) must be calculated. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Gi} \times EC \times LSF = ITT_{Gi}$$

Where

$ZMkm_{Gi}$	=	Zonal Marginal km for each generation zone
EC	=	Expansion Constant
LSF	=	Locational Security Factor
ITT_{Gi}	=	Initial Transport Tariff (£/MW) for each generation zone

2.43 Similarly, for demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Di} \times EC \times LSF = ITT_{Di}$$

Where

$ZMkm_{Di}$	=	Zonal Marginal km for each demand zone
EC	=	Expansion Constant
LSF	=	Locational Security Factor
ITT_{Di}	=	Initial Transport Tariff (£/MW) for each demand zone

2.44 The next step is to multiply these initial transport tariffs by the expected metered triad demand and generation capacity to gain an estimate of the initial revenue recovery. Both of these latter parameters are based on forecasts provided by Users and are confidential.

$$\sum_{Gi=1}^{21} (ITT_{Gi} \times G_{Gi}) = ITRR_G \quad \text{and} \quad \sum_{Di=1}^{14} (ITT_{Di} \times D_{Di}) = ITRR_D$$

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation
G_{Gi} = Total forecast Generation for each generation zone (based on confidential User forecasts)
$ITRR_D$ = Initial Transport Revenue Recovery for demand
D_{Di} = Total forecast Metered Triad Demand for each demand zone (based on confidential User forecasts)

2.45 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. This has been determined to be 27:73 by the Authority for generation and demand respectively. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

$$\sum_{Gi=1}^{21}\left[(ZMkm_{Gi}+C)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[(ZMkm_{Di}-C)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p(CTRR_G + CTRR_D)$$

Where
CTRR = "Generation / Demand split" corrected transport revenue recovery
p = Proportion of revenue to be recovered from demand
C = "Generation /Demand split" Correction constant (in km)

2.46 The above equations deliver corrected (£/MW) transport tariffs (CTT).

$$(ZMkm_{Gi} + C)\times EC \times LSF = CTT_{Gi}$$
$$(ZMkm_{Di} - C)\times EC\times LSF = CTT_{Di}$$

So that

$$\sum_{Gi=1}^{21}(CTT_{Gi}\times G_{Gi})=CTRR_G \quad \text{and} \quad \sum_{Di=1}^{14}(CTT_{Di}\times D_{Di})=CTRR_D$$

Offshore substation local tariff

2.47 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of a transformer, switchgear, and platform components.

2.48 Each tariff component, expressed in £/kW, shall be the ratio of the OFTO revenue (£) and rating associated with the transformers, switchgear, or platform (kW) at each offshore substation. In the case of the platform component, the relevant rating shall be the higher of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the OFTO revenue associated with each tariff component shall be averaged over the remaining years of the GBSO price control.

2.49 A discount of £0.35/kW shall be provided to the offshore substation tariff, to reflect the average cost of civil engineering for onshore substations.

2.50 Offshore substation tariffs shall be inflated by RPI each year and reviewed every price control period.

2.51 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\text{All offshore substations}} \left(SLT_k \times \sum_k Gen_k \right)$$

Where:

SLTk = the offshore substation tariff for substation k

Genk = the generation connected to offshore substation k

Renumber subsequent paras

The Residual Tariff

2.47 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

TRR_t = TNUoS Revenue Recovery target for year t

R_t = Forecast Revenue allowed under National Grid's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition AA5A of National Grid's Transmission Licence.

PVC_t = Forecast Revenue from Pre-Vesting connection charges for year t

SG_{t-1} = The proportion of the under/over recovery included within R_t which relates to the operation of statement C13 of the National Grid Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

2.48 In normal circumstances, the revenue forecast to be recovered from the corrected transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

2.49 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the corrected transport tariffs so that the correct generation/ demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times PTRR) - CTRR_D}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times PTRR] - CTRR_G - SLTR}{\sum_{Gi=1}^{21} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

Final £/kW Tariff

2.50 The final Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the corrected transport tariff and the non-locational residual tariff:

$$FT_{Gi} = \frac{CTT_{Gi} + RT_G + SLT_k}{1000} \quad \text{and} \quad FT_{Di} = \frac{CTT_{Di} + RT_D}{1000}$$

Where

FT = Final TNUoS Tariff expressed in £/kW

2.51 If the Final demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then i = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the demand zones with positive Final tariffs is given by:

For i= 1 to z: $RFT_{Di} = 0$

For i=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

where:

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
RFT_{Di} = Revised Final Tariff (£/kW)

2.52 The tariffs applicable for any particular year are detailed in National Grid's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

2.53 The zonal maps referenced in National Grid's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

2.54 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

2.55 National Grid has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the GB network. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the **Charging** Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

2.56 National Grid will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

2.57 The factors which will affect the level of TNUoS charges from year to year include the forecast level of peak demand on the system, the Price Control formula (including the effect of any under/over recovery from the previous year), the expansion constant, the locational security factor, changes in the transmission network and changes in the pattern of generation capacity and demand.

2.58 In accordance with Standard Licence Condition C13, generation directly connected to the GB 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

Stability & Predictability of TNUoS tariffs

2.59 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in Appendix TN-8.

Chapter 5: Generation charges

Parties Liable for Generation Charges

5.1 The following CUSC parties shall be liable for generation charges:

i) Parties of Generators that have a Bilateral Connection Agreement with National Grid.

ii) Parties of Licensable Generation that have a Bilateral Embedded Generation Agreement with National Grid.

iii) Interconnector Asset Owners that have a Bilateral Connection Agreement with National Grid and/or Interconnector asset Owners of Interconnectors capable of exporting 100MW or more to the Total System.

5.2 **Appendix TN-5: Classification of parties for charging purposes** provides an illustration of how a party is classified in the context of Use of System charging and refers to the relevant paragraphs most pertinent to each party.

Basis of Generation Charges

5.3 The value of generation to be multiplied by the relevant generation tariff, for the calculation of generation charges, is set out below. For the avoidance of doubt, the intention of the charging rules is to charge the same physical entity only once.

5.4 The basis of the generation charge for Power Stations and Interconnectors (including Interconnector errors with the exception of Emergency Assistance actions) is the Chargeable Capacity and the short-term chargeable capacity (as defined below for positive and negative charging zones).

Positive Charging Zones

5.5 The Chargeable Capacity for Power Stations situated in positive charging zones is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year. A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity, STTEC). For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

5.6 The short-term chargeable capacity for Power Stations situated in positive charging zones is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as appropriate.

5.7 The Chargeable Capacity for an Interconnector connected to a positive charging zone is the highest TEC applicable to that Interconnector for that Financial Year. An Interconnector should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity).

5.8 The short-term chargeable capacity for an Interconnector connected to a positive charging zone is any approved STTEC or LDTEC applicable to that Interconnector during a valid STTEC Period or LDTEC Period, as appropriate.

5.9 For Power Stations and Interconnectors, the short term chargeable capacity for LDTEC in positive zones referred to in Paragraphs 5.6 and 5.8 will be the capacity purchased either on a profiled firm[13] or indicative[14] basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second of 50MW. Further examples are provided on Pages 35 and 36 of this document.

Negative Charging Zones

5.10 The Chargeable Capacity for Power Stations and Interconnectors situated in negative charging zones is the average of the capped metered volumes during the three settlement periods described in 5.11 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station in Appendix C of its Bilateral Agreement) or Interconnector. A Power Station or Interconnector should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station or Interconnector applicable for that Financial Year. For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

5.11 The three settlement periods are those of the highest metered volumes for the Power Station or Interconnector and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the Triad.

Example

If the highest TEC for a Power Station were **250MW** and the highest metered volumes and resulting capped metered volumes were as follows:

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[13] where an LDTEC Block Offer has been accepted (Profiled Block LDTEC) and a firm profile of capacity has been purchased.

[14] where an LDTEC Indicative Block Offer has been accepted (Indicative Profiled Block LDTEC) and a right to future additional capacity up to a requested level has been purchased, the availability of which will be notified on a weekly basis in accordance with the CUSC.

Date	19/11/08	13/12/08	06/02/09
Highest Metered Volume in month (MW)	**245.5**	**250.3**	**251.4**
Capped Metered Volume (MW)	**245.5**	**250.0**	**250.0**

Then, the chargeable Capacity for the Power Station would be:

$$\left(\frac{245.5+250+250}{3}\right) = \mathbf{248.5\ MW}$$

Note that in the example above, the Generator has exceeded its TEC on 13 December 2007 and 6 February 2008 and would therefore be in breach of the CUSC unless the generator had an approved STTEC or LDTEC value. (The STTEC and LDTEC charge for negative zones is currently set at zero).

5.12 The short-term chargeable capacity for Power Stations situated in negative charging zones is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as applicable.

5.13 The short-term chargeable capacity for Interconnectors situated in negative charging zones is any approved STTEC or LDTEC applicable to that Interconnector during a valid STTEC Period or LDTEC Period, as applicable.

5.14 For Power Stations and Interconnectors, the short-term chargeable capacity for LDTEC in negative zones referred to in Paragraphs 5.12 and 5.13 will be the capacity purchased either on a profiled firm or indicative basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second at 50MW.

5.15 As noted above, the LDTEC tariff in negative generation charging zones is set to zero. Accordingly no payments will be made for use of LDTEC (in any of its forms) in these zones.

Small Generators Charges

5.16 Eligible small generators' tariffs are subject to a discount of a designated sum defined by Licence Condition C13 as 25% of the combined residual charge for generation and demand. The calculation for small generators charges is not part of the methodology however, for information the designated sum is included in **The Statement of Use of System Charges.**

Monthly Charges

5.17 Initial Transmission Network Use of System Generation Charges for each Financial Year will be based on the Power Station Transmission Entry Capacity (TEC) for each User as set out in their Bilateral Agreement. The charge is calculated taking the forecast Chargeable Capacity and multiplying it by the zonal £/kW tariff. This annual TNUoS generation charge is split evenly over the 12 months and charged on a monthly basis over the year. For positive charging zones, if TEC increases during the charging year, the party will be liable for the additional charge incurred for the **full** year, which will be recovered uniformly across the remaining chargeable months in the relevant charging year (subject to Paragraph 5.18 below). An increase in monthly charges reflecting an increase in TEC during the charging year will result in interest being charged on the differential sum of the increased and previous TEC charge. The months liable for interest will be those preceding the TEC increase from April in year t. For negative charging zones, any increase in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. However, as TEC decreases do not become effective until the start of the financial year following approval, no recalculation is necessary in these cases. As a result, if TEC increases, monthly payments to the generator will increase accordingly.

5.18 The provisions described above for increases in TEC during the charging year shall not apply where the LDTEC (in any of its forms) has been approved for use before the TEC is available, which will typically mean the LDTEC has been approved after the TEC increase has been approved. In such instances, the party shall commence payments for TEC during the LDTEC Period for LDTEC purchased up to the future level of TEC and LDTEC Charges will only apply to LDTEC that is incremental to the TEC increase. For the avoidance of doubt, where TEC has been approved after LDTEC in a given year, these provisions shall not apply and the LDTEC shall be considered additional to the TEC and charged accordingly.

Ad hoc Charges

5.19 For each STTEC period successfully applied for, a charge will be calculated by multiplying the STTEC by the tariff calculated in accordance with Paragraph 3.3. National Grid will invoice Users for the STTEC charge once the application for STTEC is approved.

5.20 For Power Stations and Interconnectors utilising LDTEC (in any of its forms) the LDTEC Charge for each LDTEC Period is the sum of the charging liabilities associated with each incremental level of short term chargeable capacity provided by LDTEC within the LDTEC Period (assessed on a weekly basis). The charging liability for a given incremental level of short term chargeable capacity is the sum of:

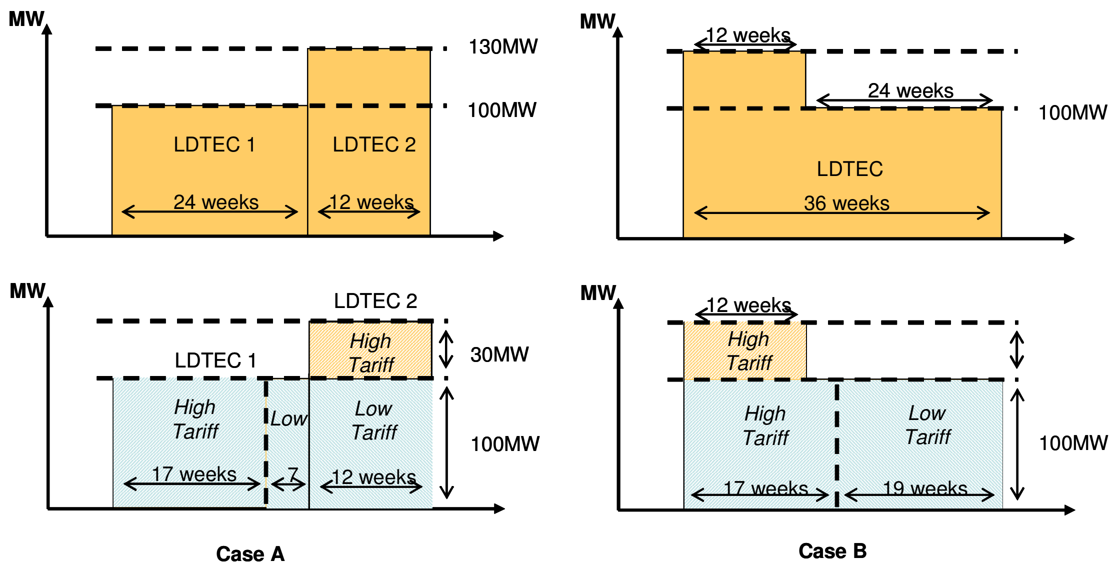
i) the product of the higher tariff rate (calculated in accordance with Paragraph 3.6) and capacity purchased at this increment for the first 17 weeks in a Financial Year (whether consecutive or not); and

ii) the product of the lower tariff rate (calculated in accordance with Paragraph 3.6) and capacity purchased at this increment in any additional weeks within the same Financial Year (whether consecutive or not).

5.21 For each LDTEC Period successfully applied for, the LDTEC Charge will be split evenly over the relevant LDTEC Period and charged on a monthly basis. LDTEC charges will apply to both LDTEC (in any of its forms) and Temporary Received TEC held by a User. For the avoidance of doubt, the charging methodology will not differentiate between access rights provided to a generator by LDTEC or through Temporary Received TEC obtained through a Temporary TEC Exchange (as defined in the CUSC).

Example

The diagrams below show two cases where LDTEC has been purchased: in Case A, two LDTEC Periods have been purchased; and in Case B one LDTEC Period has been purchased. The total capacity purchased in both cases is the same. The top diagrams illustrate the capacity purchased, while lower diagrams illustrate the incremental levels of short term chargeable capacities of LDTEC and the tariff rate that would apply to that capacity.



In both cases, the total amount charged for the LDTEC would be the same:

Capacity charges at the higher tariff rate:	Capacity charges at the lower tariff rate:
• 17 weeks at the 100MW increment • 12 weeks at the 30MW increment	• 19 weeks at the 100MW increment

THE FOLLOWING SECTION (5.22 – 5.27) ONLY APPLIES TO OPTION 1 AND NOT TO OPTION 2

Embedded Transmission Use of System Charges "ETUoS"

5.22 The ETUoS charges are a component of Use of System charges levied on offshore generators whose offshore transmission connection is embedded in an onshore distribution network. The charge relates to the provision and use of the onshore distribution network.

5.23 The purpose of ETUoS charges is to pass through the charges that are levied by the DNO on the GBSO to the offshore generator(s). This charge reflects the charges levied by the DNO for the costs of any works on and use of the DNO network in accordance with the DNO's charging statements and will include, but is not limited to, upfront charges and capital contributions in respect of any works as well as the ongoing and annual Use of System charges for generation connected to the distribution network

5.24 The specific nature of the ETUoS charge and the payment profile for these will depend upon the charging arrangements of the relevant DNO and reference should be made to the relevant DNO's charging statement.

5.25 Where a DNO's charge relates to more than one offshore generator, the related ETUoS charge will be pro-rated based on the TEC of the relevant offshore generators connected to that offshore network.

5.26 Invoices for ETUoS charges shall be levied by the GBSO on the offshore generator as soon as reasonably practicable after invoices have been received by the GBSO for payment such that the GBSO can meet its payment obligations to the DNO. The initial payments and payment dates will be outlined in a User's Construction Agreement and/or Bilateral Agreement.

5.27 As the ETUoS charges reflect the DNO charges to the GBSO, such charges will be subject to variation when varied by the DNO. Where the User disputes regarding the ETUoS charge please note that this will result in a dispute between the GBSO and DNO other the DCUSA.

Reconciliation of Generation Charges

5.27 The reconciliation process is set out in the CUSC and in line with 5.14 above.

5.28 In the event of a manifest error in the calculation of TNUoS charges which results in a material discrepancy in a User's TNUoS charge as defined in Sections 4.24 to 4.26, the generation charges of Users qualifying under Section 4.25 will be reconciled in line with 5.17 and 5.22 using the recalculated tariffs.

Further Information

5.29 **The Statement of Use of System Charges** contains the £/kW generation zonal tariffs for the current Financial Year.