cornwallenergyassociates

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Enduring Charging Arrangements for Embedded Generation

A report for:

Ofgem
9 Millbank
London
SW1P 3GE

Prepared by:

Nigel Cornwall
Cornwall Energy Associates
Heath Farm Cottage
Paston
North Walsham
Norfolk
NR28 0SQ

Telephone: + 44 (0)1692 407 865
Facsimile: + 44 (0)870 705 2249
E-mail: info@cornwallenergy.com

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Executive summary

Introduction

The scope of work is defined in terms of reference issued by Ofgem on 21 May. The terms of reference in summary are to:

provide an overview of the current GB electricity transmission charging arrangements as they affect embedded generation;

undertake a critical assessment of the current transmission charging treatment of embedded generation in the context of the objectives of NGC's charging methodology and considering comparisons with other classes of transmission user; and

identify and assess a range of options for reform to the charging arrangements as they affect embedded generators in the context of the objectives for NGC's charging methodology.

The issue of transmission charging and the basis for passing through costs to embedded generators is a difficult issue. The difficulty arises for two particular reasons. First there is the fragmented development of arrangements in the market place for dealing with embedded generation. Second, there is the problem of attributing costs arising from use of the transmission system on a causal basis. What is clear is that current arrangements do not seem well suited to the large level of recent and expected generation developments at low voltage across the GB system. The possibility of a grid supply point (GSP) or GSP group consistently exporting onto the transmission system has not been envisaged until recently, but is likely to occur increasingly frequently.

Key features of current transmission charging

The key commercial concepts underlying the NGC charging methodology, including how this has applied to embedded generators, have been broadly stable since vesting. A key concept has been that only power stations located on distribution networks that can be "seen" by the transmission system operator – that is, impact on the operation of the transmission system - should be contractually obligated to NGC. The basic rule is that plant above a defined limit is deemed to be "large", and only then makes use of the transmission system. It must therefore contract for an appropriate level of transmission capacity through applying for transmission entry capacity (TEC) and pay for its use through payment of transmission network use of system (TNUoS) charges. Transmission access payments in this context can be negative as well as positive.

With the roll out of BETTA, NGC in its role as the GB system operator (GBSO) has further developed its contractual framework, and introduced the concepts of the BEGA and the BELLA to formalise its ability to regulate its commercial and operational relationship with embedded generation.

The basic threshold in England and Wales for defining large plant is 100MW. In Scotland, where the transmission voltage reaches further down the physical network to include the 132kV system, the levels have been 30MW in the Scottish Power transmission area and 5MW in the Scottish Hydro transmission area, and these thresholds have been applied for licence exemption purposes. With the evolution of the BETTA, which also applies to medium classified plant, transmission charges can now be levied down to a lower level provided an embedded generator holds a BEGA.

Conclusions

The main conclusions we have reached are:

there are a variety of **cross subsidies** inherent in the current transmission charging arrangements as they apply to embedded generators, but that is to be expected in any averaged charging structure based on zonal tariffs. That said, the currently administered thresholds for charging to embedded generation are inconsistent across GB and the costs charged do not seem to reflect either the physical conditions, commercial circumstances or operational impacts of the generator. The same can be said for those generators under legacy arrangements who are presently outside of the current charging mechanism, some of whom may be eligible for BEGAs and/or charges;

with regard to **undue discrimination** between different types of generation plant, the basic parameter is “one size fits all” above the designated thresholds in the applicable region and “another size fits all” below. Whilst size may be a reasonable proxy for cost causality in some circumstances, it is by no means appropriate in all cases. This situation does not foster cost reflectivity, could have detrimental competitive impacts and creates perverse incentive with regards to sizing and location of plant. As there is no logic between the distinctions drawn other than absolute size, it is hard to argue that the discrimination that arises is “due”, especially as they vary by region;

current definitions of **small, medium and large** are arbitrary. Given the importance of cost reflectivity in National Grid’s transmission licence objectives and design criteria for its transmission charging methodology, it is very necessary to take into account the costs an embedded generator could cause for the transmission system. Important criteria here are the impact a generator might have (relative to other generators) on a GSP export, predictability and controllability of production at times of high demand and possibly the commercial relationships a generator might have with suppliers, none of which are allowed for in the current charging methodology. We note that the size definitions are to be reviewed through the Grid Code Review Panel, and welcome this move, and believe the outcome should be taken into account in the further development of transmission charging;

the materiality of transmission charges, combined with the arbitrariness of qualifying criteria for which embedded generators pay what, mean that locational decisions can be skewed by the current charging methodology, though we doubt they create a **barrier to entry** in absolute terms. Other factors, such as the complexity and evolving nature of the wider transmission access regime, the rigidity arising from the application of the contracted background by NGC and access queuing issues, are all likely to be more significant in this regard;

the transmission charging arrangements generally encourage **grid bypass** and drive sizing issues because of the interaction with embedded benefits. The position is particularly anomalous in Scotland because of the number of developments in progress, current network location and the treatment of the 132kV system; and

the probability of generation plant **locating at distribution voltages** is set to increase significantly simply because of the location and utilisation of existing networks, but also the asymmetry of current charging arrangements and the perverse incentives that can be created either side of current tresholds. Under current policies, the thresholds can exert a disproportionate effect on siting and sizing.

Of the various options flagged by Ofgem in the terms of reference, we have reached the following main conclusions:

do nothing is not an option. There are a mix of cross subsidies and perverse incentives within the current transmission charging arrangements with regard to treatment of embedded generation, and these need to be addressed by NGC;

we do not see **de-energisation** as a credible commercial mechanism; the cure is worse than the symptoms of the illness;

the current charging arrangement based on TEC is inappropriate with regard to its application to embedded generation, and more generally as a firm access regime it is incomplete. A regime based on **universal TEC** for all generators **and overrun charges** could be developed, but it requires significant reworking and development of current access arrangements to remove existing deficiencies. Whether this would be an appropriate development is doubtful. For such a regime to be more appropriately cost reflective and equitable, there would need to be a significant reworking of the concept of spill onto the transmission system and it should be accounted for in a different way, and then translated into charges. Some other accounting term and basis for allocation is needed for the purpose of allocating TNUoS charges to embedded generation on a more cost-reflective basis;

the rationale for **BEGAs and BELLAs** is not well understood outside of NGC. From a generator's point of view, the BEGA should have merit if the embedded generator is reasonably expected to be exporting onto the grid and has a firm access requirement. It is unclear, though, what value a BELLA confers. Furthermore, the thresholds that determine the need for these agreements do not have a robust logic, and discriminate with the treatment of demand. The current charging mechanism they enforce is arbitrary, and it does not necessarily follow that because a distribution connected party has a BEGA because of its size that it should also be levied charges for transmission use. In the time available, we have not carried out a thorough critique of these contracts, but suggest such an exercise is carried out promptly before wider consultation on charging options so that the issue is progressed "as a package";

further development of embedded generation will strengthen the need for active network management at the distribution level, and there are attractions from the local DNO taking a more proactive **agency role** in determining access arrangements into and out of its licensed area. Not all DNOs will want to or necessarily need to carry out this role, at least over the foreseeable future. We identify a possible GSP group agency role, and it may be possible to delink the GSP group agent role we have developed from that of the DNO and exercise it through a supplier. In the current context of transmission charging, the GSP group agent might acquire explicit export rights for each GSP group or combinations of GSPs, then would allocate implicit rights (measured in MW) to each generator unless they elected to buy their own explicit rights direct from NGC; and

different generation technologies can impose different costs on the transmission situation, especially where they are intermittent. We are attracted to an approach that reflects these different impacts and which takes into account the actual contribution an embedded installation is likely to make to spillage onto the transmission system at times of high system demand. However, a **commodity or MWh** based approach would undermine the relationship between NGC's costs drivers, which are primarily linked to ensuring availability of transmission capacity at times of high demand. Nonetheless we consider that the allocation mechanism for rolling through transmission charges where appropriate should take into account only the actual costs caused by individual generators, which in the case of intermittent technologies may reflect some diversity benefit. The issue of firm versus non-firm rights for use of the transmission system also warrants further exploration in this context. It may be feasible to develop non-firm rights combined with charges on a MWh basis.

We also reach a number of other conclusions:

there is not a strong case for the **reclassification of the 132kV network** in Scotland as distribution at this time as it remains predominantly used as transmission. There may come a point in the not too distant future when the current treatment needs to be reviewed. In this context any significant proposals for significant changes to transmission charges should take into account the possibility of reclassification at a future point;

there is no case for 132kV transmission connected generators in Scotland to be further **exempted from TNUoS** charges at this time;

there may be merit over the medium term in **harmonizing commercial network arrangements applying to 132kV** generators. A logical way to do this may be to extend application of NGC's DCLF model to the DNO EHV system or creating a coherent "132kV tariff" or sub-transmission tariff again at some future point, but we acknowledge that this would represent a radical departure. Under such an approach, it would be for consideration how the 33kV system should be treated in Scotland, as current problems may simply "step down";

creating **charges by voltage levels,** which might at first glance have the benefit of simplicity and predictably, would also represent a major upheaval in the charging methodology. It should not be contemplated to provide an enduring solution to embedded generation charging on its own, and we strongly doubt that such an approach would be superior to the current locational ICRP methodology given the applicable objectives;

more generally governance of network charging arrangements should be brought together within a single framework based on consistent principles;

we do not think the **interim 132kV rebate** mechanism should be adopted as an enduring solution, subject to development of an alternative commercial mechanism that can replace it from April 2008. In this context wider changes to the charging methodology that could see the elimination of residual charges to generators may have merit and should be explored;

enhancements to the transport model should be seen as a valid alternative to methodological changes, and may provide flexibility to address the issue of the 132kV rebate. Possible model changes warranting consideration include the introduction of changes to expansion constants or of a locational substation charge, either of which might prove to be a means of ensuring no detriment to 132kV transmission-connected generators in Scotland; and

we recognise that other charging changes under consideration (for instance, changes to the charging basis to reflect intermittency or introduction of longer-term tariffs) could also interact with the embedded charging issue and its materiality. The issues are not, however, mutually exclusive, and in some instances may be complementary.

Recommendations

We identify a possible way forward, which is in two parts.

Over the **short term** NGC should be invited to focus on establishing a more equitable and appropriate methodology for charging embedded generation on a causer pays basis, and which would be administered in the short term bilaterally between NGC and the embedded generator.

In considering its options NGC should be invited to consider an approach that entails:

a different allocation mechanism to qualifying (i.e. causal) generators;

a replacement to the arbitrary and regionally discriminatory thresholds regime;

rationalisation of its contract offers; and

introduction of an overrun regime and associated overrun charges where access rights (however defined) are exceeded.

We set out more detailed proposals addressing these points as "an Aunt Sally" in the main body of the report.

Over the **longer term**, we favour development of an enduring route to the treatment of embedded generators that in exporting GSPs or GSP groups draws much more heavily on the concept of the DNO agency. Key elements of this longer-term arrangement might be that embedded generators who want firm access would continue to contract with NGC. Additionally, we propose definition of a GSP group agent (probably the DNO) and establish a bilateral GSP or GSP group agreement between NGC and DNO to deal with exporting GSPs or zones, and again more detailed proposals are set out in the report.

The merit of the agency arrangement over the bilateral arrangement is that it would provide a more stable basis on which to evolve active DNO management of embedded generation, which more correctly in this context should be termed the DSO. This is not a value judgment by us on the merits of active network management per se, but recognition that wider industry development is moving in this direction, and NGC's charging development should not be inconsistent with it.

We should also like to see development of some mechanism that recognises the **deferred investment impacts** of embedded generation on both transmission and distribution networks if benefits as well as costs are to be more accurately captured. This objective could be achieved through the agency structure. In the case of transmission costs avoided, this might take the form of a rebate against TNUoS charges that might flow through the DNO to the embedded generator taking into account at the same time the impacts on the distribution system.

In terms of timing, it would seem sensible to seek to aim to:

implement the shorter-term changes from April 2006;

scope wider changes in parallel; and

work towards more enduring change from April 2008 when the interim rebate falls away.

International comparisons

Our terms of reference ask that we specifically consider network charging approaches to embedded generation from overseas. We have conducted a survey but concluded that international comparisons of transmission charging arrangements are of little value in helping considering appropriate arrangements for charging embedded generators in GB because specific transmission charges to generators are relatively scarce. Ireland is the one example we have identified of a transmission tariff specifically constructed to deal with off-grid generation. The other two examples we are aware of from Norway and Finland do not provide any robust lessons that we can find.

Introduction

This section:

- summarises the terms of reference;
- identifies key issues for consideration; and
- explains our approach and the report structure.

Terms of reference

The initial scope of work is defined in terms of reference issued by Ofgem on 21 May. In summary the initial task is to:

- provide an overview of the current electricity transmission charging arrangements as they affect embedded generation;
- undertake a critical assessment of the current transmission charging treatment of embedded generation in the context of the objectives of NGC's charging methodology and consider comparisons with other classes of transmission users; and
- identify and assess a range of options for reform to the charging arrangements as they affect embedded generators in the context of the objectives for NGC's charging methodology.

Work commenced on 1 June, and an outline framework for coverage of the report was agreed with Ofgem on 4 June.

Linkage with "five conditions"

The immediate trigger for this Ofgem review is the promulgation of common transmission arrangements across GB from 1 April 2005. The transmission licence places an obligation on NGC in its role as GB system operator (GBSO) to levy transmission use of system (TNUoS or access) charges on behalf of the three GB transmission owners (TOs) under a charging methodology approved by Ofgem. The charging methodology has three key objectives, and it must in broad terms:

- be cost reflective;
- facilitate effective competition; and
- reflect developments on the transmission system.

A defining feature of these new transmission charging arrangements is that the transmission network in England and Wales goes down to and includes the 275kV network; in Scotland it also still embraces the 132kV system.

Against this background, in March 2005, the Authority approved NGC's proposals for the first charging methodology under the new British electricity transmission and trading arrangements (BETTA)[1] covering the period 2005/06. The approved charging methodology draws extensively on previous charging principles and structures applied by NGC in England and Wales only, but changes were made specifically to accommodate the geographical roll out of the charging methodology to include the Scotland transmission system, including the 132kV network in that country.

[1] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10622_8005.pdf.

In giving its approval to the charging methodology for 2005/06, the Authority came to the view that there were five specific conditions that needed to be addressed to allow NGC to determine whether it could better meet its relevant charging methodology objectives going forward. One condition relates to potential alternative methods of treating **intermittent generation** in the charging methodology. This condition does not distinguish between directly connected transmission generation and generation embedded in the distribution networks. The context of the condition is that Ofgem says it would like to see further analysis of the charges presently levied, to ensure that they appropriately reflect costs.

One of the factors impacting on demand for network capacity, at both transmission and distribution level, is from **embedded generation** plant. Embedded generation (also known as distributed or dispersed generation) is electricity generation connected to a distribution network (up to and including the 132kV network in England and Wales but not in Scotland) rather than the transmission network (275kV and 400kV). Embedded generators are mostly - though not exclusively - those generators producing power from low carbon, usually renewable, energy sources, including small hydro, wind and solar power or from combined heat and power (CHP) plants. Many such installations, but by no means all, are intermittent. As a consequence, Ofgem and NGC also agreed in finalizing the 2005/06 charging methodology that it would be appropriate for NGC to review the appropriateness of its current charging arrangements, to accommodate among other things the demand from embedded plant.[2]

In addition, under the approved methodology since 1 April 2005, small transmission-connected generators on the 132kV system have been receiving a **25% discount** of the total residual element of their transmission access charges. The discount is mandated under the transmission licence, and specifically it is to be applied to 31 March 2008. In its decision letter on the treatment of 132kV transmission-connected generators[3], Ofgem said that the discount would be an interim measure, to address a specific charging discrepancy identified by DTI/Ofgem during the BETTA design phase. The discrepancy is between small transmission-connected generators in Scotland and small distribution-connected generators in England and Wales caused by the differences in network voltage definition and use of the 132kV system. Ofgem, in reaching its conclusions on the matter, noted that an enduring solution would be required to ensure that charging arrangements across distribution and transmission networks better meet the applicable objectives in NGC's transmission licence.

<u>Issues for consideration</u>

Ofgem intends to publish an initial consultation on the scope of the charging review for embedded generation in late summer/early autumn 2005. The consultation is expected to set out some of the embedded generation charging areas and issues where NGC may need to bring forward possible changes and develop more enduring arrangements, to help focus discussion and review. The requirement in the five conditions in this regard is for NGC to produce an interim report by April 2006, and for it to identify possible changes with a view to their implementation no later than April 2007.

Ofgem has said it considers that there may be merit in considering certain specific issues as part of a review, though these are not intended to be exhaustive, and it wishes to see these matters addressed in this study. They are:

whether the current charging arrangements create cross subsidies between generators who pay TNUoS charges and generators who are exempt from TNUoS charges;

whether there is any undue discrimination between the charging arrangements for different types of generation plant (also taking into account embedded benefits);

[2] The conditions are summarised at www.nationalgrid.com/uk/indinfo/charging/mn_TNUoS.html.
[3] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10377_5905.pdf.

whether the classification of small and large generation plant in industry codes should be redefined;

whether the current charging arrangements create barriers to entry or create perverse incentives for generation to bypass the transmission system and connect to the distribution system; and

whether there is an increasing number of embedded plant (or plant deemed to be less than 100 MW) that may be located close to a grid supply point (GSP) and that may spill onto the transmission system, but which will not be exposed to transmission use of system charges.

Ofgem's autumn 2005 consultation document is likely to set out options and proposals to address these considerations. Ofgem says that the options could include the following matters, though again this list is not intended to constrain consideration of possible alternative enduring changes, and this study provides initial consideration of these matters:

whether it is economic and efficient for NGC to de-energise plant that spills onto the transmission network (over and above its requested transmission entry capacity (TEC));

whether all generation plant should be required to buy transmission capacity, measured by TEC, (or to declare zero TEC) and to face overrun charges, for exceeding TEC;

whether it is appropriate to review bilateral embedded generation agreements (BEGAs) and bilateral embedded large exemptible large power station agreement (BELLA) under the CUSC, so that embedded plant, identified as able likely to spill, will need to sign a BEGA;

whether a distribution network operator could act as an agent, which buys TEC for embedded plant which spills onto the transmission system; and

whether NGC could introduce in place of the current capacity-based system a range of prices (and products) for use of system, dependent on plant type and system usage to better reflect the costs (e.g. whether it is intermittent or firm) .

We have identified a range of options, including some additional to those highlighted above, demonstrating how they might work and be implemented. However, it has not been straightforward in compiling this report in the time available to identify substantial information on the location and power flows from existing and planned embedded plant. There are also significant gaps and inconsistencies in the overall commercial framework within which embedded generation presently operates. Further there are increasing interactions with and impacts arising from distribution charging, which will have both practical and commercial implications for suppliers and generators, especially as there is at present a variety of different DNO charging methodologies. Consequently the options we have identified are subject to development in the light of further information and policy clarity in these areas.

Report structure

The rest of this report is structured as follows:

general background, including summary of current network pricing regime;

international approaches;

critique of current charging arrangements;

assessment criteria and evaluation of options for change; and

possible model solution.

The report has been written primarily by Nigel Cornwall, but with input and review from David Lane, one of our associates.

Setting the scene

This section sets out relevant background information, including:

physical information on networks and the location of embedded generation, the current treatment of embedded generation and the scale of the issue;

the regulatory and commercial framework that presently applies to embedded generators, including transmission charging arrangements;

the associated "embedded benefits" currently available; and

recent changes to codes and charging structures that have impacted on the treatment of embedded generators.

Physical background

- *Definition of embedded generation*

Embedded generation is any generation that is connected to the distribution network, and not part of the transmission network. Of itself, the term is loaded, suggesting that on the modern power system generation plant is not ordinarily embedded, but rather it is connected to the transmission network. This assumption reflects the prevailing significance of the economics of the 1960s and 1970s when the term became currency. That was a time of development of large–scale generation when most power was wheeled from the point of production close to coal fields or new nuclear developments, both of which tended to be remote from large demand centres. The relative economics resulted in the closure of large swathes of older, locally-connected generation and, in England and Wales at least, the transfer of the ownership and management of the 132kV system to the local Area Boards responsible for distribution.

There are many types of embedded generation: from a 1kW domestic device to combined cycle gas turbines and large industrial CHP plant generating well over 100MW. Government policies and targets for renewables technologies and CHP could mean that, whereas now a Distribution Network Operator (DNO) might have up to 300 generators in total on its network, it could by 2010 have more than 300 at every substation – particularly if the smaller generation technologies approaching commercialization prove successful. Wind developments, many of which are embedded, will present particular issues for physical coordination of the power system in certain parts of the country where natural resources are abundant because of their intermittent operation.

- *Power station impacts and size*

Historically there have been a number of defined levels that vary geographically across GB that have influenced the relevance of embedded plant to the local system operator, and plant deemed to be "large" has been singled out for specific treatment. These levels have been determined by the extent to which a generator might impact on the costs of – or "be seen" by – the relevant system operator.

In England and Wales this level has been 100MW, and there are no "small" generators below this size in England and Wales connected to the transmission system. A significant amount of plant remains connected at lower voltages, but since the late 1960s with the completion of the super grid it generally meets local demand.

In England and Wales, transmission charging arrangements and system access, together with the rights of the GBSO, are managed within the industry agreement that establishes the framework for connection and use of system to the transmission system, termed the connection and use of system code (CUSC). CUSC paragraph 6.5.1[4] deals with notification of development proposals on the distribution networks to the GBSO, and was introduced some while ago when the generator licence threshold for England and Wales was 10MW. However, licence exemptions for embedded generators were increased to 50MW in 1995 and 100MW in 2000, and the treatment of embedded generation with it. In 2001, NGC put forward CAP002 as an amendment to the CUSC that would have had the effect that NGC was notified of any generators of 30MW. Note that CUSC 6.5.1 provides for operational thresholds and notification, not charging thresholds.

The rationale for a 30MW threshold given by NGC[5] at the time was based on the effects on fault levels and transformer rating:

fault in-feed - in practice a generator will in-feed three to four times its size into a fault. For a 30MW generator this could be between 100 - 140MVA of fault in-feed compared with equipment rating of 3500MVA (generally minimum rating at 132kV but is rating at over 25% of National Grid sites). This is approximately 3% of rating although in practice this may be lower due to the system impedance between the connection site and the fault and is project specific. However, this is significant when considering National Grid uses a 5% margin of design rating when assessing fault levels at 132kV and below and in some cases 2%. It is believed that deeper embedded generators of less than 30MW will not have a material impact on the joint planning carried out at GSPs by the local DNOs and National Grid. It is likely that any works necessary for smaller generators will have already been identified and planned for, although this work would still need to be completed prior to energisation; and

transformer rating - standard supergrid transformer ratings are 240MVA, and therefore a 30MW generator represents some 15% of potential loading. This is significant in the design and development of a site and more specifically when considering operational planning through the year and determining outage windows for maintenance.

An alternative to CAP002, with a 50MW limit, was also proposed at the time. This limit was based on the Grid Code definition of medium power station (>=50MW and <100MW). In the event CAP002 could not be introduced due to a technicality. However, in the decision letter, the Authority did express a preference for a 50MW threshold indicating that it did not consider that sufficient justification had been provided for a threshold level of 30MW.[6]

In Scotland, where the transmission voltage reaches further down, to include the 132kV system, the levels have been 30MW in the Scottish Power transmission area and 5MW in the Scottish Hydro transmission area.

The introduction of BETTA from April 2005 resulted in a series of changes to contractual arrangements and industry codes to provide better alignment between the regulatory and commercial arrangements for transmission access north and south of the border with the objective of providing a single, almost seamless GB market. In aligning these arrangements, new agreements have been introduced that broadly align the physical and commercial relationship of embedded generators with the new GBSO, which has combined and replaced the three regional SOs. The thresholds have continued to differ reflecting the different local circumstances. A key change has been the introduction of contracts between the GBSO specifically with embedded parties who are equal to or greater than the appropriate threshold.

- *Anatomy of embedded generation*

[4] Originally MCUSA paragraph 2.5.1.

[5] Full details of CAP002 and the Authority decision are available at: www.nationalgrid.com/uk/indinfo/cusc/mn_amendment_archive_cap02.html.

[6] A further modification CAP067 was subsequently introduced with similar intent, but was withdrawn. NGC has just introduced a further related change proposal. CAP093, but this does not specify as yet a specific notification threshold.

Based on execution of these new agreements under BETTA, the number of embedded generators "seen" by the GBSO at mid 2005 as evidenced by the number of specifically mandated contracts was:

36 in England and Wales;

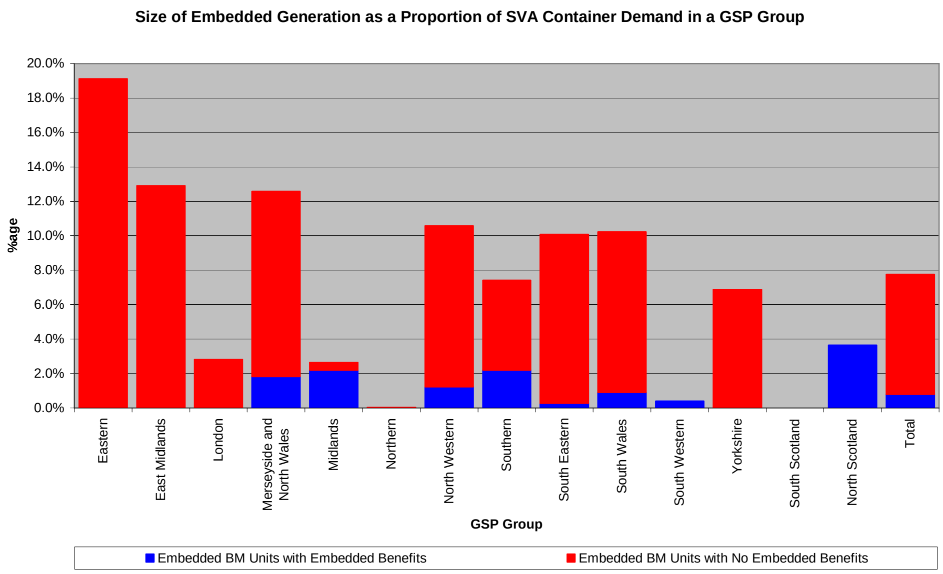
27 in the Scottish Power Transmission licensed area; and

75 in the Scottish Hydro Transmission licensed area.

The total amount of embedded generation eligible to enter contracts is almost certainly in excess of this, especially in Scotland. This situation arises because new agreements seem to have tended to apply to new applicants for connection, rather than existing sites. That said, we are not aware of any evidence that this has caused a particular problem for the GBSO.

Figure 2.1 below shows the relative contribution of reported embedded generation as evidenced by output traded through suppliers based on April 2005 data. Take in the Eastern, East Midlands and Manweb GSP groups[7] represents the largest contribution to local demand. On average some 8% of demand reported through supplier volume allocation (SVA) under the BSC is from embedded generation.

Figure 0.1: Embedded generation as a proportion of SVA container demand in GSP groups



Source: Enappsys

Of course absolute or relative levels of embedded generation in a region does not of itself signify any direct impact on the GBSO. The capability of any network varies depending on geographical location as a consequence of (among other things) wider system power-flows, customer density and type.

- *Expectation of significant growth*

[7] The grouping of supply points that feed off the transmission network (called grid supply point groups or GSP groups) that presently provide the anatomy of energy trading and power settlement in GB.

The numbers of embedded generators are expected to grow significantly going forward as the effects of the government's renewables and CHP policies kick in. A large proportion, together with new 132kV connected schemes, are likely to be located in Scotland, especially in the remote lying areas to the north. Increasingly, demand associated with individual distribution areas will in some instances be more than counter-balanced by local generation.

If the government's targets are to be met[8], some 14GW of new generation capacity will be required, much of which could be connected to distribution networks. DNOs have predicted that they will need to spend some £380-583m (£76-117m p.a.) in the period 2005-10 to meet the renewables target alone.[9]

Embedded generation is already an important feature of the GB power system and networks. Its importance is set to grow considerably and soon. A significant amount of new embedded schemes are likely to be located in Scotland, especially in the remote lying areas to the north. Increasingly GSPs will export rather than import.

An enduring network charging framework, that captures the costs of embedded generators, needs to be robust to the changing physical background and the increasing development and importance of embedded generation. That background comprises the effects not only of individual power stations up to 100MW (or the relevant local threshold), but also the cumulative effect of multiple small increments of generation, many of which could be intermittent.

[8] 10% renewables by 2010 and 10GW of CHP.
[9] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6748_6204_mottsreport.pdf.

Contractual framework

The primary contractual interface for embedded generators is with the local DNO. However, NGC already has powers as GBSO to enter into contracts (including use of system and construction agreements) with, and levy charges on, large embedded plant which is considered likely to have a physical impact on the transmission system. Definitions and eligibility are a little convoluted as they are set out in a number of different places, and are given effect by a series of cross-references and cross-obligations.

NGC's transmission licence places obligations on NGC, which establish the legal framework for dealing with all transmission system users (which is the underpinning reason why charges are levied on some embedded generators, i.e. they are deemed to be system users). NGC must have in place:

a Grid Code dealing with technical issues;

a Balancing and Settlement Code (BSC) dealing with electricity trading issues, and which in effect establishes the basis for accrual of some embedded benefits;

a Connection and Use of System Code (CUSC) dealing with contractual issues for use of its system;

a use of system charging agreement;

a use of system charging methodology; and

a connection charging methodology.

Each of these impacts on charges or benefits to embedded generators, though we deal with charging issues more fully in section 2.3.

In essence, embedded power stations that use the transmission system (in turn defined by reference to the defined thresholds)[10] are subject to the requirements of CUSC, and section 3 of it determines rights and conditions of GB transmission system use. In turn the thresholds have evolved from technical definitions in the Grid Code. The rights are simply defined as the right to use the transmission system. The conditions are also defined, and focus on the requirements to have a use of system agreement and payment of the associated access charges. Another such condition is that a qualifying embedded user must have entered into a BEGA. The embedded generator must also have a distribution agreement with the DNO.

- *Connection contracts*

Distribution-connected generators have connection agreements with the relevant local distribution company. This position applies in both England and Wales and Scotland, and this position applied both pre BETTA and it applies now. Connection agreements cover site specific issues such as connection voltage, capacity, fault levels, metering and other technical details, including reference to the Distribution Code and the Grid Code, compliance with which are obligatory. Contestable and non contestable works will also be specified in the connection contract, together with timescales for completion. Charges, payment timescales and appropriate credit requirements will also be specified. In some cases the DNO will be unable to energise the connection until confirmation is received from NGC that appropriate bilateral contracts with NGC are in place (see section 2.5.4 below).

A NGC bilateral connection agreement is only applied to direct physical connectees to the transmission system, and does not apply to an embedded generator; but alternative legal obligations and contractual mechanisms have been developed. These are the BEGAs and BELLAs

[10] This section also extends to small power station trading parties (defined by virtue of being BSC signatories).

described at section 2.2.4 and 2.2.5 below. A key feature of these arrangements is that NGC administers charges to certain sizes of generators located at distribution voltages in Scotland as well as England and Wales under the jurisdiction of the GB CUSC.

In Scotland, where the 132kV network has remained owned by the transmission companies because it still deals primarily with the bulk transfer of power, small transmission-connected generators had connection contracts with the appropriate Scottish transmission company prior to BETTA. This position changed from April 2005, and a generator's contractual interface for transmission connection and use in Scotland migrated to NGC in its role as the GBSO and is now governed by connection terms in bilateral agreements administered under the CUSC.

- *Grid Code*

The Grid Code deals with planning, operational, safety and communication obligations. The primary relevance in the context of this study is that it defines the thresholds for classification of power stations. The definitions in this context are set out to enable physical compliance with the Code are:

large power station - a power station in NGC's transmission area with a registered capacity of 100MW or more or a power station in SPT's transmission area with a registered capacity of 30MW or more or a power station in SHETL's transmission area with a registered capacity of 5MWor more;

medium power station – a power station in NGC's transmission area with a registered capacity of 50MW or more, but less than 100MW, or a power station in SPT's transmission area with a registered capacity of 5MW or more, but less than 30MW; and

small power station – a power station in NGC's transmission area with a registered capacity of less than 50MW, or a power station in SPT's or SHETL's transmission area with a registered capacity of less than 5MW.

The Grid Code is administered by the Grid Code Review Panel (GCRP). NGC proposed in July 2005 that a working group be formed under the jurisdiction of the GCRP to review the existing regional differences triggered by the existing definition of small, medium and large power stations commencing in September 2005, probably for a period of six months. This working group will also be specifically charged with seeking an appropriate way forward in those areas where the working group believes that the regional difference can be reduced or eliminated.

- *CUSC*

The CUSC sets the contractual framework for connection to and use of transmission systems. Since 1 April 2005, the responsibility for system use has extended to the Scottish transmission networks and all commercial arrangements with transmission-connected parties are now administered by NGC in its role as GBSO.

Section 3 of CUSC determines rights and conditions of GB transmission system use, and section 3.2.1 specifically addresses embedded system use. As noted the right is to use the system. The conditions presume execution of a suitable distribution agreement with the DNO and a BEGA. The main conditions, which are summarized at Box 2.3, are a requirement to pay TNUoS charges. This part of CUSC also sets out NGC's credit requirements.

Other conditions relate to:

not exceeding TEC or any short-term TEC (STTEC)[11] as specified in the BEGA;

commissioning of any reinforcement works required by NGC;

[11] TEC's are set annually, but there is provision within CUSC for within year TEC increases, termed STTEC.

agreeing outage arrangements with NGC;

meeting NGC's commissioning and on-load testing requirements; and

receiving operational notification from NGC as a condition of operation.

Non-connected parties wishing to use the transmission system must complete and submit to NGC a use of system application under CUSC section 3.7. NGC's use of system offer must be made as soon as practicable but no later than 28 days after receipt of the application. In the case of embedded generators, the offer must under CUSC 3.7.3 be in the form of a BEGA together with any relevant construction agreement. A key requirement before the agreements can take effect is that applicant must become a party to the CUSC Framework Agreement.

CUSC section 6.5.1-4 goes on to specifically prevent a DNO from energising a connection until requirements to enter the appropriate contracts with NGC are met. This process is designed to ensure that any transmission system short circuit, thermal, voltage and stability limitations are identified and addressed. Note that there is nothing in the CUSC to define the level at which an embedded generator may have an impact on the transmission system; this has to be decided on a case by case basis by the appropriate DNO and NGC, though the size definitions set out above are an obvious starting point.

Additionally, agreements under the CUSC Framework Agreement are specifically applied to embedded generators:

greater than or equal to 50MW in England & Wales – a BEGA applies;

greater than or equal to 30MW in South of Scotland area – a BEGA and/or a BELLA; and

greater than or equal to 5MW in the Scottish Hydro area - a BEGA and/or a BELLA.

In turn these requirements are enforced through cross requirements in other industry codes[12].

Under the CUSC and statement of use of system charges, NGC may also apply these agreements to embedded generators with a lower output than the above thresholds where there is an effect on the transmission system (for example where fault levels are increased beyond equipment ratings), but there is no guidance or parameter we can find that helps determine such circumstances. Thus, although the CUSC allows for BEGAs between NGC and embedded generators which can specify charging terms, the NGC charging methodology states that only licensable embedded generators that have a BEGA (that is, in excess of the thresholds) are usually liable for transmission charges.

The CUSC Amendments Panel oversees the assessment of all amendment proposals to the CUSC. Any changes have to be assessed against specified applicable objectives, which reprise the licence objectives of NGC.

- *Use of System Agreement*

Where an embedded generator may have an impact on the transmission system, the generator may be required to sign a Use of System Agreement (Generators) with NGC and may also be required to sign a further bilateral construction agreement with NGC if system reinforcement is involved. In effect the use of system agreement has been superceded by the BEGA in the context of use of the transmission system by an embedded generator. Entering into any agreement with NGC also brings with it a requirement to sign the CUSC Framework Agreement. Further details of the appropriate bilateral agreements are set out below.

[12] DNOs have an obligation under CUSC 6.5.1-4 not to energise an embedded generation connection until appropriate bilateral agreements with NGC are in place, and NGC's works (if any) are complete. The DNO would normally discharge this obligation through the connection agreement with the embedded generator.

Use of system agreements (and the BEGA) are administered under the CUSC.

Box 2.2: Summary of CUSC Section 3 Rights and Conditions

Rights to use the transmission network

the user may take power from, or supply power to, the GB transmission network;
the user must provide proof of having entered into distribution [connection] agreement with the appropriate DNO; and
NGC must receive confirmation from the DNO of satisfactory distribution running arrangements and acceptance of any necessary modification offer relevant to the embedded power station.

TEC obligations

the user shall not exceed the TEC or STTEC as specified in the BEGA unless permitted by an emergency instruction under the Grid Code or the Fuel Security Code or as necessary in accordance with good industry practice.

TEC rights

NGC must accept into the GB transmission system power generated by the user up to the TEC or STTEC, as defined in the BEGA unless NGC is prevented from doing so by transmission constraints which could not be avoided by the exercise of good industry practice by NGC.

Outages

NGC and the user are each entitled to plan and execute outages

Commissioning

NGC agrees to assist the user, on request, with commissioning and testing, subject to a charge. The user must coordinate with the DNO.

Site specific technical conditions

The user must ensure compliance with the site specific technical conditions set out in the BEGA.

Use of system

The user submits a use of system application to NGC and complies with any terms imposed. NGC must make a use of system offer "as soon as practicable" and in any event not more than 28 days after receipt by NGC of the application. The offer, which will normally be valid for 3 months, will include a BEGA and may include a construction agreement if NGC needs to carry out works on the transmission system on behalf of the user.

Framework agreement

The user must be a signatory to the CUSC.

Charges

The user is obliged to pay NGC use of system charges and balancing services use of system charges according to NGC’s current published methodology. One off charges may apply where NGC has to carry out works.

Information

Various information exchanges are required; for example user’s demand forecasts and NGC demand and financial reconciliation statements.

- *BSC*

The BSC deals with electricity trading between BSC parties. Only a BSC party can register the metering at a connection point for use in electricity settlements. Any BSC impacts will typically be seen indirectly by the embedded generator through the contract with their supplier. However, through acceding to the CUSC, an embedded generator must also accede to the BSC, which seems anomalous and rather unnecessary.

The BSC is administered by the BSC Panel.

- *Bilateral construction agreement*

A bilateral construction agreement applies where NGC has to carry out physical works associated with the connection of the embedded generator, and it is required under CUSC in such circumstances. NGC's transmission licence allows it to recover:

the appropriate proportion of the costs directly or indirectly incurred in carrying out any works, the extension or reinforcement of the licensee's transmission system or the provision and installation, maintenance and repair or (as the case may be) removal following disconnection of any electric lines, electric plant or meters; and

a reasonable rate of return on the associated capital.

This agreement generally sets out the rights and obligations covering construction and commissioning programmes, operational and technical requirements, disputes, variations, credit arrangements and third party works.[13]

- *BEGA*

The bilateral embedded generation agreement - BEGA - is the means by which NGC can ensure that transmission charges are applied to large embedded generators to cover works required to, and use of, the transmission system. CUSC, para 1.3.1(b) stipulates:

> *"Each User in respect of each category of connection and/or use with an Embedded Power Station (except those which are the subject of a BELLA) and/or in relation to a Small Power Station Trading Party and/or a Distribution Interconnector shall enter into and comply with a Bilateral Embedded Generation Agreement in relation to such use as identified in Paragraph 1.3.1(d)."*

A BEGA may contain clauses dealing with:

one off charges;

transmission use of system charges;

balancing services obligations and payments;

allocation of TEC, which in turn define transmission access rights; and

Grid Code and site-specific technical conditions.

[13] A sample construction agreement is at www.nationalgrid.com/uk/indinfo/cusc/cuscpdf/Sch_2_%20Exh1_V1.0.pdf.

At mid 2005 there were approximately 50 cases where a BEGA applied to embedded generation across GB.[14]

- *BELLA*

A bilateral embedded licence exemptible large power station agreement - BELLA - applies to an embedded large licence exempt power station (EELPS). CUSC para 1.3.1(c) stipulates:

> *"Each User in respect of its Embedded Exemptable Large Power Station whose Boundary Point Metering System is registered in SMRS or is registered in CMRS by another User who is responsible for the Use of System Charges associated with the BM Unit registered in CMRS shall enter into and comply with a BELLA as identified in Paragraph 1.3.1(d)."*

A BELLA is in effect a less onerous, technical version of a BEGA absent of any commercial requirements and only applies if the power station metering is registered in the BSC supplier meter registration service (SMRS) by a supplier. A BELLA may contain Grid Code and site-specific technical conditions; all other contractual arrangements save for connections to the local DNO are between the supplier and NGC.[15]

Currently there are approximately 90 cases where a BELLA applies to embedded generation. Its application is restricted to Scotland.

- *LEGA*

When an exemptable power station applies for licence exemption, the DTI will consult NGC (among others). NGC will attempt to establish a LEGA with the embedded generator, and once the LEGA is in place, NGC says it will not object to the licence exemption. The LEGA deals with technical issues and, as far as we can ascertain, is independent of the BSC, CUSC, Grid Code and charging methodology. Indeed, we can find no reference to a LEGA in any of these documents, and it is unclear how many of these agreements are in place.

- *CEC and TEC*

Under the current arrangements, a generator's transmission access rights are defined by their connection entry capacity (CEC) and their TEC.

Approved amendment CAP043 introduced the concept of CEC and TEC. These terms replaced "registered capacity" which was the term previously used in the CUSC (and the old Master Connection and Use of System Agreement which it replaced). TEC defines a generator's maximum allowed export onto the system in a financial year; CEC is a measure of the physical sizing of the connection. CAP043 was, therefore, an incremental development on defining generator's rights of access to the transmission system and how it should be paid for. CEC does not apply to embedded generators; it only applies where there is a physical connection to the transmission system. CEC is implemented through a bilateral connection agreement which, again, does not apply to an embedded generator.

Once a user's TEC and CEC have been set, they effectively 'roll forward' each year (for the duration of a connection agreement) unless the user makes an application to NGC to reduce their TEC. If TEC is reduced, then any subsequent request by the user to increase its TEC again will be treated by NGC as a new application for TEC, and the sought capacity might not be available immediately. The user's access charges – the TNUoS part of the transmission charges - are then based on their TEC and the relevant TNUoS tariff in place for that year.

[14] A standard form of the BEGA is attached as exhibit 2 to schedule 2 to the CUSC. Go to www.nationalgrid.com/uk/indinfo/cusc/cuscpdf/Sch_2_Exh2_V1.0.pdf.

[15] A standard form of this agreement is attached as exhibit 4 to schedule 2 to the CUSC. www.nationalgrid.com/uk/indinfo/cusc/pdfs/Sch%202%20Exhibit%205%20-%20V1.0.pdf.

TEC values are also applied to embedded generators through the BEGA. A figure is derived from the value declared by the embedded generator and will be based on the maximum capacity of the power station. Any unlicensed or exemptable exempt power station is assumed to improve the overall capability of the transmission network and is therefore paid TNUoS payments by NGC. The value of payment to the generator will depend on the average metered volume of actual generation during the period 1600 – 1900 hrs November – February inclusive, i.e. during the potential triad periods, and the appropriate zonal tariff applicable in any given year.

Current arrangements for TEC are relatively simple, apply only to generators and are still evolving, with a building bloc approach being adopted through sequential CUSC amendments.[16]

Users do not presently have the choice of buying long-term, fixed-price access rights. They face uncertainty over the price from year to year and also that the allocation mechanism for TEC may change in the future. This uncertainty flows through to embedded generators in at least two ways:

the annual charge to large embedded generators subject to transmission access charges varies in line with changes to the corresponding generation zonal tariff; and

the value of embedded benefits, including payments to exempt generators, will also change year on year.

Provisions, including costs, for varying TEC for any generator are set out in appendices to the charging statement.

It would, of course, be possible for a CUSC party to raise an amendment proposal that would give rise to a different allocation mechanism for TEC. It is also this route that would need to be utilized if the concept of over-run charges were to be introduced into the TEC regime.

The key commercial concepts underlying the NGC contractual framework, including how this has applied to embedded generators, have been broadly stable since vesting. A key concept has been that only power stations located on distribution networks that can be "seen" by the transmission system should be contractually obligated to NGC, though licence exemption limits have been raised. The basic rule used to be that plant above the limit is deemed to be large, and uses the transmission system. It must therefore contract for an appropriate level of transmission capacity through a TEC and pay for its use through access charges. Conversely plant below the limit is medium or small and did not ordinarily pay access charges and, because it is assumed to improve the overall capability of the transmission system, through netting off against demand, is paid TNUoS.

With the roll out of BETTA, NGC in its role as GBSO has further developed the concepts of the BEGA and the BELLA to formalise its ability to regulate its relationship with distribution connected generation. Where a station is deemed to be large enough to impact on the transmission system, it must now sign a BEGA and be subject to payment of TNUoS charges.

In England and Wales the licence exemption threshold was 100MW, though in most cases NGC now seeks to make charges down at least to 50MW through the BEGA. In Scotland, where the transmission voltage reaches further down the physical network to include the 132kV system, the levels have been 30MW in the Scottish Power transmission area and 5MW in the Scottish Hydro transmission area.

[16] Specifically CAP043, CAP048 and CAP068

Transmission charges

In addition to embedded generators paying the appropriate local DNO charges, they also pay transmission access charges where they have a BEGA. This section explains the derivation of those charges.

- *NGC's charges*

Transmission charges are usually levied on two separate bases. First there is an asset specific charge that applies to an individual user's point of connection. Second there is a use of system or access charge set via a tariff embodied in the statement of charges.

In the UK the costs of the transmission system are met via connection and use of system charges levied on distribution/supply businesses (75%) on the consumption side of the industry and generators on the production side (25%).[17] Other short-run transmission-related costs, such as thermal losses and the provision of balancing services, are paid for via separate recovery mechanisms attaching to the wholesale energy market. Many power markets internationally, essentially for simplicity, levy usage charges exclusively or predominantly on demand, though connection charges are invariably user specific and apply to both sides of the industry. Because of this split on system usage, the GB structure can be regarded as a hybrid structure.

The wider context on international approaches to transmission charging is set out more fully in section 3 below.

- *Connection charges*

Connection charges are specified in a party's bilateral connection agreement and are based on the cost of the assets involved at each site, and are defined by reference to a common interface boundary. NGC calculates the costs in two parts:

a capital component based on the gross asset value (GAV) of the connection asset calculated at the time of installation, which is the indexed; and

a non capital component including a site-specific maintenance charge based on actual costs incurred in the previous year, and a charge for transmission running costs based on the GAV.

These charges are payable by all transmission-connected generators, and thus also apply on a site-specific basis to 132kV connected generators in Scotland.

- *Generator access charges*

An investment cost related pricing (ICRP) methodology introduced by NGC from 1993/94 remains the basis of a transport model for calculating electricity transmission access charges. Key features of the methodology are:

an annually updated model is used based on generation and demand information by node, and transmission circuits between these nodes, using data from NGC's Seven Year Statement which in turn reflects the contracted background pertaining at that time;

capacity or kW-based charges for generators are calculated, reflecting the relative impact of a grid user at times of highest system use in positive charging zones[18];

[17] To maintain this broad proportionality across transmission charges and to recognise a general shift in the incidence of connection charges, the split presently translates into a 73%/27% split on TNUoS charges.

[18] For negative zones, the average metered demand during the triad is used.

the charges were based on registered capacity, though more recently this concept has been replaced by that of TEC as explained above;

the model estimates the marginal investment costs of adding one MW at each node on the transmission network, based on the resulting flows of power, thereby establishing a locational charge; these costs can be negative as well as positive;

nodes are grouped into zones with comparable cost levels so that incremental costs do not vary by more than £1/kW; this means that zones and their composition can vary year-on-year;

a zonal generation charge is then calculated as the average of incremental costs assigned to nodes within each zone, which can differ for generators and demand, and converted into costs in the form of a tariff through multiplication by the appropriate expansion constant and a locational security factor;

a monthly charge is then calculated taking an estimate of the forecast chargeable capacity and multiplying by the zonal £/kW tariff, and dividing it by 12;

addition of a residual charge to ensure NGC can recover the differences between the estimated marginal costs that will be recovered from the access charge and the revenue entitlements of the TOs in any one year; and

as noted, an allocation of access charges to generators paying TNUoS that is intended to ensure that total generator charges from transmission (connection and access) do not exceed 25% of total transmission charges.

Important changes were implemented to the ICRP model in April 2004, and were:

the introduction of a DC load flow (DCLF) model to upgrade the transport model; and

further rationalisation of the connection/shared network boundary for generators and demand (the so-called PLUGs method).

Both changes emerged out of a charging review carried out by NGC, and they were designed to increase the cost reflectivity of the current transmission charging system.

Additionally the DCLF model was modified from 1 April 2005 to:

incorporate Scottish network data; and

include multi-voltage expansion constants, including specific factors for the 132kV system in Scotland that differs between the two transmission owners.

Appendix TN-2 of the methodology statement sets out an example of the calculation of the zonal generation tariff.

The methodology statement notes that:

> *"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, charges 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. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy."*[19]

[19] www.nationalgrid.com/uk/indinfo/charging/pdfs/UOSCM_I1R0_GB_Final.pdf, para 1.6, page 9.

Appendix TN-5, classification of parties for charging purposes, provides an illustration of how a party is classified for use of system charging purposes, highlighting the relevant paragraphs of the methodology to each party. This appendix defines classes of parties liable for generator TNUoS charges:

parties with a bilateral connection agreement with NGC;

[licensable] generators that have a BEGA; and

interconnector asset owners that have a bilateral connection agreement with NGC or who are capable of exporting100MW or more to the system.

With regard to [licensable] generators that have a BEGA, the generator is treated on a par with a transmission-connected generator in the equivalent zone. This means that for:

a generator in a positive zone, charges are calculated by reference to the highest TEC applicable to that power station in the relevant financial year; and

a generator in a negative zone, charges are calculated by reference to the average of the capped metered volumes during the three settlement periods of highest demand separated by at least ten days between November and February, but which do not have to be coincident wit the triad, again within the relevant financial year.

- *Charging to exempt embedded generators*

Prior to UoSCM-M-07[20] implementation on 1 April 2003, the charging methodology treated licence exempt generators according to where they were registered for trading purposes and how they traded. The methodology at that time resulted in different treatment for physically similar plant because of contractual and meter registration issues. It also created inconsistencies with the effect on the power system. The modification therefore changed the methodology for determining liability for TNUoS charges, by making all embedded generators capable of exporting less than 100MW exempt from generation TNUoS charges. It changed the term CVA registered ELEGs to “exempt export BMUs”, who have since paid (or been paid) demand TNUoS charges on the basis of their metered volumes during the half hours used in calculating these charges irrespective of where they are registered or how they trade. Hence, if there is a net import over the average half hourly period, they have been charged the relevant kW tariff multiplied by the average export. Conversely, if there is a net export, they are paid the relevant kW tariff multiplied by the average export. Therefore suppliers who had a netting off agreement in place with an exempt export BMU, either within a trading unit or through an agreement facilitated by NGC, saw an increase in their TNUoS demand charges, and parties to the netting off agreements have subsequently been paid or charged directly.

Transmission charging methodologies in Scotland have historically differed from England and Wales, and have remained asset-based, comprising separate entry and exit charges, infrastructure and system service charges. Also in contrast to England and Wales where the 100MW limit has imposed a limit for charging, the Scottish system operators (SOs) that existed until recently administered charges to “visible” distribution connected generation reflecting the costs they imposed.

To illustrate, SPTL’s charging statement for 2004/05 noted:

> *“5.1 If a Generator, connected to a distribution system, requires the use of the transmission system then the owner of that distribution system may be liable for transmission use of system charges. The level of these charges will depend on factors such as the maximum and minimum demand at the grid connection point, the registered generation capacity, the likely load factors and other relevant factors.*

[20] Under the charging methodology, changes proposed by NGC are implemented after due process, provided they are not vetoed by the Authority.

5.2 Due to the many possible combinations of variables at each connection point, it is not possible to provide definitive rules for charges. As a result, Distributors are encouraged to contact SP Transmission at an early stage in connecting an embedded generator."

With BETTA, the same rules now apply for charging purposes but with the regional changes to the threshold we have noted above.

- *NGC's "eight commitments"*

In March 2003, as part of the negotiations on NGC's SO incentive scheme for 2003/04, NGC gave Ofgem a series of commitments about development of its electricity transmission charging and contractual framework with a delivery date of April 2004. Transmission charging in this context comprised both TNUoS and connection charges.

In summary these commitments were to look across transmission charging with a view to assessing the merits of change in a range of broadly-based areas, but which included a requirement to review charging of licence exempt embedded generators, the main tangible impact arising from the eight commitments was in the form of the transmission charging review. This, broadly speaking, resulted in the changes implemented in April 2004 with regard to PLUGs and the new DCLF transport model. An internal report commissioned by Ofgem and dated February 2004 from Cornwall Consulting author noted:

"In the last 12 months, there has been no obvious progress on the treatment of embedded generators and NGC has not published any thoughts or conclusions on this area to the wider industry."

Subsequently change in this area was picked up by the BETTA project, especially the "small generators" workstream, and NGC has not since issued any further thoughts we can find on the subject.

- *Governance of transmission charges*

The transmission licence requires that NGC:

(a) shall, except where the Authority consents to a shorter period, give 150 days notice to the Authority of any proposals to change use of system charges other than in relation to charges to be made in respect of the balancing services activity, together with a reasonable assessment of the effect of the proposals (if implemented) on, those charges, and

(b) where it has decided to implement any proposals to change use of system charges other than in relation to charges to be made in respect of the balancing services activity, shall give the Authority notice of its decision and the date on which the proposals will be implemented which shall not, without the consent of the Authority, be less than a month after the date on which the required notice required was given.

Unless otherwise determined by the Authority, the licensee shall only enter arrangements for use of system which secure that use of system charges will conform with the statement last furnished under paragraph (b) above either: (i) before it enters into the arrangements; or (ii) before the charges in question from time to time fall to be made, and, for the purposes of this paragraph, the reference to the statement last furnished under paragraph (b) above shall be construed, where that statement is subject to amendments so furnished before the relevant time, as a reference to that statement as so amended.

With regard to non-discrimination by NGC in the provision of use of system, or in the carrying out of works for the purpose of connection to the licensee's transmission system, the licensee shall not discriminate as between any persons or class or classes of persons.

NGC is also required to offer terms: "The licensee shall offer terms as soon as practicable and (except where the Authority consents to a longer period) in any event not more than three months after receipt by NGC of an application containing all the information reasonably required by NGC. Various exclusions apply, for example if making the offer would cause a breach of licence, grid code, CUSC, certain parts of the Electricity Act 1989 or safety standards".

Changes to the use of system charging methodology may be notified by NGC and the Authority has the power to veto a proposed change, although it must do so within 28 days of any change being formally notified. All changes to the connection charging methodology must be approved by the Authority.

NGC has set up a transmission charging methodologies forum (TCMF) where current issues are discussed with electricity industry representatives. The charging issues sub group (CISG) of the TCMF discusses detailed issues and reports to the TCMF. This group is providing a focus for discussion of the March 2005 conditions placed by Ofgem on the GB transmission charging methodology. Neither group has a formal remit other than acting as a means of facilitating discussion and improving transparency.

- *Credit ratings*

The "NGC credit rating", is a key concept in the contractual framework, and all transmission users, including embedded generators, where charges are payable to NGC are subject to achieving such a rating or posting credit. The term is defined in the CUSC as:

a credit rating for long-term debt of A and A3 respectively as set by Standard and Poor's or Moody's respectively; or

an indicative long-term private credit rating of A- and A3 respectively as set by Standard and Poor's or Moody's as the basis of issuing senior unsecured debt.

Alternatively, if none of NGC's credit rating criteria is met, the current security provisions are:

an irrevocable on demand standby letter of credit or guarantee;

cash held in escrow; or

any other form included in NGC's then current policy and procedure.

Note that these provisions may be subject to change, depending on the outcome of the CUSC amendment proposals CAP089-091 currently under consideration.

This basic system of GB transmission charges (as successively modified) is based on a reasonably strong degree of locational price signaling and capacity-based pricing as applied in England and Wales for over a decade. With appropriate consequential changes, this system has formed the basis for rollout of charges to Scotland under BETTA from 1 April 2005.

The thresholds regime is the key determinant of eligibility for charging embedded generators for access to the transmission system. All generators above these thresholds (and some limited cases of generators below them) are subject to TNUoS charges within the applicable zone, on the same basis as transmission-connected generators. Below these levels exempt generators are effectively paid in recognition of the reduced demand in a zone served by the transmission system.

Distribution charges

Charges for distribution assets in GB are split between connection and use of system. The boundary (which is consistent for demand and generation) is explained in each DNO's licence condition 4B statement.

- *Connection charge*

A generator connected to a distribution system will generally be liable for DNO distribution charges to cover:

full cost of the work to be done and equipment to be installed, including metering, to provide the connection and to maintain the security of the distribution system;

the capitalised or ongoing cost of anticipated operation, repair and maintenance (depending on the methodology adopted by the DNO);

the DNO's scheme preparation, including the calculation of load flow, fault level and electrical losses and the assessment of the effect of the generation on distribution system reinforcement requirements;

attendance at generation commissioning tests;

the installation and operation of suitable telemetry equipment and on a periodic basis:

the provision of export statements;

additional system control costs resulting from generation connected to the distribution system; and

system studies.

To give some indications of the typical charges:

- a simple low voltage connection to an existing main might be charged in the region of £500-£1000;
- a 300kVA commercial low voltage connection might charged be in the region of £2,500;
- provision of a new 200kVA substation might be in the region of £20,000;
- a new 33/11kV substation might be in the region of £850,000-£2,000,000; and
- a new 132/33kV substation might be in the region of £2.3-£4.2m.

- *Deferred generator terms*

The capital cost of any distribution assets, provided for the sole use of the generation connection, is normally payable prior to energisation. This payment may include the capitalised cost of future operation, repairs and maintenance and may also include distribution use of system support allowances, depending on the methodology used by the DNO. The cost of new or replacement joint user assets is normally charged via agreed deferred generator charges.

DNOs will not normally charge for reinforcement of parts of the existing distribution system for common use where the new or increased load requirement or fault level contribution does not exceed 25 per cent of the existing effective capacity of those parts. In general, charges will not take into account reinforcement at more than one voltage level above the voltage of connection. The need for reinforcement of the distribution network may be driven by:

equipment fault level limits;

thermal or current carrying capacity limits;

voltage stability limits; and

network security planning limits according to Engineering Recommendation P2/5.

- *Interactive connection applications*

Interactive connection applications arise where a DNO receives two or more applications for connection that make use of the same part of the network in a way that could have an impact on the terms and conditions of any connection offer. Where this occurs, the DNO will normally advise all parties concerned, including details of how the interactive applications will be processed. This procedure would normally only apply to connections of 1MVA or more.

- *Competition in connections*

The embedded generator may carry out some of the connection work either itself or using third party contactor. Full details of work to be carried out and the specifications of equipment to be used would be agreed with the DNO. Reinforcement of the existing distribution network would normally be excluded from this provision.

- *New GDUoS charges*

Generator distribution use of system (GDUoS) charges are normally applied to generators connected from 1 April 2005. On that date, connection charges were changed with Ofgem's approval of "shallow" charges, generally reflecting only the costs of assets installed for the exclusive use of the generator. In other words, the GDUoS charge represents an ongoing charge for network reinforcement that was previously capitalised and charged in upfront connection charges prior to 1 April 2005. This new approach has resulted in an average reduction in the reinforcement element of connection charges for like for like generators of approximately £50/kW. This amount will now instead be collected over time through GDUoS charges. These changes have resulted from Ofgem's wide-ranging review of the structure of distribution charges initiated in 2000.[21]

GDUoS charges are set by each DNO based on their assessment of system costs, using a charging model to determine the cost of additional load at each level of the distribution system and an appropriate cost recovery split between customer groups. The model assesses reinforcement costs, but excludes costs which are recovered from the customer in full (connection charges or transactional charges). The 500MW distribution reinforcement model (DRM) has been in widespread use by DNOs since the 1980s. The DRM theoretically provides cost reflective charges for each customer or group of customers. These charges are then scaled to allow the DNO to recover its allowed revenue. The model does not accommodate GDUoS charges; it is voltage-based and does not take account of locational factors. It was set up to take account of the cost required to meet incremental demand (500MW simultaneous maximum demand) assuming that power flows from grid supply points at high voltage to customers at lower voltage levels.

Charges are allocated between customer classes based on their contribution to system peak demand. Generators do not feature in the calculations and the model fails to recognise that peak generation may or may not occur at times of maximum demand and that coincidence of peak at different points in the system may not occur at times of system peak. For example, the DRM would

[21] Full details of the latest developments can be found at:
www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges.

not take account of the cost implications of reverse power flows caused by net generation. The discussions within the structure of charges review include the merits of replacement for the DRM. One candidate is similar to the ICRP model currently used by NGC.

Non-half hourly GDUoS charges generally take the form of a p/MPAN/day charge, varying by profile and voltage level, billed to the registered supplier for the MPANs through the super-customer billing system. Half-hourly GDUoS charges generally take the form of a p/kVA/day, varying by voltage level, billed to the registered supplier for the MPAN on a site-specific basis. The value of kVA of chargeable agreed export capacity will be agreed with the generator individually prior to connection. Once fixed, the chargeable agreed export capacity will remain fixed, typically, for five years.

Table 2:3: Approximate Range of GDUoS Charges from 1 April 2005

Domestic Profile 1 and 2		Nil - 0.83p/MPAN/day
Non-domestic Profile 3 and 4		Nil – 4.16p/MPAN/day
Non-domestic Profile 5 to 8		Nil - 7.80p/MPAN/day
Half-hourly	LV	Nil - 2.00p/kVA/day
	HV	0.416 - 2.48p/kVA/day
	EHV	1.3 - 1.88p/kVA/day*

*In some cases a p/kVArh charge may be levied instead and or site specific charges may apply.

NGC exit charges (connection charges) levied on the DNO are not recovered normally as a component of the GDUoS charges.

- *Governance of distribution charges*

Concerns over the transparency and modification arrangements of the existing rules and obligations for connecting to and using the distribution networks have led to a number of industry work-streams and an Ofgem consultation paper. In response to Ofgem's consultation paper in December 2004, the overwhelming majority of respondents were in favour of some consolidation of the existing rules into a single document having multilateral application in most respects and applying bi-laterally where appropriate. In its May 2005 impact assessment, Ofgem stated its intention to publish, in August 2005, its conclusions on introduction of governance.[22]

- *Incentives to connect embedded generation*

A number of incentives have been introduced over the recent past to stimulate small-scale generators.

Ofgem has introduced a 'hybrid' incentive scheme **for DNOs in relation to the connection** of embedded generation:

the costs incurred by the DNOs to provide network access to embedded generation are given 80% pass-through treatment; and

the DNOs (with one exception) receive a further supplementary incentive of £1.50/kW/year (7.9% real pre tax rate of return or 1% above the normally allowed 6.9%). Scottish Hydro Electric receives a different incentive of £2.00/kW/year.

[22] Source: www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/electricitycodes.

Connection charges paid by the generator in respect of shared costs will be subtracted from the 80% passed-through costs and the net amount will enter the DNO’s allowed revenue under the hybrid mechanism. The total revenue that a DNO can recover under the incentive scheme (the pass-through and the incentive rate) should normally be recovered from those generators connecting to the distribution system after 1 April 2005. The incentive rate will be recoverable by DNOs once generating capacity connects to the distribution network, and it is only applicable whilst the generator remains connected to the network (i.e. continues to operate).

The assumed asset life for assets associated with distributed generation is 15 years and it is intended that the incentive (excluding the operations, and repair, and maintenance charge) applying at the time of connection will apply for the 15 year period. The maximum rate of return (i.e. allowed cost of debt) for each DNO’s overall portfolio of embedded generation connected in the next price control is 13.8% real pre-tax and the minimum is 4.1%. For any projects with direct reinforcement costs in excess of £200/kW (which is four times the average capital expenditure estimate), the generator seeking connection would be expected to fund the required additional investment through payment of connection charges.

Network access rebates for generators connected after 1 April 2005: a generator rebate of £0.002/kW/hour for network unavailability may be paid where the individual connection has suffered abnormal interruption. This would normally be limited to EHV distribution connected generators, although distribution-connected generators would have access to the same guaranteed standards payments as those paid to demand customers where failures exceed 18 hours. DNOs will still be able to recover the incentive rate in instances where the generator decides to cease generating power temporarily (for example, due to weather and other conditions).

Where innovative technical solutions are demonstrated by the DNO, there is an additional incentive of an extra £3/kW/year (over and above the main embedded generation incentive) for a five year period commencing from the date of commissioning of the project based on the concept of **registered power zones** (RPZs). Ofgem will register RPZ projects and, when appropriate, will seek advice from an independent panel, to confirm the innovation content and potential benefits of an RPZ proposal. The generator(s) directly involved in the innovation must be informed of the RPZ proposal, as this might have commercial impacts on the negotiation of a connection agreement. The DNO takes full responsibility for the management of the risks of the scheme and should offer the connecting generator commercial terms reflecting these risks. DNOs are allowed to seek registration for up to two RPZs per year for the first two years of the scheme.

- *Distributed Generation Coordinating Group (DGCG)*

This group has now stood down, being replaced by a distribution sub group of the Energy Networks Coordinating Group. DGCG originally identified 24 barriers to the development of embedded generation and has reported that at least half of them have now been removed. The focus of the DGCG has been the removal of barriers to the development and connection of distributed generation. Barriers that have been removed include a lack of:

a standard approach by distribution companies where more than one generator is seeking connection to the same section of the distribution network

standard technical guidance on the connection of distributed generation, and

a modern methodology for assessing the contribution of modern types of distributed generation to network security.

Work on this third barrier is now near conclusion. The standard distribution licence requires that the “licensee shall plan and develop the licensee’s distribution system in accordance with a standard not less than that set out in Engineering Recommendation P2/5”. This standard was issued in 1978. In March 2005, a consultation was issued by the Distribution Code Review Panel on an updated version – draft P2/6. This development is relevant in that, if implemented, for the first time it will allow DNOs to take account of the contribution from embedded generation in DNO's planning standards for security of supply.

Ofgem recently consulted on the regulatory implications of domestic scale microgeneration.[23] This consultation paper considers what regulatory changes may be necessary to reflect the connection of domestic-scale microgeneration to distribution networks. Decisions are awaited.

There is still a great deal of work to be done on developing active network management. One of the perceived barriers to this development is the generation prohibition in the DNO licence.

We note that:

- **current distribution charges have been constructed on the assumption that all power flows on a DNO's system was from a grid supply point to a customer's terminals;**
- **exported energy from embedded generators would normally be absorbed at the voltage of connection or a lower voltage;**
- **no recognition is made of power exported onto the transmission system;**
- **a number of incentives have recently been developed to further encourage distribution-connected generation; and**
- **some limited consideration has been given to the impact of an increase in embedded generation on the distribution network and the charges levied (e.g. introduction of the new GDUoS charge) but a more holistic assessment of the charging impact across networks has yet to be made.**

We also note that:

- **distribution use of system charges for embedded generators were introduced on 1 April 2005;**
- **"deep" connection charges for embedded generators were replaced with relatively "shallow" connection charges at the same time; and**
- **there are uncertainties surrounding distribution commercial governance that should be resolved in the foreseeable future.**

[23] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11267_12305.pdf. This consultation closed on 15 July 2005.

Embedded benefits

"Embedded benefits" are a key feature of the current commercial arrangements that apply to embedded generators. They arise from both energy trading arrangements and network pricing.

Generators directly connected to the electricity transmission network are registered within the trading system in the Central Meter Registration Service (CMRS), and pay access charges for use of the network. Suppliers also pay TNUoS charges for the use of the transmission network. As signatories to the BSC, directly connected generators and suppliers also incur other related charges including Balancing Services use of System charges (BSUoS) and costs administered by Elexon, the BSCCo, who manage the centralized trading system. These BSCCo costs include the costs of transmission losses and control trading charges.

Smaller generators, which are neither connected to the grid nor signatories to the BSC, are generally not CMRS registered and are not subject to these charges.[24] The generator typically "sits behind" the BM unit of the relevant supplier, which in turn is usually the local GSP group. Consequently it is the supplier who takes responsibility for registering the embedded generators meter through the Supplier Meter Registration Service (SMRS).

Suppliers that contract with distributed generators incur reduced charges from NGC, since the use of locally generated electricity by that supplier reduces the extent to which that supplier has to offtake from the transmission system. It can also diminish the supplier's use of energy balancing services. A reduction in charges arises, and this is seen both in TNUoS and BSUoS charges paid by the supplier, and there can also be a reduction in the charges they face from Elexon. Suppliers typically pass on the majority of these savings to distributed generators, subject to bilateral negotiation. While there are a range of standard practices with regard to the negotiation and treatment of embedded benefits, there is no codification or industry standard governing such matters.

The treatment of these arrangements has been subject to change. P100, a Modification Proposal to the BSC, and UoSCM-M-07, an amendment to the use of system charging methodology, have enabled embedded licence exempt generators registered in the CMRS to access these embedded benefits directly, without the need for a contractual relationship with a supplier within the GSP group in which the generator is situated.

The various benefits have different monetary values, and the values also vary by location and over time. However, it is possible to derive some indicative values and ranges for these as shown below. Note that these are not only indicative but they suggest the total value available before negotiation between the supplier and the embedded generator. The generator's proportion of this value will vary by benefit type and with the size of the generator, but empirically seems to be in the range of 50-70% of the total.

TNUoS demand tariff = £10/ kW

The TNUoS half-hourly (HH) demand charge is levied on the basis of average power (expressed in kW) consumption in a triad, and not on metered energy demand (in kWh or MWh terms). The calculated benefit applies to the annual HH demand TNUoS charge for supplier BM units. This benefit accrues to the lead parties defined under the BSC of the relevant supplier BM units. It is also possible to estimate a value per MWh that indicates the order of magnitude of the TNUoS tariff in a manner more easily comparable to the other benefits studied.[25]

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[24] A further "benefit" is avoidance of exposure to the residual cashflow reallocation cashflow. This is a charge or payment based on BM unit metered volumes levied by Elexon to neutralize the difference in any given settlement period that arises between total payments made to parties and total charges under the BSC.

[25] This estimate is carried out in the "Report to the DTI on the review of the initial impact of NETA on smaller generators", available at www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/103-3aug01.pdf. See appendix 8.

BSUoS benefit = £2.00/ MWh

The BSUoS benefit is calculated simply as twice the value of a typical balancing services price, as the benefit accrues both on the generation and supplier meters, which can be conservatively assumed to be no less than £1.00/ MWh.

TLM benefit = £0.90/ MWh (2% of £45 energy price per MWh)

Transmission Loss Multipliers (TLMs) are the basis under the BSC for setting payments for thermal transmission losses. If the TLM's are 1.01 for offtaking trading units and 0.99 for delivering trading units, the Transmission loss benefit will be 0.02 (= 1.01 – 0.99) of metered energy. This corresponds to 2% which gives a monetary value of £0.90/MWh when multiplied by annual electricity price at mid 2005 to the order of of £45/MWh. This benefit accrues to the BSC party who owns the energy account to which the metered energy is credited.

BSCCo benefit = £0.20 / MWh

This benefit depends on Elexon's direct expenses and on aggregate energy flows on the transmission system on a monthly basis. In general, the benefit increases with higher expenses and lower energy flows. It should also be noted that the BSCCo benefit accrues to the BSC party who owns the energy account to which the metered energy is credited. Again, this party need not be the BMU Lead Party.

It is apparent that:

- **embedded benefits are a key incentive available to both the embedded generator and the supplier;**
- **the benefit of greatest potential value to the embedded generator is the TNUoS benefit;**
- **this value varies proportionately with the locational cost element in NGC's TNUoS generation tariff; and**
- **this value when realised by the embedded generator takes no account of the share of the value retained by the supplier.**

BETTA

- *GBSO, the 132kV system and transmission charging*

The fundamental commercial transmission charging and energy trading rules with regard to embedded generation were developed against the background of the England and Wales market. With the design and development of BETTA, the appropriateness of these rules was reviewed, starting with open consultation on a range of small generation issues from November 2003[26], and resulting in decisions being published in November 2004.[27]

Transmission charging arrangements in GB developed differently north and south of the Scottish Border prior to the introduction of BETTA. At its simplest, the differences have arisen because of:

historically a different approach to connection charges was locked in at vesting in Scotland relative to England and Wales;

although all three transmission operators started from an asset-based transmission charging methodology, NGC in England and Wales introduced a different ICRP model from 1993/94;

enhancements and modifications have been introduced subsequently to meet local issues; and

the further divergence that arose in 2004/05 when NGC further evolved the DCLF method within its ICRP transport model, and with the implementation of the PLUGs connection methodology.

Further, in both Scottish transmission areas, distribution-connected generators were liable for transmission charges where they were deemed to require use of the transmission system. While the charges were levied on a case by case basis, a typical charge in SP Transmission's area was £12.90/ kW. In contrast, in England and Wales, all generators below 100MW are licence exempted and are connected to the distribution system; they were assumed not to use the transmission system and were exempt from transmission charges.

The BETTA design resulted in three key changes for users of the transmission system:

transmission services are now provided to users by the GB system operator, rather than the host transmission licensee (including, in the case of SP Transmission and NGC, in their capacity as owners of the assets that comprise the Anglo-Scots interconnector);

the rules governing the relationship between users of the transmission system (including the charging arrangements) are now common across GB under the CUSC and Grid Code; and

from the embedded generators point of view, the BEGA was introduced. Under the CUSC Framework Agreement, all embedded generators above 50MW (and some below in Scotland) must enter a BEGA, and BEGA counterparties must pay TNUoS.

A number of supporting decisions were taken, which have also had a direct impact on the treatment of embedded generation in Scotland, including:

the terms of the Exemption Order made under section 5 of the Electricity Act 1989, setting out the criteria under which a generator was automatically exempt from the requirement to hold a generation licence, have been harmonised between England and Wales and Scotland;

[26] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5125_Small_Generators_issues_20nov03.pdf.

[27] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6973_9604.pdf.

the classification of 132kV lines as forming part of the transmission system in Scotland was not revisited in order to remove perceived commercial differences in treatment between transmission-connected generators in Scotland; and

the interim measure to reduce transmission charges for small generators connected to the 132kV network in Scotland was introduced to remove what DTI/ Ofgem saw as undue differences in the treatment of this class of generator in comparison with distribution connected small generators in England and Wales.

- *132kV rebate*

The roll-out of the prevailing arrangements in England and Wales across GB resulted in all transmission-connected generators (regardless of size) being liable for charges under a single charging methodology. The methodology has been applied therefore to 132kV connected generators in Scotland, who were previously charged by the Scottish TOs. Currently, there is around 1GW of generation capacity connected to the 132kV transmission network in Scotland.

Ofgem/DTI's assessment of the application of the arrangements in England and Wales to GB highlighted one particular area of concern. In the England and Wales market, there are no small, transmission-connected generators, which contrasts with a significant number of small, transmission-connected generators in Scotland. Ofgem/DTI therefore considered potential alternative interim measures to address this difference. The commercial position of 132kV connected generators in Scotland paying TNUoS was very different from 132kV connected generators in England and Wales who enjoyed embedded benefits.

The specific area of concern related to the TNUoS benefit of a distribution-connected generator being able to net off demand with a local supplier. The net benefit of a small embedded generator being able to count its output against the demand of a local supplier is the residual transmission charge avoided by the generator plus the residual charge avoided by the supplier.[28] If the share of this total net benefit realised by the generator (recognising that this will depend on a negotiation between the supplier and the generator) is greater than the equivalent residual charge levied by the relevant DNO, then the generator will be better off (regardless of the actual marginal costs associated with its connection and ongoing use of the system) as a result of connecting to a distribution system rather than the transmission system. Ofgem/DTI concluded that such systematic bias would not be consistent with non-discrimination and would distort competition.

Ofgem/DTI assessed that the total residual charge currently implied by NGC's charging methodology in England and Wales was at the time in the order of £8.60/ kW, of which around £2.00 was paid by generation and £6.60 was paid by demand. While the equivalent charge by DNOs was less transparent, given its incorporation within a 'deep' connection charge at the time, Ofgem noted that the value was significantly less than £8.60. Ofgem/ DTI therefore concluded that the operation of the TNUoS embedded benefit conferred a benefit to small distribution-connected generation relative to small transmission-connected generation, and that this difference in treatment was "not proportionate", and designed a rebate for 132kV transmission-connected generation.[29]

The rebate or discount was formalised through NGC's transmission licence and implemented from 1 April 2005. Condition C13 stipulates that small generators connected to the 132kV transmission system in Scotland are eligible for a reduction in the appropriate charge from the generation TNUoS tariff. This discount has subsequently been calculated in accordance with a direction from the Authority, which effectively sets the rate, and equates to 25% of the combined generation and demand residual components of the TNUoS tariffs. For 2005/6, this figure has been calculated as £3.611587/ kW.[30] A unit amount of £0.04111/kW to the demand tariff and 0.00561p/kW to the

[28] Essentially, through the netting off arrangement between the supplier and the generator the positive (or negative) locational charge avoided by the generator is cancelled out by negative (or positive) locational charge avoided by the supplier – leaving the avoidance of the residual charges (which are both positive in all cases) as the remaining net benefit.

[29] The Authority's decision letter dated 25 February 2005 is at www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10377_5905.pdf.

[30] See page 7 of the 2005/06 charging statement.

energy consumption tariff is added on a non-locational basis (that is, it is applied against the residual charge within the TNUoS tariff).

Condition C13 also requires the small generators discount mechanism to be revenue neutral over the period of its operation so that the net effect on revenue of the licence condition is zero. National Grid's statement of charges says it must calculate the unit amount added to the demand tariffs using a forecast of the total discount payable to eligible generators, and a forecast of the demand charging base. If either of these factors outturns differently from the original forecast made by NGC, then an under/ over recovery would occur. It is therefore necessary to manage any under or over recovery associated with the small generators discount separately from the under or over recovery mechanism within National Grid's main revenue restriction. The amount of any under/ over recovery would be added to the revenue recovery used to derive the unit amount in subsequent years.

Ofgem acknowledged at the time that it would need to undertake work in the longer term to ensure greater consistency of transmission charges and benefits between transmission-connected and distribution-connected generators, which would remove the interim measure. The condition is time-limited and will fall away on 31 March 2008.

BETTA was premised on the concept of minimum necessary change. In aligning arrangements to fit the NETA model, a number of changes were made to the contractual and charging regime for transmission in Scotland. A particular feature of these changes was the introduction of a single transmission charging regime under the GBSO, but which includes the implementation of the time limited 132kV rebate. The approach to embedded charging has also been aligned, with an England & Wales style thresholds regime supplanting the more generalised assessment in Scotland.

International comparisons

The terms of reference asks for comment on charging approaches to embedded generation that have been adopted in other markets. This section:

places the current GB approach to access charging into a wider context; and

identifies some approaches adopted in other markets that may be of relevance.

Total network tariffs, of course, comprise distribution plus transmission charges. A joint comparison of transmission and distribution tariffs is complicated by the fact that some countries do not have uniform national distribution tariffs, which depend on the individual distribution utilities.[31] Assembling detailed information on distribution charges has not been possible in the timescales available, so this chapter focuses on transmission aspects.

This section and the appendix is based primarily on two documents - a Comillas study carried out for the European Commission in 2002[32] into transmission charging in Europe, and a more recent study by the Irish regulator, CER[33], summarizing network charging more generally. It has been supplemented with data trawled from various websites on markets outside of western Europe, and more detailed examination of tariffs in some of the highlighted countries.

Tariff structure

The structure of transmission tariffs comprises several aspects but tend to have four main differentiators:

the split in charges between classes of network users;

the format or structure of the charges (e.g. fixed charges, variable capacity component and energy component);

the level of geographical differentiation (nodal, zonal or uniform); and

the level of time differentiation (e.g. hourly, daily, seasonal, etc.).

Each of these aspects is considered below, together with the few examples of mechanisms we have identified that deal specifically with embedded generation.

- *Who pays – demand vs. generation*

Transmission charges in most liberalised electricity markets tend to be targeted on demand, as illustrated for Europe in Figure 3.1, with very few markets outside of the Nordic markets and the UK and Ireland levying access charges on generators.[34]

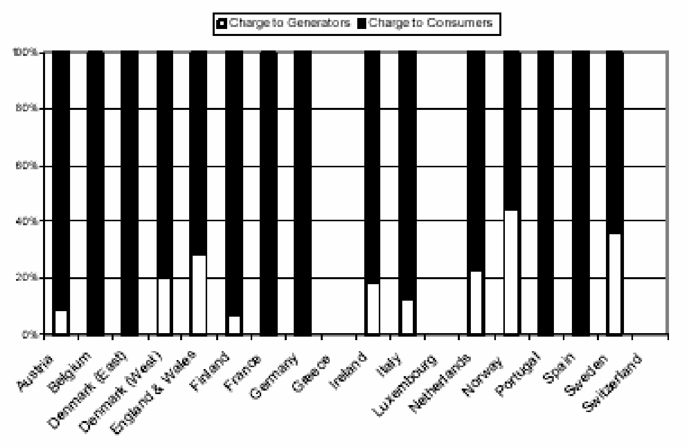
Figure 3.1 – Split in European transmission charges – by class of payer

31 Countries with low or high transmission tariffs do not necessarily correspond to countries with low or high distribution tariffs, respectively. Actually the correlation is very weak. The discrepancy is most notable with Germany, with comparatively much higher distribution tariffs and also, but moderately, with The Netherlands, Austria and Norway. The opposite happens to Spain, with comparatively lower distribution tariffs.

32 http://europa.eu.int/comm/energy/electricity/publications/doc/bench_trans_tarif_en.pdf.

33 www.cer.ie/CERDocs/cer04101.pdf.

34 To these, we can add Argentina from outside of Europe.



Source - Comillas

The reasons for allocating charges to generators in the systems that do charge them seem to be:

England & Wales and Ireland - explicitly to provide a locational signal to generators;

Sweden - to minimise cost shifting from a former contract path methodology;

Norway – to preserve a concept of equity whereby consuming users and generators pay about half each of total transmission charges; and

Argentina and Chile - a wish to impose the costs and risks of building new lines on the parties that benefit from them, who are generally considered to be generators because they can capture higher energy charges, and to avoid “socialisation” of costs and risks.

From a wider economic point of view, of course, there is in general no difference to customers in how the charges are borne by generators, as they will pass these through in their energy prices. However, in practice the main reasons for allocating all of the costs directly to consuming users is that it is easy – albeit probably inefficient - option. Perhaps because of this, European Commission officials seem to be moving towards a position where generation charges are rebalanced towards demand, though this of itself does not mean that generators as a class will not see locational differentials even if generation access charges sum to zero.

The argument against imposing charges onto generators runs as follows. If they pay for any of the costs of the shared network, it may influence investment decision-making because requiring generators to pay may increase the riskiness of investing. This will be more so if the wires charge is uncertain due to an allocation methodology that leads to changes in charges when new plant comes on-line.

In terms of overall efficiency, however, the objective arising from imposing some of the charges for the shared network on generators should be to achieve a number of different objectives:

to provide differential locational signals;

to avoid grandfathering; and

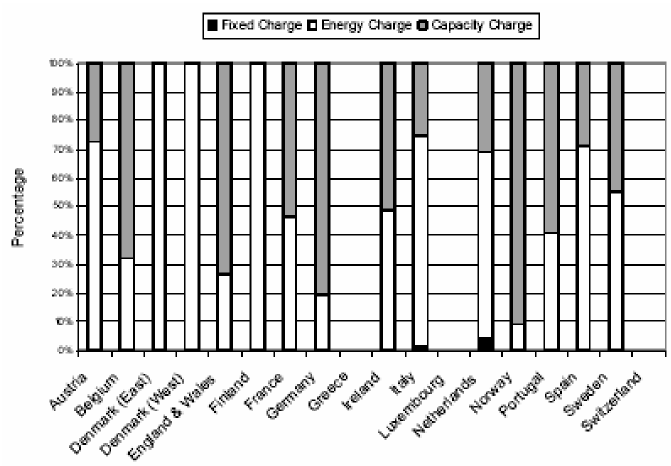
to interest generators in the costs of developing of the network.

Further, allocating charges to those who benefit is desirable on grounds of equity, and generators clearly do benefit by gaining a route to market. These arguments provide the basis for allocating some charges at least to generators. However, what is economically important is the locational differential, not the absolute level. What is also important is that beneficiary on a common integrated network in this context is determinable irrespective of the point and voltage of location, and location can be off - as well as on – the transmission system.

- *Structure of charges*

With regard to the structure of charges by participant class, there is a much wider diversity of experience. Again the Comillas study shows the split between different types of charges.

Figure 3.2 – Split in European transmission charges – by type of charge



Source - Comillas

In all but three countries from which data was available, some form of capacity charge is used, and this capacity charge is often used to recover a significant element of the total charges, and usually more than half. This approach reflects the conventional wisdom that the bulk of the costs on the transmission system are usually attributable to provision of capacity to met high system demands. In England and Wales over 70% of the access charges are recovered from capacity-based fees, and NGC has estimated that over 90% of its costs are peak dependent.

- *Geographical differentiation*

Geographical differentiation is not commonly applied. As Figure 3.3 on the next page shows, nodal costs are reflected in the marginal loss payment in Sweden and Norway for both consumers and producers. In Sweden this nodal differentiation is also applied to the capacity charge. In Ireland, it is applied in the capacity charge and also for payment of thermal losses. In England and Wales (and since extrapolated to Scotland), zonal differentiation is applied to the charges for both consumers and producers. In Italy, there are six different production zones for loss payment. However, in the rest of Europe, no nodal or zonal discrimination is applied.

- *Time of day differentiation*

This seems not to be a matter for the production side of the industry, and we do not explore it further.

Figure 3.3: Geographical differentiation in transmission tariffs

	Nodal	Zonal	None	Remarks
Austria			✓	
Belgium			✓	
Denmark			✓	
England & Wales		✓		In the capacity charge for both consumers and producers
Finland			✓	
France			✓	
Germany			✓	
Greece				
Ireland	✓			In the capacity and the energy (loss) charge for producers
Italy		✓		In the loss coefficients that are applied to producers
Luxembourg				
Netherlands			✓	
Norway	✓			Only applied for marginal loss payments
Portugal			✓	
Spain			✓	
Sweden	✓			For both the capacity and the energy charges
Switzerland				

Source - Comillas

<u>Embedded generator charges</u>

- *Existing approaches*

In nearly all of the systems we have considered, the issue of integrating embedded generators within transmission charging structures is effectively ignored, and embedded generators tend to be treated as negative loads, reducing the transmission charge according to the charging rules. There are three exceptions that we have identified outside of GB.

In **Norway** there is a considerable amount of embedded generation from small hydro schemes, and in Finland from urban combined district heating and power schemes. In consequence there are in these countries some significant sub-transmission/distribution networks, which are effectively self-sufficient. The issue of embedded generation has been addressed in a similar way in both. This has been done by structuring the grid charge in two parts, a “net charge” which is based on the power withdrawn from the grid and is reduced as a consequence of the embedded generation, and a “gross charge” which is based on the end-user consumption and losses which are beyond a grid supply point.

Fingrid has a three part charge to a distributor connected to one of its grid supply points:

a charge for exporting to the grid;

a charge based on end-use consumption plus losses beyond the grid supply point; and

a charge based on the power that flows out from the grid.

If the power taken from the grid is relatively modest, and the gross charge levied on end-use customer consumption is also modest, then the charge for use of the grid will be low. A recent appeal to the Finnish regulator about the pricing structure highlights the scope for disagreement about the relative magnitude of the charges, which impacts on the relative charges paid by (at one extreme) users who have no embedded generation and (at the other) those who have a significant amount.

In **Norway** the relationship between the numeric values of the access charge (which is charged based on i) all generation capacity beyond a grid supply point and ii) all consumption beyond a grid supply point) and the power charge (which is based on the measured supply or withdrawal across a grid supply point during the regional peak demand and is thus a net charge) implicitly determines the benefit of all embedded generation. Because the power charge could be zero if there is extensive embedded generation, there is an additional minimum power charge.

Ireland is the third, and probably most relevant, exception. The access charges applicable to generators in Ireland are set out in the generation transmission service (GTS) schedule in the network company's annual statement of charges[35]. The GTS schedule recovers 25% of the annual transmission network costs and recognises two distinct categories of generators:

tariff schedule GTS-T applicable to generators connected directly to the transmission system; and

tariff schedule GTS-D applicable to generators greater than or equal to 10MW[36] connected indirectly to the transmission system via the distribution system.

Generators face access charges on the basis of their contracted maximum export capacity, which is conceptually similar to TEC and connection location. This charge is referred to as the generation network location-based capacity charge and is calculated using a "*Reverse MW-mile"* approach. This approach allocates a share of the annual costs of the network to the generator based on its usage of the transmission system, reflecting the fact that cost depends on the distance and direction that power is being transmitted as well as the level of power being transmitted. It is a location specific charge (i.e. nodal), and is not zonal. The methodology rewards generators that offset network flows and allocates the cost of unused capacity that exists in the network across all users. The modeled approach allocates approximately 12% to 15% of network costs to generators. Therefore, there is an uplift required to recover the 25% of costs allocated to generators which is similar to the residual charge applied by NGC, meaning that approximately 40% of the generation access charge is non-locational.[37]

The Irish regulator, the CER, is understood to be considering separate tariff categories for transmission-connected generation and distribution-connected generation above 10MW reflecting the different cost they impose on the system. It is also considering mechanisms to reduce the variability of annual charges.

In contrast to England and Wales where the 100MW limit imposed an absolute threshold for charging until BETTA, the **Scottish system operators** that existed until recently have historically administered charges to "visible" distribution-connected generation reflecting the costs they impose on the transmission network, effectively based on a case-by-case judgement.

- *Relevance*

In summary none of the other systems examined with the possible exception of Ireland have tried to approach this issue based on an economic analysis of how charges to embedded generators should be structured. Most ignore the issue and simply charge based on the net flow of power out of the grid supply points. In the two systems where there is significant generation beyond the main grid supply points (Norway and Finland), we cannot find a numerical justification of either export charges. Furthermore, the balance of charges seems to have been determined more by industry politics rather than by economics except that a limit exists in not wishing to structure charges in such a way as to encourage the uneconomic development of embedded generation or

[35] The 2005 Statement of TUoS Charges can be downloaded from: www.eirgrid.com/EirGridPortal/uploads/Regulation%20and%20Pricing/Statement%20of%20Charges%20-%202005.pdf.
[36] This threshold corresponds to the dispatch threshold in the Trading and Settlement Code.
[37] Generators under the above schedules also pay a small portion of non-network costs via a direct trip and fast wind-down trip charge. This charge is levied on per MW basis of trip output in excess of 100MW.

transmission lines just to reduce transmission charges. In Ireland, the approach effectively requires a system-wide charging model that ignores voltage boundaries, which does not appear to be a practical option open to NGC. It looks anyway if the Irish are poised to move away from this approach and develop separate voltage tariffs.

- *Deferred expenditure benefits*

A number of other jurisdictions consider that distribution-connected, or embedded, generation may help to defer or avoid future investment in transmission and higher voltage distribution networks because they deliver energy to meet loads of other consumers without using the higher voltage facilities. Avoided distribution network investment could potentially occur at contiguous voltages to where an embedded generator is sited. While there is much discussion of the concept, the only commercial development of the issue we can find is in Australia, and even there it is at an early stage.

We note that:

(c) international comparisons of transmission charging arrangements seem to be of little value in helping considering appropriate arrangements for charging embedded generators in GB because charges to generators are relatively scarce;

(d) generally speaking charging arrangements in GB are advanced in terms of their level of sophistication and the degree of cost-reflectivity compared to many neighbouring markets, with a distinctive locational element on both sides of the market;

(e) Ireland is the one example we have identified of a transmission tariff specifically constructed to deal with off-grid generation;

(f) the other two examples we are aware of from Norway and Finland do not provide any robust pointers; and

(g) as a consequence none of the systems examined, except for Ireland, have tried to approach this issue based on an economic analysis of how the charges to embedded generators should be structured, but the transport model they utilise is conceptually very different to the ICRP model utilised by NGC.

Critique of current arrangements

Introduction

This section provides a critique of the current transmission charging methodology with regard to its treatment of embedded generation, and addresses (among others) the specific matters identified in the terms of reference.

The specific matters identified in the terms of reference considered in this section are:

whether the current charging arrangements create cross subsidies between generators who pay TNUoS charges and generators who are exempt from TNUoS charges;

whether there is any undue discrimination between the charging arrangements for different types of generation plant (e.g. eligibility for embedded benefits);

whether the classification of small and large generation plant should be redefined;

whether the current charging arrangements create barriers to entry or create perverse incentives for generation to bypass the transmission system and connect to the distribution system; and

whether there is an increasing number of embedded plant (or plant deemed to be less than 100 MW) that may be located close to a grid supply point (GSP) and may spill onto the transmission system but will not be exposed to transmission use of system charges.

Other related matters that struck our attention are also addressed in this section are:

to what extent is the transmission network an homogenous system;

what costs does embedded generation create relative to the transmission system, and what benefits does it draw;

what are the desirable properties of an efficient transmission charging methodology; and

what interactions would one expect to see between transmission and distribution charging in such an arrangement?

Discussion

- *Cross subsidies*

Whether the current charging arrangements create cross subsidies between generators who pay TNUoS charges and generators who are exempt from TNUoS charges.

This issue is a key issue, given the importance of cost reflectivity in the applicable objectives in NGC's transmission licence.

The ability to answer this question and quantify the subsidy clearly depends on the assumptions made about the costs and benefits of embedded generation relative to the transmission system. There is, however, no such consensus on the value of these wider costs and benefits.

The benefits comprise:

access: first and foremost access to transport power to customers outside the local distribution area;

quality: a local network or sub-system of loads with a maximum load of XMW and generators with a maximum sub-system coincident capability of YMW that is connected to the transmission system benefits from the balancing services procured by the GBSO through its operation of the main transmission system (for instance, through provision of reserves and voltage support). The requirement for, and value of, frequency control and regulation is also based on gross system consumption, and so the costs of central and operating reserves should be charged out on a gross basis. The value of voltage support is also based on the gross system consumption, but local generation may reduce the need for reactive power support and so in principle it may be appropriate to credit the distribution network;[38] and

reliability: the sub-system also gains reliability from standby for both planned and unplanned outages. The value of reliability is the most complex of the benefits to assess. The sub-system will be connected to the main grid through a transformer with a capacity of ZMW, which will need to have a capacity of at least X-YMW and may be as much as X MW or more if it is over-sized. To the extent that the transformer capacity is greater than the net load, then that capacity is providing security for those connected to the distribution network from the transmission system, and the distribution network should pay for a share of the shared network.

In each case the cost of the service provided by the GBSO is the direct cost incurred. However, it is assumed that save for access the cost of these benefits is presently paid for through BSUoS, and not transmission access charges. For present purposes, therefore we assume that the benefit, which embedded generators should correctly pay for through access charges is their **proportionate** access to the transmission system measured at the relevant (i.e. connecting) GSP or GSPs.

Against this background, there are a number of cross subsidies, which by definition deter cost reflectivity of charging for transmission access, inherent in the current charging arrangements. The most obvious examples are:

generators who are not eligible for a BEGA in England and Wales (typically below 50MW) who are distribution-connected and presently exempted from TNUoS but who export onto the transmission system[39];

generators who are not eligible for a BEGA (typically below 30MW) in SPTL's area who are exempted from TNUoS but export onto the transmission system;

generators who are not eligible for a BEGA (typically below 5MW) in SHETL's area who are exempted from TNUoS but export onto the transmission system;

as the amount of revenue to be recovered from generators as a class is fixed, the converse of this position is that all generators who pay TNUoS have a larger burden of the absolute charges to bear through charge avoidance by generators who spill onto the transmission system but do not pay TNUoS;

similarly distribution-connected generators above the thresholds who do not export significantly in terms of their output or frequently onto the transmission system or at times of system peak are exposed to a cost for which they do not receive a service;[40]

the arbitrary nature of the charging rules, which do not seem to have a robust basis for assessing causer pays, will create regional distortions between TO licensed areas and perverse locational signals because of the arbitrary nature of the thresholds. For instance, there are obvious incentives for 10-29MW generation developers in Scotland to locate in the SPTL area rather then

[38] In England & Wales embedded generators can already bid into the reactive power market.

[39]In this context we heard anecdotal evidence that in one GSP Group, one developer is proposing 10 separate 99MW schemes, the bulk of the output from which would be exporting onto the transmission system. Under the current rules, the schemes if they proceed to operation would be paid as negative demand although in isolation they are creating a possible 1GW import onto the transmission system.

[40] Given the recognition of the perverse incentives inherent in current charging arrangements, we suspect the number of such generators is modest.

SHETL area. Similarly it is clearly advantageous for developers of medium size projects up to 99MW to locate in England and Wales rather than Scotland all other things being equal. There are also strong incentives for developers to modularize their schemes so that they can game the thresholds and therefore avoid TNUoS payments;[41]

additionally the 132kV rebate creates a further subsidy in favour of 132kV transmission-connected generators in Scotland. While the subsidy may be rationalized on wider policy grounds, it is not justified within the narrower context of the transmission methodology and is not obviously reflective of any costs; and

the cost of the subsidy, an estimated £2.4m in 2005/06, is made good by adjustments to the residual charge levied against both generators and demand customers. They are thus paying more than would otherwise have been the case without the rebate.

On the basis of the information presently available to us, it is not possible to quantify the extent of the subsidies or their distribution. Additionally the different charging methodologies at DNO level mean that there is considerable diversity in charging at the distribution level, which could further aggravate comparison of the total costs to which embedded generators are exposed and their distribution. It is necessary for both sets of charging arrangements to be looked at it the round to assess the overall impact of network charging on embedded generators, which is outside the scope of this paper.

Irrespective of this caveat, the concept of cross subsidy in this context and its existence means that some costs at least are not being allocated appropriately, and these are probably significant. The assumption behind the current charging methodology is that a generator above the relevant local threshold “spills” onto the transmission system because in isolation it imposes an incremental effect on the transmission system. However, “spill” in this context can have at least two widely differing definitions. At one extreme, all embedded generators spill if it reduces the expected GSP group demand. At the other extreme, no individual generator can spill unless its output is higher than the entire GSP group minimum demand (which is highly improbable). There are related questions that also need to be addressed. For instance, is there a concept that generators near GSPs spill more than generators that are more deeply embedded? We doubt this is the case, but some of the literature we have reviewed implies that some parties hold this view.

Of course, the total effect of the siting of a new embedded generation is based on a number of complex interactions. There will be consequential impacts on the transmission charges faced by other generators in the zone (irrespective of whether there is a shared connection), and also demand charges would be affected. The developer will also almost certainly have a netting agreement with a local supplier, and will be receiving embedded benefits. However, the issue of cross subsidy in the context of this review is about causality of costs recovered through transmission charges only, and we do not believe the current charging methodology treats embedded generators appropriately in this regard.

There are several cross subsidies inherent in the current transmission charging arrangements that impact on embedded generators. Whilst this is to be expected in any

[41] The obvious example is for Solway Firth wind development to connect into the England and Wales distribution system rather than Scottish transmission. Similar issues arise in the NEDL distribution area, which is seeing significant developmental interest.

averaged charging structure, the extent of the cross subsidies is greatly aggravated by specific charging rules applied by NGC. The currently administered thresholds for charging to embedded generation do not exhibit any specific operational logic, and the costs charged do not reflect either the physical or commercial circumstances or impacts of the generator. The same can be said for those who are outside of the charging arrangements or who can "unbundle" themselves to be outside the current charging mechanism. This situation creates real incentives to bypass the transmission network and game the charging rules.

The implications of this assessment are that:

a. a charging mechanism is needed to more appropriately allocate costs to embedded generators who routinely export from a GSP at times of high system demand;

b. an alternative approach to the absolute thresholds regime is needed for the purposes of allocating charges to embedded generators; and

c. **the 132kV rebate should be removed from April 2008.**

- *Undue discrimination*

Whether there is any undue discrimination between the charging arrangements for different types of generation plant (e.g. embedded benefits).

Again this issue is critical given the importance of facilitating competition in generation in the applicable licence objectives.

In an idealized world, a uniform charging methodology would apply to all generation plant that used the networks irrespective of their location, and this would enable quantification of their area of influence given the power flows they create, and the costs of these impacts could be quantified accordingly. Current charging methods do not permit this because:

there is a clear segmentation between transmission and distribution for charging purposes;

there is a much less clear demarcation between the uses made of different voltages. This is most apparent at the 132kV level which is deemed to be transmission in Scotland but distribution in England and Wales, but where there is some haziness about actual usage;

essentially absolute thresholds are used in place of an area of influence methodology; and

transmission charges for generators off-grid are allocated in effect at the power station fence, not the grid access point.

Moreover the interaction of transmission charging arrangements for distribution-connected generation with other commercial arrangements with suppliers for embedded benefits creates a number of additional complications and competitive distortions.

The 132kV network in Scotland has generally speaking a different role from the 132kV network in England and Wales. Nonetheless the differences in treatment between distribution and transmission-connected generators are material. Generation connected at 132kV in Scotland is not eligible for embedded benefits, the value of which can be considerable, and we are surprised this matter does not seem to have been considered in any detail during the Betta development process, especially the interaction between embedded benefits and network charges more generally. This matter is likely to be increasingly significant going forward given the projected growth of Scottish renewable projects, many of which are set to connect at 132kV level and the consequent reinforcement of the higher voltage system, which may over time render large parts of the 132kV system in Scotland also to be a distribution network. A further consequence is that small generators connected at 132kV in Scotland face more complex trading arrangements than if they were connected at distribution level, though this can not of itself be attributed to the transmission charging structure.

All similar sized generators that have an impact on transmission costs should be exposed to similar levels of charges. However, transmission assets are defined exclusively by voltage levels and geography, and this leads to inconsistencies and distortions. Charges are levied by reference to size as a proxy for operational impact. The application of the current thresholds strike us as particularly arbitrary, and very game-able. It is clear that they are having a significant influence on commercial behaviour and classification of new generation developments. Either side of the thresholds they can create a significant cost or a significant benefit.

The England and Wales threshold has received some scrutiny as a result of the work on CAP002 and CAP067, and we share Ofgem's view expressed in the CAP002 decision letter[42] that 50MW in general has some operational significance in terms of grid impacts. We have seen no such similar evidence with regard to the 30MW and 5MW thresholds in Scotland, and think the 5MW threshold in particular is most questionable, especially given the high number of BEGAs that have been entered into.

There also remains some doubt about the robustness of the basis on which NGC determines eligibility as this does not specifically take account of generation output outside of highest demand periods, and as such would seem to create a degree of discrimination between the basis on which generators are assessed on and off grid for the purposes of transmission charging. There is also an issue about the different approach for positive and negative charging zones, though this is a feature of the current methodology as it applies to all generation and not just embedded generation.

With regard to undue discrimination between different types of generation plant, the basic parameter is one size fits all above and another size fits all below the designated thresholds. This situation does not address cost reflectivity and probably has detrimental competitive impacts. Looked at regionally the thresholds are also clearly discriminatory. As there is no logic between the distinctions drawn other than absolute size, it is hard to argue that this discrimination is "due".

The different commercial arrangements applying to the 132kV transmission system north and south of the border is also an issue, especially as over time reinforcement of the Scottish high voltage system is likely to lead to changes in its use.

"Large" and "small" generation

Whether the classification of small and large generation plant should be redefined.

Any classification of generation plant is likely to be problematic, and the current definitions of large, medium and small are arbitrary. We have listed under section 4.1 a series of examples where the current thresholds are anomalous and do not in our view appropriately reflect costs. These anomalies lead us to conclude that new definitions are required.

Similarly, while it is clear that different fuel and technological types of plant raise different operational issues for the GBSO, any robust charging methodology should be "technology blind". The voltage of connection also has the effect of creating different sub classes of generator, further obscuring hard and fast classifications. Overall we do not like definitions that relate to generation characteristics but prefer a series of definitions that are unambiguous from the GBSO's point of view, relate to operational characteristics and which can have national application.

We would suggest that in developing alternative allocation rules for embedded generation:

[42] www.nationalgrid.com/uk/indinfo/cusc/pdfs/CAP002_Amendment_Report_Version_1_0.pdf.

a distinction is made between the interaction of plant with other generation and demand within a DNO's area;

account is taken of the resulting export requirement onto the transmission system at times of high system demand;

intermittency characteristics should be factored in **should** any differentiation be introduced into wider transmission charging arrangements, such as scaling or non-firm rights; and

NGC's ability to operationally control plant should also be factored in.

It is not, as we have noted, always obvious when a distribution-connected generator is spilling onto the transmission system or who the causer is. Because of these issues it may be helpful to think in terms of physical size as a proxy but **at the GSP**. This is more than semantics, because if it is deemed necessary to develop formal transmission charging mechanisms for generators less than the current thresholds, then some ability to assess the degree of firm or predictable exporting capability **onto the grid** will be necessary if the mechanism/s is/ are to be genuinely cost-reflective and equitable.

Thresholds should not be applied arbitrarily. The onus should be on NGC to demonstrate why, in any particular situation, charges should be levied. In this context, the physical characteristics – and therefore the typical cost impacts of the plant - should be taken into account. These matters should provide the basis for a policy or guideline in this area.

We have also struggled to rationalize the differences between the current thresholds on a regional basis. Intuitively 100MW feels too high, which is why NGC is de facto administering a policy based on 50MW. In contrast 5MW in SHETL "feels" too low. It is not sensible for NGC to be involved in every 5MW generation scheme in North Scotland. NGC should be asked to provide analysis of, and justification for, the current thresholds.[43] Further consideration is needed but with a presumption that over time there should be a move towards harmonisation across GB.

Current definitions of small and large are arbitrary. Given the importance of establishing cost reflectivity in the licence objectives and some relationship of causer pays, it is necessary to take into account the costs a generator causes for the transmission system. Important criteria here are:

the impact a generator might have (relative to other generators) on a GSP export;

(possibly) predictability of production; and

the commercial relationships a generator has with suppliers.

None of these factors are allowed for in the current charging methodology.

Comment [L1]: These points should be bulleted

<u>Barriers to entry</u>

Whether the current charging arrangements create barriers to entry or create perverse incentives for generation to bypass the transmission system and connect to the distribution system.

We do not consider that the current charging arrangements create barriers to entry. The cross subsidies that occur are unlikely to deter new entry, though the treatment of embedded generation

[43] CAP093 may precipitate further consideration of this matter.

across codes and charging arrangements is undoubtedly complex. However, it is clear that the use of thresholds for charging of embedded generation creates some perverse incentives with regard to location and development sizing and definition..

Without significant further analysis based on GBSO and DNO tariffs, it is hard to substantiate arguments about incentives to bypass. Ofgem has recently said that they intend to review the interaction between transmission and distribution charging, and this is clearly necessary. Initial comparisons suggest that there are real and material commercial differences faced by a potential 132kV network connection in Scotland compared to a 132kV connection in England and Wales that flow from the application of existing industry rules, including network charging arrangements, and these greatly reinforce locational decisions in Scotland to site at distribution level.

In fact Ofgem has said:

> *"When comparing transmission charging to distribution, it is recognised that there are some significant differences between the arrangements which may cause different incentives. Although there are these different approaches between the two systems, as long as both transmission and distribution charges reflect the actual costs imposed by a party on each level of the system, then a balance should be achieved and the two charging regimes should interact harmoniously.*
>
> *The greater concern is that in some cases the transmission costs are not being reflected to parties, which in turn is causing potentially uneconomic behaviour. Generation connected to the distribution system will affect load flows and therefore long run costs on the transmission system. Under the current transmission charging rules, these generators may not be charged for these costs, potentially allowing uneconomic connections to proceed, or incentivising parties to connect at distribution level."*[44]

The interim nature of the 132kV rebate has introduced an element of uncertainty within the transmission charging arrangements. That said, the degree of risk is no greater than the possibility of other changes or fine-tuning likely to the charging methodology over the next three years, and we do not consider this to constitute a barrier to entry. We also strongly doubt whether the limited extent and availability of this incentive will eliminate incentives to bypass in Scotland.

The materiality of transmission charges, combined with the arbitrariness of qualifying criteria, mean that locational decisions can be skewed by the current transmission charging methodology, though we doubt this creates a barrier to entry in absolute terms. Current uncertainties such as the complexity of the access regime, the use of the contracted background and queuing issues will all be more significant in this regard.

<u>GSP interaction</u>

Whether there is an increasing number of embedded plant (or plant deemed to be less than 100 MW) that may be located close to a grid supply point (GSP) and may spill onto the transmission system but will not be exposed to transmission use of system charges

The probability of generation plant locating at distribution voltages is set to increase significantly simply because of the location and utilisation of existing networks and the volume of known

[44] "Structure of distribution charges – Consultation on longer term charging issues", Ofgem (May 2005), para 4.49-4.51.

applications for network access and use. Wider government initiatives under the Renewables Obligation and schemes for the promotion of distributed and micro-generation will also greatly increase the volumes of further applications. The asymmetry of current transmission charging arrangements and the perverse incentives that can be created by the charging thresholds will also significantly increase this possibility of biasing connection at distribution voltages. As we have illustrated, under current charging policies, size thresholds can exert a disproportionate effect on siting decisions. This will increase pressure on GSPs and some will switch to exporting at times of high demand (because of the commissioning of back-up plant, high wind or high rainfall). Recent information from one distributor illustrates the scale of the problem.[45]
.

The perverse incentives are presently so strong that it is very likely that a GSP could be created for no other purpose than to group together a number of sub-threshold power stations simply to avoid transmission use of system charges. In such a case, if requested by the embedded generator, the DNO would be in the position of having to offer terms and connection under its licence obligations. The efficiency and technical considerations for optimum development of the transmission and distribution systems in this instance would be completely overwhelmed by the perverse commercial incentives on the embedded generation developer.

Although the risk can be assessed in an individual case, developing an overall risk assessment is not, however, straight-forward. To do so would require detailed discussions with DNOs and trade associations connected with independent developers. However, the timing of the introduction of CAP093[46] is interesting, and the first GB Seven Year Statement provides high level indications of the exacerbation of power flows across certain parts of the transmission system.

There is an increasing number of embedded plants that may be located close to a grid supply point (GSP) or within a DNOs operational licensed area, and which may spill onto the transmission system but will not under the current transmission charging approach be exposed to transmission use of system charges.

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[45] A recent note to a CUSC working group provides the following information. Currently, there are 18 GSPs in NEDL and 20 in YEDL (the electricity distribution licensees of CE Electric UK. Of these, Blyth B and Saltholme (both NEDL) currently export regularly onto the transmission system.

A projection from public domain data suggests that, by 2020:

- there might be more than 1 GW of new renewable generation connected to each of the NEDL and YEDL systems;
- export from Blyth B might increase;
- Hartmoor, Stella South, Keadby and Saltend North might export regularly;
- six further sites might export from time to time; and
- the output of small and medium embedded power stations will readily be absorbed by demand within the GSP groups.

[46] CAP093 envisages changing to CUSC to recognise that GSPs can spill onto the transmission system.

Assessment

Any assessment must align with both NGC's applicable objectives and the Authority's statutory duties. This section summarises:

NGC's applicable objectives;

relevance of the Authority's legal duties and obligations;

the options for change; and

an assessment of those options against the objectives.

NGC Assessment criteria

Under the prevailing regulatory approach in GB, NGC must bring forward proposals to modify its charging methodologies that it considers will better facilitate achievement of the relevant objectives set out under the transmission licence. The relevant objectives of the use of system charging methodology, as contained in condition C7A.5 of the transmission licence, are:

that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs incurred by the licensee in its transmission business; and

that, so far as is consistent with the objectives above, the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in the licensee's transmission business.

In addition, the transmission licence sets out that NGC cannot discriminate between any persons or class or classes of persons in providing use of system or in carrying out works for the purpose of connection to the transmission system.[47]

The objectives can interact. For instance, the Authority has noted:

> *"the interaction between facilitating competition and cost-reflective charges. In the Authority's view cost-reflective charges derived from a transparent and robust charging model are important in facilitating competition. The Authority is also aware that charges which are not cost-reflective can distort competition significantly and work against the interests of consumers."*[48]

Authority duties

The Authority's principal objective and statutory duties, insofar as they relate to the electricity industry, are set out in sections 3A to 3C of the 1989 Act.

The general duties of the Secretary of State and the Authority in section 3A that seem relevant here are as follows[49]:

3A(1) sets out the Authority's principal objective and states: "The principal objective of the Secretary of State and the [Authority] in carrying out their respective functions under [Part 1 of the

[47] See condition C7C of NGC's transmission licence.
[48] Ofgem decision document, para 4.76, page 34.
[49] The section 3A(3) social duties have been omitted here as they are not considered relevant.

Electricity Act] is to protect the interests of consumers in relation to electricity conveyed by distribution systems [or transmission systems], wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors."

3A(2) states: "The Secretary of State and the Authority shall carry out those functions in the manner which he or it considers is best calculated to further the principal objective, having regard to:

> the need to secure that all reasonable demands for electricity are met; and
>
> the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under [Part1 of the 1989 Act], the Utilities Act 2000 or Part 2 or 3 of the Energy Act 2004."

Interpreting the objectives

The statutory duties and licence objectives are obviously important in determining the basis on which to contemplate any change to the current transmission charging arrangements. They do not specifically or necessarily help, however, in helping us determine what of itself constitutes an efficient transmission charging structure, and whether (and if so how) it might be applied to embedded generation. The following comments may help in this regard, as it may guide us towards a number of properties or characteristics that support the statutory and regulatory assessment criteria.

The objectives in designing a transmission pricing structure should be to broadly emulate the consequences of the *idealised* cost minimisation approach and to encourage efficient and optimal investment in, and maintenance of, the transmission system. This overriding design objective includes the development of appropriate price signals to generators and large end-use customers where it is economic to locate from a transmission system perspective. At the same time, transmission charging should not distort either operational or investment behaviour away from that of the integrated generation and transmission undertaking, whose objective is that overall production and transport costs should be minimised. Costs in this context include not only the capital and operational cost of the power plants and associated networks, but also congestion, ancillary services, losses, governance, regulatory and transaction costs.

With this primary objective in mind:

prices should equal 'marginal cost' where practicable or opportunity or scarcity value where appropriate. These principles can be relatively simple to apply for the variable short-run system operational costs, but can be difficult to apply to the network hardware costs where marginal cost based pricing will not recover all of the costs; and

users should bear the costs that their use imposes on the system **to the extent that** those costs can be identified.

Ultimately customers will pay for all costs that are allowable under industry regulation. However, it is important to structure the components of pricing and how risks are borne to provide the correct incentives to minimise costs in the medium to longer term. Consequently the primary focus of a transmission charging methodology in a competitive market should be to structure prices to promote efficient investment in both transmission expansion and generation and efficient operating decisions that maximise use of the network and minimise system operational costs. Any remaining costs should be recovered as far as practicable in a way that is either related to benefits or costs incurred for particular beneficiaries. Finally any residual charges should be recovered in a way that does not distort decision-making and appears equitable.

To these ends, pricing signals should:

indicate to generators and large loads where they should locate from a transmission system perspective;

indicate the need for investment in the network;

encourage short-run efficient operation of generators and management of large loads; and

provide incentives to the system operator and the transmission owner to minimise operational costs of ancillary services and congestion.

In addition the pricing structure should:

offer similar, if not the same, treatment of price and non-price conditions to users facing similar circumstances, i.e. the pricing structure should not be discriminatory; and

provide sufficient revenue to cover infrastructure costs, but the pricing system should recover appropriate costs in ways that least distort economically efficient behaviour.

Meeting these criteria will avoid incentives to:

develop uneconomic embedded generation schemes and avoid network by-pass;

promote competition in network services wherever practicable;

be reasonably stable;

facilitate economic inter-system trading where appropriate; and

be simple, transparent, understandable, inexpensive to administer, and auditable.

It is difficult, probably impossible, to meet all these criteria, some of which are in conflict with others, and whose significance will vary depending upon the characteristics of the network in a particular case. For example the weight of factors in an immature grid is likely to differ from a mature grid, and the weight of factors in a geographically dispersed grid is likely to differ from a dense and interconnected grid. Furthermore as gas and electricity increasingly "converge", it is important to ensure that the choice between "gas by pipe" or "gas by wire" is not distorted by flawed pricing of either electricity or gas transport, and in an ideal world the transmission pricing of both would be considered together.

Other considerations that may need to be taken into account are:

the differing nature of the transmission network in Scotland relative to England and Wales and associated cost structures;

the differing nature of the generation in Scotland and associated cost structures;

anticipated developments in both transmission and generation in Scotland and their likely effect on power flows; and

to the extent considered achievable, wider government objectives for sectoral development (e.g. renewables and other low carbon targets).

Options for change

This section addresses the specific changes identified by Ofgem and the additional potential mechanisms flagged in this paper.

- *Plant de-energisation*

Whether it is economic and efficient for NGC to de-energise plant that spills onto the transmission network (over and above its requested TEC).

In contrast to many customer installations, generation connection points are usually discrete and identifiable. However, while it is physically feasible to disconnect plant through the local DNO (indeed this can be done now for safety or reasons relating to system integrity)[50], there are obvious disadvantages with use of this route to effect commercial outcomes. These include:

ultimately it is a very heavy-handed response and is unlikely to be considered proportionate to the problem being addressed;

potential alternative commercial mechanisms are available or can be designed (over-run regimes, deeming arrangements, credit lodging etc, which we explore below);

it could undermine other licence objectives with regard to the security of the transmission system;

it would materially aggravate perceptions of regulatory risk; and

it could also deter competition.

Further difficulties arise in that it is not presently possible to attribute a particular spill from a GSP onto the transmission system to a particular embedded generator. Exceeding a TEC for a station embedded in the system does not necessarily mean a GSP would spill onto the transmission system. Further, where an unforeseen export might occur, the spill may be caused by an unexpected loss of load on the DNO's system, an unforeseen decrease in generation embedded further into the DNO network or an increase in demand within a neighbouring GSP Group. It would appear to be better to have a charging regime that provides sufficient incentives to ensure that embedded generators stay within their agreed limits (for instance, TEC or any alternative definition that might be identified) and any other capacities that may be agreed with the DNO.

We do not consider it feasible or efficient to de-energise plant that produces above connection capacity reflected in a BEGA. More fundamentally, there is no obvious reason why production above levels stipulated in contracts between embedded generators and NGC would necessarily translate into physical spills onto the transmission system.

- *Universal TEC*

Whether all generation plant should be required to buy TEC (or to declare zero TEC) and to face overrun charges (where identifiable), for using above requested TEC.

TEC is a term that in effect defines a generator's maximum allowed export capacity onto the transmission system. At the same time it provides the basis on which their TNUoS charges are calculated. Under the CUSC, parties with TEC rights have the option of purchasing the same or less quantity of TEC in the following year. Since the implementation of CAP068, if a generator is seeking additional TEC within year or a new generator is seeking an initial allocation of TEC, this may be done by completing an application and sending it to NGC irrespective of its location on the network. The TEC concept was initially developed for transmission-connected generation and generally works well at this level in its current form, but the roll-out of GB transmission

[50] For example, "The electricity safety, quality and continuity regulations 2002" confer powers of disconnection on distributors in certain circumstances

arrangements, and specifically the introduction of the BEGA, has evolved with powers now available to NGC to develop the appropriate commercial terms for generators it deems require such an arrangement, and it has extrapolated the concept of TEC for these purposes.

NGC has a licence obligation to offer terms to all parties seeking access to its transmission system and presently, if a generator is in excess of the thresholds defined in CUSC, it is deemed to require such access and must execute the relevant agreements. If NGC considers that the additional generator capacity crystallized as a TEC value would require network reinforcement for its system to continue to comply with its security standards, then NGC would typically provide a connection offer on an invest-then-connect basis and insist on execution of a bilateral construction agreement. Once connected, any production above TEC levels would be a breach of CUSC. One obvious point is that the current ability to impose a TEC applies only to generators who have BEGAs, and in Scotland only, to those with BELLAs. It is relevant that we think there may be some generators already sitting on the distribution system who do not have BEGAs and who have not as yet been brought within the current transmission charging regime.[51]

It might be practical to fully administer the extension of such a regime **in theory** through the GB CUSC to all generators above de minimis levels, though it is evident that the current TEC and supporting contractual regime would require significant development. For instance:

Comment [L2]: Starting?

practically a contractual mechanism would be required, probably administered through the DNO's connection terms, to require all embedded generators to enter into appropriate arrangements with NGC;

this might be accompanied by an extension of the concepts in CUSC 6.5.1 to much lower threshold levels and to incorporate a requirement to enter into a contract with NGC; and

there is no current commercial mechanism for dealing with over-run above TEC; a mechanism would have to be developed to levy overrun charges, though we think this is required anyway.

In our view it is clear that this route is not attractive for a number of reasons:

the approach would be administratively complex, and unnecessarily increase compliance requirements and costs for all small generators;

some de minimis limits would still need to be defined;

a TEC implies use of the transmission system which does not apply to many medium and most small (as currently defined) power stations whose output is usually readily absorbed by demand within GSP groups; and

we do not think it equitable to deem TECs and associated charges to apply to connection capacity or at the generation meter on the distribution system because this would not reflect the impact of the embedded generator on the transmission system.

The practical issues are complex. Take the case of a generator directly-connected to the transmission system: the generator will simply apply for a TEC corresponding to the maximum output required. But take an embedded generator connected to the distribution system, at the voltage immediately below the transmission system and at a substation with no other connected generators or demand customers. This is slightly less simple than the case of the transmission-connected generator, but nevertheless reasonably predictable and under the control of three parties – NGC, the DNO and the embedded generator. Now take this same case but add some other demand and generation electrically at or near to the embedded generator connection. The effect of the embedded generator on the transmission system can be theoretically predicted, but in practice the effect will depend on what happens to the other demand and generation. Moreover, NGC, the DNO and the embedded generator will have no control over what happens. If an overrun

[51] Conversely we suspect there are parties subject to BEGAs who should not be.

of TEC occurs, how can it be identified and is it right to charge an embedded generator for something that may be outside their control?

For these reasons, we believe an alternative approach to the TEC is needed anyway, but administered in a manner that would not apply to all embedded generation. This would centre on a physical measurement that takes into account the circumstances on the DNO's system and the interactive effect of other generation and demand on that DNO system, much of which does not presently see transmission charges:

for such arrangements to be cost-reflective there would need to be allocation arrangements at GSPs containing more than one embedded generator, and possibly for GSP groups more generally; and

a key issue for any allocation process would be how to apportion quantities between generation above and below thresholds for charging purposes. Bearing in mind our comments that current thresholds are arbitrary, we have strong reservations as to whether these arrangements could be equitable, based on the current thresholds regime.

One possibility might be to charge a proportion of TEC (or some alternative measure) according to the size of the embedded generator, compared with all the demand and generation electrically at the same part of the distribution system. This proportion could be periodically reviewed. Bilateral contracts to increase or reduce generation at specific times might be a further development. These contracts could be between embedded generator and DNO or embedded generator and NGC, or both. This method would pass on maximum TEC charges where an embedded generator has maximum effect on the transmission system. Definition of such an arrangement would be a much better proxy for the cost impact of the generator on the operating costs of the transmission system, though obviously issues of deferred expenditure by NGC and DNO should, arguably, still be taken into account. This issue is developed further in section 5

The current charging arrangement with regard to qualifying embedded generation based on TEC is in our judgment flawed. A regime based on universal TEC and overrun charges could be developed, but it would require significant reworking and development of current arrangements to remove deficiencies. Whether this would be an appropriate development is doubtful, as it would increase contractual complexity and create unnecessary compliance costs for many small developers and operators, DNOs and NGC.

For any regime to be more appropriately cost reflective and equitable, there should be adjustment to the concept of TEC as applied to distribution-connected generation, and a reworking of the concept of spill onto the transmission system and how it should be accounted for.

- *Review of BEGAs and BELLAs*

Whether it is appropriate to review BEGAs and BELLAs under the CUSC, so that embedded plant, identified as able likely to spill [onto the transmission system], will need to sign a BEGA.

There was consultation on development of BEGAs and BELLAs during the BETTA development process. Nonetheless, timing considerations were to the fore, and development occurred before actual offers were made to connection applicants. It is noteworthy that a number of embedded generators and their representatives believe there to be real inconsistencies and limitations in the present form of the agreements, but that is to be expected given the creation of new compliance requirements in relatively short timescales.

Where there is a strong possibility that an embedded generator may have an effect on the transmission system, then it is reasonable to expect the generator to comply with basic standards -

perhaps provision of mandatory balancing services such as frequency response and reactive support – and operational directives from the GBSO. It also has a right to be subject to a stable contractual framework that administers terms and charging arrangements for use of system equitably. This, in effect, is what the BEGA tries to achieve. Given the number of parties now signed up and early experience of operation of the BEGA, we think it timely to review how these agreements are operating. As a minimum we consider that some fuller guidance is needed to explain the basis on which current powers are being applied by NGC, and on the appropriateness of requiring parties to enter into contracts on a case by case basis.

From the embedded generators perspective, the attractiveness of a BEGA is that it confirms a right to firm access on the transmission system. It is already clear that it is appropriate to hold a BEGA for generators that are CMRS registered, as they have a direct relationship with NGC via the Balancing Mechanism. However, it is not obvious why a generator should be forced to accede to the BSC etc just because NGC thinks a BEGA is appropriate. The strongest argument at present that such an arrangement is appropriate on an enduring basis might be in the continuing absence of a proper framework for NGC, DNOs and embedded generators in which to work. However, looking forward, in the new world of active networks we are probably approaching, it seems more appropriate to us for DNOs to contract with embedded generators and for there to be a robust interaction at the distribution/ transmission boundary.[52]

The rationale for a BELLA is harder to establish, and we have some significant reservations as to how the current requirements are administered. The generator gains no real benefit from a BELLA; there is no firm transmission access involved. The concept of the agreement is also discriminatory in that it has been developed for application specifically to Scotland. The threshold issue also remains debatable in this context, especially with regard to Scotland, and it is not obvious why NGC should dictate when or if a 5MW station in Scotland should be allowed to connect. The current mechanism also arguably introduces discrimination with demand since NGC does not prevent 5MW demands in Scotland from disconnecting nor does it require them to take full demand over the triads.

We are also confused by references to a LEGA, which seems to be applied by NGC on an opportunistic basis where licence exemption is sought.

Based on the limited review of the agreements we have carried out, it would seem better for NGC to move towards a position where it has a meaningful relationship with the DNO and for that to be backed off with an (industry standard) DNO/ generator agreement. This agreement could, among other things, provide for the physical impact of a new development, including any spillage onto the transmission system. Again we develop these thoughts further in the next section.

The rationale for BEGAs and BELLAs is not presently well understood outside of NGC, and some of the powers contained in them seem in some instances at least to be heavy handed. That said, there is a clear need for a BEGA in the absence of a use of system agreement for application to embedded generators that do use the transmission system. However, the thresholds that determine the need for these agreements do not have a clear logic. The current transmission charging mechanism they enforce is applied arbitrary to qualifying embedded generation.

In the time available we have not carried out a thorough critique of the contractual terms within the standard contracts and how these have been applied, and suggest such an exercise is carried out soon.

- *DNO agency*

Can a distribution network operator act as an agent, which buys TEC for distribution connected plant which spills onto the transmission system

[52] Conceptually there is no difference with the NGC/SP relationship pre BETTA where SP took responsibility for the power flows across the boundary circuits.

Despite consideration within industry forums considering distributed generation, there is no agency role currently provided for in industry trading or access arrangements (save for the energy consolidator). However, one possibility is that the DNO could deal with the transmission issues on behalf of NGC in its distribution area, acting as a "one stop shop", in an agency capacity. DNOs have best incentive to manage flows through its GSP group, as well as the best and most up to date information. It would be able to add particular value when there are several small generators in the same part of the network, when diversity techniques can be applied. Further, large connections may anyway involve an iterative discussion process between the embedded generator, NGC and the DNO. This process is necessary to identify specific issues, their related costs and associated charges and methods to reduce costs and charges to a minimum. However, it is the DNO, and not NGC, that is best placed to judge how the embedded generator's profile would fit in with the local demand and therefore the effect on the relevant transmission system connection.

The boundaries of such an arrangement could go well beyond interaction with the GBSO. The DNO could offer a package – TNUoS, GDUoS, plus ancillary services. It might also be a useful vehicle for developing concepts of deferred expenditure by the network operators. This mechanism would be applicable to the main problem area identified where the large embedded generator or generators are not party to the BSC. Again this would also be sensible if the DNO can act as aggregator/consolidator for a large number of small generators, and the costs and benefits of similar local developments could be allocated through such arrangements. This route may also require unbundling some services currently carried out by the supplier.

Ultimately the DNO might establish a TEC value for a GSP, a group of related GSPs or for the GSP group as a whole reflecting the net position of embedded generation in its distribution area. At this stage it is not necessary to define all the elements of a possible agency arrangement, beyond the application to access to the transmission system. Key elements of this more limited arrangement might be:

define a role of a GSP group agent;

establish a bilateral GSP or GSP group agreement between NGC and DNO to deal with exporting points or zones;

GSP group agent acquires explicit export rights for each GSP group, then allocates implicit rights (measured in MW) to each generator unless they buy their own explicit rights. Rights and obligations could be based on explicit rights or a proportionate share of GSP group rights;

the agreement could establish a GSP group import TEC (ITEC, from NGC's perspective or ETEC, export TEC, from the DNO's) or be isolated to ETEC values for significant exporting nodes;

transmission charges would be payable against the ETEC, calculated in the same way as other generator TNUoS charges in the relevant zone;

overrun charges would be defined and payable by the DNO for exceeding these values;

establish an agency agreement between the DNO and qualifying embedded generators above a defined threshold; and

the agreement would set out a mechanism to allocate generator TNUoS and any overrun charges amongst causal generators assessed by comparison of their profile to the local demand (or perhaps pro-rated to their registered firm capabilities).

Further work is required to determine among other things compensation rate for access failure, basis of determining overrun charges, and linkage with price control/TNUoS.

It would be possible to build flexibility by providing for the DNO to agree with NGC as GBSO how individual GSPs connected into the transmission system and what TEC (if any) each GSP is allocated based on the DNOs views of power flows. Managing the TEC at individual GSPs might facilitate the DNO to more effectively manage constrained networks, thereby ensuring that capacity is best utilized. Proceeding in this way might help mitigate some of the rigidities in the EELPS system. In such an arrangement it is likely that the BEGAs and BELLAs – or many elements of them – would be rendered superfluous save where an embedded generator wished to specifically reserve transmission capacity or participate directly in balancing activities. Such an arrangement need not be mandatory. It is conceivable that the role could be discharged over time by a GSP agent who was not the DNO.

We develop thoughts on this approach in the next section.

The development of embedded generation will reinforce the need for active network management, and there are evident attractions from the local DNO taking a more proactive role in determining access arrangements into and out of its operational area. Not all DNOs will want to or need to carry out this role at least over the foreseeable future, and it may be possible to delink the GSP group agent role from that of the DNO. In the current context of transmission charging, the GSP group agent might acquire explicit export rights for each GSP group or combinations of GSPs, then would allocate implicit rights (measured in MW) to each generator unless they elected to buy their own explicit rights.

- *Differential products*

Whether NGC could introduce a range of prices (and products) for use of system, dependent on plant type and (intermittent, firm) usage to better reflect the costs of system usage.

There are a variety of ways in which network charge methodologies have been developed in liberalised markets. Each approach is explainable within the context of the network and trading structures that have developed in each market, and some structures have set out to be dynamic than others. There has also been some limited consideration of incorporating a commodity based or usage based charge within the current transmission charging methodology under development of UoSCM-M-11, but only from the perspective of moving from a capacity based charge to one which reflected system usage outside of peak periods.[53]

The concept of TEC and existing TNUoS charging methodology are structured on identification of a specific capacity-based measure (MW for generators). With the introduction of CAP048 the capacity is firm[54] in the sense that physical unavailability owing to problems on the transmission system will result in rebating of pro-rated TNUoS charges. The concept of non-firm or interruptible capacity has been developed in some markets (e.g. PJM), but it does not exist in the GB electricity market as yet.[55] The merits of commodity-based charging are not immediately apparent for generation as cost recovery for this class of grid user is usually structured to cover the costs that their maximum likely output at times of high system usage. However, there may be some attractions of considering alternative approaches from the perspective of intermittent generators that pay TNUoS, enabling differential treatment (where justified) with despatchable or firm generation. This is a matter being considered by NGC in response to the Ofgem March 2005 conditions, and two questionnaires have already been circulated to market participants to capture industry views on some of the key issues.

[53] A consultation document for modification proposal UoSCM-M-11 was issued on 12 September 2003. The document set out for consultation National Grid's proposal to modify the Use of System Charging methodology to introduce a non-locational flat year round tariff to recover 10% of the annual Transmission Network Use of System (TNUoS) revenue across daytime hours, specifically daily between 0700hrs and 1900hrs. NGC elected after assessment not to pursue this proposal. See report at: www.nationalgrid.com/uk/indinfo/charging/pdfs/UoSCMM11_Industry_Report.pdf.

[54] The concept of financially firm rights does not exist in the GB market.

[55] Arguably the development of within year charges such as short term TEC could be construed as a shift to more volumetric charging.

Our initial thoughts on this matter are very limited at this stage. There could be attractions from development of a differential charging regime. These should not be developed for different types of plant (not on fuel type) but rather on operating regime (i.e. despatchable vs. intermittent). Despatchable plant can be expected to run at peak since energy prices should be highest, whereas intermittent plant will not have the same choices and will run as and when it can. It might be possible to allow more MW of intermittent plant at a lower cost (per MW) to accommodate this. This would allow for higher usage of the networks at off peak times at a cost of occasional constraint requirements. Use of a MWh component of network charges might also encourage off peak generation and avoid perceptions of favourable treatment towards low load factor plant.

A hybrid approach might be to recover the cost of the transmission network from intermittent generators in two parts:

a portion, say 50%, recovered through a cost-reflective use based network pricing allocation (probably MWh) which allocates costs on the basis of network use;

the remaining portion recovered through a fixed capacity (MW, probably TEC-based) or postage stamp allocation.

Whatever the basis adopted for structuring charges, the problems we have identified with regard to TEC would also be apparent with regard to MWh generated component. Where would the MWh be metered and how would the proportion flowing into the transmission system be determined? In this context the need to transpose the denominator for charging purposes from the generator meter or its connection capacity to the relevant GSP or GSPs would still arise.

In developing its own thinking, we would expect NGC to show how its proposals for dealing with intermittency impacted on embedded generation and how it would propose to tackle some of the deficiencies we have identified.

Different generation technologies impose different costs on the transmission system, and a further differentiator is where the plant is located on the overall system. We are attracted to an approach that reflects these different impacts and which takes into account the actual contribution an embedded installation is typically likely to make to spillage onto the transmission system given the cost reflectivity objective. However, a MWh based approach would undermine the relationship between NGC's costs drivers and their sensitivity to generation on its own system and on the local networks.

We consider that the allocation mechanism for rolling through transmission charges where appropriate should take into account not only the actual costs caused by individual generators, which in the case of intermittent technologies may reflect some diversity benefit, and the concept of non-firm charges clearly needs to be addressed further for a combination of reasons.

- *132kV network reclassification*

Reclassification of 132kV system in Scotland as distribution

An important constraint on the BETTA designers was that the scope of the reform should not include significant reform to the distribution sector. One possibility would be that the 132kV system could be reclassified as distribution in Scotland. This might be achieved by re-designating the Scottish 132kV assets as distribution assets by an appropriate amendment to the definition of 'high voltage lines' within section 64 of the 1989 Act.

This is not a new issue. In response to proposals in this regard during the development phase, Ofgem/DTI made various statements that such an appropriate would be "inappropriate both at a fundamental level, and in the context of the policy objectives of BETTA".[56] The reasons for Ofgem/DTI's views were:

the distinction drawn in the licensing regime between transmission and distribution is not arbitrary. It reflects the physical purpose of different sets of wires. The **primary** purpose of the 132kV network in Scotland is the bulk transfer of electricity;

while it could be argued that under certain circumstances some 132kV wires in England and Wales facilitate the bulk transfer of electricity (i.e. perform the function of transmission), and that conversely some 132kV wires in Scotland perform the function of local distribution, Ofgem/DTI were of the view that a (principally) voltage-based definition of transmission continued to be robust when considered in aggregate, although this assessment might change over time, as a consequence of growth in embedded generation;

the objective of BETTA is to deliver open and non-discriminatory access to a GB transmission system as a means of promoting wholesale competition. A reclassification of 132kV in Scotland would, by reducing the scope of the transmission system, reduce the benefits of BETTA for a significant proportion of current and, importantly, future generators and 132kV connected demand customers;

a reclassification of the 132kV network in Scotland as distribution would change the pattern of cost recovery. Distribution costs are recovered from local users, while transmission costs under BETTA are recovered from GB transmission users. Significant investment in the 132kV network in Scotland to accommodate new generation in Scotland would, if 132kV were reclassified as distribution in Scotland, be paid for by distribution users in Scotland.

It is hard to disagree with these broad arguments, though at the local level there are blurrings in which assets are used for transmission and which are used for distribution as some GSPs in England and Wales already export onto the transmission system. This haziness is set to increase with the sustained upgrade of the network in Scotland. One obvious such trigger point is the commissioning of the Beauly-Denny upgrade, which should have far-reaching impacts on the lower voltage system in Scotland.

We reject the classification of the 132kV network in Scotland as distribution, though there may come a time when the current treatment needs to be revisited and reviewed. In this context any significant changes to transmission charges should take into account the possibility of such usage change at a future point.

[56] "Small generator issues under BETTA", Ofgem (November 2003), page 49.

- *Separate sub-transmission tariff*

Establishment of a separate sub transmission tariff.

The argument for embedded generation to bear charges for spilling onto the transmission system flows primarily from arguments about the area of influence or usage of a network user (that is, it does not sit behind the supplier at all times). It could follow that a discrete tariff could be structured for generators using the 132kV system either in its own right or to step up or down voltage levels.

If this direction were considered suitable, the starting point might be to extrapolate the NGC ICRP transport model so that it could calculate prices on the 132kV distribution network in England and Wales, and then follow on with the 33kV network in Scotland. The ICRP transport model is applied to all transmission voltages in GB including 132kV in Scotland, and we see no obvious reason why in principle at least it could not also be applied to parts of the the DNO networks[57], much of which in terms of value are also at 132kV in England and Wales. If the ICRP model were utilized in this way, and utilized across all DNOs 132kV systems, it would be possible to charge connections above specified limits to all voltages more consistently. Furthermore, within the model it might even be possible to classify and cost all 132kV assets as a separate class of assets, effectively creating a separate sub transmission tariff, if this were considered desirable.

This option brings into focus the obvious merit in having a single party evolving a single charging methodology for this class of assets, and avoiding the obvious inefficiencies of 14 DNOs applying different models and methodologies in a context where they may, in effect, be competing for the location of new generation. Such a new approach could generally enhance cost reflectivity of EHV charges; it would also be consistent with the stated desire of Ofgem to introduce consistency and convergence across transmission and distribution network charges. Furthermore, if use of system charges are cost reflective and calculated by reference to the same methodology as costs on the 132kV system in Scotland, it may be possible to define a shallower connection boundary. In turn this development could facilitate competition in a number of ways, not least by removing the current differences between DNOs. Charging diversity also adds complexity for the industry, especially developers, and therefore may not be consistent with the desirable objectives of transparency, simplicity and predictability in charging arrangements. In fact, presumably because of these factors, in Ofgem's structure of electricity distribution charges consultation on the longer-term charging framework - May 2005, views were invited on whether an ICRP-type model could be adopted for DNO use.[58]

There are contrary views. It is unlikely that aligning 132kV charging structures in a way that embeds the current transmission charging methodology will be seen as incremental change, and it could be considered a disproportionate response to the immediate problems raised by embedded generation. It could be construed as extending locational pricing into the distribution networks which at a glance appears less stable year on year that currently applied methodologies. This could fuel perceptions of regulatory risk. There could also be value impacts for existing connectees and applicants, so some form of grandfathering of existing agreements or phasing could be necessary to deal with this and the regulatory risk issue. It would also emphasise the differences between 132kV in England and Wales and the rest of the local distribution networks. Depending on decisions on the EHV network, this approach could perpetuate current perceived problems but simply transfer them onto the 33kV level.

A further issue is how consistent or convergent arrangements could be administered by 15 companies (14 DNOs plus the GBSO). As has been demonstrated with the establishment of the GBSO to deal with transmission charging, it is possible to decouple charging from asset ownership. Setting aside the concept, however, a number of practical issues would need careful

[57] These parts of the network account for 100 out of 7.8 million customers on the EDF Energy network, and about 10% of all consumption.
[58] Available at: www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges.

consideration – including management of prudential requirements for billing and credit, as well as billing.

There is merit in harmonizing commercial network arrangements applying to 132kV generators, and the logical way to do this may be to extend application of NGC's DCLF model to the DNO EHV system with a view to creating a coherent "132kV tariff" at some future point. It is for consideration how the 33kV system should be treated in Scotland under this scenario. However, this is a very big step that many DNOs are likely to resist. It could also result in significant value shifts for existing 132kV connected parties.

Irrespective of whether this direction is considered further, governance of charging arrangements should be brought together within a single framework based on common principles to ensure optimal consistency across such arrangements.

- *Voltage-based tariffs*

Implement standard charging classes by voltage.

Another route could be that industry codes should be revised such that treatment of generators was harmonised in respect of voltage of connection, irrespective of whether the connection was to a distribution system or the transmission system. For instance the definition of transmission could be retained, but that adjustments would need to be made to industry codes to ensure that parties of the same size connected at the same voltage operated under the same commercial conditions, irrespective of whether the connection voltage is defined as transmission or distribution at the point of connection.

The TISC report[59] noted that:

> *"It is contrary to the principles of open competition that generators connected to the electricity network at 132kV in one part of the country and supplying only their local network should have to incur costs which are not borne by competitors of similar size doing the same thing in another part of the country. Whether by regulation or amendment of the industry codes to exempt small generators from the burden of transmission charges, or by other means, an equality of treatment must be established among generators connected at 132kV"*

An alternative approach might be to define a homogenous class of charges that applied across the 132kV network, and in practical terms takes us back to some of the issues discussed at section 5.4.7 above. Again this approach would entail major reform. Over the short term, it would be based on a false premise that the 132kV networks in England and Wales on the one hand and Scotland on the other had a common functionality and the associated costs were similar (if not uniform), which is not the case at present.

An alternative approach would be to assess a more broadly based area of influence methodology such as those applied in Australia, but this too would entail a total overhaul of the current transmission charging methodology, and we have not therefore considered this further.

Achieving such a series of changes and creating charges by voltage levels is a far from trivial matter, and would involve a major upheaval in network charging. It should not be contemplated to provide an enduring solution to the isolated problem of embedded generation charging. We have no reason anyway to believe that such an approach might be superior to the current locational ICRP methodology.

[59] Tisc report of pre-legislative scrutiny of the Electricity (Trading and Transmission) Bill.

- *Retain 132kV rebate*

Preserve the current discount beyond March 2008.

The three year interim rebate for 132kV generators could be retained. The mechanism could be made enduring by simply varying the duration provision in NGC's transmission licence.

Our initial reaction is that:

the approach lacks a rigorous enduring economic basis; and

it may be judged as discriminatory to other transmission-connected generation.

At a lower level, the approach raises a number of complexities, which also need to be taken into account:

it is not a fixed rebate and will be of uncertain value;

it is proposed to apply the arrangement for three years which will provide only limited relief;

because it is entrenched through the transmission licence, it could be regarded as restricting changes to other elements of the methodology; and

it distorts to a small degree the energy market (e.g. competition by Scottish hydro for fast response through the Balancing Mechanism).

We conclude there is no reason to retain the rebate, and believe it should be replaced by a more enduing and robust mechanism from April 2008.

The interim 132kV rebate mechanism should not be retained subject to development of an alternative commercial mechanism that can replace it on an enduring basis from April 2008.

- *Eliminate TNUoS residual charge*

The generation residual charge could be removed.

The current 132kV rebate is administered against the residual charge element of the TNUoS charge to generators. As we have seen in section 3, grid users in GB pay both a locational element which is intended to recover a party's marginal cost impact on the system and a residual element to enable NGC to meet its revenue requirement in a given year.

There is an argument that, as the residual charge is recovered on a MWh basis, it could be construed as offsetting the locational signal administered through the kW zonal charge and reducing the impact of the locational signal within the charging structure as a whole. This argument is reinforced by the observation that the total level of the charge to generators has been set to enable recover of a pre-specified amount of revenue from generators, and does not of itself have a strong economic basis.

Against this background, one possibility for eliminating the differential between 132kV generators and other grid connected generators from 2008. Such a measure would necessitate either:

a scaling up of locational charges to make good the revenue currently recovered from generators under the residual charge; and

the recovery of the displaced costs from demand, in which case it would shift the current 73/27 split of TNUoS.

It would:

sharpen locational signals by removing the dampening effect of the residual charge;

be non-discriminatory in that it would impact all generators embedded or otherwise in the same way;

be seen as providing further relief to 132kV generators from the point of removal;

but relatively speaking worsen the position and costs of 132kV transmission connected generators relative to other transmission connected generators by removing a specifically targeted benefit.

The removal of the residual charge would represent a much more fundamental intervention in the current transmission charging methodology but would have the associated benefit of rendering the current discount unnecessary. It would, however, restore the relative perceived difference in the positions of 132kV transmission-connected generators to other transmission-connected generators which Ofgem/DTI sought to tackle when the rebate was implemented.

- *Transport model changes*

Adjustments could be made to the transport model to compensate for the loss of value from the discount.

There are a number of mechanisms available within the current transport model that might provide the necessary flexibility to establish a more level playing field for transmission-connected generation. These include:

adjustment to the application of under-utilised lines;

development of a locational substation tariff;

adoption of a lower (if justified) security factor taking into account 132kV assets;

use of a more sophisticated security factor (zonal, nodal) GB wide;

adoption of Scottish multi-volts expansion constants;

use of separate generation/demand scaling factors for Scotland and England and Wales;

incorporation of identified circuit upgrades (e.g. 132kV to 257kV reduction factors); and

use of a merit order-based approach to matching generation to demand.

These factors should be assessed in isolation, but they could also be grouped. DCLF based TNUoS should also be flexed to incorporate some combination of 132kV expansion constants, new Scottish zones (and possibly based on different criteria), zero cost under-utilised lines and new factors reflecting potential line upgrades and different security levels. The merits of a separate geographically-differentiated (or at least Scotland-specific) substation charge should also be reviewed. There is considerable latitude available to NGC additional to that already identified in its own scenario modeling, and it should be possible to use these factors (and other variables if need be) to derive Scottish TNUoS charges deemed as more acceptable by Ofgem and wider stakeholder groups without compromising key design objectives.

Each of these mechanisms if applied can provide flexibility in changing the locational differentials derived from the DCLF model, and it is important the materiality available under each is identified and the logic for their use more fully developed. Our own initial analysis suggests that the three first-listed mechanisms could provide a relatively low effort means of moderating some of the differentials and lowering Scottish charges overall and might be justifiable based on wider cost considerations and against the applicable licence objectives.

Quantitative analysis would be needed to identify which of the mechanisms available to tweak locational differentials is most intellectually robust and justifiable under the applicable licence objectives. To the extent that these cannot be fully justified on economic efficiency grounds, thought could then be given to phasing or capping differentials but this should be a last resort. Generally speaking, phasing, capping and administered rebates are not desirable and could damage the cost reflectivity of transmission charging for all grid users and will create significant subsidy issues. The only benefit of phasing and other transitional approaches is as a short-term palliative, but such measures simply defer the immediacy of the longer-term issues, which need to be addressed now.

The issue of changes to the model should be seen as a valid alternative to changes to more structural changes to the transmission charging structure. The issues are not, however, mutually exclusive, and in some instances may be complementary. An example is that introduction of a differential expansion constant or a locational substation charge might prove to be one means of ensuring no detriment to 132kV transmission-connected generators in Scotland on removal of the interim rebate.

- *Do nothing*

Retain the current arrangements.

A final and obvious possibility would be to retain the current transmission charging arrangements and definitions. A variant, already considered above, would be to make the interim 132kV rebate enduring.

We do not consider this an option because of the significant deficiencies highlighted in section 4.

Possible model

This section sets out some initial thoughts on how current arrangements can be enhanced. It also makes some suggestions as to a how a more enduring solution might be defined drawing to a greater extent on the concept of an active DNO.

Short term enhancements

Over the short term NGC should be invited to focus on establishing a more equitable and appropriate methodology for charging embedded generation on a causer pays basis, and which would be administered as at present bilaterally between NGC and the embedded generator.

In considering its options NGC should be invited to consider an approach that entails:

each embedded station above a defined size, say 10MW, would have an operating threshold related to its distribution connection capacity; it would be this measure that would be relevant for determining whether a contract (and possibly what type) was applicable – though not necessarily required - with NGC;

the form of the contract, and the circumstances in which it would be applied, as now would be governed by an industry guideline developed under CUSC;

the contract should be a generic one that applies to all qualifying embedded generators, even if certain parts could be switched on or off, and should replace BEGAs, BELLAs and LEGAs, and we call it an Embedded Generation Access Agreement or **EGAA;**

the EGAA could be developed in such a way that existing contracts could be deemed to be consistent with its terms; it could cover items such as construction, connection, use of system, mandatory and ancillary services;

the operating thresholds methodology should distinguish between;

generators who produce for the purpose of exporting onto the system and auto-producers, such as CHP plant, which produce at least in part for their own use (or have offsetting demand within the trading unit);
whether the connecting GSP might potentially export to the transmission system;
expected production at times of high system electrical loading;
possibly intermittency;

the methodology would be used to derive a value for expected transmission system impact, which we call transmission export assessments or **TExAs**;

NGC, with the local DNO, would determine an export value for each GSP (or possibly groups of GSPs); we call this term **ETEC** – embedded transmission entry capacity;

TNUoS charges would be allocated to each GSP with an ETEC, on the same basis as transmission connected generation in the corresponding zone;

there are at least two possible options for allocating TNUoS charges to embedded generation:

pro-rate it based on TExAs of qualifying generators with operating thresholds at the qualifying GSP;
conduct a load flow analysis with the local DNO and NGC, to develop an area of influence methodology;

in all instances to deal with import levels above ETEC, an **overrun charge** could be developed; and the overrun charge should be calculated based on each incremental MW above the ETEC applied as part of a more general over-run regime that should be developed to accommodate TEC, and be applied to eligible embedded generation on the same basis as TEC.

Longer-term direction

Over the medium term, we favour development of an enduring route to the treatment of embedded generators that in exporting GSPs or GSP groups draws much more heavily on the concept of the DNO agency. Ultimately the DNO might establish an ETEC value for a GSP, a group of related GSPs, or for a GSP group, reflecting the net position of embedded generation in a particular electrical area, derived from calculation of appropriate TExAs.

Key elements of this longer-term arrangement might be:

embedded generators who want firm access would continue to contract with NGC through a EGAA acquiring ETEC at a defined GSP or GSPs;

additionally, define the role of a DNO or GSP group agent; and establish a bilateral GSP or GSP group agreement between NGC and DNO to deal with exporting GSPs or zones;

this agreement might cover items such as use of system or transmission access and mandatory and ancillary services;

the GSP group agent acquires ETECs for each transporting GSP group, and holds the associated access rights and liabilities. It would then allocate implicit rights (measured in MW) to each generator with a positive TExAs, unless they have elected to buy their own explicit rights:

transmission charges would be payable by the DNO against the ETEC as above, on a par with TEC and calculated in the same way as other generator TNUoS charges in the relevant zone;

overrun charges would be payable by the DNO for exceeding these values as above;

an agency agreement would need to be developed between the DNO and qualifying embedded generators;

the agreement would set out a mechanism to allocate generator TNUoS and any overrun charges amongst causal generators assessed by comparison of their profile to the local demand (or perhaps pro-rated to their registered firm capabilities).

The merit of the agency arrangement over the bilateral arrangement is that it would provide a more stable basis on which to evolve active DNO management of embedded generation, which more correctly in this context should be termed the DSO. This is not a value judgment by us on the merits of active network management per se, but recognition that a wider industry development is moving in this direction, and NGC's charging development should not be inconsistent with it. Furthermore:

the agency agreement would provide the basis for allocating charges paid by the DSO, including any adjustments for active network management agreed with NGC; and

we should also like to see development of some mechanism that recognises the **deferred investment impacts** of embedded generation on both transmission and distribution networks if benefits as well as costs are to be more accurately captured. This objective could be achieved through the agency structure. In the case of transmission, this might take the form of a rebate against TNUoS charges that might flow through the DNO to the embedded generator taking into account at the same time the impacts on the distribution system.

In terms of timing, it would seem sensible to seek to aim to:

implement the shorter-term changes from April 2006;

scope wider changes in parallel; and

work towards more enduring change from April 2008 when the interim rebate falls away.

Rebate mechanism

Current incentives on their own do not necessarily reflect avoided network investment. Additionally, therefore:

we should also like to see development of some mechanism that recognises the deferred investment benefits of embedded generation on both transmission and distribution networks; and

in the case of transmission, this might take the form of a rebate against TNUoS charges that might (directly or indirectly) flow through to the embedded generator.

This avoided network cost could feed through to an embedded generator in the following ways:

rebate to embedded generators in the form of a payment per kWh of energy exported to the network during peak hours. It could be based on the full avoided cost of demand-related distribution or alternatively a percentage of this cost. Ideally, the rebates should vary by location, although the avoided costs by sub-region might be difficult to estimate; and

end-of-year rebate: based on actual peak usage. This rebate could be based on rebates should vary by loc could, for instance, be based on how often an embedded generation customer produced its full maximum output system peak (that is, or during the triad).

The design of an appropriate rebate for embedded generation should consider a number of factors, including:

the production of an embedded generator must be consistent or reliable in order for it to help defer or avoid network investment; and

this production should be at times of peak demand on the affected facilities. If sites with embedded generators are exporting say 80% of the time while importing at times of peak, there are no savings in network investment vis-à-vis a demand customer.

The problem of unpredictability of embedded generation exporting at peak times could be eased by making the rebates on a time-differentiated per-kWh basis.

Again it would seem sensible to aim to introduce any such incentives for transmission from April 2008, though interactions with the current generation of distribution price controls would need careful definition.