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# Enduring transmission arrangements for distributed generation

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**Overview:**

In September 2005 Ofgem issued a document titled 'Enduring transmission charging arrangements for distributed generation'. This document summarises responses to that document and sets out our further thoughts on whether the existing charging and contractual arrangements for distributed generation are appropriate on an enduring basis and, if not, how those arrangements could be amended. It also sets out our views regarding how to take this issue forward.

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**Target Audience:** Distribution and transmission connected generators and any other interested parties

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## Context

Ofgem's principal responsibility is to protect the interests of consumers, wherever appropriate through the promotion of effective competition. In the context of network charging, Ofgem considers that consumer interests are best served by developing cost reflective charging arrangements, i.e. ensuring that parties, both distribution and transmission connected, face the costs they impose on the system. Cost-reflective charges contribute to efficient use of the network, the efficient trade-off of costs and benefits when deciding on connection sites and thus the lowest cost solution for all parties who pay transmission charges. Consumers ultimately benefit from cost effective decision making in the amount they pay in utility bills.

Recent developments in the regulatory arrangements and incentives to connect, particularly renewable technologies, to transmission and distribution networks, has meant that the traditional pattern of network usage has altered and is likely to continue to do so. In the light of this and other issues highlighted in the September 2005 Ofgem document titled 'Enduring transmission charging arrangements for distributed generation', Ofgem considers that it may be appropriate to continue to examine the transmission charging arrangements relating to distributed generation to ensure that they are facilitating economic and efficient decision making and promoting effective competition. Ofgem further acknowledges that issues of operational control, planning and access are also relevant when considering enduring arrangements which reflect the impact of distributed generation on the transmission network.

## Associated Documents

- Enduring transmission charging arrangements for distributed generation: A discussion document - Ofgem, September 2005 #211/05

www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/12472_211_05.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributedgeneration

- NGC's proposed GB electricity transmission use of system charging methodology: The Authority's decisions - Ofgem, March 2005

www.ofgem.gov.uk/temp/cache/cmsattach/13512_1206.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/betta/betta02

- Electricity distribution use of system charging: Bath University benefits analysis report on the long term charging framework

www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13513_1206a.pdf

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# Summary

## Enduring transmission arrangements for distributed generation

### Background

In September 2005 we issued a document titled 'Enduring transmission charging arrangements for distributed generation' ("the September discussion document"). The document set out a number of issues relating to the existing charging and contractual arrangements for distributed generation[1] (also known as embedded or dispersed generation) that had been highlighted by various parties to Ofgem. It also outlined a number of models which could potentially address some or all of these issues and invited views.

### Purpose of this document

Our views with regard to the development of enduring charging arrangements for distributed generation have been informed by responses to the September discussion document and opinions expressed at the two industry workshops held on 19 and 24 January 2006 in Glasgow and London respectively. We would like to thank respondents and workshop participants for their considered, informative and helpful views.

Having considered the range of views expressed, this paper sets out our further thinking about the appropriateness of the existing charging and contractual arrangements for distributed generation on an enduring basis. It also discusses the role we intend to take in the further development and consideration of the issues raised in the two documents.

### Way forward

The next stage in this process is to develop specific options for change. This process should appropriately be driven by industry parties. Having said that we think there is an ongoing role for Ofgem to facilitate and co-ordinate. We therefore propose to establish and chair a working group to develop specific options for change, or 'straw-men' for the form of enduring transmission arrangements for distributed generation. This is discussed in more detail in Chapter 6.

[1] Distributed generation is a generator directly connected to a distribution system or the system of another user. See Appendix 4 for a glossary of this and other terms used in this document.

# 1. Rationale

**Chapter Summary**

This chapter sets out details on the background to this document and the legal framework against which this document is developed. It also sets out a summary of the chapter structure of the document.

## Context

1.1. Following on from the September discussion document, this document further considers whether the existing charging and contractual arrangements for distributed generators are appropriate on an enduring basis, when considered in the light of recent developments in both the nature of connections to the electricity transmission and distribution networks and in the regulatory framework in Great Britain ("GB").

1.2. In this context, key developments include: the implementation of British Electricity Trading and Transmission Arrangements ("BETTA") in April 2005, which has included the introduction of single GB-wide transmission charging arrangements developed by National Grid Electricity Transmission plc ("NGET") in its role as GB system operator ; and the Government's Renewables Obligation ("RO") which has provided strong incentives to develop new renewable generation projects, creating a step change in the demand for connections to both the transmission and distribution networks.

1.3. These developments have meant that the traditional pattern of network usage has altered. One of the principal changes has been the increase in the volume of distributed generation connected to the network. It is likely that, if this trend continues as is currently anticipated[2], distribution networks will increasingly export power on to the transmission system at certain times rather than consistently taking power from it and this may impact on transmission investment. An enduring transmission charging framework, taking full account of the costs arising as a consequence of the connection and actions of distributed generation, needs to be robust to this changing physical background.

1.4. We recognise that distributed generators can in many situations meet local demand thereby reducing system peak. However, we also appreciate that such generators may, in certain circumstances, make use of the transmission network without being liable for transmission charges, and yet their impact on network flows may lead to additional transmission investment the costs of which will ultimately be paid by consumers. It is essential that distributed generators see the full costs of the use they make of both the distribution and transmission systems so that efficient decisions can be taken regarding the development and use of the network. This will ensure equitable treatment of all generators and the protection of consumers' interests.

[2] Data and analysis on the anticipated changes in the pattern of generation and demand connecting to each network are presented in Appendix 2.

1.5. In approving NGET's proposed GB transmission charging arrangements in March 2005 the Gas and Electricity Markets Authority ("the Authority") recognised that there would be merit in NGET further reviewing the appropriateness of its current charging arrangements to accommodate the increasing demand from distributed generation. As a first stage in this process we announced our intention to undertake a consultation setting out the key issues and a discussion of possible options.

## Legal framework

1.6. The legal framework against which this document is developed was set out in detail in Chapter 1 of our discussion document on enduring transmission charging arrangements for distributed generators in September 2005[3]. Further detail on Ofgem's statutory responsibilities is set out in Appendix 3 to this document.

## Structure of this document

1.7. The remainder of this document is structured as follows.

- Chapter 2 explains the background to the current document.
- Chapter 3 sets out an update on related areas of work which are relevant to the review of arrangements for distributed generators.
- Chapter 4 revisits the issues which we identified in the September discussion document and sets out our further thoughts.
- Chapter 5 outlines the options that were set out in the September discussion document, explains how our thinking has developed in light of respondents' views and expands on a number of other possible options.
- Chapter 6 sets out our views on the appropriate way forward.

[3] Enduring transmission charging arrangements for distributed generation – a discussion document – September 2005, Ofgem #211/05

## 2. Background

**Chapter Summary**

This chapter sets out a summary of the background to this review of the enduring transmission arrangements for distributed generation. It also outlines respondents' views regarding the justification for the review and sets out our further thoughts in light of these comments.

### Issue

2.1. In developing its GB transmission charging arrangements NGET noted that there had been, and there was expected to continue to be, a significant increase in the demand for connections at distribution voltages, primarily from renewable generators, and that this was impacting on the transmission system. NGET argued that the existing charging methodologies and wider contractual frameworks were not sufficiently robust to address the implications of this change.

2.2. Given the timescales associated with the introduction of BETTA, NGET noted that it did not intend to address these concerns within the initial GB methodologies. However, NGET confirmed its intention to undertake further work post-BETTA to consider the wider implications of distributed generation.

2.3. As a first stage in this process and to give focus to the debate, we published the September discussion document. The document outlined a number of key issues posed by the existing charging and contractual arrangements and highlighted a range of potential options for addressing these issues.

2.4. The purpose of the September discussion document was not to draw firm conclusions or prescribe a specific way forward but to facilitate debate and encourage parties to consider the extent to which changes to existing arrangements could be expected to result in benefits to competition. We noted our intention to publish a further document in early 2006 summarising responses and outlining thoughts on a way forward.

### Respondents' views

2.5. In total we received nineteen responses to the September discussion document. Thirteen respondents explicitly supported the review. Two respondents were not convinced of the need for any changes to the existing arrangements. Two further respondents did not consider that the arrangements needed wholesale changes to overcome the perceived problems. The final two respondents noted that the review should focus on wider issues than charging including: transmission access; system planning; and operational control were all central to debate on the impact of distributed generation on the transmission system.

2.6. A more detailed summary of responses is set out in Appendix 1 of this document.

## Ofgem's views

2.7. We note that a majority of respondents supported the need to review the arrangements relating to distributed generation. We recognise the view that the projected increase in distributed generation may have implications for transmission investment and consider that these require more detailed consideration.

2.8. We note that there are differing views as to the extent to which the existing arrangements require reform. However, we also note the view of several respondents that the issues highlighted may be localised and small in size. A wide range of respondents argued that the extent to which volumes of distributed generation are likely to increase, and the size of current and future inefficiencies, should be quantified. We recognise that this is a critical issue in considering the appropriate solution to the issues highlighted in the September discussion document. Consequently, following the industry seminars we wrote to NGET and all distribution network operators ("DNOs") requesting initial, high level, estimates of the likely changes in the pattern of generation and demand connecting to their networks over the next five years. This information is presented in Appendix 2 and discussed further in Chapters 4 and 5.

2.9. Finally, we agree that the title of September discussion document did not fully reflect the full range of issues which are relevant in considering enduring arrangements which reflect the impact of distributed generation on the transmission network. We acknowledge that issues of operational control, planning and access, as well as charging, are all relevant. These issues are discussed in further detail in Chapter 4.

# 3. Update on interrelated work areas

**Chapter Summary**

The September discussion document provided a detailed overview of key ongoing and interrelated work areas which were relevant in considering the arrangements for distributed generation. This chapter provides an update on developments in these areas in the period since that document was published.

## BETTA and transmission charging

3.1. The Authority attached five conditions to its approval of NGET's GB use of system charging methodology in March 2005[4]. These related to future actions by NGET which the Authority considered might reasonably be expected to further the attainment of the relevant objectives of that methodology. NGET has continued to make progress against these conditions. In particular it has met both condition 1, relating to negative demand charges[5], and condition 5, which related to the publication of forecasts of the future path of tariffs[6].

3.2. Three conditions remain outstanding with NGET tasked with bringing forward, where appropriate, proposed modifications for implementation by April 2007. These relate to reviewing and consulting on: estimating the incremental cost of capacity (condition 2); alternative methods of treating intermittent generation (condition 3); and enabling users to contract for rights to use the transmission system with Transmission Network Use of System ("TNUoS") charges fixed for periods of more than one year (condition 4). We note that progress has been made against these conditions in the form of industry workshops and questionnaires. Further, NGET has recently issued a report providing an update on progress against condition 2[7], and intends to similarly report on the other conditions shortly.

## Distribution charging

3.3. In January 2005 we published an open letter consultation on a report by Bath University which was commissioned to evaluate the benefits (at Extra High Voltage level) of potential amendments to the DNO charging regime[8]. Bath University's study concludes that there may be significant benefits associated with moving to a forward looking economic charging model. Our open letter notes that this study appears to support our view that demand and generation regimes should be aligned, with distribution use of system charges established via charging models based on forward

[4] NGET's proposed GB electricity transmission use of system charging methodology: The Authority's decisions – Ofgem, March 2005 #80/05.
[5] NGET brought forward a modification proposal, GB ECM-02, in order to address this condition. Ofgem's decision letter is available at:
www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/12841_241_05.pdf
[6] Details of progress against NGET's conditions can be found via the NGET website at:
www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/
[7] The report is available at: http://www.nationalgrid.com/NR/rdonlyres/DA355E39-9E52-4676-B777-85BE425EE67C/7014/Condition2progressreportApril2006.pdf
[8] www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13512_1206.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributioncharges/edc2

looking long run incremental costs. We noted in our open letter that we expect the DNOs to consider the report in their ongoing work.

3.4. The DNOs are working collectively on the development of revised electricity distribution charging arrangements through the Electricity Networks Association. They are holding a series of public workshops on this issue during 2006 which are being followed by consultation papers which are designed to canvass and clarify stakeholder opinion on the future electricity distribution charging frameworks.

## Grid Code modification proposals

3.5. The September discussion document identified three Grid Code reviews that had implications for the treatment of distributed generation. In each case, this review work has led to NGET proposing changes to the Grid Code. NGET has also consulted on a proposal to make changes to the Grid Code Balancing Codes which are associated with Embedded Exemptable Large Power Stations ("EELPS").

### D/05 ("Grid Code Changes Associated with Licence Exempt Embedded Medium Power Stations")

3.6. The joint Grid Code Review Panel ("GCRP")/ Distribution Code Review Panel ("DCRP") working group recommended changes to the Grid and Distribution Codes to implement a framework whereby Grid Code technical requirements in relation to Licence Exempt Medium Power Stations ("LEEMPS"), would be passed to the generator through the distribution licensee. NGET consulted on the Grid Code changes (D/05) and DCRP consulted on Distribution Code changes in August 2005.

3.7. NGET submitted a report to the Authority proposing changes to the Grid Code on 3 February 2006. The chair of the DCRP (on behalf of DNOs) submitted a report to the Authority proposing changes to the Distribution Code on 3 Feb 2006. Both of these complementary change proposals were approved by the Authority on 10 March 2006 and implemented on 1 April 2006.

### G/05 ("Time Extension for the Requirements of Grid Code General Conditions GC.15")

3.8. General Condition 15 of the Grid Code allows relaxation of the requirement to apply the Grid Code in relation to EELPS and Embedded Exemptable Medium Power Stations in Scotland for a time limited period. NGET submitted a report to the Authority proposing a change to the Grid Code to extend the defined time limit until 31 March 2007. This change proposal was approved by the Authority on 15 September 2005[9] and implemented on 30 September 2005.

[9] The decision letter is available at: www.nationalgrid.com/NR/redonlyres/1F5CB2FA-80A8-4320-8DD9-1C08473763CF/63CF/2104/014aGrid CodeB05DecisionD.pdf

**B/06 ("Regional Difference Working Group")**

3.9. A GCRP working group has been established to review the Grid Code definitions of Small, Medium and Large Power Station ("the Regional Differences Working Group"). The Regional Differences Working Group has completed its review work and has submitted a report for consideration at the GCRP meeting in February 2006. The Regional Differences Working Group recommends changes to the definitions of Small, Medium and Large Power Stations. Specifically, the threshold for Large Power Stations in Scottish Hydro Electric Transmission Limited's ("SHETL") area would be increased from 5MW to 10MW, and the upper limit for Small Power Stations in SP Transmission Limited's ("SPT") area would be increased from 5MW to 30MW. The effect of these changes would be that the definition of Medium Power Stations would only apply in NGET's area, with generators in Scotland being either Large or Small. NGET issued a consultation (B/06) on 25 April 2006 proposing changes to the Grid Code[10].

**I/05 ("Grid Code Changes associated with Embedded Exemptable Large Power Stations")**

3.10. NGET issued a consultation (I/05) in December 2005 proposing changes to the Grid Code which it considers rectify an unforeseen interaction between the generic provision modifications and changes introduced as part of BETTA relating to EELPS. NGET submitted a report to the Authority relating to these proposed changes on 26 April 2006[11]. This change proposal was approved by the Authority on 16 May 2006[12] with an implementation date of 30 May 2006.

## CUSC modification proposals

3.11. The September discussion document identified three proposed amendments to the Connection and Use of System Code ("CUSC") which had implications for the treatment of distributed generation. The relevant proposals were CUSC Amendment Proposals CAP093, CAP094 and CAP097.

**CAP093**

3.12. CAP093 aimed to recognise the flow of electricity from distribution systems into the transmission system at GSPs by altering the CUSC definitions of GSP and Distribution System.

3.13. The final Amendment Report for CAP093 was submitted to the Authority on 5 December 2005. On 19 January 2006 we published our decision to reject CAP093 and two proposed Alternative Amendments on the grounds that these would not

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[10] The consultation is available at: www.nationalgrid.com/NR/rdonlyres/B2C54D4C-4A60-4499-9BB4-424EC79A3569/6949/CP_B_06_Regional_Differences.pdf

[11] The report is available at: www.nationalgrid.com/NR/rdonlyres/AE38E561-BF12-49FA-8286-67338C45D8D2/6992/ReporttotheAuthorityI06.pdf

[12] The decision letter is available at: http://www.nationalgrid.com/NR/rdonlyres/071D384B-4221-4AFB-A447-090A00CA6C64/7177/010GridCodeI05DecisionMay2006issued.pdf.

better facilitate the achievement of the Applicable CUSC Objectives[13]. In the CAP093 decision letter, we set out a view that it was unclear that the CUSC prevented NGET from making an offer of terms to a distribution licensee for a connection site which may export power onto the transmission system.

**CAP094**

3.14. CAP094 aimed to introduce a new access product to enable transmission users to purchase Transmission Entry Capacity ("TEC") for a limited period.

3.15. A consultation report on CAP094 was circulated on 4 October 2005 with a second period of consultation following on 14 November. The draft Amendment Report was circulated on 5 December and the final Amendment Report submitted to the Authority on 13 December. The Authority published its decision to approve Working Group Alternative Amendment 5 on 23 February[14].

**CAP097**

3.16. CAP097 is intended to revise and clarify the processes to be followed by NGET and DNOs regarding the energisation of distributed power stations recognising that not all distributed generators will enter into a bilateral agreement with NGET.

3.17. The Working Group presented their Final Report to the Panel on 28 October 2005. The Panel determined that CAP097 should proceed to wider industry consultation which commenced on 10 November. A consultation on Alternative Amendments was circulated on 23 December. The Final Amendment Report was submitted to the Authority for consideration on 15 March.

3.18. The System Operator - Transmission Owner Code ("STC") Committee has identified the need for consequential changes to the STC should CAP097 be approved. Three modification proposals (CA016, CA017 and CA019) have been raised and have been developed by an STC working group. A public consultation on these change proposals commenced on 4 April 2006. The Final Amendment Report for these three STC modification proposals was submitted to the Authority for consideration on 27 April 2006[15].

## Access to the GB Transmission System

3.19. As noted in the September discussion document, in parts of the transmission network, predominantly Scotland and northern England, the demand for transmission capacity exceeds the existing capability of the network, such that parties wishing to connect in these areas may be unable to connect until contingent reinforcement works are carried out. The unprecedented number of applications for connection to or use of the transmission system submitted before BETTA (known as

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[13] The decision letter is available at: www.nationalgrid.com/NR/rdonlyres/98F53699-753B-451A-9B12-4A0D806D7E35/5678/CAP093D.pdf

[14] The decision letter is available at: www.nationalgrid.com/NR/rdonlyres/07E0E714-D30D-46C5-AB19-1D7BACF42ED3/6212/CAP094D.pdf

[15] The amendment report is available at: www.nationalgrid.com/uk/Electricity/Codes/sotocode/

the "GB queue") has meant that in many cases potential connectees are receiving offers for connection where the connection date is well into the future.

3.20. As part of the ongoing transmission price control review process, we have questioned whether the existing mechanisms for allocating transmission capacity operate in the best interests of consumers, in the context of facilitating market entry and generating sufficient information to allow licensees to make efficient decisions concerning network investment.

3.21. This process has been led through the Access Reform Options Development Group ("ARODG"). This group, chaired by Ofgem, was charged with considering options for amending the existing transmission access arrangements in a more holistic manner. The group identified a range of potential options for amending the existing arrangements and a number of illustrative options. The findings of the group are contained in the ARODG group report which was published in April 2006. The report, along with all of the group's discussions, is available from our website[16].

## BSC modification proposals

3.22. In addition to the updates set out above, one new work area which has arisen since the publication of the September discussion document is in relation to zonal transmission losses.

3.23. On 16 December 2005 RWE Npower raised a proposed modification to the BSC, P198[17], which seeks to allocate the costs of ‘variable’ transmission system losses to parties on a zonal basis, according to the extent to which each party gives rise to them. P198 is based closely on a previous modification proposal, P82[18].

3.24. In addition, on 21 April 2006 Teesside Power Limited raised a further proposed modification to the BSC, P200[19]. The proposed methodology for the treatment of variable transmission losses is consistent with P198, however in addition P200 proposes the introduction of a transitional scheme to be applied to a fixed volume of energy for specific generating plant which allows for the retention of a non-zonal share of transmission losses over a period of 15 years. P200 is in turn based closely on a previous modification proposal, P109[20].

3.25. P198 and P200 are following the standard process for BSC modification proposals. Assessment of both proposals will be taken forward by Elexon before final reports are submitted to the Authority for a decision as to whether or not the proposals better facilitate the achievement of the applicable BSC objectives and are in accordance with the Authority’s broader statutory duties.

[16] Material relating to the ARODG is available on Ofgem's website at: http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr
[17] www.elexon.co.uk/documents/modifications/198/P198.pdf
[18] www.elexon.co.uk/documents/modifications/98/P98.pdf
[19] www.elexon.co.uk/documents/modifications/200/P200.pdf
[20] www.elexon.co.uk/documents/modifications/109/P109.pdf

## The Electricity Networks Strategy Group (ENSG)

3.26. We are working closely with the DTI and stakeholders through the ENSG to address a wide range of transmission and distribution network issues. We will encourage all parties involved in this work to engage in the work to develop enduring transmission arrangements for distributed generation.

# 4. Issues to be addressed

**Chapter Summary**

Chapter 4 of the September discussion document set out the issues which we considered required addressing in developing enduring arrangements for distributed generators. This chapter refines our views on these issues in light of respondents' views. A detailed summary of these views is set out in Appendix 1.

## Ofgem's views

### Scope of the review & issues to be addressed

4.1. We note that respondents have identified a significant number of additional issues that need to be addressed in developing enduring arrangements which appropriately reflect the impact of distributed generators on the transmission system. This is not surprising given that the September discussion document acknowledged that there are a wide range of interrelated areas of work that impact upon the decisions parties make in connecting to and using transmission and distribution networks.

4.2. However, while it is important not to lose sight of the full range of issues which impact on distributed generators, and where appropriate reflect these in developing revised arrangements, we consider that it is also imperative that this review focuses on its principal objective of assessing the enduring applicability of arrangements relating to distributed generation and if appropriate considering amendments to these arrangements.

4.3. Nevertheless, we agree with respondents that the scope of the review should not focus narrowly on charging issues. Indeed, we agree that the title of the September discussion document was, arguably, too narrow in scope. It is clear that the issues involved in considering arrangements relating to distributed generation are wider than purely charging related issues. Operational control, system planning and transmission access are, as highlighted by respondents, all areas which require consideration in the assessment and design of enduring arrangements. It will be important to consider the extent to which any model for amending charging or contractual arrangements is able to address these issues. This is discussed further in Chapter 5.

### Exporting GSPs without access rights

4.4. We note that, while the majority of respondents recognise that there are issues associated with exporting GSPs, there are a range of views regarding the significance of these issues and the extent and manner in which they should be addressed. However, we should not lose sight of the fact that distributed generation can affect flows on the transmission system irrespective of whether an individual GSP exports at peak. For example, an increase in distributed generation in southern Scotland might be expected to result in higher net flows across the transmission system in northern England regardless of whether any individual GSP in southern Scotland exports.

4.5. We agree with respondents that, if power is exported onto the transmission network and no charges are levied for this export, the cost-reflectivity of charges is likely to be adversely affected. While we note that the issue is made more significant by the different definitions of transmission in Scotland and England & Wales, we do not accept that the issues would disappear if 132kV was classified consistently across GB as a distribution voltage. Indeed we note that there are currently a number of GSPs within England & Wales which, at times, transport power from a distribution system onto the transmission system.

4.6. The issue of whether significant changes are required to address these issues is by no means straightforward. We recognise the wide ranging views of respondents with regard to the extent to which GSPs currently export and are likely to do so in future and the extent to which this is a problem. On this basis we wrote to NGET and the DNOs requesting initial, high level, information of the likely future change in the pattern of generation and demand connecting to the networks. This information is published in Appendix 2. This should build on the analysis previously developed as part of the Working Group on CAP093 and will enable parties to put in context the projected growth in distributed generation and consequently the magnitude of the perceived problem and therefore better assess how to take this issue forward.

**Cost-reflectivity**

4.7. We continue to consider that cost-reflective charges play an important part in protecting customer interests. The principle of cost reflective charging is both a legal requirement under European law and a licence requirement. Cost-reflective charges can be expected to promote efficient use of the network and thus the lowest cost solution for all parties who pay transmission charges. Consequently, we do not subscribe to the view that cost-reflective locational charging arrangements are inconsistent with either sustainable development or renewable generation. Efficient arrangements are likely to benefit system users in general. Key questions concerning the cost-reflectivity of charging arrangements are discussed further in Chapter 5.

**Perverse incentives**

4.8. The issues set out by respondents have strongly reinforced our view that the existing charging and contractual arrangements contain a number of potential perverse incentives. In particular respondents have largely focussed on size differentials, both in the Grid Code and in relation to the licence exemption criteria.

4.9. We also note that respondents raised the issue of the classification of 132kV circuits as transmission in Scotland and distribution in England & Wales. We have consistently stated that the treatment of 132kV circuits in England & Wales and Scotland reflects the different functionality of these circuits in each area. 132kV circuits in Scotland remain predominantly for the bulk transfer of electricity across long distances, while in England & Wales they predominantly perform a distribution role. We have previously set out that were this position to change then reclassification of 132kV circuits would be considered, although we note that this would require primary legislation.

### Interactions with access issues

4.10. As noted earlier in the chapter we recognise that the issues that require addressing as part of this project are likely to be wider than those related purely to charging. In our opinion, there could be significant merit in considering the extent to which the output of distributed generation is correlated with system peak and, if appropriate, developing proposals for alternative access products which reflect the correlation of distributed generation's output with transmission cost drivers. We note the ability of industry participants to raise modifications to industry codes should they consider changes likely to better facilitate achievement of the relevant objectives of those codes. However, we have also had regard to respondents' views on the appropriate way forward for this project and, particularly, the significance that respondents place on our continuing involvement in this process. On that basis we propose to establish and chair a working group to be tasked with developing specific options for change. This is discussed in Chapter 6.

4.11. We also note the view of respondents that one of the key issues to be addressed relates to the system operator's ability to control flows over the transmission network. We consider that, if this need is accepted, there is a case for developing contractual interfaces to manage such flows. An access product which allowed for the output of a distributed generator to be reduced in the event that its output caused a problem or exacerbated a constraint on the transmission network, and incurred a commensurate charging liability, could be envisaged. We consider that there may be merit in further developing these options. We also note the view of respondents that the liability for transmission charging should be related to the firmness of access provided.

4.12. It will be important to consider any proposals for amending the existing arrangements in the context of the issues around access to the GB transmission system highlighted in Chapter 3, including their implications for the GB queue. Were an increased number of parties required to procure entry capacity, it is likely that the demand for capacity would further increase and that a method of allocating this capacity would need to be considered. In addition, the impact of any amendments to the existing mechanisms for allocating capacity proposed following the work of the ARODG will need to be fully considered.

### Implementation costs

4.13. We strongly support the view that any revision to the existing arrangements should be justified in cost terms and equally that it should avoid unnecessarily increasing the complexity or reducing the transparency of the existing arrangements. However, we do not consider it appropriate to conduct an impact assessment at this stage given the absence at this stage of a manageable number of clearly defined options.

4.14. Section 5A of the Utilities Act 2000 requires Ofgem to undertake an impact assessment where the Authority is proposing to do anything for the purposes of, or in connection with, the carrying out of its functions under Part 1 of the Electricity Act which is considered to be “important”. At this stage Ofgem is not carrying out one of its functions but rather is seeking to facilitate debate and set in course a process for determining the arrangements for reflecting the impact of distributed generation which ultimately should be industry driven.

4.15. Instead we consider it to be the responsibility of the industry to consider the implementation costs of different proposals though the process of developing options. As set out in Chapter 6, this is a task that we consider may appropriately be taken forward through a working group. Establishing the costs involved in revising the existing arrangements will depend on the nature of the options proposed and this in turn will be informed by a thorough assessment of the issues to be addressed.

# 5. Options for an enduring framework for distributed generation

**Chapter Summary**

In the September discussion document we set out a range of options for revising the existing contractual and charging arrangements applying to distributed generation. At one extreme the document invited views on approaches involving minimal or no change to existing arrangements. At the other extreme it discussed more complex models involving wholesale changes to existing arrangements. The various options set out in the September discussion document, and respondents' views on these options, are described in more detail in Appendix 1.

Having considered the views of respondents and opinions offered at the two industry seminars, this chapter refines our views on the models presented in the September discussion document and outlines alternative models suggested by industry parties. For the avoidance of doubt the options are numbered in a manner consistent with the September discussion document.

## No change: Option 1 - Do Nothing

5.1. We note the views of respondents to the September discussion document and attendees at seminars in Glasgow and London that the case for change has not been sufficiently well proven. We additionally note the desire of parties to quantify the magnitude of the issues to be addressed, and the extent to which the materiality of these can be expected to increase over time, before considering the development of proportionate solutions to these issues.

5.2. As noted in the September discussion document, and reaffirmed in this document, we remain of the view that the probable benefits of any solution must outweigh the costs associated with implementing any changes. As a result we considered it appropriate to further consider the materiality of the increase in distributed generation and wrote to the DNOs and NGET requesting projections of demand and generation growth over the next five years. This data is contained in Appendix 2.

5.3. Nevertheless, generally we agree with the view of the majority of respondents that the do nothing option does not seem appropriate. We concur with the view that, if left unaddressed, the increasing volumes of distributed generation connections could impose costs on the transmission network which these parties would not fully face. We further consider that this is likely to diminish the cost-reflectivity of charges over time and lead to inefficient decision making, the costs of which will ultimately be borne by the consumer.

## Minimal change: Option 2 - De-energise plant that spills & Option 3 - Amendments to the charging model

5.4. We note that there was very limited support for any of the minimal change options set out in the September discussion document. Respondents broadly considered that none of the options could adequately address the issues raised in that document.

5.5. We agree that, in isolation, none of these options would address the issues set out in the September discussion document and refined above.

## Medium change: Option 4 - Extend the DCLF ICRP model to parts of the distribution network

5.6. We note the views of respondents that this option may be both costly to implement and may result in more complex charging arrangements.

5.7. As noted in Section 3.3 above, in December 2005 Bath University produced a report for Ofgem evaluating the benefits of potential amendments to the electricity distribution charging methodologies in order to introduce economic signals. A number of different approaches were considered including Incremental Cost Related Pricing ("ICRP") models.

5.8. The Bath report concluded that while the ICRP approach might have some attractions on the grounds of consistency with transmission, under certain circumstances it could provide perverse signals for the location of generation and load and may also lead to unstable charges when applied to distribution voltages. Their study suggested that a Long Run Incremental Cost ("LRIC") approach would have the most merit on the distribution system in reflecting both the cost of the assets required to transport power to a node and the utilisation of those assets.

## Medium change: Option 5 - Amend use of size definitions as the basis for charging and contractual arrangements

5.9. We agree with respondents that, in isolation, this option would not serve to solve any of the issues highlighted in the discussion document on an enduring basis and concur that identical issues may be expected to arise around any threshold. We additionally note that, as discussed in Chapter 3, a GCRP working group has recently reviewed the Grid Code definitions of Small, Medium and Large Power Stations and as a result of its recommendations NGET has proposed changes to the Grid Code to amend the size thresholds in Scotland.

## Medium change: Option 6 - Creating a consistent liability for charges

5.10. We note that there was some limited support for this option with respondents expressing a number of reservations. We consider that this option, possibly in tandem with a number of supporting contractual changes, may be able to address a number of the issues highlighted in the discussion document. We also note that a number of respondents considered that this option may be similar to an agency option.

5.11. The September discussion document outlined a model whereby the two elements of TNUoS charges were separated. The locational element of the charge is equal and opposite for demand and generation at every node. It is only the setting of charging zones and adjusting of tariffs to ensure revenue recovery and the correct split between generation and demand which alters the symmetry of charges. The second element, which recovers almost three quarters of allowed revenue, is a non-locational residual charge. This covers, amongst other things, the costs of substations and non-distance related assets.

5.12. If purely the locational element of charges is considered, at any given node, the demand tariff is the negative of the generation tariff. This reflects the modelling assumption that the cost imposed by an incremental MW of generation (demand) has the same effect as a decremental MW of demand (generation). Given that distributed generators are paid the negative demand tariff, were only the locational element of charges being levied then the charge faced by all generators at any given node, regardless of their voltage of connection, would be identical.

5.13. If this were the case, a route may need to be developed for charging distributed generators. Such a role could be performed by any aggregation agent, such as a supplier or DNO, or through a direct contract between NGET and a distributed generator. It could be argued that such a model would be very similar to a purely charging focused agency agreement and may require fewer amendments to the existing arrangements in order for it to be implemented.

5.14. However, a necessary question to address under this approach would relate to how the residual, non-locational element, of TNUoS charges was levied, and parties may wish to consider whether the current arrangements for apportioning these costs lead to any arbitrary difference in the charge faced by a distributed and directly connected generator at the same location, and whether this leads to discrimination in favour of, or against, one class of generator.

5.15. Should parties consider that it is appropriate for all generators, irrespective of connection voltage, to pay the residual charge then this option may naturally complement a model with a supplier acting in an aggregator role. One potential method of achieving this could involve the charging methodology being amended such that, in addition to being subject to locationally varying demand and generation charges, suppliers would also have a requirement to pay a fixed generation charge in respect of their total volume of distributed generation and a fixed demand charge in respect of their total volume of demand. With similar fixed charges being levied to parties with direct contractual relationships with NGET, a method of consistently charging all parties, which would not create arbitrary differences based on the G/D split, can be envisaged.

5.16. Alternatively, and as was proposed by a presenter at the Glasgow seminar, the residual element could be charged out as a commodity charge. However, the extent to which this altered long term investment signals would need to be considered.

5.17. We consider that the characteristics of this option are similar to agency models, perhaps particularly a supplier agency model. We consider that there may be merit in further considering the interactions and similarities between the two sets of models and the relative degrees of change and implementation costs likely to be involved in introducing them.

## Agency Arrangements: Option 7

5.18. We note that a majority of respondents considered that an agency type approach may provide a number of benefits and could form the basis of a revised approach to treating distributed generation. We further note that discussion at both Ofgem seminars focused extensively on the viability, benefits and costs associated with various forms of agency model.

5.19. We consider that, of the options set out in the discussion document, agency style agreements, albeit perhaps complemented by the development of a wider suite of access products and amendments to contractual arrangements, have the potential to form the basis of an enduring solution. We note and endorse the view of attendees at the Glasgow seminar that any set of revised arrangements must, as far as practicable, be sufficiently robust to provide lasting solutions to the problems highlighted both by ourselves and a majority of respondents.

5.20. We consider it likely that an agent acting in an aggregation role on behalf of distributed generators will be better placed than an individual generator to assess the impact that generators will have on the system. As such, it may be appropriate for a party to provide an interface between the distributed generator and system operator.

5.21. We also note the views of respondents and seminar attendees that it is important that any set of arrangements are simple and do not expose distributed generators to undue risk. We consider that agency style arrangements may be expected to reduce the administrative burden on small generators and that applying charges on a consistent basis may increase predictability and transparency and facilitate competition in the generation market.

### DNO Agency Arrangements

5.22. We note that a majority of respondents who favoured an agency solution supported a DNO agency model. These respondents considered that the DNO is in possession of the most complete information regarding flows on its network and as such is best placed to act as an interface between generators connected to its network and NGET.

5.23. There is a clear need to further consider the detail of possible forms of a DNO agency model in order to more clearly establish its possible merits. In doing this it will be important to consider issues raised by respondents and seminar attendees such as:

- whether DNOs are currently incentivised to perform the role of an agent and, if not, what form any incentivisation should take;
- whether the anticipated transition towards more actively managed DNO networks is a relevant consideration in assessing the viability of an agency model;
- whether the possible creation of a 'one stop shop' for small generators could form the basis of a DNO agency arrangement;
- whether a DNO agency model would necessitate the development of a new type of transmission exit product and if this is not the case, how charges are levied in the event of a change in demand will need to be considered;

- the manner in which charges would be passed through to suppliers and any interactions with the distribution structure of charges project; and
- the extent to which a DNO agency model would necessitate an energy trading role for the DNO, noting that at present this is not permitted by the DNO licence and acknowledging that primary legislation may be required to amend this position.

**Supplier Agency Arrangements**

5.24. We note that several respondents expressed the view that the simplest model to implement would be a supplier agency model. The model presented by NGET at both seminars, which is available from our website, expressed a preference for, and outlined details of, a supplier agency model. Respondents noted that an existing contractual and charging interface between NGET and suppliers exists and that this could be developed under a supplier agency model, avoiding the need for a new interface being created.

5.25. As noted in looking at the DNO agency model, there is a general need for further development and in depth consideration of the operation of all agency models. In the context of supplier agency, key questions to address may include:

- whether a supplier agency agreement would disadvantage small suppliers with small volumes of demand within a GSP group and whether this could represent a barrier to entry into the supply market;
- whether and how access products could be developed and implemented under a supplier agency model; and
- whether there are any technical impediments to the implementation of such a model e.g. metering. It will also be important to establish the data requirements and how half-hourly ("HH") and non half-hourly ("NHH") demand would be treated.

**Hybrid Agency Arrangements**

5.26. We note that a number of respondents suggested forms of hybrid agency models, involving elements of both the DNO and supplier agency models outlined in our discussion document. One such model, which is available via our website, was presented by Scottish and Southern Energy at the Glasgow seminar. A hybrid model could take elements of both the DNO and the supplier agency models, utilising and developing existing contractual interfaces.

5.27. It has been suggested by respondents that a supplier may be best placed to deal with charging issues, while DNOs may be best able to address operational questions. A model can therefore be envisaged which would see the extension of a supplier's existing liability for TNUoS charges to cover their contracted levels of distributed generation, perhaps with the option to purchase a range of access products which reflect the needs of the generators within their portfolio. However, the greater amount of information held by a DNO about conditions on its network may make it appropriate to develop arrangements to enable power flows onto the transmission network, which cause or enlarge constraints, to be controlled by a DNO.

5.28. We highlighted in the September discussion document that it was important for any changes to arrangements to involve the minimum change necessary to achieve the desired outcomes. As such, we consider that further discussion and development of hybrid models may be beneficial.

**Distribution System Operator ("DSO")**

5.29. We note that the majority of respondents who commented on the model of a DSO considered that, while there were benefits associated with such an approach, it was unduly complex when compared to the other suggested agency models in return for little additional benefit for the transmission charging arrangements.

5.30. We recognise and agree with the views expressed by respondents. While we are of the view that there are a number of merits of a DSO model which would be worthy of consideration in a wider context, factors such as cost and complexity mean that the development of a DSO model would require to be justified as providing significant benefits compared to the other options under consideration and may not be feasible in the short to medium term. However, we note that the DSO model could be, potentially, a natural evolution of a DNO agency model, and that as the level of distributed generation increases then there may be an associated need for active network management.

**Agency Arrangements - General**

5.31. We recognise that there appears to be a high level of industry support for some form of agency model. However, it is clear that further thinking is required to assess the relative merit of the various models set out in the September discussion document, those outlined here and other credible alternatives. It will be necessary to establish how they might function in practice and evaluate likely levels of implementation costs. We think that the development of agency model straw men should be the primary focus of the proposed industry workgroup.

5.32. In our September discussion document we noted that an enduring solution, such as an agency model, could apply on either a gross or net basis. There is clear evidence that any change in the volume of generation and demand, on either the transmission or distribution networks, will have a corresponding effect on flows on the transmission network. However, a number of respondents questioned whether “use of” and “impact on” the system are synonymous and considered that it was only appropriate to design arrangements to cater for flows from the distribution to transmission networks, effectively treating the interface as an interconnector.

5.33. We highlighted in our September discussion document that a key objective of the review was to improve the cost-reflectivity of charges in order to promote economically efficient decision making. As such, it would appear appropriate to consider the costs that directly connected and distributed generators impose on the transmission network. Having done so, methods of targeting these costs at the parties which cause them can be developed. In apportioning these costs, whether on a gross or net basis, it may be appropriate to consider the nature of the access right and the associated charging arrangements.

# 6. Way forward

**Chapter Summary**

This chapter sets out our views of the appropriate way forward for the enduring arrangements for distributed generation project.

## Ofgem's views

6.1. Ofgem remains of the view that it is appropriate to review the transmission arrangements relating to distributed generation to ensure that they are facilitating economic and efficient decision making and promoting competition. Ofgem further acknowledges that issues of operational control, planning and access are also relevant when considering enduring arrangements which reflect the impact of distributed generation on the transmission network.

6.2. We consider that, of the options set out in the discussion document, agency style agreements, albeit perhaps complemented by the development of a wider suite of access products and amendments to contractual arrangements, have the potential to form the basis of an enduring solution. We note and endorse the view of attendees at the Glasgow seminar that any set of revised arrangements must, as far as practicable, be sufficiently robust to provide lasting solutions to the problems highlighted both by ourselves and by respondents.

6.3. We note the ability of industry participants to raise modifications to industry codes should they consider changes likely to better facilitate achievement of the relevant objectives of those codes. However, we have also had regard to respondents' views on the appropriate way forward for this project and, particularly, the significance that respondents place on our continuing involvement in this process. Our view remains that it should be for licensees, in tandem with the industry, to develop any proposals. We continue to consider that Ofgem should not be centrally involved in prescribing particular solutions given our decision making role in any proposed modifications to existing arrangements.

6.4. However, we note the view of respondents that the complexity of the issues to be addressed, and the possible difficulties associated with reconciling the diverse commercial positions of different stakeholders, could be difficult in the absence of strong leadership. We also note the need for a high-level holistic discussion of possible options, which it may not be possible to achieve through existing industry fora. On this basis we accept that Ofgem has a role to play in facilitating such discussion and, depending on the degree of change associated with any option which is pursued, an ongoing role in the development of revised arrangements.

6.5. At a first stage in this process, and in light of respondents' views, this document has identified a number of models which we consider merit further development. Further, we also consider that there is a role for Ofgem in setting out a short term timetable for progressing this work and in identifying a programme of work for taking this forward. However, we retain the view that it should be the responsibility of the industry to undertake the detailed design work. Consequently, we consider there to be merit in an approach based on developing a working group to discuss issues in more detail. We would expect any working group to consider both interim and enduring solutions to the issues raised.

## Next steps

6.6. As the next stage in this process Ofgem proposes to establish an industry working group tasked with developing specific options for change, or 'straw-men' for the form of enduring transmission arrangements for distributed generation. In light of respondents' views we think that the development of agency model straw-men should be the primary focus of the proposed industry workgroup.

6.7. We envisage that the role and operation of the working group will be similar to that of the Access Reform Options Development Group ("ARODG"). As noted in Chapter 3 above, the ARODG was established in March 2006 as part of the Transmission Price Control Review and tasked with developing options for changes to the way in which capacity on the GB transmission system is allocated. The ARODG published its findings in April 2006. It is our initial view that a working group to consider enduring transmission arrangements for distributed generation would meet less frequently than the ARODG but over a longer timescale.

6.8. We will shortly issue an invitation to participate in, together with draft terms of reference for, this working group. This invitation and all subsequent material relating to the new working group will be made available on our website.

# Appendices

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# Appendix 1 - Respondents' views

1.1. The September discussion document invited respondents to comment on any aspect of the document. In particular it sought views on: the case for considering the arrangements relating to distributed generation; whether we had correctly identified the full range of issues to be addressed; the relative merits of the range of options in assessing these issues; and the way forward. We received 19 responses. We have had regard to the views of respondents, along with views expressed at the industry seminars in Glasgow and London, in developing this document. Responses are summarised by topic below.

## The need for review

1.2. In total we received nineteen responses to the September discussion document. Thirteen respondents explicitly supported the review. Seven of those noted that the case for considering the enduring viability of the existing arrangements was justified given the projected increase in distributed generation. Five respondents argued that the review was crucial in order to develop arrangements that would allow for the more efficient connection of distributed generation and the delivery of the Government’s policy aspirations vis-à-vis renewable generation. The other respondent noted that Ofgem's document was important in highlighting the issues in relation to distributed generation.

1.3. Two respondents were not convinced of the need for any changes to the existing arrangements. One of the respondents noted that the present methodology was consistent with the principles underpinning the market arrangements and that many of the proposed changes would only serve to undermine the market. The other respondent argued the need for a comprehensive Impact Assessment and noted that in the absence of one they were of the view that the existing arrangements were broadly appropriate.

1.4. Two further respondents did not consider that the arrangements needed wholesale changes to overcome the perceived problems. One noted that there were a relatively small number of distributed generation schemes without contractual arrangements which avoid paying transmission charges. Further they noted that the problem may only occur in limited areas of the country, most notably Northern Scotland. The other respondent, while recognising that there is a discrepancy in the treatment of transmission and distributed connected generation, did not consider fundamental changes were required to overcome that discrepancy.

1.5. The final two respondents noted that the review should focus on wider issues than charging including: transmission access; system planning; and operational control which they considered were all central to debate on the impact of distributed generation on the transmission system.

## Range of issues

1.6. Eighteen respondents commented in some respect on the range of issues that require addressing. Of these, four explicitly noted that Ofgem had correctly identified the full range and complexity of issues. One respondent considered that the discussion document had not clearly identified the issues it was seeking to resolve, while another respondent noted that Ofgem had only considered narrow issues concerning the efficiency of decision making.

1.7. A number of other parties highlighted additional issues which they considered had not been highlighted by Ofgem and which should be addressed as part of the review. These are set out in the following paragraphs.

1.8. Three respondents suggested that the review had been overly focused on transmission charging arrangements. While these respondents recognised the need to consider these arrangements, they considered that commercial and operational frameworks should be included within the scope of the project. In particular they noted that a central aspect of the review should be the control of, and contractual arrangements to manage, flows on to the transmission system which are caused by the actions of distributed generators which do not have access rights. A fourth respondent considered that NGET requires a mechanism through which it can manage the flow of power onto and across the transmission system in real time. The respondent considered that NGET may not have the tools to manage the transmission system against the background of increased distributed generation.

1.9. Seven respondents commented on the timing of the review. Five of these considered that the timing was appropriate. The two remaining respondents argued that the review was long overdue and that such issues should have been considered as part of the BETTA process. Of those that considered the timing appropriate, three suggested that addressing the issues identified by Ofgem now would provide time to find an enduring solution in advance of the anticipated growth in distributed generation.

1.10. Four parties noted that the review presented an opportunity to establish a strategic direction for developing charging arrangements to support the delivery of the Government's aspirations regarding the percentage of energy supplied from renewable sources of generation. A further respondent expressed the view that some modest economic inefficiency in charging arrangements may provide benefits by facilitating the connection of increased volumes of renewable generation.

1.11. One respondent expressed concern that the September discussion document had misrepresented the current arrangements. The respondent set out the view that all parties paid for their use of the transmission system, generators being charged in accordance with the terms of the transmission charging methodology and suppliers charged for their offtake net of distributed generation within a GSP group at system peak. However, the respondent accepted that it was not clear that the current arrangements adequately reflected the use of the transmission system made by distributed generators.

1.12. In addition, respondents highlighted a wide range of issues which they considered relevant to the review of the existing arrangements for distributed generations. These included:

- the future classification of 132kV circuits as transmission or distribution. A number of respondents argued that Ofgem should set out how it will review the future classification of 132kV circuits in Scotland in the event that their primary function ceases to be for the bulk transfer of electricity;
- how the roll out of generator distribution use of system charges will work in relation to generators who have paid for continuing connections;
- the impact that a change in the pattern of generation connections across the transmission and distribution networks will have on charges;
- the impact of the rebate against the residual element of transmission charges for island generators;
- uncertainty over the future split of revenue recovery between generation and demand;
- the view that the range of complex contractual obligations place a disproportionate burden on small distributed generators; and
- the interaction between this project and the future regulation of offshore transmission.

## Exporting GSP’s without access rights

1.13. Ten respondents commented on the issue of exporting GSPs. Of these, three considered that the increase in distributed generation is likely to lead to an increased likelihood that GSPs will export and that the impact of such exports could be to reduce the cost-reflectivity of charges and thus increase costs to customers. These respondents therefore considered that the flows should be accounted for within contractual and charging arrangements.

1.14. Another four respondents, while recognising the issues associated with exporting GSPs, questioned the extent to which the need to address these issues was either significant or immediate. One respondent argued that exporting GSPs were not currently a significant problem, but recognised that there was likely to be an increasing requirement for two-way flows between transmission and distribution systems in the future. Another respondent questioned whether the export from sub-100MW distributed generators will ever be significant and therefore argued that making significant changes to the existing arrangements could be disproportionate. A third respondent noted that the majority of GSPs do not export but provide benefits to the system by netting off against demand and reducing costs to the transmission network.

1.15. One respondent did not agree with the issues that Ofgem has identified as potential problems relating to exporting GSPs. The respondent, while accepting there was a discrepancy in the treatment of transmission and distribution connected generation, argued that the problem reflected the different definitions of transmission voltages. They therefore did not identify a case for making wholesale changes to the existing arrangements.

1.16. Another respondent, while recognising that the operational concerns had some merit, considered that these had been overplayed. They recognised the need to control flows on the transmission system but considered this to be an issue of information provision rather than one requiring a change to charging arrangements.

1.17. Four respondents argued that the impact of distributed generation on the transmission system was a function of the net effect of all demand and generation connected to that distribution system. One respondent argued that charges should thus be based on the net flows of electricity between networks. Two respondents considered that a new connection site which is offsetting demand locally has no effect on transmission flows and indeed by reducing the need for transmission reinforcement could actually be reducing transmission costs. The fourth respondent considered that the existing arrangements were already consistent with distributed generation netting-off against local demand on a GSP Group basis.

1.18. Three respondents argued that given the existing system is based on aggregation at GSP Group level any arrangements should be concerned with export from GSP Groups as a whole rather than individual GSP points.

1.19. One respondent argued that any proposed solutions to exporting GSPs should recognise that if charging arrangements are to be consistent then when generators export in zones where transmission charges are negative then they should be paid transmission charges.

## Cost reflectivity

1.20. Fourteen respondents commented on cost-reflectivity. Of these, four noted that only properly cost-reflective charging arrangements would address the problems of free-riding, and the associated distortion of competition, by encouraging efficient decisions concerning where to locate plant. However, one of these respondents further noted that there needs to be a pragmatic trade-off about the extent to which charges can be cost-reflective without introducing undue complexity.

1.21. Another four respondents, while supporting the concept of cost-reflectivity, argued that charges should be based on net flows on and off the transmission system. One such respondent noted that it is important to recognise the benefit that distributed generation provide to reducing reinforcement costs on the transmission network. Another of the respondents suggested that charging on a gross basis would not be cost-reflective as it would ignore generation absorbed within the GSP Group. A third respondent did not accept that distributed generators impose costs on the transmission system.

1.22. Three respondents expressed concerns regarding the existing locational charging arrangements levied to transmission network users. One respondent argued that locational charging as a principle was inconsistent with the achievement of sustainable development and the promotion of electricity from renewable sources. On that basis the respondent expressed concern regarding the extension of these locational charging arrangements to distributed plant.

1.23. Two respondents commented on what constitutes “use” of the transmission network. One of the respondents argued that it was a gross oversimplification to equate “using” the network with “affecting” the network. They thus considered that charging all distributed generators was neither necessary nor desirable. The other respondent argued that charges must reflect “actual usage” or distributed generators would face unnecessarily high charges.

1.24. One respondent argued that if distributed generators paid to use the transmission system then it would logically follow that transmission connected generators should pay to use the distribution networks.

## Perverse incentives

1.25. Ten respondents commented on the scope for perverse incentives within the existing charging arrangements.

1.26. Eight respondents considered that the existing size limits are arbitrary. Of those, seven considered that they created perverse incentives unrelated to the actual interaction between distributed generation and the transmission system. Another respondent argued that the fact that size definitions are arbitrary is not obviously a problem, as generators would make a commercial choice about its sizing and that in doing so it may have to recognise lost economies of scale. The same respondent further noted that commercial decisions had already been taken on the basis of these limits and that to change these without good reason would be damaging to market confidence. Another respondent noted that it was unlikely that size definitions had had a substantial influence on system development to date.

1.27. One respondent considered that the arrangements should take into consideration where distributed generation is located and the extent to which it is offsetting demand, concluding that size itself should not be the key criteria determining its liability for transmission charges.

1.28. Three respondents commented on the licence exemption criteria. The first noted that the licence exemption criteria were also arbitrary. The second argued that the current problems reflect policy decisions taken previously; including the Department of Trade and Industry's (DTI) decision to change the thresholds at which a generator requires a licence, and thereby removing contractual relationships with NGET, and Ofgem allowing charging regimes to ignore generators below 100MW. The third considered that Ofgem has misunderstood criteria for TNUoS charge liability on the basis that the key determinants of charge liability are not size and/ or voltage of connection but rather the licence-exemption criteria. The respondent argued that licence exempt generators should not be liable for TNUoS charges.

1.29. Another issue raised by one respondent was whether the existing procedures ensured there was adequate transmission capacity in place. The respondent argued that, given the definition of a large power station varies across GB, this could lead to perverse incentives to size generation stations below the relevant threshold and could lead to a lack of transmission capacity. The respondent argued that some refinements to the planning process may be required to ensure the adequate provision of transmission capacity.

1.30. In relation to voltage and location, three respondents considered that the current arrangements create the potential for distorted incentives. One respondent noted that connection at a sub-optimal voltage would increase costs across the network. However, the same respondent stressed that even if the party connects at the appropriate voltage it would reduce input from transmission into distribution system thus rendering transmission assets oversized for the required generation.

1.31. In a similar vein a number of parties argued that the treatment of 132kV circuits in Scotland as transmission was a potential source of perverse incentives. Three respondents argued that Ofgem should commit to review the management of the 132kV network to ensure consistency across GB.

1.32. One respondent proposed that it would be more cost-reflective if any charges for distributed generation were related to their effect on the transmission network during times of system stress. Another respondent argued that, providing charges are cost-reflective, there should be no perverse incentives associated with connection at a particular voltage or in a particular location.

## Interaction with access issues

1.33. Six respondents made a range of comments in relation to access issues. Two of these respondents set out the merits of non-firm access rights; which would allow the system operator to constrain plant when necessary. One respondent noted that distributed generators do not require the same type of rights as transmission connected generators. They argued that while TEC provides a firm right, non-firm access rights, possibly restricted to times other than system peak, may be more appropriate. The respondent considered that such rights could reduce transmission investment costs, and thus costs to customers, and argued that contractual frameworks and charges should be developed to accommodate both types of access right. Another respondent argued that it would not be appropriate to allocate TEC to distributed generation as it was not clear to what extent they would use it and thus that there was merit in a non-firm product.

1.34. Another three respondents raised the issue of liability for charges in relation to access. Two of those respondents argued that liability for charges should be commensurate with the firmness of access to the system. The third argued for a two-tier charging system, with licensable plant being required to purchase firm access rights through TEC, and therefore facing a liability for TNUoS charges, and embedded exemptible plant having no requirement to purchase TEC but facing a lower liability for charges.

1.35. One respondent argued that distributed generation already connected to the distribution networks should have its access rights recognised and thus that any change to access rights should only affect new connections. Another respondent noted that all distributed generators already had the right to use the transmission system either directly from NGET through a Bilateral Connection Agreement ("BCA") or Bilateral Embedded Generation Agreement ("BEGA") or indirectly through a contracted supplier. A third respondent recognised the interaction of the review with GB queue issues.

## Trade-offs and implementation issues

1.36. Seven respondents commented on the issues associated with revising the existing, and implementing new, arrangements. Among these comments the common theme was that the solution should be efficient and avoid fundamental change to the market structure; which is likely to increase complexity or costs. Three respondents noted that the benefits of any change must outweigh the costs of disruption, change and implementation.

1.37. Four respondents supported the production of an impact assessment to allow informed judgements of costs and benefit of any changes to be made.

## Options for change

**Option 1: Do Nothing**

1.38. Ofgem noted that the least change option would involve no changes being made to existing arrangements beyond those brought forward via amendments to industry governance arrangements.

1.39. Sixteen respondents commented on the viability of a do nothing option. Of these, nine opposed such an approach, six supported it and one made additional comments.

1.40. Of the six respondents which supported the option, one acknowledged that it would fail to improve the cost-reflectivity of transmission charges but stated that the case for any change to the transmission charging arrangements must be robust. Three considered that the existing arrangements may not be fit for purpose in future but considered that the magnitude of the problem in the medium term did not merit addressing at this stage. One respondent stated that, in the absence of a clear problem, doing nothing represented the most appropriate option. Another respondent considered that in the absence of fundamental change, such as an agency type option, doing nothing was appropriate.

1.41. All nine respondents which opposed the option considered that it was inappropriate not to address the issues highlighted in Ofgem's discussion document. Several respondents suggested that the magnitude of the problems associated with the issues highlighted in the discussion document was likely to increase over time and failing to address issues in the short term would be detrimental to the overall cost-reflectivity of charging arrangements. Two respondents considered that the option would increase the risk currently being faced by distributed generators which was unacceptable, while one respondent considered that the costs of doing nothing were high both in terms of inefficiency and uncertainty.

### Option 2: De-energise plant that spills

1.42. Ofgem noted that it would be theoretically possible under the CUSC for NGET to request that a DNO disconnect a party without an access right in the event that it spills power onto the transmission network.

1.43. All fourteen respondents which commented on the de-energisation option opposed it. Six respondents considered the option to be disproportionate, draconian, regressive or untenable. Two others suggested that it would increase risk and be inefficient. Three respondents considered that de-energisation did not have the potential to address any of the perceived problems as highlighted in Ofgem's discussion document, while two further respondents noted the difficulties associated with tracking flows and attributing responsibility for a specific export from a GSP which had not secured, or had breached, an access right. Two respondents noted that operational control of flows onto the transmission network was the key issue to address. One of those respondents noted that, while the option in question could undermine existing arrangements, that it would be possible to develop commercial arrangements in order to constrain the output of distributed generation in the event that flows onto the transmission network caused costs during certain periods.

### Option 3: Amendments to the charging model

1.44. Ofgem noted that, as a minimum, the purpose of the review of enduring transmission arrangements should be to develop, if appropriate, an enduring solution to the interim discount for 132kV connected parties in Scotland. This discount was introduced because of concerns over discrepancies between the charges faced by 132kV connected generators in Scotland and those connected in England & Wales. We suggested that amendments to the parameters of NGET's charging model could improve the cost-reflectivity of charges, particularly at 132kV, and remove the need for the current discount arrangements.

1.45. Thirteen respondents commented on the viability of this option. Of these, two expressed conditional support, noting that it may facilitate the development of an enduring solution to the arbitrary discount currently in place for generators connected to the 132kV transmission network in Scotland. The remaining respondents did not consider that this option was viable.

1.46. Eight respondents argued that such an option would not address any of the wider issues highlighted by Ofgem. They considered that the option would not increase the number of parties liable for transmission charges and would serve only to redistribute revenues. One respondent suggested that modelling the costs of 132kV transmission connected generation on a more cost-reflective basis may increase TNUoS charges to this category of generator, while two respondents suggested that a sub-transmission tariff, applicable to generators connected at 132kV should be developed.

**Option 4: Extend the DCLF ICRP model to parts of the distribution network**

1.47. Ofgem suggested that applying NGET's charging model to some parts of the distribution networks could introduce a consistent liability for transmission charges. We noted this could address a number of the perceived perverse incentives raised within the discussion document.

1.48. Fourteen respondents provided comments on the extension of NGET's charging model to certain distribution voltages. Of these, none considered that, in isolation, it could form the basis of an enduring set of arrangements.

1.49. Four respondents noted the interaction between such an approach and the ongoing distribution structure of charges project. Five respondents considered that the approach would be costly to implement and introduce unnecessary complexity to arrangements in both transmission and distribution, with one noting that it may necessitate the reopening of distribution price controls. Two respondents suggested that the cost drivers for transmission and distribution differ and hence that harmonisation would be undesirable. One of these respondents noted that complete harmonisation would not be achievable. One respondent considered that the option could only deliver benefits if considered alongside wider changes to commercial frameworks. Another respondent considered that the approach would simply serve to push the currently perceived problems down to lower voltage levels.

**Option 5: Amend use of size definitions as the basis for charging and contractual arrangements**

1.50. Option 5 suggested that alterations to the thresholds at which a party is currently defined to be a 'Large Power Station' could affect the number of parties requiring a contractual relationship with the system operator. This has implications for the number of parties which would be required to have a direct contractual relationship with NGET which includes a liability for transmission charges. Ofgem additionally noted that consistent size definitions, or definitions based on other objective criteria, could address issues of geographical discrimination.

1.51. Fourteen respondents commented on the effect of amending the Grid Code definitions in terms of the size at which generating plant is classified as a Small, Medium or Large Power Station. As with the previous option, no respondent considered that, in isolation, amending size definitions would address the issues highlighted by Ofgem.

1.52. Eight respondents considered that changing size definitions would only result in the issues identified by Ofgem occurring around different thresholds and would not serve to address any of the identified issues on an enduring basis, although one respondent considered that it may marginally improve the current situation. Two respondents considered that, were thresholds in England & Wales reduced, the option would increase the administrative burden on NGET associated with managing an increased number of BEGAs. One respondent noted the interactions with the GB queue for transmission access were the number of BEGAs to increase, while another suggested that size definitions in Scotland should increase and questioned the rationale for BEGAs and Bilateral Embedded Licence Exemptable Large Power Station

Agreements ("BELLAs"). One respondent suggested that Ofgem's assumption that size is a criterion related to charging liability is incorrect. Another respondent noted the difficulties associated with defining what an appropriate size definition would be.

**Option 6: Creating a consistent liability for charges**

1.53. Ofgem suggested that an approach in which distributed generators are paid the inverse of the demand tariff, as they do currently, but where that inverse demand tariff was equal to the generation tariff at the same location, could create a consistent liability for charges. This approach would separate the transport and tariff models and mean that all parties faced a purely locational charge, with the residual element of transmission charges being apportioned separately.

1.54. Thirteen respondents commented on the option of attempting to create a consistent liability for charges. Eight of these opposed the option while five respondents demonstrated limited support.

1.55. Four respondents considered that the option is overly complex, with one suggesting that it would undermine the existing charging arrangements, and a further respondent considering that it is disproportionate. One respondent considered that zonal averaging could create problems for supplier charges and two respondents questioned how the model would work in the presence of negative demand charges. Another respondent considered that this was not a solution to any of the issues raised by Ofgem and would only serve to remove embedded benefits. Four respondents gave tentative support to the option but noted that a significant problem would need to be justified were it to be implemented. Two further respondents considered that, with associated contractual amendments, the option could address a number of the issues highlighted but noted that, in this case, it would resemble a supplier agency model.

**Option 7: Agency Models**

1.56. Ofgem outlined three high level types of agency model: DNO Agency, Supplier Agency and DSO agency. Ofgem noted the increased degree of complexity associated with the latter.

*General Agency Models*

1.57. Sixteen respondents commented on the feasibility of agency models. Of these, nine expressed conditional support, four opposed such an approach and three provided comments without expressing a definitive view. Those in favour of an agency approach consider that, in providing a single interface between distributed generation and the system operator, it may be expected to increase efficiency and allow relationships between parties to be managed more easily. Two respondents suggested that an agency approach represented a relatively simple model while one respondent considered that it was the only enduring solution to the issues raised in Ofgem's discussion document. Respondents also considered that an agency approach could facilitate more effective system management by NGET and reduce the existing administrative burden on distributed generators.

1.58. Two respondents noted the likely complexity associated with the introduction of such an approach and reiterated the view that the deficiencies in the existing arrangements must be quantified in advance of any change. Two respondents stated a view that, as far as practicable, fundamental change should be avoided. One respondent noted that the number of GSPs that export is low and that no GSP group currently exports power to the transmission network. One respondent considered that, given this situation, an agency style arrangement would be disproportionate. Another considered that this approach would treat demand and generation differently, which would be inappropriate, and in practice would be impractical because of difficulties associated with tracing flows.

1.59. Three respondents expressed support for agency arrangements applied at GSP level, while one considered that it should be applied on a GSP group basis. One respondent considered it appropriate that all parties impose costs on the transmission network regardless of the voltage of connection and supported an agency arrangement on a gross basis.

*DNO Agency Models*

1.60. Fifteen respondents commented on DNO agency arrangements of which nine considered that the DNO represents the most appropriate party to act as the agent, while three respondents considered the approach was inappropriate. Three respondents noted that there are no incentives on a DNO to fulfil such a function and questioned whether, in the absence of the development of such incentives and the provision of an income stream to the DNO, this option would be practicable. Respondents noted that the provision of such an income stream could increase costs to consumers.

1.61. Two respondents expressed concerns over the possibility of a DNO theoretically operating as a Balancing Settlement Code ("BSC") party given they are currently prohibited from trading energy. Respondents also noted that, given a number of DNOs have generation interests, ensuring non-discriminatory treatment would be important.

1.62. Three respondents in favour of the DNO agency approach considered that it was most appropriate as distributed generators already have a contractual interface with the DNO which could be developed relatively simply. Two respondents noted that the approach would incentivise efficient and cost effective system management by DNOs while reducing the administrative burden on distributed generators, noting that it may be more appropriate if distribution networks become more actively managed. Two users also noted the interactions with the LEEMPS proposals being progressed via the Grid Code and the provision of a ‘one stop shop’ for access. Other respondents considered that the DNO benefits from the greatest volume of information and as such is the best placed party to contract on behalf of users of its system and manage its system and its impact on the system of the system operator. One respondent considered that this informational advantage may lead to more efficient network investment.

1.63. One respondent considered it appropriate that the DNO has a role in managing non-contracted export onto the transmission network but that it is inappropriate for it to have a role in securing transmission entry capacity or energy trading. Another respondent noted that under a DNO agency role a range of access products could be developed to reflect the circumstances in which spill onto the transmission network is likely to occur.

*Supplier Agency Models*

1.64. Eight parties made comments in regard to supplier agency models. Two respondents were supportive of the model, three were cautiously supportive and three opposed the approach.

1.65. One respondent considered that it would be difficult to deal with HH and NHH demand, another suggested that such a model may provide incentives for suppliers to change contractual patters; causing problems for distributed generators. One respondent suggested that large suppliers with significant volumes of demand connected within a GSP group would be better placed than small suppliers under this model and that it could consequently hinder competition.

1.66. Respondents in favour of the option considered that it could: give suppliers a right to export; remove the perverse incentives to locate at distribution voltages highlighted by Ofgem; create a consistent liability for transmission charges; improve cost-reflectivity by including suppliers within NGET's charging model; and create an interface through which the management of flows could be facilitated.

1.67. One respondent considered that, as suppliers already have a liability for demand charges, it would be logical for generation charges to also be levied and that this would require minimal changes to existing arrangements and settlements systems. However, another respondent considered that implementing the model would necessitate wholesale changes to settlements to the point that the costs of implementation would exceed any benefits. One party suggested that the level of complexity involved in supplier agency was significantly greater than under DNO agency.

*Hybrid Agency Model*

1.68. Two respondents set out an agency model which contained elements of both the supplier and DNO agency models. Such a model was also presented at the seminar held in Glasgow[21].

*DSO Agency Model*

1.69. Nine respondents commented on a DSO agency approach. While two of these noted the theoretical benefits of the approach, all respondents considered that it represents an unnecessary degree of complexity when compared to the other suggested agency models in return for little or no additional benefit. Respondents considered that in introducing an additional contracting party the model would introduce an unnecessary degree of bureaucracy with two respondents suggesting that, as such, it would be disproportionate.

[21] The presentations given at both the London and Glasgow seminars are available from Ofgem's website

## Further thoughts and way forward

1.70. Fourteen respondents set out a range of views in relation to the next steps in taking forward the review of enduring transmission charging arrangements for distributed generators.

1.71. Four respondents argued that Ofgem should engage with the industry at the earliest possible stage. One of those respondents argued this was necessary to ensure all affected groups would be represented in discussions. Another respondent noted that Ofgem needed to set out a programme of work which would involve defining milestones to provide a clear target for the industry to work towards.

1.72. Two respondents considered Ofgem should publish its further thoughts document as early as possible in 2006 to allow for a detailed consideration of issues. Another respondent noted that they expected that document to stimulate broader debate. Four respondents encouraged Ofgem to organise industry workshops to facilitate discussions on the options proposed for the development of the existing arrangements and also of other possible options. Two of those respondents envisaged an ongoing role for an industry working group and noted the process adopted in developing new distribution commercial arrangements. Another two respondents argued for a further stage of work in the consultation timetable whereby Ofgem should revisit some key issues before issuing another consultation document. The respondents considered this longer process would ensure that a greater consensus develops among different parts of the industry which they noted would be important when conclusions need to be implemented by the relevant code panel and network operators.

1.73. Three respondents explicitly supported Ofgem's suggestion that the best solution would be for industry players to bring forward changes to the various codes and other industry documents. However, a fourth respondent expressed concern about an approach based on implementation through code amendments on the grounds that it could allow interested parties to "cherry pick" elements of a solution that suit their commercial position whilst an enduring solution may never be fully implemented.

1.74. Five respondents, while not specifically commenting on the appropriateness of an approach based on changes to various codes, argued that the more important issue was the requirement for Ofgem to take a more proactive role in taking forward the review. Two of those respondents argued this was important as only Ofgem was in the position to develop holistic enduring arrangements to allow consistency of approach across legal frameworks. The other three made the point that without Ofgem's leadership, given the diverse commercial positions of different stakeholders, it would be impossible to achieve consensus and thus to propose all the changes required to solve the problems set out in the consultation.

1.75. Two respondents commented on the target date for bringing forward charges to the existing arrangements. One argued the solution should be targeted for 2010 such that any impact on DNOs costs could be considered in formulating the next distribution price control. The second respondent argued that a realistic target date would be between April 2007 being the start of the next transmission price control and April 2010 being the next distribution price control.

# Appendix 2 - Impact of Distributed Generation: Data

1.1. A key issue raised by respondents to our September discussion document and in the industry seminars was in relation to the extent to which volumes of distributed generation are likely to increase. A number of parties have argued that this requires quantification.

1.2. As a first stage in this process we wrote to NGET and all DNOs on 6 February 2006 requesting initial, high level, information of the likely future change in the pattern of generation and demand connecting to the networks. The information provided is summarised below. Table 1 sets out the increase in distributed generation; table 2 sets out the increase in connected demand; and table 3 sets out the increase in transmission connected generation.

1.3. The information received from the DNOs was not (on the whole) disaggregated to the requested GSP level. We are still of the opinion that understanding future changes in demand and connected generation is an important stage in this process. To this end we are considering the merits of a further information request for this more disaggregated information. We wish to discuss this issue in the proposed distributed generation working group in the first instance.

**Table 1: Forecast distributed generation connections (MW)**

| **Demand Zone** | **2006/07** | **2007/08** | **2008/09** | **2009/10** |
|---|---|---|---|---|
| North Scotland | 19 | 164 | 60 | 379 |
| South Scotland | 75 | 240 | 237 | 165 |
| Northern* | 73 | 72 | 73 | 72 |
| North West | 254 | 127 | 312 | 223 |
| Yorkshire* | 188 | 188 | 188 | 188 |
| North Wales & Mersey | 120 | 29 | 0 | 0 |
| East Midlands* | 396 | 139 | 112 | 55 |
| Midlands* | 19 | 30 | 45 | 44 |
| Eastern* | 220 | 77 | 25 | 812 |
| South Wales | 154 | 497 | 120 | 0 |
| South East* | 6 | 123 | 304 | 20 |
| London* | 1 | 1 | 8 | 66 |
| Southern England | 18 | 44 | 87 | 50 |
| South West England | 17 | 72 | 57 | 37 |
| **TOTAL** | **1560** | **1803** | **1629** | **2111** |

* *Data was supplied in calendar years*

**Table 2: Forecast demand growth (MW)**

| Demand Zone | 2006/07 | 2007/08 | 2008/09 | 2009/10 |
|---|---|---|---|---|
| North Scotland | 17 | 18 | 19 | 17 |
| South Scotland | 40 | 17 | 0 | 0 |
| Northern* | 42 | 31 | 22 | 22 |
| North West | 81 | 48 | 48 | 49 |
| Yorkshire* | 30 | 3 | 34 | 29 |
| North Wales & Mersey | 10 | 0 | 14 | 0 |
| East Midlands | 56 | 57 | 57 | 58 |
| Midlands* | 33 | 65 | 38 | 125 |
| Eastern* | 132 | 186 | 154 | 103 |
| South Wales | 36 | 76 | 88 | 27 |
| South East | 61 | 69 | 36 | 67 |
| London | 176 | 129 | 73 | 80 |
| Southern England | 100 | 101 | 102 | 104 |
| South West | 48 | 49 | 49 | 50 |
| **TOTAL** | **862** | **849** | **734** | **706** |

** Data was supplied in calendar years*

**Table 3: Forecast change in generation directly connected to the transmission system (MW)**

| Transmission Area | 2006/07 | 2007/08 | 2008/09 | 2009/10 |
|---|---|---|---|---|
| **NGET** | 4070 | 2024 | 200 | 314 |
| **SPTL** | 971 | 0 | 0 | 0 |
| **SHETL** | 1129 | 0 | 640 | 506 |
| **TOTAL** | **6170** | **2024** | **840** | **820** |

## Appendix 3 - The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[22]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[23].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[24]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[25]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[26] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;

[22] Entitled "Gas Supply" and "Electricity Supply" respectively.
[23] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[24] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[25] The Authority may have regard to other descriptions of consumers.
[26] or persons authorised by exemptions to carry on any activity.

- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[27] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[27] Council Regulation (EC) 1/2003

# Appendix 4 - Glossary

**A**

### The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

**B**

### Balancing Mechanism

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the BSC.

### Bilateral Connection Agreement (BCA)

An agreement between the licensee and a CUSC user relating to a direct connection to the GB transmission system identifying the relevant connection site and setting out other site-specific details in relation to that connection to the GB transmission system.

### Bilateral Embedded Generation Agreement (BEGA)

An agreement entered into between NGET and a CUSC user relating to a generating station (or other connections provided for in the CUSC) connected to a distribution system and the use of the GB transmission system. It identifies the relevant site of connection to the distribution system and sets out other site specific details in relation to that use of the GB transmission system.

### Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA)

As agreement entered into between NGET and a CUSC user relating to a generating station (or other connections provided for in the CUSC) connected to a distribution system and the use of the GB transmission system. Unlike the BEGA, the BELLA does not allocate any use of system rights to the generator. Further, the generators would not be required to become a BSC party and fewer elements of the Grid Code would be applicable.

### British Electricity Trading and Transmission Arrangements (BETTA)

BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system which came fully into effect at BETTA go-live (1 April 2005).

### Balancing Services Use of System Charges (BSUoS)

The charges levied by NGET in respect of the activities it undertakes to keep the transmission system in electrical balance at all time.

**C**

### Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the GB transmission system, parties connected to the GB transmission system and NGET is relation to their connection to and use of the transmission system.

**D**

### Direct Current Load Flow (DCLF)

A standard technique used by electrical engineers to model electrical flows across a network. NGC use a DCLF ICRP (see definition below) transport model to calculate how much extra transmission capacity is required to accommodate extra generation being put on the network at each point of the network.

### Distributed Generation

A generator directly connected to a distribution system or the system of another user.

**G**

### Generation Use of System (GDUoS) charges

New distribution use of system charge covering the costs of network reinforcement not captured within connection charges. The charge is intended to replace the previous deep connection charging regime.

### GB system operator

The entity responsible for the day to day operation of the GB transmission system and for entering into contracts with those who want to connect to and/or use the GB transmission system. NGET is the GB system operator.

### GB transmission system

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain.

### GB transmission use of system charging methodology

The methodology which NGET is required to have in place by its transmission licence and which is used to calculate the charges to customers for use of the GB transmission system. The GB transmission use of system charging methodology is in practice comprised of two separate methodologies – a BSUoS charging methodology (defined above) and a TNUoS charging methodology (defined below).

### Grid Code

A document prepared by the transmission licensee in accordance with Standard Licence Condition C14 of the Transmission Licence setting out the technical parameters for the operation and use of the transmission system and of plant and apparatus connected to the transmission system.

### Grid Supply Point (GSP)

A point of delivery from the GB Transmission System to a Distribution System or a transmission connected customer.

### Grid Supply Point (GSP) Group

Those GB Transmission System substations bounded solely by the faulted circuit(s) and the overloaded circuit(s) excluding any third party connections between the Group and the rest of the GB Transmission System.

## I

### Investment Cost Related Pricing (ICRP)

A means of setting charges which seeks to link the charge paid for a particular service (such as use of an electricity transmission network) to the cost of the investment (in the network) required to provide that service.

## K

### Kilowatt (kW)/ Megawatt (MW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts.

## L

### Licence Exemption Criteria

Criteria which determine whether a generating party is, or would (if it generated electricity at no other generating plant and/or did not hold a generation licence) be, exempt from the requirement to hold a generation licence.

### Long Run Incremental Cost (LRIC)

Method of assessing the marginal cost from the change in the present value of the anticipated costs of reinforcing the network as a consequence of adding an additional unit of production.

**N**

### Netting-off

The ability for a supplier to contract with a small distributed generator for output as a result of both parties avoiding using the transmission network and consequently paying TNUoS charges.

**O**

### Offshore transmission

Transmission within an area of offshore waters (that is, the territorial sea and waters as designated under section 1(7) of the Continental Shelf Act 1964) of electricity generated by a generating station.

**S**

### System Operator - Transmission Owner Code (STC)

The document which sets out the terms between the transmission licensees whereby the GB transmission system is planned, developed and operated and transmission services are provided.

### System Peak

Times of highest system demand during the year.

**T**

### Transmission Entry Capacity (TEC)

Defines a generator's maximum allowed export capacity onto the transmission system. The holder of the TEC has the right to export the specified number of megawatts onto the transmission system at any one time, and is eligible for compensation if NGET cannot accommodate this export on the network.

### Transmission Network Use of System (TNUoS) charges

Charges levied by NGET on users of the GB electricity transmission network to recover the costs of providing and maintaining the general network infrastructure assets. TNUoS charges vary by location, and are different for generators and for suppliers.