Transmission Arrangements for Distributed Generation (“TADG”)

Working Group Report

July 2007

Executive Summary

During the development of British Electricity Trading and Transmission Arrangements ("BETTA"), which were implemented in April 2005, parties raised a number of issues with the treatment of distributed generation ("DG") within the transmission charging arrangements. These issues included cost-reflectivity and incentives created by embedded benefits and the interaction with transmission access issues, particularly in the context of DG leading to exports from the distribution system to the transmission system and leading to transmission investment. As an interim measure, Ofgem introduced the "small generator discount" to address the differences in treatment for 132kV connected generators under 100MW in Scotland compared to England & Wales. The discount was set for three years with a view to reviewing the transmission charging arrangements with respect to DG after BETTA.

The review process was initiated in September 2005, when Ofgem published a discussion document seeking views on the appropriateness of the existing transmission charging arrangements for DG, and on high level options for change, in the context of changes to the traditional pattern of network usage including an increase in the volume of DG connections. Ofgem further noted that, as a minimum, the review should seek to develop, if appropriate, an enduring solution to replace the small generator discount noting that it will cease in March 2008.

Taking into account responses to the discussion document, in May 2006 Ofgem published a further thoughts document in which it announced its intention to establish an industry working group to develop specific options for change to the charging arrangements, while also considering related issues of transmission access, operation and planning. In particular, the group would seek to develop enduring transmission arrangements which reflect the impact of DG on the transmission system. In doing so it would focus on the development of agency models, which enable DG to use an agent, such as their supplier or distribution network operator ("DNO"), to deal with transmission-related issues thereby minimising the need for direct interfaces with NGET.

That working group, known as the Transmission Arrangements for Distributed Generation ("TADG") Working Group (the "Group"), held eight meetings between July 2006 and April 2007, in which it:

- Explored the issues with the treatment of DG in the existing transmission arrangements and associated consequences of the continued growth of DG, in terms of operation & planning issues and access & charging issues

- Developed a range of strawman agency models each designed to address particular issues

- Assessed each strawman, and the existing arrangements, against the Group's key objectives, namely to minimise implementation costs, be cost-reflective, and facilitate efficient development and use of the network.

This Working Group Report (the "Report") summarises the process followed by the TADG Working Group and sets out its key findings. Although the Group was chaired by Ofgem and this Report was drafted by Ofgem, Ofgem's role in the Group was purely to facilitate and co-ordinate industry debate. **This Report seeks to document the discussions and findings of the Group as a whole, and should not be taken as representing Ofgem's views**.

The Group had representation from across the industry, amongst which there were diverse views. A number of issues were raised with the existing arrangements, in the context of both operation & planning and access & charging. However the Group was divided on the nature and materiality of individual issues.

The majority of the Group agreed that the existence of a gap in the contractual framework with respect to exports to the transmission system is a material issue and that there is a need to minimise contractual burden. The majority of the Group agreed that agency models are an appropriate means to address these issues, and that the operation & planning issues identified are not the primary driver for change. The Group was split on the issue of the cost reflectivity of the current treatment of DG in transmission charging. Some questioned the continuing appropriateness of embedded benefits and argued that DG should pay transmission charges, with mixed views on whether such charges should be applied to gross generation exports or based on net exports to the transmission system, at a GSP or GSP Group level.

Four strawman agency models were put forward by Group members, which were each targeted to addressing particular issues from the proposer's perspective:

- A DNO agency model with charges applicable to net exports at individual GSPs and charged out to DG on the basis of connection voltage, proposed by SP T&D

- A DNO agency model with charges applicable to net exports at individual GSPs and charged out to all DG contributing to export, proposed by Airtricity

- A supplier agency model with charges applicable to net exports from suppliers over each GSP group, proposed by CE Electric UK

- A supplier agency model with charges applicable to gross generation exports from suppliers at individual GSPs, proposed by NGET

By applying transmission charges for exports associated with DG any of these models could impact, to varying extents, on the existing embedded benefits received by DG, but they differ in the way in which those exports are defined and charged for, the party acting as agent and the scope of the agency model. Each model would also confer transmission access rights to DG via the respective agent, without requiring DG to contract directly with NGET.

The Group assessed each strawman model against the TADG objectives. The Group noted each strawman could be implemented with minimal change, although a number of areas of further work were identified in each case. The Group agreed that either a supplier or DNO agency model could theoretically form a suitable basis for an agency model, but were unable to agree on individual strawman in terms of cost-reflectivity and facilitating efficient network development. The Group considered that the primary source of this division of views was the use of a gross or net model for access and charging, which was perceived as the main driver of the commercial impacts on industry parties. Overall, the majority of the Group favoured a net DNO agency approach, while a small minority supported a gross supplier agency approach.

It is noted that the TADG Working Group is not a decision-making body. Its role is to facilitate development by the industry of holistic options for change, in terms of the package of changes to industry codes required to implement each model. **It is for the industry to decide whether to take forward any given option, through change proposals to industry codes.** Any such proposals will ultimately be submitted to Ofgem for decision.

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1. Introduction

Background

Context

1.1. This document is the Working Group Report (the "Report") of the Transmission Arrangements for Distributed Generation ("TADG") Working Group. The TADG Working Group (the "Group") is an industry working group which was set up by Ofgem to develop options for change to the existing transmission charging and contractual arrangements for distributed generators ("DG"). The Group was established by Ofgem[1] at the request of the industry, to build upon the findings of an initial review through a series of Ofgem documents and workshops, set out as follows.

Ofgem consultation process pre-TADG

1.2. In April 2005, British Electricity Trading and Transmission Arrangements ("BETTA") were implemented in Great Britain ("GB"), including the introduction of single GB-wide transmission charging arrangements developed by National Grid Electricity Transmission plc ("NGET") in its role as GB system operator. During the development of GB charging arrangements a number of concerns were raised by parties in relation to the transmission arrangements with respect to DG, including:

- Impact of DG on the transmission system
- Cost-reflectivity of transmission charges and embedded benefits
- Perverse incentives – voltage, location, size
- Interaction with access issues.

1.3. NGET noted that given the timescales for implementing BETTA it did not intend to address these concerns within the initial GB charging methodologies but that it may be appropriate to further review the matter after BETTA. One consequence of these considerations was that Ofgem introduced an interim discount for 132kV connected generators under 100MW in Scotland. This "small generator discount" was introduced because of concerns over discrepancies between the transmission charges faced by 132kV connected generators in Scotland and those of the same size connected in England & Wales. The discount was set for a period of three years as an interim measure with a view to reviewing the charging arrangements with respect to DG and developing enduring arrangements.

1.4. Further, in approving NGET's proposed GB transmission charging arrangements in March 2005, the Gas and Electricity Markets Authority ("the Authority") confirmed that it considered that there would be merit in NGET further reviewing the appropriateness of its charging arrangements to accommodate the increasing demand for transmission capacity from DG. As a first stage in this process Ofgem announced its intention to undertake a consultation seeking views on the key issues and high level options for change.

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[1] For more detail see the Invitation and draft Terms of Reference, attached as Appendix 1.

1.5. In September 2005 Ofgem published a discussion document[2] which described the existing transmission charging and contractual arrangements with respect to DG, outlined a number of key issues arising from the arrangements and highlighted a range of potential options for addressing these issues. The purpose of the 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. These views were explored further in two industry workshops hosted by Ofgem in Glasgow on 19 January 2006 and in London on 24 January 2006.

1.6. On 31 May 2006 Ofgem published a further thoughts document[3]. This summarised respondents' views and sought to focus debate on the future direction of the development of the existing transmission charging and contractual arrangements with respect to DG.

1.7. In initiating the above consultation process Ofgem highlighted that recent developments (including BETTA and the Government's Renewables Obligation ("RO")) in the regulatory arrangements and incentives to connect new generation had meant that the traditional pattern of network usage has altered, and was likely to continue to do so. Ofgem noted that one of the principal changes was an increase in the volume of DG connected to the network, leading to the likelihood that distribution networks would 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. The Ofgem consultation process considered, in the context of these developments and in the light of the issues noted above, the appropriateness of the existing charging arrangements on an enduring basis and outlined some high level options for change. Ofgem further noted that, as a minimum, the purpose of the review of enduring transmission arrangements should be to develop, if appropriate, an enduring solution to replace the small generator discount noting that it will cease in March 2008.

1.8. Having taken into account industry views expressed during the consultation process, Ofgem reaffirmed its view that an enduring transmission charging framework, taking full account of the costs arising as a consequence of the connection and actions of DG, needs to be robust to the changing physical background. Ofgem further acknowledged industry views that issues of operational control, planning and access are also relevant when considering enduring arrangements which reflect the impact of DG on the transmission network.

1.9. One of the key views that emerged out of the consultation process was the complexity of the issues to be addressed and the fact that those issues potentially cut across a number of different industry codes and documents. This would mean that the governance and consultation processes for any of the individual codes or documents would be insufficient to develop a holistic solution to the existing problems. While retaining the view that it should be for licencees, in tandem with the industry, to develop any proposals, Ofgem accepted industry views that Ofgem needed to have a central role in the process going forward to facilitate development by the industry of holistic options for change.

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

[3] Enduring transmission arrangements for distributed generation – further thoughts document – 31 May 2006, Ofgem #92/06

Establishment of TADG

1.10. Taking these industry views into account the TADG Working Group was set up by Ofgem to build on the findings of the review and to develop specific options for change which are both achievable in the medium term and capable of addressing identified issues with the existing arrangements.

1.11. The Group would primarily focus on developing in more detail the options identified by industry parties through that process as having the most potential to deliver a robust enduring framework, namely agency models. In this context, agency models seek to enable DG to use a third party such as their supplier or Distribution Network Operator ("DNO") to deal with transmission-related issues, in particular access and charging, rather than contracting directly with NGET.

Group composition and role

1.12. On 21 June 2006 Ofgem issued an open letter[4] announcing the establishment of the TADG Working Group, setting out its purpose and draft Terms of Reference, and seeking applications from parties wishing to be involved.

1.13. In total the Group had 27 full industry members, together with a number of alternates and correspondence members. The membership was drawn from a broad range of industry parties including transmission licencees, distribution licencees, large generators, small generators, suppliers, and trade associations. The meetings of the Group were well attended with an average of 20 industry attendees per meeting, plus Ofgem.

1.14. In the first meeting of the Group Ofgem noted that the Group was specifically focussed on developing options for change to the transmission arrangements to reflect the impact of DG on that network, but that it recognises that there were also wider issues affecting DG. Ofgem clarified that while it was not the purpose of TADG to address all issues affecting DG it would note any interactions to be considered as part of the implementation issues associated with any of the models developed by the group.

1.15. In establishing the Group Ofgem anticipated that the working group format would facilitate and co-ordinate industry discussion in a holistic manner, leading to the development of strawman models and the identification of changes to the industry codes, licences or other documents, the combination of which would be necessary to deliver those models. It would then be for the industry to consider whether to take forward any of the strawmen and if so to submit change proposals to the industry codes, which would then be subject to the relevant modification procedures including industry consultation as appropriate.

1.16. Ofgem also highlighted that it was important to note that the Group was a development group and not a decision making body. In particular, nothing presented or discussed at the Group, nor contained in this Report, can have the effect of fettering the Authority's discretion in relation to any decisions it takes on any forthcoming relevant industry code modification proposals.

[4] Attached as Appendix 1.

Group objectives and scope of work

1.17. The Terms of Reference for the Group were finalised following the first meeting of the Group, taking into account parties' views. The final Terms of Reference are attached as Appendix 2. The following is an outline of some of the key points. For more detail the reader is referred to the full Terms of Reference.

TADG objectives

1.18. The purpose of the Group is to seek to identify options for change[5] to the existing transmission arrangements as they affect DG in the light of the following criteria:

- **Minimising implementation costs.** The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumers.
- **Cost reflectivity.** The arrangements should seek to reflect the costs and benefits that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.
- **Efficient network development.** Arrangements should encourage efficient decisions to be taken regarding the development and use of the transmission and distribution networks.

Scope

1.19. The key work areas noted as being in scope of the Group were:

- the development of appropriate **transmission charging** arrangements including appropriate thresholds that ensure parties pay charges which reflect the costs they impose on the networks and which thereby remove the scope for **perverse incentives** when deciding where, and at which voltage, to connect
- the interaction with issues of **transmission access** including the treatment of exporting Grid Supply Points without access rights to the GB transmission system, the contractual arrangements associated with and nature of access rights appropriate to DG and any interactions with the work of the Access Reform Options Development Group
- the impact of DG, as compared to transmission connected generation and demand, on the **operation and planning** of the GB transmission system and what that implies for system planning and operational control, including issues around the need for direct interfaces between DG and the GB system operator
- the ease of **implementation** and implementation costs, both one-off and ongoing, associated with any solution and associated **interactions** with other policy areas.

[5] Specifically agency models, as noted above.

1.20. It also noted key questions to consider when developing options for change:

- to what extent is the **impact** (flows, operation, planning, investment and associated costs) of DG on the GB transmission system, either individually or in aggregate, the same as that of transmission connected generation?

- are the existing transmission **access products** appropriate to DG, is there merit in considering access products based on the export to the GB transmission system rather than the full capacity of a given generator or group of generators, or procured via an agent?

- if a DG does not have firm transmission access rights then how can its export to the GB transmission system be **controlled** if necessary? Can this be achieved through the Distribution Network Operator or the supplier?

Deliverables

1.21. The main deliverable of the Group is this Report, together with publication of the Group's findings.

Availability of documentation

1.22. Material from each meeting of the Group including agendas, minutes, papers and presentations, together with this Report, is publicly available on Ofgem's website, as are the Ofgem documents referred to above and industry responses to the September 2005 discussion document.

Structure of this document

1.23. This Report focuses on the process followed by and key outputs of the Group. For more detail the reader is referred to material from the individual meetings.

1.24. The remainder of this document is structured as follows:

- **Chapter 2** summarises the overall process followed by the Group
- **Chapter 3** sets out the Group's assessment of the issues with the existing arrangements
- **Chapter 4** describes the Group's development and assessment of agency options for change
- **Chapter 5** discusses interactions with developments in interrelated areas as noted by the Group
- **Chapter 6** sets out the way forward.

2. Process

Structure of meetings

2.1. In Meeting 1 the Terms of Reference were finalised and overall scope of work agreed. This included an initial programme of work over a period of seven meetings, which was refined in subsequent meetings to that set out in Table 1.

Table 1: Structure of meetings

Meeting	Date	Location	Scope
1	14 July 2006	Millbank	Introduction and scope of work
2	17 August 2006	Millbank	Operation & planning issues
3	15 September 2006	Millbank	Access & charging issues (1)
4	26 October 2006	Glasgow	Access & charging issues (2)
5	22 November 2006	Millbank	Agency strawmen
6	19 December 2006	Millbank	Strawmen assessment (1)
7	13 February 2007	Millbank	Strawmen assessment (2)
8	26 April 2007	Millbank	Draft working group report

Assessment process

2.2. The Group's assessment over Meetings 1–7 comprised two stages[6]:

- **Stage 1** focussed on discussion of issues with the existing transmission arrangements and associated consequences of continued growth of DG, in terms of operation & planning issues and access & charging issues; in parallel, initial strawmen were developed by and presented to the Group.
- **Stage 2** focussed on establishing a common framework for defining and assessing models, and then applying this framework to the individual strawmen proposed as specific options for change.

2.3. Finally, in Meeting 8 the Group reconvened to review the draft working group report and agree its conclusions.

Incorporation of working group views

2.4. Although the Group was chaired by Ofgem and this Report was drafted by Ofgem, Ofgem's participative role in the Group was purely to facilitate and co-ordinate debate. **This Report seeks to document the discussions and findings of the Group as a whole from the assessment process outlined above, and should not be taken as representing Ofgem's views.**

[6] The Group's assessment process and findings are discussed in more detail in Chapters 3-5.

2.5. In Meeting 1 Ofgem issued an open invitation to attendees to present their perspectives on the issues under discussion at each meeting and to develop strawmen for presentation to the Group. In total 8 industry parties gave presentations or submitted papers for discussion at meetings, of which 4 industry parties ultimately proposed strawmen for assessment by the Group[7]. These contributions are summarised in Table 2.

Table 2: List of parties submitting papers, presentations or strawmen

Industry party	Paper / presentation for discussion	Strawman model for assessment
Airtricity	Yes	Yes
CE Electric UK	Yes	Yes
NGET	Yes	Yes
SP T&D	Yes	Yes
DTI Centre for DG & Sustainable Electrical Energy	Yes	No
EON	Yes	No
Garrad Hassan	Yes	No
REA	Yes	No

2.6. In addition to the discussions within meetings, including the above papers and presentations by attendees, Ofgem specifically invited views from the Group at the following key stages in the process:

2.7. **Terms of reference**. The draft Terms of Reference were presented by Ofgem for discussion by the Group at Meeting 1, and finalised at Meeting 2 taking into account comments from the Group. Both versions are included as Appendices to this Report.

2.8. **Meeting minutes**. Minutes of each meeting were drafted by Ofgem and circulated to the Group for comment before being finalised at the subsequent meeting taking into account comments received.

2.9. **Issues questionnaire**. Following Meeting 6, Ofgem sought written views from the Group, by way of a short questionnaire, on the nature and materiality of the issues with the existing arrangements. The non-confidential responses are attached as Annex 1 to this Report.

2.10. **Strawman definition and assessment framework**. Following Meeting 5, Ofgem sought views on the framework to be used by the Group to define and assess strawman models, such that they could be compared in consistent terms. The agreed way forward was then used as a basis for the assessment of individual strawmen.

[7] A number of other parties informally expressed an initial interest in developing strawmen, but subsequently did not bring forward specific proposals on the basis that their views were covered by the models already under discussion.

2.11. **Strawman assessment questionnaire**. Following Meeting 7, Ofgem sought written views from the Group, by way of a short questionnaire, on the proposed strawman models and on retaining the existing arrangements on an enduring basis. The non-confidential responses are attached as Annex 2 to this Report.

2.12. **Draft working group report**. Ofgem issued the draft Working Group Report to the group for discussion at Meeting 8. The Report was subsequently updated incorporating the final conclusions of the group.

3. Issues with the existing arrangements

Assessment structure

Overall approach

3.1. In agreeing the broad scope of work in Meeting 1, the Group agreed that it would be necessary to consider both operation and planning issues, and access and charging issues, in the context of developing agency strawmen. Parties also raised the issue of a need for a clearer understanding of the nature and materiality of the issues with the current arrangements and of the approach to the development of agency models.

3.2. In Meeting 2 Ofgem proposed a structure for progressing TADG in light of these views. The assessment structure sought to identify the issues or problems with the current arrangements and their associated consequences, and the extent they are currently, or may in the future be, addressed through agency models, in the context of future DG growth and developments in interrelated areas.

3.3. Ofgem noted that at a high level the issues raised through the Ofgem consultation process related to:

- Perverse incentives
- Shortage of transmission access capacity
- Growth of DG without becoming a BMU
- Growth of DG without any bilateral agreement with the GBSO
- Current contract forms and access products available to DG
- Treatment of DG as negative demand.

3.4. Ofgem noted that these issues may individually have consequences spanning both operation & planning issues and access & charging issues, and that implementation issues were also a key consideration in the overall assessment.

3.5. It was agreed that to give structure to the debate going forward, the Group would first focus on operation & planning issues then access & charging issues, separately and in terms of the above framework, before consolidating issues across all areas. In parallel, strawman models would be developed and then assessed, relative to the existing arrangements, in the context of the issues identified. In doing so the Group would also consider implementation issues for each model, including interactions with developments in interrelated areas.

3.6. This Chapter sets out the Group's assessment of the issues with the existing arrangements. The Group considered both the nature of the issues, building on findings from Ofgem consultation process to date, and their materiality. This process culminated in Ofgem seeking written views from the Group in the form of a short questionnaire. The Group's development and assessment of strawmen, with reference to the particular issues which each model seeks to address, is discussed in Chapter 4.

3.7. This Chapter also outlines various aspects of the existing arrangements with respect to DG which were highlighted in the Group's discussions, including a number of recent changes to industry codes. For a fuller description of the existing arrangements the reader is referred to Ofgem's September 2005 paper and to the documentation associated with subsequent changes to industry codes to which this Chapter refers.

Quantification

3.8. A key issue raised by industry parties throughout the process was in relation to the need for quantification of the extent to which volumes of DG are likely to increase. Prior to the establishment of the Group Ofgem had written to NGET and the DNO's requesting initial, high level, information of the likely future change in the pattern of generation and demand connecting to the networks. The information provided was published as part of Ofgem's May 2006 paper.

3.9. The intention in publishing this information was to enable parties to put into context the projected growth in DG and consequently the magnitude of the perceived problem. Ofgem highlighted that data indicated the following approximate overall changes between 2006 and 2010:

- an additional 7GW of DG
- an additional 10GW of transmission connected generation
- an additional demand of around 3GW.

3.10. Ofgem further noted that while there was uncertainty as to the exact figures, the data indicated a net position in which the increase in DG outstripped the increase in demand.

3.11. The Group discussed the merits of undertaking further quantification but agreed that the data provided to date remained the best data currently available, given the ongoing uncertainty as to the future growth of DG, and expected that a similar exercise undertaken based on the latest information would yield similar results. The Group concluded that no further analysis was required for the purposes of this Report, but that it should include the information previously published in the May 2006 paper; this is set out in Appendix 3.

Operation and planning issues

Structure of debate

3.12. The main focus of Meeting 2 was the discussion of operation and planning issues and their implications for the development of agency models. In this context there was an introductory presentation from Ofgem and a presentation from NGET[8] setting out its perspective, followed by a working group discussion on the issues raised. Further, at Meeting 5 the Group discussed a paper by Garrad Hassan[9] on international examples, which was submitted as an action from Meeting 2. These contributions to the debate are outlined below, followed by a summary of the key themes from the associated working group discussions.

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[8] NGET elaborated further on these views in subsequent meetings in the context of its presentations on its strawman model, in particular its presentation to Meeting 4 and paper to Meeting 7

[9] The Garrad Hassan paper also raised wider issues beyond the scope of TADG, discussed in Chapter 5

Ofgem introduction

3.13. Ofgem's introductory presentation at Meeting 2 outlined a number of operating and planning issues which may be relevant to the consideration of transmission arrangements for DG in general. It also set out some questions for the Group to consider when assessing the existing arrangements and developing agency options for change.

3.14. The general operation and planning issues related to:

- **Transmission planning and investment** – what are planning drivers for DG as compared to transmission connected generation or demand?
- **Constraint management** – to what extent are transmission constraints caused by DG and how are they managed? Is there a need for DG to be controlled by the GBSO?
- **Information provision** – what information does the GBSO require on DG and how is this provided?
- **Ancillary services** – to what extent are DG able or required to provide ancillary services to the GBSO?
- **Interfaces** – what are the interfaces for the above?
- **Differential treatment –** what thresholds / criteria apply and what is their rationale? Does this create perverse incentives?

3.15. The Group were asked to consider the robustness of the existing arrangements to the projected growth of DG and in the context of ongoing developments in interrelated areas.

3.16. Ofgem also invited the Group to consider the extent to which an agency approach already exists in, or could be applied in, the above areas. As an example of an existing agency approach, Ofgem referred to the recent changes[10] to the Grid Code and Distribution Code which provided a framework whereby Grid Code technical requirements associated with Licence Exempt Embedded Medium[11] Power Stations ("LEEMPS") could be passed to DG through the DNO. The arrangements provide an indirect route for applying the relevant Grid Code obligations and remove the requirement for such DG to have a direct contractual relationship with NGET[12].

Industry papers and presentations

3.17. NGET's presentation to Meeting 2 set out its perspective of the specific issues and problems to be addressed in the context of operation and planning. The Group identified that the key issues from the presentation, which are set out in more detail below, related to:

- provision of information in relation to DG

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[10] Changes in association with Grid Code consultation D/05 ("Grid Code Changes Associated with Licence Exempt Embedded Medium Power Stations") and consequential changes to the Distribution Code, both implemented on 1 April 2006. For more information see NGET's website and the Distribution Code website
[11] See Table 3 below
[12] The contractual requirements for DG with NGET are discussed in later in this Chapter under Access and charging issues

- planning for the connection of DG
- the ability of NGET to control the operation of DG.

3.18. NGET also noted its view that the issues would best be addressed through agency models by having:

- contractual relationship with the agent responsible for DG, in order to control energisation and manage constraints
- chargeable access product for the agent in relation to DG, in order to incentivise accurate data submission on DG by the agent and ensure DG face the costs they impose on the system.

3.19. In Meeting 2 Garrad Hassan raised the issue of drawing from international examples of the treatment of DG when developing agency models with respect to operation and planning issues, and subsequently presented a paper entitled "Wind Farm Forecasting and Implications for Agency Models". The main conclusions from the paper, which focussed on international examples and studies of forecasting in short term timescales, were noted by Garrad Hassan to be:

- markets do not always incentivise accurate information provision
- forecasts produced by the market are not always useful to the grid operator, which may in fact produce and use its own forecasts
- for wind energy, forecast accuracy can be improved by aggregation, particularly over large geographic area, and in timescales close to real time.

Key themes from working group discussions

Planning timescales

3.20. NGET outlined the planning process under the current arrangements, contrasting the "invest and connect" approach, applicable to transmission-connected generation and some DG, with the "connect and invest" approach generally applicable to smaller DG. The key differences between these approaches relates to the processes for identification of any associated transmission investment and the level of control NGET have over the energisation of connections. For DG the applicability of each approach varies according to its classification in terms of the size definitions in the Grid Code, which vary by transmission area; the current definitions[13] are set out in Table 3.

Table 3: Grid Code size definitions by transmission area

Grid Code size definition	England & Wales (NGET area)	South Scotland (SPT area)	North Scotland (SHETL area)
Small Power Station	< 50 MW	<30 MW	<10 MW
Medium Power Station	50 – 100 MW	-	-
Large Power Station	≥ 100 MW	≥ 30 MW	≥ 10 MW

[13] Applicable from 1 September 2006 following Authority approval of Grid Code changes arising from consultation B/06 ("Regional Differences"), for more information see NGET's website

3.21. Under the "invest and connect" approach a party submits an application to the GBSO and any associated transmission investment requirements are identified. Where works are required, a contractual arrangement is entered into so that energisation of the connection is contingent on those works being completed and secured throughout construction. This applies to all transmission-connected generation and any DG who contract directly with NGET. This includes all DG which are classed as Large Power Stations under the Grid Code, which must contract directly with NGET[14].

3.22. Following implementation of CAP097[15], the "invest and connect" approach also applies to any DG which are classed as Medium Power Stations but do not contract directly with NGET. In that case the DG applies to the DNO for connection to the distribution system, and the DNO in turn applies to the GBSO and enters into a contractual arrangement in relation to transmission works if the DG is deemed to have a material effect on the transmission system. The energisation of the DG connection is then contingent on the transmission works being completed and the DNO secures the works throughout construction. These arrangements introduced by CAP097 also apply to any DG classed as Small Power Stations which the DNO believes may have a significant impact on the GB Transmission System. Such Small DG are identified as Relevant for the purposes of CUSC paragraph 6.5.1.

3.23. Under the "connect and invest" approach, which applies to all other Small DG, there is no contractual arrangement with NGET in relation to a new DG connection and NGET has no control over the timing of its energisation. However, NGET receives information on such connections through the Week 24 data submitted by DNOs under the Grid Code, which then form the basis for identification of transmission investment requirements, e.g. SGTs.

3.24. NGET raised the following issues with the above process, and noted they would only be exacerbated with continued growth of DG:

- Volatility of Week 24 data and uncertainty of DG operation impacting on the planning process and complicating SGT investment decisions
- Connection of small DG can lead to transmission investment, but the latter has longer lead times leading to transmission playing catch-up
- DG energisation before transmission reinforcements are ready, leading to bypass of GB queue
- CAP097 does not address cumulative impact of multiple small DG.

3.25. While noting that the above issues were not the primary drivers for change, NGET argued that they could be addressed by introducing a chargeable access product procured by an agent on behalf of DG. That agent in turn would have a contractual relationship with NGET by which energisation of the DG connection could be controlled.

[14] See the section on Access & Charging Issues in this Chapter
[15] CUSC Amendment Proposal CAP097 "Revisions to the Contractual Requirements for Small and Medium Embedded Power Stations Under 6.5", of which Consultation Alternative Amendment CAA2 was approved by the Authority on 14 June 2006 for implementation on 14 July 2006, for more information see NGET's website

3.26. The majority of the Group were not persuaded by NGET's views. In terms of NGET's arguments on information provision, it was noted that NGET had not to date raised any issues with the DNOs in relation to the Week 24 data submissions under the Grid Code. Further, the existing arrangements allowed for those provisions to be strengthened by modification to the Grid Code but NGET had not to date pursued this, nor had it provided any evidence as to materiality. Attendees further argued that introducing a chargeable access product may not necessarily incentivise more accurate data provision, and that it is unclear that greater accuracy is indeed feasible given the inherent uncertainty as to the volume and timescales for growth of small DG.

3.27. Additionally, some thought NGET should share some exposure to the risks this uncertainty creates from a planning perspective, e.g. by undertaking its own forecasting based on probabilistic techniques and taking diversity into account, rather than relying on firm information provision from users. The interaction with variability of demand, e.g. due to energy efficiency measures, was also noted. These arguments were further developed in the discussion on the Garrad Hassan paper, where the Group noted that aggregation may improve forecast accuracy where there is diversity in underlying sources, particularly in short term timescales, but that this may work less well when aggregating different types of DG and demand. It was also suggested that the same principles might apply to forecasting household micro-generation in terms of demand usage. The Group also recognised that from a transmission design perspective it is appropriate to base investment on worst case scenarios, while also noting that such conditions may be less likely to occur in practice when diversity is taken into account, and that this may have implications for the development of agency models.

3.28. Attendees also referred to the recent Grid Code review of size definitions[16], noting this altered the thresholds for determining the level below which NGET do not need visibility of operation of individual DG, and suggesting that this forms a suitable basis for determining whether DG impact on the transmission system. It was also argued that the incremental growth of multiple small DG may be slow to have a cumulative impact on investment in the transmission system, and could be planned through trending rather than direct control over energisation of connections. It was also suggested that the treatment of DG in the GB SQSS could be reviewed noting that P2/6[17] had recently replaced P2/5.

Operational timescales

3.29. In terms of real time operation NGET noted that under the current arrangements transmission constraint management is normally via transmission connected generation, and that it generally has no direct control over DG as there is currently no commercial procedure to constrain DG without a defined access product. It highlighted that DG can exacerbate boundary overloads and make them more difficult to manage, and that from a system operation perspective it is important to be able to constrain plant on a nodal basis. While it noted that under the current arrangements it could do so by entering bilateral commercial agreements with individual DG, it raised concerns as to the practicality of managing multiple bilateral contracts with continued growth of DG. NGET argued that these issues could be addressed by NGET having a contractual relationship

[16] Undertaken by the Regional Differences Working Group which submitted its report to the Grid Code Review Panel in February 2006, on the basis of which NGET issued its consultation on B/06 ("Regional Differences"), see footnote 13
[17] Engineering Recommendation P2/6 in the Glossary of Terms in Appendix 4.

with an agent via which the output of the DG could be controlled under an associated commercial framework for managing constraints.

3.30. There were mixed views within the Group as to the appropriateness of, and need for, NGET being able to control small DG for constraint management purposes. Attendees raised a number of issues as to the practicalities and procedures for doing so. Noting that under the current arrangements DG have a choice whether to participate in the BM, including those trading in the wholesale arrangements by becoming a BMU, it was argued that this principle of choice should be retained with all constraint management being through market-based mechanisms.

3.31. However, parties generally accepted that there may be a need for emergency control of DG, while noting that the current arrangements enabled NGET to use emergency measures through DNOs to manage total system demand but that there is no equivalent with respect to DG. It was suggested that this could be addressed by modification to the Grid Code to introduce parallel provisions.

Agency arrangements

3.32. As described in more detail above, in addition to the LEEMPS arrangements referred to by Ofgem, the following existing agency arrangements were noted by the Group with respect to operation and planning:

- CAP097 provisions introduced an agency arrangement whereby the DNO contracts with NGET with respect to the energisation of and securing of transmission works associated with a new DG connection, in cases where that DG does not contract directly with NGET but may have a significant impact on the transmission system.
- The week 24 data submissions are also an existing form of agency arrangement whereby the DNO provides forecast demand information to NGET which takes into account DG connected to their distribution networks.

3.33. The Group also considered implications for the development of agency models. The Group noted the benefits of minimising the number of interfaces through agency arrangements for DG, while retaining the principle of choice between entering that arrangement and contracting directly with NGET. It was noted that an agency approach may be suited to provision of information on an aggregate basis and taking diversity into account, and that a DNO may provide better information on flows on and off its network associated with both generation and demand. Noting the current Grid Code size definitions relate to individual DG, it may be appropriate to consider appropriate thresholds for aggregate DG under an agency model. The issues around applying an agency approach to constraint management were also noted, where it would be necessary to consider how to map control instructions from NGET to individual DG.

Access and charging issues

Structure of debate

3.34. The discussion on access and charging issues followed a similar structure to that followed for operation and planning issues. At Meeting 3 there was an introductory presentation from Ofgem and presentations from NGET and E.ON each setting out their perspectives, followed by a working group discussion on the issues raised. This discussion continued at Meeting 4, which also included a presentation from REA on its perspective. Further, at Meeting 4 the Group discussed a paper by NGET on BEGAs and BELLAs. In addition, the DTI Centre for DG & Sustainable Electrical Energy[18] gave a presentation at Meeting 6 and followup paper to Meeting 7 on its work in relation on transmission investment, access and pricing. The DTI Centre for DG & Sustainable Electrical Energy submitted a further paper to and presentation at Meeting 8, which put this work in the context of developing agency models for DG. These contributions to the debate are outlined below, followed by a summary of the key themes from the associated working group discussions.

Ofgem introduction

3.35. Ofgem's introductory presentation at Meeting 3 outlined a number of access and charging issues which may be relevant to the consideration of transmission arrangements for DG in general and to the development of agency models, as follows:

- **Bilateral agreements** – what forms of bilateral agreement with NGET are available to, required by or relate to DG, whether contracting directly with NGET or via an agent? What DG rights and obligations do these agreements cover?
- **Access rights** – what is the nature of the rights under these agreements for DG to use the total system; the basis of the transmission access product, if applicable; the compensation arrangements and mechanism for curtailment of access?
- **Cost-reflective transmission charges** – to what extent do DG with such rights impact on transmission investment costs, compared to transmission connected generation or demand? How is DG treated in the transmission charging methodology? Are charges applied directly or via an agent?
- **Differential treatment** – what thresholds / criteria apply and what is their rationale? Does this create perverse incentives?

3.36. The Group were asked to consider the robustness of the existing arrangements to the projected growth of DG and the extent to which an agency approach already exists in or could be extended to the above areas. In this context Ofgem also invited the Group to consider the extent to which the existing forms of bilateral agreement meet the needs of DG and NGET, the appropriateness of the existing transmission access products for DG, the extent to which the charging methodology currently reflects the impact of DG on transmission investment, and the treatment of exporting GSPs.

[18] The DTI Centre for DG & Sustainable Electrical Energy presentation and paper also raised wider issues beyond the scope of TADG, discussed in Chapter 5

Industry papers and presentations

3.37. NGET's presentation on "Embedded Generation – Charging and Access" at Meeting 3 outlined the key access & charging issues from NGET's perspective as:

- the cost-reflectivity of TNUoS embedded benefit (the absolute difference between being charged as transmission connected generation vs being charged as negative demand, being the sum of the respective residual charges)
- the potential discrimination arising from current differential treatment given that DG have the same impact on transmission flows as equivalent transmission connected generation and avoided investment is not proportional to TNUoS embedded benefit
- the need to formalise DG's transmission access rights in order to apply charges and better inform transmission investment
- the benefits of an agent purchasing access rights on behalf of DG.

3.38. E.ON's presentation on "Net versus Gross Transmission Access and Charging" at Meeting 3 highlighted the key issues from E.ON's perspective as:

- the need to consider distribution charges when comparing the charging arrangements for DG vs transmission connected generation
- the difference in TNUoS charges is due to the residual charge, not the locational charge
- charging DG the same TNUoS as transmission connected generation would create a perverse incentive to be transmission connected when distribution charges are taken into account
- net charging is consistent with other aspects of the trading arrangements
- gross charging is not necessary for information provision given other routes are available
- is it cost-reflective to apply gross charges to distribution users if the transmission system is designed to accommodate net flows to/from the distribution system?

3.39. REA's presentation on "Gross and net charging issues" at Meeting 4:

- sought to highlight some areas of common understanding from discussions at the TADG working group meetings to date
- argued that net charging is appropriate as costs are imposed by net flows
- noted various examples of interconnected networks, arguing that all should be treated the same in terms of whether charges are gross or net
- highlighted some issues with applying gross charging to other examples of interconnected networks.

3.40. NGET's paper "Embedded generation agreements under the CUSC", submitted as an action from Meeting 3, sought to explain the differences between a BEGA and BELLA, both agreements under the CUSC applicable to DG. It focussed on the rights to switch between a BEGA and a BELLA and the wider rights and obligations associated with each.

3.41. The DTI Centre for DG & Sustainable Electrical Energy presentation at Meeting 6 on "Transmission Investment, Pricing and Access in Systems with DG" and following paper to Meeting 7 outlined some work undertaken with the DTI in this respect, and:

- discussed the concept of TEC, in terms of efficiency of network investment, cost-reflectivity of TNUoS charging and efficiency of system operation
- suggested various limitations with the existing arrangements
- argued that TEC does not provide an appropriate framework for DG.

3.42. The DTI Centre for DG & Sustainable Electrical Energy presentation at Meeting 8 on its second paper "Integration of distributed generation into the UK power system" sought to highlight where its work raised issues relevant to TADG and in particular the development of agency models, and:

- sought to address key questions in the TADG Terms of Reference in terms of the impact of DG on the transmission system and the appropriate access products for DG
- argued that DG do not impact on transmission system capacity requirements in the same way as conventional generation, relating this to differences in the pattern of operation and the effect of diversity of generation at a GSP
- argued that while the existing access products (TEC) are appropriate to conventional generation, they are not suitable for DG as they may lead to inefficiency by not permitting sharing of transmission capacity
- highlighted the general benefits of agency models in terms of reflecting diversity and time of use, and argued in favour of a net model based on the net position at the GSP and with the DNO as agent
- outlined some areas of further work.

Key themes from working group discussions

Bilateral agreements and associated access rights

3.43. The Group referred to the CUSC which sets out requirements to enter into a bilateral agreement with NGET and includes standard contract forms for those agreements. The forms of bilateral agreement directly applicable to DG are the BEGA and BELLA, the differences between which were set out in NGET's paper "Embedded generation agreements under the CUSC". The Group noted that the requirements to enter into these agreements relate both to the current criteria for exemptions from the requirement to hold a generation licence[19] and to the size thresholds under the Grid Code. All licenced DG, which includes all DG over 100MW, must be parties to the CUSC and the BSC, and contract directly with NGET by entering a BEGA and are directly subject to the requirements of the Grid Code. This option is also open to, but not mandatory for, exemptable DG under 100MW[20]. The BELLA applies to exemptable DG which are classed as Large Power Stations but do not choose to enter a BEGA[21].

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[19] For more information on the licensing arrangements see the papers associated with the Ofgem/DTI review of distributed generation, discussed in Chapter 5. Historically, the divide between the licensed and unlicensed sectors for DG is based on balancing the need to minimise regulatory burden on smaller operators against the need to protect the reliability and integrity of the integrated network.
[20] Generators below 50 MW are allowed a class exemption, and those between 50 MW and 100 MW can obtain an individual exemption. The licensing arrangements

3.44. In terms of the applicability of these agreements, and the associated access and charging arrangements, key points to note are that:

- the BEGA is available to all DG, and mandatory for all DG over 100MW
- the BELLA only applies to DG classed as Large Power Stations, and is mandatory for Large DG which do not choose to enter a BEGA
- in practice, the BELLA only applies in Scotland, noting that in England & Wales the Large threshold is 100MW and therefore all Large DG must enter a BEGA.

3.45. The Group compared the arrangements for DG entering a BEGA ("BEGA DG") and those which do not ("non-BEGA DG", which includes DG entering a BELLA), the findings are summarised in Table 4 below. The Group noted that in many respects BEGA DG currently have similar arrangements to transmission-connected generation (other than the noted differences in treatment in transmission charging, which are discussed below), and that there is a gap in the current contractual framework in that there is no defined right to export from the distribution system from non-BEGA DG. It was noted that for Large DG in Scotland the choice between BEGA and BELLA may then depend on the party's view of future local conditions at the time of application to NGET, and that it may not be straightforward to subsequently change from one to another.

3.46. The Group generally agreed that the gap in the contractual framework should be addressed, and did not think it appropriate to do so by lowering the threshold for DG being required to enter a BEGA, as this would increase contractual burden and shift the issue, and so not provide an enduring solution. It was recognised that agency models could potentially fill the gap while simplifying the arrangements for the DG it would capture, as the agent would contract with NGET for transmission access rights on behalf of the DG thereby minimising the need for direct interfaces with NGET.

3.47. With reference to its earlier arguments with respect to operation and planning issues, NGET noted that the continued growth of DG leads to the increased requirement for NGET to constrain off plant with TEC, and reduces the availability of transmission access rights which may be allocated to parties seeking TEC, noting that non-BEGA DG is included in the transmission planning background. As a result DG may trigger transmission investment without having a defined access product or being liable for transmission charges, e.g. in an area in which there are exports from the distribution system or shortage of transmission access rights. NGET argued that these issues do occur at present and that a defined access product is needed for DG in order to justify transmission investment, provide the right signals and enable transmission charges to be applied to DG such that they can be exposed to the costs they cause.

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allow for DG in the latter category to be granted a conditional exemption. In some cases this has required the DG to enter a bilateral agreement with NGET known a LEGA in order to apply certain technical obligations. Under the LEEMPS arrangements the LEGA is no longer required as the relevant obligations are passed via the DNO.

[21] The BELLA was introduced as part of BETTA and its main purpose is to require compliance with certain provisions of the Grid Code which are applicable to Large Power Stations, for DG which are classed as Large Power Stations but do not enter a BEGA. There is no route for those provisions to be passed to DG via the DNO.

Table 4: Key features of arrangements for BEGA DG vs. non-BEGA DG

Feature	BEGA DG	Non-BEGA DG
Applicability	Mandatory for licenced DG (includes all DG > 100MW), but open to all	Exemptable DG only, includes Large DG entering a BELLA
Trading arrangements	Trade in wholesale arrangements under BSC	Trade with supplier in same GSP group by netting off supplier's demand
Metering registration	CVA-registered BMU in own right	SVA-registered Part of a supplier BMU
Access rights	Contract with NGET for firm transmission access rights based on TEC, includes eligibility for compensation	No defined access product Implicit rights via supplier use of system agreement, but this only covers imports not exports
Participation in constraint management	Access to Balancing Mechanism	No framework for curtailment of outputs to the transmission system
Treatment in TNUoS charging	Directly subject to transmission charging methodology – explicitly treated either as generation or as negative demand based on 100MW threshold	Not directly subject to transmission charging methodology – implicitly treated as negative demand through netting off supplier's demand - no provision for application of generation charges
TNUoS embedded benefits	DG receives embedded benefits directly and in full (applies to DG treated as negative demand, excludes those over 100MW)	Supplier directly benefits from reduction in TNUoS charges DG receives a proportion of embedded benefit via contractual arrangement with supplier

3.48. As noted above, some parties considered that the transmission planning issues raised by NGET did not in isolation justify changes to the transmission access arrangements, noting they could be addressed by improved information provision and forecasting. There were also differing views on the appropriate treatment of DG in transmission charging, as discussed in the next subsection.

3.49. In addition, some Group members considered that TEC may not be the most appropriate transmission access product for DG as it reflects the characteristics of despatchable conventional generation. This issue was further discussed in the context of the presentations and papers to Meetings 7 and 8 by the DTI Centre for DG & Sustainable Electrical Energy, which argued for a review of the GB SQSS and the development of transmission access products which permit sharing between different users based on diversity taking into account characteristics of different technologies and time of use issues. While the Group considered that this raised issues beyond the scope of TADG it noted that it may be relevant to agency models in which the agent procures access rights based on the aggregate requirements of multiple DG. With respect to the issues raised with the appropriateness of TEC for DG, the Group noted the key factor is the pattern of output not the point of connection. Attendees considered this applies specifically to conventional vs. intermittent generation, rather than generally to DG vs. transmission connected generation. The Group also noted that TEC is a commercial product which gives firm rights to users to generate up to a given level at any time, and they can seek TEC at the level they require. Therefore the current arrangements reflect the fact that any generator with TEC may generate at peak, irrespective of whether they are less likely to, e.g. due to intermittency.

3.50. The Group noted the following additional issues to take into account in developing enduring transmission access arrangements with respect to DG:

- there is currently no defined transmission access product for demand
- DG may not necessarily need or seek firm transmission access rights
- DG which only occasionally lead to exports may prefer rights based on net export or restricted to certain time periods
- any exports from the distribution system which do occur are the combined effect of all DG at the given location
- under distribution connection agreements DG may be constrained off due to distribution constraints
- the treatment of existing DG was noted as an implementation issue.

Cost-reflective transmission charging and differential treatment

3.51. Noting that NGET have an obligation to charge on a cost-reflective basis, the Group generally agreed with the principle that the transmission charging arrangements for a given user should reflect its impact on transmission investment. However, there was no consensus on how this should apply to DG, and polarised views on the cost-reflectivity of the existing charging arrangements with respect to DG. In particular, a running theme of the discussions was the appropriateness of a gross vs. net model, and this proved a contentious issue on which views were split.

3.52. It was noted that transmission investment is based on the combination of the deterministic minimum requirement under the GB SQSS and the economic assessment of the costs and risks of curtailment. The economic assessment considers the balance of costs to constrain off plant compared to the costs of additional investment, taking into account the access rights.

3.53. NGET argued that DG have the same effect on transmission flows and impact on transmission investment as transmission-connected generation and implicitly enjoy firm transmission access rights, but are not exposed to the same transmission charges. In the light of this NGET considered that the existing differences in transmission charging may be discriminatory and not cost-reflective, and that it may be appropriate for all DG to be exposed to generation charges on a gross basis rather than being treated as negative demand.

Table 5: Comparison of generation and demand TNUoS charges

Feature	Generation TNUoS	Demand TNUoS
Locational element of tariff	Differentials derived from ICRP model with nodal marginal costs averaged by generation zone	Differentials derived from ICRP model with nodal marginal costs averaged by GSP group
Residual element of tariff	Uniform tariff set to recover 27% of total TNUoS revenue overall	Uniform tariff set to recover 73% of total TNUoS revenue overall
Total tariff	Positive or negative	Non-negative
Basis for charge or payment	Positive charging zones: - Charge based on contracted capacity (TEC) Negative charging zones: - Payment based on proven capacity derived from metered volumes over winter months (capped at TEC)	Charge for demand based on metered volumes at Triad[22] - results in a payment (or credit to the supplier) for DG treated as negative demand
Applicable generation	All transmission-connected generation All DG over 100MW	DG treated as negative demand

3.54. There were strongly held opposing views within the Group that a net model is appropriate, on the basis that transmission investment is driven by the net flows onto or off the transmission system, and that DG are already exposed to the locational element of TNUoS charges through being treated as negative demand. These arguments were set out in the REA presentation, which also highlighted some parallels with other examples of interconnected networks which are currently based on net charging. It argued that for consistency similar rules should apply in each case but that extending gross charging to the other examples would raise complex issues.

3.55. In considering the above arguments, the Group looked in more detail at the implications of the existing differences. As indicated in Table 4, under the size threshold criteria DG are either subject to generation TNUoS charges or are treated as negative demand, whether directly or by netting off their supplier's demand, in which case the demand TNUoS tariff applies. The key differences[23] between these approaches identified by the Group are summarised in Table 5 above.

[22] The £/kW demand TNUoS tariff is used directly for demand which is metered on a half-hourly basis, for which it is applied to the average metered volume over the three Triad half-hours. For non-half hourly demand customers, the £/kW tariff is converted to an equivalent p/kWh consumption tariff which is applied to metered volumes over a longer time period.
[23] For more detail see NGET's Statement of the Use of System Charging Methodology, available on NGET's website.

3.56. The Group noted that other than the differences in zones, the tariff differentials for generation and demand are equal and opposite at each location, such that the difference in the total tariffs is primarily driven by the residual charge. The difference in the residual charges does not vary by location and is approximately £17/kW, leading to a large step change between users exposed to the demand tariff compared to the generation tariff. A further difference is whether the charge is based on applying the tariff to capacity or to metered volumes at Triad, which also leads to some differences in whether the charge is applied to the relevant user at a nodal or zonal level.

3.57. The Group noted that the existing arrangements are based on the principle that exemptable DG are deemed not to be using the transmission system, such that DG treated as negative demand lead to a reduction in the transmission investment which would otherwise be required for demand. NGET argued that the TNUoS embedded benefit associated with the resulting difference in transmission charges discussed above may not be proportional to any such avoided investment. It further noted that in practice DG treated as negative demand may sometimes drive additional transmission investment beyond that which would otherwise be required for demand and transmission-connected generation. As such some Group members questioned the appropriateness of exporting DG saving the residual charge, while not necessarily agreeing with NGET's view that all DG should be charged gross. Some Group members thought that DG should pay generation charges for net exports. Some Group members were of the view that DG should not pay for use of the transmission system if not explicitly using it. Some also argued that reductions in demand can have the same effects on transmission flows as increases in DG output. The Group also noted the interaction with issues around access products and user commitment by securing works during construction, under consideration by ARODG, as discussed in Chapter 5.

3.58. It was also noted that the existing access and charging arrangements were developed in the context of a transmission system dominated by large transmission connected conventional generation, and focus on costs associated with bulk transfer of power whereas DG growth may require increasing emphasis on provision of system security. Some Group members argued that a wider review of those arrangements was required to take account of the evolution of the transmission system, and referred to the issues raised by the DTI Centre for DG & Sustainable Electrical Energy in this respect as noted above. It was also suggested that alternative access products may have different implications for transmission investment, and that this should be reflected in charges.

3.59. In addition to the cost-reflectivity of the existing differences in transmission charges, the Group also considered the extent to which they may create perverse incentives for users deciding where, and at what voltage, to connect. The step change for DG either side of the 100 MW threshold was generally recognised as an issue, as was the fact that multiple sub-100MW DG individually treated as negative demand would in combination have the same impact on transmission system as a single DG which would be charged as generation. However there were mixed views on whether the TNUoS embedded benefit is a significant influencing factor for smaller generators choosing to connect to the distribution system rather than the transmission system, where it was noted that other technical and cost issues were more likely to drive such decisions. Some parties argued that the existing differences may not be undue discrimination.

3.60. The Group also noted the issues raised by the E.On presentation, which highlighted the need to consider the differences in transmission charges in the wider context of other differences which may also impact on decision-making and on competition between each class of user, e.g: the wider consequences of holding a generation licence; whether they trade in the wholesale arrangements or with a supplier in the same GSP group; the nature of their access rights; and whether they are also subject to distribution charges.

3.61. The Group also noted the following additional issues to take into account in developing enduring transmission charging arrangements with respect to DG:

- DG without TEC generating outside system peak might not impact on transmission investment
- the impact of demand reduction and energy efficiency
- some users co-locate generation and demand so as to offset each other locally
- the treatment of existing DG, for which investment decisions were based on the existing charging arrangements, was noted as an implementation issue.

3.62. In the light of all the above discussions, the Group remained divided on the issue of transmission charging with respect to DG and in particular the principle of gross versus net charging. As such, a range of models for the enduring arrangements were put forward by Group, which collectively covered each approach in various forms. These models are discussed in Chapter 4.

3.63. In addition it was noted that from a revenue-recovery perspective the choice between gross and net models was a zero sum game for NGET. NGET clarified that in terms of addressing the issues it identified it is not opposed to a net model on principle but considers that a gross model would be easier to implement. It was also suggested that from a practical perspective any model would have to define criteria by which some DG is treated as negative demand.

Agency arrangements

3.64. In terms of existing agency arrangements, the Group noted that the current SVA arrangements and associated supplier use of system agreements are a form of agency model for DG not entering a BEGA, in terms of trading of output and pass-through of (savings in) transmission charges on the supplier. As such, DG can either participate in the trading arrangements as "physical participants" (BMUs) or "virtual participants" (via an agent). However, it was thought that while this agency arrangement works for imports it does not for exports, noting that while the settlement systems can deal with exports the charging and contractual arrangements do not.

3.65. The Group considered that an agency arrangement could potentially address the identified gap in the contractual framework with respect to exports to the transmission system, without requiring all DG to enter a BEGA, and may also simplify the arrangements for those it would capture. The agency arrangement could also provide a mechanism for charging such DG, while minimising contractual burden. However, as noted above there were mixed views as to the appropriate nature of the access product for the agent and the basis for the associated charges to be passed to DG, although the potential to take diversity into account by treating DG on an aggregate basis was recognised.

Issues questionnaire

Scope of questionnaire

3.66. As noted above, in assessing the issues in relation to the treatment of DG in the current arrangements and associated consequences of continued growth of DG, the Group initially gave separate consideration operation and planning issues and then access and charging issues. However, it was recognised that individual issues may span more than one of these areas and it would be necessary to consolidate issues.

3.67. In this context, at Meeting 6 Ofgem gave a presentation which sought to summarise the issues and associated consequences raised by at least one party at meetings to date, in order to facilitate debate. At that meeting, it was agreed that Ofgem would seek written views from the Group on the materiality of the issues, by way of a short questionnaire. The issues on which views were sought in the issues questionnaire are set out in Table 6 and includes the issues identified in Ofgem's presentation plus some additional issues which the Group agreed should be included in the questionnaire.

3.68. On each issue, the following questions were asked:

- **Q1:** Do you consider this to be an issue?
  - YES / NO
- **Q2:** How big an issue do you consider this to be?
  - NOT AN ISSUE / IMMATERIAL ISSUE / MATERIAL ISSUE
- **Q3:** Set out your views on the issue in the context of your answers to questions 1 and 2.

Respondents' views

3.69. Ofgem received 15 responses from the Group to the issues questionnaire, of which 2 were confidential. The answers to questions 1 and 2 are summarised in Table 7 and Figure 1, from which the Group made the following high level observations at Meeting 7:

- There was a majority view that Contractual Burden (Issue 10) was a material issue, similarly on the need to clarify Rights and Obligations of non-BEGA DG (Issue 3)

- The majority considered Perverse Incentives (Issue 5) to be an issue, and of these respondents the majority consider it material

- The majority considered GSP vs GSP Group Treatment (Issue 7) to be an issue, although only a minority of these respondents think it material

- The Group also noted that in general, a party's view on materiality may depend on the extent to which it is directly affected by the issue, either commercially or in terms of licence obligations, and whether the issue is viewed as theoretical or has an impact on behaviour.

3.70. The non-confidential responses on each issue are discussed in more detail below.

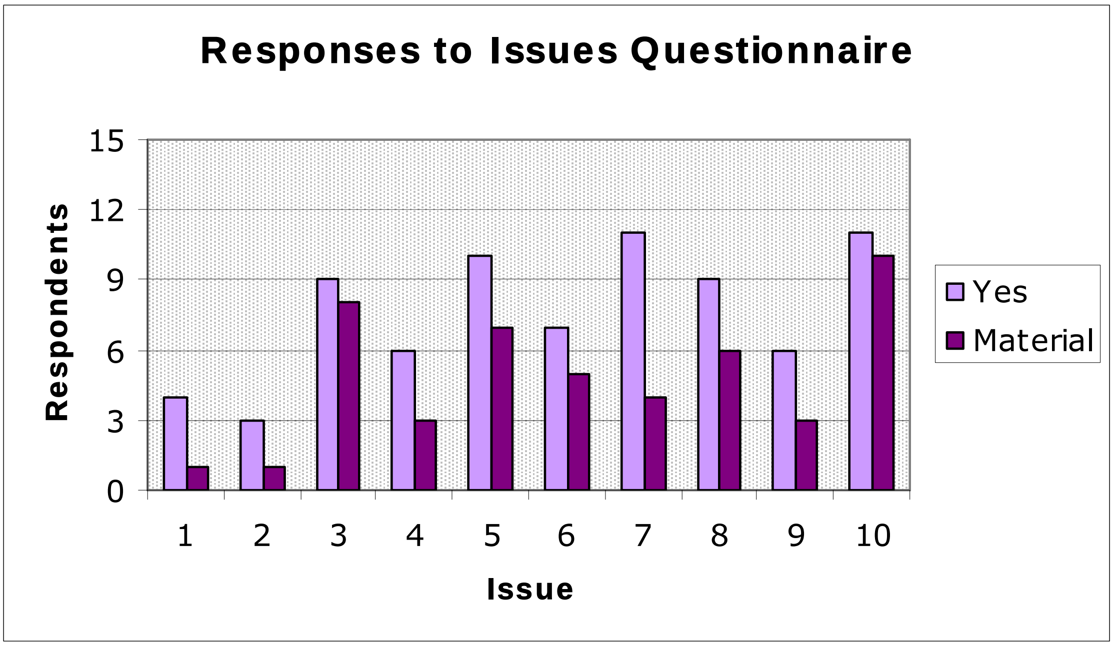
Table 6: Issues identified in issues questionnaire

Issue		Description
1	**Impact on GB Queue**	There are no contractual arrangements between NGET and any party in relation to energisation of new small DG connections not covered by CAP097, with implications for the availability of transmission capacity for other users
2	**Information available to NGET**	There are no contractual arrangements between NGET and any party in relation to energisation of new small DG connections not covered by CAP097, with implications for information provision to NGET in planning timescales and for signals for NGET to invest in the transmission system
3	**Rights / obligations of non-BEGA DG**	There is a gap in the contractual framework in relation to exports from the distribution system to the transmission system not associated with BEGA DG, with implications for transmission rights and obligations of affected users
4	**Impact on constraint management**	There is no formalised procedure for NGET to constrain down DG not actively participating in the BM, with implications for system operation
5	**Perverse incentives** from differential treatment in transmission charging for DG<100MW	DG are treated as either transmission-connected generation or as negative demand in transmission charging, based on size threshold criteria, with implications for size/voltage-related incentives
6	**Cost-reflectivity** of differential treatment in transmission charging for DG<100MW	DG are treated as either transmission-connected generation or as negative demand in transmission charging, based on size threshold criteria, with implications for cost-reflectivity
7	**GSP vs. GSP group treatment**	The current arrangements allow distribution-connected users to net off within a GSP group, but there is no transmission charge for any resulting flows on the transmission system between GSPs in the same GSP group, with implications for cost-reflectivity
8	**Evolution of transmission system**	The existing transmission access & charging arrangements are based on the transmission system providing for bulk transfer of power, while growth of DG may lead to an increasing emphasis on provision of system security and have implications for cost-reflectivity
9	**Competitiveness**	Issues of cost reflectivity have a knock on effect on the competitiveness of embedded generation vis-à-vis directly connected generation
10	**Contractual burden**	Different interfaces with NGET and DNOs create complexity and an administrative burden for small parties

Table 7: Summary of responses to issues questionnaire[24]

Issue		Q1 An issue?		Q2 A material issue?		
		Yes	No	Not an issue	Immaterial Issue	Material Issue
1	Impact on GB Queue	4	11	9	5	1
2	Information available to NGET	3	12	10	4	1
3	Rights / obligations of non-BEGA DG	9	5	1	6	8
4	Impact on constraint management	6	8	5	7	3
5	Perverse incentives	10	5	5	3	7
6	Cost-reflectivity	7	8	7	3	5
7	GSP vs. GSP group treatment	11	4	3	8	4
8	Evolution of transmission system	9	6	6	3	6
9	Competitiveness	6	9	8	4	3
10	Contractual burden	11	4	3	2	10

Figure 1: Responses to issues questionnaire



[24] Based on 15 responses

3.71. The following summary should be read in conjunction with Table 7, where it should be noted that there some differences in the approach used by respondents in that parties who identified an issue as an "Immaterial Issue" under question 2 varied in their responses to question 1. For example, in some cases parties answered "Yes" to question 1 and "Immaterial Issue" to question 2 where they agreed the issue identified is indeed an issue but considered it insufficiently material to need to be addressed. In other cases parties answered "No" to question 1 and "Immaterial Issue" to question 2 where their view that the given issue is not in fact an issue, was on the basis that it is either immaterial or readily addressed. Taking this into account, in the following summary the responses are grouped by the arguments used.

Issue 1: Impact on GB Queue

3.72. The majority of respondents either did not consider Issue 1 to be an issue or thought it is an immaterial issue. Of these respondents, the majority considered it entirely appropriate that there are no contractual arrangements with NGET with respect to energisation of individual small DG. Some of those believed connection of DG is an issue for the DNO to manage, who would in turn deal with NGET with respect to the interface between their respective networks. The remainder referred to the uncertainty with respect to DG growth and the need for some DG to be treated as negative demand from a practical perspective. Other respondents who did not think Issue 1 is an issue considered that the CAP097 provisions were either sufficient, noting that they could theoretically be applied to any DG with a connection agreement with the DNO, or could be modified through a CUSC amendment if deficient. While some respondents agreed that in theory multiple small DG could have a cumulative impact on the availability of transmission capacity for other users, they did not consider this to be a material issue at present. One further respondent did not consider that transmission-connected users should be protected from the impact of small DG.

3.73. Only one respondent considered Issue 1 to be a material issue. This respondent noted that the criteria for identifying relevant small DG under the CAP097 provisions are subject to DNO interpretation, and the DNO may not be best placed to ascertain the cumulative impact of small DG on the transmission system. It also noted that any "capacity gaps" in the GB queue could be absorbed by many small DG treated as negative demand which are not subject to the same access restrictions as larger individual generators.

Issue 2: Information available to NGET

3.74. The majority of respondents either did not consider Issue 2 to be an issue, or thought it is an immaterial issue. These respondents generally considered the existing arrangements to be sufficient with respect to information provision by DNOs, or that they could be amended through a change to the Grid Code if deficient.

3.75. Only one respondent considered Issue 2 to be a material issue. This respondent referred to a need for contractual arrangements to provide cost-reflective investment signals. Some other respondents disagreed with this view, arguing that it is not appropriate to address the issues of information provision by contractual arrangements or charging DG. Another respondent noted that NGET had stated that operation and planning issues were not the primary drivers for change.

Issue 3: Rights/obligations of non-BEGA DG

3.76. The majority of respondents considered Issue 3 to be a material issue. Most respondents agreed there is a contractual gap, but there were differing views as to its nature and how it should be addressed in terms of introducing rights and obligations. Around half of these respondents viewed it in terms of exporting GSPs, and argued that such nodes should be treated the same as transmission connected generation in the charging and contractual framework, either on a net or gross basis. The other half viewed the issue in terms of exports from the distribution system as a whole, and argued that both BEGA and non-BEGA DG contributed to this and should not be distinguished from each other.

3.77. A minority of respondents considered Issue 3 to be an immaterial issue. Of these respondents, around half believed it was an interface issue between the distribution and transmission systems and considered it could be addressed by a net DNO agency model; the remainder considered the materiality of the issue to be unclear or insignificant.

3.78. One respondent did not consider Issue 3 to be an issue at all. This respondent noted that DG have the choice as to whether to enter a BEGA, and the arrangements for non-BEGA DG are based on not using the transmission system and netting of GSP group demand, and having correspondingly reduced rights and obligations.

Issue 4: Impact on constraint management

3.79. The majority of respondents either did not consider Issue 4 to be an issue, or thought it is an immaterial issue. Many of these respondents considered that any participation in constraint management should be on a voluntary basis and not forced upon DG, noting that active participation in the BM is not mandatory and that NGET can additionally bilaterally trade with parties on a commercial basis for the provision of balancing services. Some of these respondents considered that it was inappropriate for NGET to seek to control DG which are not active in the BM, variously noting that NGET cannot directly control demand customers, that it is more effective to use larger generation to balance the system, and that parties with compensatable rights should be constrained first. A number of respondents considered that it was for NGET to ensure it had sufficient services with which to balance the system and that reform of the BM should be considered if necessary to achieve this.

3.80. A minority of respondents considered Issue 4 to be material, either at present or in the future. One of these respondents recognised that NGET could bilaterally trade with individual DG on a commercial basis, but did not consider this to be a sustainable long term solution. The others suggested addressing the issue by active distribution network management under a DNO agency model, or introducing emergency control provisions in the Grid Code and Distribution Code.

Issue 5: Perverse incentives

3.81. The majority of respondents thought Issue 5 is an issue, with the majority of these respondents also thinking it material. Some of these respondents thought the issue related to differences in treatment between classes of DG, and argued that all DG should be treated the same irrespective of size and whether or not CVA registered. Suggested approaches for this included charging all DG as negative demand, charging all DG the same as transmission connected generation, and charging DG with respect to exports under a DNO agency model. One respondent thought there was no logic in having size thresholds, noting that two smaller DG have the same combined impact as an equivalent larger DG charged as generation, or an equivalent reduction in demand. One respondent thought the existing differences were discriminatory and not cost-reflective, and noted that the £17/kW difference in TNUoS tariffs creates an incentive of around 3-6 £/MWh. Another respondent thought there was no evidence of voltage-related incentives, but accepted the existing differences created size-related incentives. The other respondents who considered Issue 5 to be material noted that it would become more so with continued growth of DG, such that it would be necessary to review the continuing appropriateness of the existing thresholds, in terms of striking a balance between improving efficiency by charging DG deemed to impact on the transmission system in their own right and reducing administrative burden by treating other DG as negative demand.

3.82. The remainder of respondents either did not think Issue 5 is an issue at all, or agreed it is an issue but thought it immaterial. While accepting that any threshold is a compromise and would always create incentives, these respondents thought that the existing arrangements already strike an appropriate balance. One of these respondents referred to the fact that that existing threshold is based on the licensing threshold and another noted that parties took other factors into account in their decisions with respect to new connections.

Issue 6: Cost-reflectivity

3.83. The respondents were split on whether Issue 6 is an issue, although of those who thought it is an issue the majority thought it material. This included the respondents noted above who thought that Issue 5 would become more material with continued growth of DG and that the existing thresholds should be reviewed. Another respondent who considered Issue 6 to be material thought that the existing embedded benefit bears no relation to the actual benefit in terms of transmission investment, and argued that DG with the same impact as transmission connected generation should subject to the same charge. Another restated its arguments under Issue 5 regarding the lack of logic in having thresholds, and thought that net exports from the distribution network should be subject to a generation charge irrespective of the size of the DG contributing to that export.

3.84. The majority of respondents either thought that Issue 6 is not an issue or thought it an immaterial issue. Some of these respondents similarly referred to their responses to Issue 5, where they thought the existing thresholds were a suitable compromise. Others thought that Issue 6 would be resolved by treating all DG consistently by charging with respect to exports under a DNO agency model. One respondent thought the issue is that the existing charging arrangements are not cost-reflective in treating DG as negative demand, while another thought it entirely appropriate not to charge DG which are not deemed to use the transmission system. This respondent noted that DG already get a cost-reflective locational signal through the supplier TNUoS tariff and argued that the residual charge is not relevant to the issue as it is not set to be cost-reflective, only to recover the allowed revenue 27:73 from generation and demand. Another respondent thought the charging arrangements should reflect changes in usage patterns noting NGET’s statement that transmission investment is driven by changes in flows.

Issue 7: GSP vs. GSP group treatment

3.85. The majority of respondents thought Issue 7 is an issue, with the majority of these respondents also thinking it material. One of these respondents thought the existing treatment represented a cross-subsidy from transmission connected generation to DG, noting that both compete to supply demand in a given zone, and suggested an intra-zonal charge be developed. The other respondents who thought Issue 7 is material suggested it would be addressed by charging for net exports at a GSP level.

3.86. The remainder of respondents (also a majority) either did not think Issue 7 is an issue at all, or agreed it is an issue but thought it immaterial. Most of these respondents noted that the issue is an unavoidable consequence of GSP group based settlement arrangements which are costly to change. Some respondents thought that there was little evidence of inter-GSP flows being a problem at present nor a significant driver of transmission investment, although some of them thought it may become an issue in the future or may already affect some GSP groups.

Issue 8: Evolution of transmission system

3.87. The majority of respondents thought Issue 8 is an issue, with the majority of these respondents also thinking it material. These respondents thought the growth of DG created distortions and that the existing arrangements are not robust to the changing role of the transmission system.

3.88. One such respondent thought the existing arrangements are unsuited to a more dynamic mix of DG and transmission connected generation, and suggested that the resulting variability should be dealt with by a probabilistic approach rather than using worst case scenarios. Others who thought Issue 8 was material referred to the changing balance of functions between bulk transfer of power and provision of system security, and suggested the charging structure should be reformed now to introduce separate charges for each function, so as to be robust to the future.

3.89. Some of the respondents who thought Issue 8 is material thought that the access and charging arrangements should evolve as appropriate to remain cost-reflective as the transmission system evolves, but thought this evolution was slow or uncertain so should not drive change at this time; these views were shared by those who did not think Issue 8 is material.

Issue 9: Competitiveness

3.90. The majority of respondents thought that Issue 9 either is not an issue, or is an immaterial issue. Most of these respondents noted that other factors also influence connection decisions or that the voltage of connection may be driven by other factors. Some respondents thought that the differences in charging were not an issue so long as charges were cost-reflective, with some noting that this would be addressed by a model which charges for net exports. One respondent thought the existing arrangements did not favour either DG or transmission-connected generation, while another thought that charging DG the same as transmission connected generation would promote connections to the transmission system which may not always be more economical.

3.91. A minority of respondents thought that Issue 9 is a material issue. These respondents thought that the current arrangements put transmission-connected generation at a disadvantage to relative to DG, either now or potentially in the future. One such respondent restated its views on Issue 7 that the existing treatment represented a cross-subsidy from transmission connected generation to DG, noting both compete to supply demand in a given zone.

Issue 10: Contractual burden

3.92. The majority of respondents thought that Issue 10 is a material issue, with a further minority agreeing it is an issue but not thinking it material. Most of the respondents thinking Issue 10 is material did not believe there should be a requirement on DG for multiple interfaces, noting this creates additional complexity and burden for small DG, and may also create a barrier to entry for DG. One respondent thought that current uncertainty as to changes to the future arrangements was a greater barrier than complexity. Some respondents considered that the issues around multiple interfaces reinforced a need for an agency model to maximise the efficiency of contractual and operational interfaces and minimise the contractual burden for DG. Several thought DG should only contract with the DNO, while transmission-connected generation should contract with DG. One such respondent believed that a DNO agency approach should also cover DG which currently contract directly with NGET by entering a BEGA.

3.93. A minority of respondents thought that Issue 10 is not an issue at all. These respondents did not identify any problems with the existing contractual arrangements, and one such respondent believed that the requirement for three interfaces (NGET, DNO and supplier) was not overly onerous for any party.

Working group conclusions

3.94. In terms of NGET's arguments as to the need for better information on DG from the perspective of planning the operation of and investment in the transmission system, the Group had mixed views on:

- whether forecasting would supply the information required or be helpful to the process, noting the inherent uncertainty of DG growth
- whether the risks associated with this uncertainty should be borne or managed by NGET, the DNO or the connecting party
- whether it is purely an informational issue capable of being addressed by amendments to the current data exchange provisions and/or NGET undertaking its own forecasting
- whether there is a necessity for parties to provide firm information by procuring chargeable access rights at a defined level.

3.95. The Group generally recognised that DG which do not have firm access rights have an impact on transmission system flows, but were divided on:

- whether that impact constituted use of the transmission system
- the extent and nature of its impact on transmission system investment
- the appropriateness of treating that impact as negative demand
- whether it is necessary for NGET to be able to control those flows
- whether such control should be for commercial management of constraints or for emergency control only.

3.96. The Group generally agreed that there is a need for formalisation of the rights and obligations for DG with respect to exports, but were divided on:

- how that export should be defined
- the appropriate nature of the access rights
- the corresponding treatment in transmission charging (see the next point)
- in particular, the use of a gross or net model and whether it should be based on GSPs or GSP Groups.

3.97. The Group noted that the existing charging arrangements include thresholds for differential treatment of DG based on assumptions as to their impact on the transmission system, and while recognising the issue of the step change at 100MW arising from the difference in the residual charge were divided on:

- the cost-reflectivity of the differences in treatment
- the extent to which this creates perverse incentives to parties connecting to the system and impacts on competition between classes of generation, when considered in the context of other factors
- whether there is currently a need for a wider review of the transmission charging methodology and of the existing thresholds to reflect evolution of the transmission system.

3.98. The Group generally agreed that it is important to minimise contractual burden and complexity, and considered agency models an appropriate means of addressing many of the issues identified without requiring DG to contract directly with NGET, but were divided on:

- who should act as agent
- the extent of the agent's role, in particular with respect to control of DG
- whether the agency arrangement should supplement or replace the existing arrangements for DG which already contract directly with NGET
- whether the agency model should include thresholds or criteria for differential treatment.

3.99. The Group generally considered that the operation and planning issues were not the primary driver for change, and identified a number of potential ways forward through which they might be addressed within the existing arrangements:

- strengthening of Week 24 data exchanges under the Grid Code
- introduction of emergency control provisions under the Grid Code
- review of criteria for identifying Relevant Power Stations in the provisions introduced by CAP097.

3.100. Further, although the Group recognised a number of theoretical issues and identified various means by which they may be addressed, there were also mixed views on the materiality of the issues and the urgency of addressing them, noting the ongoing uncertainty as to DG growth. The Group were also mindful that the costs of any change would be ultimately borne by the consumer. They noted that the justification for and benefits associated with an agency solution may depend on the level of increase of small DG over time.

3.101. While some Group members considered that there was no case for change in the short term, several Group members considered that at least some of the issues were material and put forward strawman models specifically targeted to addressing those issues. The design of those models, which are discussed in the next Chapter, were in turn driven by the proposer's view on the choice and role of agent, and the nature of the access right and associated charge.

4. Agency options for change

Development of agency strawmen

Overall approach

4.1. In Meeting 1 Ofgem issued an open invitation to attendees to develop strawmen for presentation to the Group. Group members engaged constructively in this process both in terms of putting forward strawmen for discussion and, through that discussion, contributing to their development and assessment.

4.2. During the assessment of issues with the existing arrangements discussed in Chapter 3, a number of initial strawmen were presented by members of the Group, each of which either sought to address issues from the proposer's perspective, or were presented to illuminate the debate by illustrating the broad range of potential agency models and the extent to which they differ. In addition, a number of other parties informally expressed an initial interest in developing strawmen, but subsequently did not bring forward specific proposals on the basis that their views were covered by the models already under discussion.

4.3. The Group also developed a structured framework for defining and assessing strawmen, such that they can be compared and contrasted, and then assessed consistently in terms of the TADG objectives set out in Chapter 1. Ultimately, four strawmen were assessed by the Group in terms of this framework. The Group also considered the existing arrangements in terms of the TADG objectives. This process culminated in Ofgem seeking written views from the Group in the form of a short questionnaire.

4.4. This Chapter outlines the initial strawmen presented to the Group, the definition and assessment framework, and the Group's assessment of the four strawmen in terms of that framework and of the existing arrangements.

Initial strawmen presented to the Group

4.5. In Meeting 1 Ofgem gave an introductory presentation which provided a brief high level overview of agency models and the views of respondents to the consultation process pre-TADG as to the relative advantages and disadvantages of supplier agency, DNO agency, DSO and hybrid agency models in generic terms. In addition, NGET presented a paper setting out its view of the problems to be addressed and describing a range of agency models. In total, NGET identified eight potential models, three of which it developed into strawmen. Of these, it noted its preference for the Gross Nodal Supplier Agency Model ("GNSAM"), in which all DG are exposed to generation TNUoS charges via the supplier; in turn the supplier is subject to separate charges from NGET for its demand and contracted DG.

4.6. In Meeting 4 NGET gave a further presentation which reviewed the agency model options and the issues identified by the Group, and reiterated its preference for its GNSAM model. Also at Meeting 4, SP T&D gave a presentation on its "Thin DNO Agency Model". This net model introduces a "DTEC" required by the DNO for exporting GSPs, which represents an operational limit for that GSP and is subject to lower charge than for TEC as it does not include compensation for curtailment. The DTEC charge is then charged out to DG above a given connection voltage, through the distribution charging methodology.

4.7. At Meeting 5 the Group further discussed both the NGET model and the SP T&D model, together with further models presented by two other parties. Airtricity presented a "Thin DNO Agent Strawman", which is similar to the SP T&D model but its DTEC charge is charged out to all DG contributing to that export and it includes a compensation mechanism. CE Electric UK gave a presentation which considered a range of generic strawman models progressively ranging in complexity and scope of agency role from a "thin supplier, net model" to a "full DSO model". The presentation sought to illuminate the debate by showing the degree of change between the options and considering the extent to which the outcomes of the "full DSO model" can be gained by less extreme approaches.

Definition and assessment framework

4.8. At Meeting 5 Ofgem noted that the CE Electric UK presentation highlighted benefits of using a common framework for discussing a range of strawman models, such that they can be more readily compared and contrasted. It sought views on developing the approach used by CE Electric UK into a framework which could be applied to the strawmen proposed by other parties.

4.9. The Group supported the use of a structured approach and agreed that the definition of each strawman should cover the following elements:

- **Why**
    - the issues which the model seeks to address, thereby stating its view of the main problem(s) with the existing arrangements
    - the means by which the model seeks to address those issues

- **What**
    - the descriptive specification of the model design
    - the nature of the changes needed to implement it

- **How & when**
    - the process and timescales for implementing the identified changes
    - the interaction with other policy areas

4.10. The strawmen defined in this way would then be assessed, relative to the existing arrangements, in terms of the TADG objectives:

- **Minimising implementation costs.** The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumers.

- **Cost reflectivity.** The arrangements should seek to reflect the costs and benefits that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.

- **Efficient network development.** Arrangements should encourage efficient decisions to be taken regarding the development and use of the transmission and distribution networks.

4.11. The Group also agreed that the individual strawmen to be further developed and assessed by the above process must meet the following criteria:

- have at least one advocate and a clear rationale
- be targeted to addressing specific issue(s)
- be distinct from other strawmen.

4.12. The existing arrangements would also be assessed in terms of the TADG objectives by considering the impact, in the light of the issues and consequences discussed in Chapter 3, of retaining those arrangements on an enduring basis.

4.13. This assessment comprised two stages:

- **firstly**, the proposer presented the strawman to the Group for initial discussion and refinement, and the Group also discussed the existing arrangements
- **secondly**, written views were invited from the Group in the form of a short questionnaire.

Strawmen assessed by the Group

4.14. The following four strawmen were considered by the Group in terms of the above framework:

- **SP T&D's** "Thin DNO agency model"
- **Airtricity's** "Thin DNO agent strawman"
- **CE Electric UK's** "Very thin supplier net model" [25]
- **NGET's** "Gross nodal supplier agency model".

4.15. For full details of each strawman model the reader is referred to the papers and presentations submitted by the respective proposers for consideration in the Group's assessment. In terms of the issues discussed in Chapter 3, all of the strawmen seek, as a minimum, to address the gap in the contractual arrangements with respect exports by means of an agency model. At the same time the strawmen seek to minimise the contractual burden on parties subject to that agency arrangement. However, each strawman differs in its perception of the nature of that gap, in particular the appropriate definition of export, and the means by which it should be addressed. These differences are summarised in Table 8. These and other key features of each strawman model are discussed in more detail below, followed by a summary of responses to the questionnaire.

4.16. This Chapter also summarises the Group's discussion and assessment of the existing arrangements against the TADG objectives, in the light of the issues discussed in Chapter 3. It is noted that Table 8 does not cover the existing arrangements, given that it does not include an agency arrangement for charging for exports. Key features of the existing arrangements are set out in Chapter 3, see in particular Table 4 and Table 5.

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[25] CE Electric UK noted that the aim of its initial presentation was to illustrate the range of potential models, and that it only wished to propose the "very thin supplier net model" for assessment by the Group. The Group were given the opportunity to take forward any of the other models, but none did so.

Table 8: Comparison of strawmen key features

Model feature	SP T&D	Airtricity	CE Electric UK	NGET
Name	Thin DNO agency model	Thin DNO agent strawman	Very thin supplier net model	Gross nodal supplier agency model
Agent for transmission export rights & associated charges	DNO	DNO	Supplier	Supplier
Nature of export rights via agent	Contracted operational limit	Contracted firm rights	Permission to export with charges applied ex post	Contracted firm rights
Basis of export charge to agent	DNO net export by GSP	DNO net export by GSP	Supplier net export by GSP Group	Supplier gross export by GSP
Nature of export product	Contracted DTEC based on required net GSP capacity at peak	Contracted export component (DTEC) of Hybrid Grid Connection Product	Ex post permission based on actual export of SVA BMUs	Contracted TEC based on required gross DG capacity
Charge-out by agent	Via distribution charges, to all DG above 33kV	Via distribution charges, to all DG contributing to export	Contractual arrangement between supplier and DG	Contractual arrangement between supplier and DG
Mechanism for export curtailment	Distribution connection agreement	New Constraint and Compensation Agreement for ex-BEGA DG	New reserve powers under Grid Code (analogous to OC 6)	Bids and offers
Compensation for export curtailment	No	Yes	No	Yes
Impact on BEGA arrangements	BEGA option remains for DG to contract directly with NGET	BEGA arrangements superseded, all DG contract for access rights via agent	BEGA option remains for DG to contract directly with NGET	BEGA option remains for DG to contract directly with NGET
Impact on supplier TNUoS	None	None	Additional charge for net export by GSP Group	Separate charges for gross demand and generation

Discussion on existing arrangements & proposed strawmen

Existing arrangements

Assessment against TADG objectives

4.17. **Minimising implementation costs**. The Group noted that retaining the existing arrangements would have benefits in terms of avoiding implementation costs associated with change. However it also recognised that these benefits should be considered against the costs of inefficiencies under the other two TADG objectives arising from the issues discussed in Chapter 3, together with any impact of continued growth of DG on the administrative costs under the existing arrangements. NGET argued that the existing arrangements are unsustainable as continuing to treat DG as negative demand would require fundamental exit reform. Some Group members, while recognising theoretical issues with the existing arrangements, raised the issue of materiality and thought it unclear the point at which the existing arrangements become unsustainable making change necessary. NGET argued the issues are material at present and will only get worse.

4.18. **Cost-reflectivity**. The Group noted there is no unanimity on the issue of cost-reflectivity of the existing arrangements. On the one hand, NGET argued that the existing arrangements are not sustainable in that they do not provide appropriate cost signals to users by treating DG as negative demand. NGET illustrated this point with reference to new DG in Scotland triggering transmission reinforcement in the same way as transmission connected generation, although it recognised that DG may save substation costs. NGET argued that the current embedded benefit is not cost-reflective and that it is more appropriate to treat DG the same as transmission connected generation. Others considered it appropriate to treat DG as negative demand, and noted that the same geographical differentials in TNUoS apply to DG as to transmission connected generation. Some thought there is an issue with the cost-reflectivity of the difference in charges between DG and transmission connected at a given location, as driven by the residual charge. It was also suggested that further transparency as to the level of DG connections would be beneficial towards assessing materiality of the issue.

4.19. **Efficient network development**. Some parties raised general issues about the overall appropriateness of the existing GB SQSS and access products, referring to the issues raised by the DTI Centre for DG & Sustainable Electrical Energy[26] which suggested that the arrangements should permit sharing of transmission capacity taking into account requirements of different technologies and time of use issues. NGET noted that changing the access product may change the economic assessment, and argued that the lack of firm information provision on small DG connections, with associated user commitment, means there are no clear signals for NGET to invest in the transmission system to accommodate such DG. Some thought this raised issues with the sustainability of charging demand without requiring user commitment. Others pointed to other means by which the information issue could be addressed, and thought it unclear that it leads to inefficient investment.

[26] See Chapter 3

SP T&D model

Why

4.20. SP T&D noted its model is based on a principle of simplistic minimal change and seeks to address problems existing today, not potential future problems. In SP T&D's view the main problem at present is the gap in the existing codes and framework with respect to exporting GSPs. It seeks to address this issue through a DNO agency model in which GSP export capacity limits are agreed and all users of the transmission system pay for the privilege of doing so. SP T&D considered that the other issues discussed in Chapter 3 were either able to be addressed through existing measures or not currently of sufficient materiality to need to be addressed now.

What

4.21. A DTEC would be required by the DNO at exporting GSPs based on the net export capacity required at system peak, noting that peak conditions are the main driver of transmission costs. The DTEC would be set in the Bilateral Connection Agreement (BCA) for the given GSP; where there are existing exports the DTEC would be agreed on implementation of the model, while any subsequent changes would require the DNO to submit a Modification Application.

4.22. The DTEC would provide an operational limit for exports at the given GSP, to be managed by the DNO through constraining DG under the distribution connection agreement. However, the model would not alter the existing provisions for transmission constraint management, as it does not consider the operational issues to be material hence does not seek to address them in the model.

4.23. The associated DTEC charge would be applied by NGET on a GSP basis but charged out by the DNO within the given GSP group based on a voltage threshold, as it would not be possible to assign GSP exports to individual DG. With no constraint payments applicable the DTEC charge would be lower than that for TEC. The BEGA arrangements would remain an alternative available to DG, who could choose TEC or DTEC depending on their view of the risk of curtailment of access.

How & when

4.24. SP T&D noted that the model is based on minimal change to the existing arrangements and could be implemented in relatively short timescales through changes to the CUSC, charging methodologies and licences.

Proposer's assessment against TADG objectives

4.25. **Minimising implementation costs**. SP T&D noted the implementation costs are expected to be low.

4.26. **Cost-reflectivity**. SP T&D noted that the model seeks to only charge users who are using the transmission system.

4.27. **Efficient network development.** SP T&D noted the model would provide a framework for managing issues associated with exporting GSP's.

Issues raised in working group discussions

4.28. As the model would not replace the BEGA arrangements it was noted that any interaction between DTEC charges and charging arrangements for BEGAs would need further consideration. The Group also noted that there may be issues in relation to defining the level of net export to be used as the basis for DTEC given variability in both demand and generation; while some Group members suggested the probable total should be considered taking diversity into account, others noted the need to plan for extreme cases.

4.29. Some Group members thought the model one-sided by dealing with exports only, although SP T&D noted that the issue which the model seeks to address is that there is currently no commercial framework for exporting GSPs. NGET disagreed with SP T&D's view, arguing that the main issue is the lack of cost-reflectivity in the signal to DG treated as negative demand. It considered that exporting GSPs are only a minor part of this issue and that the model is not cost-reflective for the majority of DG so would not provide appropriate signals to users. Another argued that addressing issues at a GSP level within arrangements based on GSP Groups creates inconsistency.

4.30. The following possible extensions of the SP T&D model were noted by the Group, each of which would be more complex and require additional changes and associated implementation cost:

- the removal of the BELLA arrangements by subsuming the technical provisions into the agency arrangement
- the addition of a constraint management mechanism, which would in turn require a transparent methodology for the DNO to respond to instructions from NGET in addition to changes to the contractual relationship between the DNO and DG and to the Grid Code, and may also require changes to the BM.

Airtricity model

Why

4.31. Airtricity noted its model is based on a principle of equitable charging treatment for all DG, in that all DG contributing to exports should pay towards the associated charge. It is also based on DG having a single interface with the DNO, with the DG managing the issues it causes the DNO and the DNO in turn managing those it causes to NGET. As such it treats the transmission and distribution networks separately and the DNO agency model bases transmission access and charges on requirements at the interface.

4.32. While the Airtricity model shares many common features with the SP T&D model it includes a number of additional changes, including the addition of a constraint management mechanism and removal of the BEGA arrangements, and the export charge would be charged out more widely.

What

4.33. The model would introduce a hybrid power flow product and apply a DTEC charge to the DNO in relation to exports and continue to charge suppliers for imports. The DTEC charge would be charged out through the DNO's distribution charging methodology to all MPANs which have a connection agreement which permits exports. Airtricity considered that DNO's already have all the necessary data through meter point registration and have a tariff structure for recovering costs from distribution users which could be further developed to recover the export charge.

4.34. The agency arrangement would incorporate all DG and therefore the model would also remove the existing BEGA arrangements. It would also include the introduction of a Constraint and Compensation Agreement (CACA) which would enable NGET to constrain large generators and make compensation payments. Airtricity noted that by the interaction between the demand reduction and the DTEC charge and associated distribution charges, the net DNO agent model can incentivise generation/demand balance within a GSP Group.

How & when

4.35. Airtricity noted that its model could be implemented in relatively short timescales and would have low IT impact, similarly to SP T&D's model. In addition to the changes identified by SP T&D for its model the Aitricity model would involve the development of additional Line Loss Factor codes with respect to the new distribution charges, a new Constraint and Compensation Agreement, the removal of the BEGA arrangements and a more active network management role for DNOs.

Proposer's assessment against TADG objectives

4.36. **Minimising implementation costs**. Airtricity noted the impact would be similar to SP T&D's model.

4.37. **Cost-reflectivity.** Airtricity noted that the model seeks to ensure all users contributing to exports pay a share of a charge for that export, according to the DTEC charge-out methodology to be developed by the DNO.

4.38. **Efficient network development.** Similarly to the SP T&D model, the Airtricity model was thought to give better investment signals at GSPs than the existing arrangements if transmission investment is driven by exports onto the transmission system, and that the DTEC charge would incentivise DNOs to forecast the level of DTEC correctly. Airtricity considered its model could address not only issues with exporting GSPs but also the issue of fluctuating import due to demand reduction.

Issues raised in working group discussions

4.39. It was noted that the model could be considered a "next step on" from the SP T&D model and effectively passes responsibility to the DNO for determining a methodology for charge-out of transmission costs to distribution users. The model would also need to capture both imports and exports at each GSP.

4.40. As with the SP T&D model, parties raised the issue of how to set DTEC taking into account variability of both DG output and demand, including the possibility of demand reduction. NGET also considered the Airtricity model did not fully address the cost-reflectivity issue. It was also noted that the model would affect the charging base and so impact on the charges paid by other users. The issue of addressing issues at GSP level within GSP Group arrangements was again raised.

CE Electric UK model

Why

4.41. CE Electric UK noted that the objective of its model is to provide a clear framework for investment decisions, with least change to the current arrangements. Its focus is to provide clear access rights and to ensure co-ordinated operation of the transmission and distribution systems. It seeks to resolve the access issues through simple administrative changes to accommodate, and charge for, exports from SVA BMUs.

What

4.42. The model would grant "permissive rights" for suppliers to export to the transmission system and provide for exporting SVA BMUs to be charged as generation with a "soft TEC" based on actual usage rather than being contracted for in advance. CE Electric UK noted this would only result in a charge for exports at a GSP group level, which may be unlikely to occur, and that the model does not seek to charge for exports at individual GSPs. The model would also amend the Grid Code to strengthen the week 24 exchanges and create a reserve power for the GBSO to direct DNOs to shed generation.

4.43. The model would not include a compensation mechanism as it does not grant firm rights to exporting suppliers. The model also recognises that active management of the distribution network is currently restricted to turning generation off and is based on a principle that constraint management should be through market mechanism, e.g. bids and offers, with the reserve power a last resort. CE Electric UK also noted the model does not seek to address the CAP097 issue nor charging distortions associated with charging on a GSP group basis. It argued that DTEC charging may not improve quality of forecasts and that cost-reflective charging should be gross and diversified but that the model does not go that far.

How & when

4.44. CE Electric UK noted the model is based on least change to the existing arrangements and could be implemented in relatively short timescales. It would involve changes to the CUSC, charging methodologies and Grid Code. It may also amend SVA processes to recognise export from SVA BMUs.

Proposer's assessment against TADG objectives

4.45. **Minimising implementation costs**. CE Electric UK noted the implementation costs are expected to be low.

4.46. **Cost-reflectivity**. CE Electric UK noted that the model seeks to charge for exports at a GSP group level. It recognises that this does not fully address the cost-reflectivity issue, but considers there is no intermediate charging model between its model and the NGET strawman.

4.47. **Efficient network development**. CE Electric UK considered the model to be as effective as any of the other strawmen at promoting efficient network development, and noted that it assigns that responsibility to the DNO and may also impact on a supplier’s contracting decisions with DG in zones in which it is generation rich.

Issues raised in working group discussions

4.48. With respect to the proposal to create a reserve power for the GBSO to direct DNOs to shed generation, it was noted that NGET cannot despatch SVA BMUs and that there would be less value to the GBSO in managing constraints on a GSP group basis than nodally. Although the model would not grant firm rights to exporting suppliers, NGET noted that it would still need to invest in the transmission system to accommodate the exports. It was noted that the model could dilute the Triad-related incentives on DG to generate at peak, and that this may lead to increased transmission investment.

4.49. The Group noted that in any supplier agency model it would be necessary to address how changes of supplier are dealt with, and also the issue of suppliers going bust. CE Electric UK considered the “soft TEC” could be accommodated by any supplier the DG contracts with. It was also noted that DG could get charged as a result of its supplier losing demand customers.

NGET model

Why

4.50. NGET noted its model is driven by its licence objectives and seeks to avoid fundamental exit reform, which it believes would be necessary were DG to continue to be treated as negative demand.

4.51. NGET considers it cost-reflective to charge DG the same as transmission connected generation as they drive the same transmission investment.

4.52. NGET noted that a supplier can buy from either DG or transmission connected generation so they do compete against each other. It noted the TNUoS embedded benefit is around £3/MWh and argued that although DG trade on a zonal basis they use the transmission system within a zone, and the local market is not independent of the wider market.

4.53. NGET clarified that it does not consider exporting GSPs to be an issue in itself, the issue being its treatment as negative demand. Its model does not distinguish between exporting GSPs and GSPs with reduced demand.

4.54. The model seeks to address operational issues by providing firm access rights with compensation for curtailment.

What

4.55. NGET's GNSAM model would apply demand tariffs to gross demand and require the supplier to procure TEC on behalf of non-BMU DG. Such DG would each be mapped to a supplier BMU and the supplier would then also be subject to generation charges on a gross basis. The TEC would be based on the DG capacity, and with consolidation it would be based on the combined requirement of multiple DG. DG which contract for TEC via a supplier would receive firm transmission access rights and be eligible for compensation.

How & when

4.56. NGET noted its model would require limited changes to systems and industry codes, which would evolve the existing arrangements to facilitate the wider integration of DG. It would involve changes to the CUSC, charging methodologies and Grid Code, and possibly consequential changes to the BSC, DCUSC and Distribution Code. It may also require additional SVA metering information to support charging systems.

Proposer's assessment against TADG objectives

4.57. **Minimising implementation costs**. NGET noted implementation costs were difficult to quantify as all the models were principles-based.

4.58. **Cost-reflectivity**. NGET considered the model was more cost-reflective than the existing arrangements.

4.59. **Efficient network development.** NGET considered the model provided better signals and would better facilitate efficient investment.

Issues raised in working group discussions

4.60. While NGET had noted its model seeks to avoid fundamental exit reform, some parties considered that the move to gross charging for DG and impact on Triad-related incentives to reduce peak demand was in itself fundamental reform. There was also a view that the charging arrangements should distinguish between users only participating in a local market from those which choose to participate in the central market. While NGET noted that the impact on transmission flows is the same in both cases and that the local market is not independent of the wider market, an attendee noted that there is a difference in access rights as well as in obligations to pay charges.

4.61. With respect to the proposal to provide firm access rights with compensation for curtailment, the mechanics of switching off small DG was noted as an issue to be addressed in NGET's model. The issue of size thresholds was raised. NGET noted that different thresholds could apply for operational issues as for charging issues, and suggested the gross charges should apply to all DG with Half-hourly metering. In terms of the impact on Triad-related incentives, NGET considered that energy prices would provide sufficient incentive on DG to generate at peak, while others considered that diluting the Triad signals would mean that some DG would not generate at peak under NGET's model.

4.62. Some attendees were concerned that under NGET's model a DG's access rights would be tied to a supplier and asked how changes of supplier would be dealt with, noting this may be more complex than under CE Electric UK's model which was based on permissive rights. It was suggested that the rights should be linked to the DG and transferred to any new supplier. NGET noted the DG could alternatively contract directly with NGET or set up as its own supplier. The treatment of supplier default was noted as an implementation issue. Some attendees thought that DG may prefer to deal with the DNO, with which they have a fixed relationship.

4.63. It was also suggested that in NGET's model the technical obligations associated with TEC should be passed through to DG through the Grid Code and Distribution Code, and that it would be necessary to clarify liabilities for breach of TEC in the contractual arrangements between the DG and the supplier. The Group noted that this would not apply to CE Electric UK's supplier agency model given that it is based on permissive rights.

Strawmen assessment questionnaire

Scope of questionnaire

4.64. At Meeting 7 the Group agreed to seek written views from the Group on each strawman in the form of a short questionnaire. On each strawman, the following questions were asked in relation to the issues which the model seeks to address:

- **Q1a:** Do you agree that the issues identified are material?
  - YES / NO
- **Q1b:** Irrespective of your views on materiality, do you believe that the model would address those issues?
  - YES / TO AN EXTENT / NO
- **Q1c:** Are there any other issues which you believe to be material but not addressed by the model?
  - YES / NO
- **Q1d:** Provide any detailed comments in the context of your answers to questions a), b) and c).

4.65. Respondents were also invited to comment on the rationale and specification of each model ("why" and "what"), the process and timescales for implementation ("how" and "when") and asked to identify any model-specific interactions with developments in interrelated areas; and to set out their views on the model, relative to the existing arrangements, in terms of its impact on the TADG objectives. The questionnaire also sought respondents' views on the impact on the TADG objectives of continuing with the existing arrangements on an enduring basis, in the light of the Group's assessment the issues in relation to the treatment of DG and associated consequences of continued growth of DG.

Respondents' views

4.66. Ofgem received 10 responses from the Group to the strawman assessment questionnaire, of which 1 was confidential. The answers to the above questions are summarised in Table 9 and the non-confidential responses are discussed in more detail below.

Table 9: Summary of responses to strawman assessment questionnaire[27]

Strawman	Q1a Are the issues identified material?		Q1b Would the model address the issues identified?			Q1c Are there other material issues not addressed?	
	Yes	No	Yes	To an extent	No	Yes	No
SP T&D	8	2	5	4	1	7	3
Airtricity	8	2	5	5	0	4	6
CE Electric UK	8	2	4	1	5	6	4
NGET[28]	5	4	2	3	4	6	3

Existing arrangements

4.67. **Minimising implementation costs.** The majority of respondents noted that maintaining the existing arrangements involves no implementation costs, although a minority also thought that the existing arrangements are not sustainable in the long term. Some of these respondents thought that the benefits of any change must outweigh any associated implementation costs; although one respondent considered the cheapest solution or "do nothing" may not necessarily be optimal. Another respondent noted that the inefficient costs of the status quo should also be considered when assessing the benefits of change but that no evidence of those costs had been presented.

4.68. **Cost-reflectivity.** The majority of respondents considered the existing transmission charging arrangements to be broadly cost-reflective overall while at the same time identifying a number of distortions arising from, and issues with respect to, the treatment of DG which would worsen with continued growth of DG, specifically:

- non-contracted DG having the same impact as contracted DG without facing a transmission charge
- Large DG being charged for transmission on a gross basis
- disparity between parties paying TNUoS and distribution-connected users of the transmission system not bearing the costs of that use
- anomalies in current charging of demand and generation, and need to reflect that users are connected to a network other than the transmission system
- the £17/kW difference in charges being a feature of the charging model rather than reflecting actual embedded benefit.

4.69. A minority of respondents thought the existing charging arrangements for DG are entirely appropriate. One such respondent thought that treating DG as negative demand is cost-reflective as it provides a strong incentive on DG to generate at peak and reduce overall demand, thereby avoiding transmission investment. Another noted that the current charging arrangements are designed for trading arrangements in which DG are treated net on a GSP group basis.

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[27] Based on 10 responses
[28] One respondent did not comment on NGET's model

4.70. **Efficient network development.** The respondents were split on whether the existing arrangements have an impact on efficient network development. Of the respondents which identified an impact, two respondents considered the existing arrangements to be unsustainable, one of which referred to an adverse impact on efficient distribution network development through the partial incorporation of DG into the transmission arrangements, and another respondent considered that change is needed to allow exports from the distribution system. One further respondent noted that transmission network investment is governed by the GB SQSS, in which the assessment is reliant on accurate data. The respondent argued that cost reflective charging and user commitment to pay that charge is necessary to provide appropriate signals and to demonstrate efficient network development. While some other respondents noted the information issue, they did not consider it to be an issue of transmission access, and referred to other means by which it may be addressed.

4.71. Of the respondents which considered the existing arrangements do not have an impact on efficient network development, several referred to the lack of evidence in this respect, although one noted the arrangements would not be efficient if they prevented export from the distribution system. Another considered that under CAP097 the current arrangements do not restrict efficient network development.

SP T&D model

4.72. The majority of respondents agreed that the issues which the SP T&D model seeks to address are material, although a minority thought it was unclear that an access product is required. The respondents were split on whether it would fully address the issues it identified, and the majority of respondents thought there were additional material issues which it did not address. In this context some respondents considered that it only partially addresses the cost-reflectivity issue, should go further in other respects, or raises some additional issues.

4.73. Some respondents thought further clarity or development was required with respect to: the rationale for DTEC being different to TEC; the proposed process for managing DG output via the DNO; the impact on BEGA DG; the identification of relevant DG in the charge-out of the DTEC charge and the rationale for not extending it to all DG; and the treatment of overrun. Some respondents also commented on the fact that the model would not impact on supplier TNUoS: one respondent suggested this may create conflicting or diluted incentives on DG exposed to both signals; another argued that to avoid double counting DG subject to the DTEC charge should not be included in calculation of the supplier TNUoS charge, and noted that this would require changes to settlement arrangements. While several respondents noted the model had the benefit of enabling DG to contract with the DNO with respect to transmission rights, one respondent thought it conflicted with the philosophy that microgeneration should only deal with its supplier.

4.74. **Minimising implementation costs**. The majority of respondents thought implementation costs would be low as the model would involve minimal change, although some identified the scope for further costs in relation to additional issues noted above. Complexities identified included new DNO processes with respect to the administration of the DTEC arrangements, development of distribution charging methodologies, and potential changes to supplier TNUoS charges.

4.75. **Cost-reflectivity**. The majority of respondents thought the model would be more cost-reflective than the existing arrangements by ensuring distribution-connected users of the transmission system pay transmission charges. However, some preferred an approach where the DTEC charge is applied to all DG while others thought a smeared DTEC charge would weaken signals. Some respondents thought the model was one-sided in only addressing exporting GSPs.

4.76. **Efficient network development**. Respondents were split on whether the SP T&D model would promote efficient network development compared to the existing arrangements. Those who did variously noted it would supplement existing processes introduced by CAP097, encourage DNO-NGET interaction, provide clear investment signals and allow, and apply charges for, exports from the distribution system. Others thought the signals would be weak or that the issue related not to exporting GSPs but to the overall impact of DG growth or distribution users as a whole.

Airtricity model

4.77. The majority of respondents agreed that the issues which the Airtricity model seeks to address are material. All respondents thought the Airtricity model would address the issues it identified at least to an extent. The majority of respondents did not think there are additional material issues which the Airtricity model would not address.

4.78. The majority of respondents expressed similar views on the Airtricity model to the SP T&D model, or noted that their comments in relation to SP T&D model also applied to the Airtricity model. This included the issues noted above in relation to the development of DNO methodologies for charge-out of DTEC, impact on supplier TNUoS and dilution of signals by smearing the DTEC charge over a GSP group. In addition, issues were raised with the proposed removal of the BEGA arrangements and introduction of the CACA. Some thought the proposal was confusing and more clarity was required on how BEGA DG would be treated, others thought the need for the CACA is unclear or that active participation should remain through the BM.

4.79. **Minimising implementation costs**. In addition to the comments noted above in relation to the SP T&D model, several respondents noted that the Airtricity model would also involve further costs and complexity in relation to the development of additional Line Loss Factor codes with respect to the new distribution charges, a new Constraint and Compensation Agreement and the removal of the BEGA arrangements. One respondent thought that when developed in more detail the Airtricity model would become a more significant change than it first appears and would logically lead to exit capacity reform and development of DNO balancing arrangements. Another respondent thought that the more active DNO role would increase suppliers' risk profile in the BM.

4.80. **Cost-reflectivity**. As with the SP T&D model, the majority of respondents thought the Airtricity model would be more cost-reflective than the existing arrangements. Some respondents preferred the Airtricity model as it charges out the DTEC charge more widely and provides for demand side participation. One respondent thought it would be more cost-reflective if it included exit reform.

4.81. **Efficient network development**. Respondents again expressed similar views to those previously expressed for the SP T&D model.

CE Electric UK model

4.82. The majority of respondents agreed that the issues which the CE Electric UK model seeks to address are material. The respondents were split on whether the CE Electric UK model would address the issues it identified. The majority of respondents thought there are additional material issues which the CE Electric UK model would not address.

4.83. Some respondents thought that the supplier should not be the agent responsible for procuring access rights for DG, preferring a DNO agency model. Several respondents thought that the model would have limited impact.

4.84. **Minimising implementation costs**. The majority of respondents considered that the CE Electric UK model is the least change model, and also the cheapest, simplest and quickest to implement. Some respondents questioned whether it would involve sufficient change to address the issues and deliver real benefit. One respondent noted it would only require changes to billing systems and minor changes to industry codes and business practices, although another identified a need for renegotiation of supplier contracts which would be difficult and expensive.

4.85. **Cost-reflectivity**. The majority of respondents thought the CE Electric UK model would not significantly improve cost-reflectivity. Some respondents noted that exporting SVA BMUs were unlikely to occur in practice so the model would have minimal impact. Another respondent noted that the existing charging arrangements can already accommodate exporting SVA BMUs, which are paid negative demand TNUoS. This respondent noted that under CE Electric UK's model the charge would be sensitive to the given supplier's portfolio of contracted DG in the given GSP group and may not relate to the true net position for that GSP group, and argued that export charges should only be applied if the GSP Group as a whole exports. Some respondents noted their preference for other models.

4.86. **Efficient network development**. Some respondents noted that the strengthened information provision would better facilitate efficient network development. Others considered that the supplier agency aspect of the model would provide little improvement in this respect as it is such minimal change. Some such respondents preferred a DNO agency model and another noted that a zonal model cannot send useful investment signals. One respondent, who did not think the model cost-reflective, thought it would increase the risk of inefficient network investment by facilitating greater levels of connection without being exposed to appropriate signals.

NGET model

4.87. Respondents were split as to whether the issues which the NGET model seeks to address are material and also as to whether it would address the issues it identified. The majority of respondents thought there are additional material issues which the NGET model would not address.

4.88. A number of respondents considered the NGET model to be very complex and to represent significant change, while not being convinced that it would improve either cost-reflectivity or, even if more cost-reflective, promote efficient network development. Some respondents disputed the central assumptions underpinning NGET's model, in particular that all generation have the same impact on transmission system investment and that DG compete with directly connected generators. As with the CE Electric UK model, some respondents thought that the supplier should not be the agent responsible for procuring access rights for DG, preferring a DNO agency model. Some respondents thought more clarity was required on the treatment of final sums liability particularly in circumstances of changes of supplier. One respondent thought the model is too "transmission centric".

4.89. **Minimising implementation costs**. Although some respondents thought the NGET model may be simpler to implement than either the SP T&D model or the Airtricity model as it would not require new billing processes, several respondents considered that the NGET model represents significant change and would be complex and costly to implement. As for the CE Electric UK model, a respondent identified a need for renegotiation of supplier contracts which would be difficult and expensive. One respondent noted it would be complex to identify which GSP an SVA DG is connected to, which would require extra work by DNOs, suppliers and Elexon.

4.90. **Cost-reflectivity**. Although some respondents thought the NGET model may be the most cost-reflective, the majority of respondents did not think it improved cost-reflectivity compared to the existing arrangements. The latter set of respondents mostly considered gross charging for DG to be not cost-reflective, with one respondent unclear that the nodal approach would provide any advantages.

4.91. **Efficient network development**. The majority of respondents thought the NGET model would have either no impact or an adverse impact on efficient network development. Several respondents favoured a DNO agency model, one respondent noted that a supplier agency model may lead to over-contracting and also impact on the Triad-related incentives. Some respondents thought that the network planning issues could be addressed by strengthened information provision. One respondent thought that the NGET model would create incentives to generators to connect to the transmission system rather than the distribution system, and another thought it had too much focus on the transmission system vs. efficient development of the distribution system.

Working group conclusions

4.92. As discussed in Chapter 3, the Group identified a number of issues with the existing transmission arrangements with respect to DG, but had diverse views on their nature, materiality, and means by which they should be addressed. In the light of these discussions, four strawman agency models were put forward by members of the Group and assessed as options for change:

- A DNO agency model with charges applicable to net exports at individual GSPs and charged out to DG on the basis of connection voltage, proposed by SP T&D
- A DNO agency model with charges applicable to net exports at individual GSPs and charged out to all DG contributing to export, proposed by Airtricity

- A supplier agency model with charges applicable to net exports from suppliers over each GSP group, proposed by CE Electric UK

- A supplier agency model with charges applicable to gross generation exports from suppliers at individual GSPs, proposed by NGET

4.93. Each strawman is targeted to addressing particular issues from the proposer's perspective. In terms of the issues discussed in Chapter 3, all the strawmen seek, as a minimum, to address the gap in the contractual arrangements with respect exports by means of an agency model, while minimising contractual burden on parties subject to that agency arrangement. However, each strawman differs in its perception of the nature of that gap, in particular the appropriate definition of export, and the means by which it should be addressed in terms of introducing rights and obligations. There are also differences in the scope of the agency models and whether they supplement or supersede the BEGA arrangements. Key differences between the strawman models were summarised in Table 8 above.

4.94. In considering implementation issues the Group noted that each strawman professes to involve minimal change, and hence low cost, within the context of its perceptions of these issues. In terms of the comparison between models in this respect, the majority of the Group considered the CE Electric UK model to involve least change overall, and to be the most straightforward to implement. However some questioned whether it involved sufficient change to justify its costs in terms of having a positive effect on cost-reflectivity and efficient network development.

4.95. In addition, for each model parties identified a number of aspects which require further clarification or development, for example in relation to:

- impact on arrangements for BEGA DG
- impact on supplier TNUoS and Triad-related incentives
- definition of access product and treatment of breach/overrun and imbalance
- methodology for charge-out of export charge to DG
- scope and processes for management of DG output via the agent, including interaction with BM
- user commitment in relation to transmission investment.

4.96. In some cases parties considered that the issues they had identified with a given model may increase the complexity and cost of its implementation. In particular, a number of parties considered that either the Airtricity model or the NGET model represented fundamental change when their respective full implications are taken into account.

4.97. Drawing on its consideration of the design and implementation issues for individual models, the Group compared and contrasted DNO agency models and supplier agency models in generic terms, identifying common features and issues to be addressed which relate to the choice of agent rather than the specific model design. These findings are summarised in Table 10. In particular, the Group noted that either approach is amenable to taking diversity into account, but that they do so in different ways: the DNO has a full picture of the demand and DG connected to its network, although its current focus is on peak boundary flows; the supplier only has information on DG with which it contracts, but has a better understanding of year-round operation. It also considered that both approaches could accommodate either a net or gross model of access and charging.

Table 10: Generic comparison of DNO agency and supplier agency models

Aspect	DNO agency model	Supplier agency model
Common features or advantages	• Capable of accommodating either a net or gross model for access and charging • Amenable to taking diversity into account • DNO has full picture of planned DG connections and net position over all DG and demand at peak • DNO can provide information on aggregate physical output in planning and operational timescales • Can evolve to accommodate more active distribution network management • DG have stable relationship with DNO, access rights and charges are not affected by DG changes of supplier	• Capable of accommodating either a net or gross model for access and charging • Amenable to taking diversity into account • Supplier has good information on year-round operating regime of individual DG • Can use existing commercial interface for TNUoS charging • No new billing processes required • Keeps DNO role technical
Issues to be addressed or disadvantages	• How to define / measure net export taking into account variability in both generation and demand • Need for new billing processes • Development of distribution charging methodologies • Impact on imbalance and supplier's risk profile in BM • Interaction between BM and processes for DG output management via agent • Development of DNO commercial risk management processes • Incentivisation of DNOs • Arrangements for IDNOs	• Metering issues • How to deal with DG changes of supplier • Renegotiation of supplier contracts • Impact on Triad-related incentives • Risk of over-contracting • Interaction with GB queue • Higher risk of agent default

4.98. On this basis the Group concluded that either approach could theoretically form a suitable basis for an agency model, while also noting a number of issues to be addressed in each case. However, some expressed a generic preference for a DNO agency approach on the basis that it may accommodate future evolution of the DNO role and the development of active network management, or because it was perceived as less complex or lower risk from the DG perspective than a supplier agency approach. Some additionally noted that the work of the DTI Centre for DG & Sustainable Electrical Energy[29] points towards a DNO agency model. Some Group members preferred a supplier agency approach on the basis that it would not need new billing processes and could use the existing commercial interface for TNUoS charging.

4.99. Turning to consideration of the individual models assessed by the Group, it was noted that this comprised two net DNO agency models (both by GSP), one net supplier agency model (by GSP group) and one gross supplier agency model (by GSP), but that no gross DNO agency model had been proposed. The Group considered that the issue of whether a given model is net or gross could potentially have a significant commercial impact on industry parties.

4.100. On this basis the Group identified the gross vs, net issue as the main source of the division of views, and noted that it would never be able to agree on individual models in terms of the TADG objectives. As highlighted elsewhere in this Report and outlined below, there was no consensus on the cost-reflectivity of the existing transmission charging arrangements with respect to DG. Further, even amongst the parties who identified deficiencies in those arrangements there were mixed views on whether, and if so in what way, they should be changed in order to improve cost-reflectivity and better facilitate efficient network development.

4.101. Specifically, in the Group's discussion on access and charging issues set out in Chapter 3 it was noted that the embedded benefits associated with the current difference in transmission charges between those treated as generation (on a gross basis) and those treated as treated as negative demand (either directly or by netting off supplier demand) is primarily driven by the sum of the respective residual charges, which is around £17/kW at any given location. The Group had noted that this treatment is based on the principle that DG treated as negative demand lead to a reduction in the transmission investment that would otherwise be required by demand, rather than triggering additional transmission investment.

4.102. While some Group members thought that this treatment remains appropriate, others considered that with continued growth of DG it may not represent reality and is not cost-reflective. In particular, the appropriateness of exporting DG saving the residual charge was questioned, and some parties considered that DG should pay generation charges either on a gross basis or on the basis of net exports to the transmission system. The operation of the access and charging arrangements on a nodal (by GSP) or zonal (by GSP group) basis, and the associated impact on the GSP Group based settlement arrangements, was another theme in the discussions. Parties also raised a number of issues with the cost-reflectivity of the existing charging arrangements in their responses to the strawman assessment questionnaire.

[29] Discussed in Chapter 3.

4.103. In terms of the options for change discussed by the Group, each strawman seeks to apply transmission charges for exports associated with DG, although as noted above they define these exports in different ways. As such they could each impact, to varying extents, on the level of embedded benefits currently received by DG, and may also have an associated impact on charges to other users. The Group considered that the most significant factor in determining this impact is whether the model is gross (as for the NGET model) or net (as for the SP T&D, Aitricity and CE Electric UK models). The Group therefore concluded that NGET's model may be likely to have the greatest commercial impact relative to the existing arrangements given that it is the only model to apply transmission charges to DG on a gross basis. The Group also noted that amongst Group members NGET's model is the least popular of the proposed strawmen, primarily for this reason, although as noted above some parties also expressed a generic preference for a DNO agency model over a supplier agency model. In addition, it was suggested that a gross model with aggregation could potentially have a similar impact to a net model.

4.104. Given the significance of the net vs. gross issue, and noting that it would never be able to reach agreement on individual models, the Group considered it appropriate for the Report to summarise the arguments in support of net charging and gross charging respectively. Table 11 summarises the arguments expressed in TADG meetings in support of net charging. Table 11 is based on a summary submitted by a Group member as an action from Meeting 8, and includes arguments used either in favour of retaining the existing arrangements or in support of using a net rather than gross approach in any given option for change. Also as an action from Meeting 8, NGET provided a summary of its arguments for using a gross model rather than a net model to address the issues it identified. This is set out in Table 12. The Group were invited to indicate whether they agreed with the arguments in each summary. Of those who commented, the majority expressed support for the arguments set out in Table 11 in support of net charging.

4.105. Taking the above factors into account, overall the majority of the Group favoured a net DNO agency approach, with a small minority supporting a gross supplier agency approach.

Table 11: Summary of arguments expressed in support of net charging

Issue	In favour of net charging	Against gross charging
Network charges applicable to each user	Generators should pay for the network to which they are connected At present transmission connected generators pay transmission charges, but not distribution charges. Similarly, DG generally pay distribution charges, but not transmission charges	Gross transmission charging implies DG would be liable for transmission and distribution charges, but transmission connected generators would only pay transmission charges. This would provide a perverse incentive to always connect to the transmission system as this will always be cheaper for a specific location
Transmission investment drivers	The transmission system is built to accommodate the expected net flows to and from the distribution system	It is not cost reflective to charge users on the basis of fictional gross flows which do not exist in reality
Consistency with other aspects of trading arrangements	Other elements of the trading arrangements are undertaken on a net basis, e.g. energy settlement & imbalance, transmission losses, BSUoS charges, Trading Sites	Providing and charging for access on a gross basis would be inconsistent with this and would create a distortion in the trading arrangements
GSP Group based settlement arrangements	Presently, DG is aggregated and netted off demand at the GSP Group level in the central settlement systems	Changing these settlement arrangements to a gross basis would involve significant implementation costs
Signals to DG	Gross charging is not required to ensure DG receive the correct signals as to where in the country to locate a power station. Present net charging arrangements expose DG to the locational element of TNUoS tariffs through avoided demand charges, so DG are exposed to essentially the same geographical TNUoS differentials as transmission connected generators. DG and transmission connected generators are exposed to different residual tariffs. However these are set simply to recover the correct level of transmission costs, not to signal where to locate generation.	
Impact on smallest sized DG	Logical extension of argument behind gross model, that it is the collective impact of DG which determines the effect on the transmission system, is that all DG should be charged regardless of size - this implies charging down to the smallest generation which does not appear to be sensible or efficient	
Information provision	Gross access and charging should not be seen as solution to the need for improved information on DG. You do not need to charge something to know that it is there	

Table 12: Summary of arguments expressed in support of gross charging

Issue	Against retaining existing arrangements	In favour of gross charging
Level of charges	Net regime is not being properly applied at present, reforms to correct this would share the residual charge with DG and result in lower but correct embedded benefits	Misconception that gross charging results in higher charges for DG – impact on embedded benefits would be similar for a net regime with the residual charge corrected
Exit arrangements	No defined exit product, so demand pays for what it uses not what is installed for it – netting off arrangements transfer this flexibility to DG – this is not sustainable	Pragmatic means to avoid fundamental exit reform (with explicit capacity booking for demand, overrun charges and negative demand charging) to take account of impact of DG
Interpretation of gross	Clarification that gross model would not be based on sum of rated capacity, but on aggregated capacity (e.g. 70MW for two 50MW windfarms)	

5. Interactions with developments in interrelated areas

Ongoing work in other areas

5.1. Throughout the process a number of members of the Group raised issues in relation to the specific impacts of any proposals on particular users, e.g. microgeneration, CHP, renewables and offshore generation, and also in the context of ongoing work in other policy areas.

5.2. Ofgem clarified that the role of the Group is to focus specifically on the development of appropriate contractual and charging arrangements for DG to reflect its impact on the transmission system. In this respect it is not the role of TADG to address wider issues in relation to DG or the transmission arrangements in general, or to focus narrowly on specific types of users when developing transmission arrangements for DG. However, where parties raised issues outside the scope of TADG, the Group would note interactions with other policy areas where appropriate. The interactions noted by the Group are summarised below.

Energy Review and Energy White Paper

Ofgem/DTI review of distributed generation

5.3. In the Government's Energy Review, published in July last year, the DTI and Ofgem committed to carry out a comprehensive review of the incentives and barriers that impact on DG. The scope of the review was to include the following:

- The economic and other incentives for suppliers to buy electricity from distributed generators;
- The economic costs and benefits, and other incentives, for DNOs to connect new generators and to invest in upgrading distribution networks in order to accommodate increasing amounts of distributed generation;
- Options for resolving potential barriers to the sale of electricity from small generators, for example:
    - licensing procedures
    - technical standards for connection and for network operation; and
- The incentives for DNOs to engage in innovation aimed at minimising the costs and capturing the benefits of distributed generation.

5.4. The review process was initiated in November 2006 with the joint publication by DTI and Ofgem of a Call for Evidence[30]. This explained the issues that were considered to be most relevant to the scope of the review and sought responses on a number of specific issues. At the time of the last TADG meeting on 26 April 2007, the review process was drawing to a close and providing inputs to the Energy White Paper.

5.5. A number of Group members raised concerns that the models being developed through TADG may erode the current level of embedded benefits available to DG, and hence conflict with government policy to create appropriate

[30] Distributed energy - A call for evidence for the review of barriers and incentives to distributed electricity generation, including combined heat and power, a joint Government-Ofgem review – November 2006, Ofgem #193/06

incentives and address existing barriers to DG. Ofgem confirmed that it was liaising with the DTI with respect to the interactions between the work of TADG and the Energy Review. It noted that while the interaction between the work areas was noted their separate purposes and objectives were also noted.

5.6. The joint DTI/Ofgem report[31] on the review of distributed generation was published in May 2007 alongside the Energy White Paper[32]. In terms of the network benefits of DG, the DTI/Ofgem report[33] noted that while DG may potentially create benefits by reducing or avoiding network investment costs and losses, this is not always the case, and that sometimes the impact of DG output on system flows can in fact trigger reinforcement and increase losses, e.g. in locations where DG output significantly exceeds local demand. The DTI/Ofgem report noted that industry parties had challenged the existing arrangements for embedded benefits for exemptable DG, which provide a reward to generators which are deemed not to be using the transmission system as a result of reducing demand, and further noted that this issue was being reviewed through the TADG process. The Energy White Paper itself also referred to TADG, where it noted the Government's view that "charges should be cost-reflective, with charges being proportionate to the costs imposed, and with parties appropriately rewarded for any benefit contributed" and that "the burden of regulation on a distributed generator should be proportionate to its use of the network".

5.7. The DTI/Ofgem report also announced the intention to undertake a broad review of the industry arrangements, including those relating to energy trading, to facilitate DG and enable them to compete on a level playing field with conventional generation. This review will include a joint DTI/Ofgem consultation later in 2007 on options for more flexible market and licensing arrangements for distributed low-carbon electricity within the licensed framework, to be implemented by the end of 2008. A range of options to form the basis for that consultation will be developed by the Distributed Energy Working Group, which is an industry working group chaired by Ofgem.

Future development of electricity networks

5.8. A number of further initiatives relevant to the work of TADG were noted in the Energy Review and Energy White Paper. This includes the Foresight project on Sustainable Energy Management and the Built Environment[34], whose work will include examining the long term potential for, and challenges associated with, the growth of low carbon, decentralised energy and its interaction with centralised generation, taking key uncertainties into account. In addition Ofgem will undertake a project on long term scenario planning for the electricity networks, looking at key drivers on the demand side and potential changes on the supply side. Since the last TADG meeting Ofgem published an open letter[35] setting out initial thoughts on its proposed approach to this project.

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[31] Review of distributed generation – a joint Government/Ofgem report – May 2007
[32] Energy White Paper: Meeting the Energy Challenge – May 2007, Department of Trade & Industry
[33] See in particular chapters 3 and 7
[34] http://www.foresight.gov.uk/Energy/Energy.html
[35] Long Term Electricity Network Scenarios – Initial thoughts and workshop invitation – 15 June 2007, Ofgem #146/07

5.9. The Energy White Paper also noted a range of measures which aim to create incentives for and remove barriers to the connection of low carbon and decentralised generation, and as such may influence the long term development of the electricity network. This includes the Government's commitment to strengthening the Renewables Obligation (RO) and the EU Emissions Trading Scheme (ETS), and improving the planning system. Further, in March 2007, the European Council agreed a binding target of a 20% share of renewable energies[36] in overall EU consumption by 2020.

5.10. In addition, under the recent Transmission Price Control Review[37] Ofgem agreed funding to the electricity transmission licencees for significant investments (over £4bn in total, including £0.5bn under the Transmission Investment for Renewables (TIRG) project) in the GB transmission network, in response to significant demand for new connections. Further, recognising the uncertainty as to the timing of new connections, the arrangements are sufficiently flexible to allow the transmission companies to make further investment in response to future demand from users. Ofgem is also working with the DTI and industry to develop the framework for offshore connections and for extending the transmission networks to the Scottish islands (see below). Overall, these measures will facilitate the efficient expansion of transmission infrastructure to accommodate the increased demand for new connections, particularly from renewable generators, while ensuring the interests of consumers are protected.

5.11. A key driver of the future development of the transmission network is the technical standards, set out in the GB Supply Quality and Security Standards (GB SQSS) and the Grid Code, which determine the appropriate level of transmission investment to maintain system security and ensure economic and efficient operation of the system. Work is currently being undertaken by Ofgem, DTI and NGET to review these standards to ensure they reflect the characteristics of different technologies including renewable generation, both in the context of onshore and offshore connections.

5.12. The Energy White paper also refers to a number of other areas of work being undertaken to improve grid access for renewable generation, both in the short term and in the longer term. This is discussed below.

Offshore and Scottish Islands

5.13. Ofgem and the DTI are currently working together on a project to develop the necessary regulatory framework for delivery of offshore electricity generation to the onshore electricity grid through new offshore transmission cables. The aim of the project is to design a framework that will allow offshore transmission networks to be built in an economic, efficient and co-ordinated manner so that they will enable generators located in offshore waters to deliver their generation to the onshore electricity grid, whilst maintaining the integrity of the system as a whole, at the best value to network users and consumers.

5.14. The principal mechanism which Ofgem and DTI intend to use to implement offshore arrangements is modifications to licences, codes and agreements. It is anticipated that at least the majority of these modifications would be made by the

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[36] This applies to transport and heat as well as electricity
[37] Transmission Price Control Review: Final Proposals – Decision document - December 2006, Ofgem #206/06

Secretary of State using powers provided to him under ss. 90 & 91 of the Energy Act 2004. Once sections 90 & 91 have been commenced and all modifications made, the offshore regime will be "active". Once the Secretary of State has commenced sections 89 & 180 of the 2004 Act, the offshore regime will be 'live'.

5.15. At an early stage in the TADG working group it was recognised that there were interactions between the work of TADG and the development of offshore arrangements. In particular, there are questions regarding how the GBSO should interface with the DNO when developing and contracting for works associated with an offshore connection application connecting to an onshore distribution network.

5.16. It was noted that the offshore framework was not sufficiently developed for these issues to be dealt with within the scope of TADG. However, it was also recognised that to the extent to which any revised arrangements, including agency models, are considered appropriate to address this impact onshore, then they would be expected to be relevant to addressing offshore issues.

5.17. Ofgem published a scoping paper[38] setting out its initial thoughts on policy proposals and providing a detailed framework for the implementation work that needs to be undertaken to develop offshore arrangements. Chapter 4 of that paper considered issues of connecting via distribution networks.

5.18. In addition, after the last TADG meeting Ofgem published a consultation document on applying a similar approach for connecting the Scottish Islands to the mainland transmission network[39].

Distribution issues

5.19. There are a number of ongoing distribution issues noted by the Group as having potential interactions with the work of TADG. These include:

5.20. **Structure of charges project**. Following the previous Distribution Price Control Review, a process was put in place to look at the charging and commercial framework for distribution connected generation with a view to reflecting the more robust modelling of costs and benefits to be reflected in use of system charging. As a result, GDUoS charges were introduced for new generators from April 2005 along with shallower connection boundary. At present new charging models are being developed at EHV level. Consideration of charges for generation connected at HV and LV require further work. The project includes consideration of charging arrangements for existing generators from 2010.

5.21. Work on the distribution charging framework may have implications for the work undertaken by TADG. One such area that was identified was in relation to the availability of a mechanism for charge-out of DTEC charges under a DNO agency model. The Group also noted that differences in the distribution charging methodologies used by different DNOs may create inconsistencies between GSP Groups in how charges on the agent are passed through to DG.

[38] Offshore electricity transmission: Second scoping document – Consultation document – March 2007, Ofgem #58/07
[39] Connecting the Islands of Scotland – Consultation document - June 2007, Ofgem #138/07

5.22. **Ongoing review of DNO incentives to connect generation**. Under the Registered Power Zone (RPZ) arrangements an incentive is available for each DNO for each year of the price control for projects where they use innovative and cost effective ways of connecting DG. Another mechanism is the Innovation Funding Incentive (IFI) which encourages DNOs to invest a percentage of their turnover in research and development that focuses on the technical aspects of network design, operation and maintenance. IFI can therefore also assist the connection of DG.

5.23. **Distribution Connection and Use of System Agreement (DCUSA)**. The recently designated DCUSA governs the commercial relationship between electricity distributors, suppliers and other parties such as distributed generators. This document replaced hundreds of bilateral contracts and provides for a more flexible and responsive governance process, whereby parties to the agreement can propose changes to the commercial arrangements. This document also gives legal backing to the arrangements for connection of microgeneration.

5.24. **Distribution Price Control Review (DPCR)**. The DPCR process which will determine the basis for distribution charges between 2010 and 2015 will commence in 2008. After the last TADG meeting, Ofgem published an open letter[40] seeking views on the general approach and the key issues for the review. Among the issues that will be considered by Ofgem during the review will be the role of DNOs regarding distributed generators and associated incentives.

Transmission access issues

Access Reform Options Development Group (ARODG)

5.25. In early 2006, Ofgem established the Access Reform Options Development Group (ARODG). In light of significant changes in the demand for capacity on the network the Group was charged with developing a range of options for amending the existing arrangements for securing transmission capacity.

5.26. The ARODG group originally met in March/April 2006 and published a group report and covering letter[41] in May 2006 highlighting a range of possible options for change. Following the publication of that report modifications to industry codes have been raised to reform pre and post commissioning securities and to introduce new access products and trade capacity. In particular, two CUSC modification proposals were raised within the period over which the TADG Group met and noted to be relevant to TADG, namely CAP131 and CAP143.

5.27. CAP131, raised by NGET in September 2006, proposes to add a new Schedule to the CUSC defining the principles of "User Commitment". The new section would define the charge a TEC User would face in terminating its Construction Agreement and therefore the level to be secured during the Construction Programme for infrastructure works. Other changes would also be made to increase the period existing TEC Users would be required to notify NGET in advance of reductions to TEC. A consultation on CAP 131 closed on 13 April 2007. This was followed by second consultation on six consultation alternative amendments, which closed on 21 May 2007. If implemented, CAP131 would apply to any user with TEC, which includes DG with a BEGA. It may also have

[40] DPCR5 – looking ahead – open letter - 17 May 2007, Ofgem #119/07
[41] Documents relating to the work of ARODG are available on Ofgem's website.

implications for the development of agency models applying user commitment principles to the applicable access product.

5.28. CAP143, raised by SSE Generation Ltd in January 2007, proposes to introduce a new access product – Interim TEC (ITEC) – which would have less commercial firmness than the current TEC products. The intention of CAP143 is that ITEC would enable access to be brought forward for new connectees who can tolerate less firm access in the first instance. CAP143 could have significant implications for smaller parties. If introduced, ITEC would provide smaller parties with a different type of access product with different associated charging arrangements. This raises parallels with the discussion of DTEC product and what options they might provide for smaller parties.

Other CUSC developments

5.29. Also noted as being relevant to the work of TADG is CAP097, which was raised by National Grid in July 2005, approved by Ofgem in June 2006. Its purpose was to revise and clarify the processes to be followed by NGET and DNOs regarding the energisation of distributed power stations. As discussed in more detail in Chapter 3, the TADG Group noted that while CAP097 solved problems for medium sized generators it did not address the issues for small generators.

5.30. At the final TADG meeting, the Group also noted two forthcoming CUSC developments which may have relevance to the work of TADG, namely CAP148 and TASG.

5.31. CAP148, raised by Wind Energy (Forse) Limited in April 2007, proposes to prioritise the use of the transmission system for renewable generators through the introduction of a Deemed Transmission Entry Capacity. Also following on from the work of ARODG, it seeks to grant renewable generators firm access rights, up to their CEC limit, by a fixed date irrespective of whether any deep reinforcements have been constructed and commissioned. At its meeting on 27 April 2007 the CUSC Panel submitted CAP148 to a working group for 3 month assessment.

5.32. Also at the 27 April CUSC Panel meeting it was agreed to reconvene the Transmission Access Standing Group (TASG) to consider the development of alternative entry access arrangements which facilitate more flexible use of the system e,g, through short term access products or trading, particularly in the context of enabling the efficient and non-discriminatory integration of renewable generation.

Initiatives identified in Energy White Paper

5.33. As noted above, the Energy White paper refers to a number of areas of work being undertaken to improve grid access for renewable generation. In the short term this includes work under the current industry governance arrangements to manage the GB queue and improve access arrangements, e.g. through the work of ARODG and TASG. Ofgem will report on progress on these issues in September 2007.

5.34. In addition, Ofgem and DTI will review the appropriateness of the current technical, commercial and regulatory framework for transmission investment and operation, in the context of an increasing proportion of renewable generation on the system. This transmission access review will take into account access reform work already underway, as noted above, in developing proposals for changes to the framework in the medium and longer term. Ofgem and DTI will provide an interim report in December 2007 and a final report in May 2008. The interim report will include consideration of the case for changes to legislation while the final report will set out recommendations and a delivery plan.

Wider issues raised in working group discussions

5.35. The Group also noted where its discussions raised wider issues beyond the scope of TADG, as follows.

5.36. The two presentations[42] by the DTI Centre for DG & Sustainable Electrical Energy[43] raised a number of issues centred on an assessment of whether the existing transmission arrangements are able to support cost effective system operation of systems that include integrated DG. The first presentation was based on the Centre's report "Transmission Investment, Access and Pricing in Systems with Wind Generation". It focused on transmission access and security standards for systems with wind generation, and questioned the current concept of TEC in terms of efficiency of network development, cost-reflectivity of TNUoS charging and efficiency of system operation in systems that include significant penetration of wind generation. The second presentation, based on the Centre's report "Integration of DG into the UK Power system", reiterated what the Centre perceived to be the differential impact on the system between distributed and transmission connected generation, suggested weakness in the present arrangements which do not reflect these differences, and highlighted areas for further work in development of cost reflective transmission arrangements for DG.

5.37. The Group noted that the issues raised with respect to the need to take diversity into account were relevant to the development of aggregate TEC or DTEC for multiple DG. It was suggested that further work in this area could potentially form a theoretical basis for a sophisticated methodology for setting DTEC under a DNO agency model. This was noted as an interaction, but not a matter for the group to solve.

5.38. With respect to the issues raised with the appropriateness of TEC for DG, the Group noted the key factor is the pattern of output not the point of connection. Attendees considered this applies specifically to conventional vs. intermittent generation, rather than generally to DG vs. transmission connected generation, and as such are equally applicable to transmission connected windfarms but may not apply to conventional DG. As such, some thought the presentations raised more general issues about the use of the same access product for all technologies, and that there may be scope to develop a range of access products allowing for sharing of transmission capacity between generators not running at the same time. In this respect it was equally applicable to transmission connected generation, and may have interactions with the work on transmission access.

[42] Both papers referred to in the presentations are available on the DTI Centre for DG & Sustainable Electrical Energy website, www.sedg.ac.uk
[43] See Chapter 3 under Access and charging issues

5.39. The Garrad Hassan paper[44] also focussed on wind generation, which it considered in the context of forecasting output in short term timescales. It argued that forecast accuracy can be improved by aggregation, particularly over a large geographic area and in timescales close to real time. The Group considered that aggregation improves forecast accuracy if there is diversity in the underlying sources, and that this may have implications for the development of agency models which seek to take diversity into account.

5.40. In its discussion on operation and planning issues[45], the Group suggested that there may be a need to review the treatment of DG in the GB SQSS, noting that P2/6 had recently replaced P2/5. In addition, a Group member referred to an issue raised at the Ofgem/DTI Distribution Working Group (DWG), where it was suggested that P2/6 be further developed to include security standards for exporting distribution networks.

5.41. In the assessment of agency strawmen[46] some parties highlighted potential interactions with or need for consequential changes to other aspects of the regulatory and commercial framework. This included:

- offshore and distribution arrangements as noted above
- BSUoS charging
- other embedded benefits
- trading arrangements based on GSP Groups
- SVA metering
- contractual arrangements between DG and suppliers.

5.42. Finally, throughout the process a number of members of the Group raised issues in relation to the specific impacts of any proposals on low carbon generation, in the wider context of government energy policy. As noted above, Ofgem clarified that the role of the Group is to focus specifically on the development of appropriate contractual and charging arrangements for DG to reflect its impact on the transmission system. In addition, as highlighted in the discussion on the work of the DTI Centre for DG & Sustainable Electrical Energy, there exist a range of generation technologies connected to both the distribution and transmission networks. The Group therefore recognised that some of the issues raised by Group members related not to distribution vs. transmission connected generation in general, but specifically to intermittent vs. conventional generation or to low carbon vs. fossil generation, and that it is not the role of TADG to address such issues.

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[44] See Chapter 3 under Operation and planning issues
[45] See Chapter 3 under Operation and planning issues
[46] See Chapter 4

6. Way forward

Process for taking forward proposals

6.1. The Group has undertaken an assessment of the issues in relation to the existing transmission arrangements with respect to DG, and developed four agency strawmen as options for change to those arrangements. It will be for the industry to consider whether to take forward any of the strawmen developed by the Group and if so to submit change proposals to the industry codes or other documents. Any such proposals will be subject to the relevant modification processes, including industry consultation as appropriate, in which they will be developed by the industry in more detail and assessed in terms of any specific objectives applicable to the given industry code or other document.

6.2. It is important to note that the Group was established as a development group and not a decision making body. Its key purpose was to facilitate and co-ordinate industry discussion of issues and development of options in a holistic manner, including the identification of potential changes to the industry codes, licences or other documents, the combination of which would be necessary to deliver those models. Further, any assessment by the Group of individual strawmen has been necessarily high level and based on holistic consideration of the overall package comprising that proposal, against the key objectives for the group.

6.3. In this way the work of the Group was intended to be a helpful pre-cursor to (and not a substitute for) parties considering whether they wish to raise specific change proposals to implement any particular model. However, the work of the Group, as set out in this Report, may in turn help inform parties' proposals in this respect and the modification processes by which they are assessed.

6.4. All of the strawmen developed by the Group involved minimal change to the existing arrangements, and can be taken forward through change proposals to industry codes and other documents. It is noted that industry parties can propose changes to the industry codes but that only NGET can propose modifications to the transmission charging methodologies. However, there exist industry fora (TCMF and CISG) through which transmission charging issues are discussed and it is open to industry parties to raise issues directly at those meetings or by proposing CUSC amendments which require consequential changes to the charging methodologies. Should parties develop further proposals which cannot be taken forward under the existing governance arrangements, e.g. which require primary legislation, then it is open to them to lobby for this.

Ofgem role

6.5. Any change proposals to industry codes and charging methodologies to take forward any particular model will ultimately be submitted to Ofgem for decision. As appropriate Ofgem may also consider the requirement for any associated action by Ofgem. **Nothing presented or discussed at the Group or contained in this Report can have the effect of fettering the Authority's discretion in relation to any decisions it takes on any forthcoming relevant industry code modification proposals.**

Future of TADG

6.6. No further meetings of the Group are scheduled at this stage. However, the Group may reconvene at a later date should this be deemed appropriate.

Appendix 1 – Invitation and draft Terms of Reference

Bringing choice and value
to customers

Direct Dial: 020 7 901 7050
Email: robert.hull@ofgem.gov.uk

21 June 2006

Dear Colleague,

Transmission Arrangements for Distributed Generation ("TADG") Working Group: Invitation and draft terms of reference

Ofgem has recently consulted on and held a number of seminars to discuss the appropriate form of enduring transmission arrangements for distributed generation. Ofgem retains the view that it should be for licensees, in tandem with the industry, to develop any proposals for changing the existing arrangements. As a first stage in this process and having considered the views expressed by respondents, we propose to establish a working group to be tasked with developing specific options for change.

This letter sets out the purpose of the working group, and seeks applications from industry members wishing to be involved.

The working group

We envisage that the TADG working group will meet on approximately a monthly basis from the week commencing 10 July 2006. In the first instance Ofgem envisages the need for six meetings[1]. However, as the working group was convened in response to calls from industry participants, we would expect working group members to play a proactive role in contributing to the Group and determining its scope of work. In order to minimise the burden on group members, where possible we intend to schedule meetings at times and locations which are linked to other industry fora - such as the Charging Implementation Steering Group or the Transmission Charging Methodology Forum.

The working group will primarily be charged with developing "straw-men" for the form of enduring transmission arrangements for distributed generation, building on the findings of the consultation process to date. The key focus of the working group will be on the issues which would be encountered in implementing one of the options supported by respondents to Ofgem's discussion document. All material generated by the group will be published on a designated section of the Ofgem website. The first meeting will be on 12 July 2006 at Ofgem's London offices. This meeting will be chaired by Ofgem. One of the

[1] Further detail on the envisaged content of these meetings is set out in the attached Terms of Reference.

issues for the first meeting, given this is intended to be an industry group, will be to determine appropriate chairing arrangements for subsequent meetings.

If you are interested in attending the group, please contact Cheryl Mundie (cheryl.mundie@ofgem.gov.uk, 0141 331 6003) by 30 June. Attendance is limited to one person per relevant industry party.

Background

In approving National Grid Electricity Transmission plc's ("NGET") 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 for transmission capacity 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.

In September 2005 we published a discussion document[1] outlining a number of key issues arising from the existing charging and contractual arrangements and highlighted a range of potential options for addressing these issues. The purpose of the 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. These views were explored further in two industry workshops hosted by Ofgem in Glasgow on 19 January and in London on 24 January 2006.

On 31 May 2006 we published a further thoughts document[2]. This summarised respondents' views and sought to focus debate on the future direction of the development of the existing charging and contractual arrangements.

One of the key views that emerged out of the consultation process was the complexity of the issues to be addressed and the fact that those issues potentially cut across a number of different industry codes and documents. Respondents argued this would mean that the governance and consultation processes for any of the individual codes or documents would be insufficient to develop a holistic solution to the existing problems. On this basis it was considered that Ofgem needed to have a central role in the process.

Proposed approach

Ofgem retains the view that it should be for licensees, in tandem with the industry, to develop any proposals. It would be inappropriate for Ofgem to be centrally involved in prescribing particular solutions given our decision making role in any proposed modifications to existing arrangements. However, at the same time Ofgem accepts that we can play a constructive role in co-ordinating and facilitating the development of possible options. On this basis we set out our conclusion in the May paper that the best way of fulfilling this role is to establish a development group tasked with developing straw-men for the form of enduring transmission arrangements for distributed generation.

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

[2] Enduring transmission arrangements for distributed generation – further thoughts document – 31 May 2006, Ofgem #92/06

We consider that the role and operation of the group will be similar to that of the Access Reform Options Development Group ("ARODG"). The ARODG was established in March 2006 as part of the Transmission Price Control Review and tasked with supporting the development of potential options for changes to the way in which capacity on the GB transmission system is allocated.

Like the ARODG, the TADG working group will be clearly focussed on developing straw-men models which are considered to be both achievable in the medium term and capable of addressing the identified areas of concern with the current arrangements – focussing particularly on the issues associated with implementing any of these models. The group will be tasked with building on the work of the consultation process to date by considering in more detail those options identified by respondents as having the most potential to deliver a robust enduring framework, namely the agency models.

Terms of Reference

The draft terms of reference for the TADG working group are attached to this letter, and will be discussed at the first meeting of the group. In line with the ARODG we would like to stress that the group is intended to be a helpful pre-cursor to (and not a substitute for) parties considering whether they wish to raise specific modification proposals. The establishment of this group does not affect, in any way, Ofgem's formal decision-making role under relevant code or document modification processes.

Yours sincerely,

Robert Hull
Director of Transmission

Draft terms of reference

Transmission Arrangements for Distributed Generation ("TADG") Working Group

Group composition

Chair: Ofgem (first meeting); subsequent meetings - TBC

Objectives of TADG

The purpose of the group is to seek to identify options for change to the transmission arrangements as they affect distributed generation in the light of the following criteria:

- **Minimising implementation costs.** The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumers.

- **Cost reflectivity.** The arrangements should seek to reflect the costs that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.

- **Efficient network development.** Arrangements should encourage efficient decisions can be taken regarding the development and use of the transmission and distribution networks.

Scope

The scope of the matters for consideration by the working group is confined to those relating to the appropriate development of transmission arrangements to reflect the impact of distributed generation on the transmission network.

In light of respondents' comments to the recent consultation process, there are four key issues that are within the scope of the working group. These are:

- the development of appropriate charging arrangements that ensure parties pay charges which reflect the costs they impose on the networks and which thereby remove the scope for perverse incentives when deciding where, and at which voltage, to connect;
- the interaction with issues of transmission access including the treatment of exporting Grid Supply Points without access rights to the GB transmission system, the nature of access rights appropriate to distributed generation and any interactions with the work of the Access Reform Options Development Group;
- the impact of distributed generation, as compared to transmission connected generation, on the operation and planning of the GB transmission system and what that implies for system planning and operational control, including issues around the need for direct interfaces between distributed generators and the system operator; and
- the ease of implementation and implementation costs associated with any solution.

Given that the consultation process to date has already considered these issues in the context of a number of potential options, the working group will build on this work and primarily focus on developing in more detail the options identified through that process as having the most potential to deliver a robust enduring framework, namely the agency models.

It is anticipated that the working group format will facilitate and co-ordinate industry discussion of these options and the above issues in a holistic manner. This should lead to the development of straw-men models and the identification of changes to the industry codes, licences or other documents, the combination of which would be necessary to deliver those models. It will then be for the industry to consider whether to take forward any of the straw-men and if so to submit change proposals to the industry codes.

In developing these options, key questions for the group to consider are:

- to what extent is the impact (flows, operation, planning, investment and associated costs) of distributed generation on the GB transmission system the same as that of transmission connected generation;
- are the existing transmission access products appropriate to distributed generators, is there merit in considering access products based on the export to the GB transmission system rather than the full capacity of the generator; and
- if a distributed generator does not have firm transmission access rights then how can its export to the GB transmission system be controlled? Can this be achieved through the Distribution Network Operator or the supplier?

It is important to note that the group is a development group and not a decision making body. In particular, nothing presented or discussed at the group can have the effect of fettering the Authority's discretion in relation to any decisions it takes on any forthcoming relevant industry code modification proposals.

Organisation of meetings

The first meeting of the working group will be on 12 July 2006 at Ofgem's London offices. This meeting will be tasked with clarifying the objectives of the group and with identifying the range of agency arrangements which would be subject to further development. In particular, Ofgem considers that the Distribution Network Operator and supplier agency models and any other hybrid model or variation of the two merit further review and we consider that subsequent meetings should be subdivided to consider different aspects of both of these models.

Meeting 2 will focus on issues of developing appropriate charging arrangements which reflect the impact distributed generators have on the transmission network.

Meeting 3 will focus on the interaction with issues of transmission access including the treatment of exporting GSPs without access rights to the GB transmission system.

Meeting 4 will seek to consider wider issues of system planning and operational control.

Meeting 5 will consider implementation issues including code modification changes and costs.

Finally, meeting 6 will seek to refine any models and to test these against the key objectives for the group.

Where possible Ofgem will seek to ensure that all meetings convene at a time and location linked to other industry fora such as the Charging Implementation Steering Group or the Transmission Charging Methodology Forum.

Deliverables

1. Develop the detail of a range of agency models identifying associated changes to transmission arrangements for distributed generation

Work is expected to include:

- detailing the changes necessary, and issues associated with implementing, the options supported by respondents to Ofgem's discussion document;
- clarifying the need for change to industry codes and other related documentation; and
- identifying the future benefits and costs of any option being progressed via existing change processes.

2. Publication of group findings

Detail of the working group's discussions, straw-men and findings will be made public via a designated section of Ofgem's website.

Appendix 2 – Final Terms of Reference

Terms of reference

Transmission Arrangements for Distributed Generation ("TADG") Working Group

Group composition

Chair & Secretariat: Ofgem

Objectives of TADG

The purpose of the group is to seek to identify options for change to the existing transmission arrangements as they affect distributed generation in the light of the following criteria:

- **Minimising implementation costs.** The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumers.

- **Cost reflectivity.** The arrangements should seek to reflect the costs and benefits that industry participants impose on the system. Cost reflective charges promote effective competition between industry participants and facilitate market entry.

- **Efficient network development.** Arrangements should encourage efficient decisions to be taken regarding the development and use of the transmission and distribution networks.

Scope

The scope of the matters for consideration by the working group is confined to those relating to the appropriate development of transmission arrangements to reflect the impact of distributed generation on the transmission network.

In light of respondents' comments to the recent consultation process, there are four key issues that are within the scope of the working group. These are:

- the development of appropriate transmission charging arrangements including appropriate thresholds that ensure parties pay charges which reflect the costs they impose on the networks and which thereby remove the scope for perverse incentives when deciding where, and at which voltage, to connect;
- the interaction with issues of transmission access including the treatment of exporting Grid Supply Points without access rights to the GB transmission system, the contractual arrangements associated with and nature of access rights appropriate to distributed generation and any interactions with the work of the Access Reform Options Development Group;

- the impact of distributed generation, as compared to transmission connected generation and demand, on the operation and planning of the GB transmission system and what that implies for system planning and operational control, including issues around the need for direct interfaces between distributed generators and the GB system operator; and
- the ease of implementation and implementation costs, both one-off and ongoing, associated with any solution and associated interactions with other policy areas.

Given that the consultation process to date has already considered these issues in the context of a number of potential options, the working group will build on this work and primarily focus on developing in more detail the options identified through that process as having the most potential to deliver a robust enduring framework, namely the agency models, and with reference to the above issues.

It is anticipated that the working group format will facilitate and co-ordinate industry discussion of these options and the above issues in a holistic manner. This should lead to the development of straw-men models and the identification of potential changes to the industry codes, licences or other documents, the combination of which would be necessary to deliver those models. It will then be for the industry to consider whether to take forward any of the straw-men and if so to submit change proposals to the industry codes.

In developing these options, key questions for the group to consider are:

- to what extent is the impact (flows, operation, planning, investment and associated costs) of distributed generation on the GB transmission system, either individually or in aggregate, the same as that of transmission connected generation;
- are the existing transmission access products appropriate to distributed generators, is there merit in considering access products based on the export to the GB transmission system rather than the full capacity of a given generator or group of generators, or procured via an agent; and
- if a distributed generator does not have firm transmission access rights then how can its export to the GB transmission system be controlled if necessary? Can this be achieved through the Distribution Network Operator or the supplier?

It is important to note that the group is a development group and not a decision making body. In particular, nothing presented or discussed at the group can have the effect of fettering the Authority's discretion in relation to any decisions it takes on any forthcoming relevant industry code modification proposals.

Organisation of meetings

The first meeting of the working group will be on 14 July 2006 at Ofgem's London offices. This meeting will be tasked with clarifying the objectives of the group and with identifying the range of agency arrangements which would be subject to further development. In particular, Ofgem considers that the Distribution Network Operator and supplier agency models and any other hybrid model or variation of the two merit further review and we consider that subsequent meetings should be subdivided to consider different aspects of both of these models in the context of more detailed consideration of the key issues identified above.

Meeting 2 will focus on issues of system planning and operational control.

Meeting 3 will focus on the interaction with transmission access issues and the development of appropriate charging arrangements which reflect the impact distributed generators have on the transmission network.

Meeting 4 will provisionally be reserved to allow for further discussions on charging and access.

Meeting 5 will consider in more detail the form of possible agency models in light of the previous discussions.

Meeting 6 will consider implementation issues including code modification changes and costs.

Finally, meeting 7 will seek to refine any models and to test these against the key objectives for the group.

Where possible Ofgem will seek to ensure that all meetings convene at a time and location suitable for group attendees. Ofgem will also consider holding meetings outside Millbank including in Scotland and at National Grid House.

Deliverables

1. <u>Develop a report detailing a range of agency models, assessing the strengths and weaknesses of those models and identifying associated changes to transmission arrangements for distributed generation in order to implement changes</u>

Work is expected to include:

- developing a range of potential straw-man agency models with reference to the key issues identified above;
- detailing the changes necessary, and issues associated with implementing, the options supported by respondents to Ofgem's discussion document;
- clarifying the need for change to industry codes and other related documentation; and
- identifying the future benefits and costs of any option being progressed via existing change processes.

3. <u>Publication of group findings</u>

Detail of the working group's discussions, straw-men and findings will be made public via a designated section of Ofgem's website.

Appendix 3 – Data provided by licencees

1.1. Prior to establishing the Group Ofgem 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.

1.2. The information provided was included in Ofgem's May 2006 paper and is reproduced overleaf and discussed in Chapter 3.

1.3. Table A3.1 sets out the increase in distributed generation; Table A3.2 sets out the increase in connected demand; and Table A3.3 sets out the increase in transmission connected generation.

Table A3.1: 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 A3.2: 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 A3.2: 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 4 – Glossary of terms

This glossary of terms is intended to provide a high level explanation of some of the terminology used in the outputs of the TADG working group. For fuller information, the reader should consult the relevant industry codes, licences and other relevant documents which contain the formal legal definitions where applicable.

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 and Settlement Code (BSC)

Multi-party document governing the wholesale electricity balancing and settlement arrangements for Great Britain.

Balancing Mechanism (BM)

The mechanism for making and accepting offers and bids pursuant to the arrangements contained in the BSC and Grid Code.

BM Unit (BMU)

A unit registered as such under the BSC, and metered separately from other BM Units for the purposes of balancing and settlement.

Bilateral Connection Agreement (BCA)

An agreement entered into between NGET 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)

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. Unlike the BEGA, the BELLA does not allocate any use of system rights to the generator or require a user to pay charges in accordance with the transmission charging methodology. 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

CAP097

CUSC Amendment Proposal CAP097 "Revisions to the Contractual Requirements for Small and Medium Embedded Power Stations Under 6.5", of which Consultation Alternative Amendment CAA2 was approved by the Authority on 14 June 2006 for implementation on 14 July 2006.

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 in relation to their connection to and use of the transmission system. All licensed parties are required to accede to the CUSC, non-licensed parties may choose to accede or may be required to accede through other commercial codes.

CVA

Central Volume Allocation, as defined in the BSC. In the context of DG it applies to DG with a BEGA and registered as a BMU.

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 (DG)

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

Distribution Network Operator (DNO)

The holder of a distribution licence.

E

Engineering Recommendation P2/6 (ER P2/6)

A standard, forming part of the Distribution Code and referred to in condition 5 of the Distribution Licence, which specifies the minimum level of supply security that electricity distribution networks must achieve. ER P2/6 superseded the previous standard ER 2/5 on 1 July 2006. ER P2/6 was introduced to better account for the security contribution from modern forms of DG.

G

Generation Distribution 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 (GBSO)

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 owned or operated by Transmission Licencees providing for the bulk transfer of electricity across Great Britain.

GB Transmission System Security and Quality of Supply Standard (GB SQSS)

The document prepared pursuant to conditions C17 and D3 of the Transmission Licences, setting out the criteria and methodologies that the GB transmission licensees shall use in the planning and operation of the GB transmission system.

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 NGET 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.

GSP Group

A distinct electrical system identified by a defined group of GSPs all associated with one DNO area, the total supply into which is determined by metering for each half hour.

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

An arrangement whereby a supplier contracts with an unlicensed distributed generator to meet a local demand therefore reducing the delivery of energy from the transmission network and consequently reducing TNUoS charges.

Node

A point on a network at which circuits meet.

O

Offshore transmission

Transmission of electricity generated by a generating station 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).

P

Planning Code

Part of the Grid Code that deals mainly with the exchange of longer term information to facilitate efficient planning of the transmission system.

S

SGT

A power transformer which interconnects the transmission system with lower voltage systems.

SVA

Supplier Volume Allocation, as defined in the BSC. In the context of DG it applies to DG registered as part of a Supplier BMU.

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

Time of highest transmission 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 time, and is eligible for compensation if NGET cannot accommodate this export on the network. Generation TNUoS charges are based on TEC.

Transmission Network Use of System (TNUoS)

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 tariffs vary by location on a zonal basis, and are different for generators and for suppliers. TNUoS tariffs comprise a locational element, derived from the DCLF ICRP model, and a non-locational residual element.

W

Week 24 data

Demand data submitted by users to NGET under the Planning Code in week 24 of each calendar year. This includes data submitted by DNOs in relation to the forecast maximum demand and forecast demand at system peak, for each GSP, taking into account DG connected to their distribution networks.