Structure of electricity distribution charges

Consultation paper: Proposed DNO charging methodology statements

October 2004 235/04

Summary

This document summarises the electricity distribution network operators' (DNOs') draft charging methodology statements and requests views from interested parties on the draft methodologies. The document also provides Ofgem's initial views on the draft charging methodology statements.

A collective licence modification to standard licence condition (SLC) 4 of all the electricity distribution licences was made by the Gas and Electricity Markets Authority ('the Authority') on 7 July 2004. The modification requires the DNOs to determine use of system (UoS) and connection charging methodologies and to gain approval for these from the Authority by 1 April 2005. The DNOs are also required to prepare a UoS charging statement.

In July 2004, Ofgem published an open letter consultation summarising the DNOs' initial draft methodologies requesting views on the issues raised. Seven responses were received. Responses covered a wide range of issues. General issues raised include the suggestion for a degree of commonality between DNO methodologies and the need for the methodologies to set out exactly how charges are calculated such that users can predict likely actual or relative charge movements.

The DNOs have now submitted final drafts of these methodologies along with a draft UoS charging statement which contains illustrative tariffs. The draft methodologies and illustrative tariffs are available on the Ofgem website at www.ofgem.gov.uk, under the Electricity Distribution Charges area of work.

The methodologies contain details concerning revised arrangements for the structure of electricity distribution charges. From 1 April 2005 a new charging regime is being established which provides for a common connection charging boundary for demand and generation, the removal of the deep charging of generation and the introduction of generator distribution use of system tariffs (GDUoS). Longer term charging arrangements will be in place by 2010 with consideration being given to the earlier introduction of such arrangements where appropriate.

Following the consultation the DNOs will be required to submit their final charging methodologies for approval by the Authority. The Authority will assess the

methodologies against the relevant objectives laid out in the licence and its wider statutory duties.

Ofgem welcomes any comments and views on the draft DNO charging methodologies and statements as well as comments on this document. Respondents are requested to provide their responses by 10 November 2004.

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1. Introduction

1.1. From 1 April 2005 distribution network operators (DNOs) are obliged to produce charging methodologies for both connection to and use of their distribution systems. This is required under the electricity distribution licence following a collective licence modification made by the Authority on 7 July 2004 to standard licence condition (SLC) 4 of all the electricity distribution licences.

1.2. The methodologies are required to set out the principles and methods by which electricity distribution charges will be calculated in order to help provide a robust and predictable charging framework for all network operators and users.

1.3. Certain changes to the existing structure of charges are being implemented from 1 April 2005, following the review of the structure of charges.

Purpose of this document

1.4. This document constitutes formal consultation on the draft DNO charging methodology statements following the modification to the electricity distribution licences. It summarises the documents and provides further detail on Ofgem's preliminary view of the draft charging methodology statements.

Structure of this document

1.5. The structure of this document is as follows:

- Chapter 2 Background

Chapter 2 sets out the rationale for the charging methodologies and notes the changes to charging rules being implemented from 1 April 2005 along with a description of the process taken with the industry to get to this point.

- Chapter 3 Views invited

This chapter seeks views on the DNOs' draft charging methodology statements considering the relevant objectives detailed in the licence.

- Chapter 4 Summary of DNO draft documents

This chapter summarises the draft methodologies submitted by the DNOs on 30 September 2004.

- Chapter 5 Ofgem's initial views

Chapter 5 sets out Ofgem's initial views on key issues identified in the DNOs' latest draft methodology submissions.

- Chapter 6 Illustrative charges

This chapter highlights changes to distribution use of system (DUoS) charges where the DNO has proposed to change its charging methodology with effect from 1 April 2005. These illustrative tariffs are based on 2004-5 revenues. If no change has been made then the charges are the same as those currently published. It also comments on the new generation use of system charges (GDUoS) payable on new generation connections from 1 April 2005.

- Chapter 7 Update on longer term framework

The chapter considers ongoing work associated with the charging methodologies in terms of the longer term framework, the process for approval of changes to the methodologies and the need for an industry group going forward.

- Chapter 8 Summary Impact Assessment

This chapter sets out the impact assessments carried out to date and the process for assessing changes to the charging framework going forward.

Project timetable

1.6. The table below sets out the summary timetable for the approval of the initial charging methodologies and for the determination of DNO charges for 2005-6.

Date	Milestone
13 October – 10 November 2004	Four-week Ofgem consultation with Industry on DNO proposed charging methodologies
15 November – 26 November 2004	Two-week reassessment and resubmission of methodologies by DNOs in light of consultation responses
Late November/ December 2004	Ofgem reports on results of DNO charging methodologies approval process
1 January 2005	Three months' notice of changes to DUoS charges required (if DNOs intend to change charges with effect from 1 April).
February 2005	40 days notice required for 2005-6 charges
1 April 2005	2005-6 charges take effect; implementation of interim arrangements

1.7. Work on the longer term charging framework is ongoing. Progress will be discussed via the relevant industry groups. A consultation on the long term charging model is expected during 2005.

Responding to this document

1.8. Ofgem welcomes responses and comments on the DNO draft submissions and on the content of this document and. Comments should be sent to Mark Cox at the address below. They should be received by 10 November 2004.

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1.9. All responses will be held electronically in Ofgem's Research and Information Centre. They will normally be published on the Ofgem website unless they are clearly marked confidential. Consultees should put confidential material in appendices to their responses where possible. Ofgem prefers to receive responses electronically so that they can easily be placed on the website.

1.10. Copies of this document and other material relating to this project are available on the Ofgem website under the 'Electricity Distribution Charges' area of work.

1.11. Should you have any questions regarding the issues raised in this document please contact Mark Cox on 0207 901 7458.

2. Background

Project history

2.1. The changes to the charging arrangements follow a long period of discussion with interested parties and consideration of charging regimes across electricity and gas areas by Ofgem. Gas distribution charges are currently under review[1] and electricity transmission charges were subject to review during 2002 and 2003 which culminated in the introduction of a shallower connection boundary from April 2004[2].

2.2. Ofgem undertook an initial consultation to review whether the existing structure of electricity distribution charges remained appropriate in December 2000. The review was driven by concerns over the divergence of charging arrangements between different distribution companies and the recognition that the current arrangements needed developing given the expected increase in distributed generation (DG).

2.3. Ofgem consulted further during 2002 and 2003 and held public workshops. An Initial Decision document[3] was published in November 2003 which proposed that by April 2005 the clearest problems with the current structure would be addressed while work continued in parallel in the development of a fuller solution for the longer term.

2.4. An update document[4] was published in April 2004 which further progressed policy on the interim charging arrangements. The April 2004 document also contained details of the licence modifications required to implement the new methodologies. The Authority gave notice of the intended changes to the licence on 1 June 2004[5] and the changes took effect from 7 July. In addition to the

[1] Ofgem consulted on the structure of gas distribution charges in its May 2004 document (101/04) entitled 'Review of Transco's structure of distribution charges – Consultation paper', available on the website.
[2] See http://www.nationalgrid.com/uk/indinfo/charging/mn_charging_review.html for more information.
[3] Structure of electricity distribution charges – initial decision document November 2003 (142/03)
[4] Structure of electricity distribution charges – update document and licence modifications (76/04)
[5] Document reference 121/04, available on the Ofgem website under the Licensing (modifications) area of work.

policy drivers the distribution licence modification was required to comply with the EC Directive[6].

2.5. In July 2004, DNOs submitted to Ofgem their first draft connection charging and UoS charging methodology statements. Ofgem published an open letter[7] summarising these methodologies on 30 July setting out DNO treatment of key policy areas and issues concerning the form of the methodology. Seven responses to the open letter were received, raising issues such as the degree of commonality between DNO methodologies and the need for the methodologies to set out exactly how charges are calculated such that users can predict likely actual or relative charge movements. A summary of responses to the July open letter is provided at **Appendix 1**.

2.6. Ofgem has provided comments to DNOs on the draft methodologies during August and September. Bilateral meetings to discuss methodologies were held with each DNO in August culminating in a DNO workshop on 18 August. Following this Ofgem has provided further feedback to each DNO on a bilateral basis.

Charging rules

2.7. The November document proposed a two stage implementation with certain key changes from 1 April 2005 while work continued on the development of long–term models to set tariffs. From 1 April 2005 it proposed that there would be a common connection charging boundary for demand and generation, generators would no longer pay deep connection charges, new generators would face use of system charges within a framework designed to avoid unnecessary unpredictability and distribution companies would be required to justify their approach and methods for setting tariffs.

2.8. Further consideration was given to these changes in the April document outlining a common, 'shallowish', connection charging boundary covering

[6] EC Directive 2003/54/EC concerning common rules for internal market in electricity, and repealing Directive 96/92/EC.
[7] 183/04 – Open letter consultation on DNO draft charging methodologies for demand customers and generators.

assets required to connect a party to the distribution system and common rules for apportioning the costs of network reinforcement between upfront connection and ongoing UoS charges. The new apportionment rules will apply to second parties connecting to the system within the first five years such that second comers pay the relevant proportion of reinforcement assets. Operations and Maintenance (O&M) charges are being incorporated within UoS charges except for high cost projects and customer driven enhanced connections where the additional cost will be levied as part of the connection charge. Tariff Support Allowances (TSA) will no longer be provided against connection charges.

2.9. GDUoS charging is being introduced from 1 April 2005 which will replace the current deep connection charging regime. The GDUoS tariffs cover the costs of network reinforcement not captured within connection charges under the apportionment rules. It is recognised that initially these tariffs will be simple with development of aligned generation and demand models being undertaken during 2005.

Relevant licence objectives

2.10. The collective modification to the electricity distribution licence requires the conditions set out below to be met when DNOs determine their charging policy and their charging methodologies. These obligations, the relevant objectives, are contained within SLC4 and SLC4B of each DNO's electricity distribution licence as amended on 7 July 2004[8]:

- that compliance with the charging methodology facilitates the efficient discharge by the licensee of the obligations imposed upon it under the Electricity Act 1989 and by its licence;
- that compliance with the charging methodology facilitates effective competition in the generation and supply of electricity, and does not restrict, distort or prevent competition in the transmission or distribution of electricity;

[8] As set out in document reference 121/04, available on the Ofgem website at www.ofgem.gov.uk.

- that compliance with the methodology results in charges which reflect, as far as reasonably practicable (taking account of implementation costs), the costs incurred by the licensee in its distribution business; and

- that so far as consistent with the above objectives, the methodology, as far as reasonably practicable, will take account of developments in the licensee's distribution business.

2.11. The licence specifies that a reader of the methodology should be able to make a reasonable estimate of charges (SLC4A, para 1 and SLC4B, para 4(b)) using the methodology and charging statement.

2.12. SLC 4 requires the DNOs, by 1 April 2005, to determine and prepare charging methodologies and statements approved by the Authority that achieve the relevant licence objectives. In considering whether to approve the charging methodologies to take effect from 1 April 2005 the Authority will consider the relevant objectives and its wider statutory duties[9].

2.13. Methodologies that do not meet the relevant licence objectives will either be rejected or be approved subject to conditions on certain matters being resolved by a given point in time. If methodologies are rejected enforcement action may be taken. Alternatively, the licence provides for derogations (SLC4 para.12, SLC4B para. 24) whereby the licensee may be relieved of its obligations to the extent specified in each case.

[9] Ofgem's statutory duties are wider than the matters considered by the relevant objectives and include amongst other things having regard to social and environmental guidance provided to Ofgem by the government.

3. Views invited

3.1. Views are invited on the matters raised in this consultation document and whether the DNOs' draft methodology statements achieve the relevant licence objectives as set out above.

3.2. Views are invited on the detail of the methodologies, specifically:

- areas where the methodologies may not achieve the relevant objectives;
- whether enough information has been provided to enable users to make a reasonable estimate of charges that they may become liable for; and
- areas where the methodology statements could be improved.

3.3. Ofgem's initial views on key issues are indicated in section 5 to this document.

4. Summary of DNO draft documents

4.1. This section summarises DNO treatment of key issues, naming DNOs where relevant[10]. Individual DNO submissions may be viewed on the Ofgem website at www.ofgem.gov.uk under the 'Electricity Distribution Charges' area of work.

4.2. This is a summary of the draft connection and UoS methodologies as submitted by the DNOs on 30 September. As such, it is not the same as the July open letter consultation which considered (anonymously) submissions from July.

4.3. DNOs' submissions have varied in the following ways:

1. EDF Energy Networks (EDF – Seeboard (SPN), London (LPN) and Eastern (EPN) areas) has submitted a UoS methodology statement, a connections statement, a statement of illustrative connections charges and a statement of illustrative UoS charges. Each one covers all three distribution areas.

2. CE Electric (CE- Yorkshire (YEDL) and Northern (NEDL) areas) have submitted one UoS methodology statement, one connection charging methodology statement and separate statements of illustrative charges to cover both areas.

3. United Utilities (UU – North West area) cover only one distribution area, and have therefore submitted the three standard statements.

4. Central Networks (CN West (Midlands) and CN East (East Midlands) areas) have submitted separate methodology statements (both UoS and connections) for East and West, and a brief summary of charges rather than a full statement. The UoS statements show some very minor differences[11] and the connections statements are identical.

5. Western Power Distribution (WPD – South West and South Wales areas) have submitted separate statements for the two areas. The connection charging methodology statements are identical. The UoS methodology

[10] The July open letter summarised the initial draft DNO submissions anonymously. This document (183/04) is available on the Ofgem website at www.ofgem.gov.uk.

statements differ only in the yardstick examples shown in each one's appendix. Two UoS charging statements have been submitted.

6. Scottish Power (SP – SPManweb and Scottish Power areas) have submitted one set of the three statements to cover both areas.

7. Scottish and Southern Energy (SSE) comprising different methodology statements for Scottish Hydro Electric (SHEPD) and Southern Electric (SEPD) areas. The UoS statements have some significant differences, which are noted in further detail below. The connections statements are almost identical[12].

Format of the use of system charging methodologies

4.4. Introductions to the use of system methodology statements follow a generally common format, providing information on the licence requirements, the general contractual framework and the principles of use of system charging. All of the methodology statements except SP's contain glossaries of common terms.

4.5. The relevant licence objectives are mentioned in all the use of system methodology statements. All apart from SSE set out the relevant objectives which methodologies must comply with. Of these, EDF duplicates the complete licence wording in an appendix to the methodology statement.

4.6. The statements are available to download free of charge from company websites. A charge of between £5 and £10 is levied for a paper copy of the statements. In CE's case the charge is discretionary.

4.7. Worked examples are provided by some of the use of system methodology statements, to differing levels of detail. Two methodologies - UU and CE - provide demand use of system examples. WPD, CN, CE, SP and SSE provide generic worked examples for the calculation of GDUoS tariffs (see Generation section below).

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[11] These differences can be found at paragraphs 24, 37 and 42.
[12] Differences can be found at pages 9 and 22 of the SHEPD statement, where reference is made to the treatment of any reinforcement works necessary on the transmission system. These references are not included in the SEPD statement.

4.8. Version control of the methodology is provided by UU and CE on the last page of the methodology. All include a contents page with the exception of WPD.

4.9. Comments on the format and scope of the statements are welcomed. It would be useful to understand how much background information is needed.

Demand

Demand use of system models

4.10. WPD, SEPD, SP, UU and EDF's methodologies are based around the 500MW distribution reinforcement model (DRM). The original DRM mirrored the DNO's own load characteristics and customer mix and calculates the cost imposed by a 500MW increment in maximum demand at each voltage and transformation level, based on modern equivalent asset values.

4.11. The application of yardsticks for each customer group then apportions these costs according to each customer group's contribution to peak demand at the relevant level on the system to produce yardstick tariffs, which are then scaled to price controlled revenue. Other costs, such as local authority rates, National Grid Company (NGC) exit charges, billing costs and other administrative charges may be added into the model.

4.12. The five DRM based methodologies have varied the original DRM method in a number of ways. For example, EDF includes both reinforcement (the cost of additional load) and replacement (the cost of ongoing replacement of assets) into the system cost model. EDF runs separate charging models for replacement assets and adds the output to the reinforcement model output.

4.13. SSE's methodology for SHEPD outlines a simulation model which calculates the replacement value of the total current network in current asset prices. £/kW tariffs are then calculated, as with the DRM.

4.14. CE and CN present 'regulatory reflective' methods for setting charges to recover their regulatory income. Variable charges are scaled to allowed revenue, and annual changes to tariffs are based on the projected marginal increase in revenue with each additional GWh added to the network for a particular 'tariff basket',

then divided by GWh to produce a unit charge for each basket (p/kWh). Fixed costs are derived from a DRM model.

4.15. CE's charge-setting model has evolved from the DRM. This concentrates on calculating allowed income and scaling existing tariffs from one year to the regulatory formula in the next. This is done by looking at the proportion of variable and fixed income recovered from each customer group and varying the relationship between fixed and variable elements of charge over time as well as scaling to achieve the allowed income in any one year.

Yardsticks

Split of customers between yardsticks

4.16. Yardsticks represent costs for each customer group. SP and CN have provided a fairly detailed description of the customer groups in existence. For example, SP splits groups according to domestic/non-domestic status, half hourly and non-half hourly metering (and non-metered street lighting), voltage level and connection to the network/substations at each voltage. Average consumptions are calculated for morning, afternoon and night time peaks, with yardsticks for higher voltage levels taking account of losses and diversity factors. Long run marginal costs are then projected according to required capacity rather than calculated demand. Customer related costs vary according to the voltage level of connection.

4.17. The methodologies generally provide minimal detail on how customer groups or tariff baskets are determined although some mention metering and Supercustomer billing arrangements as a basis for determining customer groups.

Calculation of yardsticks

4.18. EDF describes how yardsticks are calculated based on reinforcement and replacement costs, reflecting the mix of underground and overground assets and using scenario capacities at each voltage level to derive yardsticks which are adjusted for power factor to give a £/kW value and then annuitised on the regulatory rate of return. Coincidence factors are derived from demand estimation coefficients created for each half hour at each time of day/season and

expressed as a proportion of the annual demand estimation coefficient. These coincidence factors are combined with the yardstick £/kW values and losses figures to give a cost figure for each tariff group, and billing costs, exit charges and rates are added in.

4.19. Other methodologies list the possible charge components, and provide limited detail on how these costs on the system are determined or apportioned. There is very little detail on the calculation of line loss factors/loss adjustment factors or on the determination of diversity factors.

Adjustments to charges / tariff disturbance

4.20. Many of the methodologies include an element of judgement in setting tariffs:

- CN state they will introduce new charges gradually over time where there is a step change in charges derived from the tariff model, and for some time have been gradually bringing average unit charges into line with the price control benchmark allowed revenue per unit values. This process is expected to be completed by the end of the next price control period;
- CE may adjust the split between different charging elements to reflect commercial strategy, taking care to avoid step changes. This process is carried out after the allowed income has been divided between customer classes and scaled, and thus does not affect the overall recovery from any one class; and
- WPD and UU judge output levels and smooth large changes where deemed appropriate.

EDF, SP and SSE do not mention judgements being made on the inputs or outputs of their model.

Reactive power charges

4.21. SP, WPD, EDF and UU include provision for reactive power charges for customers displaying poor power factor. EDF's methodology describes how their reactive power charges are set according to a number of Power Factor bands and

EDF's assessment of the need to install corrective equipment, but the other methodologies offer limited detail on the calculation of reactive power charges. These DNOs mention acceptable power factors: the lower acceptable limit on these varies between 0.95 and 0.8.

4.22. SSE, CN and CE levy availability charges in kVA and do not apply any extra reactive charges. CE and SSE, however, reserve the right to charge customers under special arrangements (for example, applying different line loss factors) for poor power factors.

Treatment of EHV

4.23. Six of the eight methodologies set site specific DUoS charges for EHV. The exceptions are SHEPD - which uses a common method for tariff setting across all voltage levels - and CN which uses a common EHV tariff for most EHV customers except very unusual loads such as railway traction. CN is proposing to peg the movement in yearly EHV tariffs to the movement in HV tariffs.

4.24. WPD, UU, CE, SP and EDF calculate site specific EHV charges using the same principles as with the DRM. UU charges are reassessed annually, with a charge levied for this service.

4.25. Four methodologies mention arrangements for the movement of EHV connections from the present to the interim regime:

- CE, WPD and UU propose capping to the higher of RPI and the general movement in tariffs any increase in charges resulting from the movement in existing charges to the new regime, where appropriate, whereas any decrease in charges associated with transition would be available in full from 1 April 2005. UU also state that existing bilateral contracts will be honoured, and transition will only begin once the contract expires; and
- SP also note that there may be implications for customers whose charges were negotiated under the old regime:

further capital charges may be levied for customers who have not paid these on connection.

4.26. SEPD is not making any changes to its calculation of EHV charges at this time, hence there are no transitional issues. EDF are considering changing their EHV charging methodology but no transitional arrangements have been proposed at this time.

Special arrangements and non-standard terms

4.27. All of the methodologies state that where none of the existing charging categories are deemed appropriate for a customer, special arrangements may be entered into. This includes cases where standards of security differ from the set norms, or where the power factor is outside a specified band.

4.28. Charges for exceeding agreed capacity are mentioned in the methodology by CN, EDF, SP, SHEPD, SEPD and CE:

- CE state that unauthorised use of extra capacity may be reflected in billing, but no further detail is provided in either the methodology or charging statement;
- SP states that (for both demand and generation) charges may be levied at the higher level for a whole year or at three times the normal level for the month of the breach. The choice of treatment depends on the capability of SP's billing system. Customers will be expected to request an increase in supply capacity, and may be liable for charges for reinforcement;
- EDF states that the availability charge will be set at whichever is higher of the agreed maximum demand or the highest actual demand of the previous 12 months;
- CN charges customers at 3 times the normal rate for the month in which the agreed level was exceeded, in order to disincentivise breaching; and

- SEPD and SHEPD mention that they will charge for supply provided over the agreed level.

4.29. Changes to agreed capacity: WPD's methodology states that changes cannot normally be made within a year of connection, EDF within 5 years and CE within 15 months. SP and UU cover tie in periods only in the UoS charging statement, stating that agreed capacities are locked for 5 years, after which they may be varied annually (this treatment also applies to generation). CN lock capacities for 3 years, after which any change is allowed. Requests for increased capacity can be made at any time, subject to the payment of further connection charges. SEPD and SHEPD also locks in capacities for 3 years, after which time reductions may be processed a maximum of once per year.

4.30. Preserved charges[13] are not mentioned in any of the methodology statements.

Inclusion of NGC exit charges in use of system charges

4.31. All of the DNOs include a contribution towards NGC exit charges in use of system charges, calculated in a variety of ways. These include apportioning charges on the basis of each customer class's contribution to total use of the system (UU, SP, CE, CN, EDF, SHEPD and SEPD) or across each class in respect of contribution to demand at 132kV (WPD).

Generation

Generator use of system models

4.32. Each DNO has provided a simple capacity based model. The price control parameters under which generator charges will be determined for distributed generation are set out in every methodology. Charges consist of the same basic elements as demand UoS charges. Beyond these basic assumptions, the models vary in a number of ways:

- CN, SP, WPD, SEPD, SHEPD, and EDF define capacity as export. CE and UU use an installed capacity definition;

[13] These are tariffs that are honoured for existing customers. These tariffs are not available to new customers.

- CN, CE, and WPD plan to vary the charge by voltage level. WPD varies charges weighted by system yardsticks. UU's customer groupings vary charges by voltage and/or by metering arrangements (half hourly (HH) or non half hourly (NHH)), although initially UU's LV models will not be utilised;

- EDF's groupings do not vary by voltage level, but by metering arrangements: Domestic, non-domestic NHH and HH;

- SP charges will vary according to voltage level, area, or a combination of the two, depending on SP's assessment of reinforcement costs. SP are the only company to mention the possibility of varying charges by location;

- SSE is offering one tariff each for SHEPD and SEPD across all HH connected generators (EHV, HV and LV) and no charge for NHH generators; and

- EHV treatment: SSE is offering one tariff for EHV connected generators, which will cover the whole distribution area. WPD is offering one tariff for EHV connections with an export capacity below 10MVA; larger connections would be site specific. SP will offer GDUoS tariffs for EHV on a locational basis. The remaining methodologies offer site specific charges.

Inclusion of NGC exit charges in GDUoS charges

4.33. Exit charges will not be charged in five of the generation methodology sections. Two of the remaining companies (CE and UU) are not proposing to charge immediately but suggest that this policy might change in the future. EDF's treatment of EHV generators is consistent with demand EHV charges, where a contribution to NGC exit charges is included based on import capacity, unless the export capacity triggers a cost. SP mention that where charges are forecast to be incurred by generation spilling onto the system, these will be included in the model.

Inclusion of business rates in GDUoS charges

4.34. The situation is similar for business rates. Five of the GDUoS methodologies have no mention of the inclusion of business rates, CE and SP state that rates will be included and EDF makes the same reference to the similarity between EHV GDUoS and demand EHV tariffs as for exit charges.

Reactive power charges

4.35. SP and EDF state explicitly that reactive power charges may be levied on generators. The remaining methodologies make more general mention in the introductions to their UoS methodology statements that any customer displaying power factor below the specified limits (with lower limits varying between 0.8 and 0.95) may be subject to charges.

Preventing volatility in GDUoS charges

4.36. UU and CE are proposing changes limited to +/- 10 percent each year. EDF is currently planning to smooth changes by using five years of forecast data, which it suggests will control volatility. SP states that increases in charges will be restricted to whichever is the greater of 10 percent or £1/kVA or £0.5/kWh for NHH metered customers. SSE proposes a tariff cap to guard against volatility in the early years of generator charging. CN is proposing to stagger the introduction of price changes according to the size of the change. This results in a limit of approximately 15 percent change in any one year. This method is intended to be applied until 2010, but where it becomes apparent that there is insufficient time to follow this method, changes will be spread over the remaining available years.

4.37. CN, SSE and UU state that capacities will be locked in for 15 years once set. SP and WPD tie the customer in for an initial 5 years. After this time capacities can be changed annually.

4.38. CE and EDF have not mentioned tie in periods for generation, and SP's policy is only included in the charging statement, not the methodology.

Treatment of microgeneration

4.39. All of the methodologies include the capability to charge for LV generation connections. UU, CE and CN differentiate between LV NHH generators classed below (small scale embedded generation - SSEG[14]) and above 16A per phase.

4.40. WPD and EDF are proposing to begin charging LV connected generators from April 2005 on a pence/MPAN/day basis, with EDF charging NHH metered customers 0.69p (domestic) or 2.27p (non domestic), and WPD charging 0.75p (domestic profiles 1 and 2), 3.76p (non domestic profiles 3 and 4) or 7.18p (non-domestic profiles 5 to 8). SSE proposes to apply a blanket charge across EHV, HV and LV for HH metered customers. However, NHH generation will not be charged by SSE at this time.

4.41. The remaining methodologies will not be charging for microgeneration in April 2005. CE and CN state that charges will be based on forecast reinforcement costs hence initially this tariff would be zero. UU is not intending to begin running its LV models until the number of DG connections increases. SP's tariffs have been set to nil.

Distributed generation and deferred expenditure: rewards for benefits to the network

4.42. None of the methodologies mentions the benefits that embedded generators may bring in deferring network investment, and do not proposed to reflect such benefits in charges.

Transitional arrangements

4.43. WPD, UU, and CE mention that arrangements will be unchanged for generators connected before 1 April 2005, but that requests may be made to opt in to the new arrangements. The other methodologies make no mention of opting in. WPD, CN and UU mention that increases in capacity for existing generators would give rise to GDUoS charges. The remaining methodologies say that arrangements for pre-April 2005 connected generators will be unchanged.

Network access rebate payments

4.44. The price control has proposed that generators be compensated for disconnection through a rebate on use of system charges. Development of this is currently ongoing. WPD, CN, EDF, SSE, CE and UU mention the scope for rebates. WPD states that the rebate rate is set out in the statement of UoS charges. SP does not mention rebate payments.

Changes to agreed capacity

4.45. SP and WPD treat changes to agreed capacity in the same manner as for demand connections: capacity is set for an initial 5 years and then may be varied annually. SP do not include any details of this in the methodology statement, only in the charging statement.

4.46. SSE, UU and CN are proposing a 15 year capacity tie in period. UU and CN do not mention of how capacity may subsequently be varied; SSE says that reductions in capacity after 15 years will be limited to once per year. CE does not mention tie in periods or arrangements for varying agreed capacities.

Worked examples

4.47. WPD, CE, SP and CN provide generic worked examples of how GDUoS charges are calculated, and the other methodologies do not.

Connection

4.48. The connection charging methodology statements are longer and more detailed than the use of system charging methodologies, primarily due to the inclusion of schedules of indicative prices and works. Much of this information is unchanged from the present connection charging statements

4.49. All of the methodology statements include a large amount of standard information on connection procedures, principles and obligations, how applications should be made, and how these will be handled. The revised

[14] This is a source of electrical energy rated up to and including 16 Ampere per phase, single or multiphase at 230/400 Volt AC.

licence requirements are detailed in full by EDF, and the objectives and change process described by CE. The remaining statements reference the licence conditions in less detail. Views would be welcome on whether greater detail on the licence requirements would be a useful guide for users.

4.50. CN and EDF offer a different format for their connections statements. Both suggest that only one section of the document constitutes the SLC4B statement, and the remainder of the document is merely guidance on connections, charges or useful information. Ofgem is keen to see the statements follow a consistent format, and will be considering whether these proposed formats conform to the requirements of the licence.

4.51. All of the connection methodology statements contain worked examples of various connection types, including generator connections, some using the apportionment rules and some for simpler connections. Similarly, all of the methodology statements contain glossaries. As for use of system, views are sought on whether there is a need for clarification of the use of any particular terms.

4.52. The statements are generally available free to download from the web. However, EDF and SSE only refer only to the UoS charging statement being available on the web. Charges of between £5 and £10 are levied for paper copies of the statements (in CE's case the charge is discretionary).

Non-standard connections

4.53. All of the methodologies apart from UU's outline procedures for speculative connections, where capacity may be reserved for development agency projects. The statements note that in these cases the right to second comer payments may be waived, and that reservation payments may be necessary. Terms will be negotiated bilaterally. CN suggest that speculative enquiries are outside the remit of the charging methodology, and reserve the right to treat such enquiries or reservations as they choose.

Connection boundary

4.54. All the methodologies commit to use of the new apportionment rules for standard connections (at all voltage levels and for both generation and demand). A number of the methodologies note that there may be non-standard occasions where these will not be applied: for example, speculative connections, connections where an abnormal standard of security is requested, and certain high cost generation connections (for costs exceeding £200/kW where overall project costs exceed £100,000).

4.55. High cost generation connections over £200/kW are mentioned by WPD, EDF, CN, CE, SP and UU (WPD, SP, CE, EDF, CN and UU mention the de minimis threshold, but UU note that its level is not yet finalised). SSE mentions high cost generation as being over £100/kW and do not mention a de minimis level.

4.56. Ofgem is aware of the need to ensure that the policy on high cost generation projects is clear, namely that it is costs in excess of £200/kW that will be capitalised (once the £100,000 threshold is breached) rather than any project costs exceeding £100,000.

4.57. WPD state that the apportionment rules will apply to non contestable assets, and to contestable assets where these are carried out by WPD. No assets installed by an independent connections provider (ICP) will be subject to the apportionment rules, even if these are classed as reinforcement. SP also make it clear that the reinforcement rules will not apply for contestable works, which will always be classed as connection assets.

Connection charges

4.58. The DNOs have offered a generally consistent description of the determination of connection charges: these will be the cost of the sole use assets necessary to provide the minimum scheme for the connection, a proportion of reinforcement costs, plus the costs of any additional requested requirements. The cost of any additional assets over and above those requested by the connectee will be met by the DNO, and where the minimum scheme can support more than one connectee, costs may be split.

Second comer charging for reinforcement

4.59. All the statements note that second comers making use of existing assets (previously reinforced within the prescribed period) will be charged a contribution towards those assets in accordance with the Electricity (Connection Charges) Regulations 2002, which are summarised briefly by some of the statements and referenced by others.

4.60. As noted above, WPD does not propose to apply second comer charging rules in the case of contested contestable reinforcement assets.

Abolition of O&M

4.61. O&M charges have now been removed from connection charges, apart from charges relating to extra assets provided at the request of the connectee for an enhanced connection. In these cases, the methodologies generally state that ongoing O&M charges will be calculated by multiplying the sole use asset valuation by the standard O&M percentage, with a contribution to joint use asset O&M determined on a similar basis.

4.62. The calculation of capitalised O&M on extra assets provided at the request of the connectee is explained in various levels of detail:

- WPD calculate the contribution as a percentage (not stated) of the initial capital value of the additional assets, reflecting the anticipated O&M costs. This is based on historical information capitalised over a 20 year period;
- SP calculate a charge estimated from the annual O&M as a percentage of the asset value, the expected asset life and the cost of capital;
- SSE charges will be 30 percent of the cost of extra assets or high cost projects for demand and 20 percent for generation. The different percentages recognise different replacement policies for demand and generation;

- CN state that O&M charges are between 10 and 30 percent, but that these are undergoing review, and revised figures will be based on the costs allowed by the price control;
- CE charges 0.98 percent per annum of the value of the extra assets;
- EDF apply a charge of 25 percent of the of the initial capital value as assessed by EDF. This is a discounted maintenance rate reflecting the agreed cost of capital and the assumed life of the asset. The rate is reviewed periodically; and
- UU states that enhanced connections may be subject to a capitalised O&M charge, but not how this would be determined. UU also mention O&M as a component of generator connection charges.

SSE sets out in a fair amount of detail the inputs in to the capitalised O&M charge. None of the other DNOs explain in detail how their O&M percentages are calculated, or state specifically how often these would be reviewed.

Contestable and non-contestable works

4.63. The methodology statements provide details on procedures for contestable and non-contestable quotes and works, and some detail on the adoption process and areas to be covered in adoption agreements. The statements include lists of contestable and non-contestable items, and indicative charges for non-contestable works. In EDF and CN's case, these procedures and details are not included in the methodology, but in separate sections of 'guidance' or 'information'.

Worked examples

4.64. Worked examples vary in complexity: explanations of connections scenarios and calculations have different levels of detail, and diagrams are provided in some cases. All of the DNOs demonstrate the operation of the security and fault level apportionment rules separately, and all but WPD show the rules working in combination. CN's examples suggest that both a 'non-contestable works only' price and an 'all works' price will be provided for each one.

Out of area networks

4.65. Some DNOs operate networks outside their distribution services area. SSE states that connection charges for out of area networks will be calculated in a manner consistent with the main methodology.

5. Ofgem's initial views

5.1. This section sets out Ofgem's preliminary views on key issues identified following the DNOs' methodology submissions on 30 September. Ofgem welcomes views on these matters.

5.2. Ofgem will consider all consultation responses before deciding whether to reject or accept the methodologies. Decisions will be based on the criteria set out in section 2.

5.3. Ofgem notes that this is the first time that the DNOs have published draft statements of their charging methodologies and this has substantially improved the level of transparency. There are resulting legacy issues to address and new challenges presented by changes in the charging regime and the introduction of GDUoS charges. In particular, GDUoS charges are new and start from a charging base population of zero. This brings with it limitations on the available options for charging and the views outlined here therefore should not be taken as a precedent for other sectors or, except as indicated, for the longer-term arrangements in electricity distribution.

Demand

Demand Use of System regulatory reflective models

5.4. The regulatory reflective DUoS models being used by CN and CE are based in part on the increase in price controlled revenue attributable to additional customers rather than on the impact a party has on the distribution system.

5.5. Ofgem believes that marginal cost pricing where possible would incentivise the most efficient and economic investment in the system. Ofgem's view is that the models used to set DUoS charges need to provide pricing messages in order to adequately incentivise the siting of demand, particularly at HV and EHV voltage levels.

5.6. Views are welcomed on this issue and the extent to which the current models achieve this aim. Ofgem recognises that these DNOs may not be able to change

their models by April 2005 and will be considering this further in the move to longer term charging models.

Use of asset replacement in setting DUoS charges

5.7. EDF's charging model calculates the increment of cost using a model and then averages these outputs with a replacement model to reflect the replacement costs that the DNO incurs.

5.8. Ofgem believes that the cost reflective obligation is to have a model that reflects how parties will affect costs on the DNO's network, since this will drive economic and efficient network investment. It is recognised that some average costs may be appropriate in achieving the full regulatory income allowance. Ofgem is not convinced that a model that reflects replacement costs meets this obligation in that replacement costs do not generally reflect costs associated with additional network capacity.

Reactive power charges

5.9. SP, WPD, EDF and UU include provision for reactive power charges for customers displaying poor power factors. SSE, CN and CE levy availability charges in kVA and do not apply extra reactive charges.

5.10. Ofgem considers that it is important that connected parties are encouraged to operate their connections near unity power factor to ensure efficient use of the system and maximise available capacity, avoid requirement for early capital expenditure in reinforcing the network and also to avoid increasing losses on the system.

5.11. Equipment exists that corrects for low power factor and therefore increases available capacity. This has the benefits of reducing losses, deferring the need for network reinforcement and improving voltage quality. Power factor correcting equipment can be installed both on customers' premises and on the network itself.

5.12. Although by charging on a kVA basis rather than kW the effect that poor power factor connections have on the peak demand capacity is reflected this does not adequately reflect the effect that poor power factors have on losses. It is Ofgem's

view that charges for reactive power should include both charges that reflect peaks of reactive power (kVA) and also total kVArh demand. Ofgem is therefore in favour of including charges for low power factors for large customers where there is appropriate metering installed.

Tariff smoothing and judgements

5.13. Many of the DNOs alter the outputs from their tariff setting models in order to minimise tariff disturbance each year.

5.14. Ofgem considers that stability in the level of charges may be valuable to customers. However, Ofgem's view is that it is not acceptable for the methodologies to provide for discretionary adjustments to the results of the methodology (or the model outputs). Ofgem believes that the major reason for step changes in model outputs is variation in asset cost valuations year on year within the cost model. Ofgem considers that asset costs should reflect long term pricing trends rather than short term fluctuations. For example, a one year contract on transformer costs would not be mirrored in the charging model where the DNO's view of the long term trend is for increasing prices.

Transition periods – EHV

5.15. Several of the DNOs (CE, SP, WPD and UU) are revising their EHV use of system methodology for April 2005. The effect of this may be to create a tariff disturbance for these customers. DNOs have proposed to pass any charge reduction on immediately to customers and for those with increasing charges CE, WPD and UU propose an annual increase limited to RPI and SP a gradual movement to new charges where a step change occurs.

5.16. This approach may create a cross subsidy from other demand users. As these tariffs are bilateral Ofgem is seeking information on the effects of the changes. Ofgem may consider that any transition should be managed over a short period of time, and in any case not longer than a 5 year period. Changes limited to the movement in RPI may therefore not be appropriate in some cases. Ofgem believes the same approach should apply in the case of other transitional matters that impact on charges.

5.17. UU proposes to grandfather existing EHV charges until the end of the contract term where bilateral terms have been negotiated. Ofgem's view is that this provides disparity between different types of customer.

Generation

Generation tariffs at EHV

5.18. CE, EDF, SP and UU and CN are proposing not to set tariffs for EHV generators. Instead they will calculate a use of system charge on a site specific basis following a connection request based on the estimated 'usage' of the existing DNO network. This treatment could be viewed as deferred deep connection charging.

5.19. Ofgem's view is that whilst site specific GDUoS charges at EHV provide predictability once connected they do not provide transparency to prospective generators at the development stage. Asset specific charges represent a snap shot of costs in time and do not enable future ongoing cost messages to be charged. Ofgem considers that a tariff should be published for EHV and that this should be locational as far as practicable.

Tie in on generation capacity

5.20. CN, SSE, and UU have proposed capacity tie in periods of 15 years for DG. These would mean that the DG could not reduce its capacity below a given level for 15 years. Any increases in capacity would need to be considered within this period.

5.21. Ofgem's view is that 15 years may present a barrier to entry and would not facilitate competition in generation. However, some tie in period may help to minimise price volatility in the initial years when there is a small population of DG and the framework is being established. A maximum period of five years would seem adequate, similar to demand. SP and WPD have proposed a five year period which is in line with their treatment of demand capacity. It also needs to be made clear what happens if a site ceases to generate.

Limiting charge volatility

5.22. Several of the DNOs have noted that generation charges may be volatile in early years for reasons such as the small new generator population and the wide variability of costs. CE, WPD and UU propose to limit volatility by capping year on year changes by +/- 10 percent and CN to limit year on year increases to 15 percent. SP mentions 'gradual smoothing' of charges. SSE proposes a cap of £5/kVA on GDUoS charges at 2005-6 price levels; EDF provides no specific level of cap on volatility.

5.23. Ofgem's view is that the charging models should be cost reflective and if costs do vary substantially then it may be appropriate to reflect these costs accordingly in tariffs. However, in light of the simple charging models being proposed, which may provide an imperfect estimate of costs, Ofgem considers that predictability of charge levels going forward may be desirable. Completely unrestricted tariff movements year on year at this interim stage due to volatile estimates rather than volatile costs may be unwise.

5.24. One option could be for DNOs to offer fixed term products (e.g. access to a given MW capacity for, say, 5 years, for a fixed price). However, Ofgem notes that given the comments above, long-term products (e.g. beyond five years) are unlikely to provide sufficient cost reflectivity and the key consideration for multi-year products is whether DNOs are able to produce good enough estimates of costs to price the products. Another option, which may better suit the short term, could be to limit tariff changes year on year, so long as any variations from cost reflectivity (as estimated) are short term, and in any event limited to a maximum period of 5 years.

UoS charging statement vs. UoS charging methodology

5.25. Some DNOs have proposed that some use of system charge items that describe how charges are set should sit within the UoS charging statement. Examples include tie in periods for charges, restricting changes in capacity and the basis of calculation of penal charges for exceeding agreed capacities.

5.26. Ofgem's view is that any items that relate to how the customer may be charged and the options available to them regarding their use of system capacity on the

network should be included within the methodology statement approved by the Authority such that changes are adopted in a controlled and transparent manner.

Connection

Approval

5.27. Some DNOs believe that certain issues are commercial decisions or voluntary activities - principally details of the Competition in Connections and adoption processes - and therefore should be excluded from the connection charging methodology statement and that Authority approval should be restricted to sections of the statement.

5.28. Ofgem's position is that any items that relate to how the customer may be charged and the options available regarding connection to the network should be included within the methodology statement approved by the Authority[15].

Apportionment rules – contestability

5.29. WPD proposes that assets provided independently[16] under the contestable option be chargeable in full to the customer. The apportionment rules would then not apply in cases where reinforcement assets have been provided contestably.

5.30. Reinforcement works by a DNO are split between the upfront connection charge and ongoing DUoS charge under the apportionment rules[17]. In the case of contestable works the independent connection provider needs to recover money for the assets provided from the customer.

5.31. In the rare cases where contestable assets include reinforcement works, Ofgem views that requiring the customer to pay for reinforcement in full is not in the spirit of the apportionment rules and would not facilitate competition in connection provision. Ofgem seeks views on this matter.

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[15] See section 2.11 to this document for further details.
[16] By an ICP - a party other than the incumbent DNO.
[17] The apportionment rules are set out in each DNO's draft connection charging methodology and are set

Tariff support allowance

5.32. From 1 April 2005 TSA will be removed from connection charges. As set out in the April update document, this removal is designed to ensure that there is transparency in costs for connection to developers and other connecting parties. Ofgem wants to achieve greater transparency in this area to ensure that competition in the provision of connections is not obscured by the opportunity to adopt and own networks.

5.33. It is Ofgem's initial view that such allowances should not be made from 1 April 2005. This will remove any potential for cross subsidy from consumers to developers and increase incentives on developers to seek lowest cost connection so promoting competition in connections.

out in the April 2004 structure of charges update document. These documents are available on the Ofgem website.

6. Illustrative charges

6.1. The DNOs have provided illustrative UoS charges for 2005-6. DUoS charges have been calculated on the basis of current year revenues so that the impact of any changes in charging methodology can be assessed independently of any change in regulated income. This section comments on the movement on 2004-5 charges where relevant.

6.2. GDUoS charges are being introduced from 1 April 2005 and will be payable by new generation connections from this time. These charges are based on anticipated revenues for 2005-6 and are for illustration only.

Illustrative DUoS charges

6.3. Illustrative charges for the four main tariffs are set out in **Appendix 2**. EHV charges are currently negotiated on a bilateral basis and are not detailed here.

6.4. UU, SEPD, SHEPD, CN(East) and CE's illustrative DUoS charges at LV and HV calculated on the basis of 2004-5 revenues are identical to the currently published rates indicating no change to their methodology.

6.5. The other DNOs have provided illustrative charges that highlight changes in the methodology, as follows:

- WPD has abolished standing charges in South Wales, bringing this area in line with the South West area. WPD previously averaged the output for domestic and non-domestic customers and is proposing to cease doing so from April 2005. These two changes have an impact on WPD's unit rates;
- EDF is bringing charging methodologies in line across LPN, EPN and SPN. The largest impact is on EPN's fixed charges for domestic customers which increase by 50 percent;
- CN is bringing the calculation of DUoS charges in its West area in line with the methodology used by CN East. The impact on the four main tariffs is approximately +/-3 percent; and

- SP illustrative charges are proposing to change significantly both for unit and fixed rate charges. At this stage SP have not explained this change – Ofgem will want to discuss this further with SP.

Illustrative GDUoS charges

6.6. Illustrative GDUoS charges are summarised at **Appendix 3**, based on anticipated revenues for 2005-6.

6.7. The basis and level of charges varies between DNOs. WPD base NHH charges on NHH metering profile class and levies a charge per MPAN per day; EDF has a blanket tariff for domestic NHH per MPAN per day and another for non domestic generators. Other DNOs levy charges set out on a per kVA or kW on a daily monthly or yearly basis.

6.8. UU[18], CE, CN and SP propose zero charges for microgeneration. The other DNOs propose to charge SSEGs for use of the system.

6.9. CN (West) have proposed zero tariffs for all voltages except EHV. It is not clear how this is cost reflective because this would imply that a generator connecting to CN (West)'s system would not be charged for use of the distribution system.

6.10. UU, CE, CN and EDF are proposing site specific GDUoS charges for EHV. The charging statement set out either a range of figures, indicating a likely average (UU) or no figures are indicated at all (CE, CN, EDF).

6.11. SP sets out locationally varying tariffs at EHV.

6.12. Registered Power Zones (RPZs) are mentioned by UU which levies a £3/kW/year surcharge on all customers in an RPZ.

[18] Except in the case of registered power zones where £3/kW/year will be levied by UU.

7. Update on longer term framework

Longer term framework

7.1. Changes to the charging regime are being introduced on an incremental basis with interim changes to the connection boundary and the introduction of simple generator use of system charges from 1 April 2005.

7.2. The longer term regime will be progressed from late 2004. In the November 2003 Initial decision document, Ofgem considered a longer-term charging framework which would treat generation and demand users on a consistent and cost-reflective basis. The move to consistent demand and generation charging is being achieved in part by the adoption of a common connection charging boundary policy for new generation and demand connections from 1 April 2005.

7.3. It remains Ofgem's view that the longer-term regime is best served by the introduction of a cost reflective forward looking long run incremental cost model.

7.4. Further work is now being considered in developing models based on forward-looking long run incremental costs that would treat generation and demand use of system charges in the same manner. Such models will be assessed against the licence obligations and will take account of locational costs and the need to avoid unduly volatile, unpredictable or complex use of system charges.

7.5. Ofgem expects that the move to the longer term arrangements will be a mixture of evolution through DNO led charging methodology modifications supported by the Ofgem led review during 2005. To continue to support this work it is expected that the ISG[19] or a similar forum will continue through 2005 and this is discussed further below.

[19] Implementation Steering Group – set up in 2003 to help implementation of this project. See below.

Approval process going forward

7.6. The methodologies effective from 1 April 2005 will provide a benchmark for the methodology statements going forward. DNOs are obliged to review their methodologies at least yearly to assess whether changes to the methodology would better meet the licence obligations. This will lead to methodologies evolving over time.

7.7. Ofgem also believes that any changes to tariff structure should be dealt with through the methodology change process. A change to the make up of the charges levied has an impact on customer charges and may also then impact on customer behaviour.

7.8. Ofgem considers that the DNOs should take account of comments from users as part of the process of keeping the methodologies under constant review and monitoring the extent to which the relevant licence obligations could be better met.

7.9. Where appropriate modifications should be made to the methodologies for the purpose of better achieving the relevant objectives. The process for changing methodologies is set out in the licence[20]. This requires a DNO to provide Ofgem with a report explaining the proposed change and how it better meets the relevant objectives. The report must also include a timetable for implementation and set out the proposed date at which the modification will take effect.

7.10. Ofgem then has 28 days to decide whether to consult on the proposal. Where no veto or decision to consult is provided to the DNO within 28 days, the modification takes effect. Ofgem must inform the DNO of the intention to consult whereby it has three months to consult and to direct the DNO of its decision.

7.11. Ofgem must be satisfied that proposed changes to the methodology better meet the relevant objectives as defined in the SLC4A 'Use of system charging methodology' and SLC4B 'Connection charging methodology'. When deciding

[20] SLC 4 (para. 4-6) and SLC 4B (para. 10-12)

whether DNOs can make changes to the methodologies, Ofgem will consider the relevant licence objectives as well as considering responses to the consultation process. Ofgem's view is that a change to the methodology includes any change to the manner in which charges are calculated.

Role of the Implementation steering group (ISG)

7.12. The ISG has supported the structure of charges project since September 2003. The group comprises representatives of each of the DNO groups, suppliers, distributed generators and customers. The ISG has met approximately every six weeks, and Ofgem has found the group to be extremely useful in taking forward the structure of charges project.

7.13. Ofgem expects the ISG to continue in its present form until at least the end of 2004 so as to ensure that the interim arrangements are implemented to plan and on time for 1 April 2005.

7.14. Ofgem is considering the possibility of the ISG continuing as a regular policy forum, and also whether it may be appropriate to establish a charging methodology forum to enable users to consider changes to the charging methodologies. The role of these groups would need to take account of the role of the Distribution Commercial Forum[21]. Ofgem would welcome views on this.

7.15. The current ISG terms of reference can be accessed via the Ofgem website at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/4764_Implementation_SteeringGroup_TermsReference_Oct03.pdf. Further information about the ISG may be obtained from Clover Powell at clover.powell@ofgem.gov.uk.

[21] For further information about the Distribution Commercial Forum please contact Georgina.lawrence@ofgem.gov.uk

8. Summary impact assessment

8.1. Ofgem provided a draft regulatory impact assessment in the November 2003 initial decision document. The costs and policies associated with the project have not altered substantially since that time.

8.2. Further consideration was given to the introduction of the DG Incentive and the change in the structure of generation charges through a joint regulatory impact assessment[22]. This was published in March 2004 and can be found on the Ofgem website. This concluded that a phased approach to the introduction of new generation arrangements would provide a net benefit.

8.3. With the two stage approach to implementation it is recognised that DNOs will only be introducing interim arrangements from 1 April 2005 and therefore we are not expecting significant changes in the demand methodologies themselves (other than changes which could or would have been made in the absence of this project) with limited impact to both the DNOs and the industry.

8.4. With the development of the longer term framework this is likely to have more significant impact on existing demand and generation customers and therefore for any significant methodology modifications proposed after April 2005 it is expected that Ofgem would consider the costs and benefits of proposed changes and undertake impact assessment accordingly.

[22] Regulatory Impact Assessment for distributed generation and structure of distribution charges 62c/04

Appendix 1 Summary of responses to July 2004 open letter consultation

Summary of responses

1.1 Ofgem received seven responses to the open letter consultation (30 July – 27 August 2004) on the draft distribution connection and use of system charging methodologies submitted by the DNOs in mid-July. The main points from the non confidential responses are summarised below. The summary does not represent the views of either Ofgem or the Authority. Responses are available to view on the Ofgem website at www.ofgem.gov.uk.

General

1.2 Respondents noted the need for clarity in the methodologies and the facility to predict likely movements in costs and cost relativity. It was suggested that this would be best provided by publishing the models in full.

1.3 There was also the suggestion over the need for commonality between DNOs, either in underlying principles, or in terms of common methodologies. It was doubted that different network design and customer densities were sufficient reason to explain divergence on methodology.

Connection

1.4 One user felt that statements should describe the methodology for the actual calculation of charges, and explain charge inputs, such as sole use/joint use split, fault level contribution and all special charges. Further, the user argued that it is insufficient for the statements to merely state the principles of charge setting.

1.5 Other points made are as follows:

- Blurring of the boundary between contestable and non contestable costs inhibits competition: clear list of charges for non contestable works needed.

- Further explanation and technical justification needed for the 3 multiplier in the fault level cost apportionment rule.
- Abolition of tariff support and capitalised O&M welcomed.
- More detail needed on what connections are likely to be subject to special terms.
- Concerns over treatment of out of area networks: should be consistent treatment to in-area, or ring fenced to be comparable with IDNO operations.
- Worked examples are welcomed, but need to be detailed, and not show general principles only.

Demand use of system

1.6 Points made are set out below:

- Some concerns over the cost reflectivity of the 500MW model, and the extent to which charges are averaged to price control revenues. If this model is used, its application should be common across all DNOs.
- Query whether the existing tariffs (and hence appropriateness of scaling those tariffs) will continue to be cost reflective after changes to connection charges.
- Concern on the allocation of demand/non-demand related costs in the simulation model, since non-demand related costs are much higher than marginal customer related costs.
- Concern that the regulatory reflective model does not reflect underlying costs, and the variable element of the price control does not reflect marginal distribution costs.
- More clarity needed on derivation of yardsticks, e.g.: demand estimation coefficients, coincidence factors, annuity factors and line loss factors.

- Concern that divergence between DNOs in the ways that charges are constructed (e.g. different allocations of customer costs in standing charges) could result in different charges for similar customers.

- Greater clarity on EHV (and other site specific) price setting is needed. If site specific charges are applied, these need to be published: currently there is confusion over who negotiates the charges (customer/supplier/DNO).

- Suggestion that kW (rather than kWh charges) for NHH customers would provide better incentives for suppliers to consider demand management and innovation in metering.

- Further investigation needed on the actual costs imposed by poor power factors, and consistent approach to charging across DNOs.

- Principles for charging for exceeding agreed capacities should be set out in the methodology statements, and common approach adopted by DNOs would significantly improve efficiency of billing.

Generation use of system

1.7 It was suggested that GDUoS models should move in line with transmission charging models to provide locational signals in tariffs and reflect benefits of DG, with implementation of this for EHV charges from 1 April 2005 if possible.

1.8 Other points made:

- Methodology statements need to explain how tripartite relationship between suppliers, distributors and generators will work, particularly in relation to import /export of active/reactive power.

- More clarity needed on methods to control volatility. Accept that this may result in some cross subsidy, and suggest that DNOs may shoulder some of the risk in RPZs for a higher rate of return. Caps subject to change within three months are not sufficient guard against volatility.

- Treatment of benefits for deferred expenditure and network access rebate payments may have implications for IDNOs trying to enter the market.

- Decision to charge LV NHH/microgeneration should be based on load factors/generator capacity/voltage of connection/fault level rather than a non-technical decision to exempt specific technology.

Appendix 2 Illustrative DUoS charges

2.1 This appendix sets out illustrative DUoS tariffs, based on 2004-5 revenues, for NHH billed customers on general domestic and non-domestic unrestricted and restricted (economy 7) tariffs[23].

2.2 Table 1 shows illustrative 2005-6 domestic unrestricted tariffs based on 2004-5 revenues alongside 2004-5 tariffs. Percentage movements for each charge element are given in the last set of columns. Similarly, table 2 sets out domestic restricted tariffs, table 3 non-domestic unrestricted tariffs and table 4 non-domestic restricted tariffs.

2.3 EDF has changed its tariffs mid-year. The latest published tariffs have been used, even though they take effect from December 2004.

2.4 Only CE (both NEDL and YEDL) includes MAP in DUoS charges. SP's charges for April 2004 excluded MAP, but it is unclear from the 2005 statement whether these charges are included or not. The remaining charges all exclude MAP (both 2004 and 2005 figures).

2.5 All charges are listed in a common format: fixed charges in pence/MPAN/day and unit charges in pence/kWh.

[23] These customers are categorised as profiles 1 to 4 in Supercustomer (i.e. NHH) billing terms.

Table 1 Domestic unrestricted tariffs

DNO	Illustrative 2005-6 tariffs		2004-5 Tariffs		% change	
	FC	Unit	FC	Unit	FC	Unit
Central Networks East	5.84	0.75	5.84	0.75	0.0%	0.0%
Central Networks West	6.111	0.804	5.945	0.819	2.8%	-1.8%
LPN (EDF)	4.07	0.945	4.403	0.878	-7.6%	7.6%
SPN (EDF)	3.84	0.719	3.6	0.69	6.7%	4.2%
EPN (EDF)	3.71	0.817	2.47	0.897	50.2%	-8.9%
SP Manweb (SP T&D)	4.7	1.32	4.51	1.361	4.2%	-3.0%
SP Distribution (SP T&D)	7.14	1.54	2.29	1.97	211.8%	-21.8%
WPD S Wales (WPD)	0	2.22	3.04	1.76	-100.0%	26.1%
WPD S West (WPD)	0	1.81	0	1.72	0.0%	5.2%
YEDL (CE Electric)	7.99	0.66	7.99	0.66	0.0%	0.0%
NEDL (CE Electric)	6.73	0.88	6.73	0.88	0.0%	0.0%
Scottish Hydro Electric (SSE)	4.27	1.76	4.27	1.76	0.0%	0.0%
Southern Electric (SSE)	4.42	1.1	4.42	1.1	0.0%	0.0%
United Utilities	3.37	1.03	3.37	1.03	0.0%	0.0%

Table 2 Domestic restricted tariffs

DNO	Illustrative 2005-6 tariffs			2004-5 Tariffs			% change		
	FC	Peak unit	Off peak	FC	Peak unit	Off peak	FC	Peak unit	Off peak
Central Networks East	7.52	0.76	0.17	7.52	0.76	0.17	0.0%	0.0%	0.0%
Central Networks West	6.37	0.949	0.119	6.197	0.968	0.122	2.8%	-2.0%	-2.5%
LPN (EDF)	4.34	1.115	0.125	4.597	1.034	0.128	-5.6%	7.8%	-2.3%
SPN (EDF)	3.72	0.876	0.08	3.6	0.76	0.08	3.3%	15.3%	0.0%
EPN (EDF)	3.71	0.825	0.25	2.47	0.915	0.268	50.2%	-9.8%	-6.7%
SP Manweb (SP T&D)	5.16	1.46	0.65	5.69	1.612	0.252	-9.3%	-9.4%	157.9%
SP Distribution (SP T&D)	8.13	1.75	0.6	4.72	2.37	0.2	72.2%	-26.2%	200.0%
WPD S Wales (WPD)	0	2.16	0.26	3.7	1.86	0.27	-100.0%	16.1%	-3.7%
WPD S West (WPD)	0	1.75	0.48	0	1.88	0.41	0.0%	-6.9%	17.1%
YEDL (CE Electric)	7.96	0.77	0.12	7.96	0.77	0.12	0.0%	0.0%	0.0%
NEDL (CE Electric)	6.75	0.92	0.11	6.75	0.92	0.11	0.0%	0.0%	0.0%
Scottish Hydro Electric (SSE)	4.27	1.76	0.76	4.27	1.76	0.76	0.0%	0.0%	0.0%
Southern Electric (SSE)	4.95	1.11	0.15	4.95	1.11	0.15	0.0%	0.0%	0.0%
United Utilities	3.18	1.2	0.08	3.18	1.2	0.08	0.0%	0.0%	0.0%

Table 3 Non-domestic unrestricted tariffs

DNO	Illustrative 2005-6 tariffs		2004-5 Tariffs		% change	
	FC	Unit	FC	Unit	FC	Unit
Central Networks East	5.84	0.75	5.84	0.75	0.0%	0.0%
Central Networks West	8.488	1.177	8.258	1.201	2.8%	-2.0%
LPN (EDF)	4.07	1.025	4.403	0.927	-7.6%	10.6%
SPN (EDF)	3.84	0.644	3.6	0.69	6.7%	-6.7%
EPN (EDF)	3.71	0.817	3.33	0.897	11.4%	-8.9%
SP Manweb (SP T&D)	9.02	1.26	8.34	1.374	8.2%	-8.3%
SP Distribution (SP T&D)	21.41	1.65	9.04	1.99	136.8%	-17.1%
WPD S Wales (WPD)	0	1.47	3.04	1.76	-100.0%	-16.5%
WPD S West (WPD)	0	1.37	0	1.72	0.0%	-20.3%
YEDL (CE Electric)	20.87	0.66	20.87	0.66	0.0%	0.0%
NEDL (CE Electric)	20.08	1.31	20.08	1.31	0.0%	0.0%
Scottish Hydro Electric (SSE)	5.95	2.81	5.95	2.81	0.0%	0.0%
Southern Electric (SSE)	4.42	1.29	4.42	1.29	0.0%	0.0%
United Utilities	5.22	1.02	5.22	1.02	0.0%	0.0%

Table 4 Non-domestic restricted tariffs

DNO	Illustrative 2005-6 tariffs			2004-5 Tariffs			% change		
	FC	Peak unit	Off peak	FC	Peak unit	Off peak	FC	Peak unit	Off peak
Central Networks East	7.52	0.76	0.17	7.52	0.76	0.17	0.0%	0.0%	0.0%
Central Networks West	8.498	1.242	0.119	8.268	1.267	0.122	2.8%	-2.0%	-2.5%
LPN (EDF)	4.34	1.075	0.105	4.597	1.073	0.122	-5.6%	0.2%	-13.9%
SPN (EDF)	3.72	0.649	0.07	3.6	0.79	0.08	3.3%	-17.8%	-12.5%
EPN (EDF)	3.71	0.825	0.26	3.33	0.915	0.268	11.4%	-9.8%	-3.0%
SP Manweb (SP T&D)	15.13	1.45	0.41	8.34	1.41	0.214	81.4%	2.8%	91.6%
SP Distribution (SP T&D)	16.5	2.81	0.93	8.45	2.64	0.2	95.3%	6.4%	365.0%
WPD S Wales (WPD)	0	1.93	0.37	3.7	1.86	0.27	-100.0%	3.8%	37.0%
WPD S West (WPD)	0	1.88	0.38	0	1.88	0.41	0.0%	0.0%	-7.3%
YEDL (CE Electric)	20.82	0.77	0.12	20.82	0.77	0.12	0.0%	0.0%	0.0%
NEDL (CE Electric)	19.92	1.34	0.11	19.92	1.34	0.11	0.0%	0.0%	0.0%
Scottish Hydro Electric (SSE)	5.95	2.81	0.76	5.95	2.81	0.76	0.0%	0.0%	0.0%
Southern Electric (SSE)	4.95	1.36	0.15	4.95	1.36	0.15	0.0%	0.0%	0.0%
United Utilities	5.09	0.94	0.08	5.09	0.94	0.08	0.0%	0.0%	0.0%

Appendix 3 Illustrative GDUoS charges[24]

DNO	Yearly illustrative GDUoS charge 2005-6	EHV
Central Networks (E)	£0 LV, Microgeneration (SSEG) £0 HV HH metered £3.72/kVA	Site specific
Central Networks (W)	£0	Site specific
LPN (EDF)	Domestic NHH £2.52/MPAN Non domestic NHH £8.29/MPAN HH £9.36/kVA	Site specific
SPN (EDF)	Domestic NHH £2.52/MPAN Non domestic NHH £8.29/MPAN HH £6.36/kVA	Site specific
EPN (EDF)	Domestic NHH £2.52/MPAN Non domestic NHH £8.29/MPAN HH £6.60/kVA	Site specific
SPManweb[25]	HV £1.48/kVA; £0 at LV	Locational by area – between £3.67 and £14.78/kVA
SP Distribution[26]	HV £1.52/kVA; £0 at LV	Locational by area – between £2.20 and £3.47/kVA
WPD S Wales	Profiles 1&2 £4.93/MPAN Profiles 3&4 £24.64/MPAN Profiles 5-8 £32.49/MPAN HH LV £8.32/kVA, HH HV £8.87/kVA	£6.46/kVA
WPD S West	Profiles 1&2 £2.74/MPAN Profiles 3&4 £13.72/MPAN Profiles 5-8 £26.21/MPAN HH LV £6.72/kVA, HH HV £6.06/kVA	£6.83/kVA
YEDL	NHH £0 split between <16A and >16A HH LV/HV £5.99/kVA	Site specific
NEDL	NHH £0 split between <16A and >16A HH LV/HV £6.39/kVA	Site specific
Scottish Hydro Electric (SSE)	HH £4.08/kVA for EHV, HV and LV NHH £0	£4.08/kVA
Southern Electric (SSE)	HH £3.00/kVA for EHV, HV and LV NHH £0	£3.00/kVA
United Utilities	HV/LV: £7.60/kW Microgeneration (SSEG): £0/kW RPZ surcharge £3/kW at all voltage levels	Site specific; average £6.75. Charges between £2.50 and £19.50/kW

[24] Charges have been converted to annual prices for ease of comparison. UU have published charges per year, WPD, CE, CN per day, SSE per month, EDF a mixture of per day (NHH) and per month (HH) and it is not clear what units SP are using.
[25] It is not clear from SP's charging statement whether this charge is per day, month or year.
[26] It is not clear from SP's charging statement whether this charge is per day, month or year.