Report on the Draft Common Distribution Charging Methodology

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Contents

Introduction and overview

1. This report accompanies proposals from the distribution network operators (DNOs) for a common distribution charging methodology (CDCM).

2. CE Electric, Central Networks, EDF Energy Networks, Electricity North West, SP Energy Networks, SSE Power Distribution and Western Power Distribution jointly prepared these proposals on behalf of the 14 entities licensed as Distribution Services Providers.[1]

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[1] The Distribution Services Providers are Central Networks East Plc, Central Networks West Plc, EDF Energy Networks (EPN) Plc, EDF Energy Networks (LPN) PLC, EDF Energy Networks (SPN) PLC, Electricity North West Limited, Northern Electric Distribution Ltd, Scottish Hydro Electric Power Distribution Plc, Southern Electric Power Distribution Plc, SP Distribution Limited, SP Manweb Plc, Western Power Distribution (South Wales) Plc, Western Power Distribution (South West) Plc, and Yorkshire Electricity Distribution Plc.

3. This report was prepared pursuant to condition 50 of the standard distribution licence conditions. Condition 50 was proposed by Ofgem on 8 May 2009 and came into effect from 1 July 2009.[2]

4. This report reviews the process by which the CDCM was developed and provides an overview of the methodology and rationale for choices made, including reasons for changes from the position originally put forward by Ofgem and reasons for the approach chosen to fill gaps in Ofgem's documents. It also outlines how the proposals meet the relevant requirements, the impact on tariffs, areas of implementation risks and areas in which the DNOs plan further development.

5. The following additional information is provided with this report:

   (a) Appendix A is a summary of responses to the DNOs' June/July 2009 consultations.

   (b) Appendix B is the proposed common methodology document.

   (c) Appendix C shows the illustrative tariffs for each licence area that might have resulted from the application of the CDCM in 2009/2010.

   (d) Appendix D is an explanation of significant tariff disturbances.

   (e) Appendix E reviews areas of implementation risk for each DNO.

   (f) The populated models used to produce illustrative tariffs for each licence area are available at http://2009.energynetworks.org/structure-of-charges/.

The process by which the CDCM was developed

How the process started

6. The CDCM development process to deliver a common charging methodology for HV and LV users started as a voluntary collective initiative by the seven DNO groups. The work was initiated in October 2008 by the DNOs voluntarily working together on developing a common charging methodology for HV and LV users, after the publication of Ofgem's 1 October 2008 document.[3]

7. Between October 2008 and June 2009, there was no formal obligation to develop a common method. Instead, the development of the CDCM was driven by the objective of developing a methodology which, if put forward and implemented as a modification to current methodologies, would comply with the DNOs' legal obligations (including under competition law) and would better meet the relevant objectives specified in the standard distribution licence conditions.

Working groups

8. The DNOs established a Common Methodology Group (CMG), reporting to the ENA's Price Control Group (PCG), and a series of workstreams under CMG as follows:

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[2] "Collective Licence Modification intended to deliver the electricity distribution structure of charges project at lower voltages", 8 May 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

[3] "Delivering the electricity distribution structure of charges project", 1 October 2008, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

(a) Workstream 1 examined EHV load flow modelling issues (not directly relevant to the HV/LV CDCM).

(b) Workstream 2 developed the cost and revenue allocation methodologies in the CDCM.

(c) Workstream 3 developed tariff structures and tariff application in the CDCM.

(d) Workstream 4 reviewed the connection charging methodology and its interaction with use of system charging.

(e) Workstream 5 developed governance arrangements.

9. The workstreams were open to stakeholder representation. Representatives from Ofgem, suppliers and IDNOs took part in workstream meetings alongside the DNOs.

10. Terms of reference for the workstreams and a variety of working documents were published on the ENA website at http://2009.energynetworks.org/structure-of-charges/.

11. Ofgem also facilitated an IDNO/DNO charging steering group. Information about this group is available from Ofgem's website.[4]

Engagement with Ofgem

12. The DNOs have engaged with Ofgem on a number of areas in which they proposed amendments or developments of the positions set out in Ofgem's 1 October 2008 document.

13. This work led to a number of developments from the approach in Ofgem's 1 October 2008 document, including:

(a) The use of p/kWh credits for generators (instead of payments based on generation capacity and F-factor assumptions).

(b) The use of a 500 MW model covering all network levels to set charges for HV and LV users (instead of relying on EHV methodologies).

(c) The use of data about power factors in the network to calculate reactive power unit charges, leading to a single charging rate for each tariff (instead of a tariff banded by power factor).

(d) The inclusion of replacement costs for customer-contributed assets in the model.

(e) The use of detailed cost modelling and tariff matrices as the basis for setting embedded network tariffs (with a portfolio structure) on the same basis as all-the-way tariffs.

Condition 50 of the standard distribution licence conditions

14. Ofgem published a document on its approach to regulating the structure of charges on 20 March 2009.[5] It proposed a collective licence modification on 8 May 2009 to

4 See http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/.

formalise the CDCM development process with a specific set of legal obligations on DNOs.[6] This licence modification was accepted by all DNOs and came into force on 1 July 2009.

15. Condition 50, introduced into the standard distribution licence conditions by this collective licence modification, specifies four relevant objectives for the CDCM:

> 50.6 The first Relevant Objective is that compliance with the CDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.
>
> 50.7 The second Relevant Objective is that compliance with the CDCM facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector.
>
> 50.8 The third Relevant Objective is that compliance with the CDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.
>
> 50.9 The fourth Relevant Objective is that, so far as is consistent with paragraphs 50.6 to 50.8, the CDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

16. Condition 50 also requires that:

    (a) The CDCM must conform to requirements specified by Ofgem in its 1 October 2008 and 20 March 2009 documents with respect to the fundamental principles and assumptions on which the development of the CDCM is to be based (paragraph 50.14).

    (b) Each DNO must take all reasonable steps to ensure that the CDCM in the form in which it is being developed will be capable of being approved by the Gas and Electricity Markets Authority (paragraph 50.17).

17. In early July, we made changes to the approach described in the 12 June 2009 consultation following discussions with Ofgem. The principal change was the exclusion of any allowance for replacement of customer-contributed assets from the model.

18. The exclusion of replacement costs for customer-contributed assets from the model had consequences for other parts of the proposed methodology. In particular, it required a recast of the approach to setting embedded network tariffs.

Stakeholder consultation

19. The DNOs formally consulted stakeholders on a number of specific issues, including through written consultations and presentations to the distribution charging methodologies forum (DCMF).

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5 "Next steps in delivering the electricity distribution structure of charges project", 20 March 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

6 "Collective Licence Modification intended to deliver the electricity distribution structure of charges project at lower voltages", 8 May 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

20. All consultations and other materials produced by the project are published at http://2009.energynetworks.org/structure-of-charges/. DCMF documents are published at http://2009.energynetworks.org/distribution-charging-methodol/.

21. The formal consultations included:

(a) A consultation on generation credits.

(b) Two consultations on the possible de-linking of unit rates from suppliers' standard settlement configurations and time pattern regimes.

(c) A consultation on three options for the common tariff structure.

(d) A consultation on the method for determining reactive power unit charges.

(e) A consultation on governance arrangements.

(f) The consultation document of 12 June 2009, which included the details of the methodology proposed at that time, and illustrations of its application.

(g) A supplementary consultation on 8 July 2009 on some of the implications of Ofgem's view on the exclusion of replacement costs from the model.

(h) A consultation on an embedded network billing code of practice, which would be intended to facilitate the implementation of portfolio billing. This consultation closes on 18 September 2009.

22. All these consultation documents were published on the ENA website and are available from http://2009.energynetworks.org/structure-of-charges/.

23. In addition to these written consultations and to the consultation undertaken through working groups, the DNOs held two workshops:

(a) A workshop on 30 March 2009 on proposals for de-linking of unit rates from suppliers' standard settlement configurations and time pattern regimes.

(b) A workshop on 25 June 2009 on the model and methodology put forward in the 12 June 2009 consultation.

Modifications to the approach after the 12 June 2009 consultation

24. Responses were received from a wide range of stakeholders to the 12 June 2009 and 8 July 2009 consultations.[7]

25. The responses did not raise any showstoppers for the development or implementation of the CDCM.

26. Responses from suppliers were mostly supportive of the exclusion of replacement costs from the model. Distributors expressed concerns about the exclusion of replacement costs from the model. Embedded network operators were not supportive of the proposal to use a single form of cost analysis to set both all-the-way and embedded network tariffs. There was no support from parties other than DNOs for the specific methods put forward in the consultation for taking account of

7 Responses are available from http://2009.energynetworks.org/structure-of-charges/.

replacement costs or for revenue matching. Appendix A reviews the consultation responses.

27. After reviewing consultation responses, the DNOs concluded that the most appropriate way for them to comply with condition 50 was to:

    (a) Exclude replacement costs from the model.

    (b) Work with Ofgem to develop a revenue matching method using a fixed adder approach that would be capable of being approved by the Gas and Electricity Markets Authority.

    (c) Adapt the methodology for setting embedded network tariffs described in WPD's UoS 012 modification proposal for use within the CDCM.[8]

    (d) Develop and implement a number of other changes or refinements (e.g. in terms of the consistency of the principles underpinning the 500 MW models) arising from consultation responses or DNOs' review of illustrative tariffs.

28. There was insufficient time to consult formally on the details of implementation of these issues, particularly the new revenue matching method or embedded network charging methodologies. Instead, the DNOs sought greater engagement of IDNOs and suppliers within the working groups during the final phase of the project. WPD's UoS 012 modification, which was the basis of the new proposals for embedded network charges, had been the subject of an Ofgem consultation on 9 April 2009.[9]

Proposals for the future governance of the CDCM

29. In the March 2009 consultation on governance, Workstream 5 proposed to incorporate the governance arrangements for the CDCM within the DCUSA. The Workstream 5 consultation document explains the grounds for this proposal.[10]

30. No responses were received to this consultation.

31. Ofgem accepted this proposal and proposed the necessary changes to the standard distribution licence conditions on 31 July 2009.[11]

Rationale for the choices made in the proposed methodology

32. This section explains the choices made in the proposed methodology. The text of the proposed methodology is quoted in green. Appendix B is the full text of the draft methodology.

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8 WPD's modification proposal (9 April 2009) and Ofgem's decision (9 June 2009) are available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/.

9 "Joint consultation on IDNO boundary charging: Consultation on WPD UoS 012 & Consultation on IDNO/DNO working group options for April 2010", 9 April 2009, available as a subsidiary document under the 9 June 2009 decision from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/.

10 "Workstream 5 paper — Governance and Change Control Arrangements for a Common Distribution Charging Methodology", March 2009, available from http://2009.energynetworks.org/structure-of-charges/.

11 "Collective licence modification proposal ref. 91/09", 31 July 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

Tariff structure

33. The common tariff structure and the common way in which tariffs would be applied under the CDCM are set out in part 2 of the CDCM methodology statement.

34. The DNOs consulted stakeholders on several aspects of tariff structure at an early stage in the process, and a range of detailed issues were debated through Workstream 3 (which was regularly attended by several suppliers). The 12 June 2009 consultation document set out the position reached following these consultations.

35. The only change to the tariff structure after the 12 June 2009 consultation was the addition of LV Sub and HV Sub generation tariffs, for consistency with demand.

Tariff components

36. Each tariff comprises the tariff components listed in table 1.

Table 1 List of tariff components and restrictions on their application

Tariff component	*Unit*	*Restrictions*
One, two or three unit rates	p/kWh	No more than two unit rates for non half hourly settled demand.
Fixed charge	p/day	Not for unmetered supplies.
Capacity charge	p/kVA/day	Half hourly settled demand tariffs only.
Reactive power charge	p/kVArh	Half hourly settled tariffs only.

37. Capacity charges and reactive power charges are only applied to half hourly settled tariffs. This facilitates the migration of all non half hourly customer to a supercustomer billing method.

38. Three unit rates are used for half hourly settled users to reflect the difference in distribution costs between a “red” period where the system as a whole has a relatively high probability of peaking, an “amber” period where a substantial proportion of substations peak, and a “green” period where the only risk of peaking is associated with substations dominated by electric heating loads.

Portfolio tariffs

39. For users that are acting as licensed distribution network operators, tariffs are “portfolio tariffs” with the same tariff components as the corresponding “all the way” end user tariff, excluding reactive power charges (but prices for some tariff components may be calculated as zero).

40. In the context of the IDNO/DNO charging steering group, the DNOs asked Ofgem for a view on LDNO tariffs. Ofgem explained that there were arguments for both

approaches but on balance Ofgem was minded to say that portfolio tariffs were more appropriate.[12]

Rounding

41. Each component of each tariff is rounded to the nearest value with no more than three decimal places in the case of unit rates expressed in p/kWh and reactive power unit charges expressed in p/kVArh, and with no more than two decimal places in the case of fixed and capacity charges expressed in p/MPAN/day and p/kVA/day respectively.

42. An explicit rounding rule is necessary for accurate publication and application of the tariffs. The number of decimal places specified for each tariff component was the minimum necessary to ensure that rounding effects would not risk leading to an under- or over-recovery of allowed revenue of more than 0.1 per cent.

Cost allocation

43. The method for determining tariffs is set out in part 1 of the CDCM methodology statement.

44. The proposed methodology applies different methods to allocate costs to all-the-way tariffs (applied to suppliers in respect of both generation and demand) and LDNO tariffs (applied to independent distribution network operators and to DNOs operating out of their distribution service area).

45. This is in line with the reasons for differential treatment outlined by Ofgem in its April 2009 consultation on LDNO tariffs.[13] In its decision of 9 June 2009 on WPD's UoS 012 proposal, Ofgem said that:

> The Authority therefore considers that WPD's proposal to move away from charging IDNOs on a marginal avoided cost approach towards an average cost approach better achieves relevant objective (b) in terms of not restricting, preventing and distorting competition in distribution.

46. The cost allocation methodology is structured in four steps. Steps 1–3 determine all-the-way charges. Step 4 determines LDNO tariffs. We follow the structure of the methodology in explaining reasons for individual choices made.

47. Figure 1, reproduced from the draft methodology statement, gives a general overview of how the four main steps in the methodology relate to each other.

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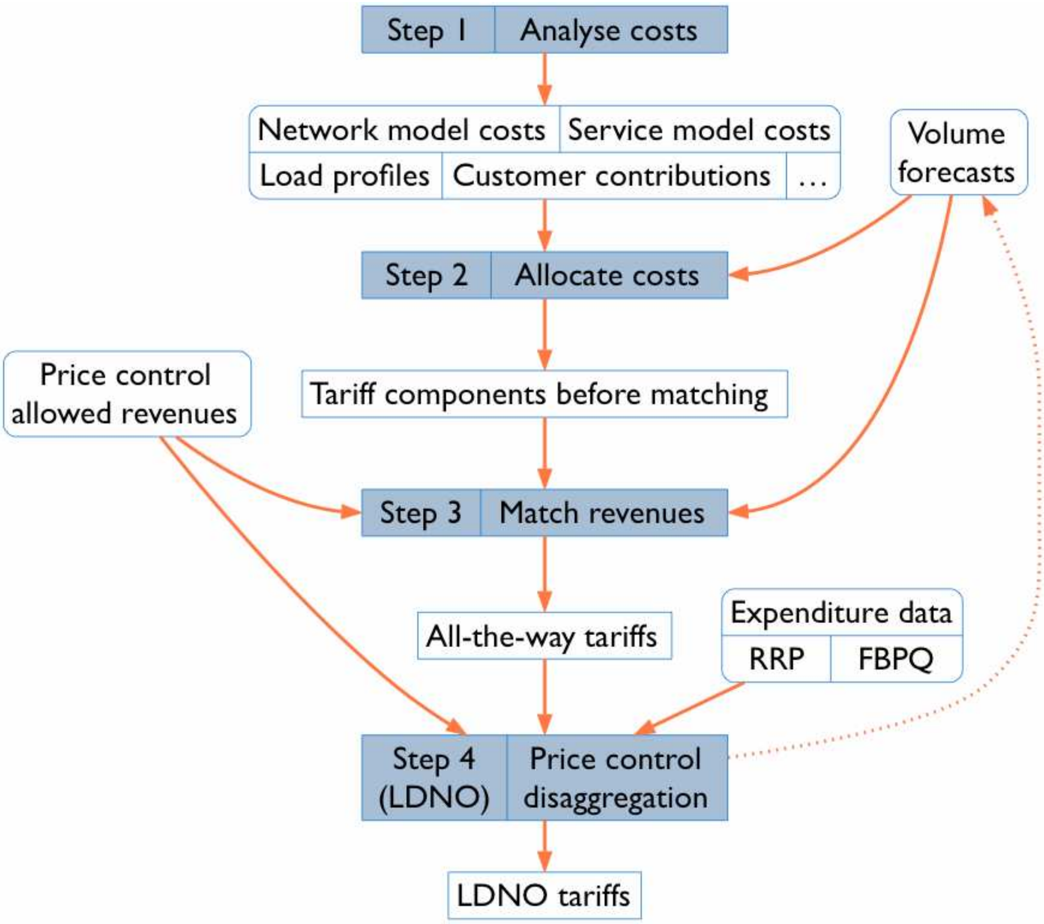
12 "IDNO/DNO Steering group minutes 2 June", section entitled "Ofgem slides on Portfolio Vs Banding", published 10 June 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/.

13 "Joint consultation on IDNO boundary charging: Consultation on WPD UoS 012 & Consultation on IDNO/DNO working group options for April 2010", 9 April 2009, available as a subsidiary document under the 9 June 2009 decision from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/.

Figure 1 Overview of the main steps in the methodology



Step 1: Analyse costs

48. The first step of the methodology involves the determination of costs or revenue allowances for various parts of the distribution networks, and the collection of information about the relevant characteristics of network users.

Network model asset values

49. The licensee specifies a network model, also known as a distribution reinforcement model (DRM) or a 500 MW model, in line with the requirements of this section.

50. In all cases, the network model determines the £/kW/year figure (based on simultaneous maximum load at each network level) corresponding to amortisation and return on capital for assets at the LV circuits, HV/LV and HV network levels.

51. For licensees that do not rely on a separate EHV charging methodology, the network model also determines these costs at the EHV/HV and EHV network levels, and, in England and Wales, at the 132kV/EHV and 132kV network levels.

52. The network model consists of a costed design for an increment to the licensee's distribution system.

53. At each network level, the model is sized to provide secure capacity to meet demand that, aggregated up to individual grid supply point (GSP) level, amounts to 500 MW of simultaneous maximum demand.

54. The model's design assumes a power factor of 0.95 and no embedded generation.

55. The assets included in the network model are modern equivalent assets of the kind that the licensee would normally install on new networks.

56. The nature, quantity and size of assets in the model is such as to meet demand and security to the licensee's design and planning standards, allowing for the use of standard size equipment and typical utilisation factors.

57. The proportion of assets of different types at each network level, e.g. overhead and underground circuits, reflects the mix of users and the topography in the licensee's area.

58. The cost assumed for each asset type reflect total purchase and installation cost in the charging year, using the licensee's normal procurement methods.

59. Ofgem's 1 October 2008 document recommended the use of a 500 MW model to set HV and LV charges.

60. However, Ofgem's documents proposed that data from an EHV charging methodology should be used instead of the 500 MW model for EHV network levels. Following dialogue with Ofgem, the following issues were identified with such an approach:

(a) It would introduce into the methodology some apparent cost data which are not, in fact, costs, raising potential difficulties with justification.

(b) It would make it difficult to attribute charges to time of day, since there would not be a breakdown of costs between the different EHV network levels, which tend to peak at different times.

(c) It would make it difficult to attribute charges between capacity and units for HV users, since there would not be a breakdown of costs attributable to primary substations (assumed to be sized by reference to agreed capacity) or to assets further upstream (assumed to be sized by reference to maximum load).

(d) It would create an unnecessary dependency between the CDCM and the EHV charging methodologies.

61. To address these problems, the working group proposed to use the 500 MW model for all EHV network levels, distinguishing between an EHV (typically 33kV) layer and a 132kV layer (in England only). Ofgem provided initial thoughts on this proposal in May 2009.

62. After the 12 June 2009 consultation, the model was expanded to allow explicit modelling of direct 132kV/HV transformation.

Diversity allowances

63. For each of the 132kV (except in Scotland), EHV and HV voltage levels, the licensee determines a diversity allowance between the transformation level above circuits at that voltage and the transformation level below circuits at that voltage.

64. Each diversity allowance represents the extent, expressed as a percentage, to which the sum of the maximum load across all substations below would exceed the corresponding sum for substations above.

65. The licensee also determines a diversity allowance between the GSP Group as a whole and the individual grid supply points.

66. Diversity allowances are used within the CDCM cost allocation methodology to calculate capacity charges. They ensure that the costs of diversity, which are already largely included within the 500 MW model asset values (since the 500 MW relate to a load diversified up to GSP level), are not double-counted when charges are applied to undiversified import capacities.

Customer contributions under current connection charging policy

67. The licensee estimates the extent to which the assets at each network level used by each category of users would have been expected to be covered by customer contributions if they had been constructed under the charging year's connection charging policy.

68. The licensee groups users into categories, by network level of supply, for the purpose of making these estimates.

69. In the case of generators, the proportions relate to the notional assets whose construction or expansion might be avoided due to the generator's offsetting of demand on the network, and takes the same values as for a demand user at the same network level of supply.

70. Ofgem's 1 October 2008 document specified that assets within the 500 MW model that would have been covered by connection charges under the current connection charging policy should be excluded. Ofgem subsequently said that replacement costs associated with these assets should not be taken into account in the modelling of all-the-way tariffs.

Service model asset values

71. The licensee specifies a set of service models covering the range of typical dedicated assets operated for the benefit of individual HV and LV users of the network.

72. For each service model, the licensee estimates the number and types of connections that the model covers, and a total construction cost for the assets in the model.

73. For each tariff, the licensee identifies the extent to which each of the service models represents the relevant assets for an average user in that tariff.

74. A weighted average of service models is used if several service models apply to the same tariff.

75. In the case of unmetered supplies, service model assets are modelled on the basis of units delivered.

76. Service model assets are deemed to be fully covered by customer contributions. These asset values are used to allocate costs such as operating expenditure which are allocated in line with asset values.

Transmission exit expenditure

77. The licensee prepares a forecast of expenditure on transmission exit charges in the charging year.

Other expenditure

78. The licensee prepares a forecast of other expenditure for the charging year, where other expenditure is defined as the sum of:

(a) 100 per cent of direct operating costs.

(b) 60 per cent of indirect costs (as defined in RRP guidance).

(c) 100 per cent of network rates.

79. The 12 June 2009 consultation included proposals for operating expenditure based on the objectives and principles used elsewhere in the draft methodology as it then stood. This included a set of "multipliers" used to allocate expenditure across network levels. Following the changes made to the draft methodology in July 2009, the working group decided to simplify the allocation to use asset values only (i.e. set all the multipliers to one). This is consistent with paragraph 1.42 in Ofgem's 1 October 2008 document.

Rationale for 60 per cent factor

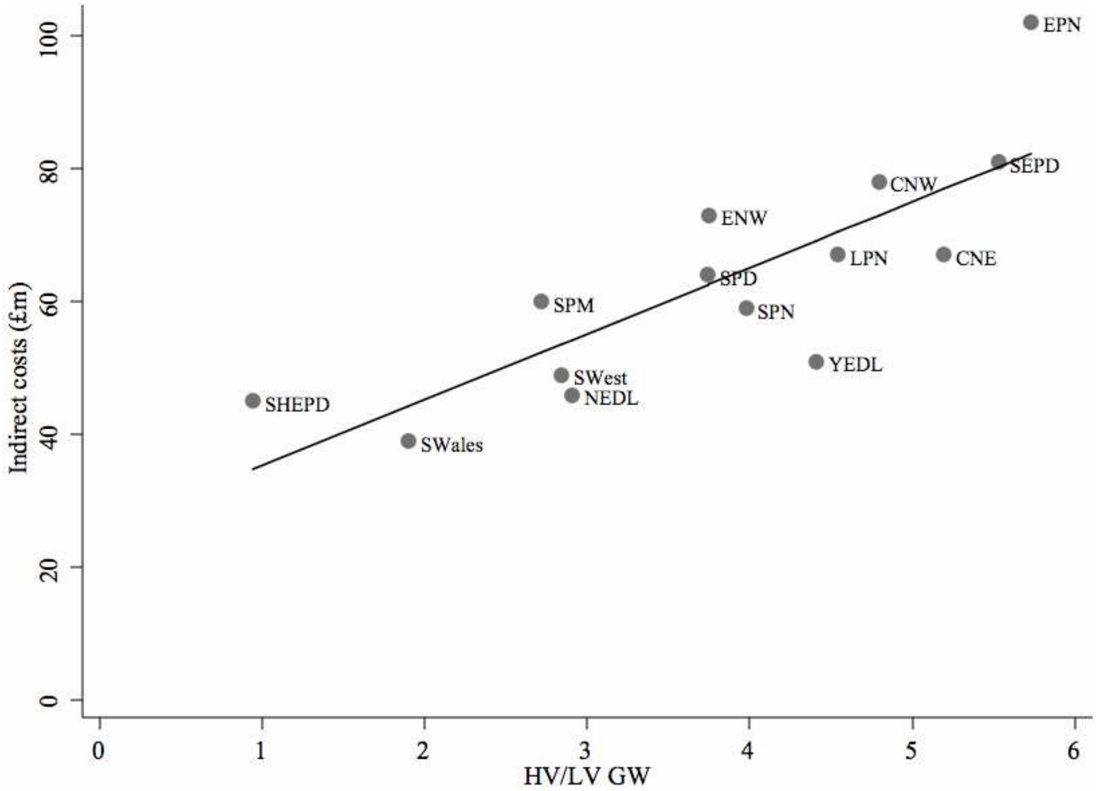
80. Ofgem suggested that not all operating expenditure should be included in the model. Instead, it thought that some expenditure should be treated as "fixed" and not allocated within the modelling (so that it will be recovered as part of revenue matching).

81. In order to identify a way of meeting this requirement that might be capable of acceptance by Ofgem, and following discussions with Ofgem, the DNOs produced a linear regression analysis showing indirect expenditure (RRP definition, 2007/2008 data) against system simultaneous maximum load from HV and LV users (estimated from the draft CDCM volume forecasts and load characteristics).

82. The fitted line for that regression had an intercept of fitted indirect costs of £25.4 million a year for no load, and a slope of £9.9/kW/year.

83. Figure 2 shows the data and this linear fit.

Figure 2 Regression of indirect cost against system simultaneous maximum load



84. The intercept in the linear regression was statistically significant from zero at a confidence level of 99 per cent, indicating that the system simultaneous maximum load data used in the regression was not sufficient to explain indirect expenditure on its own: if only that variable was used, adding a fixed per-company amount improved the fit.

85. Ofgem provided initial thoughts on the use of this regression as the basis for identifying the fixed costs that should not be allocated within the model. Ofgem's guidance was that it would be preferable to apply the deduction as a single percentage, rather than as a uniform lump sum deduction from all DNOs' costs.

86. In order to determine a single percentage of indirect expenditure to be excluded from the model for all DNOs, we converted the intercept into a proportion of indirect expenditure for a notional median DNO. The median of the indirect cost dataset is the interval between £60 million and £64 million. Using a round figure, the proposed CDCM methodology specifies that 40 per cent of indirect costs are excluded from the allocation.

Rationale for inclusion of network rates

87. In the June 2009 consultation, network rates were treated as an asset-related cost and implicitly allocated in the same way as other asset-related annuities, through the annuity scaler. This method was no longer available under the revenue matching method outlined above.

88. Expenditure on network rates is therefore included in the amount of other expenditure to be allocated by asset values. This preserves the essential feature of linking the allocation of network rates to assets, within the constraint that no cost is

allocated towards the replacement of assets that are deemed to be covered by customer contributions.

Distribution time bands

89. The licensee determines three distribution time bands, labelled red, amber and green.

90. Distribution time bands are defined separately for Monday-Friday and for Saturday/Sunday. In each case, time bands are defined by reference to UK clock time only, and always begin and end on the hour or half hour. Each time band may be divided into any number of sections.

91. Three unit rates are used for half hourly settled users to reflect the difference in distribution costs between a “red” period where the system as a whole has a relatively high probability of peaking, an “amber” period where a substantial proportion of substations peak, and a “green” period where the only risk of peaking is associated with substations dominated by electric heating loads.

92. The time bands were derived by each licensee using an analysis of load patterns in their distribution services area. All licensees use three time bands with the same general characteristics, but the times at which the rates apply and the duration of the rates vary from area to area to reflect local load patterns.

Load characteristics

93. The licensee estimates the following load characteristics for each category of demand users:

    (a) A load factor, defined as the average load of a user group over the year, relative to the maximum load level of that user group. Load factors are numbers between 0 and 1.

    (b) A coincidence factor, defined as the expectation value of the load of a user group at the time of system simultaneous maximum load, relative to the maximum load level of that user group. Coincidence factors are numbers between 0 and 1.

    (c) In the case of multi-rate tariffs that are applied to non-half-hourly meter data or to fixed time bands that differ from the distribution time bands (if any), the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band.

94. Where appropriate, the licensee determines load characteristics by analysis of meter and profiling data received for a recent 12 month period for which data are available in time for use in the calculation of charges.

95. For load factors and coincidence factors in the case of non half hourly settled customer classes, data adjusted for GSP Group correction factor are used.

96. For the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band, data are not adjusted for GSP Group correction factors.

97. Settlement data for non half hourly unmetered supplies are not used to determine load characteristics. Instead, the load factor and coincidence factor for this user class are set equal to the figures for pseudo half hourly LV unmetered supplies, if any. If no data are available for pseudo half hourly LV unmetered supplies in the relevant area, data for pseudo half hourly LV unmetered supplies from another area are used as a proxy.

Rationale for use of pseudo half hourly data as a proxy for all unmetered supplies

98. The rationale for the special method to determine load and coincidence factors for non half hourly unmetered supplies is the observation that the profiles used in settlement for these supplies are incorrect, in a way that would materially distort the calculation of coincidence factors used to set distribution use of system charges.

99. From an examination of D0030 data for a small of companies, most of the volume of non half hourly settled unmetered supplies appears to be in a "dusk-to-dawn" profile which, according to D0030 half hourly profiled load data, operates from 19:00 GMT (the first active settlement period is 39 in the winter, 41 in the summer) through to 09:00 GMT (the last active settlement period is 18 in the winter, 20 in the summer).

100. In fact, street lighting will be on from about 4 pm in the winter. Since the time of distribution system peak is very likely to be after 4 pm on a winter weekday, the non half hourly profiling error would have a large effect on the estimated coincidence factor.

101. Coincidence factors estimated from pseudo half hourly data are much higher than those based on non half hourly load profiles: this is consistent with the expectation that most unmetered loads would be active at the time of peak.

102. In these circumstances, the approximations involved in using pseudo half hourly data as a proxy seem preferable to the errors involved in relying on profiled load data.

Loss adjustment factors to transmission

103. For each network level, the licensee determines a single loss adjustment factor to transmission relating to exit points from its network at that level. These loss adjustment factors should be representative of average losses at the time of system simultaneous maximum load.

104. Loss adjustment factors are used throughout the allocation to reflect the capacity used at different levels of the network by each type of load, and the capacity offset at different levels of the network by each type of generation.

Peaking probabilities

105. The licensee determines a peaking probability in respect of each network level and each of the distribution time bands.

106. The peaking probability represents the probability that an asset at that network level would experience maximum load during that distribution time band.

Power factor data

107. The licensee determines or estimates, for each network level, the average of the ratio of reactive power flows (kVAr) to network capacity (kVA), weighted by reactive power flow.

108. If data are not available for any network level, the licensee uses data for the nearest network level at which they are available.

109. These network power factor data are used to estimate the capacity consumed at each network level by the conveyance of reactive power. This, is turn, drives the p/kVArh reactive power charges.

110. Reactive power flows are not routinely measured at all substations, particularly at lower voltages. Therefore, an estimation procedure is required. Data collected in the course of preparing the CDCM proposals indicated that there are no large systematic differences in power factors between network levels, and therefore using available data for the next level up is a sensible way of filling in the gaps.

Volume forecasts

111. The licensee forecasts the volume chargeable to each tariff component under each tariff for the charging year.

112. The volumes to be estimated are therefore:

(a) The average over the year of the number of MPANs by tariff.

(b) The total number of units by tariff and by rate or time band (kWh).

(c) The average over the year of the total chargeable import capacity (kVA) by tariff (for half hourly settled demand only), excluding any element excluded from the price control (e.g. top-up and standby).

(d) The average over the year of the total chargeable reactive power units (kVArh) by tariff (for half hourly users only). Only reactive units above the 0.95 power factor threshold used for charging should be included. Any element excluded from the price control (i.e. all chargeable reactive power units under the 2005–2010 price control) should be excluded from this forecast.

113. The volume forecasts for portfolio tariffs are multiplied by the LDNO discount percentages determined in Step 4, and combined with the all-the-way volume forecasts for each end user type. These combined volume forecasts are used throughout Steps 2 and 3 of the methodology.

114. The application of the LDNO discount percentages to LDNO volume forecasts is necessary in order to ensure that, overall, the tariffs derived from the all-the-way cost allocation methodology combined with the discount percentages will raise an amount of revenue that matches allowed revenue.

Forecast of price control allowed revenues

115. The licensee prepares a forecast of allowed revenue for the charging year in accordance with the requirements of the price control licence conditions and in a manner which is consistent with its volume forecasts.

116. This forecast is needed for revenue matching.

Step 2: Allocate costs

Categories of costs

117. The cost and revenue allocation is driven by a representation of the different voltage and transformation levels in the network and by a distinction between the elements of cost related to assets and those related to operations.

118. Table 2 shows the network levels and categories of costs used in the model. In this document, the acronym EHV refers to voltages of 22 kV and above, up to but *excluding* 132 kV. In the case of the Scottish licensed distribution areas, the entries for the 132kV and 132kV/EHV network levels are zero as these voltages are part of the transmission network. LV refers to voltages below 1 kV, and HV refers to voltages of at least 1kV and less than 22kV.

Table 2 Categories of unit costs in the model

Category	*Description*	*Unit*	*Levels*
Network assets	Amortisation and return on capital for networks or substations at each level, excluding assets that are deemed to be covered by customer contributions. This is expressed per kW of system simultaneous maximum load.	£/kW/year	132kV 132kV/EHV EHV EHV/HV 132kV/HV HV HV/LV LV circuits
Transmission exit	Expressed per kW of system simultaneous maximum load	£/kW/year	Transmission exit
Other expenditure	Other expenditure is attributed to levels and assets in the network following the rules set out below. The part allocated to network levels is expressed per kW of system simultaneous maximum load.	£/kW/year	132kV 132kV/EHV EHV EHV/HV 132kV/HV HV HV/LV LV circuits
	The part of other expenditure allocated to assets dedicated to one customer is expressed per user for each user type.	£/year	For each type of user

119. The proposal is to allocate other expenditure first to network levels, and then to allocate these unit costs in the same way as asset-related costs (except that the issue of customer-contributed assets does not arise). The idea of allocating operating expenditure to network levels was put forward in Ofgem's 1 October 2008 document. Once other expenditure has been associated with assets and their MEAVs, then we allocate these costs between users in the same way as asset-related costs.

Annuitisation of network model asset values

120. Capital costs that are not covered by customer contributions are converted to annual costs using a level annuity with using the annuity period and rate of return set out in table 3.

Table 3 Annuity rate of return and annuity period

Parameter	*Value*
Annuity period	40
Annuity rate of return	6.9%

121. The effect of writing these figures in the methodology is that any changes to them will have to be subject to the governance process.

Determination of unit costs from network model

122. For each network level, the licensee determines the flow at time of system simultaneous maximum load, measured at exit points from the network level, that could be accommodated by the network model on the basis of a normal mix and diversity of loads for its network.

123. The asset value and unit cost for that network level are obtained by dividing the annuitised cost of purchasing and installing the assets in the network model by this exit flow at time of system simultaneous maximum load.

[network level assets £/kW] = [assets £]/[modelled exit flow at time of system simultaneous maximum load kW]

[network level £/kW/year] = [network level assets £/kW]*[annuity factor]

124. The modelled exit flow at peak time is obtained by combining the 500 MW at GSP sizing assumption, the diversity allowance between GSP and GSP Group, and the loss adjustment factor for the relevant network level.

Allocation of other expenditure

125. Estimated load at each network level is calculated from:

(a) volume forecasts for each tariff;

(b) the loss adjustment factors representative of the time of system simultaneous maximum load;

(c) the load characteristics for users on each tariff, used to estimate the contribution of each user category to load at the time of system simultaneous maximum load.

126. For the purposes of this calculation, a generation user is taken to make a zero contribution to load at the network level corresponding to circuits at the voltage of the boundary point, and a full negative contribution to load at all network levels above the voltage of the boundary point. For demand users, account is taken of differences

between the diversity allowance in the network model and the diversity of each customer group in order to ensure that the estimated load matches the volumes subject to charges in respect of each network level.

127. For each network level covered by the network model, a notional asset value is calculated by multiplying the unit asset cost by the estimated load:

[notional asset value £] = [network level assets £/kW]*[estimated load kW]

128. For each service model, a notional asset value is calculated by multiplying the unit asset value of that service model by the extent to which each user requires that model.

129. Other expenditure (excluding transmission exit charges) is allocated between network levels in the proportion given by these notional assets.

130. The result is combined with forecast transmission exit charges to give an annual expenditure figure for each network level and for each service model. These figures are converted into unit cost using the same rules as for costs and revenues from network assets and customer assets.

131. These rules give effect to the policy outlined above of allocating all other expenditure in line with gross asset values.

Allocation of costs on the basis of contribution to system simultaneous maximum load

132. All £/kW/year unit costs and revenue are used in the calculation of yardstick charges for each tariff.

133. For demand tariffs and portfolio tariffs related to demand users with a single unit rate, the contributions of each network level to the unit rate are calculated as follows:

[p/kWh from network model assets] = 100*[network level £/kW/year]*[user loss factor]/[network level loss factor]*[coincidence factor]/[load factor]*(1 – [contribution proportion])/[days in charging year]/24

[p/kWh from operations] = 100*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]*[coincidence factor]/[load factor]/[days in charging year]/24

134. These calculations are repeated for each network level.

135. In this equation, the user loss factor is the loss adjustment factor to transmission for the network level at which the user is supplied, and the network level loss factor is the loss adjustment factor to transmission for the network level for which costs are being attributed.

136. For generation users and portfolio tariffs for generation users, no contribution to the unit rate is calculated in respect of the network level corresponding to circuits at the voltage of supply, and a negative contribution to the unit rate (i.e. a credit) comes from each network level above the voltage of supply. That contribution is calculated as follows:

[p/kWh from network model assets] = –100*[network level £/kW/year]*[user loss factor]/[network level loss factor]*(1 – [contribution proportion])/[days in year]/24

[p/kWh from operations] = –100*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]/[days in year]/24

137. For tariffs with several unit rates, the same principle is used but the ratio of the coincidence factor to the load factor is replaced with a coefficient calculated by the following procedure:

(a) Calculate the ratio of coincidence factor to load factor that would apply if units were uniformly spread within each time band, based on the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band and the assumption that the time of system simultaneous maximum load is certain to be in the red distribution time band.

(b) Calculate a correction factor for each user type as the ratio of the coincidence factor to load factor, divided by the result of the calculation above.

(c) For each network level and each unit rate, replace the ratio of the coincidence factor to the load factor in the above formula with the ratio of coincidence factor (to network level asset peak) to load factor that would be apply given peaking probabilities at that network level if units were uniformly spread within each time band, multiplied by the correction factor.

Rationale for the determination of generation credits

138. The method for determining the credits (expressed as negative charges) payable to generators is based on the principles set out at paragraphs 1.51 to 1.53 of Ofgem's 1 October 2008 document:

> 1.51. The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection.
>
> 1.52. The calculation of the charges for HV/LV generation that exports onto the distribution system is explained [above] in accordance with demand charges. The DRM methodology defines the costs incurred or credited to exporting HV and LV distributed generation.
>
> 1.53. It is assumed that the generator will not cause additional reinforcement costs as there will be even dispersion of generation across the network. A generator will offset demand and provide benefits to higher voltage levels by delaying reinforcement. To reflect the benefits a generator provides, a negative sign will be applied to the yardsticks when calculating the generator charges.

139. Ofgem's document of 1 October 2008 proposed a method based on £/kW/year credits for generators, which would be paid by reference to installed capacity or agreed export capacity.

140. In the course of developing the CDCM proposals with Ofgem, Workstream 2 came to the view that the structure of generation credits could be improved. The main issues with capacity-based credits were:

(a) Capacity-based payments would require DNOs to collect and validate information about installed generation capacities. (Using export capacities was not a viable alternative as it would lead to a perverse treatment of reactive power and potential perverse incentives to book unnecessary capacity.)

(b) Capacity-based payments would be open to fraud or gaming, e.g. from generators stating or installing capacity in excess of what they actually use (and therefore in excess of what actually provides benefits to the network).

(c) Capacity-based payments would reward rarely used (e.g. stand-by generators) as much as regularly operating generators, even though the latter provide more benefits to the network.

(d) To apply capacity-based payments, it is necessary to allocate generators into categories and to allot estimated F factors to each category, opening the door to disputes and perverse boundary effects. Responses to the generation consultation highlighted the large approximations that would be involved in using generic estimated F factors.

141. To address these issues, Workstream 2 put forward the alternative of paying generation credits on the basis of units delivered (kWh).

142. Non-intermittent generators can choose when to operate, and brings more benefits to the network if they run at times of high load. To reflect these differences, the DNOs propose to apply a three-rate tariff for generation credits for half hourly settled non-intermittent generation.

143. In the case of intermittent generation (as defined in P2/6), the operator has little control over operating times. Imposing a three-rate tariffs would expose operators to unnecessary financial risks depending on whether they happen to be generating at particular times. The proposal is to apply a single-rate tariff (based on a uniform probability of operations across the year) to intermittent generation.

144. A single-rate tariff is also proposed for non half hourly settled generation, as there is no readily available accurate information about the time at which units are delivered.

Allocation of network costs to standing charges (fixed and capacity)

145. For demand users, other than unmetered users, standing charge factors are used to reduce unit charges and to attribute these costs or revenues to capacity charges (p/kVA/day) or fixed charges (p/day) instead.

146. The standing charge factors for non half hourly settled users are:

(a) 100 per cent for the network level at which the end user is supplied.

(b) Zero for any further network level.

147. The standing charge factors for half hourly settled users at LV Sub and HV Sub are:

(a) 100 per cent for the transformation level at which the supply is made to the end user.

(b) 100 per cent for circuits at the next voltage level.

(c) Zero for any further network level.

148. The standing charge factors for other half hourly settled users are:

(a) 100 per cent for the voltage level of supply of the end user.

(b) 100 per cent for the next transformation level.

(c) 20 per cent for circuits at the next voltage level (including 132kV for HV users to the extent that 132kV/HV transformation is used).

(d) Zero for any further network level.

149. For each tariff, the unit rates are reduced to take account of the allocation of costs to capacity or fixed charges. This is achieved by multiplying the cost element for each relevant network level by (1 – [standing charge factor]).

150. For each demand user type, and for each network level, the unit cost to be attributed to capacity charges or fixed charges in respect of that network level is:

[p/kVA/day from network model assets] = 100*[standing charge factor]*[network level £/kW/year]*[user loss factor]/[network level loss factor]*(1 – [contribution proportion])/[days in year]/(1 + [diversity allowance])*[power factor in network model]

[p/kVA/day from transmission exit or other expenditure] = 100*[standing charge factor]*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]/[days in year]/(1 + [diversity allowance])*[power factor in network model]

151. The power factor in network model parameter is set to 0.95.

152. The diversity allowance for the LV circuit level is defined as the amount by which the aggregate maximum demand load determined for that network level exceeds the estimated demand at the time of system simultaneous maximum load. The aggregate maximum demand is calculated by aggregating agreed import capacities for half hourly settled users and estimated capacities for non half hourly settled user groups.

153. For half hourly settled demand users, except unmetered users, the unit costs calculated by the formula above are allocated to the capacity charge.

154. Otherwise, the unit costs calculated by the formula above are allocated to the fixed charge.

155. For domestic users in profile classes 1 and 2, and for small business users in profile classes 3 and 4, LV costs are allocated to the fixed charge by estimating the proportion of LV network capacity used by these categories of users, and dividing the corresponding proportion of LV costs by the number of domestic and small business MPANs. Related MPANs are excluded from this calculation and are not subject to the resulting fixed charge.

156. For non half hourly settled demand users, except unmetered users, the relevant unit costs in p/kVA/day are converted to a fixed charge by multiplying them by the

estimated maximum load per user of the user category (obtained from the volume forecast and load factor data) divided by the power factor in the network model.

157. This part of the methodology has the following effects:

(a) Capacity charges for half hourly settled demand users (except substation users) are set on the basis of costs at the voltage of supply, the next transformation level and 20 per cent of circuit costs at the next voltage. The 20 per cent figure reflects an estimate of the costs attributable to feeders into the substation.

(b) For substation users, the costs driven by agreed capacity are taken to be 100 per cent of the costs of transformation and 100 per cent of the next network level, but none of the next transformation level (where diversification means that the costs are more appropriately charged through unit rates).

(c) Fixed charges for non half hourly settled demand user include an element related to circuits at the voltage level of supply is added to the fixed charge. This element is calculated on the basis of average capacity used by non half hourly users.

(d) For smaller users (domestic and small business), the fixed charge associated with LV circuits is allocated uniformly across all MPANs (except related MPANs) rather than on the basis of estimated capacity used. This approach reflects the fact that for these users the main driver of cost is the need to have LV mains passing the road in which the customers are.

Costs associated with LV customer and HV customer levels

158. Other expenditure allocated to the LV customer and HV customer network levels are included in the fixed charge for each tariff where there is such a tariff component.

159. In the case of unmetered supplies, these charges are spread across all units.

160. This part of the allocation is driven by service model asset costs.

Costs associated with reactive power flows

161. For each tariff and each network level, the contribution to reactive power unit charges is obtained as follows:

(a) Calculate what the contribution to a single unrestricted unit rate in p/kWh from each network level would be.

(b) Take the absolute value.

(c) Adjust for standing charge factors at the relevant network levels (for demand users only).

(d) Multiply by the assumed power factor in the network model.

(e) Multiply by the licensee's estimate of the average ratio of the reactive power flow (kVAr) to network load (kVA) at the relevant network level.

162. For the purpose of the calculation of reactive power unit charges, generation users are taken to make a full contribution to the reactive power flows in the network at their voltage of supply and at each network level above their voltage of supply.

163. Ofgem's documents proposed a banded method for reactive power unit charges. The p/kVArh charging rate would have depended on each user's power factor in each half hour.

164. The DNOs identified that this approach could be improved. They identified the following concerns:

(a) It would lead to a significant increase in complexity for tariff publication and billing.

(b) The costs recovered through the p/kVArh rate are those on the network, away from the local assets which are deemed to be sized by reference to capacity (the costs of reactive power transportation incurred on the latter type of assets are recovered through the p/kVA/day capacity charge), and these costs depend on the power factor of the relevant shared network assets, not on the power factors of individual end users.

165. To address these issues, the DNOs proposed to use power factors in the network as the basis for calculating reactive power unit charges. This gives a single p/kVArh rate for each tariff.

Revenue matching

Step 3: Match revenues

166. The licensee uses its volume forecasts to estimate the revenues that would be raised by applying the tariff components derived from step 2, excluding any revenues treated as excluded revenue under the price control licence conditions.

167. If any separate charging methodology is used alongside the CDCM, e.g. for EHV users, then the forecast revenues from these charges, excluding any revenues treated as excluded revenue under the price control licence conditions, are added to the total.

168. If the forecast of allowed revenue exceeds the estimate of relevant revenues, then the difference is a shortfall. If the estimate of relevant revenues exceeds the forecast of allowed revenue, then the difference is a surplus.

169. To allocate any shortfall or surplus, the licensee calculates the effect on demand tariffs and on forecast revenues from these tariffs of adding £1/kW/year (relative to system simultaneous maximum load) to costs at the transmission exit level.

170. Using on this estimate, the licensee determines a single adder figure in £/kW/year such that adding that amount to costs at the transmission exit level would eliminate the shortfall or surplus. The single adder is positive if there is a shortfall and negative if there is a surplus.

171. If this procedure would result in negative value for any tariff component, then the tariff component is set to zero and the single adder figure is modified to the extent necessary to match forecast and target revenue.

172. The final tariffs for demand (before rounding and application of LDNO discounts) are determined on the basis of an allocation with the single adder included in costs. Tariffs for generation do not have any revenue matching element.

173. The 12 June 2009 consultation had proposed a method for revenue matching based on scaling the annuity elements of the charges (or, equivalently, scaling the assets in all 500 MW and service models).

174. As part of the changes to the methodology in July 2009, we considered a number of fixed adder options.

175. Ofgem suggested that an important feature of the revenue matching method is that it should preserve differentials in tariffs between voltage levels. Ofgem also indicated that capping of tariff components to zero (to avoid perverse negative prices) was one an option.

176. The chosen revenue matching method is a single £/kW/year fixed adder allocated to tariff components in the same way as a transmission exit charges, only applied to demand tariffs, and subject to capping to zero to avoid negative tariff components.

177. This choice is designed to preserve differentials. Because the fixed adder is at the transmission exit level (i.e. applicable equally to all tariffs) the differentials are modified only to the extent of differences in coincidence, load or loss adjustment factors between tariffs.

Cost allocation for LDNO tariffs

178. Step 4 involves calculations based on price control and expenditure data which produce a series of discount percentages to be used to determine portfolio tariffs for embedded networks.

179. The methodology is based on WPD UoS 012 and is very similar to the cost allocation used in SSEPD's interim LDNO charging methodology. Both these modifications were the subject of non-veto decisions from Ofgem.[14]

180. For the purposes of price control disaggregation the network is split into four levels: LV, HV/LV, HV and EHV.

181. The determination of discount percentages involves the following steps:

(a) Allocation of price control revenue elements to network levels.

(b) Determination of a percentage allocation of total revenue per unit to network levels.

(c) Determination of the proportion of the LV network deemed to be used by LV-connected embedded networks.

(d) Determination of the proportion of the HV network deemed to be provided by HV-connected embedded networks with HV end users.

(e) Calculation of the discount percentage for each combination of boundary network level and end user network level.

(f) Application of discount percentages to determine portfolio tariffs.

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[14] WPD's modification proposal (9 April 2009), SSEPD's modification proposal (27 July 2009) and Ofgem's decisions (9 June 2009 and 12 August 2009) are available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/.

Allocation of price control revenue elements to network levels

182. The calculation of percentage allocations of price control revenues to network levels is based on separate percentages by network level for the operating cost, depreciation and return on RAV elements of the licensee’s allowed revenue.

183. In order to determine the allocation to network levels of each element of price control revenue, the licensee uses the costs allocation drivers calculated from the following sources:

(a) 2007/08 RRP data on units distributed and operating expenditure broken down by network level.

(b) FBPQ data on elements of capital expenditure and customer contributions for the period 2005/06–2014/15, broken down by network level.

(c) FBPQ data on gross modern equivalent asset values (replacement costs) for various asset types.

184. Data from the RRP are used to distinguish between direct and indirect costs, with direct costs coded by network level. For the purpose of this calculation, capital expenditure are included, net of customer contributions, but negative figures are replaced with zero. This analysis provides direct costs percentage for each network level, based on RRP data. The direct cost percentage for LV is denoted [LV direct proportion] and the direct cost percentage for HV is denoted [HV direct proportion].

185. Indirect operating costs are allocated to network levels on the basis of an estimate of MEAV by network level. The operating cost percentage for each level is a weighted average of the direct and indirect percentages. Estimated gross modern equivalent asset values used for this purpose are derived from asset counts and unit costs from the FBPQ wherever available.

186. Transmission exit charges are allocated to the EHV network level.

187. Both the depreciation and return on capital elements of allowed revenue are allocated to network levels on the basis of net capital expenditure data derived from the FBPQ. All figures are aggregated over the 10-year period from 2005/2006 to 2014/2015, taking in actual data or forecasts for each year as available.

188. For each network level, the relevant net capital expenditure is calculated by adding up total condition based replacement (proactive and reactive) replacement, combined in the case of LV, HV and EHV with connections spend minus customer contributions for connections at that voltage level, general reinforcement capital expenditure at that voltage level, and fault reinforcement capital expenditure at that voltage level.

189. Some of these categories allow HV substation and transformer costs to be identified. These costs (and no other costs) are allocated to the HV/LV network level.

190. Some of the expenditure categories do not separately identify HV substation/transformer costs. For these categories costs are allocated to the HV/LV in the same proportion as for the other categories (where these costs are separately identified).

191. Generation-related capital expenditure is not included in the net capex attributable to each network level.

Determination of a percentage allocation of total revenue per unit to network levels

192. The percentage allocation of costs to network levels is determined as a weighted average of the percentage allocation for each of the elements of price control revenue, rescaled by units flowing.

193. The licensee determines a breakdown of price control allowed revenue over the period from 2005/2006 to 2009/2010 between operating expenditure, depreciation and return on regulatory asset value (RAV).

194. For the purpose of hat calculation, allowed revenue is adjusted by deducting the net amount earned or lost by the licensee under price control financial incentive schemes.

195. These allocations of the operating expenditure, depreciation and return elements of allowed revenue are combined using weights from the price control breakdown.

196. The weighted average allocations are then rescaled by the estimated number of units flowing through each network level, and normalised so that they sum to 100 per cent. The result of this calculation is a set of percentages for each of the LV, HV/LV, HV and EHV network levels.

LV split

197. The licensee determines the proportion of the LV network which LV-connected embedded networks are deemed to use by:

   (a) determining the total length of its LV mains used by LV-connected licensed embedded networks;

   (b) dividing that total length by the number of end users on LV-connected licensed embedded networks; and

   (c) dividing the result by the average length of LV network by LV end user on the licensee's own LV network.

198. The result of this calculation is denoted [LV split].

HV split

199. The licensee estimates the proportion of the HV network which is provided by the DNO in the case of HV loads supplied through an HV-connected LDNO. This estimate may be based on proxy data, e.g. from HV network lengths on unlicensed networks.

200. The proportion is denoted [HV split].

Calculation of discount percentages

201. The discount percentages are determined as follows.

202. For embedded networks with an LV boundary, the discount is equal to:

[LV: LV discount] = [LV allocation]*(1 – [LV split]*[LV direct proportion]).

203. The effect of this formula is to charge the LDNO for the LV element of the cost only to the combined extent that the LDNO is deemed to use the LV network and that these costs are considered to be direct. The indirect part of the costs is fully discounted from LDNO tariffs irrespective of the LV split.

204. For embedded networks with an HV boundary, three percentage discount figures are used.

205. The percentage discount applicable to tariffs for LV network end users is:

[HV: LV discount] = [LV allocation] + [HV/LV allocation].

206. This calculation the fact that the LDNO should not be charged for costs associated with the HV/LV transformation level or the LV level. No reduction in charge is made in respect of the HV level since the usual network configuration for an embedded network with an HV boundary and LV customers is that the DNO's HV network extends all the way to the LDNO's HV/LV substation.

207. The percentage discount applicable to tariffs for LV substation end users is:

[HV: LV Sub discount] = [HV/LV allocation]/(1 – [LV allocation]).

208. The denominator in this calculation reflects the fact that the all-the-way tariff does not include costs associated with LV. The numerator reflects the fact that the LDNO should not be charged for costs associated with the HV/LV transformation level.

209. The percentage discount applicable to tariffs for HV end users is:

[HV: HV discount] = [HV allocation]*(1 – [HV split]*[HV direct proportion])/
(1 – [LV allocation] – [HV/LV allocation])

210. This allocation based on a split between direct and indirect elements of costs is similar to the method used for the LV: LV discount.

Application of discount percentages to determine portfolio tariffs

211. The discount percentages are applied to all tariff components in all-the-way tariffs in order to determine embedded network portfolio tariffs.

How our proposals meet the objectives and requirements

212. This section highlights how our proposals meet the objectives and requirements specified in condition 50 of the standard distribution licence conditions.[15]

First relevant objective

> 50.6 The first Relevant Objective is that compliance with the CDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

213. The proposed methodology enables each licensee to levy charges that are compliant with its allowed revenue under the price control, enabling it to finance its activities.

[15] "Collective Licence Modification intended to deliver the electricity distribution structure of charges project at lower voltages", 8 May 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.

The methodology is designed to reflect some of the costs incurred in operating the network, thereby encouraging appropriate customer behaviour and facilitating the discharge by the licensee of its duties to plan and operate an efficient network.

Second relevant objective

> 50.7 The second Relevant Objective is that compliance with the CDCM facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector.

214. The methodology facilitates new entry into supply by introducing a simple tariff structure that is common across all 14 licensees, and by standardising tariff application.

215. The methodology facilitates new entry into distributed generation (and the associated energy trading or aggregation services) by providing for the payment of credits to reflect the benefits to distribution networks of distributed generation, and by ensuring simplicity and commonality in the application of these credits.

216. The methodology addresses a potential risk of distortion to competition in the distribution of electricity by introducing portfolio tariffs for LDNOs.

Third relevant objective

> 50.8 The third Relevant Objective is that compliance with the CDCM results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business.

217. The methodology sets charges on the basis of costs incurred, or reasonably expected to be incurred, by the licensee in its Distribution Business, and is designed to allocate these costs in a way consistent with Ofgem's guidance on these issues.

Fourth relevant objective

> 50.9 The fourth Relevant Objective is that, so far as is consistent with paragraphs 50.6 to 50.8, the CDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

218. Whilst the introduction of a common methodology inevitably introduces a degree of rigidity, our proposals for governance ensure that, where appropriate, developments in the distribution businesses will be able to be reflected in modification proposals submitted to Ofgem for decision.

Paragraphs 50.12 to 50.17

219. Condition 50 also specifies six requirements for the development of the CDCM.

> 50.12 The first requirement is that the CDCM must be developed by the licensee in conjunction with every other Distribution Services Provider.

220. The seven DNO groups worked closely together in developing these proposals, through the CMG and its workgroups.

50.13 The second requirement is that the CDCM must be able to be given effect by the licensee by not later than the Implementation Date.

221. In parallel with developing the methodology, each DNO has been assessing the potential impact on its business and systems. A few areas of risk are identified in appendix E, and in some cases a derogation from Ofgem might be necessary to achieve full compliance. Subject to that, the DNOs are confident that they can implement the proposals by 1 April 2010.

50.14 The third requirement is that the CDCM must conform to such requirements as have been specified by the Authority for the purposes of this condition in a decision given on 1 October 2008, as subsequently clarified and amended by the Authority on 20 March 2009, with respect to the fundamental principles and assumptions on which the development of the CDCM is to be based.

222. As noted in multiple places in this document, the Ofgem documents of 1 October 2008 and 20 March 2009 were used as the source of the fundamental principles and assumptions on which the CDCM in its proposed form is based.

50.15 The fourth requirement is that the CDCM must be submitted by not later than 1 September 2009 for approval by the Authority.

223. See appendix B.

50.16 The fifth requirement is that a full set of illustrative Use of System Charges for the Regulatory Year 2009/10 which would have resulted from the licensee's compliance with the CDCM if it had been in force under this licence at 1 April 2009 must be submitted to the Authority by not later than 1 September 2009.

224. See appendix C.

50.17 The sixth requirement is that during the development of the CDCM and before submitting it to the Authority in accordance with the fourth requirement, the licensee must have taken all reasonable steps (including, where appropriate, approaching the Authority to discuss how the licensee proposes to address any unforeseen charging implications of the CDCM) to ensure that the CDCM in the form in which it is being developed will be capable of being approved by the Authority in accordance with the requirements of Part B of this condition.

225. This requirement was satisfied through continuous engagement with Ofgem throughout the process, using both Ofgem staff's participation in CMG, workgroups and the Ofgem-facilitated IDNO/DNO working group, as well as ad hoc meetings and correspondence where required.

Impact on tariffs

226. Each licensee has populated a model implementing the CDCM with an illustrative estimate of what the inputs would have been if the CDCM had been implemented in respect of the charging year 2009/2010. These models are published on the ENA website at http://2009.energynetworks.org/structure-of-charges/.

227. Appendix C provides these illustrative results, including an estimate of the impact of the CDCM compared to current tariffs. Appendix D is a commentary prepared by each licensee on the most significant price disturbances.

Areas of risk

228. Appendix E provides a commentary from each DNO on areas of risk in relation to billing system modifications to permit the implementation of the methodology.

Areas for further development

229. This section outlines the DNOs' plans for further development of aspects of the CDCM.

Portfolio billing for embedded networks

230. Portfolio billing requires new data flows, new data management systems and governance for these systems.

231. The DNOs launched a consultation on a proposed data management arrangement and code of practice on 7 August 2009. This draft was developed by a working group open to representatives of suppliers, embedded networks operators, DNOs and Ofgem. The consultation period runs until 18 September 2009.[16]

232. Major risks in this area related to funding and delivery arrangements, both for the IT development and data processing required to manage the new data flows, and in respect of boundary metering. Funding is an issue for the Ofgem-facilitated IDNO/DNO charging steering group. Ofgem has indicated that it intends to consult boundary metering issues.[17]

De-linking

233. Substantial implementation issues were identified as part of the DNOs' consultation on de-linking the application of unit rates from the suppliers' standard settlement configurations (SSC) and time pattern regimes (TPR). This issue was therefore postponed for further consideration after 1 September 2009.

234. The main benefit of de-linking would be to enable cost-reflective charges to be applied to new standard settlement configurations that might be introduced by suppliers in the future, without the need for manual intervention by the DNOs or for a modification to the use of system charging statements. This would facilitate the introduction of new metering arrangements in the non half hourly market, in particular the use of smart metering.

Mitigation of tariff volatility

235. Some consultation responses suggested that more of the input data to the cost allocation methodology, for example coincidence factors, should be fixed for a period of more than one year.

236. This could help reduce the volatility of tariffs and the risks borne by suppliers as a result.

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[16] The LDNO billing consultation document and a draft code of practice are available from http://2009.energynetworks.org/structure-of-charges/.

[17] "Distribution Network Operator (DNO) and Independent Distribution Network Operator (IDNO) Charging Steering Group Minutes dated 14 July 2009", published 28 July 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/.

237. We ask Ofgem to consider this suggestion.

Long-term products

238. Ofgem's 1 October 2008 document stated that:

> 1.29. For these reasons, and as a minimum ahead of April 2010, we will require DNOs to publish their charging models on their websites and publish annually long term tariff scenarios to help customers understand the range of future charges. By April 2011 DNOs will have to develop and bring forward proposals for longer term products that would offer generators and customers the choice of fixing their network charges in return for making a long term commitment to pay them, to help customers manage the risk of charging volatility. We would also expect DNOs to consider developing more sophisticated web based tools to help customers to understand and model their future charges. We will consider in due course whether to formalise this in conditions as part of the approval of the common methodology.
>
> 3.13. As set out in Chapter 1, DNOs are required to develop longer term charging products in order to address any concerns consumers may have with annual volatility of distribution charges, particularly at EHV level.
>
> 5.6. […] In parallel, DNOs will work collectively or individually as they choose, to develop a range of tools and products to assist customers to better predict and manage the volatility associated with the charging methodology as discussed in Chapters 1 and 3.

239. These issues are on Workstream 3's agenda for the period after 1 September 2009.

Glossary

Term	*Explanation*
All-the-way tariff	A tariff applicable to an end user rather than an embedded licensed distribution network.
Boundary tariff	A tariff for use of the network by another licensed distribution network operator where charges are based on boundary flows.
CDCM	The common distribution charging methodology.
Charging year	The financial year (12 month period ending on a 31st March) for which charges and credits are being calculated.
Coincidence factor	For a user category, aggregate load at the time of the licensee's system simultaneous maximum load divided by maximum aggregate load.
Contribution proportion	The proportion of asset annuities which are deemed covered by customer contributions. This is defined for each combination of a tariff and a network level.
Customer contribution	Capital charges payable by customers under the licensee's connection charging policy.

Term	*Explanation*
DCUSA	The Distribution Connection and Use of System Agreement.
Diversity allowance	The extent, expressed as a percentage, to which the sum of the maximum load across all assets in the modelled network level is expected to exceed the simultaneous maximum load for the network level as a whole.
DRM	Distribution reinforcement model. This may refer either to a 500 MW network model or to a cost allocation method based on such a model.
EHV	In this document, EHV refers to nominal voltages of at least 22kV and less than 132kV; network elements with a nominal voltage of 132kV are excluded from EHV for the purpose of this document.
Embedded network	An embedded distribution network operated by an LDNO.
FBPQ	Forecast business plan questionnaire, a dataset produced by each regional distribution network operator for Ofgem as part of the price control review.
GSP	Grid supply point: where the distribution network is connected to a transmission network.
HV	Nominal voltages of at least 1kV and less than 22kV.
kV	Kilovolt (1,000 Volts): a unit of voltage.
kVA	Kilo Volt Ampere: a unit of network capacity.
kVAr	Kilo Volt Ampere reactive: a unit of reactive power flow. The network capacity used by a flow of A kW and B kVAr is SQRT(A^2+B^2) kVA.
kVArh	Kilo Volt Ampere reactive hour: a unit of total reactive power flow over a period of time. Reactive power meters usually register kVArh.
kW	Kilowatt (1,000 Watts): a unit of power flow.
kWh	Kilowatt hour: a unit of energy. Meters usually register kWh.
LDNO	Licensed distribution network operator. This refers to an independent distribution network operator (IDNO) or to an distribution network operator (DNO) operating embedded distribution network outside its distribution service area.
Licensee	The distribution network operator using this methodology to set use of system charges for its network.
Load factor	For a user category, average load divided by maximum aggregate load.

Term	*Explanation*
LV	Nominal voltages of less than 1kV.
MVA	Mega Volt Ampere (1,000 kVA): a unit of network capacity.
MW	Megawatt (1,000 kW): a unit of power flow.
MWh	Megawatt hour (1,000 kWh): a unit of energy. Energy trading is usually conducted in MWh.
Network level	The network is modelled as a stack of circuit and transformation levels between supplies at LV and the transmission network. A network level is any circuit or transformation level in that stack. Additional network levels are used for transmission exit and for LV and HV customer assets.
Network model	A costed design for a 500 MW extension to the licensee’s distribution system.
Ofgem’s 1 October 2008 document	“Delivering the electricity distribution structure of charges project”, Ofgem, 1 October 2008, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.
Ofgem’s 20 March 2009 document	“Next steps in delivering the electricity distribution structure of charges project”, Ofgem, 20 March 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.
Power factor	The ratio of energy transported (kW) to network capacity used (kVA).
Portfolio tariff	A tariff for use of the network by another licensed distribution network operator where charges are based on flows out of/into the other licensed distribution network from its end users or further nested networks.
Related MPAN	Two or more metering points that supply the same customer and are located at the same (or are part of the same) premises. In the context of the CDCM, related MPANs mean the secondary tariff which has to be taken together with another (master) tariff.
RRP	Regulatory reporting pack, a dataset produced each year by each regional distribution network operator for Ofgem.
Service model	A costed design for the typical dedicated assets of a category of network users.
Settlement period	One of 46, 48 or 50 consecutive periods of a half hour starting at 0:00 UK clock time on each day.
Standard distribution licence conditions	The standard conditions of the electricity distribution licence that have effect under section 8A of the Electricity Act 1989 (introduced by section 33 of the Utilities Act 2000).

Term	*Explanation*
Standing charge	Any fixed or capacity charge that does not depend on actual use of the network.
System simultaneous maximum load	The maximum load for the GSP Group as a whole.
Time pattern regime	An identifier for meter registers for non half hourly settled users.
Unit	Where the context permits, the word unit refers to kWh.
Unit rate	A charging or payment rate based on units distributed or units generated. Unit rates are expressed in p/kWh. Tariffs applied to multi-rate meters and/or using several time bands for charging have several unit rates.